GEOPRESSURE ENERGY RESOURCE EVALUATION

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PROGRAM PLANNING & ANALYSIS OFFICE

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CONTENTS

	<u>Page</u>
ABSTRACT	v
SUMMARY	vii
INTRODUCTION	1
RESOURCE CHARACTERISTICS	1
RESOURCE ESTIMATES	5
RESULTS OF RESOURCE VALIDATION STUDIES	9
RESERVOIR CHARACTERISTICS AND PRODUCTIVITY	14
Reservoir Driving Forces	14
Reservoir compressibility	15
Shale water influx	18
Effect of free gas on reservoir production	19
Permeability	21
RESOURCE RECOVERY ECONOMICS	25
CONCLUSIONS	32
REFERENCES	35
Appendix A: RESERVOIR MECHANICS	41
Appendix B: EFFECT OF RESERVOIR PROPERTIES ON RESERVOIR PRODUCTIVITY	59
Appendix C: CONVERSION FACTORS	69

ABSTRACT

The geopressed aquifers that extend along the northern Gulf of Mexico are a large, perhaps the largest, potential source of geothermal energy and natural gas in the United States. Because of the high cost of completing wells into these formations and their relatively low temperatures (200 to 400°F), the utilization of the geothermal energy will be highly dependent on, and of secondary importance to, the value of the methane.

The economics of extracting either the geothermal energy or natural gas from these aquifers does not look promising. The combined requirements of high well flow rates (40,000 bbl/day), long life (20 years), and the necessity for close well spacing to minimize the cost of the collection system may be incompatible with the actual characteristics of the reservoirs. These factors place such stringent requirements on the reservoir size, permeability, and compressibility, or specific storage coefficient, that the number of promising production areas may be severely limited.

SUMMARY

The geopressured aquifers that extend along the northern Gulf of Mexico from Mexico to Louisiana are a very large, perhaps the largest, potential source of geothermal energy and natural gas in the United States. These high-pressure aquifers are characterized by higher than normal temperatures and are believed to be saturated with natural gas. Thus, these formations offer the potential for recovery of three forms of energy — thermal, chemical, and hydraulic. Although the potential exists to extract all three forms of energy, the potential for recovering large quantities of methane is of most importance and is responsible for the increasing interest in these aquifers.

Estimates of both the magnitude and the potential recovery of the energy of these reservoirs vary widely. Approximations of the energy content of the natural gas alone vary from 3000 quads to as much as 100,000 quads, and values for the potential recovery of the gas range from 28 quads to as high as 1150 quads. These figures were based on assumptions of the size of the reservoirs, their properties, and the degree to which the brine is saturated with gas. Although little more than guesses, these estimates have led to other statements implying enormous natural gas resources of 50,000 to 100,000 quads. Subsequent work at the University of Texas and Louisiana State University indicate that the actual reservoir sizes and values of the properties necessary for their economic exploitation are much smaller than those assumed in arriving at these high projections.

The economic potential of a reservoir will depend on its size, the fraction of the resource that can be recovered, its permeability, and the capital and operating costs for its development and operation. The recoverable fraction of the resource depends primarily on the compressibility of the reservoir. There is little, if any, data about compressibility available for the geopressured zones. However, if data from normally pressured reservoirs are used, a compressibility coefficient of $6.6 \times 10^{-6} \text{ psi}^{-1}$, or a specific storage coefficient of $1.32 \times 10^{-7} \text{ psi}^{-1}$, is obtained. These values would limit the resource recovery to

about 3 to 4% of the initial reservoir fluid inventory of those reservoirs with sufficient size and permeability to be of commercial interest and are about two-thirds to one-tenth of those used by other authors in estimating the potential recovery from these aquifers. There are currently no firm data from which to predict that the geopressured aquifers will have these significantly higher compressibility values.

Shale water influx into the reservoirs during production could add to the life and productivity of these aquifers. However, even less is known about this effect than about compressibility coefficients. Until additional data concerning shale water influx and compressibility coefficients are available, projections of recovery values greater than 5% appear to be highly speculative.

The development potential of a reservoir also depends on its permeability. Even in a large reservoir, the permeability must be great enough [about 20 millidarcys (md)] to yield well flow rates sufficient to make its development economically attractive. Studies of the permeability of the onshore area of Texas have been discouraging. The geopressured zones of southern Texas (south of Corpus Christi) have been shown to have such low values of permeability (an average of about 1 md) that the development of reservoirs in this area is unlikely. These results also disprove, at least for this area, the argument presented in earlier papers that the undercompaction of the geopressured reservoirs would lead to higher than normal values of permeability. In southern Texas the permeability continues to decrease with increasing depth: the change is about one order of magnitude for each 2000 ft of depth between 6000 and 14,000 ft.

Even along the northern Texas coast, the permeability varies widely and can be very low. Many of the gas and condensate wells in this area have permeability values in the range of 2 to 10 md but producing thicknesses of only 10 to 30 ft. It is expected, however, that the thicker, more porous water reservoirs will have higher permeability values. Data are needed to confirm this expectation.

The states of Texas and Louisiana have passed legislation strongly encouraging the full utilization of the geopressured resource. Thus,

most economics studies have emphasized methods and costs of using the thermal energy for either process heat or electrical power generation. These studies start with assumptions of reservoir characteristics — well flow rates, life, and spacing — that become a critical part of the conclusion. Although most of the studies reflect the earlier, more optimistic view of the aquifers, their results are still not promising.

The high cost of completing wells into these deep formations and the relatively low temperature of the water make the development of these aquifers highly dependent on the value of the methane. The expectations that the multiple energy aspects of the aquifers will enhance their economic potential derives from the assumption that the thermal energy will have some value. However, studies show that even if the value of the methane is sufficient to offset the cost associated with the production and reinjection wells and the equipment necessary for extracting the gas, the use of the thermal energy for power production will be marginal at best.

These studies also used well spacings that were too close. For example, one study of a 25-MW(e) plant with 10 to 12 wells assumed a well spacing of 1/2 mile, a 40,000-bbl/day well production rate, and a 20-year life. If reservoir compressibility values typical of normally pressured reservoirs were also assumed for this case, the producing thickness of the reservoir supplying each well would have to be 30,000 ft. For a reservoir thickness of 1000 ft, the well spacing would have to be about 3 miles. At this distance the cost of the fluid transmission system is greater than the cost of the power plant. Thus the combined requirements of high well flows (40,000 bbl/day), long life (20 years), and the need to minimize the cost of the collection system may be incompatible with the actual characteristics of most geopressured reservoirs. Directional drilling of the wells could reduce the length of the fluid transmission system. However, the higher cost of directional drilling may offset any cost reduction in the piping system.

Note that the results of this study are based on sketchy data or data from normally pressured reservoirs. There are also indications that some reservoirs may contain gas in excess of the saturation value that could alter their economic potential. Furthermore, the quantity

of energy contained in these formations is much too large to be ignored, and certainly a program aimed at providing a better understanding of the extent and characteristics of the resource is warranted. Ideally, the geopressured zone should be mapped so that reliable projections can be made of the quantity of energy recoverable as a function of cost.

INTRODUCTION

The current energy crisis has generated a widespread search of alternate sources of energy. Two of the many sources receiving increasing study today are geothermal energy and unconventional sources of natural gas. The purpose of this paper is to discuss one, perhaps the largest, potential source of geothermal energy and natural gas — the geopressured aquifers along the northern Gulf of Mexico.

The term "geopressure" was coined by drilling engineers and refers to pressures that exceed the normal hydrostatic pressure of about 0.465 psi per foot of depth. Until the mid-1950s, wells were usually abandoned on encountering these formations, then considered impenetrable. However, improvements in methods of predicting the onset of high pressures and in drilling mud technology have removed this barrier, and there are now many wells producing gas from these high-pressure reservoirs.

The aquifer fluids are characterized by higher than normal temperatures and are believed to be saturated with natural gas. Thus, these formations offer the potential for recovery of three forms of energy — thermal, chemical, and hydraulic. Although the potential exists to extract all three forms of energy, the possibility for recovering large quantities of methane is of most importance and is responsible for the increasing interest in these aquifers.

The following sections of this paper discuss the characteristics and potential magnitude of the geopressure energy resource, reservoir properties and their effect on production rates and resource recoverability, and the economics of exploiting these aquifers.

RESOURCE CHARACTERISTICS

The geopressured formations currently being investigated in the United States extend along the northern Gulf of Mexico basin from Mexico to Mississippi (Fig. 1). The existence of these formations has been known for years, and from the extensive petroleum exploration in this area, a wealth of information concerning their location, pressure, and temperature has been gained.

Fig. 1. Areas of potential geopressure resources in the United States. Source: M. H. Dorfman and R. W. Deller, *Summary and Future Projections*, vol. 1 of *Proceedings, Second Geopressured Geothermal Energy Conference*, Center for Energy Studies, University of Texas, Austin, Feb. 23-25, 1976.

These high-pressure zones are sedimentary basins of alternating or interfingering beds of sand and shale. During the deposition of these sediments, water was trapped by thick, nearly impermeable layers of shale. The water confined in these formations partially supports the weight of the overburden and prevents normal compaction of the sediments, which, in turn, causes a rise in the pressure from hydrostatic (0.465 psi/ft) to that approaching lithostatic (1.0 psi/ft). This high pressure is the principal characteristic of the geopressured reservoirs. The tops of these zones are located at depths of 5000 to 15,000 ft, depending on the age and distribution of the sediments.¹ At depths below this interface, the sediments exhibit increasingly abnormal pressure with depth.²

The undercompaction of the sediments also results in a thermal conductivity in these formations lower than that in normal shale and sandstone formations. Studies of well logs in the Gulf Coast area show temperature gradients of 1.0 to 1.5°F per 100 ft in normal pressured zones and gradients from 2 to greater than 3°F per 100 ft in geopressured zones.¹ Temperature gradients throughout the basin vary widely; the highest temperatures are located in southern Texas. Dorfman and Deller³ state that "temperatures at depths of 10,000 feet often range from 225°F to 300°F, and at depths of 15,000 feet it is not uncommon to encounter temperatures in excess of 350°F. Within the basin, temperatures of over 500°F have been encountered in boreholes at depths of approximately 20,000 feet." Typical temperatures for the geopressured aquifers in southern Louisiana are lower.²

Both hydropressured and geopressured aquifers of the basin usually contain methane in solution. However, estimates of the quantity of methane in these aquifers are based more on theories of their formation than on actual measurements. Hise² states:

There have been no published reports of field studies on the amount of gas in solution in geopressured aquifer water. Some knowledgeable people in the oil industry believe the water will be saturated with natural gas; others do not. Until there is extensive testing and sampling of waters from geopressured aquifers, the amount of gas in solution remains unknown.

