Geopressed Energy Availability

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ABSTRACT

The objective of this work was to investigate near- and long-term prospects that geopressured/geothermal energy sources could become a viable alternative fuel for electric power generation. The work focused on technical questions of producibility and power generation, as well as economic and environmental considerations. The investigators relied heavily on the existing body of information, particularly in geotechnical areas. Statistical methods were used where possible to establish probable production values.

Potentially productive geopressured sediments have been identified in twenty specific on-shore fairways in Louisiana and Texas. A total of 232 trillion cubic feet (TCF) of dissolved methane and 367×10^{15} BTU (367 quads) of thermal energy may be contained in the water within the sandstone in these formations. Reasonable predictions of the significant reservoir parameters indicate that a maximum of 7.6 TCF methane and 12.6 quads of thermal energy may be producible from

these potential reservoirs. Natural gas costs from geopressured production facilities will apparently range upward of \$5/thousand cubic feet (MCF), for the most favorable reservoirs and most optimistic conditions, assuming high values of dissolved methane. The most serious uncertainties in the production of the geopressured resource at the present time are (1) the single-well drainage volume (size of continuous reservoirs) and (2) the actual amount of gas in solution in specific reservoir areas.

Hydraulic turbines can be used to generate a small amount of low-cost electric power. The geothermal energy can also be converted by small wellhead generators, but such power would be economically marginal.

Spent brine disposal in shallow saline aquifers is currently feasible, with costs in the range of 8 to 10 cents/bbl or more. Reinjection into the deep production reservoirs is not a viable technique at the present time.

EPRI PERSPECTIVE

PROJECT DESCRIPTION

This final report for Research Project 1272-1 contains the results of a study undertaken to determine the potential for recovering and converting geopressed geothermal energy to electricity. The scope of the project included only the Texas and Louisiana Gulf Coast geopressed region and addressed the issues of energy-in-place, recoverable energy, electricity generation, waste brine disposal and economics. The study relied primarily on the existing body of data in the geotechnical areas and made use of statistical analyses where practical to estimate likely production potentials. The significance of this report is that it provides insight into the availability of geopressed resources suitable for commercial development and gives some idea of the cost associated with this energy type.

PROJECT OBJECTIVE

The objective of the project was to examine available data and prior work and to translate this information into production potential and cost of energy. Special attention was given to producibility, cost, and environmentally related brine disposal issues.

PROJECT RESULTS

In contrast to fairly recent estimates of 3000 TCF of methane in place in geopressed aquifers along the Gulf Coast, this study concludes that geotechnical considerations are likely to limit production from the 20 best known prospects to about 7 TCF of methane. The question is not whether the gas is there, but whether the gas and the thermal energy are sufficiently concentrated so they can be produced in quantities and at costs competitive with alternative energy sources. The production cost for methane was found to range from about \$5.00/MCF and up in today's dollars. This is significantly higher than domestic gas prices and somewhat above imported Canadian and Mexican gas.

The study also concludes that about 13 Quads of low grade thermal energy might be produced along with the 7 TCF of methane. It appears feasible to convert this thermal energy to electricity in competition with other energy sources, providing the thermal energy is essentially free, or very low cost, to the power plant, i.e., if all production costs are assigned to the methane. For this reason it was concluded that the thermal component can have only a minor impact on the competitive posture of geopressed resources in general. The pressure energy can make a small contribution but will not have a significant impact on the overall economics.

If this 7 TCF and 13 Quads of thermal energy together with the associated pressure could be recovered and converted to electricity, it would amount to about 5 GWe for 30 years. This is thought to be an optimistic number since about 80 percent of the energy is located in tight sand formations that may not produce. On the near- and intermediate-term planning horizon it appears that a more reasonable projection would be the equivalent of about one GWe at premium prices.

It is possible, but it does not seem likely, that the 20 sites studied are not representative of the geopressed resource, and certainly they do not represent all of the resource. It should also be noted that conventional technology and interpretation of the data were assumed, and it is possible that advances in the technology and discovery of higher-quality resources might change the outlook. It seems more likely, however, that the geopressure potential is far smaller than once thought, or at least it is further out in the future.

Since actual well test data are still meager, it would seem prudent to continue efforts to better understand the nature and magnitude of the resource and to develop a complete and thorough assessment of its potential. In this context some continuing development is expected over the next few years, primarily in conjunction with resource evaluation on a relatively small scale.

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SUMMARY

Investigation of the Geopressured zones along the Texas and Louisiana coast has identified a total of twenty prospective reservoir areas containing an estimated 1100 cubic miles ($4.58 \times 10^{12} \text{ m}^3$) of sandstone with 5,900 billion barrels of entrained water. The energy content consists of a maximum of 232 trillion cubic feet (TCF) of dissolved methane, and 367×10^{15} BTU (367 quads) of thermal energy. On the basis of reasonable average values for the significant reservoir parameters, the maximum estimated recoverable resource in these prospects is 7.6 TCF methane, 12.6 quads thermal, and hydraulic energy representing less than 2% of the total. More than 80% of the identified resource is contained in a single area (Harris Wilcox fairway, Texas), which has poor probability of production success.

Advanced reservoir modeling indicates the natural gas released from solution deep in the reservoir as the pressure is depleted will have no significant effect on the production of gas. The methane produced will only depend upon the initial saturation, and the pressure and temperature gradients to the surface separators.

Investigation of energy utilization methods indicates that single-well development for production of dissolved methane is the most profitable development approach at this time. Because of the low enthalpy of the brine, geothermal power generation is not a highly significant factor. A single well in the most favorable geopressured prospect yet identified (S.E. Pecan Island, LA) has only a 10% probability of producing as much as 40,000 bbl of 300°F water per day for 20 years. A well in that field with optimistic parameters could supply pipeline-quality natural gas for \$5.14/MCF. Electric power could also be generated by a wellhead binary-cycle electric generator for 43 mills/kwh, assuming the methane production carries the cost of production wells and disposal. A high-pressure hydraulic turbine could supply electricity for 9.4 mills/kwh, and a low-pressure hydraulic turbine for 8 mills/kwh, in addition. Combined power capability of this installation would amount to a maximum of 1.6 MW(e) (net) from the thermal plant, and 1.5 MW(e) from the hydraulic turbines. In twenty years, the well would produce a maximum of 10 billion cubic feet of methane.

Other favorable prospects investigated include the Brazoria, Texas fairway, site of a DOE well currently under test. Methane can be delivered from a well in this area at an estimated \$7.50/MCF.

The Johnson's Bayou prospect, a relatively shallow, high-quality reservoir on the Louisiana-Texas border, should be able to produce methane from a single-well production facility for \$7.30/MCF. All these estimates are based on high values of dissolved methane. Significant differences in the methane in solution would have a profound effect upon the cost of production; for example, if the Brazoria, Texas well produces only 20 SCF methane/bbl, costs will rise to nearly \$15/MCF. On the other hand, possible "free gas" (supersaturation), would improve the economics although the prospect of any significant or general occurrence of free gas in geopressured sands is remote.

Development based on multiple-well fields was found to be less promising. A twelve-well field designed to drain the S.E. Pecan Island reservoir in conjunction with an integrated geothermal-methane fuel plant showed improved electricity generation costs over the single-well case, but significantly greater cost of the natural gas. This development showed an estimated methane cost of \$9.46/MCF, power generation costs from a 7.1 MW(e) (net) flashed steam electric plant of 20.9 mills/KWH, power costs from a high pressure hydraulic turbine [6.97 MW(e) net] of 9.3 mills/KWH, and from a low-pressure hydraulic turbine [1.5 MW(e) net] of 5 mills/KWH.

Spent brine disposal in shallow saline aquifers was found to be the most feasible disposal technique. Historically, costs of similar disposal projects were found to range from 3.6¢ to 5¢/bbl. Under current conditions, it is estimated that this cost will be 8¢ to 10¢/bbl, or more. Reinjection into the production reservoir is not a viable technique at the present time. The high pumping energy requirements make the energetics of the overall process unfavorable, and extremely high costs result from the multiple deep wells and high pressure pumps required.

Pipeline natural gas costs from geopressured production facilities will probably range upward of \$5/MCF for the most favorable reservoirs and optimistic conditions, assuming dissolved methane in the range of 35 to 40 SCF/bbl. Lower or higher values of dissolved methane will have a profound effect on the economics of the process.

Single-well geopressured development offers a more favorable prospect than does multiple-well field development with an integrated geothermal plant. Even the largest-known geopressured prospects will be

capable of producing a relatively insignificant amount of geothermally generated electric power.

Hydraulic turbines to exploit the high pressure flow can be easily implemented to provide a small amount of low-cost power, but the sizing of such units must take into account the constantly declining available energy.

Disposal in shallow saline aquifers is feasible and offers the best prospect for spent brine disposal in most geopressured areas. Re injection into the production reservoirs is not a viable undertaking at the present time.

Direct use of the heat contained in the brine appears to offer promise. On a value/BTU basis, industrial use of the heat increases the value of the brine because of the very low conversion efficiency of a geothermal electric plant using a 300°F (150°C) source. However, great difficulty can be anticipated in load equalization and the location of plants near the site of brine production.

The most serious uncertainties in the production of the geopressured resource at the present time are (1) the single-well drainage volume (size of continuous reservoirs), and (2) the actual amount of gas in solution in specific reservoir areas.

I. INTRODUCTION

Large areas of the northern Gulf of Mexico basin contain sediments under abnormally high pressure and elevated temperature. The potential energy contained within these sediments consists of hot, moderately saline brine which may contain near-saturation quantities of dissolved methane. The abnormally high pressures existing within these zones promise production wells capable of flowing without pumping, producing thermal, chemical and hydraulic energy.

Various estimates of the energy contained within these Gulf Coast geopressured sediments, both on and off-shore, range as high as 1.6×10^{20} BTU (160,000 quads), including the energy in both sandstones and shales. Such extremely high estimates indicate that this region is potentially one of the largest alternative energy sources in the United States, if an appreciable fraction of the contained energy can be recovered.

For more than thirty years geopressure has been under study by the petroleum industry. Many gas fields

produce from conventional natural gas reservoirs within the geopressured zone and data are available as a result of more than 300,000 wells drilled in the Gulf Coast over the past fifty years. During the past five years, intensive detailed examination of geopressured zones as an alternative energy source has been underway, mainly under the impetus of the Federal energy research program. As a result of this research, a total of twenty prospective reservoir sites has been identified in on-shore areas of Louisiana and Texas. Considerable information about these potential reservoirs exists; nevertheless, there are serious uncertainties and a number of critical unknowns involved in their proper assessment. The purpose of this report is to summarize the results of the research to date. Where significant questions have arisen in the assessment of these results, effort has been made to illuminate the uncertainties by acquisition of new data, by reservoir modeling and by other means. In light of present and anticipated near-term technology, an attempt has been made to place the usefulness of the energy within this resource in perspective.

II. GEOLOGICAL ASSESSMENT OF GEOPRESSURED ZONES

A. Occurrence of Geopressure

Associated with numerous depositional basins throughout the world are subsurface strata exhibiting abnormally high pressures. Through common usage of the term, these strata have acquired the name "geopressed zones", implying that the contained water is confined at pressures significantly above hydrostatic.

Geopressure is considered to be primarily the result of compaction phenomena associated with rapid deposition of sediments. In geologic basins, the depositional mechanism is one of burial and compaction, as younger sediments are deposited over the old. The weight of the resulting overburden seeks to reduce the thickness of the deeper layers; both the contained water and the particles making up the sediments exhibit low compressibility, and consequently the volume can only be reduced significantly by expulsion of water. The rate of water expulsion is a function of the permeability of surrounding rocks. If none of the water can escape, the stratum becomes abnormally pressured, and the trapped water becomes a structural member of the rock matrix.

Hottman (1966) explains that fluid pressures are directly proportional to the rate of loading, and inver-

sely proportional to the mean fluid permeability of the surrounding rock through which water must move to reduce the loading effect. Thus, in basins that have experienced rapid deposition geopressures can be expected in sand bodies isolated in shale, the permeability of the latter being very low. These sand bodies may be outer neritic, or slope sands, originally isolated in a shale envelope, or they may be sections of sandstone strata which have been isolated by faulting.

B. Geologic Setting of Gulf Coast Geopressure

During Tertiary time, vast quantities of sand and mud were transported across a slowly subsiding Gulf coastal plain and deposited along the shore of the Gulf of Mexico. In periods of marine transgression, the more recent deposits were washed ashore by long-shore currents and worked into a series of sand bars and barrier islands in an environment of which the present Texas coast is thought to be a model. The normal pattern of subsidence was accompanied by periods of high deposition, similar to that occurring in the Mississippi Delta today. The bars and islands were covered by new layers of clastic sediments, while the edge of the basin further subsided under the enormous weight, and large growth

Figure 1. Depositional Style of Tertiary Strata Along the Texas Gulf Coast (Bruce, 1973)

fault systems formed near the down-dip edge of these deposits. This process has been the subject of extensive study as reported, among others, by Athy (1930), Dickinson (1953), O'Connell (1961), Coleman (1967), Burst (1969), and Fertl and Timko (1970). An excellent description of the role of shale in growth faulting is contained in Bruce (1973). The depositional style of the Tertiary strata along the Texas Gulf Coast as described by Bruce is shown in Figure 1.

The general result of this depositional cycle is the accumulation of sediments in the form of wedges which dip and thicken toward the coast. The overall Tertiary trend has been one of Gulfward progradation so that each younger wedge is shifted basinward of the previous one. A typical geological cross-section on the Gulf Coast is shown in Figure 2. A remarkable fact is that the bulk of the sediments of current interest to the study of geopressure, have been deposited during the relatively short span of 30 million years or so. Along the Texas and Louisiana Coast, geopressure is apparently a gen-

eral feature of the deeper sediments, usually occurring at depths near 10,000 to 15,000 feet (3000 to 4500 m).

C. Geopressured Zone as an Energy Resource

1. Elevated Temperatures—Geothermal Energy

The basement structure and early history of the Gulf of Mexico basin is unclear, although Cretaceous rocks presumably underlie the Tertiary strata. A key factor in the geological development of the region appears to be a vast underlying deposit of Jurassic salt (the Louann salt) whose presence has had a profound effect upon the subsurface. Some authors, including Jones (1975), subscribe to the rift theory as the underlying cause of basement weakness that has permitted the heavy buildup of sediments over the depositional center of the basin. This idea is given credence by the apparent requirement for a massive source of localized subsur-

Figure 2. Typical Geological Cross-Section Through the Texas Gulf Coast, From Blanco Through Calhoun Counties. (Oetking and Feray, 1963)

face heat to explain many of the features of the sub-structure, including the plastic flow of enormous quantities of the underlying salt, the development of salt domes, and the elevated temperatures characteristic of the deeper Tertiary sediments. Whatever the cause, a higher-than-normal temperature gradient is characteristic of Gulf Coast geopressured zones. Undoubtedly the insulating properties of the massive, under-compacted geopressured shales play a key role in slowing the normal heat flow from within the earth.

Accurate knowledge of the Gulf Coast sub-surface temperature regime has been obtained through measurements made in literally hundreds of thousands of wells drilled in the exploration for, and production of, petroleum. The temperature gradient varies from approximately 1.4°F/100 feet to 2°F/100 feet (25.6°C/km to 36.5°C/km), increasing from Louisiana into South Texas, with the highest gradients near the Mexican border. It is evident that, from a geothermal energy standpoint, available temperatures are low. The maximum recorded bottom-hole temperature in a Gulf Coast well is reported by Jones to be 525°F (273°C) at a depth of 19,222 feet (5859 m) with an overall temperature gradient of 43°C/km. This represents an upper extreme, however, and is unusual for the region. At a depth of 15,000 feet (4572 m) observed temperatures are seldom higher than 300°F (150°C).

Unfortunately, the highest temperatures are associated with minimum sand deposition. Good reservoir-type sands apparently seldom occur at depths greater than those at which temperatures are 300°F or so. The production of fluids at temperatures much greater than this appears doubtful, with the possible exception of certain very deep areas in Louisiana where the reservoir parameters may still be favorable.

2. Dissolved Methane

There is compelling evidence that some, if not all, the water contained in the geopressured zones contains dissolved methane. Two studies of fundamental importance to this subject are reported by Culberson and McKetta (1951) and by Buckley, Hocott and Taggart (1958). In the latter study, by Buckley et al, extensive investigation of soluble methane in water recovered from exploration wells was reported. Throughout the Gulf Coast area, water samples were found to be nearly saturated with methane. The earlier study, by Culberson and McKetta, established the basis for methane solubility in water as a function of temperature and pressure. Both studies show that methane solubility increases with depth (pressure) and temperature.

O'Sullivan and Smith (1970) have shown, however, that methane solubility decreases with increasing salinity. Nevertheless, under the abnormally high pressures and temperatures of the geopressured zones, significant quantities of methane should be found in solution.

A reproduction of the results given by Culberson and McKetta is shown in Figure 3. It indicates, for example, that at a temperature of 300°F and a reservoir pressure of 10,000 psi, the solubility of methane in distilled water is more than 45 SCF/bbl. Extrapolation from work by Brill and Beggs (1975), however, indicates

Figure 3. Solubility of Methane in Distilled Water (Culberson & McKetta, 1951)

that at a salinity of 100,000 parts/million, under the same reservoir conditions, actual natural gas solubility would be only 35 SCF/bbl. As the temperature decreases to 220°F (104°C), solubility also decreases. A 220°F reservoir with 100,000 ppm TDS at pressure of 10,000 psi would only contain about 20 SCF/bbl natural gas. Consequently, there is a strong motive for exploiting the deeper, hotter reservoirs, even without consideration of thermal energy production: the amount of dissolved gas in the formation water should be considerably higher under the high temperature conditions.

Figure 4 is a histogram prepared from data presented by Buckley et al, for natural gas dissolved in Frio water samples. Buckley measured a parameter which he termed the "escaping pressure", normalizing the effects of temperature and salinity, so that a ratio between this pressure and the hydrostatic pressure yields

Figure 4. Histogram of Relative Natural Gas Saturation in Texas Frio Water Samples (Ratio of Escaping Pressure to Hydrostatic Pressure). Adapted From Buckley, Hocott and Taggart, 1955.

a measure of the actual gas in solution compared to the possible saturation value under well conditions. In Figure 4 it will be noted that the limit for all Buckley's samples is one. No samples were found to be supersaturated, and the solution gas to saturation ratio exhibits a frequency distribution ranging from 60% to 100%, strongly centered on a value of about 80%. Most of Buckley's samples were from nongeopressed Frio sands.

In the first test of a geopressed water sand sponsored by DOE (Edna Delcambre No. 1, Tigre Lagoon Field, LA) laboratory recombination experiments on the reservoir water, yielded a saturation value under reservoir conditions of 24.6 SCF/bbl. Determinations of actual in-place samples, indicate solution gas ranging from 18 to 23 SCF/bbl at the reservoir temperature, pressure, and salinity (Karkalits and Hankins, 1977).

In summary, while there is evidence of dissolved methane in the water in Gulf Coast geopressed zones, its universal presence and extent of saturation remains unproven, although the USGS (Papadopoulos et al, 1975; Wallace et al, 1978), as well as Bebout and oth-

ers, assume that the water is saturated and their assessment of the resource is based on that premise. There is a general consensus among experienced observers in the industry that dissolved methane constitutes a large reserve of natural gas, but estimates of the fraction that may be recoverable vary widely.

3. Hydraulic Energy

Water produced from a well at high pressure and high flow rate represents kinetic (hydraulic) energy. While most experts assess this as a small fraction of the total energy in the fluid, it represents an energy source which can be rather easily exploited.

D. Extent of Geopressure

The study of geopressure has so far been largely restricted to the coastal areas of Louisiana and Texas, including a portion of the continental shelf. Geopressed sediments are also known to exist in the Mississippi basin and numerous other basins throughout the world, but little detailed assessment of the potential of geopressure in those areas has been reported. Herrin (1973) locates the zone of interest along the Gulf Coast as a "belt in the northern Gulf of Mexico basin, about 750 miles long, extending from the Rio Grande of Texas to the Mississippi Sound. It underlies the coastal plain inland 60 to 100 miles and underlies the continental shelf, wherever drilled, upto 150 miles offshore." Jones (1969) in a well-referenced document, maps the location of the geopressed zone along the coastal areas of Texas and Louisiana as shown in Figure 5. A recent USGS document (Wallace et al, 1978) extends the area somewhat, although the Jones map continues to be generally accurate.

E. Aquifer Size

One of the most troublesome questions surrounding geopressure is the number of suitable aquifers within the geopressed zone. In early descriptions of the resource, both Jones and Herrin, as well as Wilson et al, (1974) discussed exploitation of the resource on the basis of large, thick, continuous aquifers of 150 square miles or more in extent. In the first definitive reservoir study of hot-water production from geopressed zones, Parmigiano (1973) established the parameters of an aquifer and production well capable of producing 80,000 bbls per day for 20 years, a production rate which indicated profitable exploitation of the resource. These parameters included a reservoir thickness of 200 feet, and a drainage area of 300 square miles, or a total volume of 11 cubic miles.

Figure 5. Location and Depth of Occurrence of the Geopressed Zone in the Northern Gulf of Mexico Basin (Jones, 1969)

In the 1975 "Assessment of Geothermal Resources of the U.S.", the USGS based an assessment of the geopressed/geothermal resource on 21 on-shore areas, each assumed to contain a continuous, separate reservoir. Bebout (1976) set the minimum size of a suitable aquifer at 50 square miles with a sand thickness of 300 feet (3 cubic miles). The existence of continuous geopressed aquifers this large is open to serious question, with some researchers of the firm opinion that geopressure and large extent are mutually exclusive by their very nature. Two factors are paramount in this question, the depositional character of Tertiary sands and the effect of secondary faulting.

1. Suitable Sand Reservoirs

While geopressure appears to occur generally throughout the Gulf Coast, suitable sands do not. "Sheet sands" of general distribution do occur, but they tend to be thin and infrequent. Thick, productive sand sections are mainly found as remnants of ancient deltas, barrier bars, sand islands and stream beds. As today, such features were common, but by no means

universal. A complicating factor over much of the Gulf Coast is the existence of salt diapirs (domes) which have drastically affected the depositional history and structural details of most of the Louisiana, and a large part of the Texas, subsurface. Certainly large aquifers do not occur with equal frequency over the entire geopressed zone, if for no other reason, because of the lack of suitable reservoir sands.

Some insight into the size of known clean sand bodies has been tabulated by Kuuskraa, et al., (1978) from contemporary literature on depositional characteristics of sands in deltaic facies. These estimates, based on known sands of geologically recent deposition indicate that single sand reservoirs with volume greater than 1 cubic mile are highly unusual. Galveston Island, Texas for example, a large barrier complex with a total volume of 2.27 cubic miles, has an estimated clean, well sorted sand volume of only 0.33 cubic mile. Doscher et al. (1979) point out that the enormous Prudhoe Bay, Alaska oil reservoir, an unusually large sand deposit, contains a total volume of 11 cubic miles, and exhibits normal pressures.

2. Faulting

Geopressed aquifers are believed to be isolated sand bodies surrounded by shale, either through deposition or faulting. The fault system in the Gulf Coast is dominated by the large growth faults which parallel the coast. However, the resulting major fault blocks are cut by innumerable smaller faults, both parallel and transverse. In general, faulting increases in complexity with depth. In the geopressed zone major fault blocks are cut by small "splinter faults", which can be expected to isolate segments of existing reservoirs to an unknown degree. Communication between reservoir segments cut by such faults is an unknown quantity.

Kuuskraa also presents data descriptive of the areal distribution of fault blocks comprising the 31 largest known oil fields in the Gulf of Mexico, and reports only one fault block with an areal extent in excess of 10 square miles, out of a total of 380 examined. Size distribution of these fault blocks is given in Table I.

TABLE I
DISTRIBUTION OF FAULT BLOCK SIZES, GULF OF MEXICO
(Kuuskraa, et al., 1978)

Size Distribution (Mile ²)	Number of Reservoirs	Total Area (Mile ²)	Percentage
0 — 1	292	146	40
1 — 2	56	84	23
2 — 3	15	37	10
3 — 4	7	24	6
4 — 5	1	4	1
5 — 10	8	60	16
10	1	16	4
TOTAL		366	100%

After nearly five years of intensive investigation in both Louisiana and Texas, no geopressed aquifers with areal extent as great as 300 square miles have been identified. If such aquifers exist, their number is simply indeterminate at the present time. Mathews (1976) of the Shell Oil Co. summarizes the skepticism of experienced industry observers as follows: "Although some 300,000 wells have been drilled in the general area of geopressing along the Gulf Coast, we are still unable to specify where we should drill in order to find such a very large, hot, highly productive reservoir . . . finding a well which will produce 80,000 bbls/day naturally from 12,000 feet may be possible, but such wells will not be common".

F. Detailed Geological Investigations

The most comprehensive published work dealing with detailed geological assessment of the geopressed zone has been provided by the Bureau of Economic Geology of the University of Texas at Austin (Bebout, Loucks and Gregory, 1978; Bebout, Gavenda and Gregory, 1978; Loucks, 1978), by Hawkins (1977) and Bernard (1979) of Louisiana State University, and by Durham (1978) of Magma-Gulf. Using separate methods, these groups have performed surveys of Miocene sediments in Louisiana and the Oligocene and Eocene sediments in Texas, comprising the major part of the geopressed zones within the two states.

1. Texas Gulf Coast-Frio/Vicksburg

The three formations of principal interest to geopressure on the Texas Coast are the Frio and Vicksburg formations (Oligocene) and the Wilcox formation (upper Eocene). Bebout and his associates have performed systematic regional surveys of these zones along the Texas coast, based primarily on the study of electric logs. A grid of selected wells at approximately five to ten mile intervals was established, and the major sand bodies within each of the three formations mapped. The principal purpose of this assessment was the identification of major sand bodies within which suitable geopressed reservoirs might exist. The study has concentrated on sands which meet Bebout's original criteria for geopressed aquifers, namely "a volume of at least 3 cubic miles (cumulative sand thickness of greater than 300 feet and areal extent of 50 square miles), greater than 250°F uncorrected subsurface fluid temperature and permeability greater than 20 mD" (Bebout, 1976).

No sand bodies fulfilling all these requirements were reported. A number of relatively large, apparently continuous aquifers were identified, however, and the main sand depocenters in the formations were mapped. The result of the three-year study was the identification of fourteen specific areas which Bebout has named "geothermal fairways". These fairways are located on the map in Figure 6.

a. Hidalgo Fairway (No. 1 in Fig. 6)

The Hidalgo Fairway in extreme south Texas contains massive deltaic sandstones of the Vicksburg and the Frio formations within a five county area including Kenedy, Willacy, Cameron, Hidalgo and Brooks counties. In this area sand deposition has been greatly enhanced by contemporaneous activity along the McAllen fault and the Frio/Vicksburg flexure. The region has been the site of extensive petroleum and natu-

Figure 6. Map of Texas-Louisiana Gulf Coast Showing Geopressured-Geothermal Fairways Under Current or Recent Study

(1) Hidalgo Fairway; (2) Armstrong Fairway; (3) Corpus Christi Fairway; (4) & (5) Matagorda Fairways; (6) Brazoria Fairway; (7) Johnson's Bayou Prospect; (8) Rockefeller Refuge Prospect; (9) SE Pecan Island Prospect; (10) Atchafalaya Bay Prospect; (11) La Fourche Crossing Prospect; (12) Sweet Lake Prospect; (13) Liberty Fairway; (14) Harris Fairway; (15) Colorado Fairway; (16) DeWitt Fairway; (17) Live Oak Fairway; (18) Duval Fairway; (19) Webb Fairway; (20) Zapata Fairway.

ral gas production for many years, and relatively large, continuous aquifers probably exist. Bebout maps the total areal extent of the fairway at about 500 square miles with the maximum size of a single individual sand body approximately 50 square miles. In evaluating the sands mapped by Bebout, Kuuskraa estimates the total (noncontinuous) sand volume at about 28 cubic miles.

The sands generally are of poor reservoir quality, fine grained, silty and highly cemented. In a detailed investigation of the south Texas region, Swanson et al. (1976) found the limiting parameter in developing the resource, to be the very low sandstone permeability.

Temperatures of 300°F occur at depths as shallow as 11,000 feet, (3353 m) with the average top of geopressure at 8,000 to 10,000 feet (2438 to 3048 m).

b. Armstrong Fairway (No. 2 in Fig. 6)

To the north of the Hidalgo Fairway, Bebout identifies a small lobate delta containing sand-shale sequences up to 1100 feet thick, with the main individual sands ranging from 10 to 200 feet in thickness.

Total areal extent is estimated to be 50 square miles with a net pay of 300 feet (2.8 cubic miles of potentially productive sandstone). The continuity of this reservoir system is unknown. The top of geopressure is 12,000 feet (3658 m) with the depth of the 300°F (150°C) isotherm at approximately 14,000 feet (4268 m).

c. Corpus Christi Fairway (No. 3 in Fig. 6)

Centered roughly on the city of Corpus Christi in Nueces County, and extending into San Patricio and Aransas Counties the Corpus Christi Fairway has an undefined (non-continuous) system of potential reservoir sands estimated to have a total extent of 200 square miles, with individual sand bodies having areas of about 4 square miles. Bebout estimates the net pay at 350 feet. Individual sands are limited in lateral extent, with inadequate thickness for good reservoir characteristics.

d. Matagorda Fairways (Nos. 4 & 5 in Fig. 6)

Two Frio fairways in Matagorda County combine for a total of approximately 100 square

miles of potential reservoir area with an average of 30 feet of net pay. This total is comprised of individual sands each covering an area estimated at 4 square miles. Bebout largely discounts the potential of the Matagorda area, because of the limited extent of the individual reservoir components.

e. Brazoria Fairway (No. 6 in Fig. 6)

The most promising of the Frio geopressured zones was identified in an area of Brazoria and southern Galveston Counties named the Brazoria Fairway. Bebout assigns a total area of 200 square miles to the fairway of which the best sand development is in a 60 square mile area known as the Austin Bayou prospect. Within this prospect, detailed mapping has identified a collection of apparently relatively high-quality stacked sandstone units covering a possible area of 16 square miles (although individual sands are by no means this extensive). Thickness of the system averages perhaps 300 feet of potentially productive reservoir sand of varying lateral extent. Other sands of lower quality could add as much as 500 additional feet, although the productive capability of the low-quality sands is doubtful. We assign a total of 3 mile³ to the potential productive sand volume of the Austin Bayou prospect, and an additional 8 mile³ to the remainder of the Brazoria fairway. The top of geopressure in this area occurs at approximately 11,000 feet (3,353 m), and the 300°F (150°C) isotherm at approximately 15,000 feet (4,568 m). The Austin Bayou Prospect is presently the site of a Department of Energy sponsored well now under test.

f. Summary of Texas Frio-Vicksburg Evaluation

In the Oligocene section on the Texas Gulf Coast, detailed regional study has isolated six areas of massive sand deposition accounting for an estimated total of 56 cubic miles of geopressured sandstone. For various reasons only one of these prospects, the Brazoria Fairway, was considered by Bebout and his associates to merit testing. Most of the limitations of the other areas are based on reservoir considerations. These will be discussed later in this report.

2. Texas Gulf Coast-Wilcox Formation

Near the coast, formations of Eocene age presumably underlie the Oligocene at great depth. Farther inland, generally between the Frio-Vicksburg flexure and the Mirando-Gohlke fault, Wilcox sands occur in the geopressured zone at depths of 10,000 feet and below. The trend has been exhaustively explored for petroleum. The depositional style of the Wilcox leads to a

high degree of heterogeneity of the sands, the characteristics of which often vary considerably from field to field and even within the same reservoir. (Swanson et al., 1976).

The Wilcox trend in Texas has been evaluated by Bebout, Gavenda and Gregory (1978) and a total of 8 promising Wilcox fairways identified. These are shown on the map in Figure 6 and are, like those in the Frio/Vicksburg trend, the result of a study of depositional factors in the geopressured zone within sediments of Eocene age. Detailed investigation of individual fairways has not yet been accomplished, although such study is underway. The discussion which follows thus represents only a preliminary evaluation.

a. Liberty, Harris and Colorado Fairways (Nos. 13, 14 and 15, Fig. 6)

These three areas contain appreciable sandstone deposits within the lower Wilcox. Depth of geopressure ranges from 11,100 to 13,300 feet (3,383 to 4,054 m), and the 300°F (150°C) isotherm is in the same range. The largest of all the prospective geopressured areas is the Harris fairway, covering an area of 1375 square miles, according to Bebout, with a total sandstone volume of 937.5 cubic miles. The Liberty fairway and the Colorado fairway are each of approximately 200 square mile extent, with an estimated total sandstone volume of 17.4 and 32.4 cubic miles, respectively. These three fairways, particularly the large Harris fairway, are relatively close to the highly populated Houston metropolitan area.

b. Dewitt Fairway (No. 16, Fig. 6)

The Dewitt fairway, approximately 60 miles southeast of the city of San Antonio is estimated by Bebout to be the most promising of the eight Wilcox fairways. It covers an area of approximately 280 square miles with about 37 cubic miles of sandstone volume.

c. Duval, Webb and Zapata Fairways (Nos. 17, 18 & 19, Fig. 6)

These three south Texas fairways, although relatively small, contain an appreciable volume of Wilcox sandstone of varying quality. The extent of each of these is as follows:

- (1) Duval fairway, area 140 square miles, estimated sand volume 10.6 cubic miles.

