THE NATURE AND OCCURRENCE OF GEOPRESSURED RESOURCE AREAS IN THE STATE OF CALIFORNIA, USA

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ABSTRACT

The publicly available database on oil and gas fields in California provides a significant and consistent source of information which can be used to evaluate geopressure. A total of 410 pools have pressure gradients exceeding 0.45 psi/foot; these are considered to be potentially geopressured. At least 70 of these have pressures distinctly higher than predicted by the regional hydrostatic gradient, and 8 pools are superpressured.

Mud weight records are useful for identifying the top of the a geopressured zone in a well; plots of shale resistivity versus depth are used to quantify such zones. A linear correlation between pressure gradient and the ratio of observed shale resistivity to normal shale resistivity for a given depth, similar to those used in the Gulf Coast region, is developed. A single correlation is probably inadequate for the entire State; others, which account for varying geologic conditions, need to be developed. Resistivity and density logs can be used to develop a correlation which accounts for the effect of overburden pressure.

There appears to be no correlation between geopressure and elevated temperature; temperature gradients are generally within the normal range. The following modal values were determined from the database of 410 potentially geopressured oil and gas pools: porosity: 20 - 25%; salinity: 0 - 10,000 ppm and 25,000 - 30,000 ppm; depth: 0 - 2,000 feet (median value 2,000 - 4,000 feet); thickness: 0 - 250 feet; and volume: 0.1 - 1 billion cubic feet. The thickness and volume estimates represent hydrocarbon pools rather than water aquifers lying below them; as such, the estimates represent lower limits. Dissolved methane content is estimated to range from 7.5 to 100 standard cubic feet per barrel.

Conversions from US to SI units are found at the end of the paper.

1. INTRODUCTION

Geopressure occurs when the pore pressure in a subsurface rock unit exceeds the normal hydrostatic pressure expected for the depth of burial. Geopressured resources have been investigated extensively in offshore Texas and Louisiana in the U.S. Gulf Coast, and pilot projects have been operating there for many years to produce the geopressured fluid and extract its heat and methane gas content. As in the Gulf Coast, geopressured zones have been identified in California as a result of extensive drilling for oil and gas. A few authors have described the geologic and tectonic settings of geopressured zones in California, and, infrequently, the characteristics of geopressured fluids in a particular oil or gas field (*e.g.*, Berry, 1973; Kharaka et al., 1981; Lico and Kharaka, 1483; and Price 1988).

A literature search revealed little specific information on either the occurrence of geopressure in California of the methodology of *its* evaluation. Therefore, the present study systematically identified geopresssured "pools" (oil or gas-bearing strata in a particular held) using published data compiled by the California Division of Oil and Gas (CDOG) from more than 150,000 oil and gas wells in the State (CDOG, 1982, 1985 and 1991). The geopressured intervals in wells which penetrated those pools were then identified using several methods, and the amount of excess pressure was quantified using well log analysis techniques. The existence of a positive correlation between elevated pressures and elevated temperatures was also investigated. Several parameters which characterize the resources were statistically evaluated for the entire State-wide database, and estimates were made of dissolved methane content

For convenience, the oil and gas fields were grouped using a somewhat arbitrary geographic division based on the regions shown in Figure 1. Location, initial static pressure, average temperature, net thickness, areal extent, porosity and salinity data from each pool in each field were entered into a computer database. Data From a total of 975 pools were examined, with the pools being divided by geographic area as follows: 98 in the northern Sacramento Valley; 122 in the southern Sacramento Valley; 37 in the central San Joaquin Valley; 212 in the southwestern San Joaquin Valley; 224 in the southeastern San Joaquin Valley; 20 in the Salinas Valley; 78 in the Santa Maria Basin; 88 in the Ventura Basin; and 96 in the Los Angeles Basin.