The quantity of the natural gas contained in the aquifers is projected from estimates of the volume of brine, its pressure, temperature, and salinity, and the assumption that the brine is saturated with natural gas. The solubility of methane in fresh water was studied by Culberson and McKetta⁴ for temperatures of 77 to 340°F and for pressures up to 10,000 psi; their data are shown in Fig. 2. However, the solubility of methane varies inversely with water salinity; at a temperature of 250°F, the solubility decreases at a rate of 3 to 4% for each 10,000 ppm dissolved solids.^{5,6} Data from a geopressured test well in Louisiana showed the solubility of the gas (which contained 93 to 96% methane) to be reduced by 35 to 50% for total dissolved solids of 110,000 to 140,000 ppm at a temperature of 240°F.⁷ These data also indicated that

Fig. 2. Solubility of methane in pure water. Source: O. L. Culberson and J. J. McKetta, "Phase Equilibria in Hydrocarbon Water Systems III — the Solubility of Methane in Water at Pressures to 10,000 psia," *Trans. Am. Inst. Min. Metall. Pet. Eng.* 192: 223-26 (1951), as adapted by R. M. Knapp and O. F. Isokrari, "Aspects of Numerical Simulation of Future Performance of Geopressured Geothermal Reservoirs," pp. 103-61 in *Reservoir Research and Technology*, vol. 3 of *Proceedings, Second Geopressured Geothermal Energy Conference*, Center for Energy Studies, University of Texas, Austin, Feb. 23-25, 1976.

—other gases (N_2 , CO_2 , and higher hydrocarbons) tend to decrease the solubility of methane in water.

The data of Culberson and McKetta, extrapolated to higher temperatures and pressures, are used in estimating the methane content of the geopressured zone. Because the economics of developing this resource is highly dependent on the methane, the assumption that the brine is saturated with methane is critical to the exploitation of the aquifers.

RESOURCE ESTIMATES

Currently, the information about the properties of these reservoirs is insufficient to provide a reliable estimate of their value as an energy resource. Estimates of both the magnitude of the geopressed aquifers and the energy that may be recovered from them vary widely. Much of the initial interest concerning the potential energy of the geopressed aquifers was generated by a U.S. Geological Survey (USGS) report by Papadopulos et al. in 1975.⁸ In this report, the authors divided the onshore area of Texas and Louisiana into 21 subareas corresponding to faulting patterns (Fig. 3) and evaluated each subarea separately. They estimated the sandstone and shale thickness and porosity and the pressure and temperature of the brine in each subarea. From this information they derived a value of the potential resource base of all three forms of energy — thermal, methane, and mechanical; Table 1 summarizes this assessment.

The quantity of methane estimated to be in solution in the brine was 23.7×10^{15} ft³, or about 24,000 quads. Although the thermal energy content was given as about twice that of the methane, its economic value is far less. The reference temperature used to calculate the thermal energy was 59°F, which gives an energy content far above that useful for either process heat or electrical generation. Furthermore, methane is a readily marketable product, whereas the 285 to 365°F brine currently has a rather nebulous value. The mechanical energy potentially recoverable from the high-pressure fluid, which would be harnessed by a turbine at the wellhead, is relatively small.

Papadopulos et al. also estimated the potential recovery of energy using three different production plans. The percentage recovered varied from about 0.5 to 3.3%. For methane, their values ranged from 113×10^{12} to 763×10^{12} ft³, or about 115 to 770 quads. The authors note that their assessment does not include the total geopressed resource. They predict the offshore and other onshore sediments in Texas and Louisiana not included in their analysis to be 1-1/2 to 2-1/2 times those estimated in their study.

Fig. 3. Location map showing the extent of the assessed geopressured zones and their division into subareas (AT₁, BT₁, etc.). Source: S. S. Papadopoulos et al., "Assessment of Onshore Geopressured-Geothermal Resources in the Northern Gulf of Mexico Basin," pp. 125-46 in *Assessment of Geothermal Resources of the United States - 1975*, D. E. White and D. L. Williams, eds., U.S. Geological Survey Circular 726, 1975.

There are many assumptions embedded in the results of Table 1 and the estimates of energy recovery. The average permeability of the formations, which is the property that determines the rate of flow from a well, was reported to be 15 to 50 millidarcies (md), the sandstone thickness 1350 to 4900 ft, and the temperatures 285 to 365°F. As will be discussed later, more recent studies of these formations indicate that the values used in the USGS report for these characteristics are far too optimistic.

In 1976 the Board of Mineral Resources of the National Research Council appointed a panel to examine the potential for recovering natural gas from unconventional geological sources. Three speakers, P. H. Jones and B. R. Hise of Louisiana State University (LSU) and M. H. Dorfman of

Table 1. Assessment of the "fluid resource base"

Reservoir	Volume of water in storage (10^{12} m^3)	Thermal energy (10^{20} J)	Methane energy		Mechanical energy (10^{20} J)
			Volume (10^{12} std m^3)	Thermal equivalent (10^{20} J)	
AT ₁	4.91	32.4	54.0	20.4	0.1
ATL ₂	11.80	66.1	99.4	37.5	0.2
BT ₁	8.81	53.8	83.7	31.6	0.2
BT ₂	3.14	17.0	23.6	8.9	0.1
CT ₁	4.62	28.5	41.1	15.5	0.1
DT ₁	2.39	14.8	21.7	8.2	0.1
DT ₂	2.56	15.6	23.5	8.9	0.1
DT ₃	4.04	22.3	32.3	12.2	0.1
DTL ₄	2.55	13.1	18.6	7.0	0.1
DL ₅	3.82	23.4	30.6	11.5	0.2
DL ₆	2.06	12.2	17.1	6.5	0.1
ET ₁	2.69	16.3	23.7	8.9	0.1
ET ₂	0.99	5.9	9.3	3.5	0.0
ET ₃	4.28	22.6	33.4	12.6	0.1
ETL ₄	1.73	8.9	11.6	4.4	0.1
EL ₅	3.75	23.6	30.0	11.3	0.1
EL ₆	4.61	27.7	35.5	13.4	0.2
EL ₇	3.70	19.6	31.5	11.9	0.1
FT ₁	1.02	6.3	10.4	3.9	0.0
FL ₂	2.25	12.6	16.4	6.2	0.1
FL ₃	<u>2.67</u>	<u>14.9</u>	<u>21.9</u>	<u>8.3</u>	<u>0.1</u>
	78.39	457.6	669.3	252.6	2.3

Source: S. S. Papadopoulos et al., "Assessment of Onshore Geopressured-Geothermal Resources in the Northern Gulf of Mexico Basin," pp. 125-46 in *Assessment of Geothermal Resources of the United States - 1975*, D. E. White and D. L. Williams, eds., U.S. Geological Survey Circular 726, 1975.

the University of Texas, were invited to discuss the potential of the geopressured zones. A National Academy of Sciences report of the panel's findings includes these three presentations.

Jones's analysis⁹ started with the results of the Papadopoulos report. Although Jones drew most of his data from this report, he argues that the thickness of the sandbeds and their porosity are greater than the USGS estimate and he used only 50% of the given 56,000-sq-mile area. Incorporating these modifications, he calculated the methane content of the onshore area sandbeds to be $17,000 \times 10^{12}$ ft³. Jones states:

If conditions offshore are comparable, sand-bed systems underlie about 50,000 mi², and the dissolved methane in them amounts to some 31,900 Tcf. The total estimated dissolved methane resource in Cenozoic geopressured sand-bed systems of the northern Gulf of Mexico basin is, on this basis, about 49,000 Tcf. A comparable volume of methane-saturated water is present in the associated geopressured shales, an appreciable part of which might migrate into pressure-depleted sand-bed reservoirs as production occurs. Perhaps 100,000 Tcf of dissolved methane is present in Cenozoic deposits of the geopressure zone in the northern Gulf of Mexico basin.

This statement was apparently the origin of subsequent claims of 50,000 and 100,000 quads of energy present in this area. He also states that "recoverable reserves of methane are believed to exceed 258.2 Tcf, the proved domestic natural gas reserves of December 31, 1970...and could very well exceed 1146 Tcf, the potential U.S. natural gas supply estimated in 1972...."

Jones argues further that development of the aquifers may also lead to increased production by conventional gas wells. He postulates that withdrawals of water from the high-pressure reservoirs will release gas from solution. When this gas reaches 4 to 5% of pore volume, he believes it will move to structural highs, forming gas caps that can be tapped by conventional wells. However, as noted in the summary of the National Academy of Sciences report, the practicality of the scheme remains questionable.

Hise² estimated the total area of the aquifers, both onshore and off, for Louisiana and Texas to be about 100,000 sq miles. He assumed

an average thickness of 10,000 ft of sediment, of which 10% was sandstone and the remainder shale. Using a value of 20% for the sand porosity and a value of 30 ft³/bbl for the natural gas content of the brine, he estimated the total gas in place in the geopressured aquifers to be 3000×10^{12} ft³, or about 3000 quads. He states that "preliminary and unfounded estimates of the number of geopressured aquifers that exist of commercial size vary from 0 to 1000." Using a value of 1000, he estimated a total recovery over a 30-year period of 27.4×10^{12} ft³, or 28 quads. The United States currently uses about 20 quads of natural gas each year.

Dorfman¹⁰ made no estimates of reserves. He does state that if the price for natural gas were high enough to make such ventures attractive, about 330×10^9 ft³ could be produced per year by the year 2000. This represents less than 2% of our current annual use.

The optimistic projections made by Jones were apparently the source of other statements implying enormous natural gas resources. In reference to the geopressured zones, Brown¹¹ states that the total resource base "has been estimated by two competent sources to lie between 60,000 and 105,000 quads for the natural gas alone." He notes that the eventual recoverability is highly uncertain "but probably lies in the range of 4 to 50 percent of the methane within the reservoirs which are eventually developed."

*Newsweek*¹² also reported the 100,000-quad value but noted that no solid research backs the claim. In this article it was also stated that Henry Linden, president of Gas Research Institute, speculated that as much as 160 quads of natural gas might be available at less than \$4/1000 ft³. This value is similar to projections of the recoverable resource made in the Energy Research and Development Administration's (ERDA's) [now the Department of Energy (DOE)] *Market Oriented Program Planning Study (MOPPS)*,¹³ which gave a total range of 150 to 2000 quads.

RESULTS OF RESOURCE VALIDATION STUDIES

During this period of speculation, detailed studies of the geopressured zones, funded initially by ERDA, were under way at the University

of Texas and LSU. The objective of the University of Texas project was to locate prospective reservoirs meeting the following specifications: reservoir volume of 3 cubic miles (greater than 300 ft thick and 50 sq miles in area), minimum permeability of 20 md, and fluid temperature of 300°F or greater.¹⁴⁻¹⁶ Three formations, the Frio, Vicksburg, and Wilcox, are believed to have the potential to meet these specifications. The Texas studies have concentrated on the Frio, the thickest and most promising of these formations.

The initial phase of this study was a mapping of the sandstone thickness and the temperature throughout the onshore part of the Frio Formation in Texas. This regional assessment located several areas of thick sandstone bodies with fluid temperatures greater than 300°F. These geothermal fairways are shown in Fig. 4; the logs for the wells indicated by the dots in this figure were used to construct sandstone thickness and isothermal maps of the area.^{15,16}

Detailed studies of these five fairways eliminated all but the Brazoria Fairway. The Hidalgo Fairway has permeabilities that are far too small, and the Armstrong Fairway does not meet the requirements because of low temperatures and probable low permeabilities. The Corpus Christi Fairway was eliminated because of probable limited reservoir area, inadequate sand thickness, and low porosity and permeability. The Matagorda Fairway does not have reservoirs of sufficient area and also lacks a sufficient thickness of permeable sandstone.

