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The Geopressured Habitat
A Literature Review

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ABSTRACT

A literature review of the geopressured-geothermal habitat is summarized. Findings are presented and discussed with respect to the principal topics:

Causal agents are both geological and geochemical; they include disequilibrium compaction of sediments, clay diagenesis, aquathermal pressuring, hydrocarbon generation, and lateral tectonic compression.

The overall physical and chemical characteristics of the habitat are dictated by varying combinations of sedimentation rates, alteration mineralogy, permeability, porosity and pressure, temperature, fluid content and chemistry, and hydrodynamic flow.

Habitat pressure seals are considered in terms of their formation processes, geologic characteristics, and physical behavior, including pressure release and reservoir pressure recharge on a geologic time scale.

World-wide occurrence of geopressured-geothermal habitats is noted. The main thrust of this topic concerns the U.S.A. and Canada; in addition, reference is made to occurrences in China and indications from deep-sea vents, as well as the contribution of paleo-overpressure to habitat initiation and maintenance.

Identification and assessment of the habitat is addressed in relation to use of hydrogeologic, geophysical, geochemical, and geothermic techniques, as well as well-logging and drill-stem-test data.

Conclusions concerning the adequacy of the current state of knowledge and its applicability to resource exploration and development are set forth, together with recommendations for the thrust of future work.

SUMMARY

The geopressured-geothermal resource resides in a highly pressured, very hot environment, and comprises three forms of energy: chemical, thermal, and hydraulic. The chemical form is methane gas, often called natural gas. Methane represents about 90% of the gas found in most of the hot geopressured brines in the Gulf Coast basins. Thermal energy is contained in the hot brines, at bottomhole pressures up to 18,000 to 20,000 psi in deep wells. The resulting 2,000 to 3,500 psi flowing wellhead pressures can also be harnessed as useable hydraulic energy. It has been estimated that there are as high as 180,000 quads of geopressured-geothermal energy in the onshore Gulf Coast alone. In the Rocky Mountain basins, there is usually much less fluid compared with the Gulf Coast geopressured reservoirs, and hence less thermal and hydraulic energy.

Geopressured basins can occur anywhere in the world in shaley sedimentary formations. In the U.S.A., they are found in the Gulf Coast area, the Rocky Mountain region, and California. Pressures approach lithostatic gradients in most of these basins, and in the Gulf Coast Frio Formation they may exceed the lithostatic gradient, showing values up to 1.06 psi/ft. Geopressured resources in the Gulf Coast area have been studied intensively under the Department of Energy Geopressured-Geothermal Program.

Temperatures in the Gulf Coast Frio Formation reservoirs range from 250 to 350°F (121 to 177°C), much hotter than boiling water. In the Upper Wilcox in south Texas the temperatures are higher, ranging from 350 to greater than 500°F (177 to greater than 260°C). In the Rocky Mountain basins the temperatures are more moderate, but still hotter than boiling water, ranging from 210 to 240°F (99 to 116°C). California reservoirs also appear to have more moderate temperatures, from 190 to 230°F (88 to 110°C), but not much data are available from California wells in the geopressured zones.

Geopressured brines in the Gulf Coast Frio Formation contain 20,000 to 200,000 ppm total dissolved solids (TDS). The majority of the TDS is usually sodium chloride. In the Rio Grande Embayment in south Texas, the Upper Wilcox Formation contains much less solids, ranging from 3,500 (the fresh end of brackish) to 70,000 ppm TDS. In the Rocky Mountain Region there is

little fluid in most geopressured reservoirs, in contrast to the Gulf Coast. In California the TDS content ranges from 8,000 to 70,000 ppm.

The geology that leads to geopressured basins involves shaley basins with a subsidence rate greater than 1 mm/year and sedimentation rates greater than 100 meters per million years. The high ambient temperatures (≥200°F) at depth promote the physical and chemical processes responsibile for developing these basins.

At about 200°F (93°C) the source material for hydrocarbons (kerogen) begins to generate oil and gas, and coincidentally, the smectite clays begin to transform to illite clays. These two thermally driven processes are powerful causal agents in the development of compartment seals and geopressure. The three most important causal agents are probably nonequilibrium compaction due to rapid sedimentation and subsidence, hydrocarbon generation, and clay transformation. Additional causal agents for geopressure are aquathermal pressuring, lateral tectonic compression, and chemical osmosis. Since many of the changes causing pressure buildup are related to temperature effects on sediments and hydrocarbon source rocks (kerogen), the effects will be more pronounced in regions of high heat flow.

Geopressured reservoirs may be considered sealed-off compartments. The top seals range in thickness from 150 ft to more than 3,000 ft in thickness. The seal can be impermeable, self-sealing shale, a mineralized zone with calcium carbonate or silica deposition, or the smectite/illite boundary in the shales. Lateral seals frequently follow faults and are nearly vertical. They can be 1/8 to 6 miles wide.

The Gulf Coast geopressured reservoirs tend to follow fairways related to deposition, heat flow, and faulting. The top of geopressure is usually found at a depth of 10,000 to 12,000 ft, but it is as shallow as 6,000 ft in south Texas and can be as shallow as 140 ft in abnormally pressured mudstones.

In California, where lateral tectonics contribute to overpressure, the reservoirs are pods and lenses. In the Rocky Mountain Region the geopressured zones are usually located in the central part of deep basins. Overpressured sediments alternating with normal hydrostatic-pressured layers are typical.

Porosity in geopressured zones may increase by 10 to 25% with depth; actual porosity may be 20 to 35%. However, a wide range of porosities have been shown to occur in geopressured basins.

Gases and fluids gradually leak from geopressured reservoirs to shallower traps and eventually to the surface, over geologic time, as a result of uplift and/or thermal cooling. Thus, with time, a geopressured basin will become a normally pressured basin, or even an underpressured basin such as the Illinois Coal Basin.

Although the predominant hydrocarbon found in Gulf Coast, Rocky Mountains, and California geopressured-geothermal reservoirs is methane gas, other hydrocarbons found in Gulf Coast reservoirs include condensate, oil, and cryocondensate, the latter so named because of the cold system used to collect the material, mainly aromatic hydrocarbons.

Geopressured zones can be identified on sonic logs, resistivity logs, mud logs, seismic data, and acoustic logs. There is some evidence that shallow thermal surveys and Landsat can be used to identify geopressured reservoirs.

The work presented here is a critical review of available literature dealing with geopressured-geothermal resources. The supporting evidence for various hypotheses set forth by investigators is examined in detail for validity, consistency among sources, trends, and applicability toward postulated mechanisms or conclusions. The information contained herein represents the present state of knowledge concerning causal agents, physical and chemical descriptions of the fluids and their behavior, and overall reservoir and seal behavior.

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THE GEOPRESSURED HABITAT
A Literature Review

INTRODUCTION

This report discusses the development of geopressures in sedimentary basins in terms of causal agents, timing, fluids, and physical and chemical properties as they are understood at the present time, with state-of-the-art data from published and unpublished sources.

The geopressured-geothermal resource encompasses three energy sources. Chemical energy is present as free and dissolved gas, mainly methane, under high pressures in the brine. Hydraulic energy is available in the high flowing pressure of the brine, and the high temperature of the brine is the source of the thermal energy. Increased interest in the potential harnessing and diverse utilization of these energy forms provides the basis for developing a better understanding of the interaction of the physical and chemical range of properties in the geopressured habitat (Negus-de Wys, 1990 and Negus-de Wys et al., 1991).

Pressures exceeding hydrostatic gradients and approaching lithostatic gradients have long been recognized in sedimentary basins in many parts of the world (Fertl, 1976; Hunt, 1990). High-pressure blowouts were recorded early in the history of the oil and gas industry. Problems of abnormal pressures related to drilling were reported by Chaney, who identified two requirements for high pressure buildup: 1) an isolated or sealed reservoir, and 2) formation of oil and gas by the progressive degradation and rearrangement of high-molecular-weight organic materials (Chaney, 1949). These early views are being echoed in present-day research and thinking in regard to the development and causal agents of geopressured chambers (Powley 1990 a and b; Bradley, 1991 private communication; and Hunt, 1991 a and b).

The interest in identification of causal agents specific to a unique basin or region has increased in recent years. Causal agents proposed include rapid accumulation of fine-grained sediments, aquathermal pressuring from thermal expansion of pore fluids, dehydration reactions of clay minerals, thermal cracking of petroleum and other organics, lateral tectonic compression, topographic relief, and diagenetic overpressures.

Nomenclature used by different authors includes geopressure, abnormal pressure, and overpressure. The term "geopressure" was originated by C. A. Stuart to describe "an overpressure generated by the overburden" (Parker, 1974). It is apparent today that overburden alone is not necessarily the major causal factor in many of the basins to be discussed. Nonetheless, the term has remained as a descriptive word communicating the high pressure conditions of a sedimentary basin, especially for the conditions in the Gulf Coast area. The focus in this report is on pressure conditions greater than the hydrostatic gradient and approaching the lithostatic gradient.

From a study by Amoco begun in 1980, it was determined that all the basins studied in the United States, with the exception of the Illinois Coal Basin, showed evidence of a geopressured compartment (Powley, 1991, private communication). Twelve basins in the Rocky Mountain Region were identified as having deep geopressured compartments.

The recognition that many, if not the majority of, basins go through a geopressured phase during basin evolution suggests that geopressure is the norm rather than the exception for sedimentary basinal evolution on a global scale, especially where organic deposits have been buried deeply enough and long enough geologically to generate sufficient hydrocarbons to contribute to the pressure buildup and seal development. This tenet, coupled with petroleum geochemistry and paleohistory, becomes a powerful tool for hydrocarbon exploration. The buildup and loss of geopressure is part of a global and possibly universal process. All sedimentary basins gradually, through geologic time, lose their fluids and gases to space, first from the rock strata through fractures, fissures, and volcanoes, and subsequently from the surface through the atmosphere. Some basins e.g., the Illinois Basin, actually become underpressured with time through uplift, erosion, and cooling, but their earlier geopressured state is readily documented.

Thus, a global process, where the proper conditions exist, follows a pattern of basinal filling with shaley sedimentation, transformation of clays [i.e., smectite to illite at temperatures greater than 200^0F (93^0C)], burial and thermal maturation of organics (kerogen), development of seals and pressured compartments, vertical and horizontal compartment leakage leading to reduction of pressure, and eventual outgassing at the surface and loss to and through the atmosphere to space, depending on the molecular weight of the final product and the planet's escape velocity.

Sedimentary basins located around the margins of the North American craton, as well as those along the interior seaways, e.g., the Cretaceous inland sea spreading from the Gulf of Mexico to the Arctic, show the evidence of fluctuating sea levels and the resulting staggered layering of sandstones, siltstones, shales, organic sediments, and carbonates, a rock testimony to transgressions and regressions of earlier seas. These layers of clastics and carbonaceous sediments are the inherent ingredients for the development of pressure gradients in excess of a column of water, the hydrostatic gradient. As the carbonaceous organic sediments are buried, compacted and lowered into an ever increasing thermal environment, acting as a geologic furnace for the contained organic debris, hydrocarbons in the form of oil and gas are generated. As pressure differentials increase, the hydrocarbons begin to migrate. The first pressure chamber may be the sandstones adjacent to the organic shale source rock.

The role of seals, both as agents in promoting the development of pressure compartments and, in turn, seal enhancement as a consequence of chamber development, has become an area of interest in itself, as evidenced by the Gas Research Institute's Research Program on Abnormal Pressure Compartment Seals (Bradley, 1991, private communication; Powley, 1990; Westcott, 1991, private communication).

For the past 17 years the Department of Energy (DOE) has researched the geopressured-geothermal reservoirs in the Texas and Louisiana Gulf Coast. This program is entering the transition period to commercialization through the development of an industrial consortium for the utilization of the geopressured resource (Negus-de Wys, 1991).

In this report, data from basins in the Gulf Coast area, the Rocky Mountain Region, California, Canada, and selected foreign examples will be discussed. The use of computer simulation in reservoir modeling focuses the need for accurate rock mechanics data, geological models, and fluid chemistry and properties. These data are included where available.

CAUSAL AGENTS

Early in the development of the oil and gas industry a relationship was recognized between hydrocarbon accumulations and geopressure, or overpressure as it was frequently called (Chaney, 1949). Specific causal agents appear to play a larger role in some regions than in others. However, the common thread in all cases appears to be hydrocarbon generation and clay transformation, both triggered by temperature.

Causal agents cited in the literature as contributing to the development of geopressured conditions include the following:

1. Disequilibrium/nonequilibrium compaction due to rapid sedimentation, also termed gravitational loading (Law and Dickinson, 1985; Bredehoeft and Hanshaw, 1968),
2. Aquathermal pressuring (Barker, 1972),
3. Clay diagenesis including
   a. Transformation of montmorillonite (smectite) to illite, also termed montmorillonite dehydration (Powers, 1967),
   b. Transformation of gypsum to anhydrite,
   c. Diagenetic reaction of carbonate and kaolinite to form chlorite, calcite, and CO_2,
4. Fluids and gas production due to hydrocarbon generation by thermal maturation, and thermal cracking of hydrocarbons, (Hedberg, 1979; Momper, 1980; and Hunt, 1991 a and b),
5. Chemical osmosis and reverse chemical osmosis (Smith and Thomas, 1971),
6. Lateral tectonic compression (Smith and Thomas, 1971),
7. Recharge (Smith and Thomas, 1971), and
8. Adsorption (Smith and Thomas, 1971).

In this section, the causal agents are defined in terms of their effects, and the results of pertinent investigations in each area are summarized, discussed, and evaluated.

Disequilibrium Compaction

Nonequilibrium compaction means that normal dewatering has not taken place with burial because of low permeability, and at greater depths the excess water carries part of the residual normal stress (Magara, 1975). According to this hypothesis, the present residual normal stress should be equal to the maximum residual stress ever suffered by the section (Plumley, 1980). The present residual stress will correspond to a maximum residual stress at a specific depth for the beginning of nonequilibrium compaction. This depth is then projected to the shale density curve, which will give a value that should be observed if nonequilibrium compaction is the sole cause of high pressures. If the value is far below that observed at any level in the formation it suggests that nonequilibrium compaction was not a primary mechanism for the generation of abnormal pressures.

Plumley (1980) concludes that "observed porosities in Gulf Coast high pressure shale formations commonly are too low to be solely the result of nonequilibrium compaction. In two field examples, shale porosities predicted with the nonequilibrium compaction model are about 20 porosity units higher than porosities determined from density logs and cores. In one example, a combined mechanism of nonequilibrium compaction and clay transformation is one possible, and internally consistent, interpretation of the fluid pressure and porosity data. In the other example, the fluid pressure and porosity data are consistent with clay transformation as the mechanism for the generation of the abnormally high fluid pressure, but are not consistent with the nonequilibrium compaction model." Plumley defines "compaction" as the stress-induced process by which porosity is reduced below the value corresponding to the Atterberg plastic limit in contrast to "consolidation," which is the stress-induced process which reduces the porosity to the value corresponding to the Atterberg plastic limit. Compaction is a process whereby grains respond to stress by inelastic deformation, which is irreversible. The deformation may be caused by breaking, bending, plastic deformation, pressure solution, etc. Thus, the compaction process is the sum of both mechanical and chemical processes. In pure quartz sandstones, compaction appears to proceed essentially by pressure solution, whereas shales appear to be responsive also to other deformation processes such as bending and plastic deformation (Plumley, 1980).

"Under conditions of rapid sedimentation and a decrease in sediment permeability during burial, fluids are unable to escape rapidly, and the fluid pressure rises abnormally. As the effectiveness of the sealing zone increases, a condition is approached whereby the entire weight of the overburden is supported by the fluid." Clay transformation and aquathermal pressuring are two processes that potentially could pump up fluid pressure systems. The pressure-history and porosity-history paths of sediments acting in response to these processes will be distinctly different from those in nonequilibrium compaction. Identical fluid pressures at depth may be associated with different porosities (Plumley, 1980). See Figures 1-3.

Korvin (1984) addresses shale compaction with statistical physics. He concludes that "the exponential compaction law expresses the maximum-entropy statistical equilibrium state of the pores in the rock." He further concludes that compaction is an irreversible process where clay particles tend towards a statistically defined final equilibrium state. "This tendency observed and proved here for shales should also be present in the evolutionary history of more complicated multicomponent geological media such as sand-shale interbeddings - let alone shale sedimentary basins." Korvin shows that the exponential porosity-depth dependence of compacted shales expressed by Athy's law can be derived using standard methods of statistical physics.

Hunt (1991 a and b) provides a number of exceptions to the sedimentation rate of greater than 100 m/my (meters per million years) attributed to Bethke (1986) as a requirement to produce overpressuring in fine-grained sediments (Table 1).

Table 1. Sedimentation rates less than 100 m/m.y. for basins cited by Hunt (1991 b).

BASIN	SEDIMENTATION RATE	CAUSE OF OVERPRESSURE
Bhazenov shale W. Siberia	30 m/m.y. normal compaction	hydrocarbon generation
Bakken Formation Antelope Field N. Dakota	11 m/m.y. normal compaction	hydrocarbon generation
Green River shale Uinta Basin	normal pressures above and below; normal compaction	hydrocarbon generation
Gippsland Basin	53 m/m.y. normal compaction	hydrocarbon generation
Brassey Field W. Canada Basin	39 m/m.y. normal compaction	hydrocarbon generation
U.S. Gulf Coast (Louisiana)	anomaly: Undercompacted	compaction disequilibrium? hydrocarbon generation?
Offshore Beaufort	normal compaction	?
Scotian Basin	normal compaction	?
Mackenzie delta	normal compaction	?
Po Valley, Italy	normal compaction	?
North Sea	normal compaction	?
Cook Inlet	normal compaction	?

