EPRI-TC-80-907-9

# Proceedings of the Fourth Annual Geothermal Conference and Workshop

EPRI

EPRI TC-80-907
TC-80-907
Conference Proceedings
December 1980

Keywords:
Geothermal
Research Projects
Power Plants

MASTER

Prepared by
Altas Corporation
Santa Cruz, California

ELECTRIC POWER RESEARCH INSTITUTE

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# AN EVALUATION OF THE AVAILABLE ENERGY POTENTIAL OF THE GULF COAST GEOPRESSURED ZONES

EPRI RP1272

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Introduction The geopressured zones presently under serious study in the U.S. are tertiary sediments in the Gulf Coastal basin which are water saturated and exhibit pressures significantly greater than hydrostatic. These sediments are primarily shale, interbedded with sandstone. The top of the geopressured zone is frequently near 10,000 ft. or so, and extends to indeterminate depths. The water contained in these zones is at a moderately elevated temperature and, more significantly, appears to contain dissolved methane at near-saturation values. Conceptually, wells drilled into the geopressured zone might be expected to produce water without pumping, due to the high pressures. The dissolved methane could then be separated at the surface and used conventionally as natural gas. The water may contain sufficient heat to provide a useful source of geothermal energy, and the hydraulic energy might also provide useful work.

Development of the geopressured/geothermal resource is largely dependent upon production characteristics of geopressured reservoirs. These in turn are intimately related to properties of the formations, and can be defined within reasonable limits.

Characteristics of Gulf Coast Sediments The Gulf Coast basin, from tertiary times to the present, has represented conditions which are generally similar to those existing along the Coast today. The land is in a continual state of subsidence and sediments brought into the Gulf of Mexico by the major river systems are worked and reworked by long-shore currents into a series of coastal sandbars and barrier islands in an environment of which the present Texas Coast is thought to be a model. This normal pattern of subsidence has been accompanied by periods of high deposition similar to that occurring in the Mississippi Delta today. The bars and islands were covered by new layers of clastic sediments while the edge of the basin further subsided under the enormous weight, and large growth fault systems formed near the down-dip edge of these deposits. The subsurface sandstones which became the basis for the deep aquifer systems are the remnants of the ancient sandbars and the stream channels of the deltaic environment.

When sections of these sandstone deposits are isolated within a shale envelope, geopressures are believed to result. Bruce[1], for instance, has provided an excellent description of this depositional environment and of the role of growth faults in the formation of geopressured sediments. The depositional style of the tertiary strata along the Texas Gulf Coast as described by Bruce is shown in Figure 1.

Energy Contained in the Geopressured Zones Speculation about the geopressured sediments has resulted in a number of estimates of the energy they might contain. The most comprehensive of these estimates is the result of work performed by the U.S. Geological Survey. The most recent of the USGS reports, by Wallace et al. [2], has defined the resource base summarized in Table I. The total estimated contained methane, 59,700 trillion cu.ft. (TCF), is a value nearly thirty times higher than the total known natural gas reserves in the United States. The estimate of 101,400 quads of thermal energy would make the geopressured zone the largest single known geothermal resource in the United States.

However, it is important to understand the assumptions Wallace made in arriving at these estimates, and to place the numbers in perspective.

Generalized Gulf-Coast Model Gulf Coast sediments may be considered to be completely saturated with water; that is, the water table is near the surface everywhere along the coast, and extends to indeterminate depth within the pore space of individual rock formations. Wallace first made estimates of the total water contained in the rocks of interest based on assumed values of porosity. This total contained-water then became the basis for the

Table I. Energy-in-Place Estimates, USGS Circ. 790 (Wallace et al, 1978)

| Location | Area $mi^2$ | Methane ($10^{12}$ SCF) Sand | Shale | Total | Thermal ($10^{15}$ BTU) Sand | Shale | Total |
|---|---|---|---|---|---|---|---|
| Total, onshore & offshore | 120,000 | 5,700 | 54,000 | 59,700 | 10,430 | 91,000 | 101,400 |
| Onshore only | 70,000 | 3,052 | 35,100 | 38,152 | 5,490 | 57,000 | 62,490 |

estimated resource base.