The Brazoria Fairway is the most promising geopressured area found in the onshore Frio Formation in Texas. This fairway is about 20 miles long and 10 miles wide and has a sandstone thickness of 1200 to 2000 ft.¹⁵ However, not all of the reservoir thickness is at temperatures above 300°F. The total volume of the sandstone reservoirs in this fairway is about 27 cubic miles. If it is assumed that the porosity of the formation is 20% (i.e., 20% of the total volume is occupied by brine) and the brine contains 40 ft³ of natural gas per barrel, then the natural gas content is about 5.6×10^{12} ft³, or nearly 6 quads.

The most favorable area within the Brazoria Fairway is the Austin Bayou Prospect, which covers an expanse of 16 sq miles.¹⁵ Between a depth of 13,500 and 16,500 ft, there are 14 sandstone intervals, which

Fig. 4. Potential geothermal fairways, Frio Formation, Texas Gulf Coast. Source: D. G. Bebout, "Geopressured Geothermal Fairway Evaluation and Test-Well Site Location - Frio Formation, Texas Gulf Coast," pp. GI-255-GI-313 in vol. 1 of *Proceedings, Third Geopressured Geothermal Energy Conference*, Center for Energy Studies, The University of Southwestern Louisiana, Lafayette, Nov. 16-18, 1977.

have a total thickness of 840 ft. If a porosity of 20% and a gas content of 40 ft³/bbl are again assumed, the total methane content is 0.43 quads. The electrical power that could be produced from the thermal energy of this prospect is estimated to be 170 MWyr assuming recovery of 10% of the brine.¹⁵ Thus, a plant of 8.5-MW capacity could be supported for 20 years from the output of the most favorable 16-sq-mile area found onshore in Texas.

Note that the University of Texas studies on resource assessment have emphasized the geothermal aspect of the resource. There may be lower temperature aquifers that have better reservoir properties for gas production but less potential for utilization of the thermal energy.

The LSU study¹⁷ included all of the known onshore geopressed areas of Louisiana and those offshore areas under state jurisdiction (Fig. 5). They studied logs of about 6000 wells ranging in depth from 7500 to 25,600 ft and averaging 12,980 ft. The maximum temperature reported was 428°F; however, the average was only 209°F. Although the maximum sandstone thickness in one well was 2955 ft, the average was 434 ft. An assessment of the recoverable geopressure energy in this area is as follows:

Mechanical	1.2 quads
Thermal	19.5
Methane	<u>13.6</u>
	34.3 quads

Several aspects of this LSU assessment may cause an overestimation of the resource: (1) the thermal energy estimate, which was based on a reference temperature of 120°F, does not include any conversion efficiency; (2) it is implied that all of the reservoirs are of commercial size; (3) no economic limits were placed on the well flow rate (the flow rate was allowed to taper off to zero); and (4) the aquifer pressures were inferred from drilling mud weights. In many wells, muds of considerably excess density were used, resulting in an overestimation of the aquifer pressures.

In addition to these items, the methane content was calculated using the data of Culberson and McKetta⁴ (Fig. 2). Salinity of the brine and the effect of other dissolved gases will reduce this value. Also, the recoverable fraction of the resource was determined using a system compressibility of 20×10^{-6} psi⁻¹; as will be discussed later, this value may be too high.

Fig. 5. Geopressured areas of Louisiana. Source: W. J. Bernard, "Geopressure Resource Assessment - Southern Louisiana," pp. GI-109-GI-119 in vol. 1 of *Proceedings, Third Geopressured Geothermal Energy Conference*, Center for Energy Studies, The University of Southwestern Louisiana, Lafayette, Nov. 16-18, 1977.

Detailed studies of the 63 areas of potential interest found in the initial LSU survey (Fig. 5) will probably show that few of these have potential for economic exploitation. The low temperature found in this survey also casts doubt on their economic viability. Thermal energy contained in brine having an average temperature of 209°F is, at best, of questionable value. Furthermore, as can be seen from the methane solubility data of Fig. 2, if the geopressure brines are only saturated with methane, the low temperature places a rather low limit on the

methane content of the reservoirs. One encouraging finding is that flow tests from the Edna Delcambre No. 1 geopressure test well (Vermilion Parish, Louisiana) indicated that the reservoir may contain free gas.¹⁸ If so, and if free gas is found in other reservoirs, it would offset the temperature limits placed on the gas content of the brine. Free gas in the reservoirs would also be very beneficial in increasing the compressibility of the reservoirs, which, in turn, would increase reservoir life and the fraction of the resource that could be recovered.

RESERVOIR CHARACTERISTICS AND PRODUCTIVITY

Regardless of the magnitude of the reservoirs, the potential for their development depends on the reservoir characteristics that determine the fraction of the resource that can be recovered and the flow rate of wells producing from the reservoirs. In this section we will examine the effects of these parameters on the productivity of a geopressured reservoir. Equations describing the mechanics of reservoirs and the flow rate of a well for single-phase (liquid only) flow and for a constant permeability are given in Appendix A. Appendix B presents a parametric analysis of the effect of reservoir properties on well flow rates and life. The units used in the following sections are those generally used in the published reports — barrels, days, feet, centipoise, darcy, and psi; conversion factors are given in Appendix C.

Reservoir Driving Forces

The fraction of the resource recoverable from a reservoir depends on the forces that maintain the pressure within the reservoir as fluids are being withdrawn. These forces are a function of the compressibility of both the fluids and rock structure; the extent to which water released from the surrounding shale repressures, or drives, the reservoir; and the behavior of the gas released from the brine as the pressure is reduced.

Reservoir compressibility

The primary driving force of a reservoir is its compressibility, which is a function of the compressibility of the liquid, C_e ; the compressibility of the rock matrix (the particles forming the structure), C_s ; and the pore compressibility, C_p . For a reservoir not containing free gas, the fluid compressibility is that of water, which, for the temperature and pressure range of interest, is $3.3 \times 10^{-6} \text{ psi}^{-1}$.⁶ Considering that the maximum pressure drawdown expected in a reservoir is about 5000 to 6000 psi, the maximum recovery from the depressurization of the brine would be 1.65 to 1.98% of the initial reservoir inventory.

As the fluid pressure in a reservoir is reduced, the weight of the overburden applies an increasing compressive load to the rock structure, which reduces its porosity and forces brine from the structure. The compressibility of the structure can vary widely depending on its degree of consolidation and cementation. Unfortunately, there are few, if any, data available on the compressibility of the geopressed reservoirs and data from normally pressured formations must be used.

Van der Knaap¹⁹ found the rock matrix compressibility to be in the range of 2.0×10^{-7} to $2.4 \times 10^{-7} \text{ psi}^{-1}$. Geertsma²⁰ recommends using the compressibility of quartz, about $1.9 \times 10^{-7} \text{ psi}^{-1}$ (ref. 21), for sandstone formations. For this study a value of 2×10^{-7} will be used.

Values of pore compressibility reported by different researchers are given in Appendix A and vary from about 2×10^{-6} to $30 \times 10^{-6} \text{ psi}^{-1}$. For a consolidated and cemented sandstone, a pore compressibility (measured by conventional laboratory hydrostatic tests) in the range of 3×10^{-6} to $10 \times 10^{-6} \text{ psi}^{-1}$ is typical.^{19,22,23} However, hydrostatically determined values of C_p are not directly applicable to a reservoir. During the pressure drawdown of a reservoir the weight of the overburden applies a uniaxial compaction load on the reservoir, whereas the hydrostatic tests subject the sample to a uniform load over the entire surface. Van der Knaap¹⁹ and Geertsma²⁴ recommend using an effective reservoir compressibility of $C_p/2 - C_s$. Adding the water compressibility gives a total effective reservoir compressibility of

$C_e + C_p/2 - C_s$. If midrange values of $7 \times 10^{-6} \text{ psi}^{-1}$ for C_p and $2 \times 10^{-7} \text{ psi}^{-1}$ for C_s are used, the effective reservoir compressibility is $6.6 \times 10^{-6} \text{ psi}^{-1}$. Thus the maximum resource recovery would be 3.3 to 4.0% for a reservoir pressure reduction of 5000 to 6000 psi. Figure 6 illustrates the effect of the value of C_p on the change in formation porosity and resource recovery for a pressure change of 6000 psi.

Fig. 6. Effect of reservoir pore compressibility on the porosity change and maximum recovery for a 6000-psi change in reservoir pressures.

Some authors express reservoir compressibility in terms of a specific storage coefficient, S_s , where

$$S_s = \phi(C_e + C_p/2 - C_s)$$

and ϕ is the porosity. The specific storage coefficient is then the value of fluid recovered per unit volume of reservoir per unit pressure change.

Reservoir compressibility can also be estimated from the uniaxial compaction coefficient, C_m , which is defined as the fractional change in the height of the reservoir (or sample) per unit load applied. By assuming that the volume change results only from the change in pore volume, C_m can be related to the pore volume compressibility by the expression $C_m = \phi C_p/2$. Geertsma²⁰ reports values of C_m for sandstone of various degrees of consolidation and different porosities for preloading conditions that correspond to burial depths of 1000 and 3000 m. For well-consolidated samples that have a porosity of 20% and are loaded to correspond to a burial depth of 1000 m, he reports values of C_m ranging between 5.3×10^{-7} and 8.8×10^{-7} psi^{-1} and an average C_m of 6.3×10^{-7} psi^{-1} . For similar samples loaded to correspond to a burial depth of 3000 m, an average C_m of about 4.9×10^{-7} psi^{-1} is obtained. These average values correspond to pore compressibilities, C_p , of 6.3×10^{-6} and 4.9×10^{-6} psi^{-1} and would give total recovery values, taking into consideration the effect of the fluid compressibility, of between 3 and 4% for a reservoir drawdown of 6000 psi. Geertsma also gives data for semiconsolidated rock; these data show greater scatter and, for a porosity of 20%, indicate a compressibility about twice that of well-consolidated rock. Even with these higher compressibility values, the total recovery would be no more than 5%.

Thompson, Menezes, and Gray²⁵ of the University of Texas are preparing to test core samples from geopressed formations. Although no geopressure cores have been used, tests of normally pressured sandstone and limestone samples with porosities and permeabilities in the range expected of geopressed reservoirs were used to check the test apparatus. During these tests, they reported changes in the porosity of the samples of less than 1.5% for uniaxial loads as high as 8000 psi. This means

that for an increased overburden load of 8000 psi, the brine forced out of the formation from rock compressibility would be less than 1.5% of the initial inventory.

These effective compressibility values are only a third of the $20 \times 10^{-6} \text{ psi}^{-1}$ used in the LSU study to estimate the potential energy recovery of the Louisiana reservoirs.¹⁷ Also, for a reservoir pressure drawdown of 6000 psi, the 4.0% recovery is less than half of the 10% recovery estimated in the Texas study of the Frio Formation.¹⁶ One basic question concerning the compressibility of geopressed reservoirs is whether their properties are similar to those of normally pressured systems. Harville and Hawkins²⁶ suggest that, because of inelastic compaction or rock failure, the rock compressibility of geopressed reservoirs may be several times that of normal systems during the early period of drawdown. However, the test results reported by Thompson, Menezes, and Gray for sandstone samples showed elastic behavior for loads up to 9000 psi. This area obviously needs more investigation.