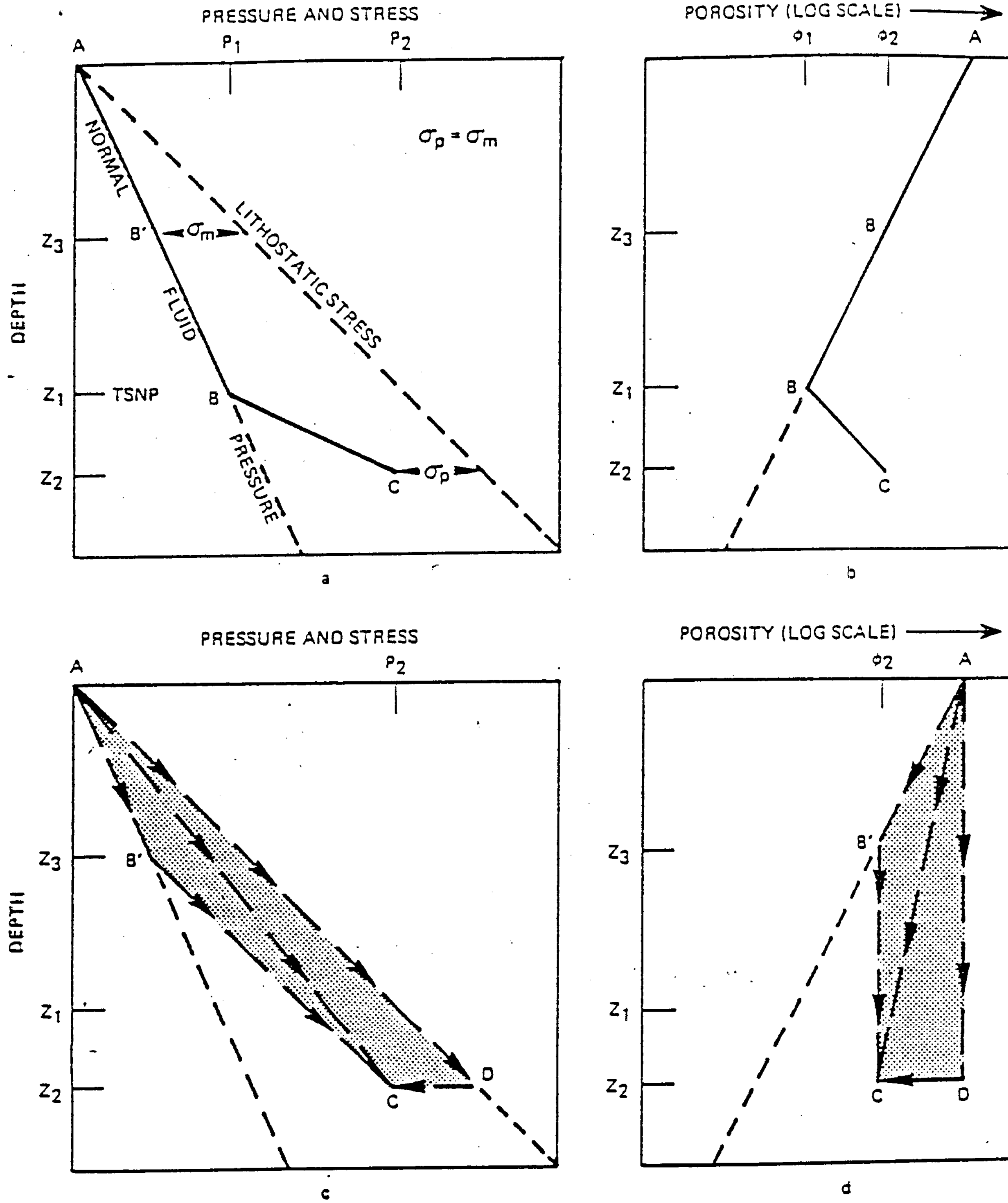


Figure 1. Pressure-depth and porosity-depth relations; nonequilibrium compaction model. a,b, Present-day curves of pressure-depth and porosity-depth. c,d, Possible pressure-depth and porosity-depth history paths of sediment (Plumley, 1980).

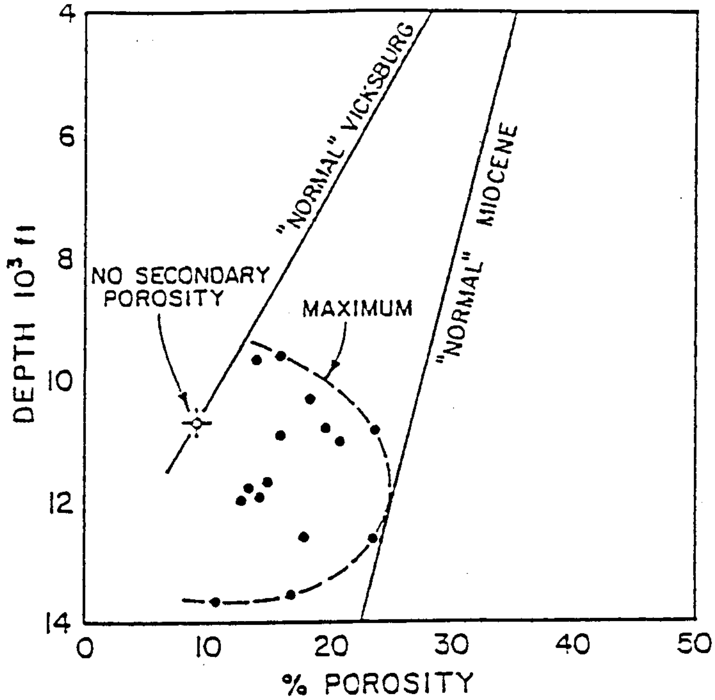


Figure 2. Porosity as a function of depth based on cores of Lower Vicksburg Sandstones. Measured porosities are proportional to secondary porosity by leaching observed in thin section (Kiass and others, 1981).

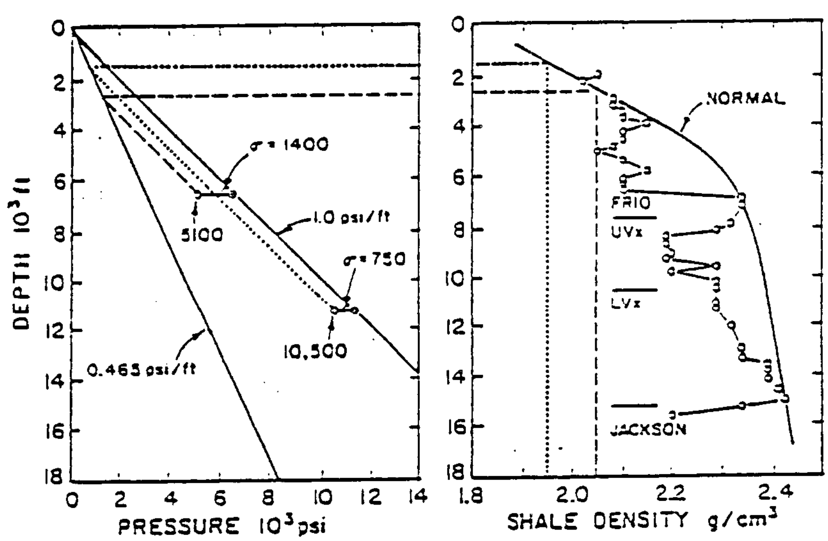


Figure 3. Bulk densities of shales compared with values of residual normal stress (sigma) in high pressure sections.

Aquathermal Pressuring

Aquathermal pressuring requires that a volume of shale was isolated during burial, and the expansion of interstitial water by increased temperature resulted in abnormal pressures (Barker, 1972). The mechanism of aquathermal pressuring may be evaluated by plotting measured and estimated pressures as a function of maximum temperature determined by the assumed gradient. If aquathermal pressuring is the sole cause of abnormal pressures, the values should be parallel to isodensity lines until the fracture-pressure gradient is reached (Barker and Horsfield, 1982).

If an isolated volume of sediment is moved into a region of higher temperature the pore fluids will tend to expand. If the rock framework restricts this tendency to expand, the fluid pressure must rise (Plumley, 1980).

This process could be effective provided that the rock-fluid system is isolated and maintains a constant pore volume as temperature rises. If typical Gulf Coast sediments were perfectly sealed and subsequently buried, following these assumptions the fluid pressure would increase at a rate of about 1.8 psi/ft (40.7 kPa/m) of burial in contrast to an increase of 1 psi/ft for a sealed system under conditions of nonequilibrium compaction and ignoring the temperature effect upon rock and fluid compressibilities (Magara, 1975). Depending upon when the seal was established and its effectiveness, high pressures could be associated with either high or normal porosities for the depth. Perfect seals, however, are hard to come by, especially in the Gulf Coast. In an analysis of Gulf Coast data, Magara (1975) concludes that overburden pressure alone could not explain actual subsurface pore pressures and that some other pressuring effect such as aquathermal, also must be involved.

Using an inverse solution to the Lagrangian equation of compaction flow (including effects of aquathermal pressuring and dehydration reactions), Bethke (1986) shows that pressured zones are likely to form in shaly basins subsiding more than about 1 mm/y but unlikely to develop in shale-poor basins or basins subsiding less than 0.1 mm/y.

Aquathermal pressuring is much less important than disequilibrium compaction in causing geopressures.

Comparing aquathermal pressuring versus mechanical loading, Chapman (1980) concludes that "the thermal hypothesis for abnormally high pore pressures in shales is not supported by inferences drawn from drilling and borehole logs in the transition zone at the top of zones of abnormal pressures." Barker and Horsfield (1982) present evidence to the contrary. By comparing the extremes resulting from mechanical and aquathermal pressuring Barker and Horsfield show that aquathermal pressuring can result in greater pressures, possibly exceeding lithostatic when the abnormally pressured zone is capped by impermeable seal. Mechanical loading cannot exceed a gradient of 1 psi/ft from the point of isolation. Chapman (1982) rebutts Barker and Horsefield's unpublished data as inconsistent with Chapman's work based on geologic evidence. Chapman considers abnormal pressures a dynamic, geologic problem. He cites evidence of early initiation of abnormal pressures at shallow depths and gives examples: 1) abnormally pressured mudstones less than 10,000 years old at depths less than 140 ft; 2) in New Zealand, abnormal pressures in Rotokautuku 1 at 1,168 ft and the need to abandon the well at 2,057 ft; 3) northwest Borneo Setap Shale Formation is abnormally pressured over a wide area; 4) abnormal pressures in the Gulf of Papua at 2,100 ft; and 5) evidence in the Gulf Coast that growth-fault movement reaches a peak within 2,000 ft above the top of abnormal pressures, i.e., the Midland Field, Louisiana. Chapman cites the last as supporting his interpretation of the effective compaction depth, commonly about 2,000 ft, as a measure of the maximum overburden thickness at the time of onset of abnormal pressures.

As further support for the mechanical hypothesis, Chapman notes the pressure-depth gradient in the transition zone from normal to abnormal pressures which exceeds the overburden gradient. This transition zone does not increase in thickness with depth, as documented by measured pressures in the Louisiana Gulf Coast. The transition zone does not involve constant water density. Chapman cites the Gulf Coast Pleistocene and Tertiary where there are several zones in which the abnormality (detected in the sonic log) first increases with depth, then decreases, and then increases again.

Daines (1982) contends that because the amount of fluid expansion is very small with temperature increases, typical hydraulic conductivities of clay rocks can accommodate the removal of this excess fluid in the time span available, and thus expansion of waters cannot contribute to the geopressure generating process. Daines found in a comparison of measured pore pressures within geopressured aquifers to pore pressures in adjacent argillaceous rocks that a difference of from -21.2% to +6.6% existed in 18 wells examined. Daines makes the following conclusions:

1. Aquathermal pressuring could be responsible for producing abnormal pore pressures only in shallow, impermeable sediments, particularly in areas of high geothermal gradients. It would appear that very small temperature increases cause the pore pressure to reach overburden magnitudes rapidly, and any subsequent temperature increase may cause the release of excess water volume through the formation of horizontal fractures. If this occurs, the fractures may play an important role in later hydrocarbon redistribution.

2. Because a small volumetric expansion due to temperature increase causes a large pressure increase in a closed system, it appears likely that, if the seal is a clay-rich lithology, the excess volume will be dissipated due to the permeability of shale. A transition zone is indicative of leakage from an abnormal pore pressure interval. If a transition zone does exist, then a process other than aquathermal pressuring must have been instrumental in producing the geopressure, as leakage of very small volumes will allow the excess pressure to return to hydrostatic (assuming no recharge mechanism).

3. Geopressure generation caused by expansion of pore waters resulting from temperature increase cannot be substantiated due to the rarity of totally impermeable sedimentary rocks in hydrocarbon provinces, the extremely small amount of excess fluid produced by thermal expansion which can be expressed within the time span available, and the almost prevalent occurrence of transition zones above geopressured sections. See Figures 4 and 5.

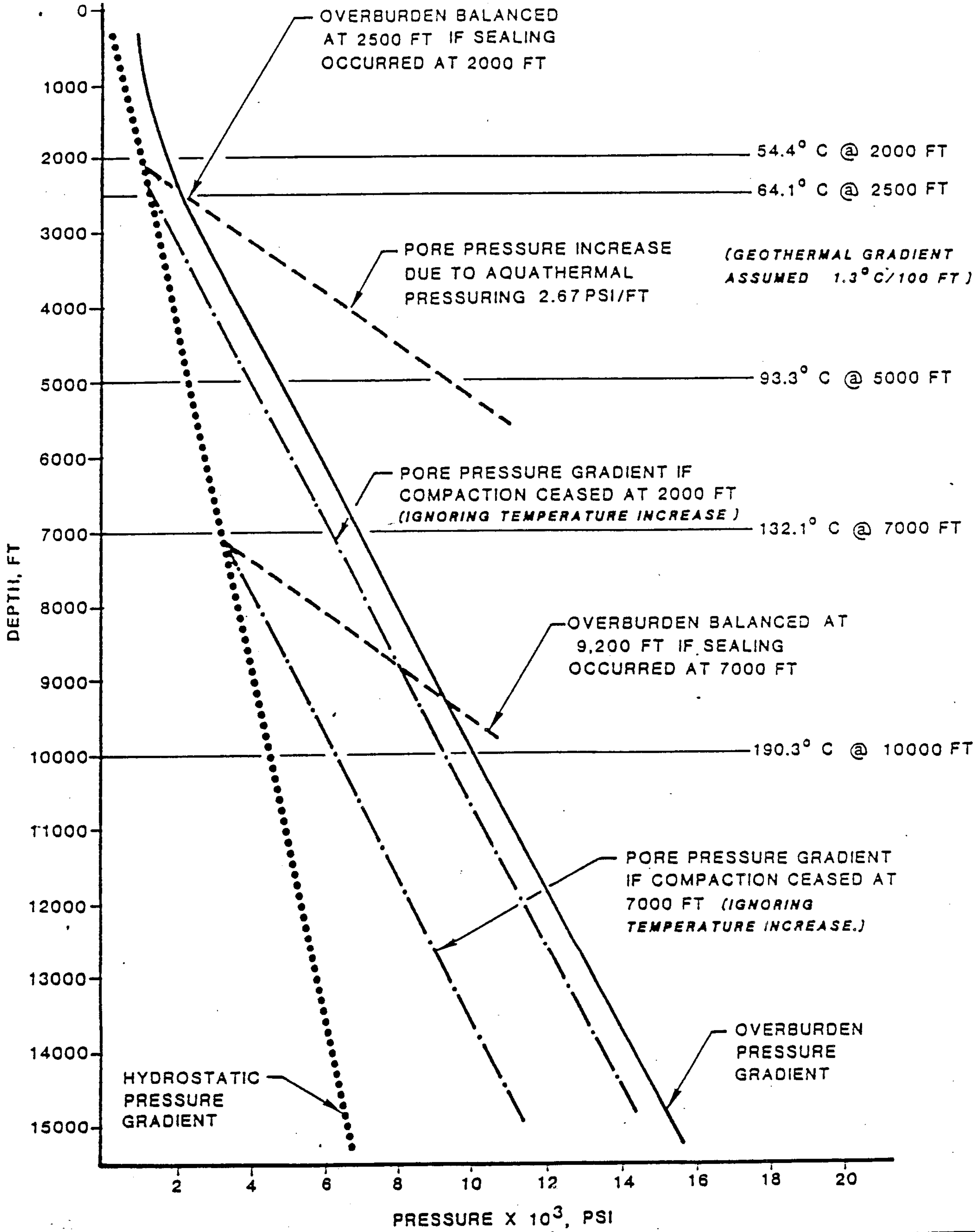


Figure 4. Pore pressure gradients produced by aquathermal pressuring allow overburden pressures to be reached rapidly, particularly at shallow depth (Daines, 1982).

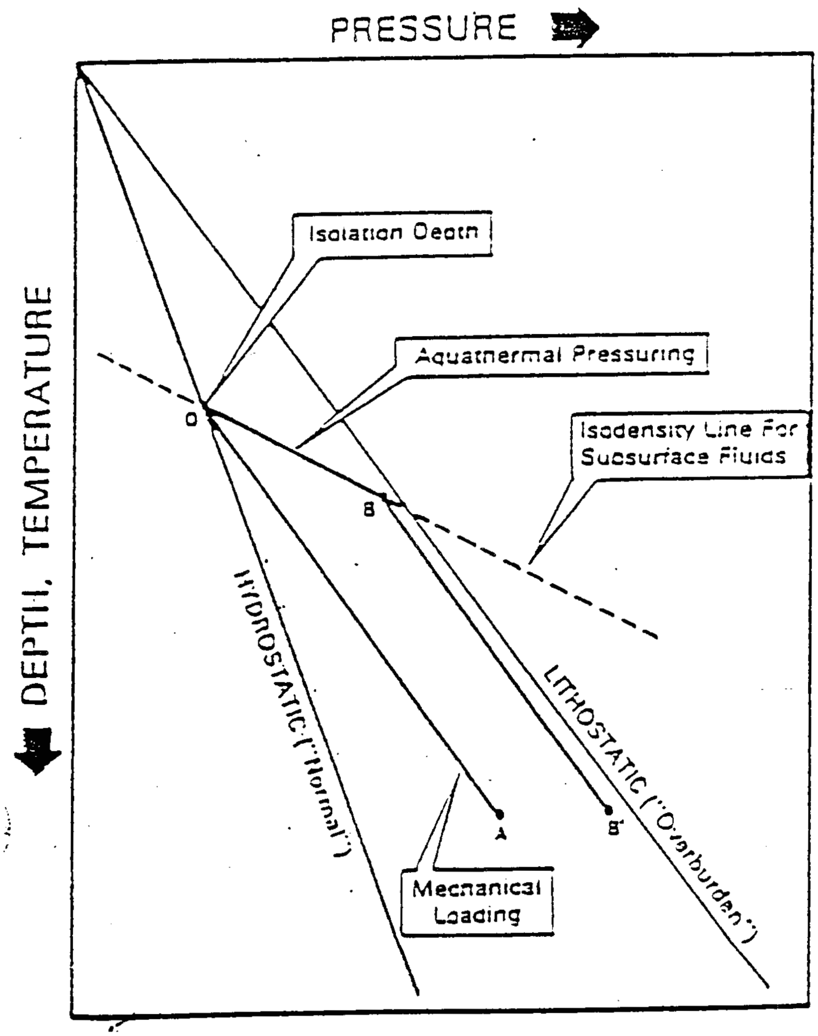


Figure 5. Pressure-depth (temperature) relations for lithostatic and hydrostatic pressures showing pressure trends developed by mechanical loading (DA) and aquathermal pressuring (DBB') (Barker and Horsfield, 1982).