Contained Methane Hydrocarbons are slightly soluble in water, and methane is the most soluble of all. Studies have indicated that oil-field type brines in the Gulf Coast generally contain dissolved methane. The actual degree of solubility is dependent upon temperature and pressure and, consequently, the water in the geopressured zones should contain an abnormally large amount of dissolved methane. Wallace estimated the temperature and pressure throughout the geopressured regime, and assumed the water was saturated with methane under these conditions. Although the data base on which this assumption was made is very limited, the data are consistent, and tend to be verified by recent work. The saturation values of methane in geopressured brines appear to be in the range of 20 to 40 SCF per barrel of water.

Thermal Energy The estimate of the contained thermal energy was based on the total heat content of the water above 15°C, although this is a temperature much lower than any practical utilization temperature for the brine. Temperatures in the geopressured zone range from less than 100°C to more than 200°C, but reservoir quality sands seldom exhibit temperatures as high as 150°C.

Sand and Shale On the basis of a regional study of over 3,000 well logs, Wallace estimated that of the total resource base, about 10% was contained in sandstones, the remainder in shale. Since there is no foreseeable prospect of recovering any useful energy from Gulf Coast shales, a much more meaningful view of the resource is the estimate of the energy in the sands, also given in Table I. This estimate cuts the useful resource by about one order of magnitude.

Recoverable Energy The amount of energy recoverable from the resource base (without regard to cost) is dependent upon the total volume of fluid which can be produced from production wells. Since the only practical production technique consists of flowing the wells and depleting the reservoir pressure, recoverable energy is predictable from reservoir parameters. Randolph [3] has shown that production from a geopressured well utilizing a range of realistic Gulf Coast reservoir parameters will range from less than 1% to a maximum of about 4% of the total contained energy (most of the fluid, as well as the dissolved gas, will remain in the formation after the pressure is depleted). Using the more optimistic of these numbers, the recoverable energy from Wallace's resource base would amount to a maximum of about 228 TCF methane and 420 quads thermal, of which roughly 40% would lie offshore.

These are still sizeable numbers, if even a moderate fraction of the latter values can ultimately be recovered.

Basis for Exploitation of Geopressure
Geopressured production wells must be capable of certain minimum performance to produce energy at a cost competitive with other energy sources, even in the relatively distant future. First, the wells would have to be drilled and completed in a productive sandstone at reasonable cost. Next, the flow of hot water would have to be substantial, and to last for an extended period of time to amortize the investment. Finally, the energy separated from the water would be required to provide sufficient revenue to pay the operating expense including spent brine disposal, amortization of the investment, and an adequate rate of return to justify the risk. The reservoir characteristics which would be required to provide such performance have been the subject of a number of recent investigations.[3-6] In general, the conclusions of these studies indicate that flow rates in the range of at least 40,000 bbl/day or more continuously for 20 years or so would be required to compete with the current cost of fuel ($2-$3/$10^6$BTU). Flow rates averaging only 10,000 bbl/day for 20 years or so might yield energy at costs in the range of $8/$10^6$BTU, a cost which conceivably could be of importance in the future. Energy costs above $10/million BTU (in 1980 dollars) are probably beyond the realm of current interest.

Reservoir Parameters The capability of a geopressured reservoir to produce fluid depends upon a combination of formation parameters, principal among which are porosity, permeability, formation thickness, compressibility and drainage volume. In general, quasi steady-state reservoir equations are adequate to predict the performance of geopressured water reservoirs.[7,8] Samuels [9] gives an excellent discussion of the reservoir aspects of geopressured fluid production and, summarizing previous work, shows that the performance of a geopressured well can be described by an equation of the form

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

where

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

Examination of this equation reveals that the flow rate, Q, is largely dependent upon the pressure and the permeability-thickness product, kh, while the pressure behavior with time (duration of flow) is mainly a function of the volume of fluid present, $\pi r_e^2 h\phi$, and the formation compressibility.

