CONF-800525--4

MASTER

AN EVALUATION OF THE GEOPRESSURED ENERGY RESOURCE OF LOUISIANA AND TEXAS

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*Operated by Union Carbide Corporation under contract W-7405-eng-26 with the U.S. Department of Energy.

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ABSTRACT

The economics of extracting either the geothermal energy or natural gas from geopressured aquifers does not look promising. The combined requirements of high well flow rates, long life, 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 that the number of promising production areas may be severely limited.

INTRODUCTION

Two of the many energy resources 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 (Fig. 1)[1]. 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.

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

RESOURCE AND RECOVERY ESTIMATES

Estimates of both the magnitude of the geopressured aquifers and the energy that may be recovered from them vary widely. Much of the initial interest concerning the potential energy of the geopressured aquifers was generated by a U.S. Geological Survey (USGS) report by Papadopulos et al. in 1975.[2] In this report, the authors divided the onshore area of Texas and Louisiana into 21 subareas corresponding to faulting patterns 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 (46,000 EJ), methane (25,000 EJ) and mechanical (2300 EJ).

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%. The authors note that their assessment does not include the total geopressured 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. A later USGS Circular[3] estimates the total resource base of this basin to be about 2-1/2 times the values listed above.

Jones[4], building on the initial USGS report, estimated the methane content of the total basin sandstone formations to be 49,000 Tcf (51,000 EJ), of which, 17,000 Tcf (18,000 EJ) was offshore. He also stated that the methane resource base, including that in shale formations, was 100,000 Tcf (105,000 EJ) and that 246 to 1145 Tcf (260 to 1200 EJ) could be recovered.

The optimistic projections made by Jones and Papadopulos were apparently the source of other statements implying enormous natural gas resources. In reference to the geopressured zones, Brown[5] 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."

References and illustrations at end of paper.

Newsweek[6] also reported the 100,000-quad (105,000 EJ) 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/Mcf^3 ($0.14/m^3). 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)*,[7] which gave a total range of 150 to 2000 quads.

Hise[8] and Dorfman,[9] speaking to a special National Resource Council Board, as was Jones, projected much smaller values. Hise estimated the total area of the aquifers, both onshore and off, for Louisiana and Texas to be about 100,000 sq miles (260,000 sq km). He assumed an average thickness of 10,000 ft (3050 m) 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 scf/bbl (5.34 m^3/m^3) for the natural gas content of the brine, he estimated the total gas in place in the geopressured aquifers to be 3000 Tcf (3100 EJ). 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 Tcf (28 EJ). The United States currently uses about 20 EJ of natural gas each year.

Dorfman made no estimates of reserves. He does state that if the price for natural gas were high enough to make such ventures attractive, about 0.33 Tcf (0.35 EJ) could be produced per year by the year 2000. This represents less than 2% of our current annual use.

More recent studies published by Swanson and Osoba[10], and Doscher et al.[11] are not encouraging. Swanson and Osoba estimates the upper limit of producible methane from known geopressure fairways to be about 7 Tcf (7.4 EJ). Their estimate of wellhead cost from one of the most promising fairway was $7.50/Mcf ($0.26/m^3). Doscher et al. estimated production costs of from $4 to $15/Mcf ($0.14 to $0.53/m^3). These latter two reports contain caveats that imply that the quantities or costs projected may be less favorable. They also assumed that 40 scf (1.13 m^3) of methane could be recovered from each barrel (.159 m^3) of brine.

RESOURCE RECOVERY COSTS

Although estimating the cost of any emerging technology or new resource is speculative, it is necessary in order to provide insight into the effects of the key parameters on its economic potential. For this purpose, results of earlier cost studies will be used to understand the importance of the key geopressure parameters - the size, compressibility and permeability of the reservoirs and the gas content, pressure and temperature of the brine.

One of the most detailed and best documented studies of the economics of using the energy from geopressured aquifers is by Wilson et al.[12] In this study of a 25-MW(e) 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 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.

The assumptions used for the Wilson et al. study and a summary of the costs are listed in Tables 1 and 2. In addition to the assumptions listed in Table 1, other ground rules adopted for the study were: the production wells were located at 1/2-mile (0.8-km) intervals, two reinjection wells were required for each production well, and the reinjection pressure required at the processing plant was 300 psi (2.1 MPa). Also, the costs shown in Table 2 do not include any costs for land, royalties, architect-engineering, interest during construction, or contingency.

The data of Table 2, without any changes, were used to calculate the power cost as a function of the methane value in the brine - shown by the lower set of lines in Fig. 2. The lower-right end points of these lines represents the methane value for which the hot brine can be delivered to the power plant without cost. For example, if the brine contains 40 scf/bbl (7.1 m^3/m^3), the methane would have to be priced at $2.80 to $2.90/MCF ($0.097 to $0.102/m^3) and the resulting power cost would be 22 to 26 mills/kWh.

In order to bring these costs up to date and to include an allowance for some of the omissions, the costs of Table 2 were increased by 75%. The result of applying this factor is shown as the middle lines of Fig. 2. The lower-right end of the lines again represent the methane value for which the hot brine can be delivered to the power plant without cost. For this case, with 40 scf of methane per barrel of brine (7.1 m^3/m^3) the methane price must be $5/Mcf ($0.18/m^3), or with only 20 scf/bbl (3.6 m^3/m^3) the price must be $10/Mcf ($0.35/m^3). Even at these methane values, the power costs would be 40 to 50 mills/kWh.

The ground rule that 20,000 B/D (0.037 m^3/s) could be reinjected by each disposal well at a pressure of 300 psi (2.1 MPa) at the processing plant is very optimistic. Doscher et al.,[11] in an analysis of brine reinjection to shallow aquifers (1800 m), determined the reinjection rate vs injection pressure for 1000 ft (305 m) thick aquifers with a porosity of 30% and a permeability in excess of 100 md (1 x 10^{-13} m^2) - their definition of a "best case" aquifer. For one disposal well per sq. mile (2.56 sq. km), they found that the injection rate varied from 2800 to 5500 B/D (0.005 to 0.010 m^3/s) for injection pressures of 1000 to 2000 psi (7 to 14 MPa). These conditions would require 4 times the number of reinjection wells and several times the reinjection pressure assumed for the Wilson et al. study.