Shale water influx

Shale water influx into a reservoir during production can increase the life of a reservoir. As the reservoir pressure is reduced, water from the surrounding or interbedded shale bodies flows into and thus recharges the reservoir. However, controversy exists over the rate of this flow, which is poorly understood. The extent to which this inflow adds to the reservoir life depends on the shale permeability and compressibility. In analyzing these reservoirs, Papadopoulos²⁷ and Knapp and Isokrari⁶ both used a value of 10^{-4} md for the shale. However, as Papadopoulos notes, this value is two to three orders of magnitude greater than normally compacted shale. He assumes that undercompaction of the shale will result in higher than normal permeability values. He also assumes a relatively high value ($2.3 \times 10^{-4} \text{ psi}^{-1}$) for the compressibility of the shale. These values are sufficiently large to have an impact on reservoir life. However, for a one order of magnitude reduction in the values, the shale water influx will have little or no impact on the life of the reservoir.

Another factor that may affect the flow of water from shale is the threshold gradient required to induce flow through clay systems. Ping²⁸ and Miller and Low²⁹ report threshold gradients as high as about 60, that is, 60 ft of head per foot of sample thickness. However, as noted by Miller and Low, this gradient is probably temperature dependent; thus, this factor may not be significant for the temperature found in geopressured aquifers.

Wallace concluded from a study of several geopressured gas wells in southern Louisiana³⁰ that water influx from shales embedded in or surrounding the sandstone was a significant factor in driving the reservoir. However, in reference to Wallace's paper, Bernard³¹ states:

Although his paper elucidates the idea of shale water production, it has not been proven that this phenomenon is indeed a real one in all geopressured systems. A study by Bourgoyne and Hawkins (1972) shows mathematically that shale water might play a significant role in supplying energy to abnormally pressured systems. Whether this will be the case remains to be proven, and it awaits the exploitation and careful testing and monitoring of an abnormal aquifer.

Effect of free gas on reservoir production

Free gas within a reservoir will also prolong its production life. However, this may not be beneficial. If the brine is initially saturated with methane, then gas will be released during production. If the released gas flows through the reservoir, it will reduce the production rate because of the increased pressure loss caused by two-phase flow. This could be especially detrimental in tight (low permeability) formations.

However, there probably will be little, or no, two-phase flow in a reservoir containing brine initially saturated with methane. Experiments by Wyckoff and Botset³² showed that gas evolved from water flowing through packed sand was trapped by and accumulated within the cavities of the sand until the gas occupied some fraction of the matrix void volume. In their studies of four different sandbeds with permeabilities of 17.8 to 262 darcys, they found this equilibrium fraction to be 0.10 to 0.27; the fraction increased with increasing permeability. Although the material used in these tests was different from the rock structure

of a geopressured reservoir, similar results with a lower saturation gas percentage would be expected. In a geopressured reservoir, the volume of gas released from brine initially saturated with methane will be less than 1% of the volume of the brine at the end of the reservoir life. If this volume of gas is trapped by the rock structure, then the evolved gas will not leave the reservoir. This could reduce the gas production rate by about 25% and have a serious impact on the economic viability of this resource.

The gas trapped in the rock matrix will increase the compressibility of the reservoir and increase the fraction of brine that can be recovered. The maximum effect of the gas would be to increase the fraction of the initial resource recoverable by 20 to 25%. Thus, gas released from brine initially saturated with methane will increase the recoverable fraction of brine but will have little or no effect on the total quantity of methane recovered.

Swanson et al.,³³ in a study of geopressured wells in southern Texas, came to a different conclusion about the behavior and effect of gas released during production. They describe several production tests of unsuccessful wells and suggest the rather abrupt drop in flow rates was caused by gas released from the water. Their description of one such attempt in Hidalgo County, Texas, is as follows:

The most recent of these tests was in the Mercedes-Donna area, near the Donna fault (Lone Star Prod. Co. No. 1 Denzer). The well is typical of the area east of the Donna fault near the Cameron County line, exhibiting low salinity, high-resistivity Frio sands. We believe this well was completed in a water sand, and represents an unwitting test of a geopressured water zone.

After several unsuccessful deep completion attempts, the well was perforated (selectively) from 9371-9268, acidized and given a nitrogen pressure treatment. The well flowed gas, nitrogen, and formation water. On a 20/64-inch production choke, the well tested an absolute open-flow potential of 280 mcf gas per day, plus 450 barrels of water (5400 ppm/Ci). This declined to 120 mcf plus 140 barrels of water, and the completion was aborted with a plug. Other perforations at depths from 8994 to 8818 produced similar results and the well was abandoned.

This completion attempt opened a total of 42 ft of perforations in the geopressured zone from which the potential test was made. The 450 barrels of water/day with substantial gas is probably typical of the test results one can expect from water sands in this area.

Likewise, the rapid decline can be expected, the probable result of gas released from the water due to the pressure drop in the formation. The relative permeability is such that released gas quickly dominates the flow, blocking further water flow as a result. This reduces the rate at which gas can be released, and the rate of flow of both steadily declines. We believe this sort of performance can be expected in any flow test in the consolidated formations of this region, unless measures are taken to drastically restrict flow rate.

The gas-to-water ratio reported in this test is much greater than the saturation value. Unless the gas was separating from the water during production, the reservoir must have contained an appreciable quantity of free gas. Furthermore, the rapid decline in flow rate would be expected from a reservoir with a very low permeability.

In summary, geopressured reservoir driving forces are poorly understood. For a reservoir containing brine initially saturated with methane and exhibiting typical rock compressibilities, the maximum potential resource recovery would be less than 5%. Shale water influx could increase this value; and if the reservoir, in addition to containing saturated brine, also contained free gas, then the recovery value might be greater. However, projections of recovery values greater than 5% are speculative.

Permeability

The permeability of a reservoir is a measure of how easily fluid can flow through the rock structure. Permeability, the most important parameter affecting the production rate of a well, depends on both the porosity of the rock and the complexity or tortuosity of the flow passages. Values of permeability vary between and within reservoirs and will probably change during the drawdown of a reservoir as the pore pressure and the reservoir volume are reduced. To give perspective to the values of permeability discussed in this section, the effect of this parameter on the production rate and life of a well should first be examined. For this example, a reservoir with an initial pressure of 12,000 psi, a depth of 14,000 ft, a temperature of 300°F, and a thickness of 200 ft will be considered.

Figure 7 shows the life of a single well as a function of the reservoir permeability and size for constant flow rates of 20,000, 40,000, and 80,000 bbl/day. For this case, the well diameter is 6 in., the effective reservoir compressibility (water plus rock structure) is $6.6 \times 10^{-6} \text{ psi}^{-1}$, the porosity is 20%, and only single-phase flow is considered. The end-of-life wellhead pressure is assumed to be 250 psi, the pressure needed to suppress boiling of the water and allow sufficient pressure to deliver the brine to a central plant. However, after the wellhead pressure drops to 250 psi, the flow rate could be reduced and production continued at a lower flow rate. During the early production period the reservoir acts as an infinite area system until the drawdown reaches the outer perimeter of the reservoir. After this time the pressure gradient in the reservoir goes through a transition period, and a new gradient is established that remains approximately constant with time. For the 80,000-bbl/day case, a reservoir of infinite size would require a permeability of about 30 md for a 20-year life. A reservoir with a radius of 8 miles (201 sq miles) would require a permeability of about 50 md for a 20-year life, whereas a 4-mile radius would be too small regardless of the value of permeability. A 20-year life at 40,000 bbl/day requires a reservoir radius of about 4 to 8 miles and a permeability of 15 to 20 md. One interesting feature of the lower flow rates is that an extreme change in life results from a small change in permeability for an infinite area. For the 40,000-bbl/day case, an increase of only 1 md increases the life by a factor of 7 or 8.

Generally, the permeability of the geopressured zone is very low along the lower Texas coast and increases toward the northern and eastern areas. Swanson et al.³³ studied the permeability of geopressured gas fields in six counties (Cameron, Hidalgo, Willacy, Kenedy, Brooks, and Live Oak) of southern Texas (Fig. 4). They found permeability values to range from less than 0.03 md to more than 8 md; the average over all of the fields was about 1 md. Although there has been considerable speculation that the undercompaction of the geopressured zone would lead to an increase in permeability, this study did not find this to be true. They found that over the entire study area the permeability continued to decrease with increasing depth; the change was about

Fig. 7. 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 7×10^{-6} psi⁻¹. All radii are given in miles.

one order of magnitude for each 2000 ft of depth between 6000 and 14,000 ft. Figure 8 shows the results of their study of more than 100 gas wells throughout this area; temperatures of 300°F are encountered at depths of 13,000 to 14,000 ft.

Loucks and Mosely,³⁴ concluding from a study of the consolidation history of the Texas Frio Formation, state that in the lower Texas Gulf Coast area (south of Corpus Christi) "kaolinite and Fe-rich carbonate and zeolite (analcime) cements drastically reduced porosity to less than 15 percent and destroyed all possibility of preserving potential geothermal reservoirs."

Even along the northern Texas coast, permeabilities vary widely and can be relatively low. Many of the gas and condensate wells in the Chocolate Bayou field of Brazoria County have permeabilities in the range of 2 to 10 md but producing thicknesses of only 10 to 30 ft. However, "it is expected that the thicker more porous water reservoirs of the Austin Bayou Prospect will have higher permeabilities."¹⁵

As the pressure in a reservoir decreases, its pore volume also decreases, and the permeability would be expected to decrease. Thompson, Menezes, and Gray²⁵ report permeability changes of core specimens

Fig. 8. Effective permeability vs depth from gas wells in Hidalgo, Brooks, Cameron, and Kenedy counties, lower Texas Gulf Coast. Source: R. K. Swanson et al., *Development of an Assessment Methodology for Geopressed Zones of the Upper Gulf Coast Based on a Study of Abnormally Pressured Gas Fields in South Texas*, COO-2687-6, Southwest Research Institute, San Antonio, Tex., August 1976, as adapted by D. G. Bebout, "Geopressed Geothermal Fairway Evaluation and Test-Well Site Location - Frio Formation, Texas Gulf Coast," pp. GI-255-GI-313 in vol. 1 of *Proceedings, Third Geopressed Geothermal Energy Conference*, Center for Energy Studies, The University of Southwestern Louisiana, Lafayette, Nov. 16-18, 1977.

subjected to uniaxial loads. Tests of samples of a Berea sandstone (mean initial porosity of 19.6% and a permeability of 76 md) showed a reduction in permeability of about 7% for a uniaxial load of 8000 psi. The porosity change was about 1.5%. Results for Leuders limestone samples (mean initial porosity of 17.1% and a permeability of 4 md) tested under the same conditions showed a permeability change of 12% but only a 1% change in porosity. Other experiments have also shown this reduction.^{22,33,35} In general, these tests indicate that the decrease in permeability depends on its initial value: the lower its initial value, the greater the percent reduction.

Gas released from solution and trapped within the reservoir during drawdown can also reduce the reservoir permeability. Orlob and Radhakrishna,³⁶ using test specimens with initial permeabilities of 8.7 to 478 darcys, found that if 5% of the pore volume was occupied by air, the permeability was reduced by 12 to 20%. When 10% of the pore volume was occupied by air, the permeability was reduced by 25 to 40%. The permeability of these specimens was about 1000 times that found in the geopressured zones, which probably invalidates any attempt to apply the data to geopressured reservoirs. If the data were applicable, the reduction would be only 2 to 4%. However, a much larger effect would be expected for specimens with lower initial permeabilities.