Samuels has given a graphic summary of reservoir behavior as a function of reservoir size and permeability. His representation is reproduced in Figure 2. Here it can be noted that for a sand 200 ft. thick, the minimum reservoir permeability that will yield an extended flow rate of 40,000 bbl/day is 10 mD. For a well to flow for as long as 20 years at this 40,000 bbl/day rate would require a minimum reservoir radius of about 8 miles (200 sq. mi. area) regardless of the permeability.

Probable Reservoir Characteristics A considerable amount of study of the formation parameters of potential geopressured reservoirs has been performed over the past several years, based on an enormous volume of data generated by more than 300,000 petroleum wells drilled in the Gulf Coast over the past 50 years. The results of these studies have produced a reasonably consistent picture of the range of values likely to be encountered in the production of geopressured water sands.

Porosity The subsurface sandstone deposits represent the only useable reservoirs for either petroleum or geothermal reservoirs, since shale is virtually impermeable. The initial porosity of Gulf Coast sands is about 40 to 45% and as subsidence and burial occur, this value is continuously reduced by compaction and cementation. Reduction in porosity with depth on the Gulf Coast as found by Loucks et al. [10] is summarized in Figure 3. The reduction typically amounts to 1.25 porosity-percent or so per 1,000 ft. of depth. The range of porosity values found in "good" geopressured water sands is from 10% or so in the South Texas Vicksburg formation, to 30% or more in the best prospects in South Louisiana. An average value for many prospective areas is about 20%. Porosity of geopressured sands is important primarily because of its effect on permeability, a crucial production parameter.

Permeability The permeability of Gulf Coast sandstones, although not a direct function of porosity, is closely related. As porosity is reduced, permeability tends to suffer drastically. In-situ permeability is known to exhibit a log-normal distribution over any particular depth interval, and while there may be individual sandstone elements exhibiting high permeability even at depth, over an extended depth interval average permeability cannot be expected to depart drastically from the statistical mean. This fact is graphically portrayed by Loucks in Figure 4. Permeability frequently is shown to decline about one order of magnitude for each two to three thousand feet of depth. Swanson et al. [11] have shown that of a large number of deep geopressured gas sands studied in South Texas, none exhibited in-situ permeability as great as 10 mD, while the average was only about 1 mD. In South Louisiana, measured permeability values range over several orders of magnitude. Average values in good, potentially productive zones may vary from 100 mD at the top of geopressure near 10,000 feet, to 10 mD at 13,000 feet, and 1 mD at 16,000 feet.

Reservoir Volume Individual geopressured reservoirs are formed from sandstone deposits which have undergone considerable modification in the process of burial to great depth. Faulting is common, and individual sand bodies tend to be relatively small. Doscher et al. [12] summarize previous work on the size of Gulf Coast petroleum reservoirs and conclude that the volume of potential geothermal reservoirs in the geopressured zone is likely to be no more than 0.3 to 1.5 cu. miles. Of the 103 largest petroleum reservoirs known in the offshore U. S. Gulf Coast, they report only three with an area as large as 8 sq. miles, and a maximum reservoir volume of only 0.05 cu. miles. While the size and volume of petroleum reservoirs may not be indicative of the size and volume of geopressured aquifers, it is consistent with the origin of the sandstone deposits and the complex faulting characteristic of the Gulf Coast.

The single-well drainage volume is probably the most serious unknown in accurate assessment of the geopressure/geothermal resource.

Probable Performance of Geopressured Reservoirs Based on the reservoir equations discussed previously, it is possible to make a probability analysis and predict the performance of geothermal wells under a range of conditions.