The effect of increasing the reinjection pressure by 1000 psi (7 MPa), which reduces the net power output of the plant, is illustrated by the upper set of lines in Fig. 2. No attempt is made to adjust the costs for additional reinjection wells and additional piping. However, if reinjection wells were limited to a flow of 5000 B/D (0.009 m^3/sec), the additional cost would shift the upper lines of Fig. 2 to the right by about 50%.

The cost of producing methane would be even higher without the power plant. For this case, the pump-

ing power for reinjection would have to be purchased or supplied by the methane. If supplied by a methane-fueled engine-driven compressor, 3.5 ft^3 ($0.1 m^3$) of methane would be required for each barrel of brine reinjected at a pressure of 1000 psi (7 MPa).

The assumption that the production wells, located at 1/2-mile (0.8 km) intervals, could produce 40,000 B/D (0.074 m^3/s) for 20 years is also far too optimistic. As will be discussed later, the required spacing between wells for this sustained production rate will probably be a few miles.

The importance of well spacing on economics is illustrated in a report by Bloomseter and Knutsen[13] on the cost of using the thermal and hydraulic energy of geopressure brine for electricity. They analysed 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 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. 3. These results are based on December 1975 costs, a well spacing of about 1.85 miles (3.0 km), and a well flow rate of 81,500 B/D (0.15 m^3/s). The high cost of the collection system offsets the savings from larger power plants and leads to the flat curves of power vs plant size. Figure 4 shows the effect of well spacing on power cost for a 55-MW(e) plant and a 327°F (164°C) brine temperature. The cost of the fluid transmission system equals the cost of the power plant for a well spacing of about 1-1/4 miles (2.0 km).

The study by Bloomster and Knutsen also emphasizes the importance of the brine temperature on power costs. Although temperatures in the geopressured formations range well above 300°F (150°C), the temperature from the Department of Energy test wells has been from 220 to 300°F (105 to 150°C).

METHANE CONTENT

Most studies of these reservoirs have assumed a methane content of 40 scf/bbl (7.1 m^3/m^3) - a reasonable value if the brine is saturated with methane and if the salinity of the brine is low. The data of Culberson and McKetta[14] (Fig. 5) shows the solubility of methane in pure water. However, the solubility of methane varies inversely with water salinity; at a temperature of 250°F (121°C), the solubility decreases at a rate of 3 to 4% for each 10,000 ppm dissolved solids.[15,16] Data from the first 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 at 110,000 to 140,000 ppm at a temperature of 240°F (115°C).[17] These data also indicated that other gases (N_2, CO_2, and higher hydrocarbons) tend to decrease the solubility of methane in water. Results from recent test wells have shown dissolved solids ranging from 100,000 to 200,000 ppm and a methane content of about 20 scf/bbl (3.6 m^3/m^3). If these low methane values are typical of the geopressured formations, then most earlier projections of the required price of the methane are too low by at least a factor of two.

RESERVOIR DRIVE

The primary driving force of a reservoir is its compressibility, which is a function of the compressibility of the liquid, *Ce*; the compressibility of the rock matrix (the particles forming the structure), *Cs*; and the pore compressibility, *Cp*. For a reservoir not containing free gas, the fluid compressibility is that of water, which, for the temperature and pressure range of interest, is 3.3×10^{-6} psi^{-1} (4.8×10^{-4} MPa^{-1}). Considering that the maximum pressure drawdown expected in a reservoir is about 5000 to 6000 psi (34 to 41 MPa), 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 sturcture, 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 data available on the compressibility of the geopressured reservoirs.

Van der Knaap[18] found the rock matrix compressibility to be in the range of 2.97 to 3.44×10^{-5} MPa^{-1} (2 to 2.4×10^{-7} psi^{-1}). Geertsma[19] recommends using the compressibility of quartz for sandstone, about 1.9×10^{-7} psi^{-1} (2.8×10^{-5} MPa^{-1}).[20] For this paper a value of 2×10^{-7} psi^{-1} will be used.

Swanson and Osoba[10] report a bulk compressibility value of 1.62×10^{-6} to 2.2×10^{-6} psi^{-1} (2.35×10^{-4} to 3.19×10^{-4} MPa^{-1}) for geopressured core samples taken from a depth of 10,200 ft (3100 m) in a Brazoria County, Texas well. For a typical porosity value of 20%, these values correspond to a pore compressibility of 8×10^{-6} to 11×10^{-6} psi^{-1} (1.2×10^{-3} to 1.6×10^{-3} MPa^{-1}). For consolidated and cemented sandstone from normally pressured reservoirs, a pore compressibility (measured by conventional laboratory hydrostatic tests) in the range of 3×10^{-6} to 10×10^{-6} psi^{-1} (4.4×10^{-4} to 15×10^{-4} MPa^{-1}) is typical.[18,21,22] However, hydrostatically determined values of *Cp* 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 Knapp[18] and Geertsma[23] recommend using an effective reservoir compressibility of $Cp/2 - Cs$ where *Cp* is the hydrostatically measured value of the pore compressibility.

Reservoir compressibility can also be estimated from the uniaxial compaction coefficient, *Cm*, 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, *Cm* can be related to the pore volume compressibility by the expression $Cm = \phi Cp/2$. Geertsma[19] reports values of *Cm* 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 3000 m, he

reports values of *Cm* ranging from 4 x 10^{-5} MPa^{-1} to 11 x 10^{-5} MPa^{-1} with an average value of about 7 x 10^{-5} MPa^{-1} (4.8 x 10^{-7} psi^{-1}). For similar samples loaded to correspond to a depth of only 1000 m, an average value of *Cm* of 9 x 10^{-5} MPa^{-1} (6.3 x 10^{-7} psi^{-1}) is obtained. These average values correspond to pore compressibilities of 7 x 10^{-4} MPa^{-1} (4.8 x 10^{-6} psi^{-1}) and 9 x 10^{-4} MPa^{-1} (6.3 x 10^{-6} psi^{-1}). 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.