- (2) Webb fairway, 48 square miles, total estimated sand volume 3.6 cubic miles.
- (3) Zapata fairway, 48 square miles, estimated total sand volume 3.1 cubic miles.

3. South Louisiana

As on the Texas Gulf Coast, Tertiary formations in South Louisiana are the potential reservoirs of interest, although sediments are geologically much younger. According to Dobie (1970) the series consists almost exclusively of a regressive sequence of sands and shales, and as a result, the sequence of beds encountered by a well is first a continental sand facies, then a marine inner-to-middle neritic sand and shale facies, and, finally, an outer neritic to bathyal shale facies. The geology of the region is complicated by the frequent occurrence of salt domes which have generally uplifted, faulted and pierced overlying sediments as the salt has intruded. Faulting associated with salt domes is usually complex, and together with the large growth faults which parallel the coast, tends to limit the extent of individual geopressured sand bodies.

Recent detailed investigation of geopressured sediments for their potential as an energy source has been pursued since about 1973, mainly through the Petroleum Engineering Department of Louisiana State University and the Louisiana Office of Conservation. The methodology used in a large study begun in 1975 was a statistical analysis of the geographic distribution of pressure, temperature, sand count and depth, based on examination of more than 6,000 well logs from throughout the state. Promising areas were located, upgraded geologically and evaluated. From this study, Hawkins (1977) reports identification of eight large, promising geopressured aquifers, in addition to fifty-five prospective areas deemed worthy of further investigation. Further analysis of these promising areas has resulted in the selection of five geothermal prospects recommended to DOE as possible sites for exploratory drilling, as reported by Bernard (1979). These five prospect areas are located on the map in Figure 6.

The sixth Louisiana prospect, also shown in Figure 6 (Sweet Lake prospect) resulted from a study by Durham (1978).

The investigations resulting in the selection of these prospective sites were preceded by a long-range study of geopressure over a number of years. The subject has been one of great interest because of its role in

the conventional production of natural gas. Pioneers in this research include the U.S.G.S., LSU, the Louisiana Geological Survey and numerous petroleum companies. Notable among the published work are papers by Bornhauser (1958), Atwater (1967), Harville and Hawkins (1967, 1969), Meyerhoff (1968), W. E. Wallace (1968), Bass (1972), Eaton (1972), and Hise and Hawkins (1973).

Of the six geopressured aquifers selected for potential test drilling, five are located on coastal marshland and four of these are partially off-shore. Summaries of the geological parameters of the six fairways follow.

a. Southeast Pecan Island (No. 9 in Fig. 6)

Bassiouni and Bernard (1978) and Bernard (1979) report detailed evaluation of the Southwest Pecan Island area, located in the coastal marshlands of south Vermilion Parish, partially off-shore. The authors report that porous and permeable geopressured sands, identified on well logs, occur in the lower Miocene at depths between 13,400 feet (4,396 m, the top of geopressure) and approximately 17,500 feet (5,741 m) with an average sand thickness of 700 feet. The prospect covers a surface area of approximately 67 square miles ($1.7 \times 10^8 \text{ m}^2$), with a total sand volume estimated at 9 cubic miles ($38 \times 10^9 \text{ m}^3$). The sand is distributed over three separate stratigraphic intervals. A composite net sand isopach map is shown in Figure 7. Temperatures range from 244°F to 350°F (118°C to 177°C). The average temperature gradient is approximately 1.46°F/hundred feet (23.7°C/km). The estimated geostatic ratio is 0.88 psi/foot ($6.07 \times 10^3 \text{ Pa/m}$) at 17,500 feet.

Based on the assumed average aquifer parameters, Bernard estimates the total water in place at 54 billion bbl at an average temperature of 271°F and an average pressure of 13,000 psi.

Continuity of individual sand units within the principal reservoir elements is unknown. Bassiouni and Bernard report that individual sands are difficult to correlate from well-to-well, with thickening, thinning and, in some instances, disappearance of sands, common. Small splinter faults are also known to exist in the prospect, but their extent and effect on communication within the sandbody is unknown.

The SE Pecan Island prospect is believed by many observers to represent the most favorable prospect for geopressured water production of any of the aquifers so far indentified.

Figure 7. S.E. Pecan Island, Net Sand Isopach Map (Bassiouni and Bernard, 1978)

b. Rockefeller Refuge (No. 8 in Fig. 6)

The Rockefeller Refuge prospect, located in Cameron Parish in the coastal marshlands and partially off-shore, contains geopressed sands estimated to cover an area of 67 square miles. The total geopressed interval, from approximately 13,000 to 17,000 feet (3962 to 5182 m), is estimated to contain an average of 800 net feet (262 m) of sand, with a total sand volume of 9.5 cubic miles ($39 \times 10^9 \text{ m}^3$). The temperatures range from 234°F to 347°F (112°C to 175°C). Bernard estimates the average pressure gradient at 0.86 psi/feet, yielding a pressure of 14,200 psi at 16,500 feet. Using estimated aquifer parameters, the total water in place is 39 billion barrels, at an average temperature of 293°F.

c. Johnson's Bayou Prospect (No. 7 in Fig. 6)

Also in Cameron Parish, on the Texas-Louisiana border, the Johnson's Bayou prospect covers an estimated 55 square miles, with the top of geopressure at 8700 feet (2854 m). Average net sand thickness is 1320 feet (433 m), with a total sand volume of 11.4 cubic

miles ($437 \times 10^9 \text{ m}^3$). Temperatures range from 183°F to 288°F (83.9°C to 142°C).

Bernard estimates the total water in place, based on average reservoir parameters, to be 89 billion bbl at an average pressure of 9500 psi and an average temperature of 201°F.

d. Atchafalaya Bay Prospect (No. 10 in Fig. 6)

This prospect also lies partially off-shore in the marshland of Terrebonne Parish in south-central Louisiana. Its total area is estimated at 127 square miles with an average net sand thickness of 330 feet, or 5.9 cubic miles ($25 \times 10^9 \text{ m}^3$). The reported temperature range is 204°F to 309°F (95.6°C to 153.9°C).

The estimated water in place is 49 billion bbl at an average pressure of 11,400 psi and an average temperature of 222°F.

e. LaFourche Crossing (No. 11 in Fig. 6)

The LaFourche Crossing prospect is the only one of the six not located on coastal marshland.

It covers an area of approximately 39 square miles and is located directly north of the city of Houma. The top of geopressure is estimated at 12,800 feet (4,200 m) with an average of 300 feet (98 m) net sand thickness in the geopressured zone. Total sand volume is estimated at 1.5 cubic miles ($6.4 \times 10^9 \text{ m}^3$). Temperatures range from 273°F to 327°F (133.9°C to 163.9°C).

The total water in place is estimated by Bernard to be 15 billion bbl at an average pressure of 12,900 psi and an average temperature of 244°F.

LaFourche crossing is the only one of the six Louisiana prospects on dry land. It is located four miles south of the small town of Thibodeaux.

f. Sweet Lake (No. 12 in Fig. 6)

Sweet Lake is a small, high quality geopressured reservoir near Lake Charles, Louisiana, covering approximately 8 square miles, with an estimated sand volume of 1.2 cubic miles. The average temperature of the zone of interest is estimated to be 280°F at a depth of 15,000 feet.

4. Other Geopressured Prospects

It is important to realize that the prospects identified in these studies do not represent the full extent of geopressure in either Texas or Louisiana. All were selected with high temperature as one important criterion. Without this constraint (considering methane potential only), there is little doubt that more prospects exist. However, since these will also generally represent shallower reservoirs, the pressure, and consequently the dissolved methane, will be correspondingly less. The number of such low temperature geopressured prospects is unknown. At least one report has identified and made preliminary assessment of several shallower aquifers in conjunction with a DOE-funded study of potential commercialization of low-temperature geopressured/ geothermal fluids (Arnold 1978).

G. Results and Conclusions

1. Summary of Geological Results to Date

Three extensive, detailed studies of the geopressured zones of the Texas and Louisiana coastal area have been performed by different, but accepted, exploration techniques. These have been aimed at identification of major sand bodies which might contain geopressured reservoirs capable of supporting production wells. The positive result of these studies has been the identification of several large geothermal fairways, although

none as extensive as that defined by the Parmigiano model (300 square miles). Given favorable reservoir characteristics (porosity, permeability, compressibility, etc.) several of these reservoirs appear to have potential as geothermal-methane producers. The extent of the estimated sandstone volume in the prospects and fairways so far the subject of detailed evaluation, is given in Table II.

2. Unresolved Issues

a. Reservoir Continuity

The current art of exploration geology cannot determine the continuity of large potential reservoirs. Petroleum reservoirs are characteristically geological traps; as such, they are almost invariably of limited extent. Identification of conditions which signify dynamic aquifers of broad extent are beyond the current state-of-the-art. Well logs, which can determine stratigraphy, porosity and density, are generally unable to determine permeability, certainly not its continuity. Seismic exploration may identify fault planes, but cannot determine whether or not such faults are sealing. The referenced geopressure studies have been unable to define the extent of drainage of potential reservoirs and this must await extensive testing of several exploration wells (even a single test well adequately tested will be unable to fully resolve the question of reservoir extent).

b. Rock Parameters

In situ rock parameters (permeability, compressibility, etc.) are poorly defined by geological exploration. Measurements on actual rock samples are necessary, and such measurements in large geopressured water-bearing strata are rare. Even when these measurements are made on cores and other samples, the results are often inconclusive. Permeability, for example, frequently changes from interval to interval, even from foot to foot, both laterally and in depth. These are, consequently, essentially engineering parameters derived by actual production experience in a reservoir zone. Geological estimates of average permeability, for example, are of limited value when based on scattered data from widely separated sidewall cores. On the other hand, the degree to which such parameters can be reliably inferred from nearby oil and gas reservoirs is unknown.

c. Methane and Other Solutes

Little additional data on methane content, or its determination, has been forthcoming, although testing of water in two geopressured sands in a Louisiana test well tends to confirm near-saturation lev-

TABLE II
EXTENT OF ESTIMATED SANDSTONE VOLUME IN GULF COAST FAIRWAYS

Name	Approx. Area (Mile ²)	Est. Total Sand Volume, (Mile ³)
<u><i>Texas Frio-Vicksburg Trend</i></u>		
Hidalgo	500 (non-continuous)	28
Armstrong	50	2.8
Corpus Christi	200 (non-continuous)	13.2
Matagorda (2)	100 (broken & non-con.)	0.6
Brazoria	200 (non-continuous)	11
SUB-TOTAL	950 (2.46 × 10⁹m²)	55.6 (2.316 × 10¹¹m³)
<u><i>Texas Wilcox Trend</i></u>		
Zapata	48	3.1
Webb	48	3.6
Duval	140	10.6
Live Oak	75	3.4
Dewitt	280	37.1
Colorado	200	32.2
Harris	1,375	937.5
Liberty	200	17.4
Sub-Total	2,366	1,012.7
Texas Total	3,316	1,068.3
<u><i>Louisiana Prospects</i></u>		
SE Pecan Island	67	9
Rockefeller Refuge	67	9.5
Johnson's Bayou	55	11.4
Atchafalaya Bay	127	5.9
LaFourche Crossing	39	1.5
Sweet Lake	8	1.2
Louisiana Total	363	38.5
TOTAL, BOTH STATES	3,679	1,106.8

els of methane in that well, if correction for salinity amounting to about 35% is applied (Hankins, et al., 1978). Estimates of methane in place are still based solely on the assumption that the water is saturated at the temperature, pressure and dissolved solids content of interest.

Only limited knowledge of other dissolved material in the water can be gained from geological investigation of an area. The possible presence of carbon dioxide, hydrogen sulfide and trace poisons such as arsenic and boron, can only be determined by actual testing of specific formation fluids.

H. Conclusions

Results of geological investigations to date have defined a total of twenty geothermal fairways representing large scale sand deposition in conjunction with relatively high temperature and pressure. In total area, these fairways represent approximately 3679 square miles (out

of a total on-shore area of 55,000 square miles) with estimated sandstone volume of 1,106 cubic miles. Of this total, 937 cubic miles, or approximately 80% is contained within the Harris/Wilcox fairway in Texas.

Perhaps the two most significant geological unknowns at the present time are the amount of gas in solution, and the drainage area one may expect from a single well. Reservoir continuity cannot be established by present exploratory means, and the large continuous aquifers postulated by early observers have not materialized.

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III. RESERVOIR CONSIDERATIONS

A. Deliverability

The capability of geopressed reservoirs to produce fluid at high rates of flow for extended periods of time (the "deliverability") depends upon a combination of formation parameters, principal among which are porosity, permeability, formation thickness, compressibility, and drainage volume. In general, quasi-steady state reservoir equations are adequate to predict the performance of geopressed water reservoirs (Parmigiano, 1973; Bernard, 1975). Samuels (1979) gives an excellent summary of the reservoir aspects of geopressed fluid production and relating the work of Bernard, Hantush (1960), Geertsma (1957), and others, shows that the performance of a geopressed water reservoir can be described by an equation of the form

$$P_s = (P_r - P_h - P_f) - \left(\frac{5.615Qt}{\pi r_e^2 h \phi C_e} \right) - \left(\frac{Q \cdot \mu}{7.08kh} \right) \left\{ \left[\ln \left(\frac{r_e}{r_w} \right) \right] - \frac{3}{4} \right\} \quad (1)$$

where

- Q — Flow in bbl/day
- k — Permeability in Darcies
- h — Thickness in feet
- t — Time in days
- ϕ — Porosity, fraction
- μ — Viscosity centipoise
- C_e — Compressibility
- r_w — Radius of the well in feet
- P_r — Initial pressure in reservoir
- P_s — Pressure at the surface
- P_h — Pressure due to the hydrostatic head
- P_f — Friction loss due to flow up the pipe

The flow from a reservoir can be compared to current in an electrical circuit, where the driving force, reservoir pressure, is analogous to the battery voltage. When connected to a complete circuit (a producing well), the battery will drive an electric current (reservoir fluid) through a series of impedance elements which comprise the remainder of the circuit.

In Equation (1) the term

$$P_r - P_w = \left(\frac{Q \cdot \mu}{7.08kh} \right) \left\{ \left[\ln \left(\frac{r_e}{r_w} \right) \right] - \frac{3}{4} \right\} \quad (2)$$

is termed the drawdown parameter, where P_w is the bottom-hole pressure in the well under flowing conditions. It is the pressure drop across the formation face.

The term

$$P_i = P_r - \left(\frac{5.615Qt}{\pi r_e^2 h \phi C_e} \right) \quad (3)$$

is the instantaneous internal reservoir pressure as a function of time, after the initial pressure wave has reached the reservoir boundary.

The parameter P_f , the friction pressure, is a function of the well bore diameter, the depth of the well, a friction coefficient dependent upon the pipe surface, and the flow rate.

The term P_h , the hydrostatic head, is a function of the fluid density and the depth.

Study of the elements of Equation 1 reveals that for given well conditions (depth, casing size, etc.), the drawdown parameter is crucial in determining the maximum flow rate. For large reservoirs, the term $\ln(r_e/r_w)$ approaches a constant, and fluid viscosity is approximately constant for brine under given temperature and pressure conditions. Consequently the critical parameters are the formation permeability, k , and the formation thickness, h . Since the product of these two factors largely determines the maximum flow rate, a very thick formation of low permeability is equivalent to a thinner, more permeable formation, insofar as drawdown is concerned.

A well will flow at a given rate, Q , for a period of time determined mainly by the instantaneous reservoir pressure (Equation 3). This term is critically affected by the reservoir volume ($\pi r_e^2 h$), the matrix porosity ϕ and the compression drive coefficient, C_e . However, the drawdown, largely kh dependent, also is critical, affecting the length of time a given reservoir pressure can remain effective.

Based on Equation 1, the flow and pressure behavior of a production well, and consequently the total fluid produced, may be predicted as a function of time. This equation may be combined with a Monte Carlo statistical routine, and probable flow performance calculated. The results of a calculation of this kind for a well in the Brazoria, Texas prospect is shown in Figure 8 using a range of minimum, maximum, and most-likely values for the nine stochastic reservoir parameters.

Figure 8. Probable Average Flow Rate Over a Twenty Year Period, Single Well, Brazoria, Texas Prospect, 250 Ft Reservoir

The results of calculations of this type for a number of the potential reservoirs about which knowledge exists indicates that geopressed wells in favorable reservoirs will be capable of flowing at rates from 10,000 to perhaps 40,000 to 50,000 bbl/day, for periods of time dependent mainly upon the reservoir drainage area. It can also be shown that the fraction of the total contained fluid recoverable, will be a function of the formation compression drive coefficient, C_e , and will range from less than 1% to a maximum of perhaps 4% of the total fluid in place. While there are uncertainties in the value of some of the production parameters, behavior of the reservoirs is relatively well understood, supported by a large background of experience with thousands of geopressed gas wells over the last 30 years.

B. Reservoir Parameters

1. Porosity

Porosity is the intergranular space in a rock matrix. In the Gulf Coast, initial porosities of sands are assumed to be in the neighborhood of 40%-45%. With burial, this porosity is continuously reduced by pro-

cesses of compaction, cementation, and mineral overgrowth (Lindquist, 1977). The original composition of sandstone greatly influences the porosity that survives at any given depth, with sands containing a high percentage of quartz being most likely to maintain high porosity under conditions of large overburden. Along the Texas Gulf Coast, Frio sandstones become more quartzose northward. In South Texas the Frio contains low quartz (about 25%) and a large amount of volcanic rock fragments. In the middle Texas coast, quartz content increases to moderate values (40%-50%). In the upper Texas coast, quartz content increases to moderately high values (70%) and other components such as rock fragments and feldspars are found in only minor amounts. The sandstones in south Louisiana are generally quartzose and as such exhibit relatively high porosity.

Bebout (1978) states that the key to reservoir-quality sandstones in the geopressed zone, is secondary porosity, the result of leaching which occurs at depth. Increase in porosity at depths greater than 11,000 feet is believed to be due to leaching of both grains and cement by a flow of subsurface waters that are rich in carbon dioxide. The source of carbon dioxide may be the thermal or bacterial breakdown of sediment hydrocarbons (Berg, 1978, this volume, Appendix A).

If high values of porosity in the geopressed zone are the result of leaching, it must be a highly selective process. Berg points out, for example, that Frio sandstones in the Chocolate Bayou field have porosities as high as 25% in the deep subsurface while in the nearby Danbury Dome area, massive cementation by quartz has reduced porosities to less than 10% at equivalent depth. Vicksburg sandstones of South Texas are an example of low porosity sandstones in a geopressed environment. In no case do Vicksburg sandstones reach porosities as high as 25%, as would be expected from leaching. In the middle Texas Coast, Frio sandstones have maximum porosities of about 20%. No examples are known of secondary porosity in the Frio sandstones of this area. At the present time, there is no known way in which leaching can be predicted or identified with the location of potential geopressed reservoirs.

Porosity values in geopressed sandstones range from 10% in the South Texas Vicksburg formation to as much as 30% in some geopressed formations in South Louisiana.

2. Formation Compressibility: The Compression Drive Coefficient

When fluid is irreplaceably removed from a geopressed sandstone, compaction of the rock will result. The initial reservoir drive mechanism in geopressed formations is the "compression drive coefficient", C_e . It is the result of the compaction of the rock matrix (reduction in porosity), the compressibility of the contained water and the compressibility of the matrix particles as the internal reservoir pressure declines, and a new vertical pressure gradient is established. Particle compressibility in Gulf Coast sandstones is generally regarded as insignificant compared to the other two effects, and, consequently, the compression drive coefficient is the sum of the effects of the brine compressibility and the uniaxial compaction coefficient, C_m , of the matrix. The compressibility of the water is predictable, discounting possible minor effects due to solution gas.

Other measurements of the uniaxial compaction coefficient, C_m , reported in the literature, tend to confirm these values. Geertsma (1973), in studies of reservoir subsidence, has presented data for C_m for many core samples of both limestone and sandstone. For 20% porosity sandstone, at a pressure corresponding to a burial depth of about 3000 meters, Geertsma reports values of C_m ranging from 2.8×10^{-7} to 12.0×10^{-7} psi^{-1} for well consolidated rock, and 7.1×10^{-7} to 23.3×10^{-7} psi^{-1} for semi-consolidated rock. These samples were all from normally pressured reservoirs.

Dorfman (1979) presents data from a geopressed sandstone in the first DOE test well in Brazoria County, Texas (14,754 feet) showing values of C_m ranging from 2.0×10^{-7} to 3.5×10^{-7} psi^{-1} .

Figure 9. Uniaxial Compaction of Representative Gulf Coast Geopressed Sands as a Function of Porosity

Values of the uniaxial compaction coefficient for geopressed sandstones are less well known; however, two recent studies of this parameter have been published based on both laboratory and field measurements (B.F. Swanson, 1978 and Dropek and Abou-Sayed, 1978). The results of these studies are summarized in Figure 9. They show a range of values of the uniaxial compaction coefficient from 2×10^{-7} psi^{-1} to 5×10^{-6} psi^{-1} with an average of about 10^{-6} . Since the compressibility of water under the temperature, pressure, and solution conditions of interest is about 3×10^{-6} , realistic values for the compression drive coefficient, C_e , lie in the range from about 3×10^{-6} psi^{-1} to perhaps 8×10^{-6} psi^{-1} .

3. Permeability

Permeability is the property of a formation which permits the flow of fluid through the intergranular space. While permeability is not a direct function of porosity, in sandstone the two are closely related. Sandstones with high porosity generally exhibit relatively high permeability, while low porosity is usually indicative of low permeability. As porosity is reduced by compaction with increasing depth of burial, permeability likewise tends to decrease drastically with depth.

Permeability is a principal determinant of flow rate. In conjunction with the reservoir thickness, h ,

the permeability-thickness product of a reservoir largely determines the drawdown, or pressure drop across the formation face, as a well is flowed. Likewise, permeability drastically affects the lifetime of a well at a given flow rate. For example, if a well in a reservoir with the parameters of the Brazoria prospect is flowed at an average rate of 11,000 bbl/day a 250 foot sand will flow for 2-1/2 years if the average permeability is 5 MD. If the average permeability is 10 MD, the well will flow for twenty years; if the average permeability is 1 MD or less, the well will not flow 11,000 bbl/day (following a very short transient period).

Review of early assessments of the resource indicate that permeability of geopressed formations was uniformly overestimated by early investigators. Jones (1975), Wilson (1974), and Herrin (1973), all describe large continuous aquifers with permeability values in the range of 28 to 150 MD throughout the South Texas area. Papadopoulos et al (1975) in the original USGS assessment, assumed permeability values ranging from 20 to 50 MD. In his assessment of the Frio formation, Bebout (1976) referred to permeability values "above 40 MD" in Texas Gulf Coast formations, although in the 1978 site selection study (Bebout, Loucks & Gregory, 1978), the University of Texas team had lowered this estimate. Predicted performance of a well in the Brazoria County (Austin Bayou) prospect was based on an average permeability of 15 MD for 230 feet of the best reservoir sandstone projected for that area.

The first document presenting evidence of in situ permeability values from actual field reservoirs in the geopressed zone was a study by Swanson et al

Figure 10. Histogram of Effective Permeability Values of 35 Gas Wells Between 8,000-12,000 Ft in Immediate Vicinity of D.O.E. Test Well Site, Brazoria Co., Texas

(1976) in which 49 geopressed gas fields in the South Texas area were examined on the basis of production records and other reservoir information. Based on intensive study of more than 100 gas wells in the South Texas Gulf Coast region, Swanson found effective permeability values of gas sands ranging from .03 MD to 8 MD with no production wells in the deep geopressed zone exhibiting permeability values as high as 10 MD. At depths where temperatures were greater than 250°F, permeability values averaged less than 1 MD.

Figure 10 presents the results of additional data, showing a statistical analysis of the effective permeability of 35 gas wells between 8,000 and 12,000 feet in the immediate vicinity of the DOE test well site in Brazoria County, Texas. This histogram shows a distribution of average permeability values ranging from .8 MD to 98 MD with an average near 5 MD.

At greater depth, Figure 11 shows a histogram of effective permeability values of 21 deep gas

Figure 11. Histogram of Effective Permeability Values of 21 Deep Gas Wells (Below 12,000 Ft) in Immediate Vicinity of D.O.E. Test Well Site, Brazoria Co., Texas

wells in the same Brazoria County area. These wells, ranging from 12,000 to 18,000 feet in depth, show permeabilities from less than .1 MD to 5 MD, with an average of about .5 MD.

Figure 12 is a similar histogram of core permeability values from a cored 10,200 foot sand in the first DOE test well in Brazoria County, Texas. Here the range of permeability values lies between .005 MD and 8 MD, with an average of about .1 MD.

Finally, Figure 13 shows a histogram of core permeability values from a continuously cored 15,500

Figure 12. Histogram of Core Permeability Values from a Cored 10,200 Ft Sand in D.O.E. Test Well #1, Brazoria Co., Texas

foot sand in the South Pecan Island Field in Vermilion Parish, LA. This shows a range of permeability values from .6 MD to 13 MD, with an average near 2MD.

Generally, speaking, in situ permeability is known to exhibit a log-normal distribution over any particular depth interval in a particular area (Law, 1944; Craig, 1969). Average permeability declines with depth, and in the Gulf Coastal region at depths below 8,000 feet the decline appears to amount to about 1 order of magnitude for each 2,000 to 3,000 feet of depth, depending upon the location. In South Louisiana, permeability values tend to be higher at depth than those in Texas. Certainly there may be intervals in all locations in which high permeability values are found, but over an

Figure 13. Histogram of Core Permeability Values from a Continuously Cored 15,500 Ft Sand in S. Pecan Island Field, Vermilion Parish, Louisiana

extended depth interval, average permeability cannot be expected to depart drastically from the statistical mean (Swanson and Osoba, 1979).

The sensitivity of reservoir performance to permeability and reservoir radius has been described graphically by Samuels (1979). His representation is reproduced in Figure 14 which shows the lifetime of reservoirs of varying permeability and size as a function of flow rate. Here it can be noted that for a 200 foot sand,

Figure 14. Well Life as a Function of Permeability, Flow Rate, and Reservoir Radius for a Well Diameter of 6 In., Reservoir Thickness of 200 Ft, and Pore Compressibility of $7 \times 10^{-6} \text{ psi}^{-1}$. All Radii Are Given in Miles. (From Samuels, 1979)

the minimum reservoir permeability to yield an extended flow rate of 40,000 bbl/day is 10 MD. For a well to flow for as long as 20 years at this 40,000 bbl/day rate requires a minimum reservoir radius of about 8 miles (200 square miles), regardless of the permeability.

4. Reservoir Volume

The total sandstone volume multiplied by the porosity fraction determines the maximum amount of fluid available to a well for production. The fraction of the total which can be produced is a function of other parameters previously described. Many factors can affect the effective drainage area. A sand body, originally continuous, may be compartmentalized by faulting. Variations in lateral permeability caused by cementation, subsurface leaching and compositional differences during deposition all limit the area which a given reservoir may drain.

Single-well drainage area is certainly one of the most significant unknowns presently outstanding in evaluating the geopressure-geothermal resource. If pe-

troleum wells are any indication (not necessarily the case), a drainage area greater than a few square miles will be highly unusual. Very large, continuous petroleum reservoirs—greater than 50 square miles—are extremely rare, and, in fact, continuous geopressed gas reservoirs of this size are virtually unknown.

C. Reservoir Models

Parmigiano (1973), on the basis of reservoir engineering fundamentals, established the parameters of a flowing well and geopressed aquifer capable of economic exploitation of geopressure, producing at the rate of 80,000 bbl water/day for a period of 20 years. The parameters of this model are given in Table III.

TABLE III
EARLY LSU RESERVOIR MODEL
(Parmigiano, 1973)

Depth	12,000 feet
Formation Pressure	10,000 psig
Thickness	200 feet
Porosity (%)	20
Permeability	100 md
Compressibility	10^{-5} psi ⁻¹
Temperature	260°F
Viscosity	0.30 cp
Pipe ID	9 inches
Production Rate	80,000 bbl/day
Reservoir Radius	10 miles (300 square mile area)
Closed External Boundary	—

Wilson, Shepherd and Kaufman (1974) presented two South Texas reservoir models, given in Tables IV

TABLE IV
DOW MODEL (Wilson, et al, 1974)

Dimensions	7 × 16 miles
Net Sand Thickness	500 feet
Permeability	0.100 darcy
Porosity	25%
Viscosity	0.2 centipoise
Average compressibility of water & rock pore space	9×10^{-6} volume/volume/psi
Well radius	0.3 feet

TABLE V
JONES MODEL (Wilson, et al., 1974)

Dimensions	10 × 50 miles
Net Sand Thickness	1000 feet
Porosity	18%
Average water and rock pore compressibility	9×10^{-6} volume/volume/psi
Viscosity	0.2 centipoise
Well radius	0.3 feet
Permeability—1	0.0275 darcy
—2	0.08 darcy

and V, respectively. Note that a critical parameter of both these models is large reservoir area: 112 square miles in the "Dow model" and 500 square miles in the "Jones model".

TABLE VI
TWO SOUTH TEXAS RESERVOIRS
(Herrin, 1973)

	Sebastian Site	Port Mansfield Site
Depth to top of geopressure	14,300 feet	12,650-15,660 feet
Average pressure gradient	0.81	0.79-0.91
Area	At least, 10 × 30 miles	At least, 10 × 30 miles
Net sand thickness	700 feet	800 feet
Porosity	20%	20%
Permeability	100-135 millidarcies	100-135 millidarcies

Table VI is an early model presented by Herrin (1973). Rock parameters are similar to those in the Parmigiano and Wilson models, with a drainage area of "at least 300 square miles."

In the 1975 USGS Assessment, Papadopoulos et al (1975) presented conceptual models of each of 21 areas comprising the total 55,000 square mile Gulf Coast assessment area. Typical of these individual reservoirs is

TABLE VII
RESERVOIR PARAMETERS REPRESENTATIVE OF
USGS 1975 ASSESSMENT
(Area "AT1", Papadopoulos et al, 1975)

Average Top of Geopressure	2.36 km (6,847 feet)
Reservoir Area	8,948 km ² (2,700 square miles)
Total Reservoir Thickness (sand & shale)	3.64 km (10,560 feet)
Total Sand Thickness	0.63 km (1,827 feet)
Average Temperature	186°C (367°F)
Well Spacing	3.1 km (1.7 miles)
Permeability	20 MD
Porosity	18%
Methane Content	11 Sm ³ /m ³ (62.7 SCF/bbl)
Total Number Wells	930

that postulated for one of the South Texas areas, designated "AT1" in the USGS document. (Table VII)

These models were developed prior to extensive geological investigation of geopressed sediments.

It is now appropriate to compare these early models with the refined model published by Bebout et al (1978) for the Brazoria County, TX, Frio prospect after detailed study. The parameters of a well in this reservoir are given in Table VIII.

TABLE VIII
BRAZORIA, TEXAS MODEL
(Bebout, et al., 1978)

Single well drainage area	16 square miles
Depth	15,200-15,900 feet
Initial bottomhole pressure	10,318 psi
Bottomhole drawdown pressure	1000 psi
Fluid flow rate	13,140 B/D
Water salinity	45,000 ppm
Temperature	325°F
Sandstone	
Thickness	230 feet
Porosity	20 percent
Permeability (horizontal)	15 md
Uniaxial compaction coefficient	$1.21 \times 10^{-5} \text{ psi}^{-1}$
Methane	40/SCF/bbl

Significantly, the rock parameters given by Bebout are similar, although somewhat less optimistic, than those of the earlier investigators. However, the size of this reservoir, the best yet identified in the Texas Frio formation, is anticipated to be no larger than 16 square miles. Even this figure is misleading; the total multi-storied sand structure identified by Bebout, is not only of unequal productive capability, but all of it does not extend over the full 16 square miles. Bebout's interpretation of the sandstone system is simply that the individual sand bodies are expected to extend for no more than 2 miles laterally, and that all of the sands will be contained within a 16 square mile area.

This model represents an extremely important set of conclusions. If all the research on geopressure over the past 6 or 7 years could be summed up in a single statement, it might be expressed as follows: unless sandstone bodies can be identified which exhibit much larger drainage areas than have so far been defined by exploration geology, the early promise of geopressured formations cannot be fulfilled.

D. Predicted Reservoir Performance

1. Early Modeling Effort

Wilson et al (1974) foresaw, on the basis of his models, 15,000 foot South Texas production wells capable of producing 51,000 bbl/day of 385°F brine. His field development plan consisted of clusters of wells spaced 300 feet apart, producing at a constant overall rate of up to 713,000 bbl/day for 20 years. Under these conditions the reservoir would support as much as 68 MW of geothermal electric generating capacity.

Papadopoulos et al (1975) on the other hand foresaw development wells throughout the Gulf Coast area at spacing distances of 2.5 to 3.9 km (1.35 to 2.11 mile). On the basis of highly optimistic reservoir

parameters, Papadopoulos predicted typical well production of $0.15 \text{ m}^3/\text{sec}$ (80,285 bbl/day) of water for 20 years, and single-well methane recovery during that period of 37 BCF (billion cubic feet).

2. Reservoir Simulation Studies

Knapp and Isokrari (1976) developed a numerical reservoir model based on reservoir parameters shown in Table IX. These parameters were intended to

TABLE IX
PARAMETERS ASSUMED FOR ARMSTRONG FAIRWAY
(Knapp & Isokrari, 1976)

Reservoir area	44 square miles
Thickness	162 feet
Permeability	18 MD
Initial Reservoir Pressure	11,000 psia
Reservoir Temperature	300°F
Depth	11,000 feet
Porosity	21.6%
Salinity	10,000 ppm TDS
Viscosity	0.2008
C_e	$1.12 \times 10^{-5} \text{ psi}^{-1}$

be representative of the Armstrong Fairway in South Texas after preliminary assessment of the lower Texas Coast by Bebout et al (1976).