Such a probability analysis, utilizing a Monte Carlo routine, has been applied to a number of known geopressured prospects in the Gulf Coast, the locations of which are shown in Figure 5. In such a procedure, minimum, maximum and most likely values are assigned to the 9 stochastic reservoir parameters. Then by an iterative process, calculations of flow rate are made and a probability distribution plotted. The results of such an analysis for the S.E. Pecan Island prospect in Louisiana are shown in Figure 6. This prospect, one of several described by Bernard [13] in an assessment study of Louisiana geopressured zones, is particularly interesting because of its large sand volume and extensive overall area (67 square miles). Laminated shale and sand occur from 13,500 feet to 17,500 feet, with a total estimated sand volume of 9 cubic miles. Geologically, it represents a destructive delta of unusually large size, although the individual reservoirs are undoubtedly segmented by faulting and other depositional features. A considerable amount of conventional gas production in this vicinity also makes it possible to estimate reservoir parameters with reasonable assurance. The principal unknown in S.E. Pecan Island is the single-well drainage area.

The probability analysis shows that wells drilled in this prospect have a 60% probability of flowing at 14,000 bbl/day for twenty years, and a 10% probability of flowing at 50,000 bbl/day. The average of all values is 22,172 bbl/day.

Selecting parameters representative of the best part of the reservoir (net sand thickness of 980 feet), and assuming an optimistic single well drainage area of 13 sq. miles, the "best" well in the prospect should perform as shown in Figure 7. The parameters used in this analysis are given in Table II. This well should flow at a rate of 50,000 bbl/day for 11-1/2 years, at which time surface pressure should be depleted to 300 psi. After that time, the production rate will continually decline as shown in the figure. At the end of twenty years the well will still be flowing at a rate of nearly 20,000 bbl/day. After 20 years, the well will have produced more than 30 million barrels of water and 10 billion cubic feet of natural gas.

It must be pointed out that this performance represents a highly optimistic case, in one of the most promising geopressured prospects known. The assumed dissolved methane, 35 SCF/bbl, is higher than any actually produced by test results to date. The assumed permeability-thickness product, 9800 mD-ft., is very high. One can be relatively assured that of all the resource base estimated by Wallace, only a small fraction can be contained in reservoirs with this quality.

Table II. Reservoir and Well Parameters, Single Well Development, S.E. Pecan Island, LA Prospect, Optimistic Drainage Area

| | |
|---|---|
| Well Depth | 17,500 feet |
| Average Production Depth | 15,800 feet |
| Average Reservoir Pressure | 13,500 psi |
| Average Hydrostatic Pressure | 7,350 psi |
| Surface Pressure (minimum) | 300 psi |
| Average Fluid Temperature at Surface | 290°F |
| Well (production tubing) Diameter | 0.46 feet (5-1/2"OD) |
| Drainage Area | 13 $mi^2$ (8400 acres) |
| porosity | 23% |
| permeability | 10 mD |
| Compression Drive Coefficient | $5x10^{-6}$ $psi^{-1}$ |
| effective sand thickness | 980 feet |
| dissolved methane | 35 SCF/bbl |
| Initial Production Rate | 50,000 bbl/day |

Economics Assuming a production well with the characteristics of the optimistic S.E. Pecan Island well just described, the economics of production can be established based on the cost of the installation, the operating costs, and value of the energy produced. In preparing the economic analysis, the methodology of byproduct costing was used as described by Bloomster and Knutson.[14] Natural gas is considered the primary product. Electric energy and thermal energy for direct use applications are regarded as saleable byproducts. The production cost of natural gas includes the capital and operating costs of production and injection wells, their interconnecting piping, other well field equipment, and the equipment necessary to separate natural gas from brine and process the gas to pipeline standards.

Under the byproduct methodology, the value of the thermal and hydraulic energy in the brine used for electric energy production is based only on the incremental equipment required to generate the electric energy. For cases where the electric energy production cost estimates are less than that typical for new conventional generating units in the Texas and Louisiana region, the difference is credited to the natural gas, thus reducing its cost.

Capital cost estimates for a S.E. Pecan Island well and production facilities are shown in Table III. (The well cost is consistent with natural gas practice in the area, and consequently is optimistic.)