For this paper a pore compressibility of 7 x 10^{-6} psi^{-1} (1 x 10^{-3} MPa^{-1}) will be used. The effective reservoir compressibility, $Ce + Cp/2 - Cs$, is then 6.6 x 10^{-6} psi^{-1} (9.6 x 10^{-4} MPa^{-1}). The effect of the pore compressibility on the reservoir porosity and the maximum amount for brine that can be recovered from a reservoir is shown in Fig. 6 for an average reservoir pressure change of 6000 psi (41 MPa). Note that the recovery percent shown in Fig. 6 is the maximum that can be recovered regardless of flow rates or time required to reach the pressure drawdown. For the reference values used here, the maximum recovery is about 4%.

Some perspective can be given to these values by noting that the total brine required from a well producing 40,000 B/D (0.074 m^3/s) for 20 years is 1.6 Bcf (4.5 x 10^7 m^3). For a porosity of 20% and a maximum recovery of 4%, the reservoir volume required to supply a single well is about 1.4 cu mile (5.8 km^3). This is illustrated in Fig. 7, which shows the reservoir thickness required as a function of well spacing for well flow rates of 40,000 and 80,000 B/D (.074 and .146 m^3/s). Large reservoirs with a sandstone thickness sufficient to support wells on less than 2 to 3 miles (3.2 to 4.8 km) will probably be rare finds.

Unless these formations exhibit unusual compressibility characteristics, only very large reservoirs can support even a single well and the cost of a collection piping system would make multiwell processing plants very costly. Free gas within a reservoir would increase its compressibility and prolong its production life. Shale water influx could also act as a driving force. However, unless the permeability and compressibility of the shale in these reservoirs is one or two order of magnitudes greater than normally pressured shale, the effect of shale water influx will be small.[24]

PERMEABILITY

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. studied the permeability of geopressured gas fields in six counties (Cameron, Hidalgo, Willacy, Kenedy, Brooks, and Live Oak) of southern Texas. They found permeability values to range from less than 0.03 md (3 x 10^{-17} m^2) 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 one order of magnitude for each 2000 ft (610 m) of depth between 6000 (1830 m) and 14,000 ft (4270 m).

Even along the northern geopressured areas, permeabilities vary widely. Results from Department of Energy geopressure test wells indicate permeability values ranging from 10 to 15 md (10 to 15 x 10^{-15} m^2) to over 300 md.

Figure 8 shows the life of a single well as a function of the reservoir permeability and size for constant well flow rates of 20,000, 40,000, and 80,000 B/D (0.037, 0.074, 0.147 m^3/s). For this case, the depth of the production interval is 14,000 ft (4300 m), the production interval is 200 ft (61 m), the initial pressure is 12,000 psi (83 MPa), the well diameter is 6 in. (15.2 cm), the effective reservoir compressibility (water plus rock structure) is 6.6 x 10^{-6} psi^{-1} (9.6 x 10^{-4} MPa^{-1}), the porosity is 20% and only single-phase flow is considered. The end-of-life wellhead pressure is assumed to be 250 psi (1.7 MPa), 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 B/D (0.147 m^3/s) case, a reservoir of infinite size would require a permeability of about 30 md (30 x 10^{-15} m^2) for a 20-year life. A reservoir with a radius of 8 miles (12.9 km) would require a permeability of about 50 md for a 20-year life, whereas a 4-mile (6.4 km) radius would be too small regardless of the value of permeability. A 20-year life at 40,000 B/D (0.074 m^3/s) requires a reservoir radius of about 4 to 8 miles and a permeability of 15 to 20 md. The 4-mile (6.4-km) radius corresponds to a well drainage volume of 1.9 cu mile (7.9 km^3).

RESERVOIR SIZE

The University of Texas and Louisiana State University have made extensive studies of the geopressured formations. The most promising area located by the University of Texas is the Brazoria Fairway.[26] This fairway has sandstone intervals totaling 800 to 900 ft (245 to 275 m) between the depth of 13,500 and 16,500 ft (4100 and 5000 m). The total area is about 60 sq miles (155 km^2). These values give a total sandstone volume of about 10 cu mile (42 km^3). However, the size of individual reservoirs will be much smaller.

The LSU study[27] included all of the known onshore geopressured areas of Louisiana and those offshore areas under state jurisdiction. They studied logs of about 6000 wells ranging in depth from 7500 to 25,600 ft (2290 to 6890 m) and averaging 12,980 ft (3950 m). Although the maximum sandstone thickness in one well was 2955 ft (900 m) the average was 434 ft (132 m).

Doscher[11] in an analysis of the Texas and Louisiana geopressured areas concluded that "it is optimistic to assume that a single geopressured reservoir having a volume of 3 cu miles will be found. Further, the geopressured aquifer volumes probably will not exceed 1 cu mile in volume, and the mode of the distribution may well be a minor fraction of 1 cu mile."

CONCLUSIONS

The geopressured aquifers of the northern Gulf of Mexico undoubtedly contain an enormous quantity of thermal and chemical energy. Much more information is needed to make accurate projections of the contributions of these aquifers to national energy needs; it will, however, probably be small, at least in the foreseeable future.

The expectation that the multiple energy aspects of the aquifers will enhance their economic potential is questionable unless improvements are made in low temperature power systems, or uses other than power generation is found for the low temperature energy.

Methane costs will be highly dependent on the reservoir size and characteristics. Costs of \$5 to \$10/Mcf (\$0.18 to \$0.35/m^3) appear to be the best that can be expected for the most favorable reservoirs. However, if recent findings of only 20 scf (0.57 m^3) of methane per barrel (0.16 m^3) of brine are typical of these aquifers, then methane costs will probably be well above \$10/Mcf (\$0.35/m^3).