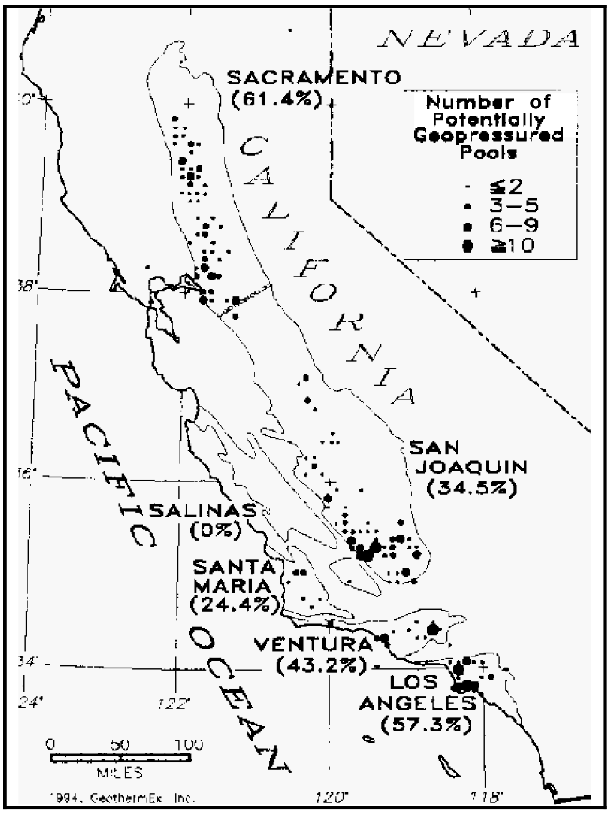


Figure 1: Oil and *gas* producing basins and distribution of potentially geopressured pools in California

2. IDENTIFYING GEOPRESSURED POOLS

For each geographic region, the initial static pressure of each pool was plotted versus pool depth, and the hydrostatic gradient was determined by force-fitting a straight line between the origin (zero pressure at zero depth) and the data points (*e.g.*, Figure 2). Hydrostatic gradients were found to be 0.4 - 0.45psi/foot, within the normal range. All points lying between the hydrostatic gradient line and the lithostatic gradient line represent "potentially geopressured" pools. In each area, there were several "distinctly" geopressured pools, with pressures significantly above the hydrostatic line. Points lying above the lithostatic line represent "superpressured" pools (Figure 2). While geopressure can be ascribed to rapid compaction of shales and consequent entrapment and thermal expansion of excess water within them, superpressure can only be caused by tectonic stress.

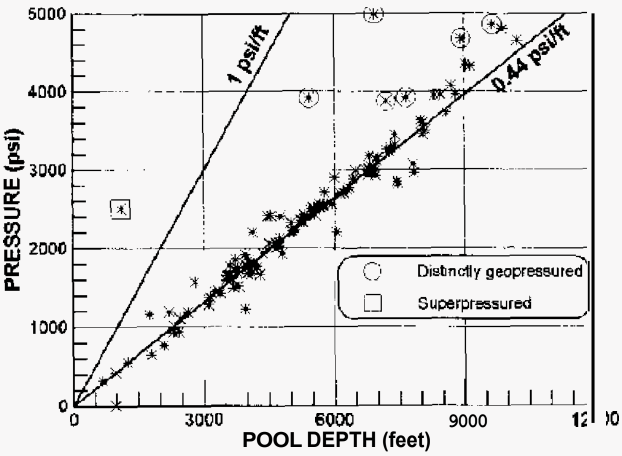


Figure 2: Example of a depth vs. pressure plot far oil and gas pools

Of the 975 pools investigated, 410 (42%) were found to be potentially geopressured, 70 were distinctly geopressured and eight were superpressured (Table 1). The percentages shown in Figure 1 represent the potentially geopressured pools in each basin: the dots indicate the location and number of these pools.