Capital costs for the natural gas processing facilities in conjunction with a binary cycle geothermal power plant are shown in Table IV (power plant cost not included). Utilizing an operating and maintenance expense of 2% of the capital cost, the estimated production cost of natural gas from this facility is $5.14/MCF.

Table III. Capital Cost Estimate for Production Well and Injection Wellfield, S.E. Pecan Island, LA Prospect ($1,000)

| | |
|---|---|
| Land Lease and Development | 800 |
| Geophysics and Geology | 300 |
| Production Well | 5,000 |
| Piping to Energy Recovery Processes | 20 |
| Injection Wells | 2,000 |
| Piping to Injection Wells | 1,580 |
| Home Office Services | 230 |
| Permits and Environmental | 250 |
| Contingency | 1,520 |
| Estimated Construction Cost | 11,700 |
| AFDC and Other Owner's Costs | 1,300 |
| Total Capital Cost | 13,000 |

Table IV. Capital Cost Estimates-Natural Gas Separation and Processing Facilities ($1,000)

Location - S.E. Pecan Island

| Power Plant | Binary |
|---|---|
| Mechanical Equipment | 969 |
| Electrical | 100 |
| Civil/Structural | 110 |
| Piping | 290 |
| Instrumentation | 160 |
| Yardwork & Miscellaneous | 20 |
| Direct Field Cost | 1,649 |
| Indirect Field Cost | 254 |
| Total Field Cost | 1,903 |
| Home Office Services | 267 |
| Contingency | 326 |
| Estimated Total Construction Cost | 2,496 |
| AFDC and Other Owners' Costs | 369 |
| Total Capital Cost | 2,865 |
| Estimated Gas Production Cost | $5.14/MCF |

Electric Power Generation Electric power can be generated by means of a binary cycle or flashed steam geothermal plant utilizing the by-product brine as a heat source. A hydraulic turbine-generator unit can also be installed at the wellhead to generate power, utilizing the excess pressure at the wellhead, although the output would continually decline as the pressure is depleted. Capital cost estimates for a single well binary power plant show a total investment of $3.4 million for a 1.6 Mw(e) (net) binary cycle plant and $680,000 for a 1.5 Mw(e) (net) installation of high and low pressure turbines. The cost of electric power from the thermal plant is estimated at 43 mills/kwh and for the two hydraulic turbine generators, 3.4 mills/kwh for the high pressure unit and 8 mills/kwh for the low pressure unit. These costs are based on an 11.4% rate of return, which is typical for electric utility companies in the Texas and Louisiana region.

Conclusions While the resource base estimated for the Gulf Coast geopressured zones is extremely high, most of the resource is apparently contained in shale, for which there is no production technology known. Of the remaining resource contained in sandstone, only a small percentage is likely to be encountered in reservoir-quality formations capable of high-volume flow for sustained periods of time. The minimum cost under the most optimistic conditions and in the most favorable known prospects is upwards of $5/mcf for natural gas, 43 mills/kwh for thermal generated electric power and about 9¢/kwh for power generated by hydraulic turbines. Under these very favorable reservoir conditions, a small amount of marginally profitable energy may be produced. The number of such high-quality reservoirs depends primarily upon the size distribution of large, connected sand bodies in the geopressured zone. While this is presently indeterminate, the probability is strong that such very large, permeable reservoirs will be few in number, difficult to locate and expensive to produce. The strongest factor in the economic success of a large high quality production reservoir, will be the amount of dissolved methane it contains. If the actual value of dissolved gas is substantially less than 35 SCF/bbl, the cost of production in S.E. Pecan Island will increase almost directly. A value of 20 SCF/bbl would raise the cost of the gas to about $9/MCF.