NOMENCLATURE

Ce = brine compressibility - psi^{-1} (MPa^{-1})
Cm = uniaxial compaction coefficient - psi^{-1} (MPa^{-1})
Cp = pore compressibility - psi^{-1} (MPa^{-1})
Cs = rock matrix compressibility - psi^{-1} (MPa^{-1})
$\emptyset$ = porosity

ACKNOWLEDGEMENT

This work was performed through the Energy Division of the Oak Ridge National Laboratory - operated by Union Carbide Corporation - under contract W-7405-eng-26 with the U.S. Department of Energy.

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Table 1

Assumptions for Plant of Ref. 12

Date of costs = January 1976,

Brine production rate per well = 40,000 B/D (.074 m^3/s),

Brine temperature = 325° (163°C),

Plant operating factor = 90%,

Brine pressure to the hydraulic turbine = 2000 psia (13.8 MPa),

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.

Table 2

Cost summary for 25-NW(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 B/D (m^3/s)	432 (0.80)	340 (0.63)
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 (¢/m^3)	11.1 (70)	11.6 (73)
Power plant		
Capital cost, $\$10^6$	14.49	16.95
Annual capital and operating cost, $\$10^6$/year	4.32	5.05
Annual power output, 10^6 kWh/year	197	197

Figs. are being redrawn
to add SI units

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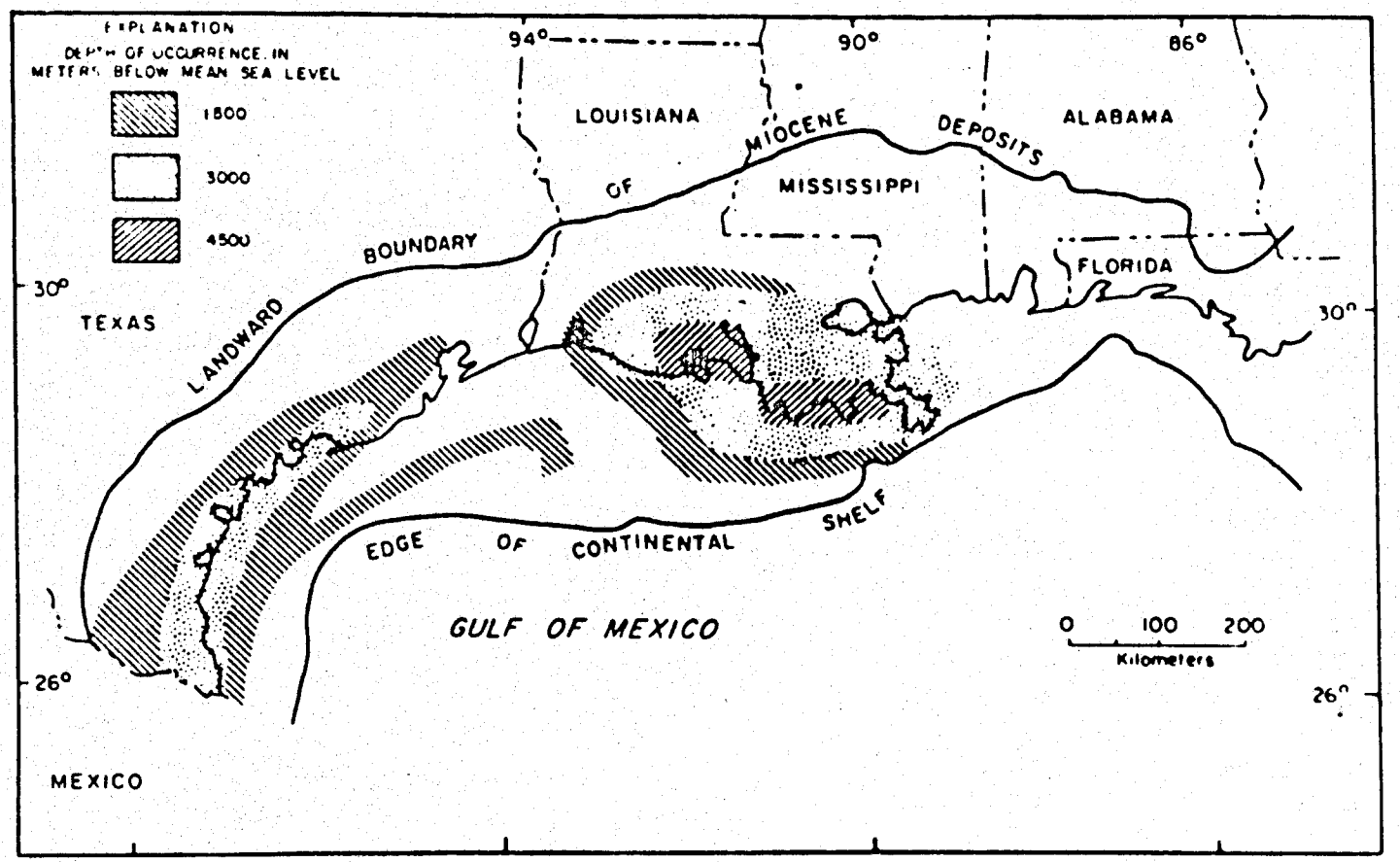

Fig. 1. Areas of potential geopressure resoures in the northern Gulf of Mexico Basin. (From Ref. 1).