Knapp showed that a single well in a continuous reservoir with these characteristics would flow at a rate of 80,000 bbl/day for more than twenty years, and at a rate of 40,000 bbl/day almost indefinitely. Consequently, he projected a field development with 11 producing wells. He predicted that the eleven wells would deplete the reservoir in about 13 years (with a correction of C_e to $2 \times 10^{-5} \text{ psi}^{-1}$ to account for some effects of shale dewatering).

Detailed investigation of the Armstrong Fairway subsequent to the Knapp modeling has shown that many of the reservoir parameters assumed were highly optimistic. At 11,000 feet, for example, the reservoir temperature in the Armstrong Fairway is only about 240°F rather than 300°F. The producing geopressured gas wells in the area show average permeability values of only about 1 MD. While the total area of the sandstone deposition may be in the neighborhood of 44 square miles, single-well drainage areas are almost certain to be far smaller, due to discontinuities in the individual sandstone elements. The compression drive coefficient, C_e , is almost certainly less than $2 \times 10^{-5} \text{ psi}^{-1}$ and the salinity at least 100,000 ppm TDS or more (with a commensurate reduction in methane content). In 1978, Bebout summarized the Armstrong fairway as follows:

"The Armstrong Fairway does not meet minimum requirements as a potential geothermal prospect. Sandstone thickness and areal extent are excellent, low fluid temperature and probable low permeability are the major problems."

Extensive examination of the performance of the Brazoria, Texas prospect has been performed by Garg, Pritchett, Rice and Riney (1977) based on a numerical simulator using a linear flow model. Garg's results (using Bebout's parameters shown in Table VIII) indicate that under depletion drive, a well in the Brazoria County, Austin Bayou prospect will flow at an initial rate of about 35,000 bbl/day, declining steadily to 5,000 bbl/day by the end of the sixth or seventh year. Garg concluded that sustained production (about 20,000 bbl/day) could only be obtained at the Austin Bayou prospect by reinjection of the spent brine to provide pressure maintenance. Prospects of reinjection will be discussed in a following chapter, "Spent Brine Disposal".

To compare the results of sophisticated numerical modeling with relatively simple analytical methods using quasi-steady state equations, the parameters of the Brazoria model prepared by Bebout (Table VIII), with one exception, were applied to an advanced reservoir simulator developed at Texas A&M University. The exception was the substitution of the more realistic value of $6 \times 10^{-6} \text{ psi}^{-1}$ for C_e , the compression drive coefficient (based on core information not available to Garg). This computer program simulates the behavior of a circular reservoir, and includes the phase behavior of the fluids, gravity, and three-dimensional flow. The effects of gas released from solution on relative permeability, fluid flow and total gas saturation are predicted by computer codes.

In calculating the reservoir behavior, the flow rate was assumed to be maintained at a fixed value of 30,000 bbl/day until the surface pressure declined to 150 psi (about 1-1/2 years). At this surface pressure, the flow rate will continue to decline so that after 20 years, the rate will be less than 500 bbl/day. This flow behavior is shown in Figure 15, along with the results of simple analytical modeling based on Equation (1).

Figure 15. Flow Performance of Hypothetical Well in Brazoria, Texas Prospect, by (1) Sophisticated Numerical Model, and (2) Simple Analytical Model

Figure 16. Cumulative Water Production From Brazoria, Texas Prospect, with Flow as in Figure 14

Figure 17. Gas Saturation at Depletion, Brazoria, Texas Prospect, Numerical Model

The cumulative water produced under this production scheme is illustrated in Figure 16 showing total water production amounting to 73×10^6 barrels of water, or approximately 2.5% of the total water in the reservoir during the 20 years.

During this same period, the volume of gas produced (assuming an initial saturation value of 40 scf/bbl) would amount to 2.9 billion scf, or 2.7% of the gas initially in place in solution.

The results of the modeling showed no significant quantity of free gas produced. The released gas remains in the reservoir, migrating slowly to the top over the production period. At the end of twenty years, the released gas will increase the gas saturation in the top 5 feet of the reservoir to a maximum of about 20%. Ten feet lower, the gas saturation will be less than 1%. The final gas saturation distribution is shown in Figure 17.

In summary, the sophisticated numerical model indicates that free gas has no appreciable effect on the performance of the reservoir and that the gas produced will consist only of gas released due to the pressure gradient to the surface. Gas released within the reservoir will remain in the reservoir, migrating slowly to the upper five feet.

Recently, controversy has arisen over the possibility of released gas forming a "gas cap" within the reservoir which might be produced by a conventional gas well. This model indicates that such a "cap" will indeed be formed. However, the quantity of gas is exceedingly small and, in any case, could not be produced. The depleted aquifer would have no remaining reservoir drive.

3. Performance Predictions based on Quasi-Steady-State Reservoir Equations

The same parameters of the Brazoria prospect (with $C_e = 6 \times 10^{-6} \text{ psi}^{-1}$), when applied to a simplified analytical model based on Equation (1), predict the results shown in the second curve in Figure 14 for a single production well. These are so similar to the results obtained from the numerical model that it may be concluded (as Bernard concluded in 1975) that, since the solution gas apparently has no significant effect on overall performance, simplified quasi-steady-state equations may be used to predict reservoir performance at this stage.

Kuuskraa et al (1978) used a similar approach in performing a sensitivity analysis of the various reservoir parameters.

4. Analysis of Other Geopressured Prospects

Aside from the Texas Brazoria prospect, two of the most favorable geopressured prospects so far identified are the S.E. Pecan Island area in Vermilion Parish, Louisiana, and the Johnson's Bayou prospect in Cameron Parish, on the Texas-Louisiana border.

a. S. E. Pecan Island

The S. E. Pecan Island prospect is particularly interesting because of its large sand volume and extensive area (67 square miles). Laminated shale and geopressured sands occur from 13,500 feet to 17,500 feet, with a total estimated sand volume of 9 cubic miles. A considerable amount of conventional gas production in this vicinity also makes it possible to estimate reservoir parameters with reasonable assurance. The principal unknown in S.E. Pecan Island is the single-well drainage area.

Figure 18. Probable Average Flow Over a Twenty Year Period for a Well in S. E. Pecan Island Prospect, Vermilion Parish, LA.

Probable flow rates over a twenty-year period for wells drilled in the S. E. Pecan Island reservoir are shown in Figure 18. This is the result of a Monte-Carlo analysis of minimum, most-likely and maximum expected values of the reservoir parameters listed in Table X. The analysis shows that wells drilled in this prospect have a 60% probability of flowing at 14,000 bbl/day for twenty years, and a 10% probability of flowing at 50,000 bbl/day. The average of all values is 22,172 bbl/day.

Selecting parameters representative of the best part of the reservoir (net sand thickness of 980 feet), and assuming an optimistic single well drainage

TABLE X
MINIMUM, MAXIMUM AND MOST LIKELY VALUES FOR
PARAMETERS OF SE PECAN ISLAND
GEOPRESSURED RESERVOIR

Wellhead diam.	5-1/2 inches
Time Period (yr)	20
Minimum surface pressure (psi)	300
Permeability, md	Minimum 2
Permeability, md	Most Likely 10
Permeability, md	Maximum 50
Reservoir radius (ft)	Minimum 2900
Reservoir radius (ft)	Most Likely 5500
Reservoir radius (ft)	Maximum 10,676
Viscosity (centipoise)	Minimum 0.2
Viscosity (centipoise)	Most Likely 0.23
Viscosity (centipoise)	Maximum 0.25
Compressibility	Minimum 3×10^{-6}
Compressibility	Most Likely 5×10^{-6}
Compressibility	Maximum 10×10^{-6}
Reservoir Thickness (ft)	Minimum 350
Reservoir Thickness (ft)	Most Likely 500
Reservoir Thickness (ft)	Maximum 980
Porosity	Minimum 0.2
Porosity	Most Likely 0.22
Porosity	Maximum 0.24
Initial Pressure in Reservoir (psi)	Minimum 13,000
Initial Pressure in Reservoir (psi)	Most Likely 13,500
Initial Pressure in Reservoir (psi)	Maximum 14,000
Frictional Pressure Loss (psi)	Minimum 300
Frictional Pressure Loss (psi)	Most Likely 750
Frictional Pressure Loss (psi)	Maximum 1500
Hydrostatic Head Pressure Loss	Minimum 7000
Hydrostatic Head Pressure Loss	Most Likely 7500
Hydrostatic Head Pressure Loss	Maximum 8000

area of 13 square mile, the "best" well in the prospect should perform as shown in Figure 19. The parameters used in this analysis are given in Table XI. This well should flow at a rate of 50,000 bbl/day for 11-1/2 years, at which time surface pressure should be depleted to 300 psi. After that time, the production rate will continually decline as shown in the figure. At the end of twenty years the well will still be flowing at a rate of nearly 20,000 bbl/day.

Figure 19. Flow Rate Versus Time, Single Well Development, S. E. Pecan Island, LA., Optimistic Reservoir Parameters, in Most Favorable Part of the Reservoir.

TABLE XI
RESERVOIR AND WELL PARAMETERS, SINGLE WELL DEVELOPMENT, SE PECAN ISLAND, LOUISIANA PROSPECT, OPTIMISTIC DRAINAGE AREA

Well Depth	17,500 feet
Average Production Depth	15,800 feet
Average Reservoir Pressure	13,500 psi
Average Hydrostatic Pressure	7,350 psi
Surface Pressure (minimum)	300 psi
Average Fluid Temperature at Surface	290°F
Well (production tubing) Diameter	0.46 feet (5-1/2" OD)
Drainage Area	13 mi ² (8400 acres)
porosity	23%
permeability	10 md
Compression Drive Coefficient	5×10^{-6} psi ⁻¹
effective sand thickness	980 feet
dissolved methane	35 SCF/bbl
Initial Production Rate	50,000 bbl/day

The cumulative water and methane production over the life of the well are shown in Figures 20 and 21, respectively. After 20 years, the well will have produced more than 30 million barrels of water and 10 billion cubic feet of natural gas.

Figure 20. Cumulative Water Production, Single Well Development, S. E. Pecan Island, LA., Optimistic Reservoir Parameters.

Figure 21. Cumulative Gas Production, Single Well Development, S. E. Pecan Island, LA., Optimistic Reservoir Parameters.

b. Johnson's Bayou

Johnson's Bayou, in Cameron Parish Louisiana, represents a different type of reservoir at shallower depth. With the top of geopressure at a depth of approximately 9,000 feet, net sand thickness totals as much as 2,200 feet, and production wells would be drilled to an average depth of 11,400 feet. At this depth, well costs should be much lower than in the deeper formations of S.E. Pecan Island or Brazoria County, Texas.

Reservoir performance for the Johnson's Bayou prospect was calculated on the basis of the reservoir parameters given in Table XII.

TABLE XII
ESTIMATED AVERAGE RESERVOIR PARAMETERS FOR
JOHNSON'S BAYOU PROSPECT, LA

Average depth	11,200 feet
Sand thickness	1,550 feet
Well radius	0.23 feet
Reservoir radius	10,000 feet (11.4 square miles)
Initial reservoir pressure	8400 psi
Hydrostatic pressure	5200 psi
Minimum surface pressure	300 psi
Permeability	100 md
C _g	5 x 10 ⁻⁶ psi ⁻¹
Methane content	20 scf/bbl

This well should be capable of flowing 40,000 bbl/day for twenty years as shown in Figure 22 if a single well will drain an area as large as 11.4 square miles. The cumulative water production will total approximately 300 million barrels and methane production about 5 billion scf as shown in Figures 23 and 24.

Figure 22. Flow Performance of Single Well Development in Johnson's Bayou Prospect, Camevan Parish, LA., Optimistic Parameters.

The weakness of a reservoir such as Johnson's Bayou (at shallow depth, where porosity and permeability are likely to be high), lies in the low temperature of the brine (average of 201°F), and the low value of dissolved methane in the water. Although the wells will cost less than wells in S.E. Pecan Island, for example, the water is likely to have no thermal value, and the predicted methane production is only half as great.

Figure 23. Cumulative Water Production, Single Well Development, Johnson's Bayou, LA.

Figure 24. Total Gas Production, Single Well Development, Johnson's Bayou, LA.

E. Summary and Conclusions

The initial interest in the geopressured zones of the Gulf Coast as a source of energy was based upon reservoir models which included high values of porosity, permeability and formation compressibility; high values of solution gas; and large single-well drainage areas. These requirements are still in effect. As more information is gained about these abnormally pressured sediments, the deviation between the required characteristics of producing reservoirs and actual reservoir parameters, becomes painfully apparent. It now appears doubtful that

any well will be able to produce as much as 50,000 bbl-/day for twenty years. The most favorable location yet identified is the S.E. Pecan Island prospect in Louisiana. Assuming favorable reservoir parameters and large single-well drainage area (13.4 square mile), a well drilled in the most favorable part of this prospect could produce as much as 10 billion cubic feet of natural gas in twenty years; but an average well in the same prospect is more likely to produce less than half as much.

This is about the equivalent production of a reasonably good conventional gas well.

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IV. ENERGY CONTAINED IN GEOPRESSURED SEDIMENTS

The magnitude of the geopressured resource has been the subject of a number of previous estimates based on a variety of assumptions. The results vary widely. The energy consists of the thermal energy in the hot water in the rock, the dissolved methane, and the hydraulic energy released by mass flow of the fluid. Since geopressure appears to be a general feature of deeper sediments in the Gulf Coast basin, extremely large energy estimates can be obtained by the most cursory examination. For example, in an on-shore area bounded by the coastline and extending 60 miles inland, one may speculate that there are at least 100,000 cubic miles of geopressured sediments. Even if the average effective porosity were only 10%, these sediments should contain 290 trillion barrels of water. If the water contained an average of 30 cubic feet of methane/barrel, the total methane in place would amount to 8700 trillion cubic feet. This represents nearly 40 times the total known natural gas reserves in the United States.

While such exercises are interesting and produce impressive numbers, their usefulness is negligible, and rate with the classic "gold in seawater" fable. The important consideration is the technically producible resource base and, more specifically, the fraction of the resource producible at competitive cost.

these assumptions were modified to reflect data from an extensive study of more than 3,000 well logs, combined with the conclusions of several studies made after the 1975 report.

1. USGS Circular 790 (Wallace et al, 1978)

In the 1978 report, the assessment area was expanded considerably over that used in the 1975 USGS document, and included off-shore as well as on-shore geopressured zones. The well log study provided the basis for estimation of sandstone volume of the sediments, which Wallace concluded contains 10% of the total resource. The remainder of the resource is contained in shale. Although Wallace includes the shale volume in his total assessment (as did Papadopoulos in 1975), there is no foreseeable prospect of producing any fluid the shale might contain. Consequently, the sandstone volume is the significant part of the USGS assessment, as it contains the potential geopressured reservoirs of interest.

The conclusions, based on the various assumptions made by Wallace and his associates, are summarized in Table XIII. The total resource contained within the sandstone volume, both on and offshore, is

TABLE XIII
ENERGY-IN-PLACE ESTIMATES, USGS CIRC. 790
(Wallace et al, 1978)

Location	Area (square mile)	Methane (10^{12} SCF)			Thermal (10^{15} BTU)		
		Sand	Shale	Total	Sand	Shale	Total
Total, onshore & offshore	120,000	5,700	54,000	59,700	10,430	91,000	101,400
Onshore only	70,000	3,052	35,100	38,152	5,490	57,000	62,490

A. Published Estimates of In-Place Resource

The most comprehensive study of the geopressured resource base in the Gulf coast has been provided by the USGS, reported in two documents (Papadopoulos et al, 1975; Wallace et al, 1978). In the earlier document Papadopoulos divided the on-shore area of the Gulf Coast into 21 separate zones and based on limited data from those individual areas postulated a hypothetical geopressured reservoir in each. Based on these hypothetical reservoirs, estimates of the contained energy were made.

In the later, revised document by Wallace et al,

estimated at 5700×10^{12} scf (5700 TCF) methane and $10,430 \times 10^{15}$ btu (10,430 quads) thermal energy. Since the economical production of geopressured water offshore must be considered unlikely, a more meaningful value is the onshore resource, estimated by Wallace at 3,052 TCF methane and 5490 quads thermal.

2. Other Estimates

In addition to the USGS, a number of other researchers have assessed the energy content of the geopressured sediments. Estimates of both the energy in-place and the recoverable energy vary widely. In the 1975 USGS document, Papadopoulos estimated the total

quantity of methane, in both shale and sand, at about 24,000 TCF with the thermal energy content about twice that amount. However, the reference temperature used to calculate the thermal energy was 59°F, a value far lower than any practical basis for utilization. Jones (1976), starting with Papadopoulos' analysis and expanding on his assumptions, calculated the contained methane in the onshore area sandbeds alone at 17,000 TCF. Further, he assumed that offshore conditions were comparable and added enough additional resource to make the total methane content about 49,000 TCF. Jones' highly optimistic estimate was primarily the result of gross overestimation of the sandbed thickness, and the depth to which potentially productive sands could be expected.

Hise (1976), on the other hand, estimated the total area of the aquifers, both onshore and offshore, to be about 100,000 square miles. If the potentially productive geopressed sediments average 10,000 feet in thickness, he estimated the total gas in place in the sandstone aquifers at 3,000 TCF.

Dorfman (1976), while making no estimate of reserves, states that if the price for natural gas were high enough, about 0.33 TCF could be produced by the year 2000. By comparison, the Chocolate Bayou gas field, for example, located within the Brazoria, Texas geopressure fairway, has produced well over 1.0 TCF natural gas over the past 30 years.

During the ensuing period, various other projections have been made, although most have apparently been based on Jones' statement implying enormous natural gas resources. Brown (1976), for example, quotes "two competent sources" as placing the resource base for geopressed energy "between 60,000 and 105,000 quads for the natural gas alone".

In contrast, Hawkins (1977), on the basis of intensive study of geopressed sediments in Louisiana, estimates the technically producible (without regard for cost) methane in the geopressed water in that state at 13.6 TCF (about 13.6 quads).

B. Energy Contained within the Twenty Prospect Areas

A more consistent estimate of the resource present in the twenty known geopressed prospects should be possible, since speculation about sand volume at least is minimized. These sites have been described in a previous section of this report, and consist of 14 areas in Texas and 6 in south Louisiana, chosen on the basis of large potential reservoir sand accumulation. While other geo-

pressured aquifers certainly exist, these twenty areas, covering somewhat less than 4,000 square miles out of a total assessment area of approximately 55,000 square miles, probably represent the most promising prospects for geopressed water production. Based on the total estimated geopressed sand volume in each area, the estimated in-place water, dissolved methane, and thermal energy are summarized in Table XIV. It will be noted that the Harris-Wilcox prospect in Texas contains more than 80% of the total energy in all the twenty

TABLE XIV
ESTIMATED WATER, METHANE AND THERMAL ENERGY
CONTENT GEOPRESSED FAIRWAYS IN TEXAS
AND LOUISIANA

	Water (in Sandstones) 10 ⁹ bbls	Nat. Gas in Solution 10 ¹² SCF	Thermal Energy 10 ¹⁵ BTU
<u>Texas Frio</u>			
Hidalgo	142	5.7	8.9
Armstrong	14	0.6	0.88
Corpus Christi	68	2.7	4.3
Matagorda (2)	3	0.1	0.19
Brazoria	56	2.2	3.5
	<u>283</u>	<u>11.3</u>	<u>17.8</u>
<u>Texas Wilcox</u>			
Zapata	16	0.6	1.0
Webb	18	0.7	1.1
Duval	54	2.2	3.4
Live Oak	17	0.7	1.1
Dewitt	189	7.6	12.0
Colorado	164	6.6	10.3
Harris	4784	111.4	301.4
Liberty	89	3.6	5.6
	<u>5331</u>	<u>213.3</u>	<u>335.9</u>
<u>Louisiana</u>			
S.E. Pecan Island	54	2.3	3.4
Rockefeller Refuge	39	1.8	2.5
Johnson's Bayou	89	1.8	2.8
Atchafalaya Bay	49	1.1	3.0
LaFourche Crossing	15	0.5	0.9
Sweet Lake	7.5	0.3	0.45
	<u>253.5</u>	<u>7.8</u>	<u>13.05</u>
TOTAL	5897.5	232.5	366.8
Total w/o Harris F'way	1113.5	41.1	65.4
<u>BASIS</u>			
Water	<u>Texas</u> 20% of estimated reservoir volume	<u>Louisiana</u> Bernard, 1979	
Methane	40 cubic feet/bbl × estimated water	Bernard, 1979	
Thermal	300°F maximum, 120° rejection temperature	Average reservoir temperature (Bernard), 120° rejection temp.	

prospects combined. The total estimated methane contained in the sands in all the prospects is 232 TCF and the thermal energy about 367 quads.

This estimate is probably reasonably compatible with the estimate of energy in the sandstones made by Wallace. If the total methane in place in onshore sands is 3,000 TCF (Wallace), the fraction of the resource occurring in potentially high quality reservoirs, 232 TCF, represents about 8% of the total.

C. Recoverable Resource

1. Water, Methane and Thermal Energy

At the present time, the only access to the energy contained in geopressed sediments is by producing hot brine from the sandstones, depleting the reservoir pressure. As shown in the preceding chapter of this report, the production capability of a geopressed reservoir is dependent upon a number of parameters, among which is the formation compressibility. Randolph (1977) has shown that production from a geopressed well declines to zero at a wellhead pressure of P_s when the fraction of total water produced is $C_e(P_r - P_h - P_s)$ where C_e is the compression drive coefficient, P_r is the initial reservoir pressure, P_h is the hydrostatic pressure and P_s the surface pressure. Thus, if an (optimistic) average reservoir pressure of 12,000 psi and an average hydrostatic pressure of 7500 psi is assumed for all the twenty prospective areas, the fraction of the resource producible by compression drive ranges from less than 1% to about 4% of the total contained energy for values of the compression drive coefficient of 1×10^{-6} to 10×10^{-6} psi $^{-1}$. Using a realistic (although optimistic) value of 7.8×10^{-6} psi $^{-1}$ for C_e , the total recoverable water becomes 194 billion barrels, the recoverable methane resource 7.6 TCF, and the recoverable thermal energy, 12.6×10^{15} BTU. This should certainly be considered an upper limit in the twenty prospects so far studied.

2. Hydraulic Energy

Hydraulic horsepower is the power produced by fluid flow under pressure. It is given by the expression

$$\text{HHP} = 1.7 \times 10^{-5} Q \times \Delta p \quad (4)$$

where

Q = flow rate, barrels/day

Δp = available pressure psia

Shaft horsepower is the hydraulic horsepower x the efficiency, η , typically 70%.

Because of the pressure dependence, the available horsepower from a flowing well is initially at its maximum, declining continually throughout the life of the well. Consequently, the difficulty with practical utilization of geopressed hydraulic energy is the design of equipment which can match the declining power availability curve. A typical example is illustrated in

TABLE XV
SURFACE PRESSURE DECLINE RATES AND WELLHEAD
HYDRAULIC HORSEPOWER, "OPTIMISTIC" WELL,
S.E. PECAN ISLAND, LOUISIANA; FLOW RATE:
50,000 BBL/DAY FOR 11-1/2 YRS

Year	Surface Pressure	Hydraulic Horsepower
1	2926	2487
2	2672	2271
3	2418	2055
4	2165	1840
5	1911	1624
6	1657	1408
7	1403	1193
8	1149	977
9	895	761
10	641	545
11	387	329
12	300	255
		Average 1312 HP

Table XV which shows the available horsepower with time from a well in the S.E. Pecan Island prospect illustrated in the previous chapter ("Optimistic" Case, p. 27). This well, flowing at a rate of 50,000 bbl/day for 11-1/2 years, would produce an average of 1,312 hp over a 12 year period or total energy of 1.38×10^8 btu. During the same period the well will also produce 8×10^9 scf methane, equivalent to 8×10^{12} btu. The hydraulic energy consequently represents less than 2% of the methane energy. On this basis, the maximum recoverable hydraulic energy in the twenty geopressed prospects cannot exceed .15 quads.

3. Electrical Generation Capability of Thermal Energy

It has been estimated that the total recoverable water from the twenty geopressed prospects is 194 billion barrels, and the recoverable thermal energy (at a rejection temperature of 120°F) 12.6 quads. To an electric utility, the usefulness of the thermal energy is related only to its ability to generate electrical power. Based on estimates of Holt (1974) for a 50 MW binary cycle geothermal plant, about 200 pounds of 300°F water is required for each kwh of electrical energy generated. The 194 billion barrels of recoverable water thus represents 3.4×10^{11} kwh of electrical energy. If this ca-

capacity could be utilized uniformly over a 50-year period, it is approximately equivalent to a single 1000 MW nuclear or conventional power plant.

Obviously not all of the thermal energy can be used to generate electricity; in fact, it is doubtful if any significant fraction could be utilized in this way. Temperatures in many of the fairways are substantially less than 300°F, many of the reservoirs are too small to support geothermal plants at all, and it is doubtful that any of the prospects can support as much as 50 MW of geothermal generating capacity.

4. USGS Estimate of Recoverable Resource

Wallace et al, for the entire Gulf Coast, both on and offshore, arrived at a recoverable energy estimate of 2.6% of the total resource base, including the energy in the shale. On that basis, a total onshore recovery of 992 TCF methane and 1625 quads thermal energy could be expected, according to Wallace.

At this point it is prudent to reject Wallace's thesis that the shale should be included in estimates of the recoverable resource. Except for the possibility of some minor shale compaction effects as the sandstone reservoirs deplete, there is no foreseeable possibility of producing appreciable fluid from Gulf Coast shales. "Shale dewatering" is the term coined to suggest possible shale behavior as an adjacent sandstone reservoir is depleted. It refers to shale compaction and drainage into the depleted sand, across the established pressure gradient. It must be stated that serious attempts to identify effects of this phenomenon have been largely unsuccessful, in spite of more than thirty years experience with conventional geopressured gas and oil reservoirs. A more conservative view holds that Wallace's recoverable energy estimates should have been based on a realistic percentage of the fluids within the sandstones only. For example, if a 3.3% recovery factor for the sandstone is assumed, estimates of the recoverable energy based on Wallace's work reduce to 100 TCF methane and 180 quads thermal, a full order of magnitude below his published estimate.

Other estimates of the recoverable gas resource, from the literature, include the following:

Jones (1976), 1146 TCF methane
Hise (1976), 125 TCF methane
House (1975), 222 TCF methane
U.S. ERDA "MOPPS" report (1977),
150-2000 TCF methane
Kuuskraa et al (1978), 42 TCF methane

D. Possibility of Greater-Than-Saturation Dissolved Methane Content

Certain aspects of the first DOE-sponsored test of a geopressured water sand in Louisiana (Osborn, 1978; Hankins et al, 1978; Karkalits, et al 1978) raised the possibility of greater-than-saturation values of dissolved methane in the brine (free gas). In simple terms, the well initially tested methane in solution at a value somewhat less than saturation. This value gradually increased as the well was flowed finally producing, at a high flow rate, a gas-water ratio several times greater than the solubility would indicate.

A considerable amount of speculation and some controversy were raised by these results. One school of thought suggested that the sand contained free gas, initially at or near "critical saturation" (the minimum gas saturation required for gas flow). The saturation was suddenly driven above the critical point by gas released from solution within the formation. In effect, the well might have been converted to a "gas well" as a result of the reduction in pressure.

An excellent treatment of the behavior of reservoirs containing gas, has subsequently been prepared by Mathews (1979), directly addressing the apparently anomalous results of the Louisiana test. Mathews has, to all intent and purpose, laid to rest the idea of free gas in geopressured water sands. Any undissolved gas in a permeable rock will inevitably migrate upward by the force of gravity, over periods of time which are short, geologically speaking. The laws of thermodynamics will insure that such migration results in the gas collecting in larger and larger gas bubbles, with the eventual formation of a "gas cap" at the nearest geologic trap. Migrating free gas has, indeed, resulted in our conventional geopressured gas deposits.

The excessive amount of gas produced during testing of the Louisiana well was probably the result of (1) a thin, tight gas-bearing zone at the top of one test sand (readily apparent from the well log) and (2) coning of gas from a producing well in the same zone, only 500 feet (152 m) up-dip, in the other sand. An alternative explanation is leakage of the liner (casing), permitting production from other gas bearing sands in the same well.

E. Summary of Recoverable Resource Estimates

The twenty identified prospects in Louisiana and Texas probably represent a sandstone concentration which includes a large share of the total producible geopressured resource. It is extremely unlikely that these twenty prospects can produce as much as 8 TCF meth-

ane and 15 quads of thermal energy. If the remainder of the onshore coastal area contains additional sites with an amount equal to this, one might set the maximum value for the producible resource at 20 TCF methane, with an equivalent amount of thermal energy of somewhat doubtful value. As a point of comparison the total current Texas annual natural gas production is about 7 TCF.

It may also be noted that without the huge Harris Fairway in Texas, which is known to contain very thick deposits of Wilcox sandstone of doubtful productivity, the estimate of producible methane in the remaining 19 prospects is only 1.35 TCF. It is also significant that all estimates, including those made in this report, are based on the assumption that all geopressured water is saturated with natural gas. This hypothesis is not based on specific data; in fact, the only data available indicate that, overall, the water is likely to contain less solution gas than has been assumed.

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V. SPENT BRINE DISPOSAL

A successful geopressured well is expected to produce from 10,000 to 40,000 bbl/day of saline water containing a variety of chemical constituents with a total dissolved-solids content ranging from 5,000 ppm to 250,000 ppm. At the present time there are three known options for disposing of the spent brine after energy recovery. These are, (1) surface disposal (local streams, bays and estuaries, evaporation pits, or directly into the Gulf of Mexico), (2) disposal by injection into shallow, normally pressured aquifers or, (3) by reinjection into the production reservoirs in the geopressured zone.

A. Surface Disposal

A wide variety of liquid wastes, including oil field brines similar to those anticipated in the production of the geopressured resource, have been disposed of by surface means for many years. Serious effects on the environment, including the salination of fresh water streams, pollution of ground water and destruction of productive land, have resulted in many cases. As a result, surface disposal of such materials has gradually been discouraged by a series of legislative and regulatory pressures over a period of the last twenty years. While surface disposal is still practiced, permits are re-

quired in both Texas and Louisiana to ensure minimal environmental effects. Such permits are now seldom issued for new projects, and it is safe to conclude that other disposal means for such materials will become universal. The impediments to surface disposal may thus be said to be regulatory; technically, the Gulf of Mexico is capable of accepting any conceivable discharge resulting from the development of the geopressured resource.

1. Composition of Geopressured Brines

The chemical characteristics of effluent brines is expected to be highly site specific. Nevertheless, considerable experience with these and similar fluids has resulted from petroleum production over the past 30 years or more. The total dissolved solids content appears to range from 5,000 ppm in isolated areas in the Hidalgo Fairway, to a high of 235,800 ppm in one Louisiana prospect. In general, chemical analyses obtained from petroleum industry sources have not included all trace elements, and careful analysis of individual brines from production sites will, of course, be required. In Table XVI are shown representative chemical constituents of formation waters in selected geopressured

TABLE XVI
CHEMICAL COMPOSITION OF FORMATION WATERS IN SELECTED GEOPRESSURED FAIRWAYS FROM
COASTAL TEXAS AND LOUISIANA (Kharaka, et al., 1977)

Area	Lafayette, La		Houston-Galveston, Tx		Corpus Christi, Tx		McAllen-Pharr, Tx	
Field	Weeks Island	Tigre Lagoon	Chocolate Bayou	Halls Bayou	Portland	Midway	Pharr	LaBlanca
Fairway	Southeast Pecan Island		Brazoria		Corpus Christi		Hidalgo	
TDS	235,700	112,200	73,300	58,100	17,800	36,000	36,600	7,500
Na	78,000	40,000	26,500	20,500	6,500	13,250	9,420	2,680
Li	16	7.1	9.9	15	3.6	4.2	7.5	1.2
K	1,065	265	400	180	68	72	240	46
Rb	3.4	0.8	0.4	0.9	0.3	0.5	0.8	0.1
Cs	11.8	3.5	---	---	---	---	2.9	0.3
Mg	1,140	270	220	170	15	48	18	3.3
Ca	10,250	1,860	2,000	800	89	330	4,225	150
Sr	920	320	365	170	7.0	23	256	9.6
Ba	185	8.2	290	59	1.4	13	27	1.5
Fe	84	0.4	10.2	22	2.3	1.6	4.1	<0.1
Cl	143,000	67,900	42,700	34,500	9,270	21,000	22,000	3,950
F	0.8	0.8	0.8	---	1.5	7.3	3.9	5.7
Br	419	63	52	32	19	45	78	15
I	18	26	16	11	25	45	22	16
B	44	57	35	91	62	35	105	117
NH ₃	100	69	29	13	5.8	13.5	21.5	4.2
H ₂ S	0.4	0.5	1.2	1.4	<0.1	0.04	<0.1	<0.1
HCO ₃	450	1,050	455	409	1,600	1,180	114	400
SO ₄	6.4	220	2.7	16	110	42	7.0	57
SiO ₂	48	57	87	110	93	132	90	88
pH	6.2	6.3	5.9	6.8	6.8	6.4	6.8	7.3

fairways from Coastal Texas and Louisiana. Solutes are heavily dominated by sodium, potassium, calcium and magnesium chlorides. Certain heavy metals such as cadmium, lead, zinc and mercury are apparently absent, along with arsenic and others. The origin of heavy metals and other elements in brines is dependent on the origin of the fluids and the host rock in which they have been contained. The addition of materials through contamination by drilling and sampling activities is also a potential source of heavy metals and other elements in analyzed samples. For these reasons, existing analyses cannot be considered complete, but the apparently rather simple character of the brines is encouraging.