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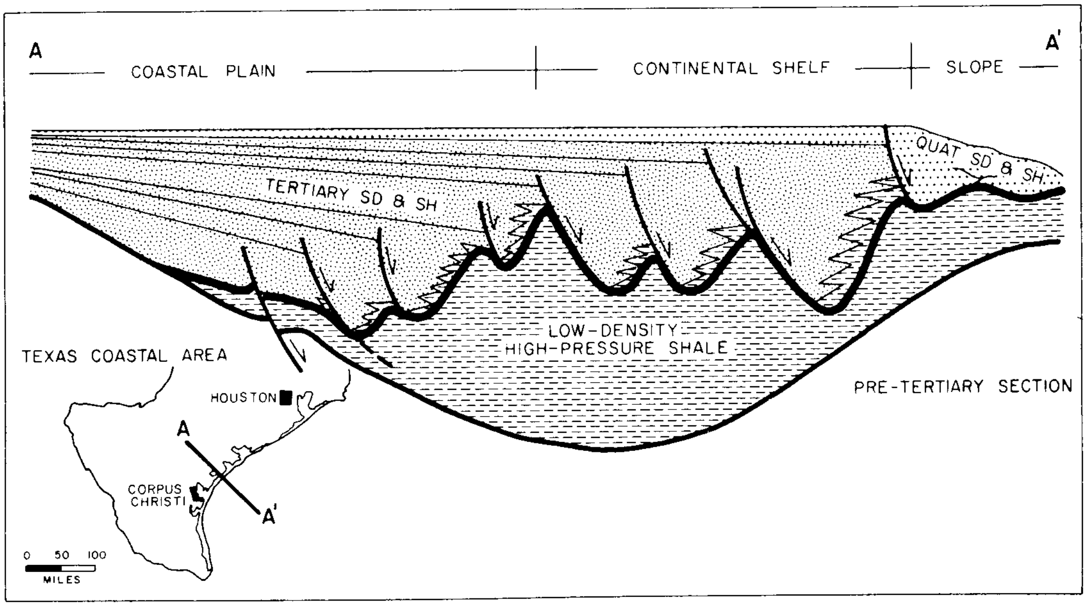


*Figure 1. Depositional Style of Tertiary Strata Along the Texas Gulf Coast (Bruce, 1973).*

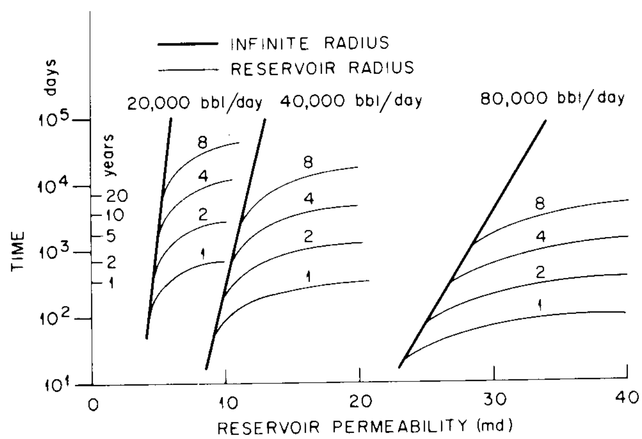


*Figure 2. Well Life as a Function of Permeability, Flow Rate, and Reservoir Radius for a Well Diameter of 6 in., Reservoir Thickness of 200 ft, and Pore Compressibility of 7 × 10$^{-6}$ psi$^{-1}$. All Radii Are Given in Miles. (From Ref. 9)*