Clay Diagenesis: Smectite to Illite Transformation

Clay transformation is a mechanism whereby interlayered water is released during burial under the influence of temperatures greater than 200°F (93°C) (Burst, 1969). The released water carries a part of the residual normal stress, and the result is increased fluid pressures and decreased bulk density of shales.

The transformation of smectite to illite has been termed smectite illitization (Bethke and Altaner, 1986). The transformation passes through a progression of increasing illite to smectite layers (I/S) and has been used as a thermal history indicator. The transformation may be a source of water which contributes to geopressures and petroleum migration (Powers, 1967; and Burst, 1969).

The abrupt appearance of high pressures that coincide with the abrupt decrease in smectite layers in shales and with temperature exceeding that required for transformation of clay minerals leads to an obvious conclusion that the clay transformation is the principal mechanism for the production of high-fluid pressures. This may not be the only cause (Berg and Habeck, 1982). See Figure 6.

The extent to which this process is effective depends upon not only the permeability, but also upon the amount of expandable clay, and the rate of clay transformation. About 10,000 ft burial depth in the Gulf Coast is required to initiate clay transformation. Field measurements of pressure and porosity may be interpreted to suggest that both nonequilibrium compaction and clay transformation (and possibly aquathermal pressuring) commonly may contribute to abnormally high fluid pressures, according to Plumley (1980). Observed porosities commonly are too low for nonequilibrium compaction to be the sole mechanism; sometimes they are too high for clay transformation to be the sole mechanism (Plumley, 1980).

Bruce (1984) studies Smectite Dehydration and its Relation to Structural Development and Hydrocarbon Accumulation in the northern Gulf of Mexico Basin.

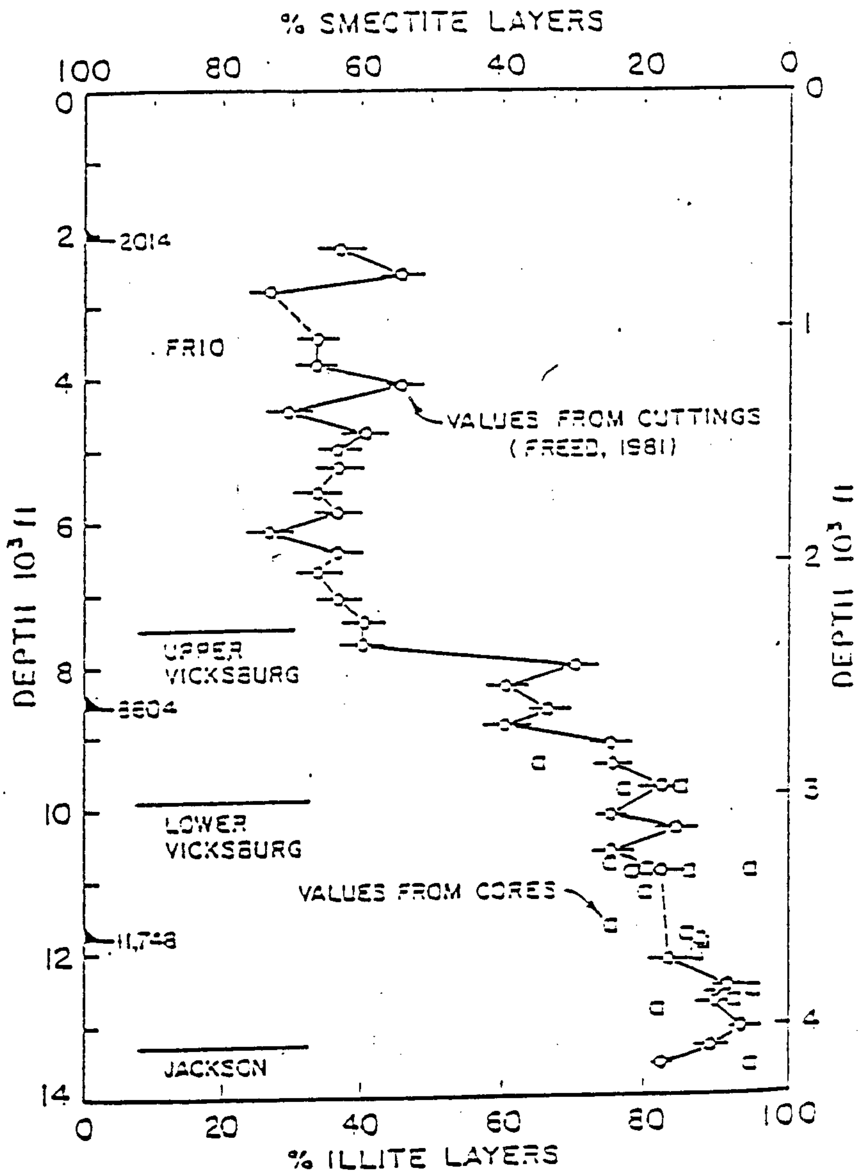


Figure 6. Proportions of illite and smectitle in mixed-layered illite-smectite clays as a function of depth. A sharp decrease in expandable clay at 8000 ft (2438 m) corresponds to a maximum temperature of about 210°F (99°C). Analysis of cuttings in Sheil McAllen 3 by Freed (1982): analysis of core samples of Habeck (1982) (Berg and Habeck, 1982.)

He writes, "Fluid movement upward through microfracture systems in the deeply buried overpressured section overlying and extending upward from fault trends in the sub-Tertiary section is proposed as a mechanism for flushing hydrocarbons from the deeper portion of the northern Gulf of Mexico Basin. This flushing process would be enhanced by smectite diagenesis because water derived from smectite that was trapped during basin subsidence would cause the flushing process to continue for longer periods of time and to extend to greater depths than could be attained if only remnants of original pore water were present." Bruce notes that the onset of abnormal pressure and smectite digenesis occurs at the same depth, below which the pore pressure gradient increased from hydrostatic to a value in excess of 0.80 psi/ft. See Figures 7 and 8.

Growth faults in the Gulf Coast frequently are deflected at the smectite-to-illite transition zone, corresponding to the top of geopressure, to the extent that the faults become horizontal bedding plane faults. Fluid movement in the high-pressure shale is predominantly vertical and upward (Bruce, 1984; Magara, 1975). The extension in the competent sub-Tertiary section results in downwarping and faulting, whereas growth faults and shale flows are formed in the overlying less competent section (Bruce, 1984). See Figure 9.

The data show that smectite diagenesis occurs at depths near the level for the onset of oil generation and the top of geopressure. Bruce concludes that smectite-illite transformation is a principal mechanism for development of abnormal pore pressure in the Tertiary section of the United States Gulf Coast.

Morton and Land (1987) report on the Frio sandstone diagenesis in the Texas Gulf Coast and deduce from detailed investigation of a small area of the northern Texas Gulf Coast (Brazoria County) that the burial diagenesis of Frio sandstones is regionally valid with only minor modifications.

Foster (1981) addresses the role of smectite-illite transformation in generating and maintaining geopressure. They note that mixed-layer smectite-illite clays comprise a significant fraction of fine-grained clastic sediments in many basins around

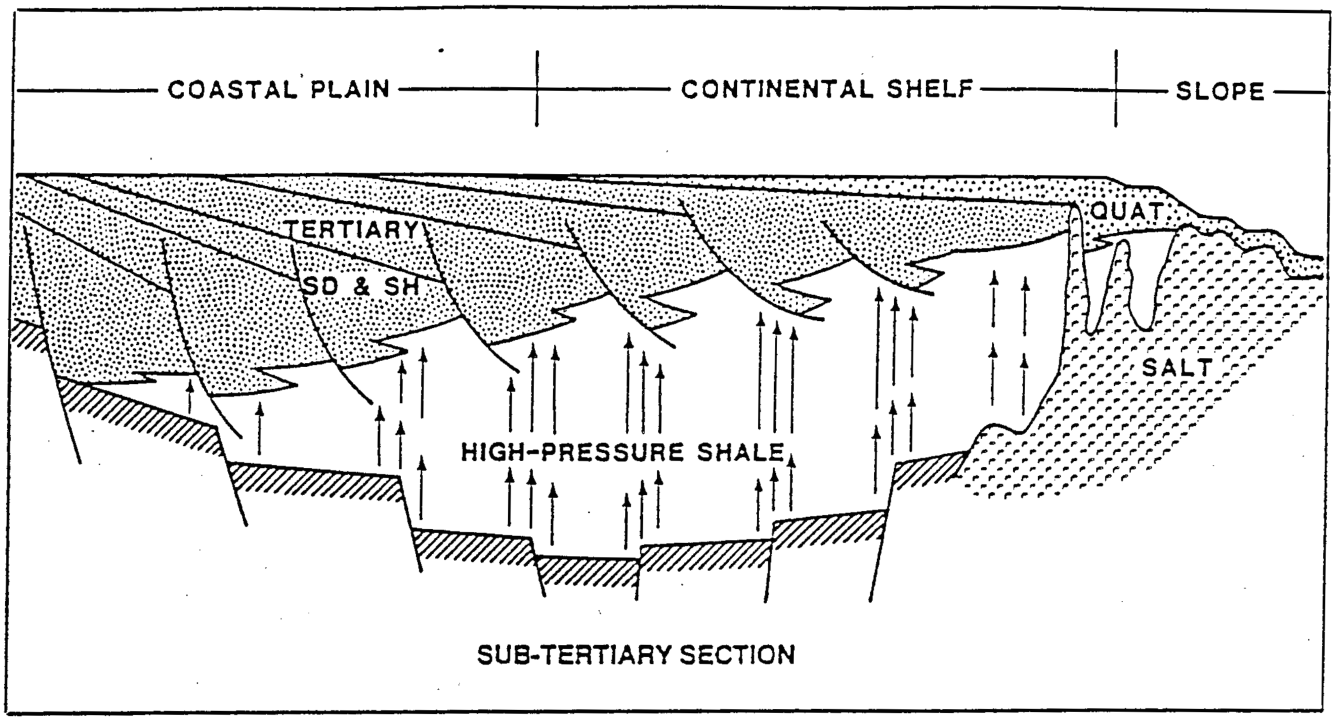


Figure 7. Schematic cross section for Texas portion of northern Gulf of Mexico basin illustrating relation of overpressured shale section to overlying and underlying faulted sections. Arrows indicate principal direction of fluid movement through pressured shale section.

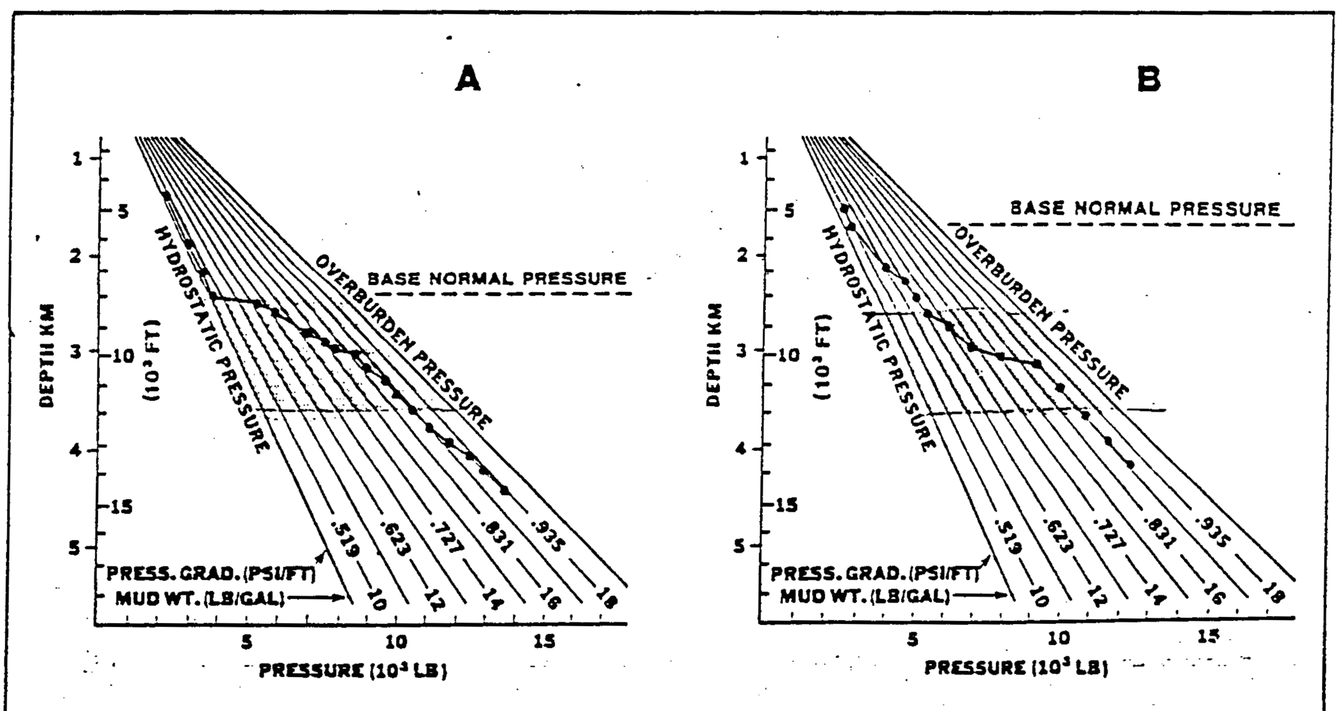


Figure 8. Relation between intervals of smectite diagenesis (strippled) and subsurface fluid pressure (Bruce, 1984).

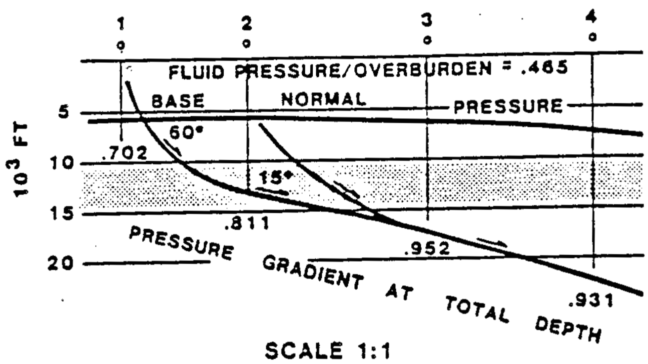


Figure 9. Stick section showing relation of interval of smectite diagenesis (stippled) to faulting.

overburden pressure. Law and Dickinson (1985) present sufficient Gulf Coast data for Powers to conclude that the high-pressure zone is depth-dependent. The depths for the montmorillonite transition to illite bear scrutiny. From Powers' conclusions: 1) At a burial depth of 3,000 ft, most water is expelled from montmorillonite and effective porosity and permeability are zero, and 2) alteration to illite begins at 6,000 ft and continues to 9,000 - 10,000 ft.

Hydrocarbon Generation

Many authors discuss the development of hydrocarbons from kerogen in shaley sediments exposed to thermal maturation by burial, the effect of geologic time with different heat flow regimes, and the expulsion of the hydrocarbons assisted by clay mineral transformation, water availability, and the undercompaction developed as a result. Hedberg (1979) reviews the concepts of methane generation and petroleum migration and describes the stages in genesis and expulsion.

"This effect would seem to be particularly pronounced in the case of highly plastic argillaceous rocks where it would make such strata an impermeable barrier to fluid migration until such time as the pressure was gradually bled off by diffusion or very gradual leakage, or until the sediment had reached a relationship of pressure to rock consistency which would allow relief by microfracturing. The phenomenon of mud and shale diapirs and mud volcanoes, associated with overpressured shales, often provides dramatic testimony to the magnitude of the forces resulting from the internal generation of methane gas in muds and shales" (Hedberg, 1979).

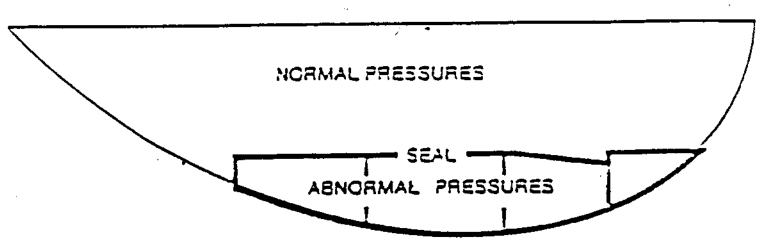


Figure 10. Layered arrangement of two hydraulic systems typical of currently subsiding basins like the Niger, Mahakam, U.S. Gulf Coast, Canadian Arctic, and Lower Magdalena Basins (Powley, 1990 a and b).

Oil and Gas

Hunt (1991 a and b) addresses the role of seals and hydrocarbon generation and migration. "Not all sedimentary basins have a normal hydraulic system open to the surface. In the deeper parts of many basins there is a vertically tiered arrangement with the normal hydraulic system overlying an abnormally pressured compartmented system. These geopressured fluid compartments are sealed on all sides from hydraulic communication with normally pressured fluids in the basin. See Figure 10.

"In currently sinking basins that have these deep overpressured compartments most of the oil and gas generation occurs within the compartments. The generation of hydrocarbons plus the thermal expansion of pore fluids are major contributors to the geopressures in these basins. See Figure 11.

"As pressures increase at greater depths, the top seals ultimately fracture and the compartment fluids, oil, gas and water, move vertically into lower-pressured reservoirs above. The fractures then reseal by secondary mineralization and the pressure gradually builds up again to another breakout. This episodic process continues with resealing and breakout cycles probably occurring in intervals of thousands of years in currently sinking basins" (Hunt, personal communication, 1991).