2. Effect of Brine Components on Surface Environment

The most tolerant plant species are capable of withstanding natural marine salt concentrations approaching 50,000 ppm. According to Hoese (1967), the Gulf salt marsh system would be destroyed by salinities which approached or exceeded 50,000 ppm. Additional plant species are extremely sensitive to ionic imbalances which could occur as a result of large scale brine disposal in surface water bodies. Obviously, the discharge of brine into fresh water streams, lakes and on the land surface would be intolerable to the vast majority of both plant and animal life in the affected areas.

The salinity of geothermal effluent alone does not preclude its disposal into the Gulf of Mexico or into certain coastal waters. Gustavson and Kreitler (1977) point out that coastal waters are characterized by highly variable salinities ranging from fresh to hyper-saline. The key to surface disposal in such bodies is adequate mixing, in which case it would have little effect on the overall salinity because of the vastly greater volume of marine water. Furthermore, periodic freshening of bays and estuaries by flood waters would not be significantly diminished by geothermal disposal. High concentrations of heavy metals which may be disclosed in specific instances (the boron concentration, for example, already appears to exceed safe limits in some samples) could invalidate this premise.

3. Thermal Considerations

Geothermal fluid produced from geopressed wells is expected to be produced at temperatures ranging from 250 to 350°F and, if used in a geothermal facility, discharge temperatures will still be in excess of 125°F. Extensive cooling will be required before such fluid can be disposed of in coastal waters of the Gulf of Mexico (Texas Water Quality Board, 1975). This is a matter controlled by regulation in both Texas and Louisiana, and such cooling (probably in holding ponds) will

be an expensive adjunct to surface disposal facility requirements. Generally speaking, cooling the effluent to 95°F or less will be required for such disposal.

B. Regulatory Constraints

1. State Control

The responsibility for regulatory control of brine production and disposition in Texas and Louisiana rests with several state agencies listed in Table XVII.

TABLE XVII
STATE AGENCIES WITH RESPONSIBILITY FOR BRINE
PRODUCTION AND DISPOSITION

<u>Texas</u>	<u>Louisiana</u>
Texas Department of Water Resources	Louisiana Stream Control Commission
Texas Railroad Commission	Louisiana Conservation Department
Texas Air Control Board	Louisiana Air Control Commission

The Texas Department of Water Resources and the Louisiana Stream Control Commission are charged by law with maintaining the quality of surface and ground water above acceptable standards in their respective states. The TDWR and the LSCC have established numerical water quality standards for individual streams for a number of specific parameters, including total dissolved solids, chlorides, sulfates, pH, and temperature.

In addition, each stream in Texas is subjectively evaluated on the basis of its suitability for contact recreation, noncontact recreation, propagation of fish and wildlife, and domestic raw water supply.

In Louisiana, the waters are subjectively classified as either class A, water contact recreation and other uses, or class B, fish, wildlife and other uses. Relative to the discharge of geothermal fluids in Texas, the following general limitations are pertinent:

- (1) There shall be no more than a 5°F (2.75°C) rise over ambient temperature for fresh water streams.
- (2) There shall be no more than a 3°F (1.65°C) rise over ambient temperatures for freshwater impoundments.

- (3) There shall be no more than a 4°F (2.2°C) rise or a maximum temperature of the receiving water greater than 95°F (52.5°C) in fall, spring, and winter; and no more than a 1.5°F (0.85°C) rise or a maximum temperature of 95°F (52.5°C) in summer for tidal reaches of rivers and bay and Gulf waters.

The corresponding temperature limitations in Louisiana are:

- Fresh Water—Temperature differential
  - (1) Maximum of 5°F (2.8°C) rise above ambient for streams and rivers.
  - (2) Maximum of 3°F (1.7°C) rise above ambient for lakes and reservoirs.
  - (3) Maximum Temperature—90°F (32.2°C) except where otherwise listed in the tables or due to natural conditions.
- Estuarine and Coastal Waters—Temperature differential
  - (1) Maximum of 4°F (2.2°C) rise above ambient during the period October through May.
  - (2) Maximum 1.5°F (0.83°C) during the period June through September.
  - (3) Maximum Temperature—95°F (35°C) except when natural conditions elevate temperature above this level.

It is recognized that regional and seasonal variances occur such that each stream segment, tidal reach, and identified bay is evaluated separately by the agency in each State. Also, mixing zones are allowed so that receiving water may actually exceed the temperatures above for a predetermined distance (relatable to a quantity of water). Applications of variances from the established standards are entertained by each State agency, and would be adjudged based on environmental/economic/social needs.

In addition to the numerical water quality standards mentioned above both the TDWR and the LSCC have established general water quality criteria for their respective states.

The Texas Railroad Commission is primarily concerned with the disposal of hot saline fluids derived from wells permitted by the Commission. In addition to regulating the drilling of the wells, and their production, the TRC is charged with regulating reinjection for disposal purposes and conducting reviews of surface disposal activities. Each application for a permit, whether proposing to operate within established standards or asking for variance, is treated individually. In early 1979 the TRC opted for a full TRC permit action for many variances that used to be routinely (administratively only) granted. It is evident that the TRC is intent on fully exercising their mandated provisions by requiring thorough investigations of probable environmental/social effects before issuing a permit.

The Texas Air Control Board and Louisiana Air Control Commission are responsible for permitting facilities that emit regulated air pollutants within their respective states. Also, if the facility has the potential to emit more than 100 tons of any regulated air pollutant it must undergo a Prevention of Significant Deterioration (PSD) review by EPA. This review and approval by EPA is necessary in both states before an air construction permit can be issued. This could be pertinent, particularly if residual methane or H₂S in the spent brine is significant.

The Texas Geothermal Act of 1975 empowers the Texas Railroad Commission to regulate the exploration, development and production of geothermal energy and associated resources on public and private land for the purpose of conservation and the protection of correlative rights. This authority will surely be exercised more frequently as geothermal energy is exploited in the future in Texas.

2. Federal Requirements

Four major thrusts of Federal initiatives which will affect the potential disposal of geopressed/geothermal fluid can be identified as follows: (1) enforcement of national standards of water quality through National Pollutant Discharge Elimination System (NPDES) permits; (2) regulation of underground waste disposal through the Safe Drinking Water Act (SDWA); (3) requirement of an environmental impact statement through the National Environmental Policy Act (NEPA); and (4) requirement to meet the Federally guided air pollution standards as set up by the Clean Air

Act. In addition, if the facility were to involve construction (e.g., pipeline) in navigable waters or wetlands, Section 10 of the River and Harbor Act of 1899 and Section 404 of the Federal Water Pollution Control Act Amendments (FWPCA) of 1972 would influence the project.

The NPDES was mandated as a result of the Federal Water Pollution Control Act Amendments of 1972. The FWPCA requires a permitting program to control the discharge of a pollutant into navigable waters. Federal permits are issued for discharges until a state permit system has been approved. At the present time Louisiana does not have NPDES permitting authority. As of April 1979 the Texas program had not been approved, though significant portions of the Texas plan appear acceptable to the Environmental Protection Agency. Before any facility which would discharge saline waters into the surface waters of either state could be operated, an NPDES permit is required.

The SDWA provides for control over subsurface disposal of waste fluids to protect underground sources of drinking water. Guidelines have been developed by the EPA for the state control of underground injection activities to guard against the introduction of contaminants into drinking water sources.

The NEPA makes it mandatory to prepare an environmental impact statement (EIS) prior to the startup of any major project which will significantly affect the Environment. Various Federal agencies (including EPA, Dept. of the Army, Dept. of the Interior and Dept. of Energy) can initiate and comment on the contents of an environmental impact statement as is deemed necessary. It is a virtual certainty that a geopressured/geothermal utilization facility disposing of hundreds of thousands of barrels of brine per day would require the preparation of an EIS.

The Federal Clean Air Act is intended to protect and enhance the quality of the air resources of the nation. As in other Federally mandated programs, the responsibility for the enforcement has been turned over to individual states when possible. The Texas Air Control Board and the Louisiana Air Control Commission regulate air quality maintenance in their respective states, and oversee permit applications, timely issuance, and subsequent compliance.

The Department of Army has responsibility under Section 10 of the River and Harbor Act of 1899 and section 404 of the Federal Water Pollution Control Act Amendments of 1972 to determine whether proposed work in navigable waters in the United States would be consistent with the public interest. Permits for

dredging/construction in navigable waters under these Sections are handled by the U.S. Army Corps of Engineers (CoE).

3. Effect of Proposed "Hazardous Waste" Guidelines on Final Disposition of Geothermal Brines

On December 18, 1978, the Environmental Protection Agency (EPA) issued in the Federal Register proposed rules under Sections 3001, 3002, and 3004 of the Solid Waste Disposal Act. These rules could have a profound effect on the economics of geothermal energy production along the Louisiana and Texas coast, and elsewhere. The EPA proposals deal with the following: (1) criteria for identifying and listing hazardous waste, identification methods, and a hazardous waste list; (2) standards applicable to generators of such waste for record keeping, labeling, containerizing, and using a transport manifest; and (3) performance standards for hazardous waste management facilities.

In the course of preparing these regulations the EPA recognized that certain very large volume wastes will be deemed hazardous. These large volume wastes, called "special wastes" by the EPA, include gas and oil production brines. Although geothermal brines are not specifically mentioned, it is reasonable to assume that they too will be classified in this special waste category. The possible hazards which the agency has identified in oil field production brines (and by association geothermal brines) are: excessive alkalinity, heavy metals and salinity. A proposed rule-making will be published at a later date regarding the treatment, storage and disposal of "special waste".

If geothermal brines are considered a potential hazardous waste under the final regulations, and if a specific brine is tested and found to be actually hazardous by the tenets set forth in the law, then limited modes of disposition are available including (1) indefinite storage, (2) incineration (evaporation), (3) surface impoundments, (4) reinjection (not listed in proposed regulations as an option, but certainly at the present time, an acceptable mode of permanent disposal.) Subsurface disposal in nongeopressured reservoirs will be open to some scrutiny; for example, adequate monitoring to ensure containment of all such brines, including oil field production brines, may be necessary. Each of the modes of disposal mentioned above can be expected to add a considerable fiscal burden to the cost of producing energy if for no other reason than because of the copious record-keeping and monitoring activities which will be required. The final EPA solid waste disposal regulations will require thorough scrutiny to determine the full implications of new, more stringent controls in the fledg-

ling geothermal energy industry, not only along the Texas-Louisiana coast, but throughout the United States.

A summary of the environmental permitting requirements for locating a geopressed/geothermal utilization facility in Texas or Louisiana is presented in Table XVIII. These permits represent only those concerned with the environmental aspects of the project, not permits required for other purposes (e.g., sales of electricity, etc.). Sample applications for disposal permits, and regulations dealing with both surface and subsurface disposal, are included in Appendix C.

Approximately 14% of the above wells are considered "high rate" disposal wells, with expected injection rates in excess of 3000-5000 bbls/day. The median disposal rate for these "high rate" wells is 8000 bbls/day with the maximum rate being 34,000 bbls/day for a well in Stratton Ridge Field in Brazoria County (Knutson and Boardman, 1978).

Regulation of subsurface disposal activities has, historically, been the responsibility of the Texas Railroad Commission and the Louisiana Office of Conservation, respectively. These agencies permit well operators to dispose of saline water only in formations that

TABLE XVIII
FEDERAL AND STATE ENVIRONMENTAL PERMITS REQUIRED FOR GEOPRESSED/GEOTHERMAL FACILITY

Activity Requiring Permit	Texas		Louisiana	
	Type of Permit	Permitting Authority	Type of Permit	Permitting Authority
Disposal of wastes to surface waters	NPDES discharge permit TDWR discharge permit	EPA TDWR	NPDES discharge permit LSCC discharge permit	EPA LSCC
Dredging/construction in navigable waters	Section 10/Section 404 permits	COE	Section 10/Section 404 permits	COE
Potential air emissions of >100 tons per year of any regulated air pollutant	PSD preconstruction approval	EPA	PSD preconstruction approval	EPA
Disposal to injection well	TRC injection well disposal permit	TRC	LCD injection well disposal permit	LCD
Emitting regulated air pollutants	TACB construction and operating permits	TACB	LACC construction/operating permit	LACC
Legend: EPA — Environmental Protection Agency COE — Corps of Engineers TDWR — Texas Department of Water Resources LSCC — Louisiana Stream Control Commission TRC — Texas Railroad Commission LCD — Louisiana Conservation Department TACB — Texas Air Control Board LACC — Louisiana Air Control Commission				

C. Shallow Subsurface Disposal

Disposal of oil field brines and industrial effluents in relatively shallow, normally pressured saline aquifers has been an accepted practice for several decades. Texas Railroad Commission statistics reveal that in the coastal counties of Galveston, Brazoria, Matagorda, Aransas, Kenedy, Willacy, and Hidalgo, more than 600 disposal wells have been permitted since 1950. The Louisiana Office of Conservation reports that some 1300 disposal wells have been permitted in the ten coastal parishes west of the Mississippi River since 1967.

contain mineralized water unfit for agricultural or general use and that do not contain oil or gas. These regulations, along with operators' precautions, have proven to be quite effective. There have been no significant cases of fresh water contamination in either state resulting from subsurface disposal.

1. Geological Evaluation of Disposal Aquifers

Geological studies of shallow normally pressured saline aquifers have been conducted in two prospective areas, Austin Bayou in Brazoria County, Texas

and S.E. Pecan Island in Vermilion Parish, Louisiana. The primary goal of the studies was to determine the volume and continuity of the sandstones suitable for disposal of spent brines. For this evaluation, geological mapping was generally limited to an area of approximately 5 mile radius around the actual or proposed disposal well site. Even with this limitation, the areas studied were quite large, each encompassing almost 80 square miles. Results of the studies are summarized below.

a. Austin Bayou Prospect (Brazoria, Texas)

In the area of the DOE test well in the Brazoria prospect, plans call for the first of the two wells already drilled to be plugged back and completed as a disposal well. This potential installation, the General Crude-DOE Pleasant Bayou #1, has logged an interval suitable for brine disposal from the base of the fresh water-salt water transition zone at a depth of about 2000 feet (610 m) to the base of the Miocene section at 7200 feet (2195 m). The section is a typical Gulf Coast Tertiary sandstone-shale sequence with sandstone comprising up to 45% (700 m) of the total interval. The stratigraphy reflects cyclic transgressive-regressive deposition in a marginal marine environment. The regressive phases are characterized by high sand percent, progradational deltaic sediments, while the transgressive phases are represented by 200 to 300 foot (60 to 90 m) marine shales. Micro-fossils (foraminifera) sampled in several wells in the area indicate deposition in water depths ranging from zero to 90 m. Due to the lack of continuity of individual sandstone beds, correlation was focused on "packages" of sand that can be correlated area-wide. The packages represent regressive cycles with a sandstone percentage up to 80% and an average thickness of about 700 feet (213 m). It is highly probable that the sandstone bodies in each of the packages are interconnected ("nested"), forming a continuous aquifer.

The structural style of the area is dominated by the salt structures of Danbury Dome, Hoskins Mound, Chocolate Bayou, and Alligator Point. The prospect area is located in the salt withdrawal syncline between these structures. No major growth faults cut the Miocene-Pliocene section within the study area; however, there are several small normal faults radiating from the salt structures into the area of the proposed disposal well. These faults are not expected to act as barriers because of the probability of sand-to-sand juxtaposition across them.

Isopach maps of intervals in the Miocene indicate that these structures were "growing" during the course of deposition, thereby exerting a major

influence on the location and extent of sand deposition. Net sand maps over the Miocene-Pliocene interval corroborate this influence, showing thinning over structural highs and thickening over the lows.

Porosity in the Miocene-Pliocene sandstones in the prospect area can be expected to range from 28% to 32% with permeabilities in excess of 200 md. These values are based on industry experience in the area.

The study revealed that there is sufficient sand in the normally pressured zone to dispose of very large quantities of brine without adverse effects on the shallower fresh water sands. The total volume of the Miocene-Pliocene saline aquifers is in excess of 25 cubic miles. A typical section and well log of the proposed disposal well is shown in Figure 25.

Figure 25. Well Log of Miocene-Pliocene Section in Austin Bayou Prospect, Brazoria Fairway, Texas Showing Shallow Sands Suitable for Spent Brine Disposal (General Crude-DOE Pleasant Bayou No. 1)

b. S.E. Pecan Island Prospect

The S.E. Pecan Island Prospect is located in the southern portion of Vermilion Parish, Louisiana. The prospect is bounded on the northwest by the Pecan Island Field, on the northeast by the Freshwater Bayou Field, on the south by the Vermilion Block 16 Field and on the southeast by the Vermilion Block 14 Field.

The potential disposal interval in the area ranges from a depth of about 900 feet to a depth of 8000 feet. This interval consists of interbedded sandstones and shales ranging in age from Plio-Pleistocene to basal Upper Miocene.

The Upper Miocene section (6000-8000 feet) is characteristic of deposition in a middle to outer neritic marine environment (150-300 foot water depth). The interval is predominantly shale with sandstone suitable for disposal comprising generally less than 20 percent. These sandstones, up to 100 feet thick, exhibit widespread extent and can be correlated for distances of several miles. Total net sand for the Upper Miocene section in the area ranges from 200 to 600 feet in thickness.

The Plio-Pleistocene section in the prospect area consists of facies deposited in a transitional to inner neritic environment (0-150 foot water depth) and ranges in depth to approximately 6000 feet. The boundary between the Pliocene and Pleistocene rocks cannot be distinguished because of the lack of shallow paleontologic data. The interval is typical of a high sand percent, regressive sequence. Correlation of individual sandstones is difficult but aquifer continuity is probably great due to most of the sandstone bodies being interconnected.

Because of the practice of setting surface casing without logging, the geology of the interval above a depth of about 3000 feet must be inferred from few data points. It appears, however, that the interval from the base of fresh water to the top of the Miocene has a total sand percentage ranging from 30 to 50 percent.

The four fields surrounding the prospect are located on separate anticlinal features that are probably related to deep seated salt movement. Major down-to-basin normal growth faults lie both to the north and south of the prospect area, but there is no evidence of large growth faults within the area. There are, however, numerous small normal faults (less than 200 feet) in the area but these should not act as barriers to flow in the aquifers.

Porosity and permeability in the disposal interval should be similar or higher than that in the Austin Bayou Prospect area.

Total disposal sandstone volume in the S.E. Pecan Island area is estimated to exceed 15 cubic miles.

Table XIX relates the disposal aquifer interval and thickness of potential disposal zones in several other prospect areas from which shallow data are available.

TABLE XIX
DISPOSAL INTERVAL IN SEVERAL PROSPECT AREAS
FOR WHICH DATA ARE AVAILABLE (FT)

Prospect	Disposal Interval	Net Sand
Austin Bayou, Brazoria County	2000-7200	2300
Armstrong, Kenedy County	2445-6200	1375
Corpus Christi, Nueces County	1980-6800	1100
Hidalgo, Hidalgo County	2500-5000	407
Matagorda, Matagorda County	1550-6600	1560
Rockefeller Refuge Cameron Parish	4000-6000*	700*
S.E. Pecan Island Vermilion Parish	900-8000	1900

*From Bernard, 1979.

2. Reservoir Considerations

From an engineering standpoint, there are at least three fundamental problems in disposing of the produced geopressured brines in shallower aquifers. These are:

- (1) chemical compatibility of the geopressured and shallower brines,
- (2) environmental effects such as leaks to adjacent potable zones through improperly abandoned holes,
- (3) legal aspects involving the permitting process with state and federal agencies.

Subsurface brine disposal to hydrostatically pressured aquifers along the Texas and Louisiana Gulf Coast is a common practice. Knutson and Boardman (1978) have summarized much of the disposal experience. Their study focused on summarizing brine injection for all wells with rates of 3000 bbls/day or greater.

a. Chemical Incompatibility Problems

Chemical incompatibility could result in clay swelling, precipitation or fines movement. Salinities, total dissolved solids and the type of ions present would be the indicators of potential compatibility problems. There appear to be two opposite views expressed. One is that the geopressed brines may be fresher than the shallower aquifers, the other that they exhibit the same or higher salinity than these shallower brines. It appears from available data that the geopressed brines vary so widely in salinity that either case could occur depending upon the specific site. The data reported by Donaldson (1970) for samples from 99 different geopressed wells was examined as a function of both depth and position along the Gulf Coast. A plot is illustrated in Figure 26. Note there is no apparent corre-

Figure 26. Diagram of Total Dissolved Solids Variation with Depth for Geopressed Brines on the Gulf Coast (Data from Donaldson 1978)

lation either with depth or position for total dissolved solids. Other authors, Wallace et al (1978), Schmidt (1973), and Bebout et al (1978), have illustrated variations of salinity with depth which show the geopressed sediments to be fresher than the shallower aquifer zones. It appears, however, that this expressed trend is highly site-dependent since Bebout et al (1978) show the

salinity profile of the Brazoria County Chocolate Bayou location as being higher in the geopressed zone than in the shallower zone from 3000 to 6000 feet (914 to 1829 m).

With regard to geochemical compatibility, Knutson and Boardman (1978) from their experience paper, state that "In general, it has seldom been possible to inject untreated brine over an extended period, thus treating should be considered a fact of life in any disposal project". At the desired rates necessary for a geopressure project, treatment costs could become important.

b. Environmental Effects

Groundwater and surface water brine contamination, surface subsidence or uplift, and earthquakes all fall into the category of potential environmental effects. Groundwater contamination is possible if injection well casing leaks or cement failures occur and allow a fresh water aquifer to take the injection brine. If the injection aquifer fracture pressure is exceeded, it is possible to conceive of a shallow potable aquifer connecting with the deeper disposal zone. More likely, a source of between-zone flow could be an improperly abandoned well. It is not uncommon to find such wells when injection projects are started. However, these wells can then normally be located and properly plugged. A cause and effect relationship has been established at some sites between seismic activity and fluid injection. However, the experience summary report of Knutson and Boardman (1978) does not indicate any such problem associated with current Gulf Coast disposal practice. Thus, it would appear that disposal of the geopressed brines in shallower zones, even at the higher required rates, will not be accompanied by important seismic effects.

c. Legal Aspects

Knutson and Boardman (1978) have cited literature references which indicate that the underground space has value and belongs to the landowner. There is also legal precedent for liability for harm for an organization injecting fluids into the subsurface. The State of Texas passed a geothermal resources act in 1975 anticipating geothermal or geopressure development. Knutson and Boardman cite those aspects of this Act which could effect brine disposal. These include:

- (1) Operation of each well so that no pollution of streams, water courses or subsurface waters will occur as a result of escape or release or injection of a geothermal resource.

- (2) Operators are prohibited from using salt water disposal pits for storage and evaporation of geothermal resource waters.
- (3) Disposal of liquid waste material into the Texas offshore or estuarine zones shall be limited to salt water and other materials which have been treated as necessary for the removal of constituents harmful to aquatic life.
- (4) Salt water unfit for domestic stock, irrigation or other use may be disposed of by injection into non-productive oil-gas or geothermal source zones, which contain water unfit for domestic stock or irrigation uses.

In addition, Texas has a Well Disposal Act which includes a requirement that a disposal well cannot be drilled to dispose of industrial or municipal waste without obtaining a permit from the Texas Water Quality Board. Knutson and Boardman (1978) point out a difficulty between the Well Disposal Act and the Geothermal Resources Act in that each specifies a different state agency as the governing permitting body.

Salt water disposal well permits are filed with the Austin office of the Railroad Commission. The Texas Water Quality Board reviews the applications and makes recommendations to the Railroad Commission.

As mentioned previously, the EPA has proposed regulations for underground injection control (40.CFR, Part 146). If these proposed regulations are promulgated, the cost of disposing of brines may be substantially increased. Considerable additional data over that of the normal salt water disposal wells is required.

3. Example Site Application—Brazoria Prospect

The disposal sands above the Brazoria geopressured zone have been mapped by INTERCOMP and were briefly described in a previous section. These data indicate a total of 1500-1800 feet (457-549 m) of sand suitable for brine disposal is located in the immediate vicinity of the Brazoria prospect. In an initial analysis, Zone 2 of several zones in this overall thickness was selected as a good potential disposal prospect. Sand

thickness for this zone varies from about 250 to 500 feet (76 to 152 m). The properties of this aquifer are listed in Table XX.

TABLE XX
ASSUMED PROPERTIES OF DISPOSAL SANDS, ZONE 2,
BRAZORIA COUNTY, AUSTIN BAYOU PROSPECT

Water Compressibility	$3 \times 10^{-6}/\text{psi}$
Sand Compressibility	$2.2 \times 10^{-6}/\text{psi}$
Water Thermal Expansion	$1.148/^{\circ}\text{F}$
Water Heat Capacity	$0.810 \text{ Btu}/\text{lb}^{\circ}\text{F}$
Sand Heat Capacity	$15.01 \text{ Btu}/\text{cu-ft}^{\circ}\text{F}$
Sand Thermal Capacity	$31.8 \text{ Btu}/\text{ft-day}^{\circ}\text{F}$
Longitudinal Dispersivity	300 ft.
Transverse Dispersivity	60 ft.
Injection Fluid Density	$67.7 \text{ lbm}/\text{cu.ft}$
Formation Temperature Grad	$1.32 ^{\circ}\text{F}/100 \text{ ft.}$
Overburden/Underburden	$35.0 \text{ Btu}/\text{ft-day}^{\circ}\text{F}$
Thermal Conductivity	
Overburden/Underburden	$2.70 \text{ Btu}/\text{cu-ft}^{\circ}\text{F}$
Heat Capacity	
Permeability	200 md
Porosity	0.28
Total dissolved solids	90,000 mg/

Several model simulation runs were made for this potential disposal zone. The model used (described in Appendix D in more complete detail) is a numerical, finite-difference solution of the "slightly compressible" continuity equation. The analytical solution for a pseudo steady-state version has been illustrated earlier in Chapter III and used in the reservoir analysis. The numerical model solves the complete transient set of equations. Three separate cases were examined: a single well, a two-well pattern, and a four-well pattern. In each case, each well had an injection rate of 40,000 bbl/day. The total dissolved solids content assumed for the disposal aquifer was 90,000 mg/L, while the spent geopressured brine was taken as 15,000 mg/L, at a temperature of 225°F. The temperature of the disposal zone was roughly 150°F. The predicted pressure and salinity concentration maps for a single injection well in the disposal aquifer are shown in Figure 27. At twenty years, the injection of some 290 million barrels results in altered total dissolved solids concentration over an area of approximately seven square miles. Temperature effects from the injection of the hot water occur over approximately a three and a half square mile area. The pressure increase at the well due to injection was about 320 psi, while the pressure some three miles from the injection well increased by only about 86 psi.

The impact of two injection wells 2-1/2 miles apart, each with a flow rate of 40,000 bbl/day, is given in Figures 28 and 29. In this case, the pressure increase at the well is about 460 psi.

Figure 27a. Areal Pressure Map for a Single Disposal Well Q = 40,000 bbl/d. Contour Interval — 6.9 psi

Figure 27b. Areal Concentration Map for a Single Well, Q = 40,000 bbl/d, t = 20 Years. Contour Interval = 3,600 mg/l.

Figure 28. Areal Pressure Map for Two Wells at 40,000 bbl/d Each. Contour Interval — 8.6 psi

Figure 29. Areal Concentration Map for t = 20 Years. Contour Interval = 3,600 mg/l.

The illustration of pressure and concentration for four disposal wells separated by 2-1/2 miles in each direction is illustrated in Figures 30 and 31. In this case the pressure interference pattern can be clearly seen.

Figure 30. Areal Pressure Map for Four Injection Wells at 40,000 bbl/d Each. Contour Interval — 11.5 psi

Table XXI indicates the pressure increases that result from various injection strategies. If improperly abandoned wells were present in this zone, the pressures could cause brine flow to an adjacent higher or lower zone.

TABLE XXI
CALCULATED INCREASE FOR VARIOUS INJECTION PATTERNS

Number of Wells	Well Separation Distance	Pressure Increase (psi)		
		At Well	At Center of Pattern	At Edge of Pattern
1	—	323.3	323.3	86
2	2.5 miles	454.4	240	
		459.5		
4	2.5 miles	644.0		
		680.0		
		664.0	437.4	343.7
		655.0		
4	1.5 miles	690.5		
		722.8		
		716.8	497.9	340.7
		696.9		

To illustrate the importance of such leakage to an adjacent zone, the case for a single injection well at 40,000 bbl/day has been estimated. In this case, the pressure increased about 260 psi at a distance of one mile from the injection well, for permeability of 100

Figure 31. Areal Concentration Map for $t = 20$ Years. Contour Interval = 3,600 mg/l.

md. If one assumes the abandoned well is partially plugged, but with a high effective permeability of perhaps one Darcy, one can use a normal Darcy flow equation to estimate the flow through the abandoned well. If the difference in salinity is neglected, the flow rate over a 1500 ft well length is about 0.5 feet³/day, or less than 0.1 bbl/day. If this flow were in an upward direction, the salinity gradient would act to decrease the overall flow. If the upper aquifer receiving the flow were fresh, and the salinity in the disposal zone were about 90,000 mg/, this flow would be reduced by about 1/3. These results tend to indicate that such leakage volumes are small compared to the disposal volume.

The example site analysis does indicate that tremendous volumes of brine could be disposed of in shallower aquifers along the Gulf Coast. Although the chemical compatibility and environmental aspects mentioned earlier would be of concern, these are problems that actual disposal experience indicates can be overcome. As a consequence, it certainly appears that injec-

tion of the geopressured production is technically feasible into shallow brine aquifers. Although there is little experience for injection rates in the 30,000 to 50,000 bbl/day range, the potential disposal zones appear large enough and thick enough to take these quantities of fluid. The equipment needed for injection of these volumes should not be a limiting factor, since rates of this magnitude for injection or production are not uncommon in the Mid-East. Thus, it does not appear that there is any unforeseen technical problem that cannot be overcome.

D. ReInjection in the Deep Geopressured Zone

1. Advantages of ReInjection

From an environmental point of view, there are two main problems in the production of geopressured reservoirs. These are (1) the disposal of the produced brines, and (2) the potential for land subsidence with pressure depletion of the geopressured zone. ReInjection into the geopressured aquifer is a partial solution to both problems. In the section discussing disposal in shallow aquifers, a chemical compatibility problem was mentioned. An additional benefit of reInjection is that chemical compatibility of the produced brines with those of the produced aquifer is at least relatively assured, thus tending to reduce potential injection plugging problems (There may still be problems of precipitation, due to the disturbance of the equilibrium temperature).

Simulation studies indicate that without reInjection and depending on compressibilities, only 1% to 4% of the in-place methane will be produced. Without reInjection, the reservoir pressure would decline after a few years, resulting in decreasing brine, and consequently methane, flow rates. In an analysis of the McAllen Ranch Prospect, Hidalgo County, Texas, Gould and Spivak (1977) state that primary depletion based on water expansion in a closed grid would yield a recovery of only about 3% of the original fluid. In a subsiding system, the recovery may be greater, amounting to as much as 10% (Garg et al, 1977). If a substantial portion of spent brine is reInjected into the producing geopressured reservoir, however, brine pressure and flow rates can be maintained, thus allowing the extraction of a greater percentage of the reservoir methane.

For the McAllen Ranch Prospect, reInjection was calculated by Gould and Spivak to yield 50% of the water in place over 20 years. Garg et al (1977) estimate that up to 90% of the methane can be produced over a 60-year period with reInjection (assuming the

wells would last for so long a period). These conclusions are supported by Bassiouni and Veazy (1978). Thus, reInjection, while being a disposal alternative, would have the benefit of enhancing reservoir brine and methane production, and for formations with low permeability-thickness product, may be the only means of maintaining production rates over the required life of a project.

2. Production Behavior-Base Case

The reInjection rate of spent brines into an aquifer, like the production rate from a producing formation, is a function of aquifer properties, brine properties and design parameters. The aquifer properties influencing injection rate, include formation and brine compressibility, formation permeability, porosity, aquifer areal extent and net thickness. Brine properties of influence are viscosity, density and, to a lesser extent, salinity. The design parameters of concern include the well pattern; that is, the separation distance between production and injection wells; the perforation interval, casing diameter, allowable pressure increment; and finally, injection strategy. Alternatives in injection strategy include reInjection of only part of the produced fluid, disposing of the remainder by other means; delaying reInjection until the pressure in the produced aquifer has been partially depleted thus lowering the surface pumping pressure; changing a production well to an injection well with the introduction of a new production well; and provision for rejuvenation of injection wells by temporary disposal elsewhere.

Of the foregoing factors, the engineering or design parameters can be directly controlled. For the aquifer and brine parameters, only limited control is possible. For example, to minimize well skin effects, hydraulic fracturing can be used, resulting in a localized permeability increase about a well, thus decreasing the head loss that occurs within a short distance of the well (the "drawdown parameter"). Viscosity can be controlled by maintaining an elevated brine temperature, i.e. by limiting the use of the thermal energy.

To analyze the effect of many of the parameters cited in the preceding paragraphs, numerical modeling procedures were applied. The numerical model used for these simulation calculations was previously developed for the U. S. Geological Survey.