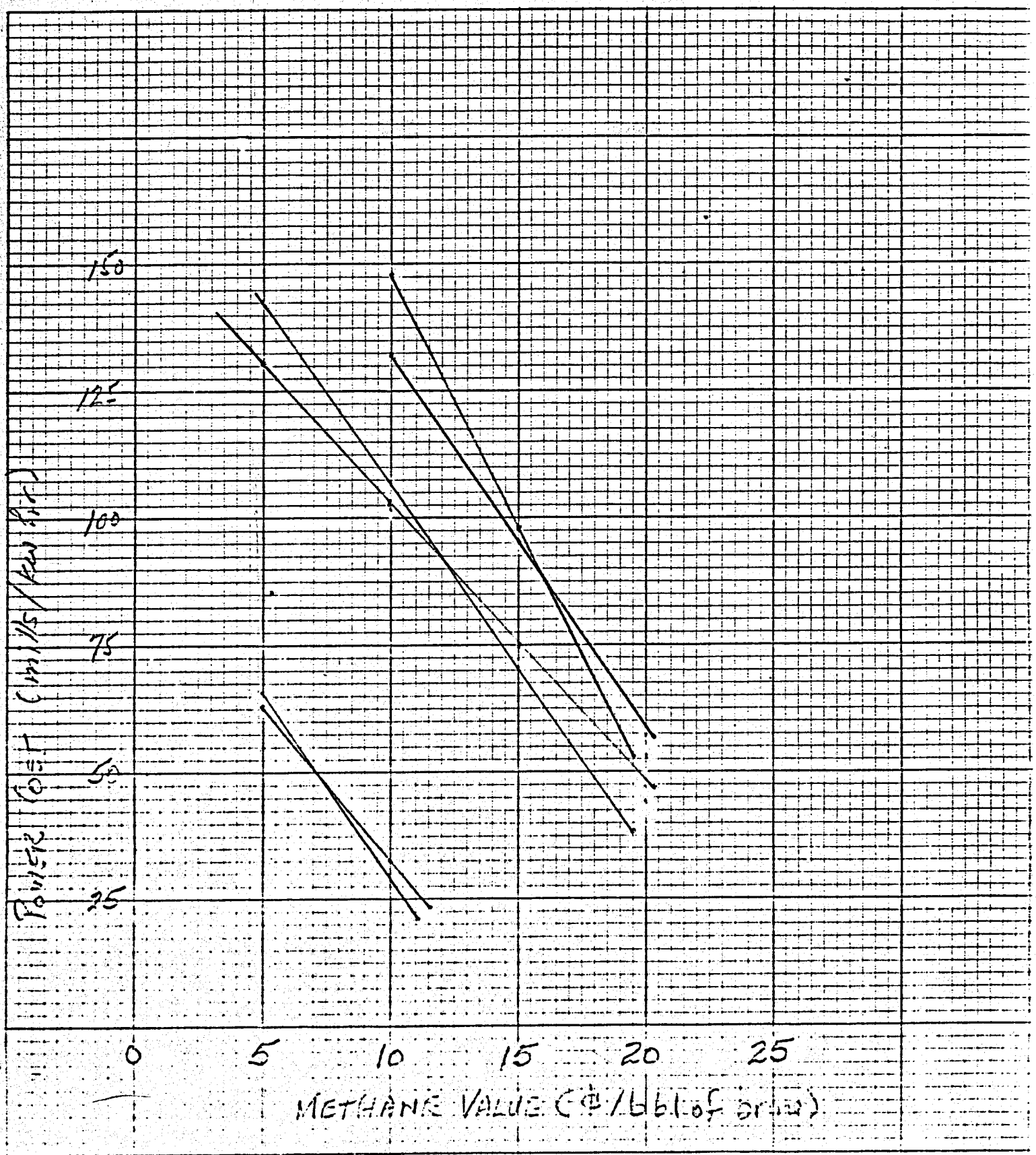

Fig. 2. Cost of electrical power from a geopressure geothermal plant as a function of the methane value.

BEE 10x10

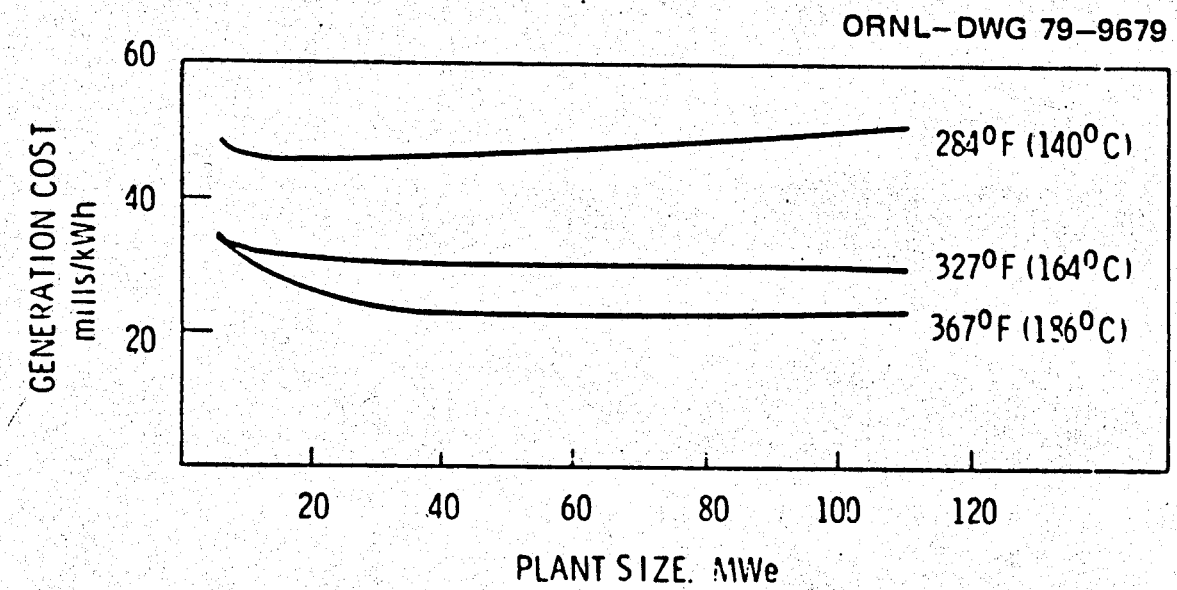

Fig. 3. Impact of plant size on generation cost (From Ref. 13).