RESOURCE RECOVERY ECONOMICS

The states of Texas and Louisiana have passed legislation strongly encouraging the full utilization of the geopressured resource. Thus, most economics studies have emphasized methods and costs of using the thermal energy for either process heat or electrical power generation.³⁷⁻⁴³ These studies start with assumptions of reservoir characteristics — well flow rates, life, and spacing — that become a critical part of the conclusion. Although most of the studies reflect the earlier, more optimistic view of the aquifers, they do provide valuable insight into the cost of systems to utilize the energy.

One of the most detailed and best documented studies of the economics of using the energy from geopressured aquifers is by Wilson et al.³⁷ In this study of a 25-MW(e) demonstration plant, the system was separated into a fuel plant and a power plant. The fuel plant consisted of production wells, a methane removal system, reinjection wells, and a piping system to collect and dispose of the brine. The production wells were located at 1/2-mile intervals. The power plant consisted of a hydraulic turbine to convert the excess wellhead pressure into electrical power, a separation system for further gas recovery, a steam flash system, and a steam turbine-generator with the electrical gear, condensers, and other equipment necessary for a complete power plant. Both a single- and a double-flash system were analyzed in the study.

Table 2 shows the itemized costs of both dry and completed wells reported by Wilson et al. for wells having 4.5, 5.5, and 7 in. diameters and depths of 14,000, 16,000 and 18,000 ft. In the analysis of the fuel plant, one of every three wells was assumed to be a dry hole. These were plugged to the 6000-ft level and then completed as reinjection wells at an additional cost of \$500,000. A total of two reinjection wells was provided for each production well. The additional reinjection wells, also completed to the 6000-ft level, were estimated to cost \$600,000 each. One spare production well in excess of that required to meet the thermal demand of the power plant was provided. In the economic analysis of the plant, the cost data for the well with the 7.0-in. diameter and 14,000-ft depth were used.

Table 2. Estimated geopressured geothermal well costs

Well diameter (in.)	Cost (\$)	
	Dry hole	Completed
<i>Depth of 14,000 ft (Nueces County)</i>		
4.5	1,067,000	1,681,300
5.5	1,067,000	1,733,300
7.0	1,149,000	1,925,300
<i>Depth of 16,000 ft (Nueces County)</i>		
4.5	1,622,700	2,287,700
5.5	1,622,700	2,346,400
7.0	2,220,500	3,077,000
<i>Depth of 18,000 ft (Cameron County)</i>		
4.5	1,895,200	2,595,200
5.5	1,895,200	2,662,700
7.0	2,548,700	3,468,200

Source: J. S. Wilson et al., *A Study of a Phase "O" Plan for the Production of Electrical Power from U.S. Gulf Coast Geopressured Geothermal Waters*, Dow Chemical Co., February 1976.

The assumptions used in the plant analysis were as follows:

Date of costs = January 1976,
 Brine production rate per well = 40,000 bbl/day,
 Brine temperature = 325°F,
 Methane content = 40 scf/bbl,
 Methane value = \$2/1000 scf,
 Plant operating factor = 90%,
 Brine pressure to the hydraulic turbine = 2000 psia,
 Return on investment = 12.8%,
 Depreciation = 5% of capital cost,
 Taxes, insurance, general and administrative costs, overhead =
 4% of capital cost,
 Operating costs = 8% of capital cost.

The operating wells required to meet the thermal demand for the single- and double-stage flash plants totaled 10.8 and 8.5 respectively, which correspond to brine production rates of 432,000 and 340,000 bbl/day. A summary of the cost data for both plant designs is given in Table 3. The basic capital and operating costs shown are identical to those of Wilson et al.; however, the analysis and results presented in Table 3 are somewhat different.

One obvious conclusion that can be drawn from these results is that the value of the resource is highly dependent on the value of the methane. In this study the value of the methane was assumed to be 8¢ per barrel of brine, whereas the assumed production cost of the brine was 11.1¢ and 11.6¢/bbl for the single- and double-stage plants respectively (equivalent to \$2.78 and \$2.90 per 1000 ft³ of methane). The sensitivity of the power costs as a function of the value of the methane is shown in Fig. 9. Note that for methane values of 11.1¢ and 11.6¢/bbl for the single- and double-stage plants, the fuel costs to the power plant are zero and the power costs are 22 and 26 mills/kWh respectively. Wilson et al. conclude that for power production to be attractive, higher temperatures or more efficient power systems are needed. They state that "the geopressured zone, assuming the presence of natural gas and high water productivity, may be used to produce economical electric power only if the water is at least 375°F or a means of conversion more efficient than flashing is found."

Table 3. Cost summary for 25-MW(e) single- and double-stage flash plants

	Single-stage flash	Double-stage flash
Production wells		
Number required	10.8	8.5
Number provided	12	10
Brine production rate, 10 ³ bbl/day	432	340
Fuel plant		
Capital cost, \$10 ⁶	53.07	43.55
Annual capital and operating cost, \$10 ⁶ /year	15.81	12.96
Cost of brine, ¢/bbl	11.1	11.6
Gas production, 10 ⁹ scf/year	5.68	4.47
Gas value, \$10 ⁶ /year	11.36	8.94
Cost of heat to power plant, \$10 ⁶ /year	4.45	4.04
Power plant		
Capital cost, \$10 ⁶	14.49	16.95
Annual capital and operating cost, \$10 ⁶ /year	4.32	5.05
Annual cost of heat, \$10 ⁶ /year	4.45	4.04
Total annual cost, \$10 ⁶ /year	8.77	9.09
Annual power output, 10 ⁶ kWh/year	197	197
Power cost, mills/kWh	45	46

The results of this study, even considering that natural gas prices and utility power costs are expected to escalate, are not encouraging. Such cost items as land, royalties, architect-engineering, interest and escalation during construction, contingency, and transmission lines were not included. Furthermore, the 1/2-mile spacing between wells is much too small. The problem with this spacing can be seen by examining Fig. 7, which is for a reservoir producing interval of 200 ft. For a 20-year life and a formation permeability of 20 md, a reservoir radius of about 5 miles (≈80 sq miles) is needed — far greater than the 1/4 sq mile of the Wilson study. The problem is further illustrated in Fig. 10, which shows the reservoir thickness required as a function of well spacing for well flow rates of 40,000 and 80,000 bbl/day, a 20-year life, and a recovery of 4% of the initial reservoir inventory. Even

ORNL-DWG 79-8673

Fig. 9. Cost of electrical power from a geopressure geothermal plant as a function of the methane value.

with these favorable conditions, a well producing 40,000 bbl/day for 20 years would require a producing interval of about 30,000 ft.

The importance of well spacing on economics is illustrated in a report by Bloomster and Knutsen³⁸ on the cost of using the thermal and hydraulic energy of geopressure brine for electricity. They analyzed three power conversion systems: a flash steam system, an isobutane Rankine-cycle system, and a "total flow" system. The power costs from the flash steam and the isobutane systems were about the same; the isobutane was slightly lower. The total flow system gave costs 15 to 30% higher than those of the other cases considered. The authors emphasize that the exploitation of geopressured energy is highly dependent on the methane value and start with the assumption that the value of the methane is sufficient to offset the capital and operation

Fig. 10. Required reservoir thickness as a function of well spacing for well flow rates of 40,000 and 80,000 bbl/day and a well life of 20 years.

and maintenance costs of the wells and the methane recovery system. However, they do include the cost of the collection piping system in the cost of the power plant.

A summary of their results is shown in Fig. 11. These results are based on December 1975 costs, a well spacing of about 1.85 miles, and a well flow rate of 81,500 bbl/day. The high cost of the collection system offsets the savings from larger power plants and leads to the flat curves of power cost vs plant size. Figure 12 shows the effect of well spacing on power cost for a 55-MW(e) plant and a 327°F brine temperature. Note that the cost of the fluid transmission system equals the cost of the power plant for a well spacing of about 1-1/4 miles. Directional drilling of the wells could reduce the length of the fluid

Fig. 11. Impact of plant size on generation cost. Source: C. H. Bloomster and C. A. Knutsen, *An Analysis of Electricity Production Costs from the Geopressured Geothermal Resource*, BNWL-2192, Battelle Pacific Northwest Laboratories, Richland, Wash., February 1976.

Fig. 12. Impact of well spacing on generation cost distribution. Source: C. H. Bloomster and C. A. Knutsen, *An Analysis of Electricity Production Costs from the Geopressured Geothermal Resource*, BNWL-2192, Battelle Pacific Northwest Laboratories, Richland, Wash., February 1976.

transmission system. However, the higher cost of directional drilling may offset any cost reduction in the piping system.

From this study, Bloomster and Knutsen conclude:

Methane content and selling prices are the most important factors affecting the commercial potential of geopressured resources — so it is important that electrical generation be viewed as a by-product of methane production. Without methane revenues to offset high well-drilling costs, estimated electrical generation costs from the thermal energy in the hot water far exceed current generation costs from conventional energy sources. However, if the thermal energy is available "free" as a by-product of methane production, then the incremental costs of electricity generation from the thermal energy in many geopressured reservoirs approaches generation costs from conventional energy sources.

The well flow rate and spacings used in the Bloomster and Knutsen study were based on the USGS report by Papadopoulos et al.⁸ and appear to be too optimistic. The reservoir thickness would have to be in the range of 5000 to 10,000 ft.

CONCLUSIONS

The geopressured aquifers of the northern Gulf of Mexico undoubtedly contain an enormous quantity of thermal and chemical energy. However, the physical characteristics of the reservoirs and the cost of recovery will probably severely limit the percentage of the energy that can be recovered. As indicated by the results of recent studies of these aquifers, some of the initial projections of both the extent and recoverability of the resource were far too optimistic. Much more information is needed to make reasonable projections of the contribution these aquifers will make to national energy requirements; it will, however, probably be relatively small, at least in the foreseeable future.

Although it is possible to recover thermal, chemical, and hydraulic energy from these formations, exploitation of the chemical energy, the methane, is of most importance. Unless the methane content and market value are sufficient to offset the cost of the production and reinjection wells, there is currently little incentive to develop this resource.

Even if thermal energy is available at no cost as a by-product of methane production, its use in electrical power production appears to be marginal at best. A small power plant (25 MW) with 325°F brine and a production rate of 40,000 bbl/day would require about ten wells. Unless

the reservoirs supplying the plant exhibited an unusually high compressibility or were driven by shale water influx, the distance between wells and thus the cost of the fluid transmission system would probably be prohibitive.