3. GEOPRESSURED ZONES IDENTIFIED FROM WELL DATA

Once a distinctly geopressured pool was identified in the manner described above, individual well data were sought from the *CDOG* archives to see if geopressured zones could be identified in individual wells. Drillstem tests, mud records and well logs can all be used for this purpose. Very little drillstem test data were available; such tests are typically conducted only at a few discrete depth in a given well. Although it is possible that some of the depths *may* correspond *to* a geopressured zone, drillstem tests are not, by their nature, adequate for vertical definition of geopressure in a well. Therefore, the other two methods were investigated more thoroughly.

Mud records are useful for identifying geopressured zones if a plot of mud weight versus depth is made (Figure *3)*. For safety reasons, the driller increases the mud wight upon encountering a geopressured zone so that the pressure of the column of drilling mud in the well exceeds the formation pressure. Unfortunately, the mud records do not reveal how "overbalanced" the mud is, and it is impossible to determine the exact pressure of the geopressured zone. Another drawback in using mud records to quantify geopressure is that once the mud Wright has been increased, it cannot be decreased again until the geopressured zone has been cased off. Therefore, only the top of the uppermost geopressured zone *can* generally be identified from mud weight records. The top of a geopressured zone is indicated at a depth of 7,000 feet in Figure 3.

Table 1 Hydrostatic Gradients and the Occurrence of Geopressured Pools

Region	Hydrostatic Gradient (psi/ft)	Number of Oil and Gas Pools	Number of Distinctly Geo-pressured Pools*	Number of Potentially Geo-pressured Pools**	Percentage of Pools Geo-pressured
Northern Sacramento Valley	0.45	98	13	66	67.3
Southern Sacramento Valley	0.44	122	6	69	56.6
Central San Joaquin Valley	0.44	37	4	20	54.1
Southwestern San Joaquin Valley	0.43	212	7	88	41.5
Southeastern San Joaquin Valley	0.43	224	10	55	24.6
Salinas Valley	0.40	20	0	0	0
Santa Maria Basin	0.42	78	9	19	24.4
Ventura Basin	0.44	88	15	38	43.2
Los Angeles Basin	0.44	96	5	55	57.3

*Based on plots like figure 2.
**Pressure gradient > 0.45 psi/ft

Where geopressure is known to occur in the Gulf Coast region, plots of shale resistivity versus depth are made, often as the well is drilled, to identify zones of high pressure. An example of such a plot is shown in Figure 4. A typical geopressured trend on a resistivity versus depth plot is a sudden increase in gradient (in the over-compacted shale above the geopressured zone) followed by a drastic resistivity decrease (in the geopressured zone itself).

Normally pressured shales have increasing resistivity with depth, as would be expected because of their increasing degree of compaction and decreasing water content. However, geopressured shales have lower resistivities because of their increased water content (*i.e.*, the excess water trapped during burial). When the drilling engineer sees a sudden increase in shale resistivity gradient, the mud weight is increased in anticipation of penetrating the geopressured zone. In some cases, shale resistivity may increase below the zone until normal shale resistivities are again encountered; in this case, unlike with mud records, it may be possible to identify the top and bottom of the zone. It is also possible to detect multiple geopressured zones in a single well using this method.

There was no indication in the literature that the shale resistivity versus depth plotting technique had been applied to geopressured resources in California. The difference in geologic environment between the Gulf Coast and California (higher tectonic stress and the disturbed nature of the sediments) may present same limitations. Other problems with this method include difficulty in sand-shale discrimination, and poor log quality. However, as can be seen in Figure 4, it is possible to identify geopressured zones using this method, and the results compare favorably with those obtained from the analysis of mud weights.

Figures 5 and 6 show another example of mud weight and shale resistivity versus depth plotting to identify a geopressured zone in a well in the Kettleman North Dome oil field in the San Joaquin Valley. The shale resistivity plot indicates that the top of the geopressured zone lies between 10,600 feet and 10.800 feet; the mud weight records indicate that the zone is about 600 to 800 feet deeper. Although the available data do not reveal the cause for this discrepancy, a plausible explanation is that the driller did not increase mud weights until after the well had encountered the transition zone and was already producing fluid.