As long as the thermal conditions are met, and there is hydrogen left in the shaley sediments, a sedimentary basin will generate hydrocarbons and contribute to overpressuring. Hydrocarbon generation is a continuous process. Hydrocarbons are still being formed in the Gulf of Mexico. After the initial oil is formed the on-going thermal maturation then causes cracking. Additional oil continues to be generated by residual kerogen. Since both sedimentation and thermal maturation are continuous, so is the pressure generation. This is important to recharge of geopressured reservoirs. See Figure 12.

Nunn and Sassen (1986) address the occurrence of large volumes of crude oil and thermogenic gas in Plio-Pleistocene reservoirs and Holocene seeps of the Gulf of Mexico slope. The authors conclude that the process of hydrocarbon generation and migration continues at the present time. Calculated thermal maturity models based on deep seismic stratigraphy indicate

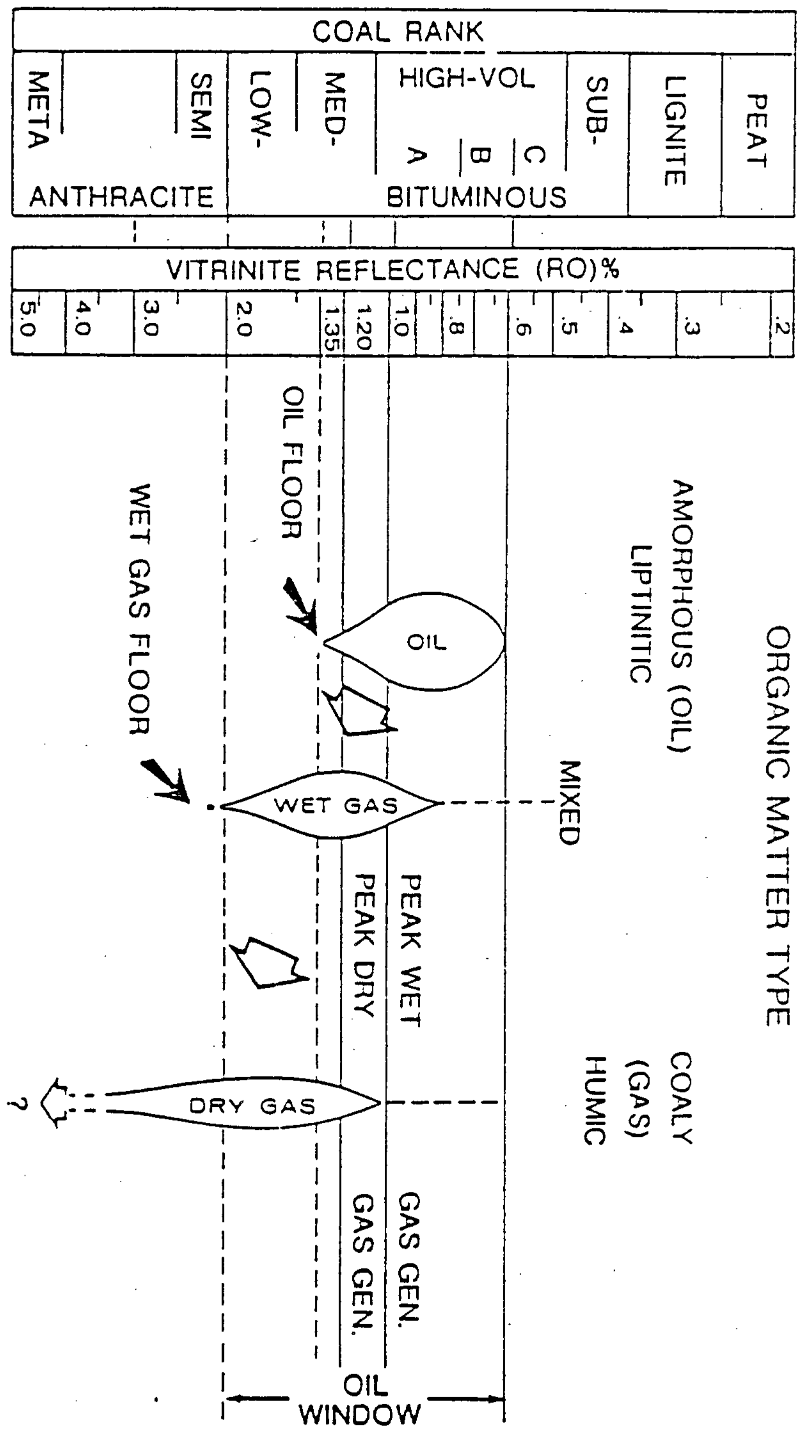


Figure 11. Correlation of coal-rank scale with vitrinite reflectance and zones of petroleum generation and destruction. Arrows indicate path of hydrocarbon destruction with increasing temperature and time. Modified from Dow 1978.

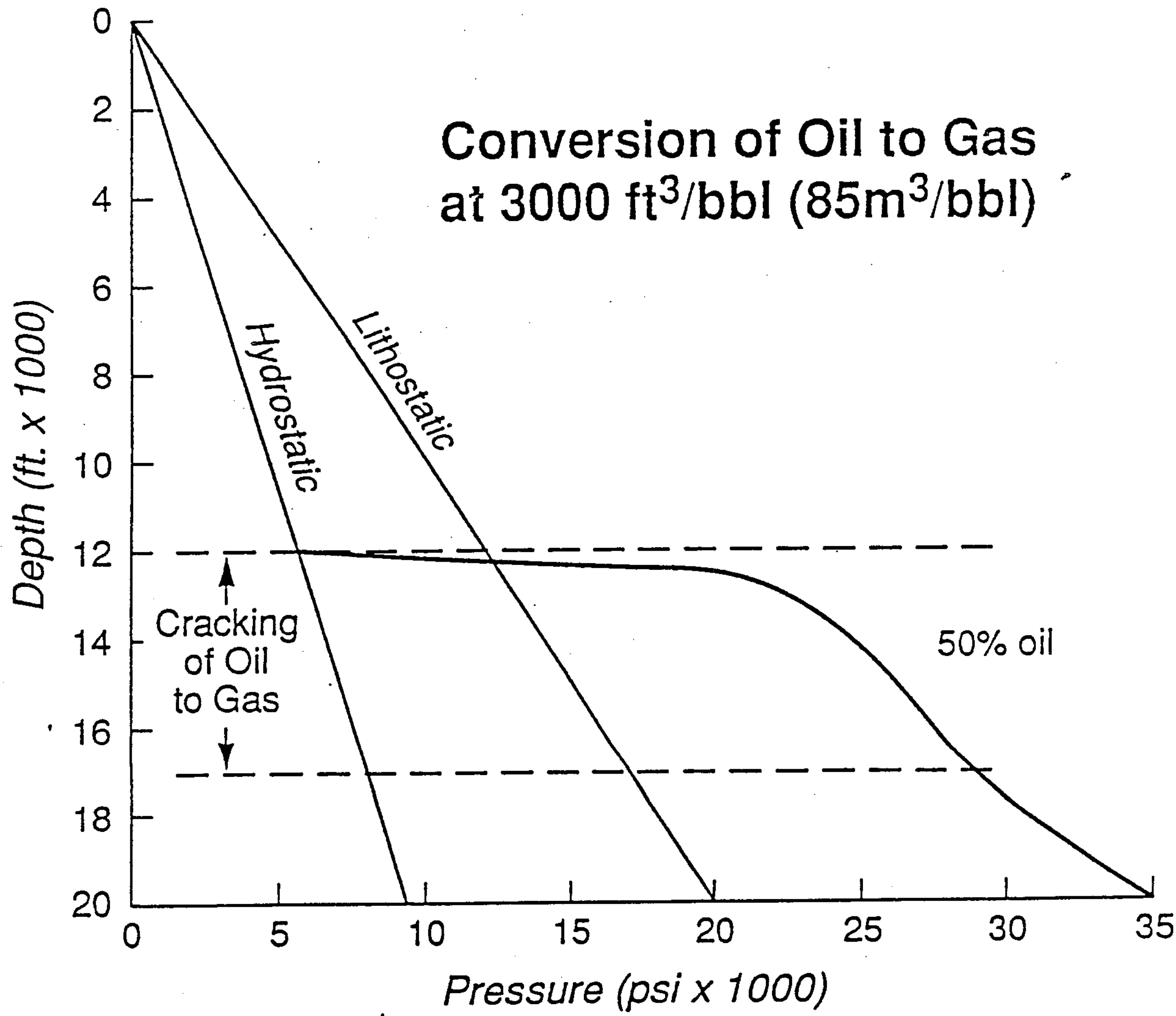


Figure 12. Pressure-depth profile showing the potential pressure trend that develops when oil cracks to gas with a conversion factor of 3,000 ft^3/bbl ($85m^3$bbl). The reservoir initially contained 50 vol.% oil (Barker, 1990).

The calculated thermal maturity profile for the slope indicates that some generation of crude oil could occur as shallow as 6 km and that liquid hydrocarbons could be preserved as deep as 9 km. Thermogenic gas is stable at even greater depths. Migration with a strong vertical component must be invoked to explain thermogenic hydrocarbons in shallow reservoirs and seeps of the slope.

The great depth at which liquid hydrocarbons and dry gas can be preserved in reservoirs of the Gulf of Mexico Salt Basin indicates that huge volumes of prospective section remain essentially unexplored.

LaPlante (1974) identifies hydrocarbon generation with the top of geopressured zone in southern Louisiana. From field data and laboratory results Thompson (1988) concludes that Gulf Coast Reservoirs best fit evaporative fractionation. The generation of oil and gas from organic material accompanied by an increase in fluid volume which results in abnormal pressures and fracturing of the shales, has been recognized by several investigators, e. g., Snarsky (1961) and Momper (1978). Berg and Habeck (1982) conclude that pressures induced by hydrocarbon generation contributed to abnormal pressures in the Vicksburg. The correlation of coal-rank scale with vitrinite reflectance and zones of petroleum generation and destruction are shown in Figure 11 (Dow, 1977).

Hedberg considers the role of hydrocarbon generation and the contribution to overpressure for many years and concludes that "it seems probable that the generation of methane in muds and shales may be an important agency frequently contributing to their overpressuring and undercompaction."

The timing of hydrocarbon generation will differ for different source materials under different burial histories. Hunt et al. (1991) published time-temperature graphs based on the Arrhenius equation for a range of Type II kerogens. Temperature is the most important aspect of the time-temperature index. Thus, any causal result from hydrocarbon generation will be affected by these differences in temperatures. For instance, the conditions for peak oil generation for Type IIA kerogen range from a possible exposure to 158-176°F (70-80°C) for 20 million years to about 356°F (180°C) for 10,000 years (looking at maximum variation in temperature requirements). These variations in time and temperature, since they affect the generation of both oil and gas, will also affect the depth of overpressure formation and the timing of overpressure formation. The geographic variations in heat flow will obviously also cause the depth of the processes to vary from locale to locale.

Jones (1975) reviews geothermal and hydrocarbon regimes in the Northern Gulf of Mexico Basin. "Geothermal heat flow in the Gulf Basin is primarily a function of its hydrology. Water expelled from sediments with deepening burial and increasing overburden load escapes upward and toward the basin margin. Where it moves freely in the hydropressure zone, the basin is relatively cool; but where rapid sedimentation and contemporaneous faulting have retarded water loss from compacting sediments, the interstitial fluid pressure reflects a part of the overburden load, and the formation waters are superheated and geopressured. The geopressured zone is common below depths of about 3 km (9,600 ft) in the basin, beneath an area of 375,000 km^2 (150,000 mi^2), and extends downward perhaps 15 km (50,000 ft) to the base of Cenozoic deposits.

"The upper boundary of the geopressured zone is the most important physical interface in the basin. Across it the head of formation water increases downward from a few hundred to several thousand feet above sea level; the geothermal gradient increases downward from 68°-104°F/km (20 to 40°C) to 212°F/km (100°C) or more; the salinity of formation water decreases downward, commonly by 50,000 mg/l or more; and the porosity of shale and sand increases downward by 10 to 15%.

"Petroleum matures in geopressured clay at 140 to 220°F (60 to 104°C). Montmorillonite is dehydrated at 180 to 250°F (82 to 121°C); fresh water released may equal half the volume of the mineral altered. Molecular solubility in fresh water of the hydrocarbons in Gulf Basin crude, under geopressured zone conditions, could account for petroleum resources of the basin. Exsolution of petroleum hydrocarbons near the geopressured zone boundary could account for observed occurrences.

"This geopressured zone is a natural pressure vessel from which superheated water of moderate salinity could be produced through wells, each yielding millions of gallons a day at pressures of several thousand pounds per square inch, and temperatures above 300°F (149°C), with considerable amounts of methane gas in solution."

In summary, Jones states, "The energy resources of the northern Gulf of Mexico Basin--petroleum hydrocarbon and geothermal waters--are both derived from clay by the thermal metamorphism of two mineral components. This metamorphism occurs in the same temperature range, producing a solvent (fresh water) and a solute (petroleum hydrocarbons) that immediately become a solution. The metamorphism drastically reduces the load-bearing strength of the clay bed. The excess pore fluid is expelled or shares the overburden load. But Pascal's law states that pressure applied to an enclosed fluid is transmitted equally in all directions without loss, and exerts equal force on equal areas. The confining pressure decreases most rapidly upward, and the system in which the clay bed occurs drains in the direction of pressure release.

"As solvent and solute move together out of the clay bed and through sand beds and fault planes in the direction of pressure release, pressure and temperature drop so low that the solute hydrocarbon can no longer remain in the solvent water. Fluid hydrocarbons then appear as a separate phase and, being less dense than water, seek the high points in the regional flow system -- the structural traps.

"Knowledge of hydrodynamic, hydrothermal, and hydrochemical regimes enables prediction of likely places for commercial accumulations of fluid hydrocarbons. This predictive capability lays the basis for a new method of exploration for oil and gas. Maps of geologic structure and sediment type supplemented by isothermal, isosaline, and isopressure maps describe important features of the fluid hydrocarbon regime and of the geothermal energy resources as well" (Jones, 1975) See Table 2.

Table 2. Core data for a Nueces County, Texas, oil test well, showing decrease in formation water salinity at sand bed boundaries.

Sample	Depth Feet	Permeability Millidarcys	Porosity %	Residual Saturation % by volume Oil	Gas	% pore space Oil	Gas	Total Chloride, ppm	Probable Production
16	11070--71	18.0	21.9	0.9	5.9	4.1	68.8	15,500	condensate
17	11071--72	29.0	20.9	5.3	5.7	25.4	47.2	27,000	condensate
18	11072--73	1.0	13.7	1.6	4.4	11.7	56.1	25,800	condensate
19	11073--74	1.5	18.2	2.5	6.5	13.7	50.6	27,800	condensate
20	11074--75	7.8	21.2	1.5	6.9	7.1	60.3	22,500	condensate
21	11075½--76	1.9	19.3	2.5	7.0	13.0	50.7	24,800	condensate
22	11076--77	21.0	21.3	4.5	6.4	21.1	48.9	25,100	condensate
23	11077--78	2.2	19.9	3.4	6.5	17.1	50.3	27,500	condensate
24	11078--78¼	1.1	13.3	0.0	4.5	0.0	66.1	21,800	condensate
25	11079--80	8.2	23.7	3.3	6.4	13.9	59.2	25,700	
26	11080¼--81	0.0	11.7	0.0	5.2	0.0	55.4	24,400	condensate
27	11081--81½	0.9	15.7	1.6	5.8	10.2	52.7	26,200	condensate
28	11082--82½	15.0	23.8	2.5	5.5	10.5	66.4	16,500	

(Jones, 1975)

Reporting in the AAPG Explorer (1991) Shirley describes the concept of Petroleum Systems and Provinces put forth by Perrodon (1983). A modification could be applied to geopressured systems since they are very much related to hydrocarbon production, temperature, and deep sedimentary basins. Shirley focuses on the "grossly underexplored" area of the leading edge of Montana's Precambrian Overthrust Belt that covers thick Mesozoic and Paleozoic sections that may contain significant hydrocarbon reservoirs. Recent drilling was through the Precambrian into an overpressured zone. The overpressuring is viewed as a positive indicator. The possibility under consideration is that the Cretaceous shales are a source rock in a thermal regime where hydrocarbons are being generated now and that it is that process which is causing the overpressuring. Although three deep tests were not productive of hydrocarbons, they produced relatively fresh water from fracture porosity.

Methane Solubility

Methane solubility in brines with application to the geopressured resource was studied by Price et al. (1981) using a large amount of experimentally determined aqueous methane solubility data over a wide range of temperature, pressure and salinity conditions. An empirical equation has been developed which allows the calculation of aqueous methane solubilities from 158 to 464°F (240 to 316°C) at pressures above 3,500 psi and from 464 to 601°F (70 to 240°C) at pressures above 5,000 psi for all salinities. These authors state that other previously published empirical equations appear to be invalid. Figure 13 shows data for methane solubility in water at constant pressures and varying temperature. (From Jones, 1975)

"Salt composition appears to have no measurable effect on methane solubility. Carbon dioxide content in the waters has large and unexpected effects on methane solubility. Previously unreported large concentrations of carbon dioxide exist in geopressured sandstone pore waters. These two facts have great import to the geopressured resource in regards to whether sandstone pore waters are methane saturated or not, as well as to the presence or absence of free gas. We do not have enough experimental data to say with certainty if Gulf Coast geopressured sandstone reservoirs are methane saturated or not. Closer cooperation between laboratory and

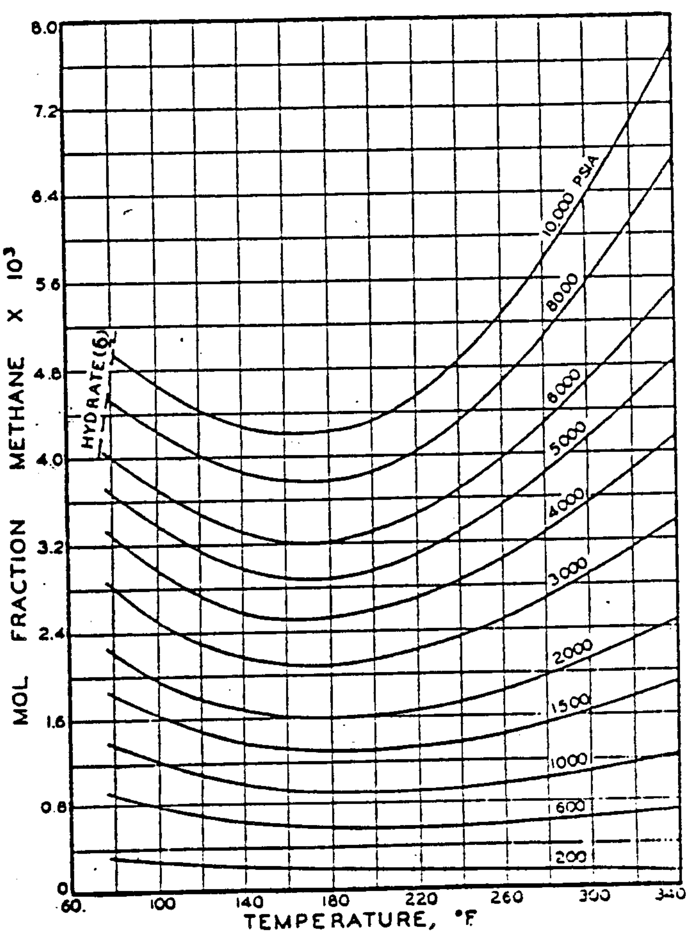


Figure 13. Solubility of methane in water at constant pressure. (Reproduced from Trans. AIME V. 1924).

field studies will be necessary to speak to this problem." The authors made the following recommendations:

"1. The effect of carbon dioxide, higher molecular weight hydrocarbon gases, and crude oil on the aqueous solubility of methane should be examined, especially carbon dioxide.