Briefly, the model solves three coupled partial differential equations describing the behavior of a liquid injected into an aquifer system. The three equations describe conservation of energy, total liquid mass, and mass of specific contaminants dissolved in the injected fluid. Equation parameters such as viscosity and

density are allowed to be functions of the equations' dependent variables. A more complete description of the model is given in Appendix D.

Using this simulation model, production from a hypothetical geopressed reservoir was first calculated. Reservoir parameters are representative of the Johnson's Bayou, LA prospect, chosen because of its relatively shallow depth, and relative ease of reinjection.

The analysis was based on a single 9-inch production well initially producing at 40,000 bbl/day at the center of a 16-square-mile geopressed aquifer at 11,400 feet (3475 m) with a net sand thickness of 200 feet. The reservoir parameters included a permeability of 100 md, a porosity of 0.29, and compression drive coefficient of 6.6×10^{-6} /psi. These and other parameters are listed in Table XXII.

TABLE XXII
PARAMETERS USED IN ANALYSIS OF THE
HYPOTHETICAL REINJECTION CASE

Compression Drive Coefficient, C_c	6.4×10^{-6} /psi
Water Thermal Expansion	1.118×10^{-4} /°F
Water Heat Capacity	0.810 BTU/lb-°F
Rock Heat Capacity	15.01 BTU/cu-ft-°F
Rock Thermal Conductivity	31.8 BTU/ft-d-°F
Dispersivity	300 ft and 60 ft
Fluid Density 68°F and 14.7 psi	67.7 lb/ft ³
Viscosity 68°F	1.248 cp
212°F	0.45 cp
Depth (Top of Layer)	11,400 ft
Initial Reservoir Pressure	10,871 psi
Permeability	100 md
Porosity	0.29
Initial Water in Place	1.804×10^{12} lbm
Bottom Hole Pressure Limitation	5136 psi

The results indicate that production at 40,000 bbl/day can be maintained for approximately 12 years, at which time the surface pressure will reach zero. This results in a rapid decline in flow rate until the entire aquifer has been depressured from its initial level of 10,871 psi to hydrostatic. For the compressibility and aquifer properties used, only 3.8% of the in-place methane is produced during the entire life of the well. (In the analysis it was assumed that the saturation concentration of methane remains constant even with the pressure reduction. Since the volumetric solubility of methane as a function of pressure decreases substantially, this will not be the case.)

The total volume of brine requiring disposal for the production well just described would amount to approximately 180 million barrels. To enhance the CH₄ recovery from the aquifer, reinjection of spent brine to

the reservoir could be implemented and the pressure, and consequently production, maintained for an extended period of time. As an additional benefit, the quantity of brine that must be disposed of by other means would be greatly reduced.

To analyze reinjection in this aquifer, several assumptions were made:

- (1) temperature effects were neglected, and
- (2) the spent brine is assumed CH₄ depleted. In reality this may not be true, as the injection strategy may not enable depletion of all solution methane.
- (3) Friction losses in both the producing well and injection wells are ignored. For 9-inch diameter wells, no significant effects will result. For 5-1/2-inch diameter wells, the friction losses may be substantial.
- (4) Plugging of injection wells and resulting well skin effects are assumed to be negligible. With well maintenance and if necessary brine treatment, the impact of this assumption should be minimal.
- (5) The effect of changing CH₄ solubility with pressure changes in the aquifer and well is ignored.
- (6) Subsidence and phenomena such as shale dewatering are neglected.

In general the impact of the foregoing assumptions should not effect the analyses made. Assumption (5) regarding CH₄ solubility, however, may be critical as it may be the case that the depressurization of an aquifer may greatly reduce the amount of recoverable methane. For assumption (1), the findings of Garg et al (1977) indicate that reinjection does not substantially change the produced brine temperature until after at least 20 years. However, the effect of cooling on the viscosity of the spent brine is highly significant, and will be discussed later.

In the first case study, a system of one producing well and one injection well separated by 1-5/8 mile in a 16-square-mile, 200-foot thick geopressed aquifer was investigated. For the injection well, the pressure limitation was set equal to the initial aquifer

pressure of 10,871 psi. The limiting bottom hole pressure for the production well is the hydrostatic pressure, 5136 psi. The parameters of Table XXI are used in the analysis. The CH₄ recovery curve as a fraction of the initial in-place methane is shown in Figure 32. The simulation indicates that with injection pressure limited to

Figure 32. Methane Recovery Versus Time for a 16 Square Mile, 200 Foot Thick Geopressed Aquifer ($k = 100$ md; $C_e = 6.6 \times 10^{-6}$ /psi)

the initial reservoir pressure, 12.08% of the methane will be recovered in 40 years, as compared to 3.79% in 12 years with no reinjection. A critical parameter is the permeability-thickness product (kh) of the geopressed aquifer. As can be noted from Figure 33, the net pres-

Figure 33. Centerline Pressure Profile for a 40,000 bbl/d Production Well

sure drop from injection to production wells is about 1840 psi (10971-9156), for a permeability-thickness of 20,000 md-ft. The maximum pressure drop at both the injector and producer is 5735 psi (10871-5136). Thus the minimum permeability-thickness for maintaining the 40,000 bbl/day production rate is about 6400 md-feet. For a 200 foot sand this implies a permeability of 32 md. This holds for the 1-5/8 mile spacing. A shorter well spacing could be used, but the project life would be shortened before methane recovery dropped substantially.

3. Re-Injection After Partial Reservoir Depletion

A potential injection strategy for a two-well production-injection system is the production of the geopressed aquifer with no reinjection, until the production well will no longer support the required flow. Then reinjection would begin. From the single-well analysis this limitation would be reached in approximately 12 years for 20,000 md-feet for a well producing 40,000 bbl/d. Thus, for the initial 12 years of the project, brine disposal to shallow, hydrostatically pressured aquifers or other alternate disposal would be required. Thereafter, full reinjection of produced brines could allow continued production at 40,000 b/d, the design production rate. By delaying injection, breakthrough of spent brine at the production well 1-5/8 miles away would be reduced, resulting in an increased CH₄ recovery to 12.7%. Significant in this strategy is the fact that the surface injection pressure would be reduced. An 1843 psi re-pressurization pressure would be required for injection, instead of 3192 psi as would be the case if injection is initiated at time = 0 and the geopressed aquifer is not partially depressured.

A potential problem in the depressurization of the aquifer, is the reduced CH₄ solubility. As has been stated, a gas phase could form and be immobile because the critical gas saturation was never exceeded. This effect was investigated in an earlier section of the report (Chapter III) and found to affect flowing gas/water ratios very little.

A more serious practical problem is reduction of the rock permeability with reduced reservoir pressure. Studies show that this effect can reduce effective permeability values by 1/2 or more.

The ratio of injection rate to production rate with time for a two-well system separated by 1-5/8 mile is plotted as a function of time in Figure 34. The injection rate will finally equal the production rate after approximately 2000 to 3000 days operation in the study ex-

Figure 34. Ratio of Injection Rate to Production Rate

ample. The ratio of cumulative injection to cumulative production for the two cases is shown in Figure 35. At 1000 days it has been possible to reinject only 60% of the produced brine for a 1-5/8 mile separation. Thus, at 1000 days approximately 14 to 16 million barrels must

be disposed of at a site other than the production aquifer, even though reinjection is selected as a disposal alternative. Over a 20-year period, it is possible to inject 94.2% of the produced brine.

Figure 35. Ratio of Cumulative Injection to Cumulative Production

To improve the amount of CH_4 recovered above 12% in 40 years, multiple production-injection wells would be required. A four-well pattern (two injectors—two producers) gives a calculated CH_4 recovery of 12% at 20 years, and 24% at 40 years.

When the maximum bottom-hole pressure of the injection well is limited to the initial aquifer pressure, injection rates are initially low and only increase as the aquifer becomes significantly depressured. Otherwise, the fracture pressure of the formation may be exceeded. This would be unacceptable since a fracture might open communication to the surface along a fault plane, or otherwise cause subsurface damage. The volume of brine that must be disposed of by alternative means can be calculated as:

$$\text{Compressibility} \times (P_i - P_s) \times \text{pore volume}$$

where P_i is the initial aquifer pressure and P_s is the average aquifer pressure at steady state when the injection rate equals the production rate. Only when $P_s \gg P_i$, can all produced brines be reinjected. For such a system, however, high surface pressures would be encountered.

4. Conversion of a Producing Well to Re-Injection

An interesting aspect of the preceding analysis is the effect of converting a production well to injection and the development of a new producing well. The injection rate to production rate ratio for such a system is given in Figure 36 for various well separation distances and conversion times. The production rate is 40,000 b/d and the permeability-thickness product 36,000 md/feet. Curve A corresponds to the case where injection is initiated from time zero at a well 1-5/8 miles from the production well. Curves B and C are for production well conversion at 30 days and 365 days, respectively. The results indicate that the time at which the injection rate equals the production rate is virtually independent of injection strategy and is simply a function of the aquifer properties, permeability-thickness and compressibility, as well as the design parameters of production well spacing, rate and injection well pressure. The excess of production over injection is thus independent of any injection strategy involving well conversion. From a disposal point of view, there is no net benefit in a well conversion policy.

Figure 36. Effect of Converting a Producing Well to an Injection Well

5. Quasi Steady-State Analysis of Re-Injection into the Producing Reservoir

It can be shown that the reservoir production equations (Chapter III) exhibit reciprocity and that flow rates, pressures and other parameters apply to injection from the surface as well as production from a reservoir.

Considerable insight into the process of injection into either shallow or deep zones can be gained by examination of these equations.

The surface pumping pressure P_s to inject water into a disposal aquifer is typically given by

$$P_s = P_e + (P_e - P_w) + P_f - P_h \quad (4)$$

where

P_e = reservoir pressure

$(P_e - P_w)$ = The draw-down parameter (pressure drop across formation face)

P_f = friction pressure in the casing

P_h = hydrostatic head

In both Texas and Louisiana the surface pumping pressure P_s is limited by regulation to insure the integrity of the disposal formation. In practice, for re-injection into geopressed formations, this will limit the injection pressure to insure that the initial reservoir pressure P_e is not exceeded. Consequently, no appreciable re-injection could occur unless the reservoir pressure were partially depleted.

It is important to observe that the drawdown pressure $(P_e - P_w)$, given by Eq. 2, Chapter III, is primarily a function of the permeability-thickness product kh , the viscosity of the water, μ , and the flow rate Q . In Figure 37 is shown the viscosity of water as a function of temperature. It can be seen that as water is cooled from 300°F to 150°F the viscosity approximately doubles. Furthermore, as the pressure is depleted, permeability generally declines. These two effects drive the injection drawdown pressure up, and to values at least twice its production value. The result is high surface pumping pressure and multiple disposal wells. In effect, this factor tells us that if a well is able to produce 40,000 bbl/day at 300°F, one can expect to reinject a maximum of only about 20,000 bbl/day at 150°F into an equivalent well, at the same surface pressure.

Figure 37. Viscosity of Water as a Function of Temperature (from Secondary Recovery of Oil in the United States, 1950)

An example based on the Johnson's Bayou prospect discussed in the preceding paragraphs illustrates the energetics of reinjection. The well described will flow at a rate of 40,000 bbl/day until the reservoir pressure declines to about 6000 psi. At that point, re-injection might be considered.

The pumping pressure P_s is given from Eq. (4) by

$$P_s = 6000 + (6000 - P_w) + 500 - 5132$$

But the drawdown, given by Eq. 2, page 17, is

$$(6000 - P_w) = \frac{40,000 \times 0.4}{7.08 (0.07 \times 200)} \left[\ln \left(\frac{11,880}{0.375} \right) \right] - \frac{3}{4}$$

$$\approx 1540 \text{ psi}$$

assuming the reinjected water is at a temperature of 150°F, and the permeability of the partially depleted reservoir has declined by 30%.

Thus the pumping pressure is

$$P_s \approx 6000 + 1540 + 500 - 5132 \\ \approx 2900 \text{ psi}$$

The hydraulic horsepower required to deliver this pressure is given by

$$\text{HHP} = QP_s \gamma_w \times 1.7 \times 10^{-5} \quad (5)$$

where

Q = injection rate, bbl/day

P_s = surface pumping pressure psia

γ_w = specific gravity of injected water

Hydraulic horsepower converts to brake horsepower by dividing by the pump efficiency (typically, 70%).

Pumping energy, in BTU/hr, is given by

$$E_{hr} = \frac{\text{BHP}}{\eta} \times 2545 \quad (6)$$

where

η = engine efficiency (a large gas turbine, for example, may show an efficiency of 28%)

Thus the pumping energy for the Johnson's Bayou example is

$$E_{hr} = \frac{\frac{QP_s \gamma_w \times 1.7 \times 10^{-5}}{0.7}}{0.28} \times 2545$$

$$\approx 26 \times 10^6 \text{ BTU/hr}$$

On a per bbl basis, this is equivalent to

$$E_{bbl} \approx \frac{26 \times 10^6}{1667} \\ \approx 15,600 \text{ BTU/bbl}$$

Using methane as the fuel, this is about 16 scf/bbl. Since the methane content of the Johnson's Bayou prospect is only projected to be 15 to 20 scf/bbl, it is obvious that, even without regard for the additional cost of disposal wells, reinjection at this site is not a viable option.

The same type of examination of the deeper S.E. Pecan Island prospect, shows an even more dismal outlook for reinjection. The single-well development discussed in Chapter III, predicted to flow at a rate of 50,000 bbl/day until the reservoir pressure declines to 10,000 psi, would require two deep reinjection wells for one producer, to limit the surface pressure to a value below the fracture pressure. The energy requirements for reinjection in that reservoir, even with two disposal wells, would amount to 27 scf/bbl.

The equivalent natural gas required to pump one barrel of water at the rate of 25,000 bbl/day for various surface pressure requirements is given in Figure 38.

6. Cost Estimates of Subsurface Disposal

The principal purpose of this section of the report is to develop disposal parameters for the economic analysis in Chapter VII. The two studies of greatest influence on this analysis are the Knutson and Boardman (1978) report and a study by Doscher, et al (1978).

Subsurface disposal costs generally break down into five principal items:

- (1) the capital and intangible cost of the disposal well field;
- (2) the capital costs of the surface equipment including the surface piping, compressors, etc.
- (3) a fixed operating cost;
- (4) variable operating costs, non-fuel related; and
- (5) variable operating costs, fuel related.

For the case of disposal to shallow aquifer systems (in the depth range of 3000 to 6000 feet), the fixed cost for compression at 1000 psi or less was listed by Doscher et al (1978) at \$.02/bbl. Additionally, they developed a processing treatment cost of \$.015/bbl.

PUMPING PRESSURE, PSI

Figure 38. Equivalent Natural Gas Fuel Required to Pump One bbl of Spent Brine at 25,000 bbl/day Rate at Various Values of Surface Pressure

We have estimated workover costs assuming there would be a four-well pattern, and that workover cost would be in the range of \$125,000/job, with each well requiring workover every four years. Basing the per/barrel cost on a rate of 40,000 bbl/day, these figures result in about a \$.009/bbl workover cost.

Doscher et al (1978) estimated an operating cost for injection based upon maintenance, upkeep and the energy cost to be related to methane rates by a simple equation equal to $0.5 P$, where P is the price of the methane in dollars/mcf. From this equation, one can note that the injection operating costs are more than \$.005/bbl if methane sells for \$1.00/mcf.

The final cost is the completion of the disposal wells. This was estimated by Dabney Engineering Company to be about \$400,000/well. Thus, the 4-well pattern would give about a \$1.6 million cost. Additionally, one should expense at least one dry hole for each

five wells drilled. As a consequence, the total cost would be near \$2 million, with about \$600,000 of that as a tangible investment. If one adds the cost that clearly can be attributed to disposal, that is, the fixed cost for compression, the workover cost, and the injection cost tied to the cost of energy, the net cost for shallow injection at a methane price of \$2.00/mcf comes out to be \$.039/bbl. Note that this has neglected the capital cost invested for drilling the wells and completing them. At a \$6.00/mcf price for methane, these injection costs rise to \$.059/bbl of water disposed.

These costs can be compared to those summarized in Knutson and Boardman (1978) from the experience in actual disposal in the Gulf Coast of Texas and Louisiana. The costs there include capital costs, but range from \$.02 to \$.05 for projects injecting in the range of 50,000 to 500,000 bbl/day. An additional comment is contained in that reference indicating that capital costs are currently higher than the experience cases

and so a multiplier of at least 2 should be used on the above figures. Moreover, they mention that if environmental programs that are currently contemplated are instituted, perhaps a multiplier of 4 would be more representative.

7. Conclusions

- a. Shallow subsurface disposal appears feasible, both technically and on the basis of experience. Direct cost of shallow disposal amounts to about 4-6¢/bbl at present gas prices (not including capital). Amortization of the capital investment will add an increment sufficient to bring the total disposal cost to an estimated 8-10¢/bbl. Proposed environmental restrictions may bring this cost to 12¢/bbl or more.
- b. Deep re-injection appears prohibitive, both in cost and in energy requirements. Disposal of the full production capacity must be provided by other means for years before re-injection would be technically feasible. Then very high cost wells and compression equipment would have to be added to produce a declining quantity of gas. The energy required to reinject, even in a partially depleted reservoir, may approach the volume of gas produced.

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VI. ENERGY UTILIZATION

Utilization of the energy contained in the Gulf Coast geopressed zones currently centers around the following concepts:

1. Production of dissolved methane as a fuel
2. Generation of electricity by geothermal heat
3. Generation of electricity by hydraulic turbines
4. Direct utilization of the heat for non-electric purposes

Obviously there are variations of these four themes involving combinations of the various energy forms.

A. Previous Feasibility Studies

Studies of the feasibility of producing energy from geopressed formations have been performed by Herin (1973), Wilson, Sheppard & Kaufman (1974), House, Johnson and Towse (1975), Gault et al (1976), Wilson et al (1976), the Brown and Root Company (1976), Randolph (1977), Kuuskraa et al (1978), Doscher et al (1979), Swanson and Osoba (1979), and probably by others. The latter four studies were concerned primarily with the production of natural gas, largely ignoring the potential of the thermal and hydraulic energy as being insignificant. These studies envisioned relatively simple plants consisting of a single production well, methane separation and compression equipment, and spent brine disposal. Estimates of the pipeline cost of natural gas produced were made, based on reservoir parameters as currently understood, utilizing petroleum industry economics analyses.

The earlier investigators uniformly assumed field development of large aquifers in which multiple-well installations would supply brine to combination methane and electric generation plants. The size of generating facilities considered for such fields ranged from 1.5 MW(e) to 68 MW(e). The two most detailed of these studies were reported by Dow Chemical Company (Wilson et al, 1976) and by the Brown and Root Company (1976). In both these reports, the case considered was a multiple-well development of 10 to 14 wells, each capable of delivering 40,000 bbl/day for 20 years, spaced on 1/2-mile centers. The brine was assumed to be fresh (10,000 ppm TDS), at a wellhead temperature of 320° to 325°F, saturated with dissolved methane (40 SCF/bbl). In each of the designs, a 25 MW(e) commercial plant

would require a total of more than 500,000 bbl/day of the brine at 300 psi delivery pressure.

1. Brown and Root Study

Brown and Root considered a single-cycle binary power plant using propane as the thermal fluid. No credit was taken for methane production and a methane fuel plant was not considered in cost estimates. Cost of the Brown and Root electric generation plant (1975 dollars) amounted to a total of \$33,740,000 or a unit cost of \$1,349./kW(e) (net) including the cost of production wells and disposal field. Conversion of hydraulic energy was included.

2. Dow Chemical Company Study

The plant proposed by Dow (Wilson et al, 1976) consisted of both a fuel plant for producing pipeline quality methane and an electric generating plant for use of the geothermal energy in the brine. For that reason, there is little direct comparison between the cost information generated by the two studies. The 25 MW commercial installation developed by Dow investigated both a single and a double-stage flash-plant, supplied by a multiple-well field (12 wells for the single stage and 10 wells for the two-stage plant). The Dow design for a combination 25 MW(e) double-flash electric plant and a methane processing fuel plant estimated a total capital cost of \$60,496,000, compared to \$33,740,000 for the Brown and Root 25 MW(e) plant without methane processing capability. Assuming the Dow plant were successful for methane production, electric generation could be added for an additional investment of \$678 per installed kW(e). Hydraulic energy conversion was included. Wilson estimated the unit power cost on this basis at 46 mills/kwh.

B. Comments on Early Studies

1. No prospective fields have so far been identified which promise the delivery of 325°F brine in quantities as great as 500,000 bbl/day, and at this time one must assume that 25 MW(e) is unrealistically large for a geopressed electric plant. The largest single reservoir so far investigated is the S.E. Pecan Island prospect in Louisiana (Appendix B) which might be drained by ten to twelve wells and deliver water at perhaps 300°F at a maximum of 240,000 bbl/day for approximately 8 years.

2. The assumed salinity (10,000 ppm TDS) in the early studies now appears to be unrealistically low. With the exception of isolated locations in the Hidalgo Fairway in South Texas, measurement of Gulf Coast geopressed brines indicates that the total dissolved solids content will more likely be in the range of 50,000 to 150,000 ppm or more. This, of course, has a profound effect on the dissolved methane content, on the salt carryover which can be anticipated in both the production of methane and in flash steam operations, and on corrosion problems.
3. It does not appear that temperatures as high as 325°F are realistic for large volume production wells. It is doubtful that significant quantities of brine at temperatures above 300°F can be produced in any of the prospective reservoirs, with likely temperatures closer to 250° to 280°F.
4. The cost of drilling deep production wells has risen significantly since 1975. Dow estimated the cost of 14 production wells to support the 25 MW plant (14,000 feet deep) at \$23,103,600 or \$1,650,000 each. It now appears that 14,000 feet is generally inadequate for production of thermally useful brines, and that actual well costs will be in the range of at least \$5,000,000 each. This can be explained by (1) greater than anticipated depth (17,500 feet at S.E. Pecan Island) and (2) the escalation of drilling costs since 1975. These costs have nearly doubled.
5. Estimated cost of collection piping for well fields must be increased drastically over the earlier assumptions. Well spacing will be at least two miles, rather than the one-half mile or less estimated by early investigators.

C. Other Studies Concerning Geothermal Power Generation

A number of feasibility studies have been performed for electric power production from liquid-dominated hydrothermal sources, using a range of brine temperatures comparable to that predicted for the geopressed resource. These studies have included both flashed-steam and binary conversion processes.

1. Flashed Steam Systems

Figure 39 gives the specific net energy for flashed steam systems as a function of brine temperature at the wellhead.

Figure 39. Specific Net Energy of Electric Power Plants with Flashed Steam Systems

The values were obtained from feasibility studies by Shaffer (1976), Holt (1976), Wilson (1975), and Bechtel (1976). The figure shows a wide range of specific net energy values for each temperature. For instance, at 300°F (150°C) the range varies from 1.7 to 3.4 Wh/lb brine, a 100% difference.

These differences are due primarily to the assumption of different design conditions used in the calculations. For a given wellhead temperature, the range of design conditions in the flashed steam systems reviewed were as follows:

- Number of steam flashing stages—1, 2, or 3
- Brine total dissolved solids—0 to 40,000 ppm
- Turbine efficiencies—66 to 85%
- Generator efficiencies—90 to 98%
- Turbine exhaust pressure—1 to 2 psia

In addition, although noncondensable gases present in the brine will adversely affect the power plant performance, this factor was often neglected in the studies.

The value of the specific net energy calculated at a 325°F (163°C) brine temperature from the Dow study (Wilson, et al 1976) was 2.84 Wh/lb brine

for a one-stage flashed steam system and 3.91 Wh/lb brine for a two-stage flashed steam system. These values, as shown in Figure 39 are in the top half of values for all the feasibility studies. The main design conditions and assumptions for both systems were:

- Brine total dissolved solids—10,000 ppm
- Turbine efficiency—60%
- Generator efficiency—90%
- Turbine exhaust pressure—1.3 psia

Figure 40. Specific Net Energy of Electric Power Plants with Binary Systems

2. Binary Systems

Figure 40 gives the specific net energy for a range of brine temperatures for binary systems obtained from feasibility studies by Wilson (1975), Starling (1977), Madsen (1975), Ingvarsson (1976), Holt (1978), Jacobs (1978), Bechtel (1975), and Brown and Root (1976).

As in the flashed steam system studies, the results show a wide range of values of specific net energy at each temperature for binary systems. The values inside the band in the figure are for systems in which the heat from the brine was transferred to the binary working fluid in conventional shell-and-tube heat exchangers. At 300°F (150°C) the range of values vary nearly 100%, from 2.7 to 5.3 Wh/lb brine. Studies by Jacobs

(1978), have been reported in which direct contact heat exchangers were used instead of shell-and-tube heat exchangers. These results are represented by the points at 290°F (145°C), not contained by the band.

The major differences in the assumed design conditions for these studies were:

- Type of binary fluid—hydrocarbons or fluorocarbons
- State of binary fluid at turbine inlet—supercritical or subcritical
- Type of cycle—single or dual pressure
- Type of heat exchangers—surface or direct contact
- Turbine efficiency—75 to 85%
- Generator efficiency—90 to 98%
- Cooling water temperatures—75 to 90°F
- Equipment pressure losses.

As shown in Figure 40, the value of the specific net energy calculated in the Brown and Root (1976) study, using a brine temperature of 320°F (160°C), is 3.20 Wh/lb brine. This value is in the lower range of values calculated by others. The main assumptions in this study were:

- Binary working fluid—propane
- State of working fluid—supercritical
- Number of heat exchangers—1
- Turbine efficiency—75%
- Generator efficiency—90%

3. Assessment of Previous Power Generation Studies

The prior feasibility analyses discussed above indicate a wide range in the performance of electric power plants operating from liquid dominated hydrothermal resources. The performance depends upon design features, such as number of flash stages for a flashed steam system and the use of a subcritical or supercritical cycle for a binary system. Additionally, reser-

voir and site conditions, such as brine total dissolved solids and ambient wet-bulb temperature, which affects the temperature of water available from a wet cooling tower, influence plant performance. Turbine, generator, and pump efficiencies also vary with manufacturer and operating conditions, and also significantly affect plant performance.

For these reasons, the assessment of previous feasibility studies for electric power plants indicate that, for valid comparisons to be made, new feasibility studies are required. These studies were made and are described in this report.

D. Production of Dissolved Natural Gas

1. Nature and Composition

The geopressed brine from Gulf Coast reservoirs is expected to be saturated with natural gas and may also contain free gas. Based on work by Karkalits,

et al (1978), gas analysis from the first DOE sponsored test of a geopressed water well (Edna Delcambre #1, LA) was reported as follows.

Nitrogen	0.2 mole %
Methane	94.1 mole %
Ethane plus	4.1 mole %
Carbon dioxide	1.6 mole %
Hydrogen sulfide	1.0 ppm by weight

This gas is believed to be typical in composition.

Figure 41 shows the solubility of the principal component of the natural gas, methane, in water and in 70,000 ppm sodium chloride brine. The water data are cross-plots from the American Petroleum Institute Technical Data Book (1977). The brine data are corrected from the water data (Pennsylvania State, 1978) using the technique of Setschenow (1889). The solubility in a multiple component brine will be somewhat different than the solubility in a simple sodium

Figure 41. Solubility of Methane in Water and in Sodium Chloride

chloride brine, but since sodium chloride is the majority component, Figure 41 should be satisfactory for feasibility analyses and for natural gas of the composition listed above. The figure shows that solubility is much more a factor of pressure, particularly low pressure, than of temperature.

2. Separation from Brine

Almost 99 percent of dissolved natural gas is liberated from the brine by reducing the pressure to 150 psia, and 81 percent is liberated at a wellhead pressure of 1000 psia and 300°F (150°C). At low pressure the sol-

Figures 42 and 43 show typical separation processes for the two general design cases, a flashed steam power plant and a binary power plant. These processes may be used with either a single well or multiple wells supplying brine.

a. Separation Process for Flashed Steam Power Plant

After the brine from the well(s) expands from the wellhead pressure to 1000 psia through a power-generating hydraulic turbine, the natural gas is separated from the hot brine at three pressure stages.

Figure 42. Natural Gas Separation Process for a Flashed Steam Power Plant

ubility is greatest at low temperature, but at high pressure the solubility is greatest at high temperature. The most economical way to liberate the natural gas is to reduce the pressure before cooling the brine and to separate the gas in intermediate stages of pressure. This procedure reduces the volume of gas requiring recompression prior to entering an existing natural gas transmission system, assumed to be 1000 psia.

The gas from each stage passes through a venturi scrubber and a wet cyclone to remove entrained brine droplets and salt carryover. After the wet cyclone the gas is cooled and moisture is separated. The 150 psia gas from the lowest pressure stage is compressed to 300 psia and mixed with the 300 psia gas upstream of the 300 psia cooler. The combined streams are then compressed to 1000 psia and mixed with the gas from the 1000 psia

Figure 43. Natural Gas Separation Process for a Binary Power Plant

brine separator. The combined gas is cooled, moisture is removed and the gas is fed to a glycol dehydration unit and into the 1000 psia transmission pipeline. The brine from the 150 psia separator goes to the power plant.

b. Separation Process for a Binary Power Plant

From the well(s) the brine passes through a power-generating hydraulic turbine and then through a heat exchanger where heat is transferred to the working fluid for the power plant. The gas processing equipment arrangement is much the same as for the flashed steam plant; the major difference is that the separators operate at a lower temperature of 212°F (100°C). As a result, two coolers and two moisture separators in the low pressure gas streams are eliminated. The cooler and moisture separator in the 1000 psia gas stream are retained to reduce the load on the glycol hydrators.

3. Basis for Feasibility Design Study

To investigate the design and economics of a geothermal-electric power plant and methane separation

facility in light of currently understood reservoir parameters, the geopressed zone within the S.E. Pecan Island, La. prospect was selected for study. S.E. Pecan Island, discussed in earlier sections of this report, is contained in an apparently isolated fault-block, bounded by two major growth faults. It contains a large, lens-shaped geopressed sand body occupying a total area of about 60 square miles with a depositional center offset from the lens axis. The potentially productive part of the reservoir consists of a series of laminated sands and shales, with total sand thickness ranging from a maximum of about 1,000 feet to less than 350 feet near the edge of the lens. These sands are distributed in depth from the top of geopressure at approximately 13,500 feet to a maximum of about 17,500 feet, with an average center depth of 15,500 feet.

Two cases were selected for the utilization model. First, at the site of a potential well location selected by Bernard (1979), a single-well facility was designed in which realistic (although optimistic) reservoir parameters were assumed. A drainage area of approximately 13-1/2 square miles was included in the reservoir assumptions, representing a very favorable case (Bernard estimated the average drainage area in the field to

be 4 square miles/well). In the second case, a 12-well development of the entire geopressed reservoir was assumed, each of the wells draining an approximate area of 4-1/2 square miles. Total productive sand was estimated for each well from the sand isopach map developed by Bernard and production behavior predicted by computer model. The 12-well case is described more fully in Appendix B.

42 and 43 will change. Figure 45 shows the gas production from each of these stages as a function of time. After the wellhead pressure drops below 1000 psia, the total gas produced must be compressed to reach transmission system pressure. At this time, the 1000 psia separator is operated at 300 psia, the two 300 psia separators are operated in parallel, and a new compressor is installed in parallel with the existing 300 psia compressor.

Figure 44. Model Analyses of Optimistic One Well at S.E. Pecan Island

a. Design Basis for a 1 Well Case

Figure 44 shows the brine production flow rate, wellhead pressure, and natural gas production rate for the S.E. Pecan Island, Louisiana "optimistic" one well case. The brine flow is constant at 50,000 bbl/day for 4,300 days, then falls off as shown to approximately 13,000 bbl/day at 10,000 days. The wellhead pressure decreases linearly from 3310 psia initially to 300 psia at 12 years. Thereafter, the well flow is controlled to maintain a 300 psia pressure.

As shown in Figure 44, after 3,100 days wellhead pressure falls below the transmission pipeline pressure of 1000 psia. As the wellhead pressure falls, the conditions in the three pressure stages shown in Figures

Figure 45. Natural Gas Production from Optimistic One Well at S.E. Pecan Island

b. Design Basis for a 12 Well Case

For the 12 well case the brine flow is constant at 240,000 bbl/day for 8 years, then falls off to approximately 41,000 bbl/day at 19 years. The natural gas flow is assumed constant at 8,400,000 SCF/day for 8 years, then falls off at the same rate as brine flow to 1,435,000 SCF/day at 19 years (the decline in solubility with pressure drop has been ignored). The wellhead pressure decreases linearly from 4100 psia initially to 300 psia at 11 years. Thereafter, the well flow is controlled to maintain 300 psia pressure.

When the wellhead pressure drops to 1000 psia another compressor will be added as was done for the 1 well case.

There are two possibilities for gas separation in the multiple well design:

- Separate the gas from the brine at each wellhead.
- Collect the two-phase mixture from the wells at a central separation and processing plant.

Only the second possibility was considered in this study. It has the advantage of economy of

scale for the larger separation and processing equipment utilized. The major disadvantage is the more expensive collection system necessary, because of the high design pressure (i.e., heavy-walled pipe) and because the pipe diameters for two-phase flow are larger.

4. Processing for Pipeline Distribution

a. Gas Dehydration

After the final compressor-aftercooler, the natural gas is saturated with water at typically 90°F (32°C) and 1000 psia. If this gas were put into a transmission line without dehydration, some of the water would condense. As the pressure dropped with flow through the line, this water would revaporize to be condensed again at the next compressor station. Experience with natural gas transmission lines has shown that it is necessary to dehydrate the gas for the following reasons:

- The wet gas is corrosive.
- Condensed water increases the pressure drop and decreases the line capacity.