Density, neutron and sonic logs could also be used to identify geopressured zones in a similar way. However, such logs are generally not found in the public archives and we were unable to thoroughly investigate their utility.

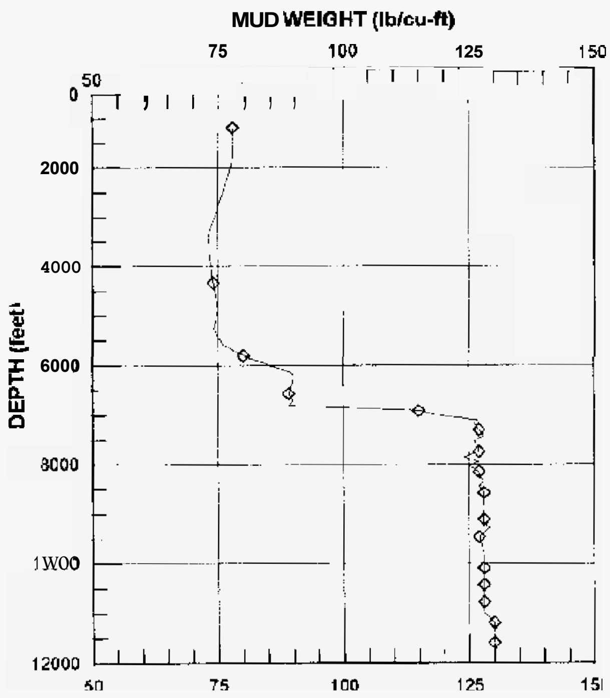


Figure 3 Mud weight vs. depth. Arbuckle well Section 4 Unit 1

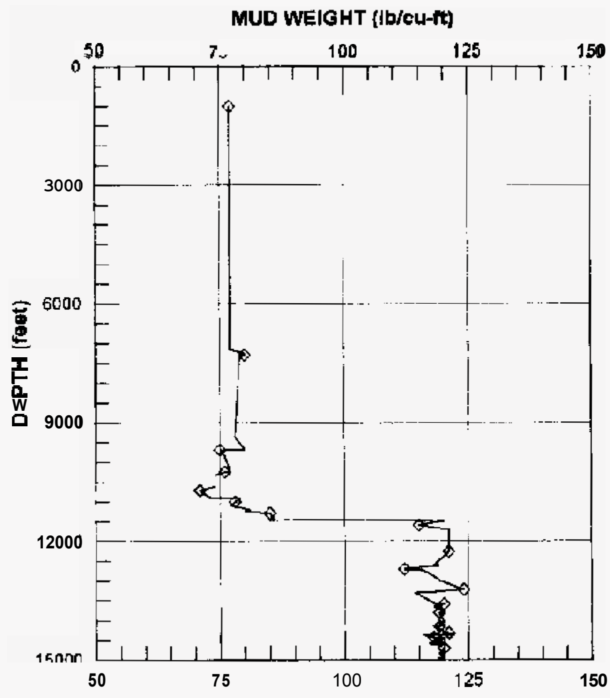


Figure 5: Mud weight vs. depth, Kettleman North Dome well 423

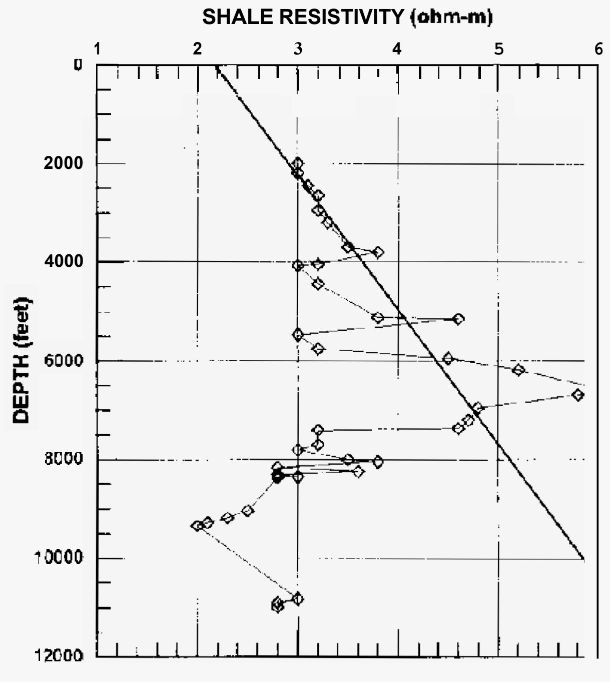


Figure 4: Shale resistivity vs. depth, Arbuckle well Section 4 Unit 1

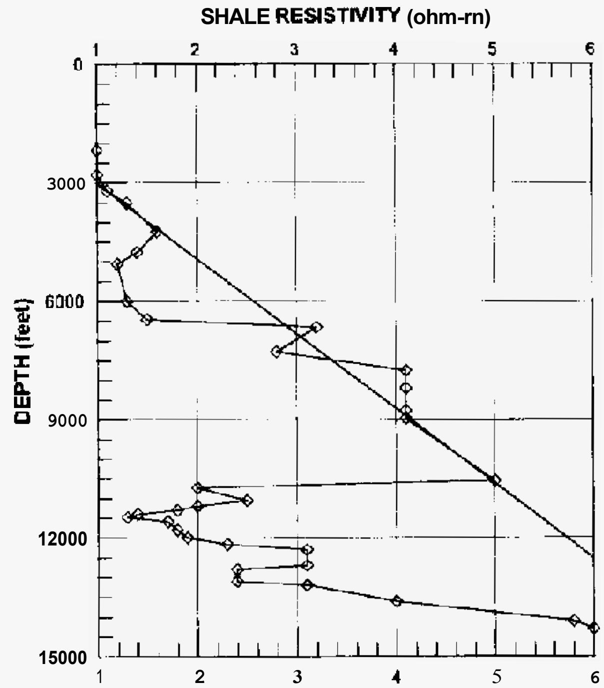


Figure 6: Shale resistivity vs. depth, Kettleman North Dome well 423

4. QUANTIFICATION OF GEOPRESSURE FROM RESISTIVITY LOGS

Quantification of geopressure is an important step toward evaluating the magnitude of geopressured resources in California. There are several well known correlations between pressure and shale resistivity which have been applied extensively in the Gulf Coast. We review those here and attempt to develop a correlation appropriate to the geologic environment in California.