2. Direct reconstitution studies should be carried out using brines from the various geothermal tests as they become available, to ascertain if the brines are methane saturated in nature. Carbon dioxide should be progressively added to these systems and samples taken and analyzed for methane saturation up to the carbon dioxide level found in nature for that sample.

3. Low temperature-pressure measurements of aqueous methane solubility should be terminated unless there is an important engineering need for such data.

4. Because the empirical equation developed in this paper to calculate aqueous methane solubility apparently can be extrapolated to 601°F (316°C) at pressures above 5,000 psi, there appears to be no need to take aqueous methane solubility data above 464°F (240°C)." (Price et al., 1981)

The following conclusions are drawn:

"1. The previously reported aqueous methane solubility data of Blount et al. (1979) are incorrect due to an error in the experimental procedure.

2. New data as well as the older corrected data have been modeled into an equation which computes aqueous methane solubilities over a broad range of conditions: 160 to 464°F at pressures above 3,500 psi, 464 to 601°F at pressures above 5000 psi, all for salinities of 1 to 25 weight percent NaCl.

3. Calculated data from this study generally agree with previous experimental work within the limits of the equation of this study.

4. Calculated data from this study do not agree with the high temperature (626, 662, and 680°F isotherms) of Sultanov et al. (1972). This agrees with an earlier observation by Price that the high temperature data of Sultanov et al. (1972) appear to be too high.

5. The calculated data of this study do not agree with the calculated data of Haas (1978) or Susak and McGee (1980). This is not surprising as the salting out coefficient they assumed (0.129) is not in agreement with our experimentally measured one of 0.1025. Also a large part of their data base was made up of the data of Sultanov et al. (1972), the higher temperature portion of which we find questionable.

6. There does not appear to be an effect of brine composition on aqueous methane solubility.

7. At 300°F (149°C) and 5.0 weight percent NaCl concentration, increasing CO_2 content has large and unexpected effects on reducing methane solubility. This effect is considerable at CO_2 content. This effect is considerable at CO_2 contents of 40 mole percent or greater.

8. In the Tertiary Gulf Coast it is quite possible that carbon dioxide could make up an increasing amount of the dissolved gas in sand and shale pore waters (greater than 40 mole percent) with depth of burial, from the thermal cracking of the kerogen in the associated shales.

9. In theory, at the onset of significant methane generation, burial temperatures of about 360°F (182°C), Gulf Coast sand and shale pore waters could have such high concentrations of carbon dioxide that the newly generated methane would immediately form a free gas phase.

10. At this point we do not understand the controlling parameters (other than pressure, temperature and salinity) of aqueous methane solubility well enough to be able to ascertain if Gulf Coast geopressured brines are saturated or undersaturated with respect to methane. Thus from solubility considerations alone, we are not able to say if we are dealing with a free gas phase or not. A tighter cooperation between laboratory and field studies will be necessary in the future to speak to this problem." (Price et al., 1981)

Coco and Johnson (1981) report on a new correlation developed on the available published data for the solubility of methane in water, based on fundamental thermodynamic relationships. An empirical relationship for the salting-out coefficient of NaCl for methane solubility in water was determined as a function of temperature. Root-mean-square and average deviations for the new correlation, the Haas correlation, and the revised Blount equation were compared. The authors make the following conclusions:

"1. A new correlation of the available published data for the solubility of methane in water, excluding the data of Blount (1979), was developed. The correlation is based on fundamental thermodynamic relationships.

2. The new correlation represents the entire data set more consistently, with a slightly lower r.m.s. deviation, than the Haas correlation.

3. Because the Haas correlation represents the Culberson-McKetta and Sultanov et al. data sets better than the new correlation, there is reason to suspect that some biases exist among the various data sets which prevent achievement of a better overall correlation.

4. An empirical relationship for the salting-out coefficient as a function of temperature was determined including the original data of Blount (1979) in the data set. This relationship exhibits a strong temperature effect, resulting in a minimum value of 0.076 at a temperature of 304°F (151°C).

5. Because of the uncertainty connected with the original Blount data, the results reported here are not as definitive as otherwise would have been expected" (Coco and Johnson, 1981). See Tables 3 and 4.

Table 3. A comparison of solubilities of methane in water (SCF/B) calculated by Haas, Blount, and LSU correlations with published data.

Data Set	N, No. of Points	t, Temp. Deg. F.	P, Pressure Psia	RMSD, r.m.s. relative dev.**			AD, avg. relative dev. ***		
				Haas	Blount	LSU	Haas	Blount	LSU
1 Sultanov et al. (1972)	10	302	715-15650	.0325	.100	.0628	-.0252	.0694	-.0213
	11	392	711-15650	.0777	.0825	.0591	-.0715	.0087	.0539
	11	482	1422-15650	.0463	.205	.0663	.0046	.0716	.0066
	10	572	2134-15650	.0540	.416	.0306	-.0038	.147	-.0251
	9	662	2845-15650	.0364	1.34	.0715	.0130	.477	-.0584
	9	626	2845-15650	.0717	.647	.0600	.0529	.228	-.0162
	6	680	3556-11379	.0714	.779	.161	-.0624	.271	-.0963
Total	66	302-680	711-15650	.0560	.627	.0743	-.0122	.167	-.0137
2 Culberson-McKetta (1951)	12	77	341-9300	.0843	--	.193	.0563	--	.0617
	12	100	330-9895	.0201	--	.0570	.0005	--	-.0104
	12	160	331-9865	.0227	--	.0249	-.0036	--	.0014
	12	220	333-8190	.0257	.124	.0259	.0069	.117	.0126
	12	280	336-9835	.0329	.130	.0436	.0153	.118	.0217
	12	340	323-9995	.0276	.143	.0413	.0017	.103	.0237
Total	72	77-340	323-9995	.0419	.133	.0870	.0129	.113	.0135
3 Price (1979)	8	309	2204-23778	.107	.0958	.0884	.0050	.0748	-.0497
	7	403	2323-27908	.0525	.0792	.0530	.0153	.0571	-.0215
	6	430	5332-20530	.0548	.0620	.0554	.0194	.9017	-.0092
	12	453	2160-23837	.0814	.119	.0693	-.0415	-.0218	-.0586
	9	536	2866-27393	.208	.181	.107	.179	.118	.101
	7	558	1567-24498	.213	.265	.104	.168	.175	.0879
	7	601	3631-27746	.275	.152	.097	.185	.0113	.0427
Total	56	309-601	1567-27908	.161	.147	.0848	.0734	.0556	.0092
4 O'Sullivan and Smith (1970)	6	125	1470-8818	.0251	.130	.0151	-.0181	-.130	.0035
	6	217	1484-8876	.0362	.110	.0164	.0081	.106	.0005
	6	257	1514-8935	.114	.237	.0953	.0960	.236	.0889
Total	18	125-257	1470-8935	.0706	.168	.0565	.0287	.0707	.0310
5 Namiot, et al (1979)	7	122-662	4595	.0465	.286	.0310	-.0099	.150	.0015
TOTAL FOR ALL DATA	219	77-680	711-27908	.0930	.414	.0794	.0214	.112	.0069

* r.m.s. and avg. deviations for revised equation of Blount (1981) excluded data points for temperatures less than 200°F and pressures less than 2000 psia

$$** \quad RMSD = \left\{ \sum^{N} \left[\frac{(SCF/B_{calc} - SCF/B_{exp})^2}{(SCF/3_{exp})^2} \right] \Big/ N \right\}^{1/2}$$

$$*** \quad AD = \sum^{N} \left[\frac{(SCF/B_{calc} - SCF/B_{exp})}{(SCF/3_{exp})} \right] \Big/ N$$

(Coco and Johnson, 1981)

Table 4. Solubility of methane in Pleasant Bayou brine at various temperatures and pressures, as well as calculated values (Table 1) for an equivalent NaCl concentration (130,000 mg/l).
(NA, not applicable)

Temperature °F	Pressure psi	Experimental solubility SCF/Bbl	Calculated solubility SCF/Bbl
201.6	12,016	20.4	21.9
196.3	9,126	19.8	18.8
198.2	5,076	13.4	14.0
198.2	2,021	8.3	8.5
198.7	1,059	4.2	NA
248.1	12,024	24.8	25.8
248.0	11,950	24.1	25.7
248.0	11,893	25.2	25.7
249.8	9,083	22.3	22.5
250.3	5,018	17.5	16.2
	2,060	9.9	10.0
250.3	2,002	9.4	9.9
	1,001	5.7	NA
301.1	12,300	29.3	32.6
301.1	12,040	27.2	32.2
302.8	9,040	25.0	28.0
299.5	5,076	19.6	20.1
301.1	2,002	12.2	11.9
299.7	1,004	7.7	NA
301.1	507	3.9	NA
301.3	260	3.4	NA
300.2	104	1.3	NA

(Blount et al., 1979)

Kharaka, Carothers, and Law (1985) address the origin of gaseous hydrocarbons in geopressured geothermal waters in an unpublished paper presented at the Geopressured-Geothermal Energy Sixth Conference Proceedings. "Geopressured-Geothermal waters in sedimentary basins are saturated with methane at subsurface temperature, pressure and water salinity. Methane is the dominant hydrocarbon gas in these waters, comprising over 90% of the total, with decreasing proportions of ethane, propane, butane, and other gases. These waters also contain high concentrations (>1,000 mg/L) of short-chain aliphatic acid anions. Acetate is the dominant organic anion comprising over 90% of the total, with decreasing proportions of propionate, butyrate, and valerate. Dissolved monocarboxylic acid anions (C6 - C9) and dicarboxylic anions (C4 - C10) have also been identified in these waters.

"A large portion and probably the bulk of gaseous hydrocarbons dissolved in these waters is produced from thermal decarboxylation of these organic acid anions. This conclusion is based on: 1) natural distribution of these acid anions--the highest concentrations (up to 10,000 ng/L) subsurface of total carbonate and methane indicate decarboxylation; 2) a good correlation between the proportions of the organic acid anions and their decarboxylation gases; and laboratory experiments showing that acetic acid can be decarboxylated to CO_2 and methane" (Kharaka, Carothers, and Law, 1985). The conditions for methane hydrate in sediments are shown in Figure 14.

Cryocondensate

Keeley and Meriwether (1985) report on cryocondensates from DOE geopressured wells. Samples of cryocondensates (materials condensed at -78.5°C) were taken on a regular basis from the gas stream from the U.S. DOE geopressured wells, Gladys McCall and Pleasant Bayou. The data reported here are mostly from the Gladys McCall as it flowed on a regular and almost continuous basis for over 4-1/2 years. The cryocondensates are almost exclusively aromatic hydrocarbons, primarily benzene, toluene, ethylbenzene, and the xylenes, but contain over 95 compounds, characterized using gas chromatography-mass spectroscopy. Although the yield of the cryocondensates from the Gladys McCall Well were reported in 1985 as steadily increasing as a function of the production volume--from 22.5 to 38.3 microliters/liter (μl/l) of brine during the production of 6.35 MMbbls of brine, examination of the data from Pleasant Bayou Well by the present author over the period 1988-91 suggest rather that the aromatic hydrocarbons possibly increase with flow rate (Table 5). The carbon isotope ratios relative to the PDB (Peedee belemnite, the recognized fossil standard) are shown in Table 6.

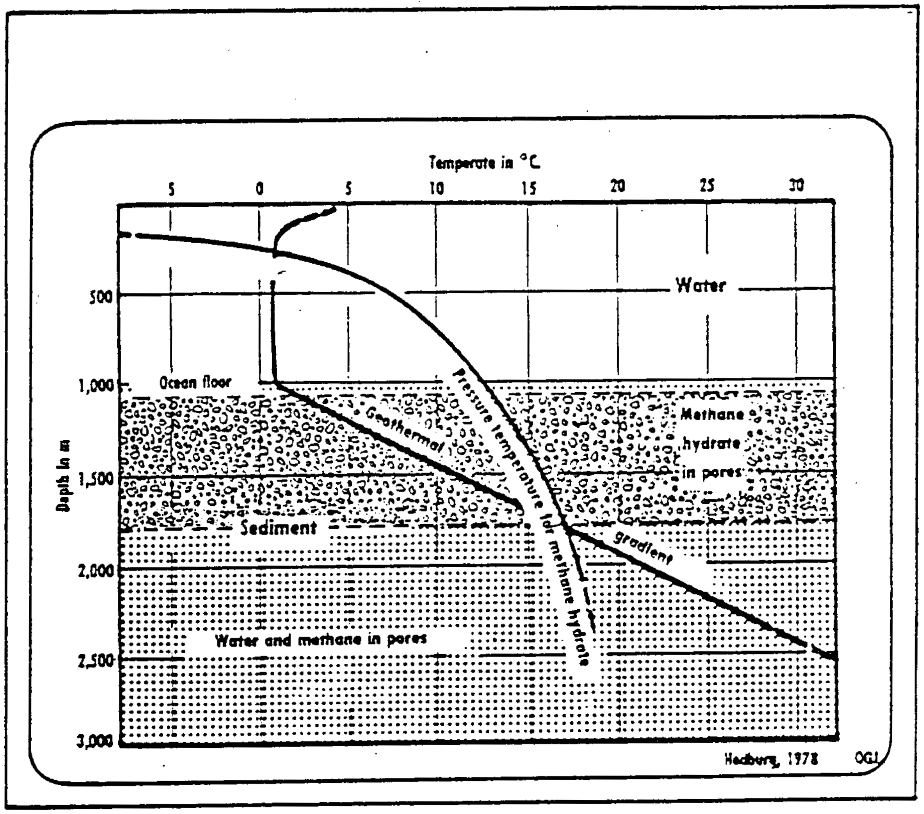


Figure 14. Conditions for methane hydrate in sediments. (Hedberg, 1979)

Table 5. Cryocodensate components.

IDENTIFICATION	G.M. 3/84	G.M. 10/84	G.M. K-8/84	A.F. 3/84	P.B. 3/83	L.R.S. 1/83
Hexane isomer		x				
Hexane isomer		x				
Hexane isomer		x				
Hexane	x	x	x	x	x	x
Benzene	x	x	x	x	x	x
Cyclohexane	x	x	x	x	x	x
Heptane						x
Methylcyclohexane	x	x	x	x	x	x
Toluene	x	x	x	x	x	x
Dimethylcyclohexane	x	x			x	
Dimethylcyclohexane	x	x				
Dimethylcyclohexane	x					
Ethylcyclohexane	x	x	x		x	x
Trimethylcyclohexane	x					
p-Xylene	x	x	x	x	x	x
o/m-Xylene	x	x	x	x	x	x
Ethylbenzene	x	x	x	x	x	x
Nonane						x
Methylethylbenzene isomer	x	x	x	x	x	x
C3-cyclohexane						x
Propylbenzene	x	x	x	x	x	x
Methylethylbenzene isomer	x	x	x	x	x	x
Methylethylbenzene isomer	x	x	x	x	x	x
Trimethylbenzene isomer	x	x	x	x	x	x
C3-alkylbenzene	x	x	x	x	x	x
Trimethylbenzene isomer	x	x	x	x	x	x
C4-alkylbenzene	x				x	
C4-alkylbenzene	x				x	
Decane						x
C3-alkylbenzene	x	x	x	x	x	x
C4-alkylbenzene	x					
C4-alkylbenzene	x				x	
2.3-dihydroindene	x	x		x	x	
C4-alkylbenzene	x					

Table 5. Cryocondensate components. (continued)

IDENTIFICATION	G.M. 3/84	G.M. 10/84	G.M. K-8/84	A.F. 3/84	P.B. 3/83	L.R.S. 1/83
C4-alkylbenzene	x					
C4-alkylbenzene	x			x		
C4-alkylbenzene	x					
C4-alkylbenzene	x					
C4-alkylbenzene	x	x				
C4-alkylbenzene	x					
C4-alkylbenzene	x					
Methyldihydroindene	x					
C4-alkylbenzene	x					
C4-alkylbenzene	x					
C4-alkylbenzene	x					
C4-alkylbenzene	x					
C4-alkylbenzene	x					
Methyldihydroindene	x	x				
Methyldihydroindene	x					
C4-alkylbenzene	x	x	x			
Tetrahydronaphthalene	x		x		x	
Undecane						x
Naphthalene	x	x	x	x	x	x
2.3-dihydrodimethylindene			x			
Dodecane						x
C13-alkane						x
2-methylnaphthalene	x	x	x	x	x	x
C13-alkane						x
1-methylnaphthalene	x	x	x	x	x	x
Cyclohexylbenzene			x			
Biphenyl			x		x	
Ethylnaphthalene			x			
Dimethylnaphthalene isomer			x		x	

Table 5. Cryocodensate components. (continued)

IDENTIFICATION	G.M. 3/84	G.M. 10/84	G.M. K-8/84	A.F. 3/84	P.B. 3/83	L.R.S. 1/83
Dimethylnaphthalene isomer			x		x	
Dimethylnaphthalene isomer			x		x	
Dimethylnaphthalene isomer			x		X	
Dimenthylnaphthalene isomer			x		x	
Dimethylnaphthalene isomer			x			
Tridecane			x			x
Tetradecane			x			x
Ethylnaphthalene isomer			x			
Methylbiphenyl isomer			x			
Methylbiphenyl isomer			x			
Dibenzofuran			x			
Trimethylnaphthalene isomer			x			
Trimethylnaphthalene isomer			x			
Trimethylnaphthalene isomer			x			
Trimethylnaphthalene isomer			x			
9H-fluorene			x			
Trimethylnaphthalene isomer			x			
Methyldibenzofurna			x			
Methyldibenzofuran			x			
Methyldibenzofuran			x			
Methyfluorene			x			
C4-naphthalene			x			
Phenanthrene or anthracene			x			
Alkane			x			

Table 5. Cryocodensate components. (continued)

IDENTIFICATION	G.M. 3/84	G.M. 10/84	G.M. K-8/84	A.F. 3/84	P.B. 3/83	L.R.S. 1/83
Methylphenanthrene isomer			x			
Methylphenanthrene isomer			x			
Methylphenanthrene isomer			x			
Methylphenanthrene isomer			x			
Methylphenanthrene isomer			x			
Alkane			x			
Alkane			x			
Alkane			x			
Alkane			x			

Table 6. Carbon isotope ratios relative to PDB (Pee dee belemnite, the recognized fossil standard).