Although the energy potential of these formations now appears to be less than some of the projections that created the initial interest, it is too large to be ignored, and certainly a program aimed at providing a better understanding of the extent and characteristics of the resource is warranted. Ideally, the geopressured zone should be mapped so that reliable projections can be made of the quantity of energy recoverable as a function of cost. This parallels DOE's position on these aquifers, which is "that fundamental data are needed to characterize the average geopressured reservoir and that developing technology for energy utilization or seriously adding geopressure to the Nation's stockpile must await the answer to those entry questions of technical and economic feasibility."⁴⁴

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Appendix A

RESERVOIR MECHANICS

This appendix discusses the mechanics of geopressured aquifers and presents equations that describe the production rate and life of wells producing from these formations. In the analyses and equations presented in the following sections it is assumed that only single-phase (liquid) flow occurs and that the permeability of the sandstone remains constant during the drawdown. The primary driving force of a geopressured well is the compressibility of the brine and the rock structure. Also, as the aquifer is depressurized, gas trapped in the rock matrix and water released from the interbedded and surrounding shale can prolong the life of the well. Equations defining the effect of shale water influx are included. Released gas trapped within the reservoir would increase the compressibility and storage coefficient of the reservoir, perhaps by as much as 25%.

Reservoir Compressibility

The two quantities needed to determine the primary driving force of a reservoir are the compressibility of the reservoir fluid and the change in the pore volume of the rock structure that occurs as fluid is withdrawn. The pressure-density relation of water for the pressure range of interest is shown in Table A.1. The rock properties required in predicting the pore change in a reservoir vary greatly and should be determined for the reservoir being studied. To understand the terminology and significance of the parameters used to describe reservoir compressibility coefficients, a familiarity with the experimental techniques used in measuring these coefficients is helpful.

In studying the properties of reservoirs, core sections jacketed with a thin layer of plastic or copper foil are used to permit the sections to be subjected to an external pressure, P_e , and an internal pressure, P . Experiments with these sections can be used to determine several compressibility coefficients, which are defined as follows:

Table A.1. Water properties at 300°F

Pressure (psia)	Density (lb/ft ³)	Viscosity (cP)
5000	58.4635	0.1926
5500	58.5575	0.1933
6000	58.6510	0.1939
6500	58.7550	0.1946
7000	58.8339	0.1952
7500	58.9335	0.1959
8000	59.0275	0.1966
8500	59.1243	0.1972
9000	59.2168	0.1978
9500	59.3112	0.1986
10000	59.4013	0.1993
10500	59.5027	0.2001
11000	59.6225	0.2008

Source: R. M. Knapp and O. F. Isokrari, "Aspects of Numerical Simulation of Future Performance of Geopressured Geothermal Reservoirs," pp. 103-61 in *Reservoir Research and Technology*, vol. 3 of *Proceedings, Second Geopressured Geothermal Energy Conference*, Center for Energy Studies, University of Texas, Austin, Feb. 23-25, 1976.

$$\text{Rock bulk compressibility } C_b = \frac{1}{V_b} \left(\frac{\partial V_b}{\partial P_e} \right)_P ,$$

$$\text{Rock pore compressibility } C_p = \frac{1}{V_p} \left(\frac{\partial V_p}{\partial P_e} \right)_P ,$$

$$\text{Rock matrix (particle) compressibility } C_s = \frac{1}{V_b} \left(\frac{\partial V_b}{\partial P_e} \right)_{(P_e-P)} .$$

The definition of terms varies with different authors and care must be used in interpreting their results. The difference between the external and internal pressure, $P_e - P$, contrary to the terminology often used, is not the net or effective overburden pressure. In the experiments the

pressure difference, $P_e - P$, acts over the total specimen surface area and induces strain in all dimensions. In a reservoir the lateral dimensions are restrained by the formation and no lateral displacement occurs – the pressure difference is felt only in the vertical direction.

Van der Knaap¹ determined the value of C_s by varying both P_e and P while keeping $P_e - P$ constant and obtained values for Belait sandstone of 2.05×10^{-7} to 2.37×10^{-7} psi^{-1} . For sandstone formations, Geertsma² recommends using the C_s value of quartz, which is about 1.9×10^{-7} psi^{-1} .³

Van der Knaap¹ also reports values of C_p for 15 different sandstones having porosity values of 15 to 30%. The data for C_p were obtained with P held at atmospheric pressure and P_e varied up to 8700 psi, and most of the data fell between the two lines shown in Fig. A.1. For values of P_e greater than 4350 psia, the value of C_p tended to remain constant. He notes a slight indication of higher values of C_p for lower porosities. Van der Knaap also recorded C_p values for 23 limestone core samples from a single well; the porosities varied from less than 1% to about 17%. In these experiments the porosity was shown to have a very significant effect on C_p . He reports the following equation for these specimens:

$$\frac{dV_p}{V_p} = \frac{7 \times 10^{-4}}{\phi} (P - P_e)^{0.42},$$

where the pressures are in MN/m^2 .

Most researchers in this field conduct tests in which P_e is held constant while P is varied. For these conditions we will define

$$C_b' = - \frac{1}{V_b} \left(\frac{\partial V_b}{\partial P} \right)_{P_e},$$

$$C_p' = - \frac{1}{V_p} \left(\frac{\partial V_p}{\partial P} \right)_{P_e}.$$

To show the relative value for compressibility from these different experimental techniques, the following relations from Geertsma⁴ will be used:

Fig. A.1. Pore compressibility data band for sandstone.

$$\frac{1}{V_p} \left(\frac{\partial V_p}{\partial P_e} \right)_P + \frac{1}{V_p} \left(\frac{\partial V_p}{\partial P} \right)_{Pe} = \frac{1}{V_b} \left(\frac{\partial V_b}{\partial P_e} \right)_P + \frac{1}{V_b} \left(\frac{\partial V_b}{\partial P} \right)_{Pe} = C_s ,$$

from which

$$C_p - C_p' = C_b - C_b' = C_s ,$$

$$C_p = C_p' + C_s ,$$

$$C_b = C_b' + C_s .$$

Another relation from Geertsma that we will use later is

$$\phi C_p = C_b - C_s .$$

For sandstone, McLatchie et al.⁵ report values of C_p' from 2.2×10^{-6} to 5.1×10^{-6} psi^{-1} . Hall⁶ reports values of C_p' for several limestone and sandstone cores; he found little difference between the two materials but noted that porosity has a significant effect on the C_p' values. His values of C_p' ranged from 10×10^{-6} psi^{-1} at $\phi = 2\%$ to 4.1×10^{-6} psi^{-1} at $\phi = 15\%$ and 3.4×10^{-6} psi^{-1} at $\phi = 25\%$. He does not report any effect of pressure in these tests, in which P_e was held constant at 3000 psi and P reduced from 1500 psi in 100- to 200-psi steps. Fatt⁷ also reports values of C_p' for several sandstone cores having porosity values in the range of 10 to 15%. He found that $P_e - P$ has a large effect on the C_p' value but does not correlate with the effect of porosity. At $P_e - 0.85P = 2000$ psi, he reports values of C_p' from 6×10^{-6} to 22×10^{-6} psi^{-1} , and at $P_e - 0.85P = 12,000$ psi, values of 1.5×10^{-6} to 9.0×10^{-6} psi^{-1} . Note that Fatt used $P_e - 0.85P$ rather than $P_e - P$.

Even if the properties of the reservoir material are known from laboratory tests, it is difficult to apply the data to a reservoir to obtain the change in $dV_p/(V_p dP)$. Van der Knaap¹ states that for a reservoir

$$-\frac{1}{V_p} \frac{dV_p}{dP} = -C_s + C_p \left(1 - \frac{dP_e}{dP} \right) ,$$

where the value of dP_e/dP depends on the reservoir boundary conditions. For the boundary conditions of no deformation in the lateral direction and a constant vertical stress (constant pressure induced by the overburden), both Van der Knaap¹ and Geertsma⁴ recommend a value of 1/2 for dP_e/dP . Then,

$$-\frac{1}{V_p} \frac{dV_p}{dP} = \frac{C_p}{2} - C_s = \frac{1}{2}(C_p' - C_s) .$$

For the boundary condition of uniform and constant stress in all directions (the same as in laboratory tests), the value of dPe is 0, and

$$-\frac{1}{V_p} \frac{dV_p}{dP} = C_p - C_s = C_p \text{ .}$$

Fatt⁷ argues that this condition, $dPe = 0$, is the initial condition of a reservoir before production and that as the reservoir is depleted the value of dPe/dP approaches 1/2.

To analyze the flow in a reservoir, the value of the specific storage coefficient, which is the change in the amount of liquid contained in a unit volume of reservoir per unit change in pressure, or $d\phi/dP$, must be known. This value can be approximated as follows:

$$-\frac{1}{V_p} \frac{dV_p}{dP} = -\frac{1}{\phi V_b} \frac{dV_p}{dP} = \frac{d\phi}{\phi dP} \text{ ,}$$

from which

$$\frac{d\phi}{dP} = \phi \left(\frac{C_p}{2} - C_s \right) \text{ .}$$

Adding the compressibility of the brine, C_e , then gives the storage coefficient:

$$S_s = \phi \left(C_e + \frac{C_p}{2} - C_s \right) \text{ .}$$

For compressibility values of $3.3 \times 10^{-6} \text{ psi}^{-1}$ for C_e , $7 \times 10^{-6} \text{ psi}^{-1}$ for C_p , and $2 \times 10^{-7} \text{ psi}^{-1}$ for C_s and a value of 0.2 for ϕ , S_s is $1.32 \times 10^{-6} \text{ psi}^{-1}$. This value of S_s varies from about two-thirds to one-tenth of those used by other authors in calculations of geopressed reservoir flow rates.

To check the above derived relations, we will use data and analyses presented by Teeuw⁸ and Geertsma² in studies of the compaction of reservoirs. Several authors neglect the effect of C_s on reservoir

compressibility, which makes the compressibility a function of only the overburden pressure, or the uniaxial compaction, of the reservoir. The compaction of a reservoir, Δh , caused by the overburden can be expressed as

$$\frac{\Delta h}{h} = C_m \Delta P \quad \text{or} \quad C_m = \frac{\Delta h}{h \Delta P},$$

where C_m is the uniaxial compaction coefficient and ΔP is the reduction in the reservoir pressure. Note that C_m represents the specific storage coefficient for the rock structure; that is, it corresponds to our value of $\phi(C_p/2 - C_s)$ or, neglecting C_s , $\phi C_p/2$. Another expression for C_m is

$$C_m = \frac{1}{3} \left(\frac{1 + \nu}{1 - \nu} \right) \left(1 - \frac{C_s}{C_b} \right) C_b$$

or

$$C_m = \frac{1}{3} \left(\frac{1 + \nu}{1 - \nu} \right) (C_b - C_s) = \frac{1}{3} \left(\frac{1 + \nu}{1 - \nu} \right) (\phi C_p),$$

where ν is Poisson's ratio. Teeuw carried out experiments to determine the values of C_m and ν . For sandstone, he reports values of ν from 0.26 to 0.35. He also notes that the ratio of the specimen deformation resulting from uniaxial compaction to that from hydrostatic tests equals $1/3[(1 + \nu)/(1 - \nu)]$, which for $\nu = 0.3$ is 0.61 — a good check with the $1/2$ recommended by Van der Knaap¹ and Geertsma⁴ in earlier papers.