For well data collected in the Gulf Coast region, Hottman and Johnson (1965) showed that the pore pressure gradient (p/D) can be correlated to the ratio of the observed shale resistivity (R_{sh}) to the normal shale resistivity (R_{shn}) at any depth in a well. R_{shn} is determined from the trend on the shale resistivity versus depth plots. The Hottman-Johnson correlation is:

$$p/D = 0.465 + 0.592\left(1 - \frac{R_{sh}}{R_{shn}}\right) \qquad (1)$$

For a normal (*i.e.*, non-geopressured) shale, $R_{sh}/R_{shn} = 1$; therefore $p/D = 0.465$ psi/foot, the normal hydrostatic gradient for the Gulf Coast region.

Lane and MacPherson (1976) developed a similar correlation based on newer data. The Lane-MacPherson correlation is:

$$p/D = 0.465 + 0.519\left(1 - \frac{R_{sh}}{R_{shn}}\right) \qquad (2)$$

Lane and MacPherson (1976) also pointed out that correlations (1) and (2) could be improved if overburden stress could be accounted for. Based on estimated overburden gradients (g_o) from density logs and gravity data, they proposed that:

$$p/D = 0.465 + m\left(1 - \frac{R_{sh}}{R_{shn}}\right) \qquad (3)$$

where m = 0.590 when 0.95 < g_o ≤ 1.00 or
m = 0.550 when 0.90 < g_o ≤ 0.95 or
m = 0.509 when 0.85 < g_o ≤ 0.80.