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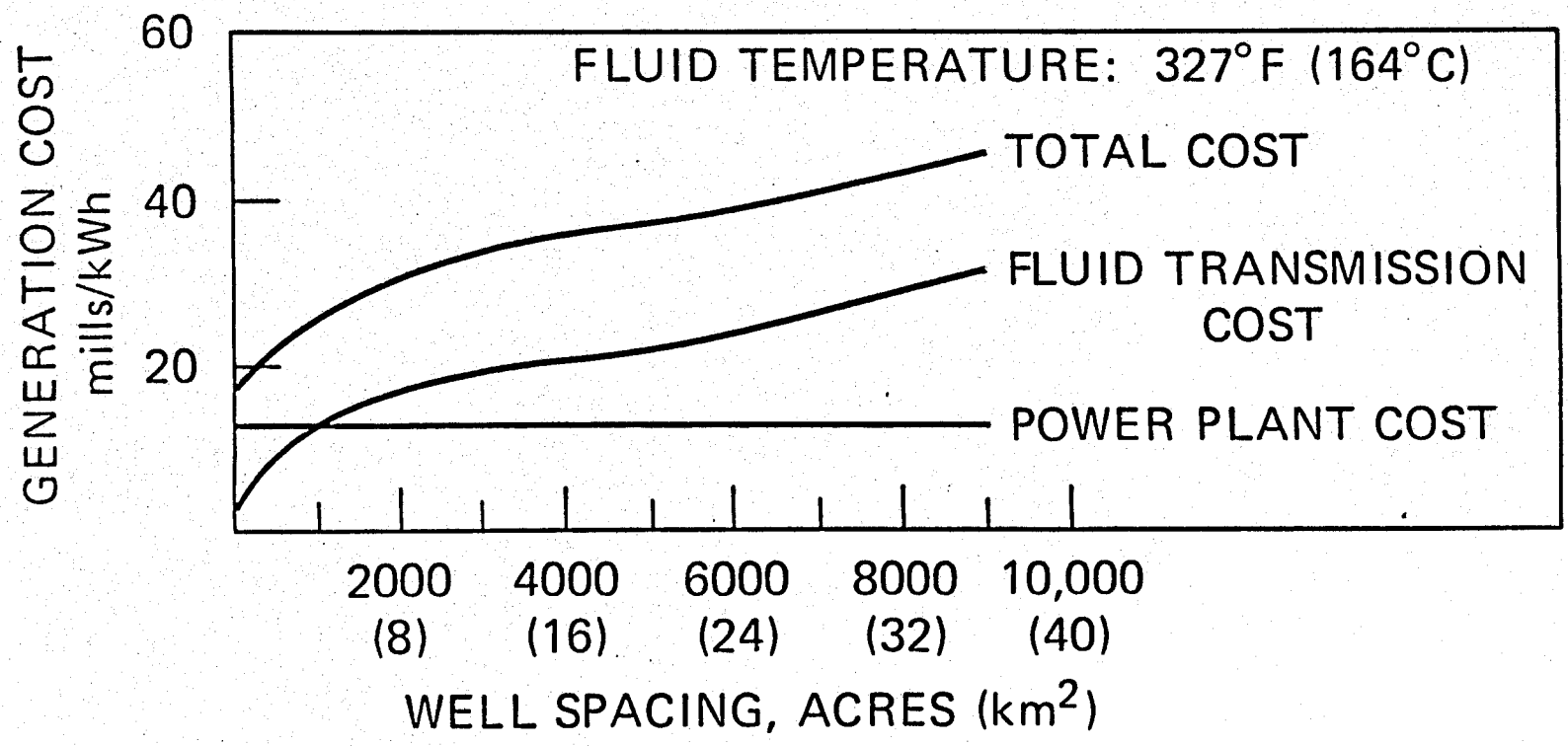

Fig. 4. Impact of well spacing on generation cost distribution (From Ref. 13).

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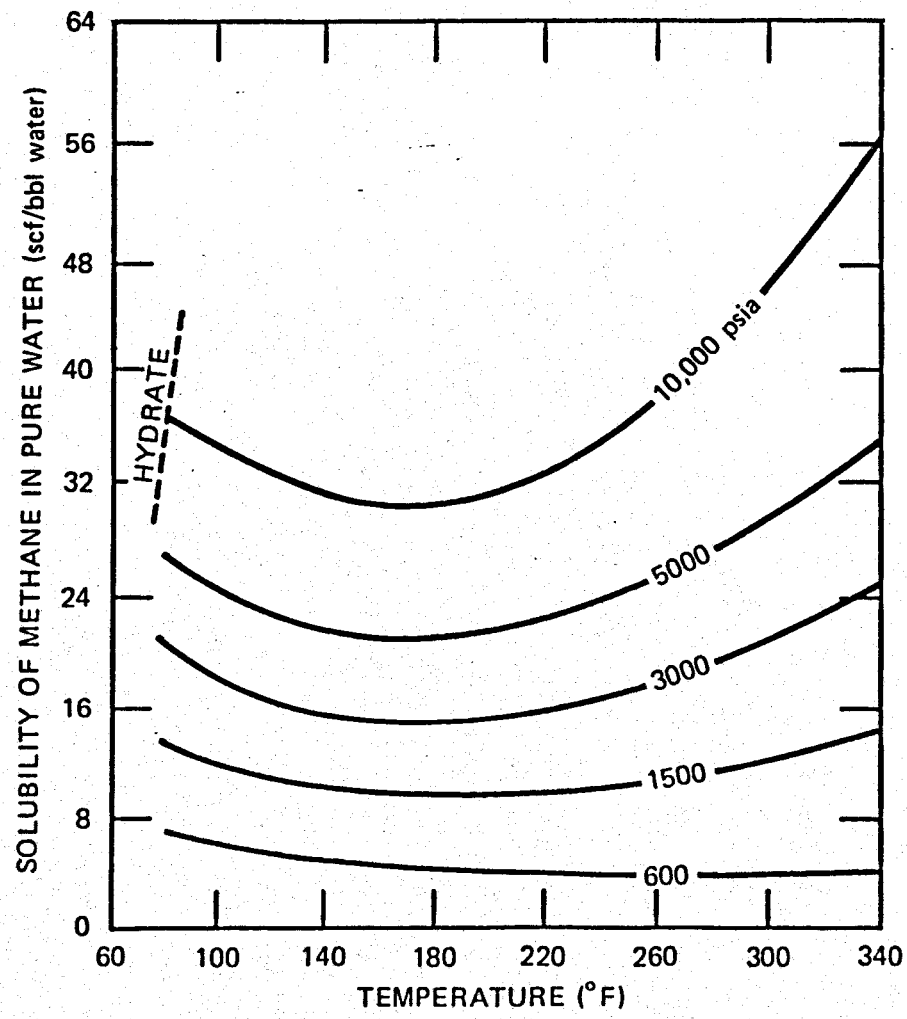

Fig. 5. Solubility of methane in pure water (from Ref. 14).