Figure 46. Gas Dehydration

- Solid hydrates (loose complexes of methane and water, in this case) form at high pressures and temperatures as high as 50°F (10°C), and can plug line restrictions.

Figure 46 shows a typical glycol dehydration flow diagram. The absorber operates at 1000 psia and the stripper at atmospheric pressure. The circulating glycol stream is filtered to remove scale and dirt that promotes foaming, a frequent operating problem with glycol systems.

The usual specification for water content of pipeline natural gas is 5 to 7 lb/MMSCF, or 110 to 170 ppm by weight. Saturation at 90°F (32°C) and 1000 psia is about 700 ppm. Removal of this much water is most conveniently done by scrubbing with diethylene glycol or triethylene glycol, a standard industrial technology. Packaged units are available for treating the quantities of gas produced by 1 to 12 geopressured wells, and these units can be built for unattended operation.

b. Dehydration Variations

It is likely that the glycol scrubber will also remove carbon dioxide from the gas. Geopressured natural gas analyses to date have shown that the hydrogen sulfide content is less than 1 ppm, lower than required for natural gas pipeline transmission. If some reservoirs are found to have higher hydrogen sulfide content, the glycol scrubber can be adapted to remove both hydrogen sulfide and water by adding amine to the glycol. The combined operation has been successfully carried out in natural gas processing facilities.

The most serious problem that is likely to occur and must be overcome in the design of the gas separation process is brine carryover with the gas. Entrained salt in the carryover causes a number of problems. It increases corrosion in the downstream piping, and in the compressors. Also, it will most likely end up in the dehydrator reboiler, which operates at a temperature of 350°F to 400°F (175°C to 200°C). At these temperatures, it will cause severe corrosion and scaling of the reboiler tubes.

Mist eliminators can be effectively used to minimize carryover. They can be either wire mesh pads, venturi scrubbers, or a relatively new rotary separator (Cermi, 1978). A venturi scrubber costs more than a mesh pad but is almost free of the disadvantages associated with a pad. Therefore, venturi scrubbers were included for this study.

E. Design Basis for Hydraulic and Thermal Energy Conversion Systems

Design data were developed for the optimistic 1 well case and the 12 well case at S.E. Pecan Island, previously described. The production well flow rates, wellhead pressures and the decline in these parameters with time are summarized in Table XXIII.

TABLE XXIII
WELL PRODUCTION PARAMETERS

<i>S.E. Pecan Island—1 Well Case</i>		
Time from Startup (Years)	Well Flow (bbl/day)	Wellhead Pressure (psia)
0	50,000	3,310
8	50,000	1,000
12	50,000	300
20	21,000	300

<i>S.E. Pecan Island—12 Well Case</i>		
Time from Startup (Years)	Well Flow (bbl/day)	Wellhead Pressure (psia)
0	240,000	4,100
8	240,000	1,300
9	222,000	1,000
11	187,000	300
19	41,000	300

The production and injection wellfield data and the power plant parameters for flashed steam and binary cycles are shown in Table XXIV.

TABLE XXIV
DESIGN DATA FOR CONCEPTUAL DESIGN STUDIES

Location	S.E. Pecan Island	
Number of Wells	1	12
<i>Wellhead Fluid</i>		
Initial Flow, bbl/day	50,000	240,000
Initial Pressure, psia	3,310	4,100
Temperature, °F	300	300
Typical Salinity, ppm TDS	80,000	80,000
Gas Content, SCF/bbl	35	35
<i>Wellfield</i>		
Production Well Spacing, ft.	—	10,000
Injection Well Spacing, ft.	5,000	5,000
Spare injection Wells	1	2
Well Ratio, Production/ Injection	1:3	1:2
Injection Pressure, psia	600	600
<i>Power Plant</i>		
Inlet Temperature, °F	300	300
Flashed System Brine Pressure, psia	150	150
Wet Bulb Temperature, °F	80	80
Heat Rejection System	Mechanical Draft Wet Cooling Tower	
Steam Turbine Efficiency, %	65	65
Steam Exhaust Pressure, psia	1.3	1.3
Steam Condenser Type	Direct Contact	
Binary Fluid	Isobutane	
Binary System Brine Pressure, psia	1,000	1,000
Binary Turbine Efficiency, %	80	80

Thermal energy conversion processes such as a flashed steam process, a binary process, or a two-phase expansion process could be used for the production of electricity. As a result of earlier studies, the single-stage flashed steam process was selected for more detailed evaluation for both the 1 well case and the 12 well case. For comparison, the binary process was also evaluated for the 1 well case. The single-stage flashed steam cycle

was selected over a two-stage flashed steam cycle because of the small electric output of the plant and the need to keep the equipment simple for unattended operation.

The layout of the production and injection wells, and the energy recovery processes is shown in Figure 47 for the 1 well case and in Figure 48 for the 12 well case. As shown, the energy recovery processes for the 1 well case are located at the wellhead. Three shallow disposal wells and one spare are required for fluid disposal for the 1 well case. Twenty-four disposal wells and two spares are required for the 12 production well case. Spacing of the production and injection wells, depth of the injection wells, and injection pressures are included in Table XXIV.

In general, production wells are assumed abandoned when individual well production drops below approximately 4,000 bbl/day.

F. Hydraulic Energy

The wellhead hydraulic pressure of the geothermal fluid can be utilized to produce electric power, and because of low capital and operating costs of the equipment this could be a significant and economic energy source.

Hydraulic turbines, which are essentially centrifugal pumps adapted for reverse rotation, are used as the power recovery units and are connected to electric gen-

Figure 47. Plot Plan of Well Field Layout for One Well Case

Figure 48. Plot Plan of Well Field Layout for Twelve Well Case

erators. These electric power producing units are self-contained. A high-pressure unit is located upstream of the high-pressure separator in the natural gas separation process, and a low-pressure unit is located downstream, as shown in Figures 42 and 43. It is anticipated that these units can operate satisfactorily with gases dissolved in the geopressured fluid, even when the gases are released from the fluid as the wellhead pressure declines.

It was estimated that the optimum electric power output rating of the high-pressure hydraulic turbine generator unit with 1 well should be 1,150 kW(e) and of the low-pressure unit, 350 kW(e). With 12 wells the high-pressure hydraulic turbine generator would produce 6,970 kW(e) and the low-pressure unit 1,550 kW(e). Figures 49 and 50 illustrate the net electrical output with time, for the single well and 12 well cases.

Figure 49. Net Electric Output for One Well Case

Figure 50. Net Electric Output for Twelve Well Case

Well flow and pressure decline influence the performance and selection of hydraulic turbines. Operation of these turbines away from their design points could severely decrease the recoverable energy. In this study, a minimum operating point was considered to be reached at 40 percent of the initial rating of a unit, at which time it was removed from service.

G. Thermal Energy

1. Nature of the Brine

For any process to recover energy from geopressured resources, technical and economic constraints are imposed by the corrosion of piping and plant components and by the deposition of scale. The consideration of corrosion and scale formation are based upon:

- The conditions in the geopressured formation
- The composition of the brine as it emerges from the geopressured formation
- The conditions to which the brine is subjected in the plant and the subsequent injection system.

Representative brines with minimum and maximum composition were published by Wilson (1978). They ranged in total dissolved solids content from 10,000 ppm to 150,000 ppm, with 80,000 ppm selected as typical. Although any conclusions must be considered tentative because of the very small number of geopressured wells actually investigated, it is possible to make some generalizations on corrosion and scaling.

The main geopressured brine conditions of the fluids that are supplied to the energy recovery processes are given in Chapter V of this report.

Data by Bechtel (1976) suggested that carbon steel will corrode in the pH range assumed for the brine. In addition, any dissolved oxygen or air inleakage would sharply accelerate the corrosion. With stainless steel, the combined attack of chlorides and oxygen would produce stress corrosion. Other materials showed evidence of general corrosion as well as pitting and crevice corrosion. Therefore, the selection of metals to be used with geopressured brines must be based on a series of carefully designed corrosion tests and economic studies to compare materials with large corrosion allowances with longer lasting more expensive materials.

Scale-forming reactions were calculated for a number of cases, among them a representative brine containing 3,000 ppm of calcium ion, 1,200 ppm of bicarbonate, and 400 ppm of silica. If this brine were flashed from a wellhead temperature of 300°F (150°C) to atmospheric pressure and 212°F (100°C), carbon dioxide would be released and a very hard calcium carbonate scale deposited in the plant. On further cooling, silica would be rapidly precipitated as a soft scale.

Scaling can be controlled by the use of either on-line scale cleaning methods, or the prevention of scale formation by brine modification techniques. Standby equipment can also be used to allow the plant to continue to operate at full capacity while the standby equipment is shut down for scale cleaning.

The right choice of alternatives for the prevention of corrosion and scale formation will be reflected in the plant capacity factor. A high capacity factor is essential for the successful commercialization of energy recovery processes.

2. Utilization

a. Electric Generation

Geopressured geothermal power plants have low thermal efficiencies which cause large amounts of heat to be rejected into the atmosphere from their waste heat rejection systems. The climatic conditions along the Gulf Coast are characterized by high dry-bulb temperatures and high wet-bulb temperatures. Typical values for these temperatures are 92°F (33°C) and 80°F (27°C) respectively.

Given these climatic conditions, several options were evaluated for heat rejection systems in both flashed steam and binary power plants. In view of the small size of the proposed geopressured plants, their proximity to available makeup water, and the relative system costs, the recommended waste heat rejection systems are:

- Flashed steam cycle
Direct-contact condenser, mechanical-draft wet cooling tower, with mechanical vacuum pumps
- Binary cycle
Surface condenser, mechanical-draft wet cooling tower.

**TABLE XXV
PLANT PERFORMANCE**

Location	S.E. Pecan Island		
Number of Wells	1	1	12
Process	Flashed Steam	Binary	Flashed Steam
Net Electric Power Output, kWe	1,481	1,637	7,120
Auxiliary Power, kWe			
Cooling Water Pumps	103	63	494
Cooling Tower Fans	110	79	527
Brine Pumps	12		57
Binary Feed Pumps	—	255	—
Blowdown Pumps		4	—
Total Auxiliary Power, kWe	225	401	1,078
Gross Electric Power Output, kWe	1,706	2,038	8,198
Brine Flow Rate, 10 ⁶ lb/hr.	0.73	0.73	3.51
Specific Net Energy, Wh/lb brine	2.03	2.24	2.03
Net Brine Rate, lb/Brine/kWe	493	446	493

Since several of the geopressured resource areas are close to the Gulf Coast or rivers, once-through cooling may be considered as an economically attractive alternative to the mechanical-draft wet cooling tower, although due to rigid regulatory control of surface waters, it represents a doubtful possibility.

Based on the well production scenarios for the resources at S.E. Pecan Island, La. (given in Table XXIII), the electric power that can be recovered from the heat content of the brine was calculated. With the 1 well case, a small electric power plant was located at the wellhead. With the 12 well case, an extensive brine gathering and disposal system was required to bring the brine to the larger unit. Table XXV is a summary of the plant performance and auxiliary power requirements for the two cases. The flow diagram of the single-stage flashed steam cycle for the 1 and 12 well cases is shown in Figure 51. The flow diagram of the binary cycle for the 1 well case is shown in Figure 52.

These electric power outputs are available only at the start of the plant operation. Due to the decline in well flow (shown in Figure 44), the electric power output will also decline. Based on performance only, the binary process gives a 10 percent improvement over the single-stage flashed steam process, as indicated by the specific net energy in Table XXV.

b. Direct Use

Direct use of the thermal energy in geopressured brine for industrial or agricultural applications is an alternative to the production of electric energy.

A new plant designed to utilize geothermal energy as the major source of process heat is more economically attractive than a typical conventional plant retrofitted to use geothermal energy. In a new

plant, the steam boiler and steam turbine drives would be eliminated. Electric motors would be used and slightly larger heat exchangers would be needed because the geothermal brine supplies heat at a somewhat lower temperature. In general, it was found that the capital cost of a process plant designed to operate with geothermal heat was not significantly different from one designed for conventional fuels.

Processes selected for direct utilization of geothermal energy must be technically feasible and economically attractive for that application. Potential processes must satisfy the following specific selection criteria:

- Temperature range available from geothermal fluid compatible with the process requirements
- Raw materials available
- Economic advantages using geothermal energy compared to conventional fuel.

Of all the industrial groups that purchase energy for the manufacture of their products, two groups, "Food and Kindred Products" and "Paper and Allied Products," use substantial amounts of heat in the temperature range 250°F (120°C) to 300°F (150°C) that could be supplied by 300°F (150°C) geopressured resources on the Texas and Louisiana Gulf Coast.

The findings of Arnold (1978), Hornburg and Morin (1975), and results of the Bechtel study on waste heat utilization (1979), together with the selection criteria outlined above, formed the basis for selecting the processes that appeared technologically and economically feasible. The selected processes are Cane Sugar Refining, Pulp and Paper Manufacturing, Sea

Figure 51. Single-Stage Flashed Steam Flow Diagram

Food Processing, and Poultry Processing. A number of other processes that are included in the applicable industrial groups are also prevalent in the Texas-Louisiana area. Examples are processing of dairy products, red meats, fruits and vegetables, grain drying, corn milling, and production of beverages and confectionary items. However, the selected processes were the only ones found to have sufficient information developed for geothermal applications. Developing the needed information was beyond the scope of this study.

H. Summary and Conclusions

Conceptual designs were developed for systems to recover natural gas from the geopressed geothermal resources and to convert the thermal and hydraulic energy content of the brine to electric energy. Direct use of the thermal energy for industrial process heating applications was also examined. The conceptual designs that were developed were based on the reservoir data for a 1 well case and a 12 well case at the S.E. Pecan Island Prospect, which is the most promising prospect of those reviewed in the current study. The results and conclusions of this work are described below.

1. Natural Gas Processing

The technology and equipment needed to separate geopressed natural gas from brine, and to dehydrate the gas to pipeline standards are well developed and have been proven in industrial operations with natural gas for many years.

Packaged dehydration units are available in the sizes needed for the projected production from 1 to 12 wells, each flowing at 50,000 barrels per day.

Some operating problems may be caused by the large variation in flow rates and pressures, which occur over the life of the geopressed wells. For example, the amount of natural gas produced from each of the gas separators, which operate at different pressures, will vary greatly as the wells age and the pressure declines. As a result, the compressors are difficult to size and will be oversized for much of their lifetime.

Mist elimination to minimize salt carryover is the only area requiring development. Since the difficulty of removing brine droplets varies with the droplet

Figure 52. Binary Working Fluid Flow Diagram

size, which is presently unknown, testing the efficiency of mist elimination by various available techniques is needed before a final design can be started.

2. Thermal and Hydraulic Energy Recovery

Brine flow and pressure decline is a major factor that has to be considered in the design of energy conversion systems. In general, these systems must be designed for the greatest flow and pressure, which occur at the beginning of commercial operation.

Hydraulic pressure energy can be effectively recovered by high-pressure turbines connected to electric generators. With 1 well, the electric output of these units was calculated to be 1,500 kW(e). With 12 wells, the electric output was calculated to be 8,470 kW(e).

Technical and economic constraints are caused by corrosion and scale deposition in any process designed to recover energy from geopressured resources. These two factors influence the economics of the processes by increasing capital costs for special materials and also increasing operation and maintenance costs for scale control.

Conceptual designs were developed for the production of electric energy from the thermal content of the geopressured fluid by flashed steam and binary systems. Based on the well production scenarios for S.E. Pecan Island, La., the net electric power outputs were as follows:

- Flashed steam system, 1 well:
1,481 kW(e)
- Flashed steam system, 12 wells:
7,120 kW(e)
- Binary system, one well:
1,637 kW(e)

Direct use of the thermal energy in geopressured brine can be used for industrial or agricultural applications needing heat at temperatures below 300°F (150°C). For the Texas and Louisiana Gulf Coast, potential applications that were selected as technically and economically feasible include cane sugar refining, pulp and paper manufacturing, sea food processing, and poultry processing. A number of other processes that are applicable are also prevalent in the Texas-Louisiana area. Examples are processing of dairy products, red meats, fruits and vegetables, grain drying, corn milling, and production of beverages and confectionary items.

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VII. ECONOMICS

The economics of geopressed energy extraction have developed from the separate economics of the individual marketable forms of energy produced. However, this development has not been an unqualified success, because the particular circumstances of geopressed energy extraction are unique. For example, although natural gas and electric power generation economics are well established, their application to geothermal, and particularly to geopressed geothermal resources, is still being developed. A review of the work to date in this area indicates that geothermal energy economics in general, and geopressed economics in particular, have often produced widely varying results, usually because of differences both in calculation approach and in the selection of technical and economic parameters.

Although these differences are understandable, they should be eliminated, or at least identified as options, so that economic evaluations will produce results which are valid for comparison with geopressed and other energy sources.

The following paragraphs first summarize some of the geopressed economics developed to date, and then present the economic analyses that were performed in this study for the well fields, natural gas separation and processing facilities, electric power generating plants, and direct use processes, which are described in Chapter VI.

A. Review of Previous Analyses

The economics of geopressed energy extraction have been described by Dow (Wilson, 1976) and Brown and Root (1976) in feasibility studies of thermal resources, discussed briefly in the previous chapter. A number of feasibility studies have also been referenced which relate to electric power production from liquid-dominated hydrothermal resources that cover the range of brine temperatures of interest for electric power generation from the geopressed resource. An economic analysis involves estimating the total capital cost and then estimating the energy production cost in terms of \$/MMBtu for natural gas or mills/kWh for electric energy. Different organizations use different methods for estimating both types of cost, which can result in wide and inconsistent variations. Since the capital cost is an input to the energy production cost, inconsistencies in capital cost will carry over into energy production costs.

Energy production costs are estimated separately for each type of facility because the facilities may be

owned by different organizations, and different financial factors would be involved in the calculations. Generally, energy production costs are based on recovering the following costs over the commercial life of the facilities:

- All invested capital
- A satisfactory return on invested capital
- All expenses
- Income and ad valorem taxes.

Comparison of the factors determining these costs as used in past studies, and the values of these factors currently recommended by interested utilities, indicates large differences due mainly to different organizational requirements and to changes by regulatory agencies.

The following items summarize some specific results in reviewing previous economic analyses of geopressed energy.

1. Natural Gas Production

Although the Dow (Wilson, 1976) studies provided useful concepts for natural gas separation and processing, the brine and natural gas flow rates and total dissolved solids content were considerably different from current estimates of the resource. Therefore, neither the designs nor cost estimates for the previous studies were considered applicable to current work.

2. Electric Power Generation

Different methods were used in the earlier geopressed geothermal feasibility studies for the flashed steam by Dow (Wilson, 1976) and the binary system by Brown & Root (1976). The flashed steam cycle total capital costs were based on quotations or pricing experience for the cost of equipment, which were then multiplied by a factor to obtain the total installed costs. The total installed costs for the binary system, however, were based on quotations or pricing experience for all cost elements. Comparisons based on such different approaches are of questionable validity.

A number of feasibility studies of electric power production from liquid-dominated hydrothermal resources, which were performed by different organizations, were also reviewed. These studies were of interest

because they cover the range of brine temperature applicable to electric power production from geopressured resources. However, like the studies that were performed specifically for geopressured resources, it was found that there were wide differences in the methods used for economic analyses and in the economic factors that were applied.

3. Direct Use

Several study and demonstration projects have been undertaken on the direct use of geothermal energy. Studies by Arnold (1978), and Hornburg and Morin (1975) were specifically directed at the potential for directly utilizing geothermal resources in Texas and Louisiana for industrial and agricultural applications. Their work, with updated economic factors, has been utilized as partial input to the current study.

B. Economics of Natural Gas Production

1. S.E. Pecan Island Prospect

The natural gas production cost, in terms of \$/MM Btu, was calculated in this study by performing a capital cost estimate for the facilities required to produce the natural gas at one of the specific prospective reservoir areas (S. E. Pecan Island, LA). Then the capital cost was amortized over the life of the project and the recurring annual costs expensed in the year incurred.

Appendix E, Cost Estimating Methodology, describes the cost estimating methods and economic factors that were used. The estimates are at third quarter 1979 price and wage levels.

In preparing the natural gas production cost estimates, the methodology of by product costing was used (Bloomster and Knutson, 1977). Natural gas was considered as the primary product. Electric energy and thermal energy for direct use applications were regarded as saleable byproducts. The production cost of natural gas includes the capital and operating costs of production and injection wells, their interconnecting piping, other well field equipment, and the equipment necessary to separate natural gas from brine and process the gas to pipeline standards.

Under the byproduct methodology, the value of the thermal and hydraulic energy in the brine used for electric energy production was based only on the incremental equipment required to generate the electric energy. For cases where the electric energy production cost estimates were less than that typical for new conventional generating units in the Texas and Louisi-

ana region, the difference was credited to the natural gas, thus reducing its cost. The same methodology was used for direct use applications. For these, the credit was based on the value of the conventional fuels that were replaced by geothermal energy.

Capital cost estimates of the wellfields for the 1-well and the 12-well (S.E. Pecan Island) cases are shown in Table XXVI. These estimates are based on the well field conceptual designs described in Chapters III and VI, and in Appendix B. Drilling costs for the production wells were estimated by Osborn Engineering Co.

TABLE XXVI
CAPITAL COST ESTIMATES FOR PRODUCTION
AND INJECTION WELLFIELDS
S.E. PECAN ISLAND, LA PROSPECT (\$1,000)

Location	S.E. Pecan Island	
	1	12
Number of Wells		
Land Lease and Development	800	8,160
Geophysics and Geology	300	3,600
Production Wells	5,000	60,000
Piping to Energy Recovery Processes	20	19,240
Injection Wells	2,000	13,000
Piping to Injection Wells	1,580	8,460
Home Office Services	230	1,500
Permits and Environmental	250	500
Contingency	1,520	17,140
Estimated Construction Cost	11,700	131,600
AFDC and Other Owner's Costs	1,300	12,400
Total Capital Cost	13,000	144,000

Note: Indirect field costs are included with well and piping estimates.

Depending upon the total dissolved solids content and chemical composition of the brine, post-treatment of the brine may be required to minimize clogging of the pores of the formation surrounding the injection wells. A pilot unit involving a reactor-clarifier system has been successfully tested for this purpose with high-salinity geothermal brine. The capital costs of reactor-clarifier systems were estimated at \$1.0 million for the 1-well case and \$2.93 million for the 12-well case.

Capital costs for the natural gas processing facilities are shown in Table XXVII. Conceptual designs, which form the basis for these estimates, are described in Chapter VI. Since the natural gas separation processes have somewhat different configurations when operating in conjunction with flashed steam and binary power plants, separate cost estimates of the natural gas facilities were made for the 1-well case. The 12-well case was estimated for operation with a flashed steam plant.

**TABLE XXVII
CAPITAL COST ESTIMATES
NATURAL GAS SEPARATION AND PROCESSING
FACILITIES (\$1,000)**

Location	S.E. Pecan Island		
	1	12	1
Number of Wells			
Power Plant	Steam	Steam	Binary
Mechanical Equipment	1,024	2,824	969
Electrical	100	280	100
Civil/Structural	110	120	110
Piping	290	550	290
Instrumentation	160	220	160
Yardwork and Miscellaneous	20	60	20
Direct Field Cost	1,704	4,054	1,649
Indirect Field Cost	254	406	254
Total Field Cost	1,958	4,460	1,903
Home Office Services	274	625	267
Contingency	335	760	326
Estimated Total Construction Cost	2,567	5,845	2,496
AFDC and Other Owners' Costs	373	965	369
Total Capital Cost	2,940	6,810	2,865

Table XXVIII shows the natural gas production costs for the 1-well case, with the natural gas processing facilities configured to operate with a flashed steam power plant and with a binary plant. The table

**TABLE XXVIII
ESTIMATED NATURAL GAS
PRODUCTION COST
(\$/MM Btu)**

1 Well with Flash Steam Process	5.17
1 Well with Binary Process	5.14
12 Wells with Flash Steam Process	9.46

also shows the natural gas production cost for the 12-well case, configured for operation with a flashed steam plant. The addition of brine post-treatment facilities was estimated to increase the natural gas production cost by \$0.49/MM Btu for the 1-well case and \$0.31/MM Btu for the 12-well case. These costs were all calculated using a discounted cash flow rate of return (ROR) of 15 percent.

Sensitivity analyses were made to determine the effects of increased production well cost (\$5.0 million per production well was used in the base estimates) and of changes in ROR to the production cost of natural gas. The results, as shown in Tables XXIX and XXX, indicate that the natural gas cost is not very sensitive to large increases in the cost of production wells, but is very sensitive to changes in ROR.

2. Brazoria County, Texas

The results of the preceding analysis may be compared to recently estimated costs of producing

**TABLE XXIX
SENSITIVITY OF NATURAL GAS
PRODUCTION COST TO WELL COST
(\$/MM Btu)**

Well Cost (\$)	Number of Wells	
	1	12
5,000,000	5.17	9.46
6,000,000	5.20	9.82
8,000,000	5.22	9.92

**TABLE XXX
SENSITIVITY OF NATURAL GAS
PRODUCTION COST TO RATE
OF RETURN
(\$/MM Btu)**

Rate of Return (%)	Number of Wells	
	1	12
10	4.08	7.52
15	5.17	9.46
20	6.36	11.57

methane at the Brazoria, Texas prospect, by Swanson and Osoba (1979). Using a comparable cost analysis method, they estimated the cost of methane at that site at \$7.50/MCF, assuming the heat energy could be sold for an amount which would exactly balance the direct disposal costs.

3. Johnson's Bayou, Louisiana

Another useful example is examined here in the case of the Johnson's Bayou, LA, prospect. This is a relatively shallow reservoir (9,000-12,000 feet; 2743-3658 m) in which production well cost would be significantly lower than in the deeper reservoirs. However, as pointed out in Chapter III, the dissolved methane content is also significantly lower because of the reduced temperature and pressure. The low temperature of the brine (estimated 201°F, 94°C) makes the heat energy of doubtful value.

The estimate of capital costs for a single-well development in this prospect is given in Table XXXI. The operating costs are estimated in Table XXXII. For a 15% rate of return on investment, the estimated production cost of methane is \$7.30/MCF.

C. Economics of Electric Power Generation

Capital cost and energy production cost estimates were made for processes that convert the thermal energy in the brine to electric energy, and for those that convert the hydraulic energy to electric energy. These cost estimates were based on the conceptual designs for electric generating plants that are described in Chapter VI.

TABLE XXXI
CAPITAL COST ESTIMATES,
JOHNSON'S BAYOU, LA
SINGLE-WELL PRODUCTION—3-WELL DISPOSAL
FACILITY, METHANE ONLY (\$1,000)

Location	Johnson's Bayou, LA
Land Lease Costs	150
Geophysics and Geology	300
Permits and Environmental	400
Lease Development	500
Production Well	
Tangible	1,000
Intangible	1,500
Production Equipment	300
Gas Processing Equipment	100
Disposal Wells	900
Disposal Pumps	700
Total	\$5,900

TABLE XXXII
OPERATING COSTS, SINGLE-WELL DEVELOPMENT,
JOHNSON'S BAYOU, LA

Annual Fixed Costs (\$1,000)	
Labor	\$140
Engineering	40
Transportation	25
Well tests, lab, etc	25
	\$230
20% overhead	46
	\$276
Variable Costs (¢/bbl)	
Production Well workover	0.75
Disposal well workover	0.50
Pump maintenance	0.30
Total	1.55
Disposal Fuel Cost	3 SCF/bbl
Royalty	15%
Estimated Production Cost of Methane, 15% ROR	\$7.30/MCF

Capital cost estimates for the 1-well case with binary and flashed steam processes, and for the 12-well case with the flashed steam process are included in Table XXXIII. The initial unit capital cost was estimated to be \$1920/kW (net) for the 1-well binary process, and \$1930/kW (net) for the 1-well flashed steam process. However, the initial unit capital cost for the 12-well flashed steam process was estimated to be only \$820/kW (net). Since the power output of these units declines as the well flow declines, the unit capital costs do not remain constant.

Capital cost estimates for hydraulic turbine-generator units are shown in Table XXXIV. The initial unit capital cost is \$453/kW (net) for the 1-well case, and \$167/kW (net) for the 12-well case. These unit costs are substantially less than those of the thermal energy conversion processes.

TABLE XXXIII
CAPITAL COST ESTIMATES
ELECTRIC POWER GENERATION PROCESSES (\$1,000)

Location	S.E. Pecan Island		
	Number of Wells	1	12
Process	Binary	Steam	Steam
Turbine-Generator	400	920	1,290
Other Electrical Equipment	870	170	517
Electrical	130	130	500
Civil/Structural	140	120	270
Piping	280	290	560
Instrumentation	90	100	190
Yardwork and Miscellaneous	30	30	50
Direct Field Cost	1,940	1,760	3,377
Indirect Field Cost	160	158	340
Total Field Cost	2,100	1,918	3,717
Home Office Services	294	268	520
Contingency	360	328	636
Estimated Total Construction Cost	2,754	2,514	4,873
AFDC and Other Owners' Costs	386	348	958
Total Capital Cost	3,140	2,862	5,831

TABLE XXXIV
CAPITAL COST ESTIMATES
HYDRAULIC TURBINE-GENERATOR UNITS
(\$1,000)

Location	S.E. Pecan Island	
Number of Wells	1	12
Turbine-Generators	323	723
Other Mechanical Equipment	—	—
Electrical	101	173
Civil/Structural	8	17
Piping	—	—
Instrumentation	—	—
Yardwork and Miscellaneous	—	—
Direct Field Cost	432	913
Indirect Field Cost	29	44
Total Field Cost	461	957
Home Office Services	65	134
Contingency	79	164
Estimated Total Construction Cost	605	1,255
AFDC and Other Owners' Costs	75	165
Total Capital Cost	680	1,420

Energy production costs are shown in Table XXXV. These costs are based on a 11.4 percent ROR, which is typical for electric utility companies in the Texas and Louisiana region. The table shows that the electric energy production costs for the 1-well case were estimated at 43.0 mills/kWh for the binary plant, and 44.1 mills/kWh for the flashed steam plant. Since the energy production cost for the new plants in the Texas and Louisiana region is, typically, 37.0 mills/kWh, conversion of the thermal energy to electric energy was not presently competitive for the 1-well case. However, conversion of the thermal energy for the 12-well case and hydraulic energy for the 1 and 12-well cases appears

TABLE XXXV
ENERGY PRODUCTION COSTS OF ELECTRIC
POWER GENERATING SYSTEMS (mills/kWh)

System	Number of Wells	
	1	12
Binary	43.0	*
Flashed Steam	44.1	20.9
High-Pressure Hydraulic Turbine	9.4	9.3
Low-Pressure Hydraulic Turbine	8.0	5.0

*The binary system was not included in the analysis of the 12-well case.

very attractive, assuming the methane production will support the wellfield and gas processing costs.

As discussed previously in Section VII.B, a credit was applied to the natural gas production cost for the difference between the energy production cost for new generating plants and that of the hydraulic units for the 1-well case. This reduced the natural gas production cost from \$5.14/MM Btu to \$4.53/MM Btu. Using a similar credit for both the hydraulic units and the flashed steam plant reduced the natural gas production cost for the 12 well case from \$9.46/MM Btu to \$8.90/MM Btu.

D. Economics of Direct Use

Estimates were made of the value of the thermal content of the brine when used to replace conventional fuel for process heating operations. These estimates were made for the four industries discussed in Chapter VI, which are representative of those in the Texas and Louisiana region.

Table XXXVI shows the resulting brine value for four representative industrial processes. Of these, sugar cane refining, and pulp and paper processing require more flow than is produced by one well, and plants for these types of processes were assumed to be constructed

for operation with the 12-well case. On the other hand, typical plants for sea food processing and for poultry processing require less than the full flow from one well, and were assumed to be constructed for operation with the 1-well case. Table XXXVI also shows the number of each type of plant that could be supplied by the full flow of the brine from 1 or 12 wells, whichever is applicable. The number of plants that a well field can support depends upon the brine temperature. Since only 250°F (120°C) brine is required by the four types of plants listed in the table, a greater number of plants could be supplied if the brine temperature were 300°F (150°C). The number of plants that could be supported by brine at both temperatures is shown in Table XXXVI.

As discussed previously in Section VII.B, a credit for the thermal value of the brine was applied to the natural gas production cost. The results show that the natural gas production costs, based on 15 percent ROR, are reduced from \$9.46/MM Btu to \$7.80/MM Btu for pulp and paper and to \$8.83/MM Btu for sugar refining. They are reduced from \$5.17/MM Btu to \$5.04/MM Btu for poultry processing and to \$5.09/MM Btu for sea food processing.

Table XXXVI also shows the credit to the natural gas production cost that could be taken for the use of the brine in these industrial processes. It should be noted that the credit is in terms of \$/MM Btu of the natural gas and not \$/MM Btu of the brine.

It was shown in Table XXVIII that the lowest production cost of natural gas is \$5.14/MM Btu for the 1-well case. With \$0.61/MM Btu credit taken for electric energy produced from the hydraulic turbine-generators, as discussed in Section VII.C, the lowest production cost for natural gas is then \$4.40/MM Btu. Since poultry processing only requires a fraction of the thermal energy from the 1-well case, additional credit could be

TABLE XXXVI
VALUE OF GEOTHERMAL ENERGY FOR DIRECT USE APPLICATIONS

	Sugar Cane Refining	Pulp & Paper	Sea Food Processing	Poultry Processing
Brine Value to Process, \$/MM Btu Brine	3.45	3.45	4.29	2.24
Credit to Natural Gas for One Plant, \$/MM Btu Natural Gas	0.63	1.66	0.08	0.13
Applicable Wellfield, Number of Production Wells	12	12	1	1
Number of Plants Wellfield Can Support:				
—with 250°F Brine	2.6	1	31	9
—with 300°F Brine	4	1.5	47	13

taken if the capacity of the poultry plant could be increased or if other types of plants could use the excess thermal energy. However, to date it has been very difficult to induce industry to locate new plants at geothermal sites and the prospect for such relocation is unknown at the present time.