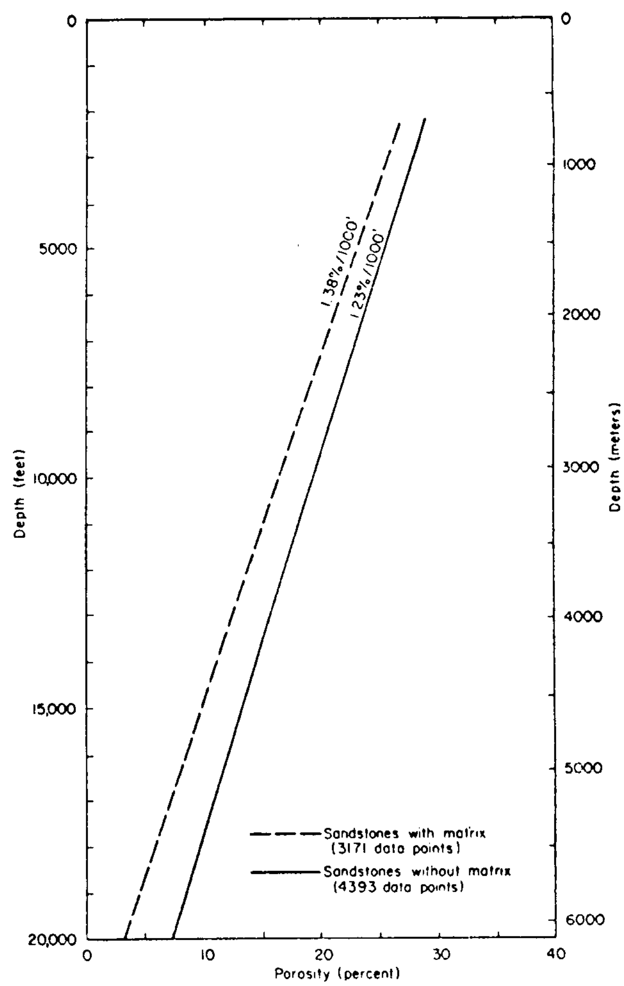


*Figure 3. Mean Porosity Versus Depth for Lower Tertiary Sandstones with and Without Clay Matrix from Along the Texas Gulf Coast. (From Ref. 10)*

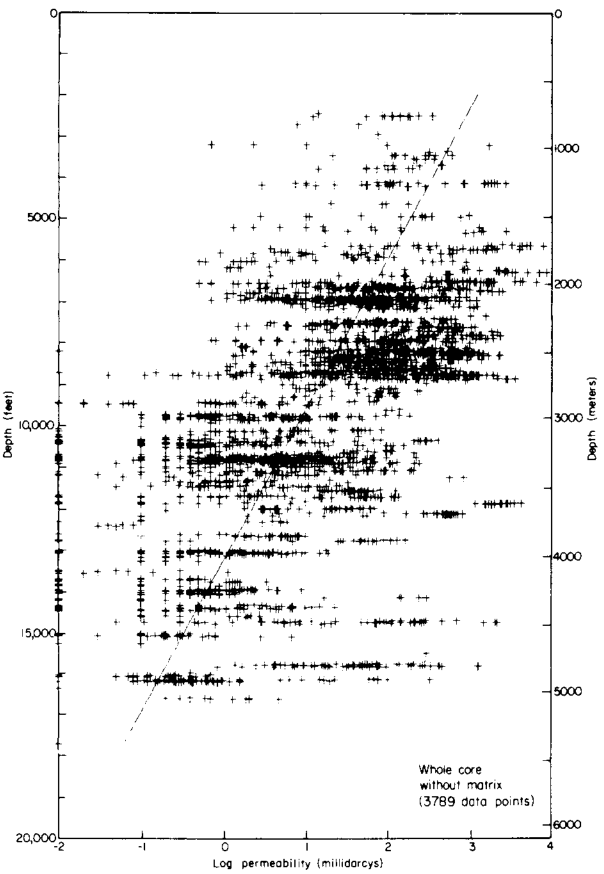


Figure 4. Permeability Versus Depth from Whole Core Analyses for Lower Tertiary Formations Along the Texas Gulf Coast. (From Ref. 10)