Geertsma,² in studies of reservoir subsidence, presents data for C_m for many core samples of both limestone and sandstone. He found that values varied widely depending on the degree of consolidation, porosity, and effective vertical stress. For sandstone with 20% porosity and an effective vertical stress corresponding to a burial depth of about 3000 m for normally pressured reservoirs, he reports values of C_m ranging from 2.8×10^{-7} to $12.0 \times 10^{-7} \text{ psi}^{-1}$ for well-consolidated rock and 7.1×10^{-7} to $23.3 \times 10^{-7} \text{ psi}^{-1}$ for semiconsolidated rock. The data presented for unconsolidated material did not include values for samples with porosity as low as 20%. However, if the data are extrapolated to 20%, the range of C_m is from 21×10^{-7} to $71 \times 10^{-7} \text{ psi}^{-1}$. Taking the average value of

the data points shown by Geertsma, the value of C_m for consolidated rock is about $5 \times 10^{-7} \text{ psi}^{-1}$ and for semiconsolidated rock is about $10.6 \times 10^{-7} \text{ psi}^{-1}$. Note that our value for the specific storage coefficient corresponds to a C_m value equal to $6.6 \times 10^{-7} \text{ psi}^{-1}$, a value greater than that of consolidated rock but less than that of the semiconsolidated specimens.

Thompson, Menezes, and Gray⁹ report data for uniaxial tests of a Berea sandstone (mean initial porosity of 19.6%). These tests showed a porosity reduction of about 1.5% for a uniaxial load of 8000 psi. This corresponds to a C_m value of $3.9 \times 10^{-7} \text{ psi}^{-1}$, which is in the range of data reported by Geertsma for consolidated rock and about 60% of the reference value used in this study.

The basic question concerning the compressibility of geopressed reservoirs is whether their properties are similar to those of normally pressured systems. Harville and Hawkins¹⁰ suggest that the rock compressibility of geopressed reservoirs may be several times that of normal systems during the early period of drawdown. They attribute this to inelastic compaction, or rock failure. However, the test results reported by Thompson, Menezes, and Gray for sandstone samples showed elastic behavior for loads up to 9000 psi. This area obviously needs more investigation. For our study, we will use the value of $7 \times 10^{-6} \text{ psi}^{-1}$ for C_p and a specific storage coefficient of $1.32 \times 10^{-6} \text{ psi}^{-1}$.

Pressure Drawdown in an Aquifer of Infinite Area with a Constant Well Flow Rate

Hantush¹¹ gives solutions for several cases for the drawdown, $P - P_1$, in the vicinity of a constant-flow well draining an elastic aquifer of infinite radius.* The equation for the case of no inflow to the aquifer is

$$P - P_1 = \frac{Q\mu}{4\pi g\rho k h} Ei\left(\frac{-r^2\mu Ss}{576gkt}\right). \quad (1)$$

*The nomenclature used in this and the following sections is defined at the end of the appendix.

The term $Ei(Z)$ is the exponential integral

$$-Ei(-Z) = \int_Z^{\infty} \frac{e^{-t}}{t} dt .$$

For all cases of interest, the value of Z will be small and the value of $Ei(Z)$ can be approximated by¹²

$$Ei(-Z) \approx -\ln\left(\frac{1}{1.781Z}\right) .$$

Thus, Eq. (1) is approximately

$$P - P_1 = -\frac{Q\mu}{4\pi g \rho k h} \ln\left(\frac{576 g k t}{1.781 r_w^2 \mu S_s}\right) . \quad (2)$$

and the pressure at the well becomes

$$P_w - P_1 = -\frac{Q\mu}{4\pi g \rho k h} \ln\left(\frac{576 g k t}{1.781 r_w^2 \mu S_s}\right) .$$

In our case, we are interested in the pressure at ground level, and two additional terms, the hydrostatic head and the friction loss in the well, must be included. The pressure at the surface can then be expressed by

$$P_g = P_1 - P_h - P_f - \frac{Q\mu}{4\pi g \rho k h} \ln\left(\frac{576 g k t}{1.781 r_w^2 \mu S_s}\right) . \quad (3)$$

Although these equations include compressibility effects, they neglect the effects of any variation in the fluid density, ρ , and viscosity, μ , on the flow rate or pressure gradient in the reservoir. As will be noted in the next section, these variations are small. The permeability coefficient, k , is also assumed to be constant.

Equation (2) can be used further to determine the radius to which the reservoir drawdown is felt. If the drawdown, $P - P_1$, is set equal to zero, then,

$$\ln\left(\frac{576gkt}{1.781r_o^2\mu Ss}\right) = 0$$

and

$$t = \frac{1.781r_o^2\mu Ss}{576gk} . \quad (4)$$

For a finite reservoir, Eq. (3) is valid until the drawdown reaches the outer radius of the reservoir. For any period of time greater than that given by Eq. (4), a different solution is required.

Equation (3) can also be written as

$$P_1 - P_h - P_f - P_g = \frac{0.014Q}{kh} \ln\left(71.8 \frac{kt}{r_w^2 Ss}\right) ,$$

where P is given in psi, Q = bbl/day, k = darcys, h = ft, t = days, r = ft, Ss = psi⁻¹; and the values used for μ and ρ are 0.198 cP and 59.8 lb/ft³. For these units, Eq. (4) becomes

$$t = \frac{0.014r_o^2 Ss}{k} .$$

Pressure Drawdown in an Aquifer of Finite Area with a Constant Well Flow Rate

After the drawdown has reached the outer radius of the reservoir, the pressure gradient, dP/dr , will shift from one that varies with time to one that is independent of time; that is, the pressure at all radii will be decreasing at a constant rate. This constant rate of pressure decline results from the assumption that the specific storage coefficient is independent of the pressure.

After some time period given by Eq. (4), the pressure gradient in the reservoir approaches

$$\frac{dP}{dr} = - \frac{q\mu}{g\rho kA} , \quad (5)$$

where the mass flow rate, q , at any radius, r , is

$$q = \frac{Q(r_o^2 - r^2)}{(r_o^2 - r_w^2)} , \quad (6)$$

and

$$A = 2\pi r h . \quad (7)$$

Substituting Eqs. (6) and (7) into Eq. (5) gives

$$dP = - \frac{Q\mu(r_o^2 - r^2) dr}{2\pi(r_o^2 - r_w^2)g\rho khr} . \quad (8)$$

The value of the viscosity, μ , and the brine density, ρ , vary slightly with pressure, as shown in Table A.1. However, the value of μ/ρ changes only about 2% for a pressure change of 6000 psi, and the effect of this change on the pressure gradient will be neglected.

Integration of Eq. (8) gives

$$P = P_o - \frac{Q\mu r_o^2}{2\pi(r_o^2 - r_w^2)g\rho kh} \left[\ln \frac{r}{r_o} - \frac{1}{2r_o^2}(r^2 - r_o^2) \right] . \quad (9)$$

For reservoir sizes of interest, $r_o \gg r_w$, Eq. (9) can be simplified to

$$P = P_o - \frac{Q\mu}{2\pi g\rho kh} \left[\ln \frac{r}{r_o} - \frac{1}{2r_o^2}(r^2 - r_o^2) \right] ; \quad (10)$$

the pressure at the well, P_w , is

$$P_w = P_o - \frac{Q\mu}{2\pi\rho khg} \left(\ln \frac{r_o}{r_w} - \frac{1}{2} \right) . \quad (11)$$

The average pressure, $\bar{P}$, in the reservoir can be determined from Eq. (9) and the relation

$$\bar{P} = \frac{\int P dA}{\int dA} .$$

Carrying out these operations gives

$$\bar{P} = P_o - \frac{Q\mu}{8\pi\rho gh} . \quad (12)$$

The average pressure in the reservoir can also be determined from the total production; that is,

$$Qt = (P_1 - \bar{P}) Ss V_t \rho$$

or

$$\bar{P} = P_1 - \frac{Qt}{\pi r_o^2 h \rho Ss} . \quad (13)$$

Combining Eqs. (12) and (13),

$$P_o = P_1 - \frac{Qt}{\pi r_o^2 h \rho Ss} + \frac{Q\mu}{8\pi g \rho kh} . \quad (14)$$

Then, substituting Eq. (14) into Eq. (11),

$$P_w = P_1 - \frac{Q\mu}{2\pi g\rho kh} \left(\ln \frac{r_o}{r_w} - \frac{3}{4} \right) - \frac{Qt}{\pi r_o^2 h \rho Ss} .$$

If the hydrostatic head and friction loss are included, the pressure at ground level becomes

$$P_g = P_1 - P_h - P_f - \frac{Q\mu}{2\pi g\rho kh} \left(\ln \frac{r_o}{r_w} - \frac{3}{4} \right) - \frac{Qt}{\pi r_o^2 h \rho Ss} . \quad (15)$$

Equation (15) is of the same form as the approximate solution reported by Bernard.¹³ However, the manner in which the reservoir compressibility is determined and its value are different from those Bernard used, and the time allowed for the pressure drawdown to reach the reservoir perimeter also differs. There is actually a transition period when the pressure gradient throughout the reservoir changes from that given by Hantush and approaches that given by Eq. (15).

If mixed units, $P = \text{psi}$, $Q = \text{bbl/day}$, $k = \text{darcys}$, $h = \text{ft}$, $r = \text{ft}$, $Ss = \text{psi}$, and $t = \text{days}$, are used, Eq. (15) can be written as

$$P_g = P_1 - P_h - P_f - \frac{0.028Q}{kh} \left(\ln \frac{r_o}{r_w} - \frac{3}{4} \right) - \frac{5.615Qt}{\pi r_o^2 h Ss} .$$

Pressure Drawdown in an Aquifer of Infinite Area with a Constant Well Flow and Shale Water Influx

Hantush¹¹ also gives a case that can be used to predict the drawdown of a reservoir with shale water inflow. His solution for this case is

$$P_1 - P = \frac{Q\mu}{4\pi g\rho kh} H(U, \beta) , \quad (16)$$

where $H(U, \beta)$ is an infinite integral that he tabulates and graphs for a limited range of values,

$$U = \frac{r^2 \mu Ss}{576 k g t} ,$$

and

$$\beta = \frac{r}{4} \left[\sqrt{\frac{k' Ss'}{k Ss h^2}} + \sqrt{\frac{k'' Ss''}{k Ss h^2}} \right].$$

The primes denote the properties of the upper and lower shale formations. This solution is valid for times less than both

$$\frac{Ss' \mu (h')^2}{10 k' g \rho} \quad \text{and} \quad \frac{Ss'' \mu (h'')^2}{10 k'' g \rho}.$$

When values of 10^{-4} md for both k' and k'' and 1.32×10^{-4} psi⁻¹ for Ss' and Ss'' are assumed, this solution is valid for $t = 20$ years if the shale formations are at least 42 ft thick.