Eaton (1972) also incorporated the overburden gradient and proposed the following correlation:

$$p/D = g_o - 0.535\left(\frac{R_{sh}}{R_{shn}}\right)^{1.5} \qquad (4)$$

Equation (4) fits Hottman and Johnson's database fairly well. It should be noted that for a normal Gulf Coast formation, g_o = 1 psi/foot and R_{sh}/R_{shn} = 1, giving p/D = 0.465 psi/foot, the normal hydrostatic gradient in the Gulf Coast region.

The methodologies and the correlations developed for the Gulf Coast are not directly applicable to the California reservoirs for at least two reasons:

- All of the correlations imply a normal hydrostatic gradient of 0.465 psi/foot, whereas the range of hydrostatic gradients for all the California regions studied has been found to be 0.40 to 0.45 psi/foot. The lower salinity of formation waters in California result in a lower hydrostatic pressure gradient.

- The correlations discussed above do not take into account the effect of tectonic stress, which is present in many parts of California.

Therefore, we have attempted to develop appropriate correlations between pressure gradient and shale resistivity ratio for California; some preliminary results are presented below.

Our first attempt was to develop a correlation similar to equations (1) and (2) above. Ideally, because of differing geologic conditions (particularly the natural variation in tectonic stress), separate correlations should be developed for each of the different sedimentary basins shown on Figure 1. However, the realities of project budget allowed us to develop only a single correlation covering all the regions studied using the limited number of well logs studied to date. It should be kept in mind that such a correlation is not expected to be very accurate.

Figure 7 is a plot of the R_{sh}/R_{shn} ratio versus p/D for a few wells known to encounter geopressured zones in California oil and gas fields. Shale resistivity versus depth plots similar to Figures 3 and 6 were made for each well, and the R_{sh}/R_{shn} ratios were estimated for each well. The p/D values were obtained from actual pressure measurements (such as drillstem test data) or estimated from mud weight records. Figure 7 also includes a normal pressure point for pure water (point 8) represented by R_{sh}/R_{shn} = 1 and an average hydrostatic gradient of 0.44 psi/foot.

The data points in Figure 7 have been force-fitted to a straight line passing through the normal pressure point. Data points 2 and 5 on the plot are known to represent questionable log data. The remaining data points seem to define a linear trend, from which one can derive the following correlation for California in the manner of equations (1) and (2):

$$p/D = 0.440 + 0.511\left(1 - \frac{R_{sh}}{R_{shn}}\right) \qquad (5)$$

We consider this correlation to be tentative and hope to refine it by further log analysis. It may be useful to develop separate correlations like equation *(5)* for each major region in California,

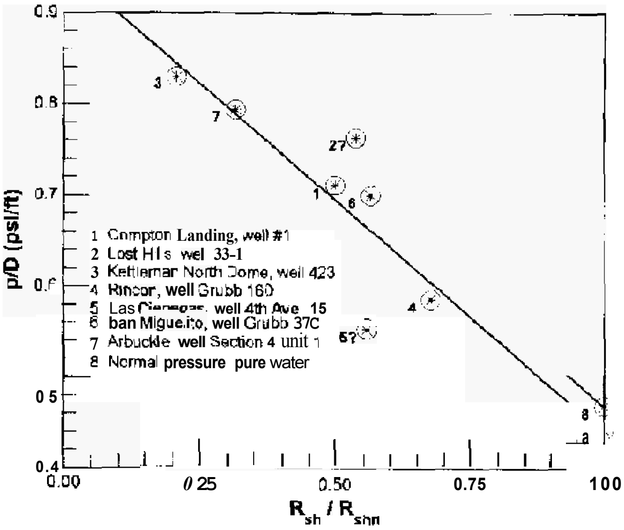


Figure 7: Pressure gradient vs. shale resistivity ratio for California oil and gas wells encountering geopressured zones

and separate correlations for several ranges of overburden pressure, following the approach of Lane and MacPherson (1976) in equation (3).