E. Summary and Conclusions

Economic analyses were performed for systems that were designed to recover natural gas from geopressured geothermal resources and to convert the thermal and hydraulic energy in the brine to electric energy. Direct use of the thermal energy for industrial process heating applications was examined. These economic analyses were based on conceptual designs for the systems, which are discussed in Chapter VI. The analyses were also based on the reservoir data for a promising prospect of those reviewed in the current study.

The economic analyses of previous feasibility studies were reviewed with the general result that large differences in parameters and methodology were disclosed. While recent legislation has changed some financial factors, the primary difficulty with the earlier analyses involves the assumed performance of the production reservoirs. Larger aquifers, capable of supporting higher rates of flow, producing higher temperatures and more methane, would all certainly improve the economics of the geopressured resource as it is now understood.

The direct use of the heat energy content of the brine was examined for a variety of industrial applications and found to be economically competitive. However, the pricing has to be a sufficient inducement to cause companies to move their processing facilities to the geothermal sites. At the present time, the prospects for such a major move of facilities are unknown.

The economics of electric power generation should be compared with that for other new electric power plants in the Texas and Louisiana region, which, typically, have an energy production cost of 37.0 mills/kWh. The lowest electric energy production cost in the current study, using the thermal content of the brine, was estimated at 20.9 mills/kWh. This was for the flashed steam process integrated with a 12-well field for reservoir utilization. This application appears to be competitive for the 12-well case, but not presently competitive for the 1-well case, even if the field cost is supported by methane production. Electric power generation by hydraulic turbine generators appears economi-

cally very attractive. For the 12-well case, an estimate of 9.3 mills/kWh was obtained for the high pressure turbine generator and 5.0 mills/kWh for the low pressure turbine generator. These costs were somewhat greater for the 1-well case, but still very competitive.

The cost of natural gas production only, for the lowest cost process examined and a 15 percent rate of return, was estimated to be \$5.14/MM Btu. This cost was for the 1-well S.E. Pecan Island case, which was much lower than for the 12-well field. In order to obtain the most optimistic value, the natural gas production cost can be reduced by applying \$0.61/MM Btu credit for the energy produced by the hydraulic turbine generators, and \$0.13/MM Btu credit for the thermal energy used in the most attractive direct use application that can be used with the 1-well case. The resulting natural gas production cost is \$4.40/MM Btu. However, compared to the current \$2.00/MM Btu price of natural gas in the area, this is still not an economically attractive result. The \$0.13/MM Btu credit for direct use assumes that only one poultry processing plant uses the thermal energy from the 1-well case and the excess thermal energy is not used. Actually, at least nine poultry processing plants or a mixture of other small processing plants could be supplied by one well. This could substantially increase the credit for thermal energy.

The sensitivity of natural gas production cost to increases in the cost of production wells and to the rate of return was examined. The results indicated that the sensitivity to large increases in the cost of production wells is relatively low, but the sensitivity to reasonably anticipated variations in rate of return are substantial. For instance, increasing the rate of return from 15 percent to 20 percent, which is within the typical range of ownership of such facilities by energy companies, increases the cost of natural gas production only, by about 23 percent. It was also determined that the addition of brine post-treatment facilities, if required, will not substantially increase the natural gas production cost.

The overall conclusion which can be drawn from the analyses, is that, while geopressured energy utilization is technically feasible now, the economic feasibility must await either substantial increases in the competitive price of natural gas from other sources, or else a decrease in the geopressured natural gas price by some device such as government incentives. Government incentives could be in the form of increased tax credits, greater depletion allowance, or unrestricted use of the natural gas produced.

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VIII. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

A. Summary

Investigation of the Geopressed zones along the Texas and Louisiana coast has identified a total of twenty prospective reservoir areas containing an estimated 1100 cubic miles ($4.58 \times 10^{12} \text{ m}^3$) of sandstone with 5,900 billion barrels of entrained water. The energy content consists of a maximum of 232 trillion cubic feet (TCF) of dissolved methane, and 367×10^{15} BTU (367 quads) of thermal energy. On the basis of reasonable average values for the significant reservoir parameters, the maximum estimated recoverable resource in these prospects is 7.6 TCF methane, 12.6 quads thermal, and hydraulic energy representing less than 2% of the total. More than 80% of the identified resource is contained in a single area (Harris Wilcox fairway, Texas), which has poor probability of production success.

Advanced reservoir modeling indicates the natural gas released from solution deep in the reservoir as the pressure is depleted will have no significant effect on the production of gas. The methane produced will only depend upon the initial saturation, and the pressure and temperature gradients to the surface separators.

Investigation of energy utilization methods indicates that single-well development for production of dissolved methane is the most profitable development approach at this time. Because of the low enthalpy of the brine, geothermal power generation is not a highly significant factor. A single well in the most favorable geopressed prospect yet identified (S.E. Pecan Island, LA) has only a 10% probability of producing as much as 40,000 bbl of 300°F water per day for 20 years. A well in that field with optimistic parameters could supply pipeline-quality natural gas for \$5.14/MCF. Electric power could also be generated by a wellhead binary-cycle electric generator for 43 mills/kwh, assuming the methane production carries the cost of production wells and disposal. A high-pressure hydraulic turbine could supply electricity for 9.4 mills/kwh, and a low-pressure hydraulic turbine for 8 mills/kwh, in addition. Combined power capability of this installation would amount to a maximum of 1.6 MW(e) (net) from the thermal plant, and 1.5 MW(e) from the hydraulic turbines. In twenty years, the well would produce a maximum of 10 billion cubic feet of methane.

Other favorable prospects investigated include the Brazoria, Texas fairway, site of a DOE well currently under test. Methane can be delivered from a well in this area at an estimated \$7.50/MCF.

The Johnson's Bayou prospect, a relatively shallow, high-quality reservoir on the Louisiana-Texas border, should be able to produce methane from a single-well production facility for \$7.30/MCF. All these estimates are based on high values of dissolved methane. Significant differences in the methane in solution would have a profound effect upon the cost of production; for example, if the Brazoria, Texas well produces only 20 SCF methane/bbl, costs will rise to nearly \$15./MCF. On the other hand, possible "free gas" (super-saturation), would improve the economics, although the prospect of any significant or general occurrence of free gas in geopressed sands is remote.

Development based on multiple-well fields was found to be less promising. A twelve-well field designed to drain the S.E. Pecan Island reservoir in conjunction with an integrated geothermal-methane fuel plant showed improved electricity generation costs over the single-well case, but significantly greater cost of the natural gas. This development showed an estimated methane cost of \$9.46/MCF, power generation costs from a 7.1 MW(e) (net) flashed steam electric plant of 20.9 mills/KWH, power costs from a high pressure hydraulic turbine [6.97 MW(e) net] of 9.3 mills/KWH, and from a low-pressure hydraulic turbine [1.5 MW(e) net] of 5 mills/KWH.

Spent brine disposal in shallow saline aquifers was found to be the most feasible disposal technique. Historically, costs of similar disposal projects were found to range from 3.6¢ to 5¢/bbl. Under current conditions, it is estimated that this cost will be 8¢ to 10¢/bbl, or more. Reinjection into the production reservoir is not a viable technique at the present time. The high pumping energy requirements make the energetics of the overall process unfavorable, and extremely high costs result from the multiple deep wells and high pressure pumps required.

B. Conclusions

Pipeline natural gas costs from geopressed production facilities will probably range upward of \$5./MCF for the most favorable reservoirs and optimistic conditions, assuming dissolved methane in the range of 35 to 40 SCF/bbl. Lower or higher values of dissolved methane will have a profound effect on the economics of the process.

Single-well geopressured development offers a more favorable prospect than does multiple-well field development with an integrated geothermal plant. Even the largest-known geopressured prospects will be capable of producing a relatively insignificant amount of geothermally generated electric power.

Hydraulic turbines to exploit the high pressure flow can be easily implemented to provide a small amount of low-cost power, but the sizing of such units must take into account the constantly declining available energy.

Disposal in shallow saline aquifers is feasible and offers the best prospect for spent brine disposal in most geopressured areas. Reinjection into the production reservoirs is not a viable undertaking at the present time.

Direct use of the heat contained in the brine appears to offer promise. On a value/BTU basis, industrial use of the heat increases the value of the brine because of the very low conversion efficiency of a geothermal electric plant using a 300°F (150°C) source. However, great difficulty can be anticipated in load equalization and the location of plants near the site of brine production.

The most serious uncertainties in the production of the geopressured resource at the present time are (1)

the single-well drainage volume (size of continuous reservoirs), and (2) the actual amount of gas in solution in specific reservoir areas.

C. Recommendations

Based on the results of the effort described, the following recommendations are made:

- Limited participation by EPRI in well tests of the geopressured zone should be encouraged, and independent evaluation of the results maintained.
- The principal purposes of such well tests should be the determination of single-well drainage area and accurate assessment of the dissolved methane.
- Plans for implementation of an electric power generating pilot plant on a geopressured site should be held in abeyance.
- Future resource assessment efforts should be concentrated on the large fairways, particularly the Harris, TX Wilcox fairway. If these prove non-productive, the total recoverable resource will assume such small proportions as to be insignificant.

APPENDIX A

SECONDARY POROSITY IN DEEP GULF COAST SANDSTONES, AN EVALUATION

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Summary

Porosity reduction takes place during burial of sands by mechanical rearrangement of grains and addition of intergranular cements. "Secondary porosity" by leaching of cement has been observed in many sandstones of different ages. In deeply-buried sandstone on the Texas Gulf Coast, secondary porosity is believed to contribute to significant porosity increases in geopressed zones. An evaluation of secondary porosity was undertaken by review of publications. Increase in porosity at depths greater than 11,000 feet is believed to be due to leaching of both grains and cement by flow of subsurface waters that are rich in carbon dioxide. The source of carbon dioxide may be the thermal or bacterial breakdown of sediment hydrocarbons.

Petrographic criteria for recognizing secondary porosity are sound. There is much evidence that some porosity enhancement has taken place by dissolution of minerals at depth. However, questions remain regarding the methods of sample preparation, measurement of porosity, nature of fluid saturations, and temperature depth relationships. The occurrence of secondary porosity cannot now be predicted, and it appears hazardous to expect that secondary porosity will be present to enhance storage and recovery of fluids at specific locations.

Secondary Porosity in Reservoir Sandstones

Background

Secondary porosity in deep sandstones has been observed in Gulf Coast Tertiary formations as well as in older sandstones in many different basins. These observations suggest that porosity by dissolution of grains and cement may be a widespread phenomenon. The occurrence of secondary porosity could be important to entrapment of petroleum as well as to the production of fluids from deep reservoirs.

The development of secondary porosity by leaching has been established largely by petrographic evidence as the result of microscopic observations. These criteria include the following (McBride, 1977):

1. Patches of corroded undissolved carbonate cement.
2. Occurrence of large pores from which calcite cement has been leached.
3. Partial replacement or corrosion along grain boundaries adjacent to large pores.
4. Molds of fossils or grains.

Other petrographic criteria may be used, but those listed above are the most direct evidence for leaching of grains and cement.

The relative order of mineral changes with depth was first outlined by Lindquist (1977) in Frio sandstones. Although additional stages can be seen, the following represents the basic succession:

1. Shallow depth: fine-grained calcite replaces feldspar; overgrowths form on feldspar grains.
2. Deeper, normal pressure zones: silica overgrowths on quartz grains, sparry calcite cement replaces feldspar.
3. Deeper, transition zone: calcite dissolution; enhanced porosity.
4. Deepest, abnormal pressure: kaolinite precipitation, formation of ferroan dolomite, and analcime; reduction of porosity.

This succession of diagenesis results in porosity changes as follows. An assumed initial porosity is 40 to 45 percent. With shallow to moderate burial, silica and feldspar overgrowths may amount to 5 percent of bulk volume thereby reducing porosity by 5 percent. Where present, sparry calcite cement may amount to as much as 25 percent of bulk volume. Therefore, porosity may be reduced to less than 10 percent before dissolution.

At greater depths, dissolution may increase porosity to 25 or 30 percent, primarily by the loss of calcite. At still greater depths, recementation may result in a porosity decrease to 15 percent.

Subsequent work on the petrography of Gulf Coast sandstones shows that secondary porosity may develop in other reservoirs in the Wilcox, Vicksburg, Yegua, and Jackson formations (Loucks and others, 1977). The development of secondary porosity in geopressed sections has been used as a criterion in site selection for the production of geothermal energy (Bebout and others, 1978).

Criteria and Measurements

The petrographic criteria are satisfactory if it is assumed that sample preparation and measurement techniques did not affect the microscopic observations. In only one paper (McBride, 1977) is sample preparation mentioned. Secondary porosity was observed by "examination of thin sections made of epoxy-impregnated sandstone 'perm' plugs" (McBride, 1977, p. 121). In all other cases, however, impregnation of samples by resin is not stated, and therefore, some dissolution phenomenon could be the result of mineral plucking during thin section preparation. The statement by McBride indicates that the samples studied were the same as those used for porosity and permeability measurements. However, this may not always be true in other studies because some recent data supplied to us lists pores counted in thin section as porosity. It is not known how widely used this method for estimation of porosity may be, but it is certain that pore counts in thin section are not a reliable measure of porosity. It must be concluded, therefore, that sample preparation and counting techniques may not have been uniform in the studies conducted so far in Gulf Coast Tertiary sandstones.

Occurrence

Secondary porosity is not found everywhere in deep, geopressed zones. Sandstone porosities are variable in most sections, and if dissolution has produced high porosities in some sandstones, other adjacent sandstones may not be affected. In other words, secondary leaching must be a selective process.

For example, Frio sandstones in the Chocolate Bayou field have porosities as high as 25 percent in the deep subsurface, as a result of secondary leaching. However, in the nearby Danbury Dome area, massive cementation by quartz has reduced porosities to less than 10 percent. Leaching and development of secondary porosities did not take place, even with greater depths of burial.

Vicksburg sandstones of South Texas are an example of low porosity sandstones in a geopressed environment. Cores from McAllen Ranch field, Hidalgo

County, show maximum porosities that range from 19 percent at 10,800 feet to 15 percent at 13,500 feet. Other sandstones in the same section show average porosities of about 13 percent at similar depths. In no case does any sandstone in this depth range reach a porosity of 25 to 30 percent as would be expected from dissolution.

Composition

The original composition of sandstones greatly influences the porosity which survives at any given depth. Along the Texas Gulf Coast, Frio sandstones become more quartzose northward. In South Texas the Frio contains low quartz (about 25 percent) and a large amount of volcanic rock fragments. In the middle Texas coast, quartz content increases to moderate values (40 to 50 percent). In the upper Texas Gulf Coast, quartz content increases to moderately high values (70 percent) and other components, such as rock fragments and feldspars are found in only minor amounts.

The Chocolate Bayou geothermal prospect is in Frio sandstones of the upper Texas Gulf Coast where the original sandstone composition was high in quartz, and calcite cement was added during burial. It is in this area that leaching of calcite increases porosity to 30 percent at depths of 9,000 to 11,000 feet (Bebout and others, 1978). In the Frio of the lower Texas Gulf Coast, leaching of calcite cement produces secondary porosity up to 30 percent (Loucks and others, 1977).

On the other hand, Vicksburg sandstones of South Texas have compositions similar to Frio sandstones in the same area in that quartz content is low and the amount of volcanic fragments is relatively high. At McAllen Ranch field, the Vicksburg sandstones have a maximum porosity of 20 percent. Some leaching may have occurred, but maximum porosities were not attained.

Frio sandstones of the middle Texas coast have not been studied for evidence of leaching. These sandstones have maximum porosities of about 20 percent at McCampbell field, Aransas County (Turner, 1977). Maximum porosities range from 17 to 22 percent in Frio reservoirs at Nine Mile Point field, Aransas County (Berg and Powell, 1976). Apparently, leaching did not produce abnormally high porosities in this area. In both fields, Frio reservoirs range from 10,000 to 12,000 feet in depth, and pressure gradients are on the order of 0.8 psi/ft or more.

The major compositional requirement for development of secondary porosity appears to be the presence of sparry calcite cement formed at an early stage.

This cement is then subsequently leached at depths greater than about 9,000 feet. The sandstones most likely to contain sparry calcite cement are those with higher quartz content of more than 50 percent, such as the Frio sandstones of the upper Texas coast. Frio sandstones with lower quartz content of 50 percent or less apparently do not develop high values of porosity. The only exception is the Frio of the lower Texas coast (Loucks and others, 1977) which does develop secondary porosity of up to 30 percent. In the same area however, Vicksburg sandstones of the same composition retain a relatively low porosity and insignificant leaching of cement. No examples are known of secondary porosity in the Frio sandstones of the middle Texas coast.

Pressure and Temperature

Secondary porosity seems to be related to geopressed zones, at least in some areas. The Chocolate Bayou geothermal prospect shows this relationship. On the other hand, other areas of high fluid pressures do not appear to have developed secondary porosity, such as Vicksburg sandstones at McAllen Ranch field and Frio sandstones of the middle Texas coast at McCampbell Ranch and Nine Mile Point fields. Therefore, the presence of geopressures does not seem to be a major influence on the development of secondary porosity.

Fluid Saturations

Most descriptions of secondary porosity have not related its appearance to fluid saturation. It may be assumed that most of the sandstones described as containing secondary porosity have come from gas fields where cores were available. This seems to be the case for the Chocolate Bayou area and may be true for other cores. In many gas fields of the Texas coast, higher average porosities are found in the gas-bearing sandstones. For example, in Vicksburg reservoirs at McAllen Ranch field higher average porosities of 20 to 22 percent are found in gas reservoirs where water saturations are 50 percent or less. On the other hand, non-reservoir sandstones in the same section have porosities as low as 15 percent and water saturations of 70 to 80 percent.

It may be concluded, then, that higher porosities are related to gas-producing horizons whether or not the higher porosities are produced by secondary leaching. It is well known that the presence of oil and gas inhibits the development of authigenic minerals. Precipitation of kaolinite commonly occurs in some reservoirs below the oil-water contact. This relationship can be demonstrated in some areas that show the effects of hydrodynamic flow. It is presumed therefore, that flow of formation water produces secondary mineral cements in these areas, and where hydrocarbon accumulation has

taken place prior to flow, the authigenic minerals do not develop or are at least inhibited.

Similar relationships may be expected in Tertiary sandstones of the Texas Gulf Coast. It is possible, for example, that secondary porosity was not developed at the depth at which it is now found. Rather, leaching of calcite may have been an earlier stage, and migration of gas into more porous sandstones may have prevented further diagenetic changes.

Some published observations may support this conclusion. For example, certain Eocene Wilcox sandstones at depths of 5000 to 6000 feet also show secondary porosity (Stanton, 1977). These depths are not greatly different from those expected for maximum depths of burial which may have been only on the order of 8000 feet. This occurrence of secondary porosity in the Wilcox suggests that deep burial was not a requirement for leaching.

Origin

The occurrence of "secondary porosity" by leaching has been widely observed, but some doubts can be raised about its measurement and relation to composition, pressure, temperature, and fluids. In short, the origins of "secondary porosity" remain obscure, and therefore, its presence cannot be predicted.

A mechanism for deep leaching has been suggested (McBride, 1977). Solution may be accomplished by carbonic acid, and the source of carbon dioxide may be from thermal or bacterial degeneration of organic materials. Presumably, carbon dioxide is derived from shale waters during compaction, and flows through aquifers in an updip direction. Leaching of calcite thereby takes place in deep sands, although dissolution cannot be expected at great depths where elevated temperatures promote precipitation of calcite. This explanation is not entirely satisfactory because others expect secondary porosity to be developed in overpressured, geothermal aquifers.

Conclusions

There is no doubt that porosity enhancement by leaching has taken place in some Gulf Coast sandstones. A major problem that remains is how the process might have worked and whether enhanced porosity can be predicted for specific reservoirs and aquifers. So far there has been no systematic study of secondary porosity that allows one to relate its development to other geologic variables. Until such a study is made, secondary porosity will remain an interesting phenomenon with little practical value in subsurface applications.

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APPENDIX B

TWELVE WELL DEVELOPMENT OF S.E. PECAN ISLAND, LA PROSPECT

To investigate full-scale development of a large promising geopressured reservoir, a field consisting of twelve production wells in the S.E. Pecan Island prospect, each well draining an area of approximately 4-1/2 square miles, was designed. S.E. Pecan Island, discussed further in earlier sections of this report, contains a large lens-shaped geopressured sand body occupying a total area of about 60 square miles, with a depositional center offset from the lens axis. The potentially productive part of the reservoir consists of a series of laminated sands and shales, with total sand thickness ranging from about 1,000 feet to less than 350 feet near the edge of the lens. The depth from the surface averages about 15,500 feet.

To simulate a full-scale geothermal/methane recovery operation, the reservoir was divided into twelve approximately equal segments, each containing one well (Fig. B-1). The thickness of the productive reservoir available to each well was estimated from the sand isopach map of the area, and other reservoir parameters

were assumed constant throughout the field. These reservoir parameters are given in Table B-I.

TABLE B-I
WELL PARAMETERS

Initial Pressure	13,500 psi
Hydrostatic Pressure	7,296 psi
Viscosity	0.2 centipoise
Compressibility, C_e	5×10^{-6} psi $^{-1}$
Wellhead Radius	0.204 feet (5-1/2 in. casing)
Formation Porosity	20%
Permeability	10MD
Initial Gas Saturation	35 SCF/bbl

Flow performance of each of the hypothetical wells was predicted on the basis of the quasi-steady-state reservoir equation described in Chapter III. Results of these calculations for each of the wells are shown in Figures B-2 through B-13. The flow rate for each well has been adjusted to optimize total production of the field over a period of about 10 years. The initial production

Figure B-1. Location of Wells for 12 Well Development of SE Pecan Island Geothermal Prospect, LA

rate for the field is 240,000 bbl/day of 300°F water, this rate remaining constant for about 8 years. Production will then gradually decline to 187,000 bbl/day at the end of 11 years. Wells are assumed to be abandoned when individual flow rate declines to 4,000 bbl/day. After 19 years, a total of 1.19 billion barrels of water will have been produced. This is approximately 2.4% of the total in-place water calculated from the reservoir volume esti-

mated by LSU. Cumulative water production over the life of the field is shown in Figure B-14.

Over the 19-year life, a total of 34 billion cubic feet of methane will be produced, assuming the water is initially saturated with 35 cubic feet/bbl of dissolved methane.

FIG. B2: FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 1, DRAINAGE RADIUS 7136 FT. THICKNESS: 288 FT.

FIG. B3: FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 2, DRAINAGE RADIUS 6675 FT. THICKNESS: 358 FT.

FIG. B4: FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 3, DRAINAGE RADIUS 7692 FT. THICKNESS: 698 FT.

FIG. B5: FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 4, DRAINAGE RADIUS 7692 FT. THICKNESS: 888 FT.

FIG. B6: FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 5, DRAINAGE RADIUS 7335 FT. THICKNESS: 988 FT.

FIG. B7: FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 6, DRAINAGE RADIUS 7335 FT. THICKNESS: 988 FT.

FIG. B8 : FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 07, DRAINAGE RADIUS 9902 FT. THICKNESS: 600 FT.

FIG. B9 : FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 08, DRAINAGE RADIUS 6358 FT. THICKNESS: 800 FT.

FIG. B10: FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 09, DRAINAGE RADIUS 6604 FT. THICKNESS: 800 FT.

FIG. B11: FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 010, DRAINAGE RADIUS 7335 FT. THICKNESS: 600 FT.

FIG. B12: FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 011, DRAINAGE RADIUS 7092 FT. THICKNESS: 500 FT.

FIG. B13: FLOW PERFORMANCE, SE PECAN ISLAND FIELD, 12 WELL DEVELOPMENT, WELL 012, DRAINAGE RADIUS 6358 FT. THICKNESS: 350 FT.

APPENDIX C

PAGE

- C-1 Louisiana Dept. of Conservation—"Underground Salt Water and Waste Disposal in Louisiana-State Regulations and Geological Concepts" (1974)
- C-14 Texas Dept. of Water Resources—"Application for Permit to Discharge, Deposit or Dispose of Wastes"
- C-16 Texas Dept. of Water Resources—"Application for Permit to Dispose of Waste by Well Injection"
- C-18 Environmental Protection Agency—"National Pollutant Discharge Elimination System-Application for Permit to Discharge"
- C-20 Texas Railroad Commission—"Application to Dispose of Salt Water by Injection Into a Porous Formation not Productive of Oil or Gas"
- C-21 Texas Railroad Commission—"Application to Inject Fluid into a Reservoir Productive of Geothermal Resources"

UNDERGROUND SALT WATER AND WASTE DISPOSAL

IN LOUISIANA

STATE REGULATIONS AND GEOLOGICAL CONCEPTS

DEPARTMENT OF CONSERVATION

R. T. SUTTON, COMMISSIONER

JUNE, 1974

DEPARTMENT OF CONSERVATION

R. T. SUTTON, Commissioner

GEOLOGICAL OIL AND GAS DIVISION

A.C. CHAUVIERE, Chief Conservation Geologist

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Geological Staff

C. G. KING   - North Louisiana

D. L. McGUIRE, JR. - Southeast Louisiana

C. C. THOMAS   - Southwest Louisiana

J. H. WELSH   - Offshore Louisiana

LOUISIANA GEOLOGICAL SURVEY

L.W. HOUGH, State Geologist

The following publication contains Louisiana's rules and regulations pertaining to underground salt water and industrial waste disposal, along with the approval procedure for each type of disposal well.

Schematic diagrams of typical salt water and industrial waste disposal wells are included, along with a geological cross section of the Baton Rouge area, which illustrates the conditions over many parts of the State where salt water or waste disposal is requested. A table lists the name and location of Louisiana's 77 industrial waste disposal wells which have been permitted, although all have not been drilled, or are now in operation.

The Department of Conservation has on file numerous records of wells drilled, some of which indicate the depth of subsurface fresh water sands enabling the Department to formulate and administer sound policies regarding their protection. Publications written by members of the United States Geological Survey in cooperation with various state agencies concerning fresh ground water supplies are on file in the Department.

Drilling methods and operating procedures for industrial waste disposal wells have generally followed those developed by the Department of Conservation for underground disposal of oil field brines. Disposal of these brines by underground injection has been employed for many years prior to industrial waste injection and has been very successful in Louisiana.

The history of successful operations of oil field brine disposal influenced the State authorities to permit underground disposal of industrial waste.

UNDERGROUND SALT WATER AND INDUSTRIAL WASTE DISPOSAL IN LOUISIANA
STATE REGULATIONS AND CONCEPTS

PART I. Salt Water Disposal

The Louisiana Department of Conservation has the responsibility of protecting fresh water sands from contamination by oil, gas, and salt water. The authority for this protection is contained in Title 30, Chapter I, Section 4, Paragraph C of the Louisiana Revised Statutes of 1950 which reads:

"The Commissioner of Conservation has authority to make after notice and hearing as provided in this Chapter, any reasonable rules, regulations, and orders that are necessary from time to time in the proper administration and enforcement of this Chapter, including rules, regulations or orders for the following purposes:

- (1) To require the drilling, casing, and plugging of wells to be done in such a manner as to prevent the escape of oil or gas out of one stratum to another, to prevent the intrusion of water into oil or gas strata; to prevent the pollution of fresh water supplies by oil, gas, or salt water; and to require reasonable bond with security for the performance of the duty to plug each dry or abandoned well."

Statewide Order 29-B issued by the Department of Conservation July 19, 1943, and subsequent amendments govern the drilling for and the producing and plugging of oil and gas wells in Louisiana.

This order has definite provision for preventing pollution of underground fresh water supplies. Section XV of Statewide Order 29-B regulates the production and disposal of salt water.

This section states:

"When a well starts to produce salt water, the operator or company shall report that condition to the Department. Permits must be secured before disposing of salt water underground."

The Department also requires that the salt water be injected into a sand which carries salt water and that the injected water will not displace any fresh water up gradient or be put in a sand which produces oil and gas. Fresh water sands which are drilled through must be protected by an adequate casing and cementing program. These provisions also apply to industrial wastes.

As stated in the Amendment to Statewide Order 29-B, dated October 19, 1967:

- (1) No waste oil or oil field waste shall be disposed of into any stream, lake or other body of water or into any ditch or surface drainage depression leading to any stream, lake or other body of water. Such waste shall be retained for proper disposal.
- (2) Produced salt water shall be disposed of into subsurface formations not productive of hydrocarbons, except:

(a) It may be disposed of in pits where such method and pits have been approved by the Commissioner of Conservation.

(b) It may be disposed of in tidally affected waters, brackish water or any other waters unsuitable for human consumption or agricultural purposes.

(3) Produced salt water shall not be disposed of into a zone producing or productive of hydrocarbons unless such disposal is approved by the Commissioner of Conservation after a public hearing or unless prior approval has been granted to use the proposed zone for salt water disposal.

The Commissioner of Conservation shall cause an inspection to be made of each completed disposal facility to insure compliance with this Amendment.

A reasonable estimate of the amount of salt water injected annually into each disposal well shall be reported to the Geological Oil & Gas Division with a copy to the appropriate District Manager, such report to be filed during the first quarter of the next calendar year.

Amendment to Statewide Order 29-B dated February 27, 1974

Section XIX F-3 c and d pertains to abandonment procedures and states:

(c) When production casing is not run or is removed from the well, a cement plug of at least one hundred feet (100') shall be placed from at least fifty feet (50') below the shoe of the surface casing to at least fifty feet (50') above. In lieu of the above, the operator shall have the option of using a cement retainer placed at least fifty feet (50') above the surface casing shoe and a sufficient amount of cement shall be squeezed below the retainer to form a cement plug from the base of the retainer to fifty feet (50') below the base of the surface casing. A ten foot (10') cement plug shall be placed on top of the retainer.

(d) If fresh water horizons are exposed when production casing is removed from the well, or as a result of production casing not being run, a cement plug shall be placed from at least one hundred feet (100') below the base of the deepest fresh water sand to at least one hundred fifty feet (150') above the base of the sand. A cement plug of at least one hundred feet (100') shall also be placed from at least fifty feet (50') below the shoe of the surface casing to at least fifty feet (50') above it. In lieu of the above, the operator shall have the option of using a cement retainer placed at least fifty feet (50') above the surface casing shoe and a sufficient amount of

cement shall be squeezed below the retainer to form a cement plug from the base of the retainer to fifty feet (50') below the base of the surface casing. A ten foot (10') cement plug shall be placed on top of the retainer.

At the end of 1972, there were approximately 1,587 salt water disposal wells in Louisiana, with some 756,917,000 barrels of salt water being injected into subsurface formations during the year.

LOUISIANA DEPARTMENT OF CONSERVATION
GEOLOGICAL OIL AND GAS DIVISION
SALT WATER DISPOSAL WELLS
APPROVAL PROCEDURE (June, 1974)

Prior to disposing of salt water by injecting same into any subsurface formation, a permit therefor must be obtained from the Commissioner of Conservation. Such permit may be issued by the Commissioner without a public hearing when the applicant has complied with the following requirements:

- (a) Application (in the form of a letter) for a permit for underground disposal of salt water produced from oil and gas wells shall be submitted in duplicate to the appropriate District Manager. Such application shall include or be accompanied by:
- (1). An electrical log of the well with the proposed zone marked in the case of a well already drilled. A statement of the proposed zone to be used for disposal and the approximate depth of said zone in the case of undrilled wells along with an electric log of a nearby well, if available.
  - (2). A plat showing the location or proposed location, of the disposal well.
  - (3). A statement of estimated daily volume of salt water to be injected.
  - (4). A statement of other known instances in which the proposed disposal zone has been used for salt water disposal.
  - (5). A statement by the applicant that such disposal well will be completed in a manner to insure that the disposal products are injected into the proposed injection zone and that provision has been made for adequate protection of fresh water sands

and other zones of commercial value. A schematic diagram of the disposal well showing the casing and cementing program shall be attached together with an explanation thereof. Where only one string of casing protects fresh water sands, a packer shall be set on tubing at a depth below fresh and brackish water sands, or some other method of completion which would insure adequate protection of fresh water sands. Adequate provision must be made to insure that the surface casing is set below the base of fresh and brackish water sands.

- (6) . In cases where the base of the fresh water sands are deeper than normal and surface casing is not set through the fresh and brackish water sands, either of the following procedures may be used after consultation with the District Manager or the Geological Oil and Gas Division:

- (a) If production casing or a long string of casing is set, a DV tool will be run below the fresh and brackish water sands and cement circulated to insure their protection.
- (b) If the well is a dry hole, adequate plugs must be set during abandonment to protect these sands.

A permit for annular disposal of salt water may be issued for an interim period of one (1) year provided the applicant has complied with the procedure outlined above. If the applicant finds it absolutely necessary to request an extension to the one year interim period, he shall furnish the following current information with his application:

- (a) Number of producing wells applicant operates in the field.
- (b) Daily amount of oil and/or gas produced in the field by the applicant.