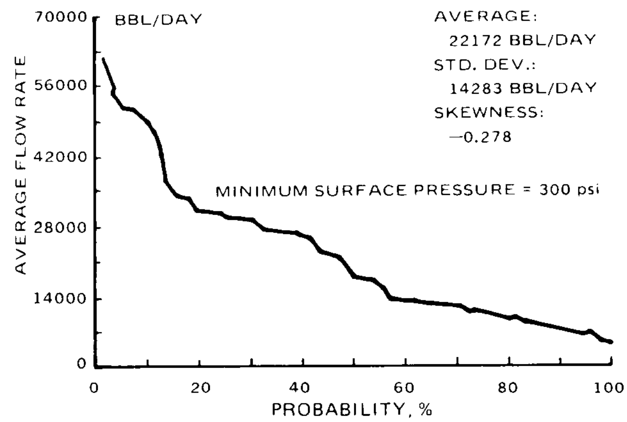


Figure 6. Probable Average Flow Over a Twenty Year Period for a Well in S.E. Pecan Island Prospect, Vermillion Parish, LA.

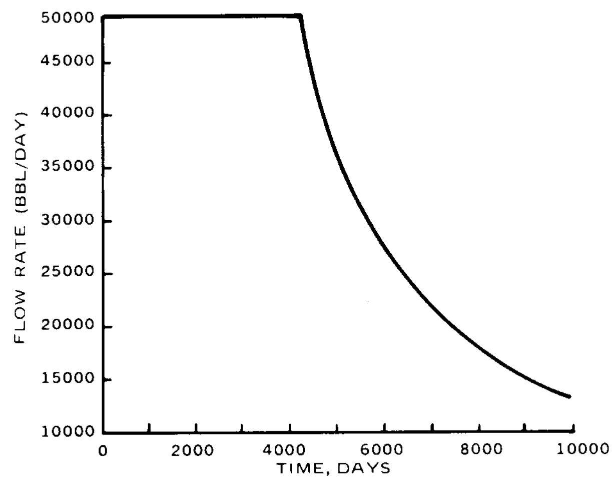


Figure 7. Flow Rate Versus Time, Single Well Development, S. E. Pecan Island, LA., Optimistic Reservoir Parameters, in Most Favorable Part of the Reservoir.

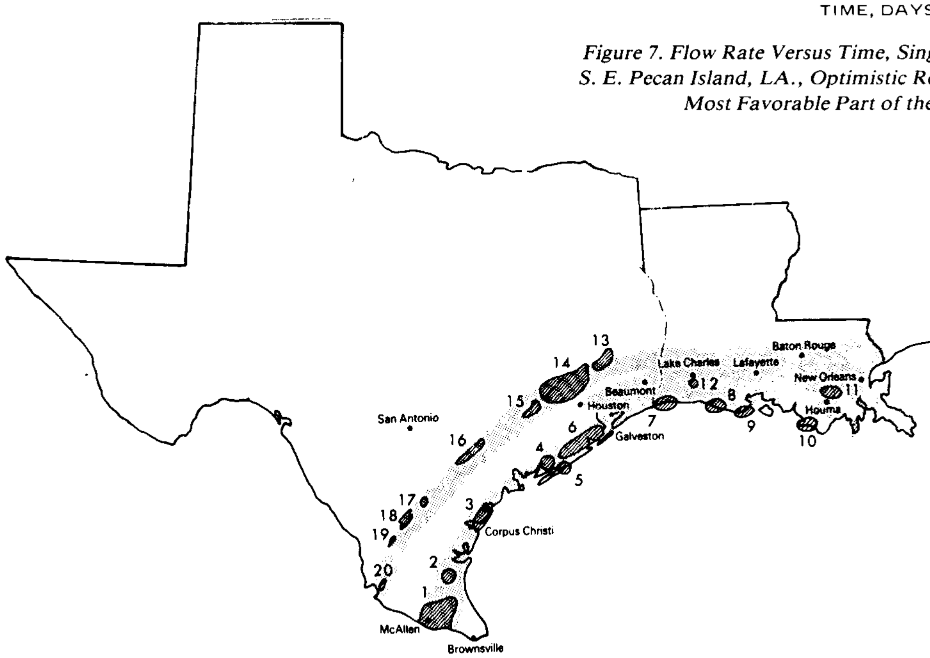


Figure 5. General Areas of Geopressured Sand Development, and Known Geopressured Prospects Which Have Received Detailed Study.