DOW/DOE L.R. Sweezy #1 Well:	
Cryocondensates from gas (7/13-23/82)	-24.7
Light hydrocarbons from 'knock-out' trap	-26.9
Heavy hydrocarbons from separator	-27.1
F&S/DOE Pleasant Bayou #2 Well:	
Cryocondensates from gas (3/12/83)	-26.2
Hydrocarbons from 'gun barrel' (3/12/83)	-25.7
MG-T/DOE Amoco Fee #1 Well:	
Cryocondensates from gas	-25.8
TF&S/DOE Gladys McCall #1 Well:	
Cryocondensates from gas, sand #9 (3/26/83)	-26.4
Hydrocarbons from gas cooler, sand #9 (3/23/83)	-25.9
Cryocondensats from gas, sand #8 (12/12/83)	-27.0
Hydrocarbons from cooler, sand #8 (12/12/83)	-26.2
Flare gas, sand #8 (5/24/84)	-41.5
Methane, sand #8 (5/24/84)	-45.8
G. M. Koelemay #1 Well: Data from Eaton report (1981)	
	-27.4
Stock tank oil	-48.7
Flare gas (9/25/80)	-49.1
Methane (9/25/80)	

(Keeley and Meriwether, 1985)

Gas-condensate

The term "evaporative fractionation: is proposed by Thompson (1987; 1988) to describe several phenomena involved in the secondary alteration of reservoired oil. Firstly, it is suggested that oil is frequently partially vaporized in the reservoir; secondly, that gas, bearing substantial portions of the oil in solution, is conducted along faults to form independent gas-condensate accumulations; thirdly, that residual oils formed in this fashion bear internal evidence of fractionation. In addition to the conspicuous loss of light ends, there is an increase in the content of light aromatic and naphthionic hydrocarbons relative to paraffins in the residual oil. Evaporative fractionation effects are recognized for the first time in the distillation and physical property data of U.S. Bureau of Mines Routine Method Oil Analyses. Fractionation effects are postulated to be the cause of sigmoid, as opposed to normal, curvilinear, aromatic profiles. The effects of evaporative fractionation are widespread in oils throughout the United States. They are evident in approximately 75% of oils in the Gulf Coast Region, and in a large proportion of the gas-condensate.

"Experimental evidence shows that partial vaporization results in enhanced levels of light hydrocarbons in residual oils. Oil samples were partially vaporized in excess methane at elevated pressure and temperature, followed by removal of the vapor. The gas-chromatographic features of many Gulf Coast oils were reproduced. Various levels of light-end depletion and enhancement of aromaticity were brought about." (Thompson, 1987)

Thompson makes the following conclusions: "Evaporative fractionation satisfactorily explains simultaneous increases in aromatics and naphthenes in the gasoline fractions of most Gulf Coast oils and condensates. Increases in aromatics are largely confined to the originally dominant and most volatile compounds (principally toluene and xylenes) generating sigmoid aromatic profiles. The majority Gulf Coast condensates are interpreted as evaporative, rather than thermal, or source-related. Thermal condensates and supermature oils exhibit simultaneous progressive increase in both paraffinicity and aromaticity, a feature absent from Gulf Coast condensates. An evaporative origin of many onshore Gulf Coast gas-condensates is compatible with the evidence of extensive light-end loss from the majority of oils.

"Severe aromatization characterizes Gulf Coast petroleums. Oils with sigmoid profiles are abundant among United States oils overall, on the basis of the prima facie evidence of distillation data. Evaporative fractionation appears to be an extremely widespread and commonplace mode of alteration, probably as significant as bacterial degradation. Studies are now required to explicitly monitor these effects, especially in places where geological circumstances favor such processes." Thompson's work is presented by permission of Arco Oil Company.

Evaporative fractionation processes occur in many basins, and are a key to understanding major aspects of petroleum variability. On the basis of aromaticity and paraffinicity relationships, evaporative gas-condensates are distinguishable from those generated by thermal cracking. Unfractionated thermal gas-condensates are rare. Evaporative condensates are the daughter products of oils which have suffered evaporative fractionation.

Law, Spencer, and Bostick (1980) evaluate the relationships of organic matter, subsurface temperature and pressure with gas generation in low-permeability Upper Cretaceous and Lower Tertiary sandstones in the Pacific Creek area in Sublette and Sweetwater counties, Wyoming. Their studies show a range of total organic carbon (TOC) values from 0.25 to 7.84 weight percent, with an average of 1.38%. The top of overpressuring and the beginning of important wet-gas generation occur at vitrinite reflectance values of 0.74 to 0.86 (color alteration values of about 2.8). The present minimum temperature at the top of overpressuring is at least 190°F (88°C). The low-permeability sandstones, siltstones, and shales are effectively serving as a pressure seal and the authors attribute preservation of abnormally high pressures to presently active generation of gas in a thick interval of discontinuous, very low-permeability shales, siltstones, and sandstones. Thus, the seal and gas generation are the present contributors to the overpressure.

The top of overpressuring occurs at 11,600 ft near the base of the Upper Cretaceous Lance Formation in the northeastern Green River Basin. The pressure gradient is as high as 0.84 psi/ft. A reversal of the spontaneous potential (SP) curve is coincident with the top of geopressure and thought to be caused by a reduction of formation water salinity.

A recent study by Barker (1990), on the conversion of oil to gas, supports the concept that hydrocarbon generation may be a major cause of overpressures in deep basins worldwide. Barker concludes that in an isolated system such as a pressure compartment, the conversion of only a small percentage of oil to gas at 3658 m would create overpressures exceeding the fracture pressure gradient. Most of the deep pressure compartments in the world extend through this depth interval. Although Barker's model applied to oil reservoirs, there is residual oil in most source rocks that would be cracked to gas. The conversion of oil to gas throughout a compartment could create overpressure that would fracture seals running through both source and reservoir rocks (Hunt, 1991 a and b).

Qiao Hansheng (1985) reports, in a study of the Bohai Gulf Basin, that the abnormal pore pressure of the fluid is related to the maturity of the organic matter and migration of hydrocarbons. Sonic logging or density logging techniques were used to identify the location of the abnormal pressure zones. Qiao identified the value of recognizing the abnormal pressure zones to petroleum drilling, production engineering, determination of unconformities, and prediction of the extent of related oil and gas reservoirs.

Lateral Tectonic Compression

Engelder and Oertel (1985) recognize a correlation between undercompaction and the distribution of tectonic joints that indicates that abnormal fluid pressure was a key mechanism during the propagation of these joints in the Devonian Catskill Delta of central New York State. The authors pursue the following logic in their discussion:

1. During burial under 2 km or more of overburden, clay deposited on the sea bed with an initial porosity of about 70% normally compacts to less than 20% porosity (Rieke and Chilingarian, 1974; Magara, 1975).

2. Shale and siltstone that retain a porosity significantly greater than 20% are undercompacted. One important mechanism for undercompaction is the support of pore space by pore fluid at a pressure above hydrostatic (abnormal pore pressure). Sediments of the Gulf Coast of the United States are well known for abnormally pressured shales;

plots of shale density or porosity against pore pressure show that undercompaction correlates with abnormal pore pressures (Law and Dickinson, 1985; Magara, 1975).

3. In wells from the Gulf Coast, the top of the abnormally pressured zone corresponds to a marked increase in the ratio of shale to sandstone (Schmidt, 1973). A similar trend is seen in moving downsection from the cap rock of wave-base sediments and into the prodelta turbidities of the Catskill Delta.

4. If abnormal pore pressures are high enough, the tensile strength of the host rock is exceeded, and mode I cracks will nucleate and propagate (Secor, 1965).

5. Two types of joints form under abnormal prepressures: tectonic and hydraulic. Hydraulic joints form under the influence of abnormal pressures developed solely during burial and the accompanying overburden compaction. A major tectonic compression is not involved. Tectonic joints develop during orogenic events which cause lateral shortening with volume loss inducing an increment of abnormal pressure beyond that due to compaction by burial alone; This increment of fluid pressure drives the effective maximum tensile stress to the point of joint propagation and the formation of cross-fold joints.

6. Engelder and Oertal (1985) contend that abnormal pore pressure in the Catskill Delta is in part caused by some combination of overburden compaction, aquathermal pressuring, and clay dewatering during burial, and was further enhanced by lateral (tectonic) compaction. The combination of this enhanced overpressure and tectonic stress led to the nucleation and propagation of ectopic joints some 500-100 m.y. after the initial deposition of the Catskill Delta. This association of lateral compaction and enhanced abnormal pore pressure was inferred by Berry (1973), but never before documented.

Regarding the high fluid potentials in California Coast Ranges, Berry (1973) identifies dynamic tectonic compression caused by current deep-seated linear diapirism of Great Valley mudstones and related rocks that possess near-perfect plastic properties as the origin of the folds with high fluid potentials on the west side of the San Joaquin Valley. Near-lithostatic fluid pressures are recorded in these Tertiary mudstones in the southern San Joaquin Valley. The high fluid potentials within the miogeosynclinal Great Valley and eugeosynclinal Franciscan sequences of Jurassic-Cretaceous age within the Coast Ranges are associated with near-lithostatic pressures that Berry attributes to compression between the granitic Sierran-Klamath and Salinas blocks resulting from late Cenozoic extension of the central Great Basin in Nevada and Utah. "The field of the Pacific plate (Salinas block) is moving northwestward relative to the North American plate (Sierran-Klamath block and the Great Valley-Franciscan sediments). The Sierran-Klamath block also is moving westward or southwestward by continued late Cenozoic central Great Basin extension; this westerly motion is terminated by compression of the rocks on both sides of the San Andreas. This compression has the greatest effect within the Franciscan and Great Valley shale mass just east of the fault; the effect is greatly reduced within the granitic basement and overlying sediments of the Salinas block west of the fault but has been responsible for folding of the sedimentary veneer. The high fluid potentials are caused by the squeezing of this belt of highly compressible shales east of the San Andreas in a vise whose jaws are formed of relatively incompressible granite; these anomalous fluid potentials are envisioned as being late Cenozoic phenomena dynamically active today." (Table 7)

Table 7. Average analysis of 32 subsurface water samples from Cretaceous rocks of Sacramento Valley.

Radicals	Average Mg/L	% of Total	Average Mg/L	% of Total	No. of wells
Na + K	6,606.8	36.20	287.31	46.62	26
NH_4	31.0	0.17	1.61	0.26	19
Ca	223.2	1.22	11.59	1.88	26
Mg	85.5	0.47	7.09	1.15	9
Ba	5.2	0.03	0.18	0.03	10
Fe	1.5	0.01	----▸	----▸	26
SO_4	133.0	0.73	2.92	0.47	26
Cl	10,452.1	57.28	294.75	47.82	3
CO_3	36.3	0.19	1.21	0.20	26
HCO_3	525.2	2.88	8.61	1.40	20
B_4O_7	68.5	0.38	0.88	0.14	16
I	28.2	0.16	0.20	0.03	12
SiO_2	50.9	0.28	616.35	----	32
Total solids	18,246.4		616.35		

	Average value	
Specific gravity at 60°F	1.0156	20
Resistivity (ohm-cm at 75°F)	34.47	26
pH	7.60	26

(Osif 1985)

CHARACTERISTICS

The principal characteristics of a geopressured-geothermal resource are keys to understanding its formation and development over geologic time, as well as to support its utilization as an energy reservoir. Temperature controls two important processes contributing to the development of geopressure. At 200°F (93°C), smectite begins its transformation to illite, initiating development of the top seal. Also at 200°F (93°C), hydrocarbon generation from kerogens begins.

The principal secondary characteristic in creating geopressured conditions is the sedimentation rate. This is especially apparent in the U.S. Gulf Coast regions, The topic also includes subsidence behavior. Rock characteristics and mineralogy can be linked directly to formation of the geopressured zone and the associated geologic seals. The chemistry of the geopressured fluid -- salinity, dissolved organic compounds (primarily hydrocarbons) and other materials (including various radioactive elements) -- has a twofold usage: it can indicate the probable chemical processes that took place during the development of the geopressured zone, and it provides essential information for engineering development of the resource. In this section, the topic headings reflect two major categories. The first comprises zone formation and the consequent physical characteristics. The second category deals with geopressured-geothermal fluids and their flow.

Sedimentation Rate

When a high sedimentation rate is coupled with the lower permeability rate of shale in shaley basins with a subsidence rate greater than 1 mm/year, geopressured conditions are expected. Thus, geopressure resulting from or enhanced by rapid sedimentation is most often found in shaley sections of actively subsiding basins where the subsidence rate is greater than 1 mm/y and the pressure buildup has not had sufficient geologic time to bleed off. The U.S. Gulf Coast is composed of sediments with greater than 85% shales and shaley sediments, showing a subsidence rate of 1 to 5 mm/y. In general, Gulf Coast type basins have subsidence rates of 0.1 to 10 mm/y. See Tables 1 and 8.

Table 8. Permeability, lithology, and subsidence with probability of developing geopressure.

Permeability	Lithology	Subsidence	Geopressure
Normal shale:	Shaley basins	>1 mm/y	Yes
10^{-16} to 10^{-12} cm^2	Shale-rich basins	<0.1 mm/y	Improbable
$=10^{-8}$ to 10^{-4} μdarcy	Thick shale section	>0.5 mm/y	Yes
10^{-4} to 1 μd)	Sandstones Limestones Dolomites		Unlikely because typical permeabilities are 10^{-13} to 10^{-9} cm^2 (10^{-5} to 10^{-1} μd). Burial well above required permeability even at 10 mm/y.

(data from Bethke, 1986)

In the Gulf Coast area there are probably several contributing factors or causal agents. In addition to rapidly subsiding shale sequences, the arcuate down-to-the-basin faulting has contributed to compression in the fault blocks. Tectonic compression will be considered in more detail in the California overpressures. The transformation of smectite to illite has been linked to the top of geopressure in the Gulf Coast and to a temperature of 200°F (93°C). Aquathermal pressuring also has a number of proponents.

Pressure and Porosity

Carstens and Dypvik (1981) address the topic of abnormal formation pressure and shale porosity. The two sides of a controversy are examined in the framework of the North Sea Viking graben abnormally pressured Jurassic shale. On the one hand is the belief and observation that abnormally pressured shales are associated with higher than "normal" porosity. The validity of this association is questioned by Bradley (1991, personal communication) and Powley (1990 a & b; and

1991, personal communication) in their belief that a complete range of high-normal-low densities is associated with abnormal pressures. The shale example given by Carstens and Dypvik is for a North Sea shale sequence in which the onset of abnormal formation pressures does not seem to be coincident with any increase in shale porosity. The authors suggest that both gravitational compaction and cementation have reduced the pore space of the Jurassic shales. Following precipitation of diagenetic quartz and kaolinite and owing to rather shallow burial, the clays did not generate pore pressures much higher than the hydrostatic pressures.

The North Sea Jurassic shale sequence is an example of an abnormally pressured shale with low porosity and corresponding high density. This example gives credibility to Bradley's and Powley's statement that abnormal formation pressures may be associated with a complete range of high-normal-low densities. It is necessary to outline the geologic and pressure buildup history to unravel these relationships. The general belief that overpressured formations are characterized by higher than normal porosity has evolved for the Gulf of Mexico Cenozoic basin, where there was rather continuous deposition and subsidence of prograding sequences transected by growth faults. Compaction of deep-water clays was restricted owing to their "self-sealing" capacity, resulting in a high water content, even at great depths. See Figures 15-18.

Temperature

The role of temperature in development of abnormal-pressure zones was explored by Barker (1972). See Figure 19. Assuming the geopressured compartment is isolated from surrounding sediments the isolated volume would have been subjected to increasing temperatures as it moved downward with burial. Barker states, "The P-T-density diagram (pressure/temperature) for water shows that, for any geothermal gradient greater than about 15° C/km, the pressure in an isolated volume increases with increasing temperature more rapidly than that in the surrounding fluids. This mechanism for producing excess pressures will operate in addition to most of the other processes that have been suggested, but the overall influence in any given area will depend on how well the system remains isolated."

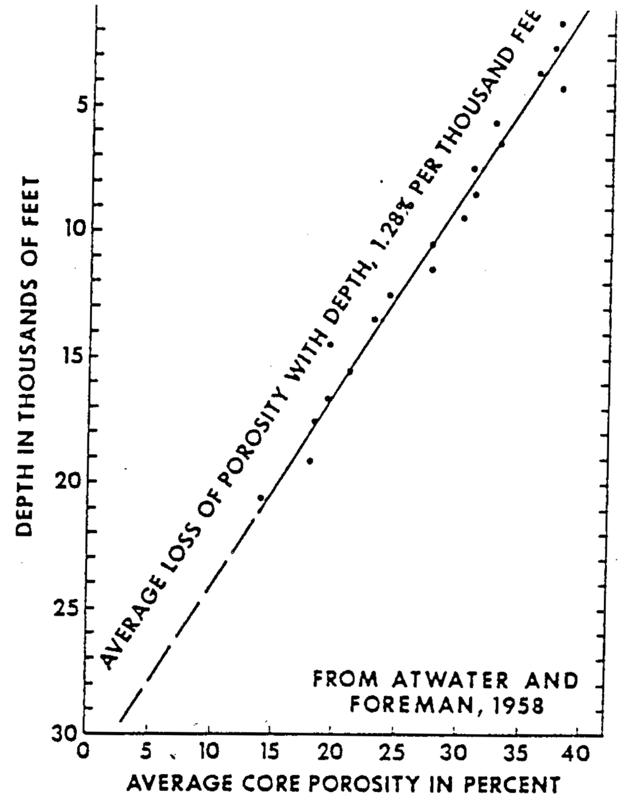


Figure 15. Average loss of porosity with depth in sand beds of the hydropressure zone, based on 17,367 samples from south Louisiana wells.