5. GEOPRESSURE - TEMPERATURE RELATIONSHIP

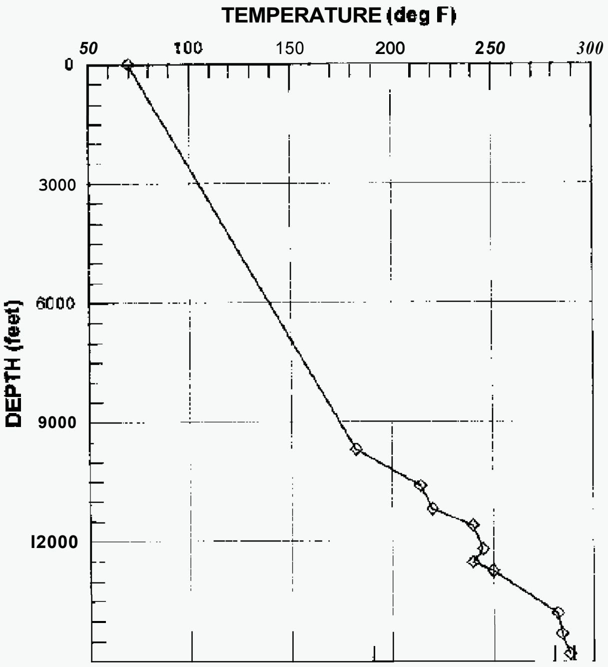
Interestingly, the CDOG data indicate no correlation between geopressure and elevated temperatures. Elevated temperature gradients near geopressured zones in areas of rapid sedimentation (such as the Gulf Coast) occur because geopressured lenses contain excess pore water (which could not be expelled during deposition and burial) and are therefore poorer heat conductors than the surrounding medium. However, plots of temperature versus depth for all pools in the California database yielded normal temperature gradients in the range of 1 to 2°F per 100 feet. This may be an artifact of poor measurements; a well may not have been fully heated when temperatures were measured, or the reported temperature was measured at a level higher than the pool depth. Alternatively, it is possible that geopressure in California may be a result of tectonic stress; in this case, the rapid burial mechanism would not apply.

In an attempt to determine if the pool data was too gross to identify a positive correlation between geopressure and elevated temperature, maximum recorded temperature data from two wells known to have encountered geopressured pools were plotted versus depth. Figure 8 shows the temperature data from the same Kettleman North Dome well used above; the data from this and several other wells drilled into geopressured zones indicate no steepening of temperature gradients above the geopressured zone.

6. INVESTIGATION OF OTHER PARAMETERS

The CDOG database was used to further assess the nature of geopressured pools in California in terms of porosity, salinity, depth, thickness and volume. Plots of each of these parameters versus pressure gradient did not yield any readily apparent significant trends; therefore, plots of statistical distribution were made. The need for a statistically significant database necessitated the use of the 410 "potentially" geopressured pools rather than the 70 'distinctly' geopressured pools. Distributions of parameters of potentially geopressured pools were compared with those from all 975 pools; for all parameters, the shape of the geopressured distribution was similar to that for all pools in the database.

The database included average porosity values for 878 pools, 380 of these being potentially geopressured. As mentioned above, the geopressured data set was found to have the same statistical distribution as the entire data set, with modal porosity in the range of 2F to 25%. Salinity data were available for a total of 424 pools,



172 hcing gcoprcssurcd. A bimodal distribution was **observed** in both cases, **with** modes of 0 - 10.0110 ppm and 25,000 - 30,000 ppm. These ranges **are** *at* least an order of magnitude lower than thc Gult Coast, wherc **salinity** typically exceeds 100,000 ppm. The implication of lower salinity is that the solubility of methane should be higher (**Kharaka** *et al.*, 1981). This **is** discussed further below.