If mixed units are again used and the hydrostatic head and friction loss added, Eq. (16) becomes

$$P_1 - P_h - P_f - P_g = \frac{0.028Q}{kh} H(U, \beta).$$

Well Flow Rate in an Aquifer of Infinite Area with a Constant Wellhead Pressure

Jacob and Lohman¹⁴ report the well flow rate for an aquifer of infinite area operating with a constant drawdown. Their solution for this condition is

$$Q = \frac{2\pi k g \rho h}{\mu} (P_1 - P_w) G(\alpha), \quad (17)$$

where $G(\alpha)$ is an integral for which the authors present tabulated values and

$$\alpha = \frac{k g t}{S s \mu r_w^2}.$$

This equation can be rewritten to include the hydrostatic head, P_h , and well friction loss, P_f :

$$Q = \frac{2\pi k g \rho h}{\mu} (P_1 - P_h - P_f - P_g) G(\alpha) . \quad (18)$$

For this case, in which the value of Q is a variable, the value of P_f will depend on Q . Equation 18, if mixed units are used, can be written as

$$Q = 35.7kh(P_1 - P_h - P_f - P_g)G(\alpha) .$$

Nomenclature

C_e	Compressibility coefficient of brine	l^2/F
C_s	Compressibility coefficient of sandstone	l^2/F
C_p	Compressibility coefficient of pore volume	l^2/F
g	Conversion factor (= 32.17)	mL/Ft^2
h	Reservoir thickness	l
k	Permeability coefficient	l^2
P	Pressure	F/l^2
P_f	Friction pressure loss	F/l^2
P_h	Hydrostatic pressure difference — ground level to reservoir	F/l^2
P_g	Pressure at ground level	F/l^2
P_o	Pressure at reservoir outer perimeter	F/l^2
P_w	Pressure at well	F/l^2
P_1	Initial reservoir pressure	F/l^2
$\bar{P}$	Average reservoir pressure	F/l^2
q	Mass flow rate	m/t
Q	Well mass flow rate	m/t
r	Radius	l
r_o	Reservoir outer radius	l
r_w	Well radius	l
S_s	Specific storage coefficient	l^2/F
t	Time	t
V_t	Total volume of reservoir	l^3
ϕ	Porosity of reservoir	
ρ	Density of brine	m/l^3
μ	Viscosity of brine	m/lt

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Appendix B

EFFECT OF RESERVOIR PROPERTIES ON RESERVOIR PRODUCTIVITY

In illustrating the effect of the various reservoir properties on the productivity of a well or reservoir, we will assume the following conditions:

Initial pressure = 12,000 psi,

Average depth = 14,000 ft,

Temperature = 300°F,

Wellhead pressure = 250 psi,

Average viscosity

in reservoir = 0.198 cP,

in well bore = 0.190 cP,

Hydrostatic head = 5640 psi.

The friction loss in the well bore for flows of 20,000, 40,000, and 80,000 bbl/day is 120, 445, and 1655 psi for a 6-in.-diam well and 20, 60, and 230 psi for a 9-in.-diam well. The wellhead pressure is assumed to be 250 psi, the pressure necessary to allow sufficient head to deliver the fluid to a central plant and to suppress boiling in the 300°F fluid. This assumption is used to calculate the life of the well and would rule out the recovery of hydraulic energy near the end of life. Appendix A gives the equations used in this analysis. These equations, with units converted to those commonly used in the literature, were used in preparing the illustrations in this section.

Flow Rate and Life of a Single Well

Figure B.1 shows the well production life for flow rates of 20,000, 40,000, and 80,000 bbl/day as a function of reservoir permeability and size. The wellhead pressure is assumed to be 250 psi for all cases, and the end of life is that time when the well will no longer deliver the specified flow at this pressure. When this occurs, however, the flow rate could be reduced and production continued at lower rates. During the early production period the reservoir acts as an infinite area

Fig. B.1. 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 storage coefficient of 1.32×10^{-6} psi⁻¹.

system until the drawdown reaches the outer perimeter of the reservoir. After this time the pressure gradient in the reservoir goes through a transition period, and a new gradient is established that remains approximately constant with time. For the 80,000-bbl/day case, a reservoir of infinite size would require a permeability of 33 md for a 20-year life. A reservoir with a radius of 8 miles (201 sq miles) would require a permeability of about 55 md for a 20-year life, whereas a 4-mile radius would be too small regardless of the value of permeability. To obtain a 20-year life at 40,000 bbl/day requires a reservoir radius of about 4 to 8 miles and a permeability of 15 to 20 md. The interesting feature of the lower flow rates is that an extreme change in life results from a small change in permeability for an infinite area. For the 40,000-bbl/day case, an increase of only 1 md increases the life by a factor of 7 or 8.

Figure B.2 illustrates the effect of increasing the well diameter from 6 to 9 in. on the life of a well for flow rates of 40,000 and

Fig. B.2. Effect of well diameter on well life for a reservoir thickness of 200 ft and a storage coefficient of 1.32×10^{-6} psi⁻¹.

80,000 bbl/day. The larger well size makes an enormous difference in the 80,000-bbl/day case as a result of both a smaller friction loss in the well and the gain of the inner 1-1/2 in. of the reservoir. The change is much less for the 40,000-bbl/day case, and for 20,000 bbl/day (not shown) the difference would hardly show on the scale used in the figure.

The effect of reservoir thickness is shown in Fig. B.3. In general, the permeability required for a given flow rate or production life is inversely proportional to the thickness. Reservoir permeability is sometimes expressed as the product of the permeability and depth, kh ; thus, low permeability can be offset by thicker formations.

Figure B.4 shows the effect of reservoir permeability on the well-head pressure as a function of time for a reservoir with a 4-mile radius (50.3 sq miles) and an infinite area. Note that the life of a well in a reservoir with a permeability of 10 md is too short for the drawdown to be felt at the 4-mile radius. Note also the extreme sensitivity of the well-head pressure to the permeability, even for very short times.

ORNL-DWG 79-8943

Fig. B.3. Well life as a function of reservoir thickness, permeability, and radius for a well diameter of 6 in., well flow rate of 40,000 bbl/day, and storage coefficient of $1.32 \times 10^{-6} \text{ psi}^{-1}$.

The effect of the specific storage coefficient on the wellhead pressure and life of a well is illustrated in Fig. B.5 for three values of the coefficient and a reservoir radius of 4 miles. The lowest value of the coefficient shown here corresponds to that of the compressibility of the water; that is, if the compressibility of the rock structure were 0, the coefficient would be $6.6 \times 10^{-7} \text{ psi}^{-1}$. The value of $1.32 \times 10^{-6} \text{ psi}^{-1}$ is the base case used in this study and is typical of sandstone formations in normally pressured reservoirs; the highest value is twice that of the base case. Note that the life of the well is directly proportional to the coefficient and that the coefficient has little effect on the sharp drop in pressure at the start of production — the drop is primarily a function of the permeability. Also, for a permeability of 20 md, the time that the wellhead pressure exceeds 2000 psi is about one-third of the total life of the well. The 2000-psi pressure is often quoted or used to calculate the output of a hydraulic turbine in recovering the pressure energy of the reservoir.

Fig. B.4. Wellhead pressure as a function of operating time, reservoir permeability, and radius for a well diameter of 6 in., flow rate of 40,000 bbl/day, reservoir thickness of 200 ft, and storage coefficient of $1.32 \times 10^{-6} \text{ psi}^{-1}$.

Figure B.6 shows the effect of shale water influx on the wellhead pressure as a function of time. The conditions for this case are a flow rate of 40,000 bbl/day; reservoir permeability, thickness, and size of 20 md, 200 ft, and infinite area; a well diameter of 6 in.; and a reservoir specific storage coefficient of $1.32 \times 10^{-6} \text{ psi}^{-1}$. The permeability and specific storage coefficient of the surrounding shale are 10^{-4} md and $1.32 \times 10^{-4} \text{ psi}^{-1}$. The upper and lower shale thickness required for the curves of Fig. B.6 to be valid for times up to 20 years is 42 ft (Appendix A). As noted earlier, the shale values may be optimistic: if they are reduced by one order of magnitude, the shale water influx would have a negligible effect on well life up to 20 years.

Figure B.7 displays the effect of several parameters in a different manner. For this figure, the wellhead pressure is held constant at 250 or 2000 psia, and the flow rate shown as a function of time for reservoir

Fig. B.5. Wellhead pressure as a function of operating time and storage coefficient for a well diameter of 6 in., flow rate of 40,000 bbl/day, reservoir permeability of 20 md, thickness of 200 ft, and radius of 4 miles.

permeabilities of 10 and 20 md. The other conditions are a 6-in. well diameter, a 200-ft formation thickness, a specific storage coefficient of 1.32×10^{-6} psi $^{-1}$, and an infinite area. This figure again emphasizes the sensitivity of the flow rate to the permeability. Also, because the time scale is logarithmic, the flow rate drops sharply during the first few days of production. This could account for the data reported by Swanson et al.¹ for the unsuccessful well completion attempts that they attributed to two-phase flow. In very tight formations, the flow would be small and would decrease rapidly in a matter of hours.

These calculations are intended to show the effects of the various parameters on the production rate and life of a well. They emphasize the

Fig. B.6. Effect of shale water inflow on wellhead pressure.

importance of reservoir size, both thickness and area; the reservoir permeability; and its specific storage coefficient. This analysis is, though, for only a single well, which would be insufficient to support the facilities necessary for economic exploitation of a reservoir.

Flow Rate and Life of a Reservoir

To add perspective to these calculations, we will examine the effects of the reservoir properties on the life, resource recovery, and economics of a reservoir. Bebout,² in an evaluation of reservoir requirements, states:

A potential geothermal reservoir along the Texas Gulf Coast should have a volume of at least three cubic miles (which translates into a cumulative sand thickness of greater than 300 feet

Fig. B.7. Well flow rate as a function of time for a constant well-head pressure.

and areal extent of 50 square miles), greater than 250°F uncorrected subsurface fluid temperature, and permeability greater than 20 millidarcies.

For this analysis we will use a reservoir with a radius of 4 miles (50.3 sq miles), a thickness of 315 ft, a permeability of 20 md, a porosity of 0.2, a specific storage coefficient of $1.32 \times 10^{-6} \text{ psi}^{-1}$, a wellhead pressure of 250 psi, and a well diameter of 6 in. The total inventory of the 3 cubic mile reservoir is 1.57×10^{10} bbl, and if the methane content were 40 ft³/bbl, the reservoir would contain about 6.3×10^{11} ft³ of gas.

Figure B.8 shows the results of an analysis of this reservoir and gives the life and percent recovery of the inventory as a function of the

Fig. B.8. Reservoir life and resource recovery as a function of well flow rate and number of wells for a reservoir volume of 3 cubic miles.

well flow rate and number of wells. This analysis is somewhat optimistic in that it assumes, for the multiple-well cases, that each well produces from its own area and does not adversely affect the other wells. This figure shows that a single 70,000-bbl/day well will produce for only 6.2 years and a 50,000-bbl/day well for only 17.5 years. For the 30,000-bbl/day case, a single well will last about 42 years, whereas two would last 21 years. The life of the reservoir for a fixed production rate is almost inversely proportional to the number of wells; that is, the total brine recovered does not change much as the number of wells is increased.

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Appendix C

CONVERSION FACTORS

Quantity	Commonly used units	Conversion factors
Volume	barrel	42 gal
		0.1590 m^3
		5.615 ft^3
Pressure	psi	$6.895 \times 10^{-3} \text{ Pa}$
		$7.031 \times 10^{-2} \text{ kg/cm}^2$
Permeability	darcy	$1.06 \times 10^{-11} \text{ ft}^2$
		$9.87 \times 10^{-13} \text{ m}^2$
Flow rate	bbl/day	$6.499 \times 10^{-5} \text{ ft}^3/\text{sec}$
		$1.840 \times 10^{-6} \text{ m}^3/\text{sec}$
Viscosity	centipoise	$6.72 \times 10^{-4} \text{ lb/sec}\cdot\text{ft}$
		$1.00 \times 10^{-3} \text{ Pa}\cdot\text{sec}$

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