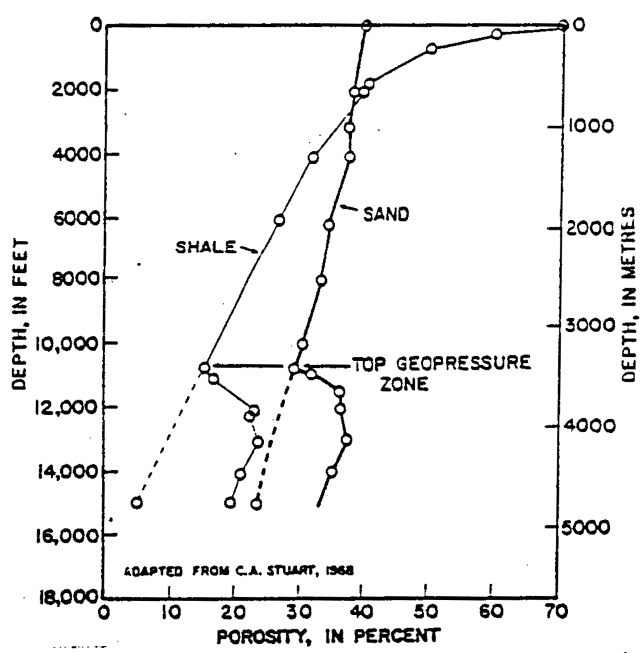


Figure 16. Relation of porosity to depth of burial in sand beds and in shale beds of Cenozoic age in the hydropressure zone and in the geopressure zone in the Gulf basin.

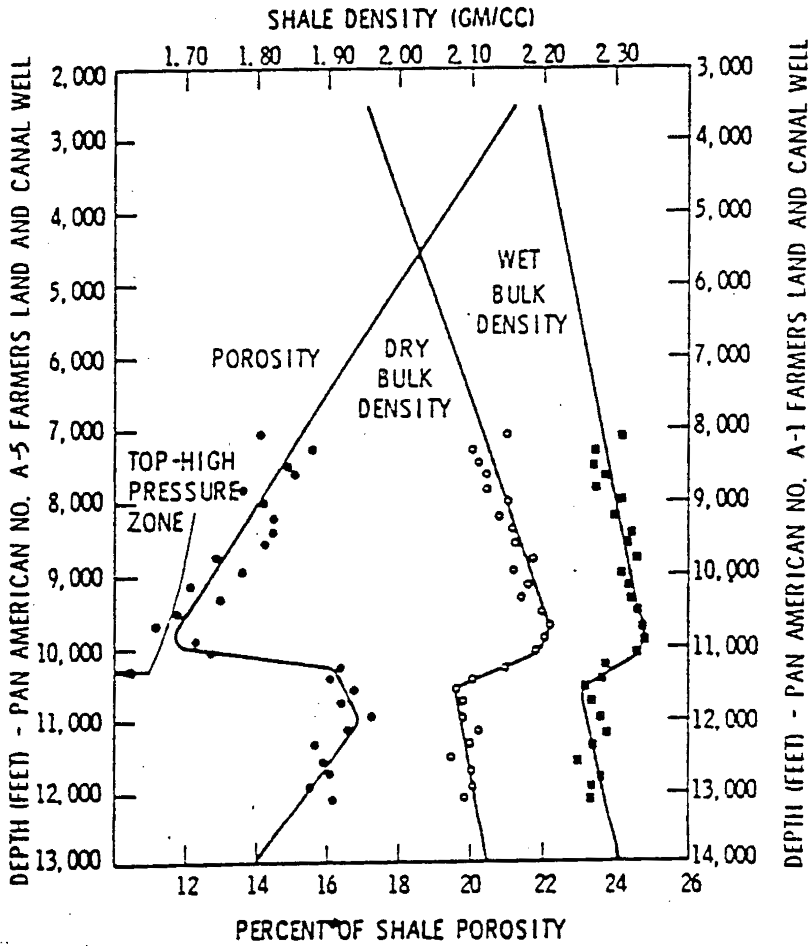


Figure 17. Determination of shale porosity for Farmers A-5 well from shale density data from nearby Farmers A-1 well.

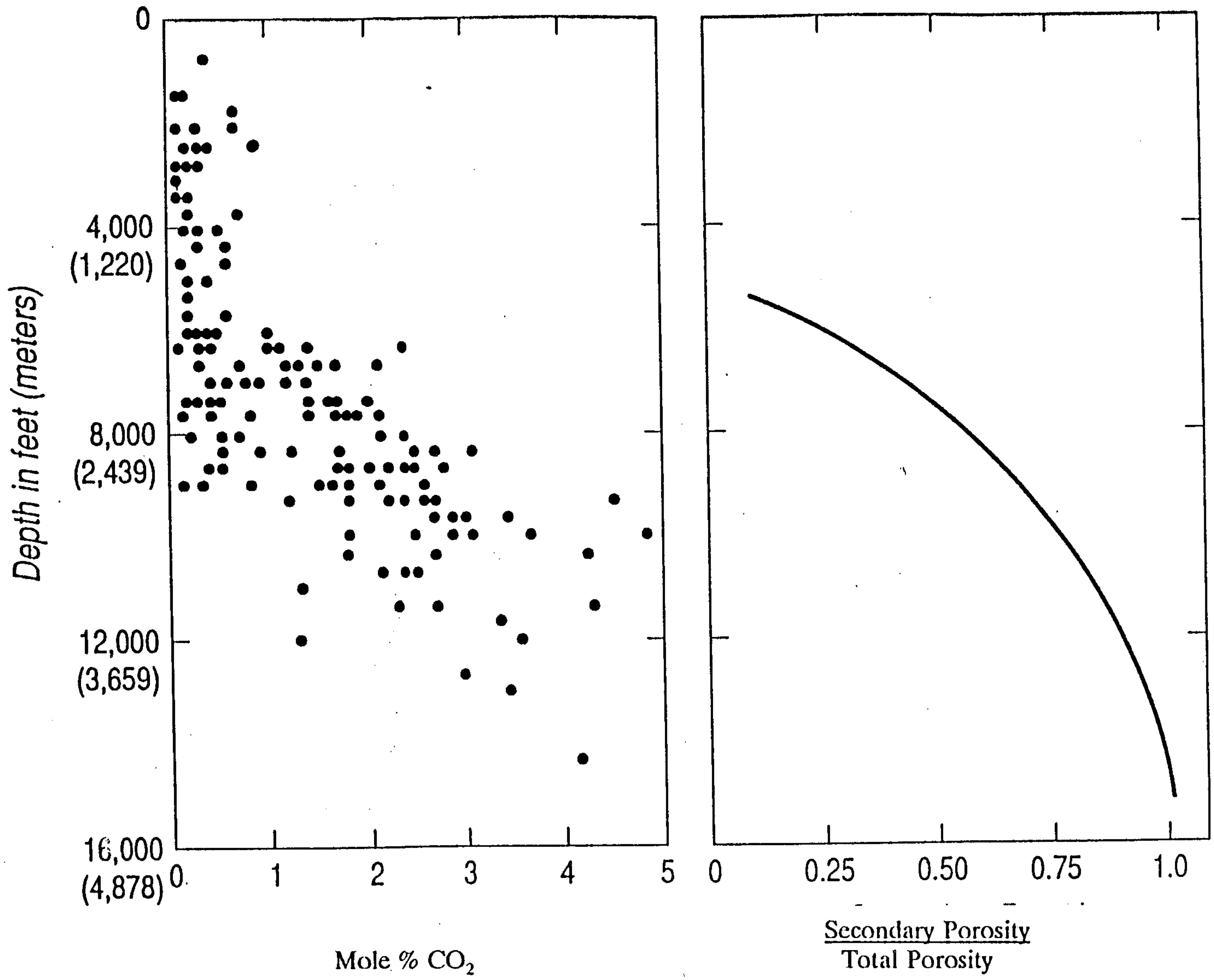


Figure 18 Comparison of CO_2 in gases produced from deep Wilcox sand reservoirs of the Texas Gulf Coast with the change in secondary porosity starting at about 6,000 ft. (Franks and Forester, 1984). The overpressures in the south Texas Gulf Coast start around 9000 ft (2,744m) and the hydrocarbon generation window is around 13,000 ft (3,963m) (Hunt, 1991).

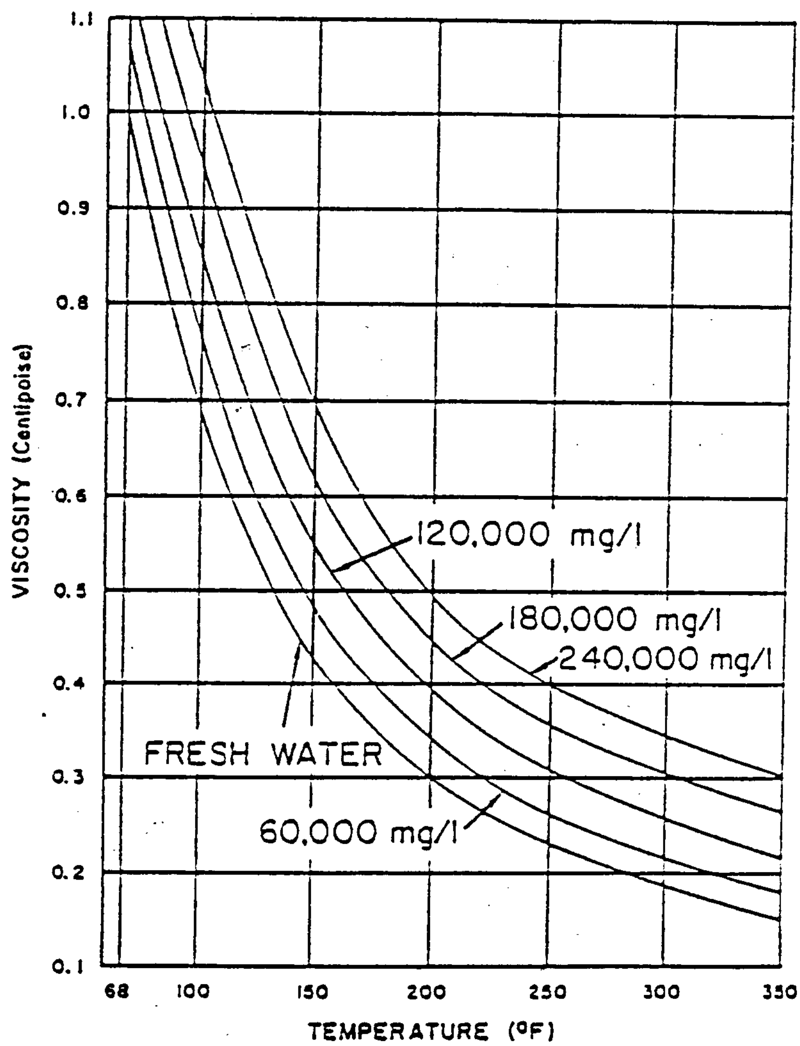


Figure 19. Relation between the viscosity, temperature, and dissolved-solids content of water (after Pirson, 1963).

M

The thermal properties of shale have implications for interpretation of the thermal effects of geopressuring (Blackwell and Steele, 1989, in a discussion of thermal conductivity of sedimentary rocks). The observed contrast in thermal conductivity for sand and shale can be used to investigate a problem in the thermal structure of the Gulf Coast - the reason for the high geothermal gradients associated with top-of-geopressure. The top of the geopressure zone is near the top of the Wilcox Formation. The mean temperature gradient to the top of the geopressure zone at about 3 km is 29 ± 3° C/km. Within the geopressure zone between 3 km and 5 km, temperature gradients are on the order of 43 ± 4° C/km. At greater depths gradients decrease to values of 22 ± 3° C/km.

The contrast in temperature gradient across the geopressure zone is almost exactly equal to the value that would be predicted by the contrast in temperature gradient between a predominantly sand and a predominantly shale section, and the contrast in temperature gradients compares closely to that observed between shales and sandstones on a finer scale in a well to the north. Thus, thermal conductivity contrasts seem adequate to explain the change in temperature gradient across the top of the geopressure zone.

Upward flow of fluids through the geopressure zone might contribute to the observed high temperature gradients (Blackwell and Steele, 1989). The vertical transport of heat by one-dimensional fluid flow through a porous medium is originally discussed by Bredehoeft and Papadopulos (1965), and their model can be used to investigate whether the apparent upward bow of the temperature-versus-depth relationship between 3 km and 6 km is related to a component of upward fluid flow. Calculations using the formulation of Mansure and Reiter (1979) suggest that upward velocities on the order of 0.3 to 0.6 cm/yr would be required to raise the gradient from 25 to 30° C/km to 40 to 45° C/km. Assuming reasonable volumes of fluid within and below the geopressured zone, velocities of this order of magnitude would require a volume of fluid that would be sufficient to deplete the high pressure fluids within a time scale on the order of 100,000 to 200,000 years. Thus, the maintenance of high gradients through the top-of-geopressure is not likely to be due exclusively to fluid flow but must be partly or predominantly due to the contrast in thermal conductivity (Blackwell and Steele, 1989).

The temperature and pressure of the fluid must ultimately be reduced. This decrease induces phase changes. Originally single-phase samples will then exhibit a vapor phase and, very likely, solid phases as well. As the pressure is reduced below the bubble-point at a given temperature, natural gas will come out of solution accompanied by carbon dioxide, hydrogen sulfide and ammonia, if present. Cooling and depressuring may cause supersaturation to develop with respect to silica and certain salts, with resulting precipitation (Silberberg, 1976).

Permeability

Two commonly stated objections to aquathermal pressuring are 1) hydraulic gradients and the finite, but very low, permeabilities now existing in the Gulf of Mexico are sufficient to dissipate aquathermal pressures, and 2) the increasing temperatures decrease fluid viscosity at a rate so that hydraulic conductivity increases fast enough to dissipate these pressures. Normal shale permeabilities range from 10^{-8} to 10^{-4} millidarcies. Sharp (1983) contends that under normal diagenetic conditions the decrease in intrinsic permeability caused by consolidation is greater than the viscosity effect. Sharp also points out that the momentum transport equations treat the problem as steady flow and not transient flow. However, Sharp suggests the permeability increases by fracturing and faulting may be sufficient to bleed off aquathermally produced excess pressures. The "measured, very low permeabilities of Gulf Coast fine-grained sediments indicate that aquathermal pressuring is a potentially important mechanism if the fine-grained sediments do control the hydraulic response."

Foster (1981) estimates shale permeabilities from drilling and well log data from a Gulf Coast well, see Figure 20. Permeabilities decrease by factors of 30 to 100 across the depth at which smectite dehydration occurs. This decrease suggests that the most important reason for association of the dehydration reaction with tops of geopressured zones may be the sealing effect of illitized shales, as suggested by Wearer and Beck (1971) and Foster (1981).

The effects of compaction on the permeabilities of sedimentary formations must also be considered when evaluating the history and production behavior of a geopressured-geothermal reservoir.

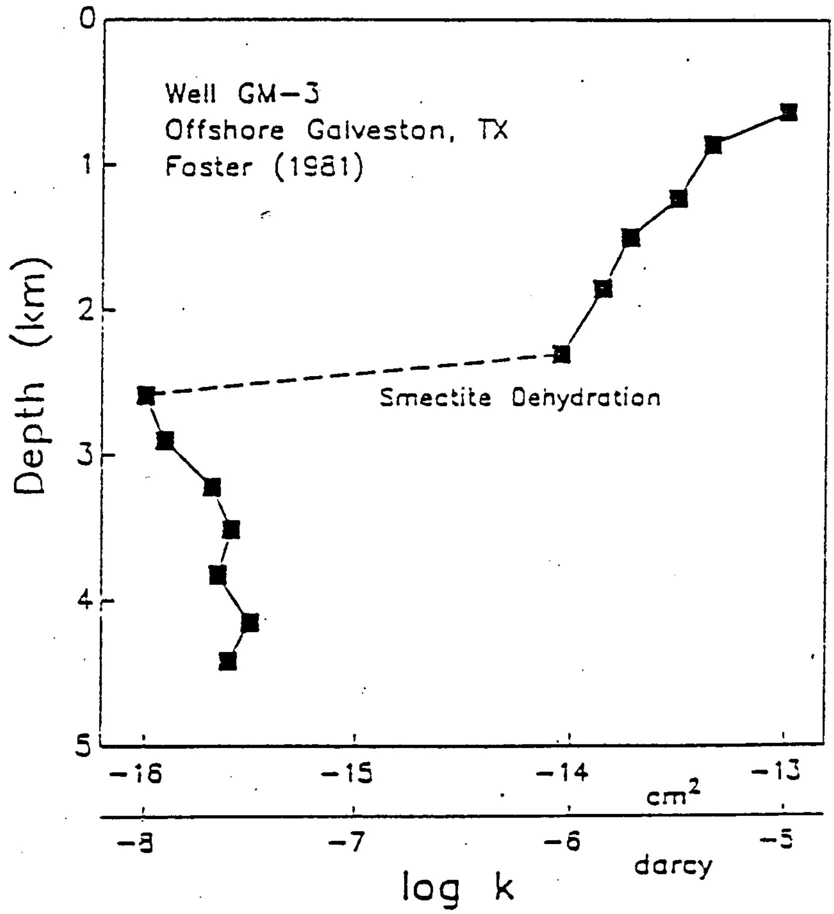


Figure 20 Shale permeabilities estimated by Foster (1981) from drilling and well log data for a Gulf Coast well.