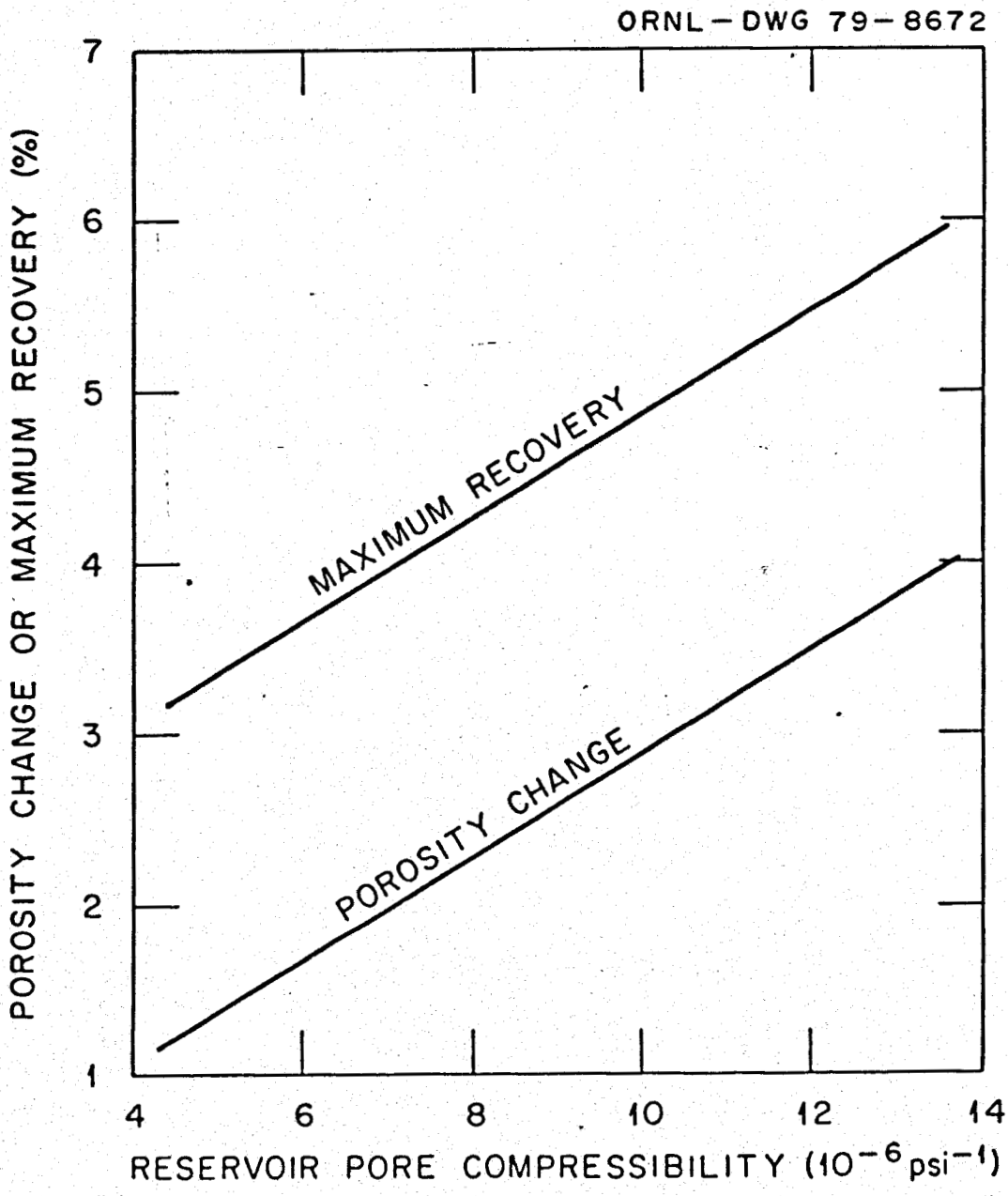

Fig. 6. Effect of reservoir pore compressibility on the porosity change and maximum recovery for a 6000-psi (41-MPa) change in reservoir pressure.