- (c) Number of wells the applicant has that produces salt water.
- (d) The amount and source of salt water to be disposed.
- (e) Number of salt water disposal wells and the number of annular disposal wells the applicant operates in the field.
- (f) Extension of time for annular disposal may be granted after a temperature or other type of survey is run to indicate the zone taking the salt water.
- (g) Additional supporting data. If it is absolutely necessary to request extension of an annulus permit, state reasons why it is not economically feasible to initiate a permanent disposal system.

The Geological Oil and Gas Division shall check each permit application and advise the appropriate District Manager, the Permit Section, and the applicant of their approval or denial. The District Manager will issue the Work Permit after approval is granted.

A typical disposal well installation is shown on Figure 1. This well is operated by the Sun Oil Company in the Shuteston Gas Field in St. Landry Parish. It is used for disposal of salt water produced from natural gas wells. The well is presently completed for injection of salt water in the sand occurring within the interval 1,095-1,185 feet. This sand contains salt water, and the top is 295 feet below the base of the fresh water. It is separated from the fresh water by 175 feet of impervious shale, 45 feet of brackish water sand, and 75 feet of salt water sand.

**SALT WATER DISPOSAL WELL NO. 1
BURLEIGH - MILLER POOL
SHUTESTON FIELD
ST. LANDRY PARISH
SEC. 37, T. 7 S., R. 4 E.**

Figure

TEXAS DEPARTMENT OF WATER RESOURCES

1700 North Congress
Stephen F. Austin Building
P.O. Box 13087, Capitol Station
Austin, Texas 78711

FOR DEPARTMENT USE ONLY	
Application No.	...
County-District	
Receipt Acknowledged By Card Dated	
Adm. Review By	
Administratively Complete	
Copies Sent: P&WD, TDH, Dist	

APPLICATION FOR PERMIT TO DISCHARGE, DEPOSIT OR DISPOSE OF WASTES

- Applicant _____
Plant Name _____
Address _____
City _____ Zip Code _____
Telephone No. _____
- List those persons or firms authorized to act for the applicant during the processing of the permit application.
- Type Of Permit For Which Application Is Submitted:
A. Original _____ B. Amendment _____ Of Permit No. _____ Pg. No. _____
(i.e. outfall number)
- List any other permits, existing or pending, which pertain to pollution control activities conducted by this plant or at this location.
- Disposal Method:
A. Discharge Into A Watercourse: Trace the flow of effluent from the plant to the nearest major watercourse with a word description: (For example: "From the plant site through a six-inch pipe to an unnamed tributary of Doe Creek, then to Doe Creek, then to the Brazos River".)

B. No Discharge Into A Watercourse: Irrigation _____, Evaporation Pond _____, Industrial Usage _____, Disposal Well _____, Other _____. Include complete description in technical report.
- County in which disposal activities will be conducted: _____
- List the street address of the facilities, if available: _____
- Attach either a USGS Topographic or State Department of Highways and Public Transportation County Map identifying the location of the wastewater treatment facilities.

9. Are your waste disposal operations within the extraterritorial jurisdiction of a municipality? _____
If so, what municipality? _____
10. Submit an application map or drawing of the site which includes the following information (Refer To Instructions For Sample Map):
- A. The approximate boundaries of the tract of land on which the waste disposal activity is or will be conducted.
  - B. The location of the point or points of discharge or disposal.
  - C. The general character of the areas adjacent to the place or places of disposal; for example, residential, commercial, recreational, agricultural, undeveloped, etc.
  - D. The boundaries of all tracts of land within a reasonable distance from the point or points of discharge, deposit or disposal and in the case of disposal to a water course, the map must show the boundaries of the tracts of land for a reasonable distance along the water course.
11. Show on the application map or include on a separate list properly cross-referenced to the map, the names and mailing addresses of the owners of all tracts of land within a reasonable distance of the point or points of discharge, deposit or disposal. You must include all landowners who might reasonably consider themselves affected.
- In case of discharge to a water course, the owners of all tracts of land for a reasonable distance along the water course must be included. In case of no discharge to a water course, the owners of all tracts of land adjacent to treatment facilities and disposal areas must be included.
12. Type of establishment, operation or process: (For example: sewerage facilities, oil refinery, steam electric generating plant, etc.) _____
13. What estimated date will waste disposal operations begin; or if operations have begun, what date did waste disposal operations begin at the site described by this application. If facilities are to be completed in stages, include schedule of dates of each increment. _____
14. Attach one of the following technical reports, as applicable to the proposed wastewater facilities: (A) Technical Report for Municipal & Private Domestic Wastewater Facilities, (B) Technical Report for Industrial Wastewater Facilities, (C) Technical Report for Agricultural Wastewater Facilities and (D) Technical Report for Industrial Solid Waste Management Facilities
15. List and index all attachments to this application below.

I, (Name) _____, (Title) _____

state that I have knowledge of the facts herein set forth and that the same are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any law, rule, ordinance or decree of any duly authorized governmental entity having jurisdiction.

Date _____ Signature _____

TEXAS DEPARTMENT OF WATER RESOURCES

1700 North Congress
Stephen F. Austin Building
P.O. Box 13087, Capitol Station
Austin, Texas 78711

FOR DEPARTMENT USE ONLY

Application No.	
County-District	
Receipt Acknowledged	
Filing Fee Receipt Mailed	
Adm. Review By	
Administratively Complete	
Copies Sent: RRC, TDH, TWWDB, Dist. _____	

APPLICATION FOR PERMIT TO DISPOSE OF WASTE BY WELL INJECTION

1. Applicant _____
Plant Name _____
Address _____
City _____ Zip Code _____
Telephone No. _____

2. List those persons or firms authorized to act for the applicant during the processing of the permit application.

3. Type of permit: Original (____) Amendment to Permit No. _____

4. List any other permits, existing or pending, which pertain to pollution control activities conducted by the plant or at this location.

5. Nature and Status of Activity

A. Type of operation or process: (for example sulphuric acid plant, petrochemical plant, sewage treatment plant, etc.)

B. Current methods of waste disposal:

6. Location of Proposed Injection Well

County _____ Lease _____ Well No. _____

Section _____ TWP-RGE or
Block No. _____

Survey _____ Abstract _____

Name and address of surface owner _____

Distance (in feet) and direction from two adjacent survey lines
_____
_____

7. Proposed Injection Program

A. New Well _____ Convert existing well _____
(Yes or No) (Yes or No)

B. Type of waste _____

C. Depth of well _____ D. Depth(s) and geologic name of
injection interval(s) _____

8. Submit with Application

A. \$25.00 Fee (Please remit by Check or Money Order)

B. Technical Report (see attached instructions)

C. Letter from the Railroad Commission (see attached instructions)

I, (name) _____, (title) _____
(Company Representative)

state that I have knowledge of the facts herein set forth and that the same are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any law, rule, ordinance, or decree of any duly authorized governmental entity having jurisdiction.

Date _____ Signature _____

APPLICATION FORM

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM APPLICATION FOR PERMIT TO DISCHARGE - SHORT FORM C

FOR
AGENCY
USE

APPLICATION NUMBER									
DATE RECEIVED									
YEAR			MO.				DA.		

To be filed only by persons engaged in manufacturing and mining

Do not attempt to complete this form before reading accompanying instructions
Please print or type

1. Name, address, location, and telephone number of facility producing discharge

A. Name _____

B. Mailing address _____

1. Street address _____

2. City _____ 3. State _____

4. County _____ 5. ZIP _____

C. Location: _____

1. Street _____

2. City _____ 3. County _____

4. State _____

D. Telephone No. _____

Area
Code

2. SIC

(Leave blank)

3. Number of employees _____

If all your waste is discharged into a publicly owned waste treatment facility and to the best of your knowledge you are not required to obtain a discharge permit, proceed to item 4. Otherwise proceed directly to item 5.

4. If you meet the condition stated above, check here ☐ and supply the information asked for below. After completing these items, please complete the date, title, and signature blocks below and return this form to the proper reviewing office without completing the remainder of the form.

A. Name of organization responsible for receiving waste _____

B. Facility receiving waste: _____

1. Name _____

2. Street address _____

3. City _____ 4. County _____

5. State _____ 6. ZIP _____

5. ☐ Principal product, ☐ raw material (Check one) _____

6. Principal process _____

7. Maximum amount of principal product produced or raw material consumed per (Check one)

Basis	Amount							
	1-99 (1)	100-199 (2)	200-499 (3)	500-999 (4)	1000-4999 (5)	5000-9999 (6)	10,000-49,999 (7)	50,000 or more (8)
A. Day								
B. Month								
C. Year								

8. Maximum amount of principal product produced or raw material consumed, reported in item 7, above, is measured in (Check one):

A. ☐ pounds   B. ☐ tons   C. ☐ barrels   D. ☐ bushels   E. ☐ square feet
F. ☐ gallons   G. ☐ pieces or units   H. ☐ other, specify _____

9. (a) Check here if discharge occurs all year ☐ , or

(b) Check the month(s) discharge occurs:

1. ☐ January   2. ☐ February   3. ☐ March   4. ☐ April   5. ☐ May   6. ☐ June
7. ☐ July   8. ☐ August   9. ☐ September   10. ☐ October   11. ☐ November   12. ☐ December

(c) Check how many days per week: 1. ☐ 1   2. ☐ 2-3   3. ☐ 4-5   4. ☐ 6-7

10. Types of waste water discharged to surface waters only (check as applicable)

Discharge per operating day	Flow, gallons per operating day					Volume treated before discharging (percent)				
	0.1-999	1000-4999	5000-9999	10,000-49,999	50,000-or more	None	0.1-29.9	30-64.9	65-94.9	95-100
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
A. Sanitary, daily average										
B. Cooling water, etc. daily average										
C. Process water, daily average										
D. Maximum per operating day for total discharge (all types)										

11. If any of the three types of waste identified in item 10, either treated or untreated, are discharged to places other than surface waters, check below as applicable.

Waste water is discharged to:	Average flow, gallons per operating day				
	0.1-999 (1)	1000-4999 (2)	5000-9999 (3)	10,000-49,999 (4)	50,000 or more (5)
A. Municipal sewer system					
B. Underground well					
C. Septic tank					
D. Evaporation lagoon or pond					
E. Other, specify					

12. Number of separate discharge points: A. ☐ 1   B. ☐ 2-3   C. ☐ 4-5   D. ☐ 6 or more

13. Name of receiving water or waters _____

14. Does your discharge contain or is it possible for your discharge to contain one or more of the following substances added as a result of your operations, activities, or processes: ammonia, cyanide, aluminum, beryllium, cadmium, chromium, copper, lead, mercury, nickel, selenium, zinc, phenols, oil and grease, and chlorine (residual). A. ☐ yes   B. ☐ no

I certify that I am familiar with the information contained in the application and that to the best of my knowledge and belief such information is true, complete, and accurate.

Printed Name of Person Signing _____

Title _____

Date Application Signed _____

Signature of Applicant _____

18 U.S.C. Section 1001 provides that:

Whoever, in any matter within the jurisdiction of any department or agency of the United States knowingly and willfully falsifies, conceals, or covers up by any trick, scheme, or device a material fact, or makes any false, fictitious, or fraudulent statements or representations; or makes or uses any false writing or document knowing same to contain any false, fictitious, or fraudulent statement or entry, shall be fined not more than \$10,000 or imprisoned not more than 5 years, or both.

**RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION**

Form W-14
Rev. 1-1-77
Eff. 7-1-77

**APPLICATION TO DISPOSE OF SALT WATER BY INJECTION INTO A POROUS FORMATION
NOT PRODUCTIVE OF OIL OR GAS**

1. Operator Name						2. Operator No.	
3. Address (Street, City, State and Zip Code)						4. RRC Dist.	
5. Lease Name				6. RRC Lease Identification No.		7. Well No.	
8. Field Name				9. RRC Field No.		10. County	
11. Location (Sec. -Twp-Rge or Block and Survey)							
CASING AND TUBING DATA							
NAME OF STRING	SIZE	SETTING DEPTH	SACKS CEMENT	TOP OF CEMENT	TOP DETERMINED BY	HOLE SIZE	CASING WEIGHT
12. Surface Casing							
13. Intermediate							
14. Long String							
15. Tubing			16. Name, Model and Depth of Tubing Packer				
17. Depth to Top of Injection Zone		18. Depth to Bottom of Injection Zone		19. Is Injection through Tubing or Casing? ☐ Tubing ☐ Casing		20. Total Depth of Well	
21. Perforation or Open Hole? ☐ Perforation ☐ Open Hole			22. Date Well Drilled		23. API No.		24. Ground Surface Elevation
25. List All Cement Squeeze Operations, Giving Interval and Number Sacks of Cement							
26. Depth of Deepest Fresh Water Zone		27. Depth of Shallowest Zone Productive of Oil or Gas In this Field			28. Anticipated Daily Injection Volume (Bbls) Minimum Maximum		
29. Open or Closed System? ☐ Open ☐ Closed		30. Is Injection by Gravity or Pressure? ☐ Gravity ☐ Pressure			31. Approximate Pressure (Psi)		
32. Will it be necessary for water to be filtered or chemically treated? ☐ Yes ☐ No				33. Is this well so cased and completed that water can enter no other formation than the above set out injection zone? ☐ Yes ☐ No			
34. NAME AND ADDRESS OF SURFACE OWNER							
35. List Name and Addresses of All Offset Operators							
36. Source of Fluids (Geological Name of Formation and Depth)							
37. Have notices of this application been mailed or given to all Offset Operators? ☐ Yes ☐ No				38. Are there any other Salt Water Disposal Wells using this same Zone in this Field? ☐ Yes ☐ No			
39. If answer is Yes to Question 38, name one such well.							
Name of Operator		Lease Name		Lease or I.D. No.		Well No.	
CERTIFICATE							
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.							
						Signature	
						Name of Person (type or print) Title	
Telephone						Date	
Area Code						Number	
FOR RRC USE ONLY							

APPLICANTS MUST COMPLY WITH THE INSTRUCTIONS ON REVERSE SIDE HEREOF (OVER)

**RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION**

Form GT-5
9/75

APPLICATION TO INJECT FLUID INTO A RESERVOIR PRODUCTIVE OF GEOTHERMAL RESOURCES

1. Field Name (as per current proration schedule - including reservoir, if applicable.)	2. RRC District
3. Operator	4. County
5. Lease Name(s) and RRC Lease Number(s)	6. Reservoir Discovery Date

7. Have any injection permits been granted previously to any operator in this reservoir? ☐ Yes ☐ No
If answer to this question is "NO", ALL OPERATORS IN THE RESERVOIR MUST BE NOTIFIED of this application, and copies of notification attached hereto.

8. Check the Appropriate Block(s):
☐ New Project or ☐ Expansion of Previous Authority to Add Either: ☐ New Lease(s) or ☐ Additional Well(s) on Same Lease(s)
 Previous Authority Dated _____ by ☐ Administrative Action or ☐ Hearing, Special Order No. _____

RESERVOIR AND FLUID DATA ON ENTIRE RESERVOIR

9. Name of Reservoir	10. Estimated Productive Area of Entire Reservoir (acres)
11. Composition (sand, limestone, dolomite, etc.)	12. Type of Structure (Include cross-section and structural maps.)
13. Original Bottom Hole Pressure (psig)	14. Current Bottom Hole Pressure (psig)
15. Was Hydrocarbon Gas Present Originally?	16. Original Average Reservoir Temperature

RESERVOIR AND FLUID DATA

17. Number of Productive Acres in Lease(s) within Project Area	18. Average Depth to Top of Pay (ft.)	19. Average Effective Pay Thickness (ft.)
20. Average Horizontal Permeability (mds.)	21. Range of Horizontal Permeability (mds.)	22. Average Porosity (%)

PRODUCTION HISTORY OF RESERVOIR

23. Date First Well Completed on Lease(s)	24. Stage of Primary Depletion of Project Area
25. Current Number of Producing Wells on Each Lease in Project Area	26. Current Mass Production (lbs. x 10 ⁶)
27. SUBMIT ATTACHED SHEET(S) GIVING THE TOTAL MASS PRODUCTION BY YEARS SINCE DISCOVERY & TOTALS. FOR THE LAST 3 YEARS, GIVE THESE FIGURES BY MONTHS.	

INJECTION DATA

28. Type of Injection Fluid (Check the appropriate block(s):) ☐ Salt Water, ☐ Brackish Water, ☐ Fresh Water, ☐ OTHER (Specify) _____	
28. Source of Injected Fluid(s) (formation(s) and depth(s) in ft.)	29. Injection Pattern and Spacing
30. Total Number of Injection Wells to be Approved in this Application	31. Estimated Maximum Daily Rate of Injection per Well (bbbls./day/well)
32. Total Estimated Maximum Daily Rate of Injection for All Wells in this Application. (bbbls./day)	33. Maximum Injection Pressure to be Used. (psig)
34. LIST COMPLETE INJECTION WELL DATA ON REVERSE SIDE OF THIS SHEET.	

DATA ON PROPOSED PROJECT AREA

(APPLICANTS MUST COMPLY WITH THE INSTRUCTIONS ON REVERSE SIDE HEREOF.) (OVER)

INJECTION WELL DATA

LEASE NAME & WELL NUMBER							
SURFACE CASING	SIZE						
	LENGTH						
	CEMENT VOL. & % GEL						
PRODUCTION CASING	SIZE						
	LENGTH						
	CEMENT VOL. & % GEL						
TUBING	LENGTH						
	PACKER DEPTH						
INJECTION	DEPTH						
	THRU CASING OR TUBING?						

I declare under penalties prescribed in Article 6036c, R. C. S., that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

Date _____

Signature _____

Operator _____

Name of Person (type or print) _____

Street Address or P.O. Box _____

Title of Person _____

City, State _____ Zip Code _____

Telephone: _____ Area Code _____

- INSTRUCTIONS -

1. ATTACH waivers from each operator offsetting the subject lease(s), or attach copies of letters of "Request for Waivers" sent to each operator offsetting the subject lease(s); provided, that if this is the initial application for fluid injection authority for this reservoir, waivers from all operators, or copies of "Request for Waivers", for all operators in the reservoir shall be attached.
2. ATTACH a list of names and addresses of all offset operators.
3. ATTACH plat of lease(s) in project area, showing producing wells, injection wells, offset wells, and also identify ownership of all surrounding leases.
4. ATTACH a complete electrical log or similar well log of one of the proposed injection wells.
5. No application will be considered unless Items 1, 2, 3, and 4 are attached to this application. If all necessary waivers are not attached, the Commission will hold this application for a period of ten (10) days from date of receipt in the Austin office. If no protest has been received in the Austin office within ten (10) days, the application will be processed.
6. Mail the complete application (including waivers) directly to the Austin office of the Railroad Commission; and the same day mail a copy of the application form, copy of plat and log to the appropriate District office.

APPENDIX D

SUBSURFACE WASTE DISPOSAL SIMULATION MODEL*

The disposal model used in the subsurface disposal analysis consists of two parts: (1) a three-dimensional finite-difference reservoir model, and (2) a wellbore model. To the user, the two parts are indistinguishable. The reservoir model solves the flow, energy and contaminant transport in the aquifer and surrounding strata. The wellbore model solves the flow and energy transport during flow up or down the well. The two models are coupled closely together since the wellbore model relates the surface pressure and enthalpy from the reservoir model. At the same time, these bottomhole quantities must also satisfy the material and energy balance relationships taking place in the reservoir. Conceptually, this coupling and the factors considered are illustrated in Figure D-1.

The reservoir model solves three coupled partial differential equations describing the behavior of a liquid phase injected into an aquifer system. The model is a finite-difference solution of these partial differential equations.

Suppose (x, y, z) to be a Cartesian coordinate system and let $Z(x, y, z)$ be the height of a point above a horizontal reference plane. Then, the basic equation describing single phase flow in a porous medium results from a combination of the continuity equation

$$\nabla \cdot \rho u + q' = -\frac{\partial}{\partial t} (\phi \rho) \quad (1)$$

and Darcy's law in three dimensions

$$u = -\frac{k}{\mu} (\nabla p - \rho g \nabla Z) \quad (2)$$

The result is the basic flow equation

$$\nabla \cdot \frac{\rho k}{\mu} (\nabla p - \rho g \nabla Z) - q' = \frac{\partial}{\partial t} (\phi \rho) \quad (3)$$

A material balance for the solute results in the solute or concentration equation

$$\begin{aligned} \nabla \cdot \left[\rho C \frac{k}{\mu} (\nabla p - \rho g \nabla Z) \right] + \nabla \cdot (\rho E) \cdot \nabla C - q' C \\ = \frac{\partial}{\partial t} (\rho \phi C) \end{aligned} \quad (4)$$

The energy balance defined as [enthalpy in-enthalpy out = change in internal energy] is described by the energy equation

$$\begin{aligned} \nabla \cdot \left[\frac{\rho k}{\mu} H (\nabla p - \rho g \nabla Z) \right] + \nabla \cdot K \cdot \nabla T - q_L - q' H \\ = \frac{\partial}{\partial t} [\phi \rho U + (1 - \phi)(\rho C_p)_R T] \end{aligned} \quad (5)$$

The system of equations (3), (4) and (5), along with the fluid property dependence on pressure, temperature and concentration, describes the reservoir flow due to injection of wastes into an aquifer. This is a nonlinear system of coupled partial differential equations which must be solved numerically using high speed digital computers.

These equations are solved by dividing the region of interest into a three-dimensional grid and developing finite-difference approximations for this grid. Once the region of interest is divided into grid blocks, finite-difference equations are developed whose solution closely approximates the solution of equations (3), (4) and (5). Flow outside the region of primary interest (grid block definition) is allowed through aquifer influence functions. Essentially, this represents the coupling of an analytical concept (for example, the region of interest surrounded by an infinite aquifer) and the numerical solution. Heat transport into regions of no flow are included by finite-difference calculations in these regions coupled to the temperature profiles in the aquifer. Specification of wells imposes boundary conditions on the reservoir model solution. The injection or production is taken into account by adding source or sink terms in the grid blocks where the wells are located.

In addition to the three-dimensional rectangular Cartesian grid, we also have provided a two-dimensional (r, z) grid system. This cylindrical coordinate system is extremely well suited to single well interpretive or predictive calculations.

Basic assumptions contained in the reservoir model are:

- (1) Three-dimensional, transient, laminar (Darcy) flow.

*Abstracted from Lantz, R. B., S. B. Pahwa and D. B. Grove, "Development of a Subsurface Waste Disposal Simulation Model", Am. Geophys. Union, Spring Meeting, Washington, D. C., 1976

Figure D-1. Schematic of the Well Disposal Model

- (2) Fluid density can be a function of pressure, temperature and concentration. Fluid viscosity can be a function of temperature and concentration.
- (3) Miscibility of the injected wastes with the in-place fluids.
- (4) Aquifer properties vary with position (i.e. porosity, permeability, thickness and elevation can be specified for each grid block in the model).
- (5) Hydrodynamic dispersion is described as a function of fluid velocity.
- (6) The energy equation can be described as "enthalpy in-enthalpy out = change in internal energy of the system". This is rigorous except for kinetic and potential energy which have been neglected.
- (7) Boundary conditions allow natural water movement in the aquifer, heat losses to the adjacent formations, and the location of injection, production and observation points anywhere within the system.

The wellbore model simulates the injection (or production) well conditions and provides the boundary conditions for the reservoir model. The energy losses in the well are calculated to obtain the bottomhole pressure and temperature values. The pressure drop between the well and the center of the grid block is also calculated and the rate is allocated between each vertical layer. The user may specify surface conditions or the bottomhole temperature and pressure values. If the surface temperature and injection rate are specified, the model calculates both the surface pressure necessary to achieve the desired rate and the enthalpy of the injection stream as it enters the aquifer. The heat losses to the formation surrounding the wellbore, the frictional pressure drop and the gravity head are calculated by the wellbore model. Alternately, one can choose to specify the surface pressure and temperature, and the model calculates the rate that can be injected limited by these specified surface conditions. In this case, an iterative procedure is required to calculate the bottomhole pressure and the allowable injection rate. Similarly, if the well is producing, one may specify the rate of the surface pressure. The latter case requires an iterative procedure to calculate the bottom hole pressure and the allowable production rate.

The assumptions used in the wellbore model can be summarized as follows:

- (1) Viscous heat dissipation can be neglected in the wellbore calculation.
- (2) The initial ground temperature surrounding each well is known and can be expressed as a function of depth only.
- (3) Flow in the well is incompressible and steady state.
- (4) For the purposes of wellbore heat loss calculations, the well is treated as a constant flux line source.
- (5) Fluid properties, heat capacity, viscosity and density are allowed to vary with pressure and temperature in the wellbore.
- (6) The enthalpy of the injection fluid can be expressed as a simple proportionality to the enthalpy of pure water at the same temperature and pressure.

NOMENCLATURE

C	=	concentration, mass fraction
C_p	=	specific heat
E	=	dispersion coefficient
g	=	acceleration due to gravity
H	=	enthalpy
k	=	permeability
K	=	Thermal conductivity
p	=	pressure
q]	=	mass rate per unit volume
qL	=	rate of heat loss
t	=	time
T	=	temperature
u	=	superficial (Darcy) velocity
U	=	internal energy
Z	=	elevation above a reference plane

Greek:

ρ	=	density
λ	=	viscosity
ϕ	=	porosity

Subscript:

R	=	rock

APPENDIX E

COST ESTIMATING METHODOLOGY

A. Introduction

The conceptual design of each system provided sufficient detail for capital cost estimates and energy production cost estimates to be made for the wellfields, the natural gas separation and processing facilities, and the electric power units.

Energy production costs were estimated separately for the power units, and for combinations of wellfields and natural gas separation and processing facilities. They were expressed in mills/kWh or \$/MM Btu, and were based on recovering the following costs over the commercial life of the facilities:

- All invested capital
- A satisfactory return on invested capital
- All expenses
- Income and ad valorem taxes

The estimates were at third quarter 1979 price and wage levels, including an allowance for funds during construction (AFDC); commercial operation of the unit was assumed to be attained in 24 or 32 months for the 1-well case and the 12-well case respectively. An escalation allowance was not included in any of the cases.

B. Capital Costs—Natural Gas Separation and Processing Facilities and Power Unit

The individual capital costs of the natural gas separation and processing facilities and of the power units are made up of direct field construction costs, indirect field costs, home office services, contingency, an allowance for funds during construction, and other Owner's costs.

1. Direct Field Construction Costs

The following cost estimating methods were used to develop the direct field construction costs:

- **Mechanical Equipment**

Cost of major mechanical equipment was based on either manufacturers' estimates or estimated using current

prices from industrial sources. Miscellaneous mechanical equipment was estimated from industrial experience as a percentage of major mechanical equipment.

- **Electrical Equipment**

Cost of electrical equipment was factored based on industrial experience.

- **Civil/Structural**

An allowance was estimated for equipment foundations, cooling tower basin, and other structural features.

- **Piping**

Large pipe diameters and lengths were calculated. Quantities were priced using unit prices from industrial sources.

- **Instrumentation**

The cost of instrumentation was factored based on industrial experience.

- **Yardwork and Miscellaneous**

An estimate of yardwork and miscellaneous costs was made, based on assumed site features.

The direct construction labor costs were estimated using a wage rate of \$15./hr. This rate includes fringe benefits (FICA, FUI, and SUI dues and workmen's compensation insurance.) It also includes an allowance of 5 percent for casual overtime and 1 percent for craft furnished supervision.

2. Indirect Field Costs

The indirect field costs are those items of construction cost that cannot be ascribed to any specific construction operation for the permanent facilities and are thus accounted separately. The items covered by indirect field costs include the following:

- **Temporary Construction Facilities**

Temporary buildings, working areas, roads, or canals, parking or docking areas, and utility system and general purpose scaffolding.

- **Miscellaneous Construction Services**

General job cleanup, maintenance of construction equipment and tools, material handling, and surveying.

- **Construction Equipment and Supplies**

Construction equipment, small tools, consumable supplies, and purchased utilities.

- **Field Office**

Labor for craft supervision, field engineering, procurement, scheduling, personnel administration, warehousing, first aid, and the costs of the field office.

- **Preliminary Checkout and Acceptance Testing**

Labor, materials, supplies, and equipment to insure that components and systems are operable.

- **Project Insurance**

Public liability, property damage, and builder's risk insurance.

- **Taxes**

State and local taxes

The indirect costs were computed at 70 percent of direct construction labor costs.

3. Home Office Services

The home office services include engineering costs, and the fee. Engineering includes preliminary engineering, optimization studies, specifications, detailed engineering, review of vendor drawings, site investigation, and support to vendors. Other home office costs include procurement, estimating and scheduling services, quality assurance, and project management.

The fee was included as a function of the total project cost. A figure of 14 percent of total field construction costs was used for home office services.

4. Contingency

Included in the estimate was a contingency allowance for the uncertainty within the conceptual design in the quantity, pricing, or productivity that is under the control of the constructor and within the scope of the project as defined. The contingency cannot be considered as a source of funds for additions to the project scope. For the purpose of comparing the several conceptual designs in this study, 15 percent contingency was applied to the subtotal of field construction cost plus home office services.

5. Allowance for Funds During Construction (AFDC)

The bulk of AFDC is composed of interest costs. The center of gravity of cash flow occurs at approximately the two-thirds completion point of construction. Therefore, AFDC was calculated by using 10 percent/annum compound interest on the total construction cost plus Owner's costs over a period of one-third of the construction schedule. These costs were prorated proportionately to labor and materials.

6. Other Owner's Costs

These include the Owner's general office and accounting costs, startup and operator training, and Owner's engineering and management. They also include spare parts and inventory costs, licenses, and taxes during construction. A figure of 8 percent of total construction cost was used.

C. Capital Costs—Wellfield

Wellfield costs include direct field costs, indirect field costs, home office services, contingency, owner's costs and AFDC.

1. Direct Field Costs

- The production and injection wells were assumed to be installed on a sub-contract basis including drilling, carbon steel casing, and wellhead equipment. Production well costs were taken at \$5,000,000 each and injection well costs at \$500,000 each. These estimates include 60% intangible drilling costs.

- Spare injection wells were provided; for the 1-well case, there were three injection wells plus one spare well; for the 12-well case, there were twenty-four injection wells plus two spare wells.
- Land lease costs were taken at \$25/acre, with 8,000 acres for the 1-well case and 38,400 acres for the 12-well case.
- Geophysics and geology costs were estimated to be \$300,000 for the 1-well case and \$3,600,000 for the 12-well case.
- Permits and environmental costs were estimated to be \$250,000 for the 1-well case and \$500,000 for the 12-well case.
- Current prices from industrial sources were used for the preinsulated production and injection brine piping cost.
- Brine injection pumps and electric motor drives were included as a well-field cost.
- The direct construction labor costs were estimated using a wage rate of \$15./hr as described in Section B.1.

2. Indirect Field Costs

Indirect field costs were taken as 70 percent of the direct field construction labor, as described in Section B.2.

3. Home Office Services

Home Office services were taken as 14 percent of the field construction costs, excluding well costs, as described in Section B.3.

4. Contingency

For comparative purposes, a 15 percent contingency allowance was applied to the subtotal field investment estimate, excluding well costs. This allowance was described in Section B.4.

5. Owners' Cost

No owners' cost allowance was assumed applicable to wellfield investments.

6. Allowance for Funds During Construction (AFDC)

AFDC of the wellfield was estimated at 10 percent per annum compound interest on the total cost over a period of one-third of construction schedule as described in Section B.5.

D. Energy Production Costs—Power Units

For the calculation of energy production costs, it was assumed that all electric power generating units will be owned and operated by utility companies. Therefore, the economic factors in this section were selected to be typical of utility companies in the Texas and Louisiana region.

The costs of energy produced from the power units comprise capital investments that are amortized over the life of the project and recurring annual costs that are expended in the year incurred. These costs include:

- Capital charges including the cost of capital and capital recovery
- Income taxes
- Operation and maintenance expenses
- Administration and general expenses
- Plant insurance
- Ad valorem taxes

1. Capital Charges

Power unit capital investments are detailed in Section B. Calculation of capital charges include the following:

- A 11.4 percent discounted cash flow rate of return was applied to all power unit capital investments.
- Straight line book depreciation was used for capital recovery purposes.
- Salvage value was assumed to be zero at the end of unit life.
- Power unit economic life was assumed to be the period from the start of commercial operation to the time when the well flow decline reduced the power

output to 40 percent of the initial output.

2. Income Taxes

Calculation of Federal and State Income tax was based on the following:

- A federal plus State income tax rate of 46 percent was used. Equipment lifetime of two-thirds booklife was assumed for federal taxes
- Accelerated depreciation (200 percent declining balance switching to straight line) was used for income tax purposes.
- For all capital investments, 10 percent was claimed as investment tax credit for federal tax purposes.
- Power unit capital was assumed to be 50 percent debt, 10 percent preferred equity, 40 percent common equity. Tax deductible annual interest rate on debt was 10 percent; annual interests on preferred and common equity were 10 percent and 13.5 percent, respectively.

3. Operation and Maintenance

Annual operation and maintenance expenses were estimated at 2 percent of the capital costs. These costs include administration and general expenses.

4. Unit Insurance

Insurance was estimated at 0.1 percent of the capital cost annually.

5. Ad Valorem Tax

Annual ad valorem tax was in the form of property tax. This was 1.9 percent of power unit value based on the initial cost of the unit.

6. Power Unit Energy Production Cost Estimating Approach

The energy production cost of each electric power unit was estimated by dividing the sum of the leveled annual capital charges and operating costs (in mills) by the level annual net electrical energy output of the power unit (in kilowatt-hours). Unit level capacity factor was assumed to be 85% in all cases.