The depth range for geopressured pools in California is 1,000 to 18,000 feet, with a **modal valuc** of ahout 3,000 feet. **This** implies that drilling costs should be significantly lower than the Gulf Coast, where depths to **geopressured** zones **typically exceed** 12,000 feet, Geopressured pools in California appear to be relatively thin (modal thickness **less than** 250 feet, with a distribution highly **skewed** toward the thin end). However, it is the thickness of the hydrocarbon producing zones which have been evaluated; **the** gcoprcssurcd water aquifer underlying the oil-water or gas-water contact may be considerably thicker. Therefore, it **must** be said that a statistically significant databasc on **the thickness** of gcoprcssurcd aquifers in California has **not** yet **heen** dcvclnpcd.

The same can he said fur geopressured reservoir volume. **As with** thickness, volume calculations are **bawd strictly upon** the thickness **and** reported areal cxtent of oil and gas pools **rather** than the geopressured aquifers. However, tlir available **data.** which indicate **a** modal **value** of 0.1 to 1.0 billion cubic feet, may **present** a lower volumc limit. An increase of one or two orders of magnitude for geopressured aquifers **may be appropriate.**

7. METHANE CONTENT

The relationships between methane solubility, pressure, temperature **and salinity** are well known (Culberson and McKetta, 1951; **Brill**, 1975). Using the correlations developed hy these authors, the **range** of dissolved methane to be expected in California geopressured pools can' **be** estimated~ **The** presenr **study** suggests that gcoprcssurcd pools **in** California **have a** temperature range of 70 to 420°F (assuming a 60°F ambient temperature) and a pressure range of 1,000 to 18,000 psi.

Using the temperature/pressure correlation with methane solubility from Culberson and McKetta (1951), we estimate **a** dissolved methane content of 10 to 100 standard cubic **feet** per barrel (**scf/bbl**) for purc water at tho temperature and **pressure** ranges listed above. Fur the salinity range of 0 to 50,000 ppm, the Brill (1975) data suggest that methane solubility **should be** 75 to 100% of that expected in pure **water.** Therefore: **dissolved** methane **could** range from 75 **to** 100 scf/bbl. The mast **important variable** controlling **the** amount of methane **is** pressure, wliicli. because **of its** depth **relationship**, indicates that **deeper pools** should **have** higher methanc content.

8. CONCLUSIONS

There appears to be considerable **geopressurcd** rcsourcc potential in the State of California. The mechanism uf **its formation** is a least partially related to tectonic stress, whereas **in** the **U.S. Gulf Coast** region, geopressure **results from** rapid **sedimentation** and burial. This conclusion is supported **by** the lack of a positive. correlation **between** elevated prcssure gradients and **elevated** temperature gradients. as well as the cxistence of superpressure in several pools.

Distinctly geopressured nil and gas pools are **identified in all of** the major hydrocarbon-producing basins except the Salinas Valley. It is highly **likely** that geopressure **may he found elsewhere in the** State; however, the **coincidence** in **location** with oil **and** gas fields is favorable because the initial use nf geopressured **fluids may be** in secondary oil recovery operations.

Certain modal characteristics have hcen identified using the database of all of the potentially geopressured pools (those with prcssurc gradients exceeding 0.45 psi/foot). **Among** these **are** relatively shallow depth, high porosity and low salinity. The latter is favorable for methane solubility, and suggests that methane may **be** present in economic quantities. **Only** lower limits on thickness and **volumc could** bc **cstimated** however. these **limits** indicate that a significant geopressured resource base **exists** in California.

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SI Metric Conversion Fnctors

foot	x	0.03048	= m
foot^3	x	2.831 x 10^{-2}	= m^3
scf/bbl	x	0.177	= m^3/m^3
psi/foot	x	2.262 x 10^4	= Pa/m
(°F-32) / 1.8			= °C
°F/100ft	x	18.228	= °C/km