ORNL–DWG 79-8674

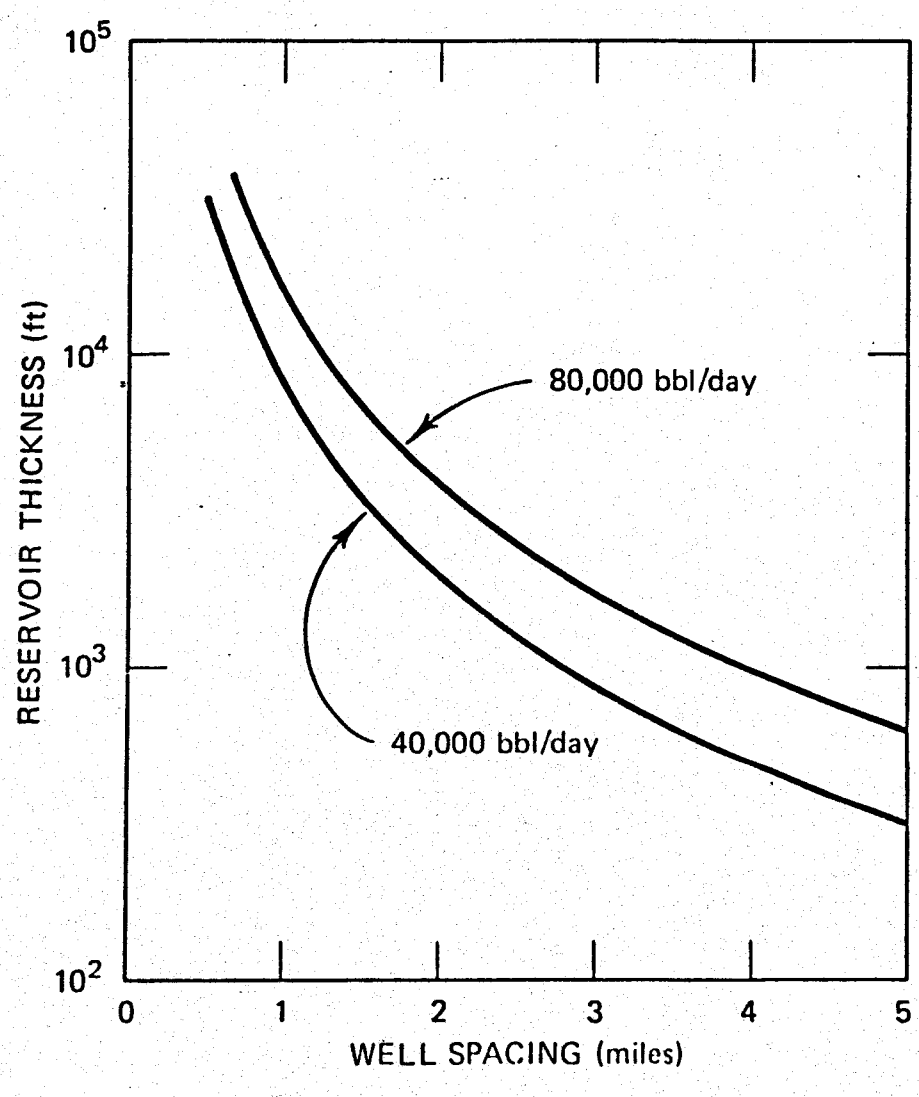

Fig. 7. Required reservoir thickness as a function of well spacing for well flow rates of 40,000 B/D (0.074 m^3/s) and 80,000 B/D (0.147 m^3/s) and a well life of 20 years.

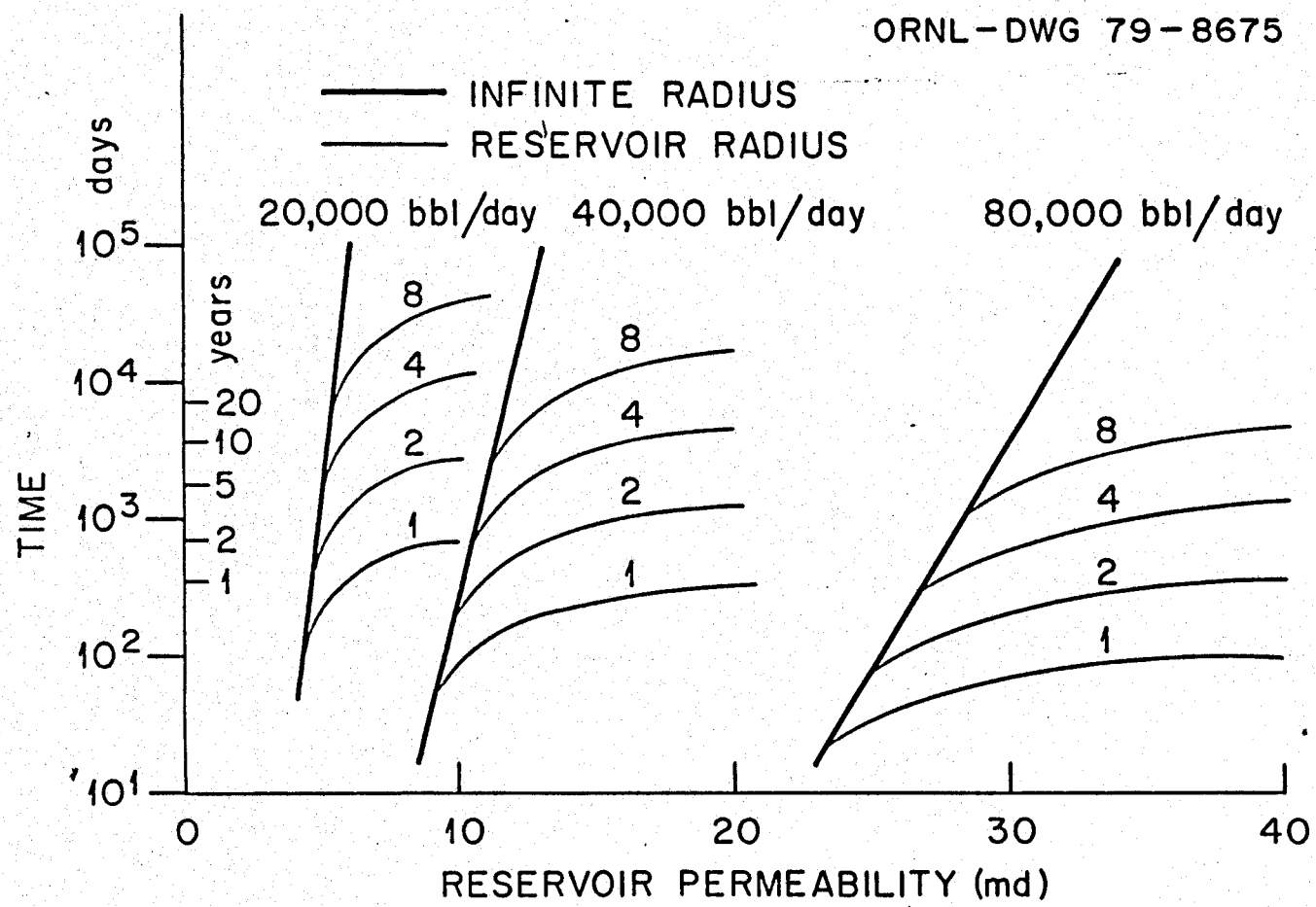

Fig. 8. Well life as a function of permeability, flow rate, and reservoir radius.