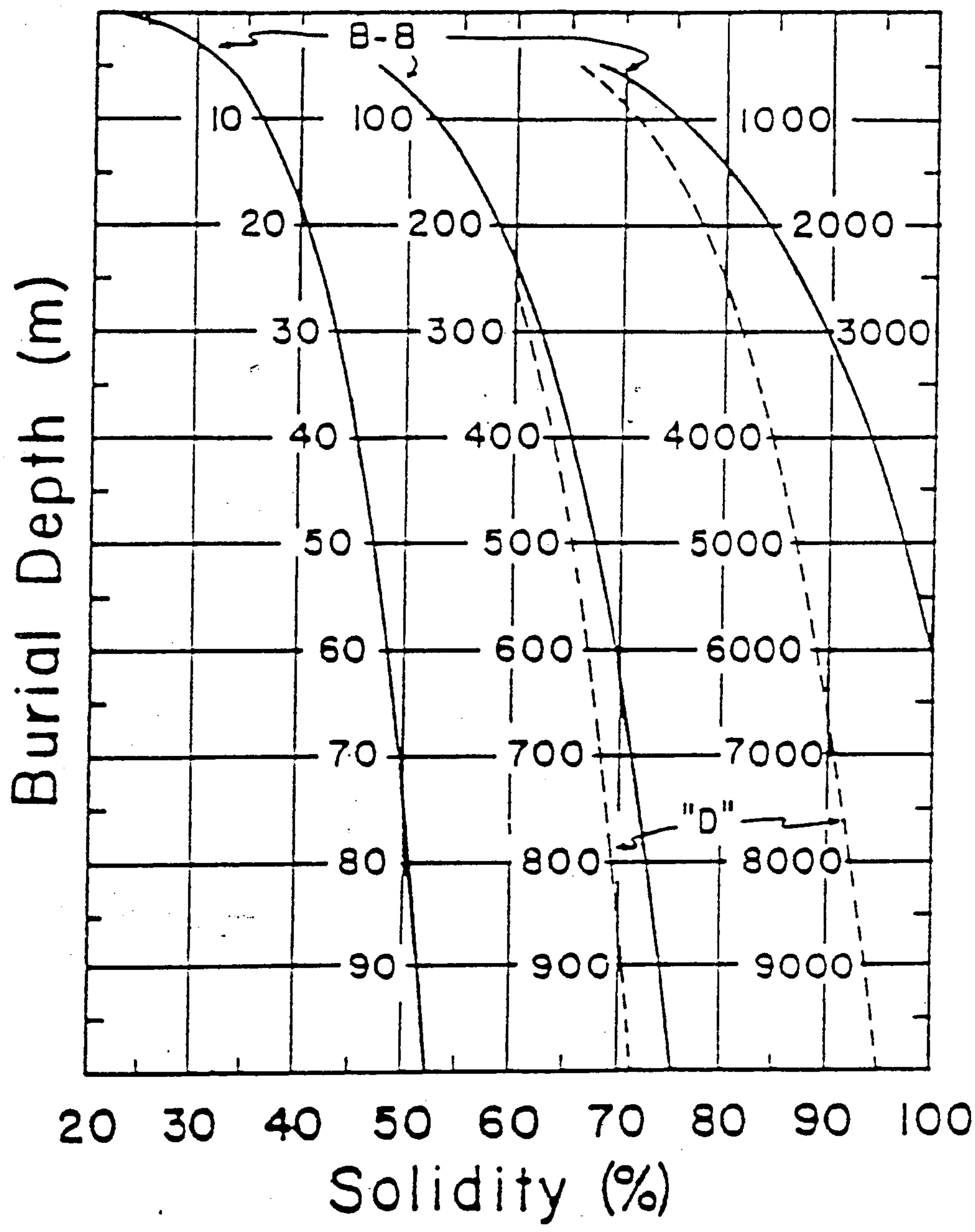


Figure 21. Calculated compaction curves for normal (B-B = Baldwin-Butler) and undercompacted ("D" = Dickinson equation") argillaceous sediments.

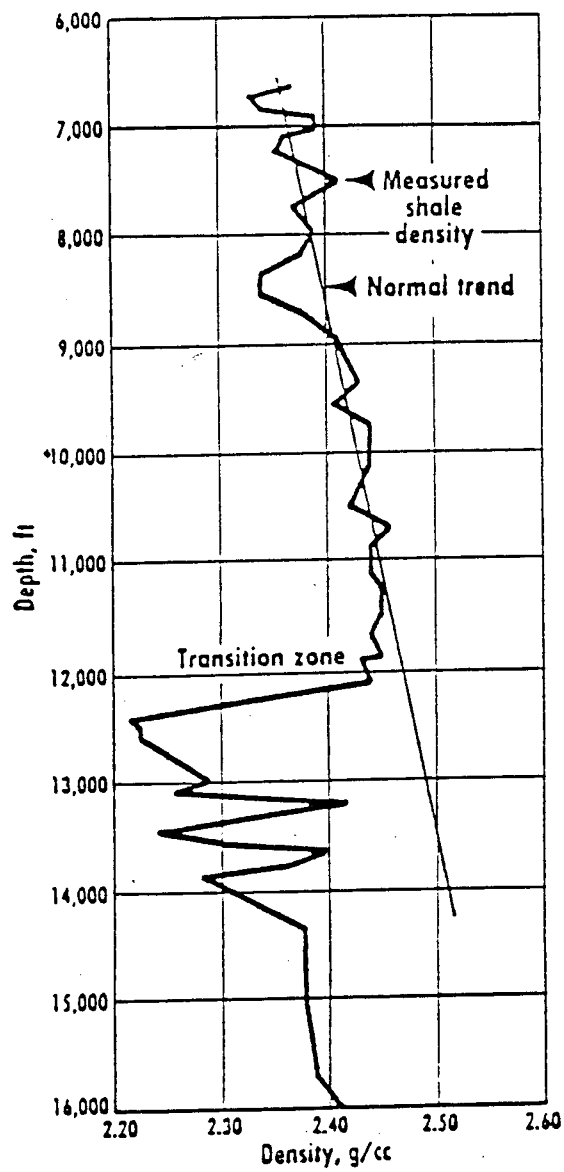


Figure 22. Shale density-depth relation in Gulf Coast well (after Rogers, 1966) (Magara, 1975).

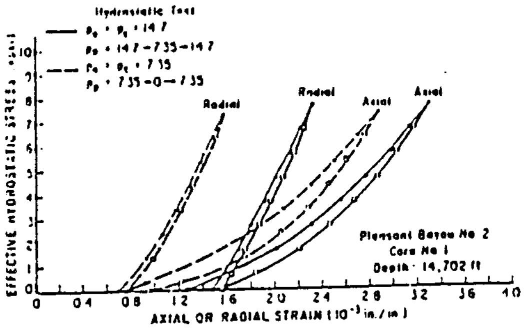


Figure 23. Typical stress-strain curves for hydrostatic loading.

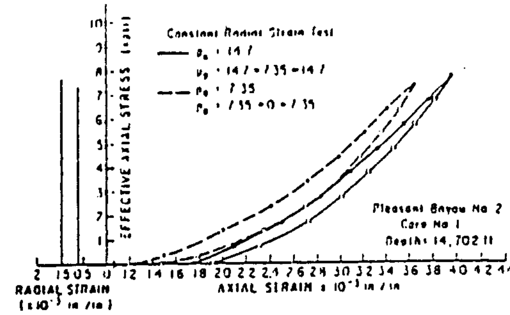


Figure 24. Typical stress-strain curves for uniaxial compaction.

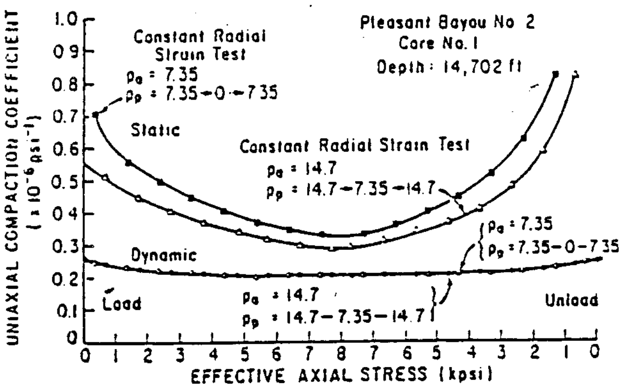


Figure 25. Uniaxial compaction coefficients as function of axial stress.

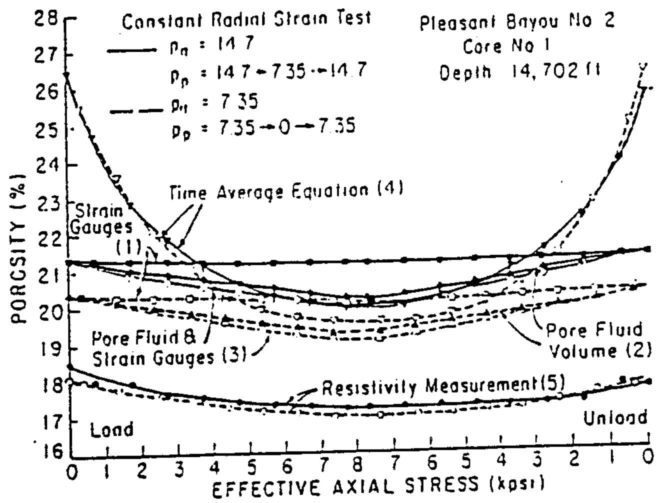


Figure 26. Porosity as function of axial stress.

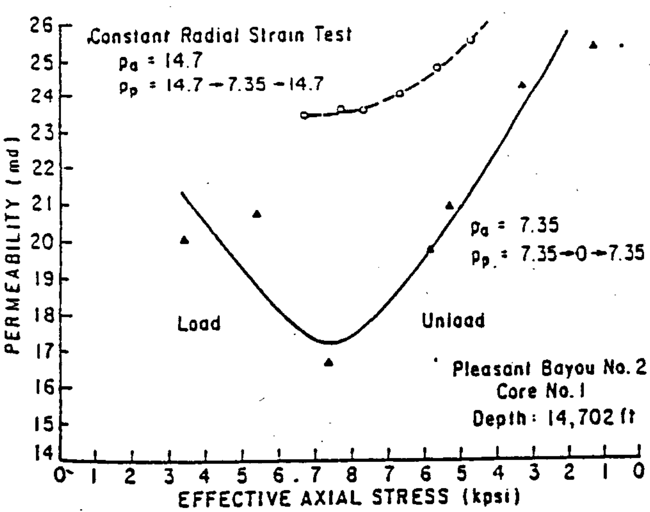


Figure 27. Permeability to brine as function of effective stress.

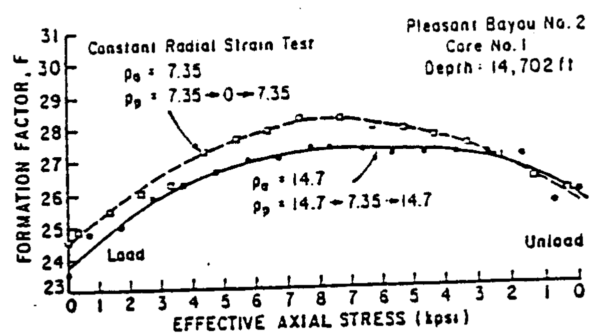


Figure 28. Formation factor as function of effective stress.

(Jogi et al., 1981)

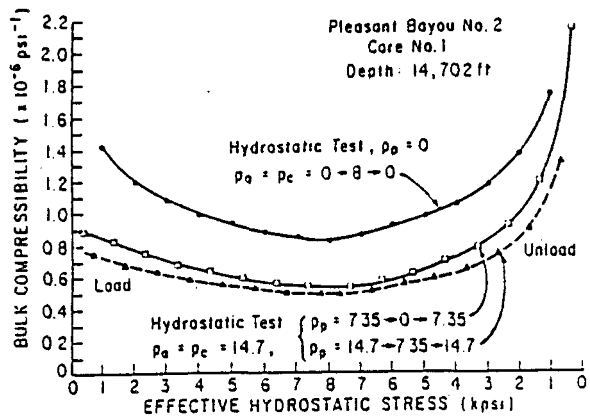


Figure 29. Bulk compressibility as function of hydrostatic stress.

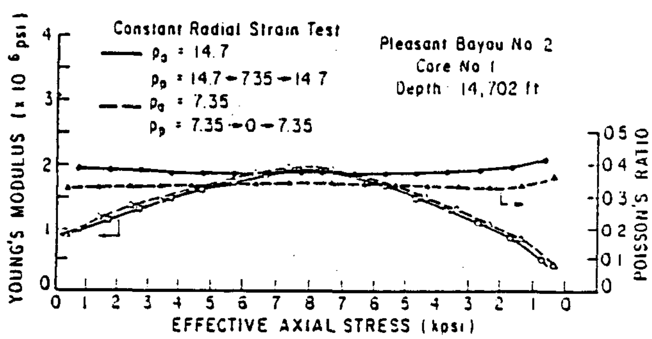


Figure 30 Young's modulus and Poisson's ratio as functions of axial stress.

Fahrenthold and Gray (1985) investigate the material properties of porous rock obtained from Gulf Coast geopressured-geothermal wells by measuring stress, strain, pore pressure, and temperature under reservoir pressure and temperature conditions. Uniaxial compaction and constant confining pressure tests were conducted. The rock demonstrated a nonlinear stress-strain behavior, with hysteresis and residual strain present upon unloading. Incremental coefficients were calculated from the experimental stress-strain curves. The maximum pressure that the samples were subjected to was less than 5,500 psi. The load/unload data converge toward the higher pressures. It would thus appear that the non-linear strain observed would be negligible at depths of 15,000 ft and more and pressures of 16,000 to 18,500 psi.

Work by Jogi et al. (1981) shows hydrostatic loading to about 7,000-75,000 psi for Pleasant Bayou No. 2 Core samples. The load/unload curves converge at the maximum pressures, again suggesting that at the depths and pressures of the geopressured wells in the DOE program, the effects are negligible and it would appear not necessary to consider the factors in modeling. The tables for rock parameters are shown in Tables 11-14. See Figures 21-30.

Creep compaction of sandstone cores from the Pleasant Bayou Wells is studied by Thompson et al. (1985). However, it is again not clear that the results are applicable to the geopressured conditions since the pressures used are in the range of 4,000 to 5,000 psi.

Table 9. Reservoir rock parameters, CCO-DOE #1 & #2.

		Bulk Compressibility		Uniaxial Compaction Test			
Stress Level		p_c =Constant p_p =Varies	p_c=increasing p_p=0	c_m (x10^{-6}psi^{-1}) F	ϕ(% Porosity)	k(millidarcy)	
CCO-DOE #1							
1-4-11755[2]	H	1.4 - .71	2.4 - .87	1.22 -.45	19.65 - 19.13	20.5- 15.5	21.1 - 25.2
	L	2.0 - .84		1.17 -.43	19.31 - 18.94	11.5- 11.0	23.9 - 27.52
1-7-14751	L	.78 - .43		.64 -.21	19.31 - 18.99	86 - 70	23.0 - 25.31
14765	H			.40 -.23	17.63 - 17.34	69 - 62	16.99 - 21.13
CCO-DOE #2					18.23 - 17.89	92 - 83	26.25 - 30.46
					17.18 - 16.93		
2-1-14696	H			.60 -.21	17.18 - 16.30		
14696	H	1.0 - .48		.87 -.29			
	L	1.1 - .50		.67 -.29			
14699	H	.88 - .41	1.30 - .71	.42 -.19	16.77 - 16.38	91 - 87	22.9 -26.74
	L	1.1 -4.44		.60 -.22	16.77 - 16.27	115 - 94	21.3 -26.45
14702[2]	H	1.3 - .48	1.73 - .81	.73 -.29	19.52 - 19.17	25.5- 23.4	23.75 -27.40
	L	2.1 - .52		.90 -.32	19.47 - 19.06	25.5- 17.2	24.6 -28.25
14703	H	1.4 - .61		.84 -.31	16.95 - 16.77	26.8- 19.5	24.10 -28.15
14711[2]	H	1.4 - .45	1.35 - .73	.52 -.23	21.16 - 20.90	168 -155	18.1 -19.25
	L	1.6 - .56		.57 -.23	21.2 - 20.78	144 -121	16.7 -18.5
14712	H		1.33 - .76	.84 -.29	19.16 - 19.02	26 - 19	23.3 -25.80
	L	1.95 - .52		.47 -.235	19.16 - 18.94	38.5- 35	23.55 -25.80
2-3-15665[2]	L	1.1 - .53		.80 -.30	19.68 - 19.25	79 - 66.5	21.15 -23.63
15668	H	.83 - .37	1.3 - .68	.48 -.19	19.82 - 19.58	69 - 51.5	25.5 -29.25
	L	1.0 - .41		.99 -.29	19.75 - 19.27	68 - 56.5	26.3 -30.2

(Jogi et al., 1981)

1 H- Corresponds to the initial stress condition on the specimen, p p p specimen depth
L - Corresponds to the initial stress condition on the speicmen, p p p the specimen depth

2 Measured matrix compressibilities vary from 0.31 to 0.33 x 10 psi

3 Range shown as effective stress increases from low to high values

Table 10. Porosity (%).

	Laboratory Data						Log-Derived Values			
	Resistivity		Static		Dynamic					
	Maximum Effective Stress	Minimum Effective Stress	Maximum Effective Stress	Minimum Effective Stress	Maximum Effective Stress	Minimum Effective Stress	Neutron	Sonic	Density	Resistivity
CCO-DOE#2										
2-1-14696 #1	16.2	17.3	17.39	13.23	15.85	21.5	17.85	15.6	16.02	34.3
#2	15.85	17.10	16.93	17.13	16.2	23.0				
14699	17.32	18.65	16.38	16.77	18.0	22.00	22.00	18.5	19.35	31.6
14702	17.20	18.10	19.17	19.32	19.85	26.0	19.20	13.65	18.07	27.6
14703	16.95	17.75	16.77	16.35	17.30	21.5	19.20	15.30	17.71	31.6
14711	21.95	22.50	20.90	21.16	19.80	24.5	18.90	16.5	17.45	37.1
14712	17.60	18.60	19.02	19.16	20.30	27.2	20.25	17.10	18.26	36.9
2-3-15665	18.4	19.30	19.25	19.68	21.25	23.5	12.45	16.80	16.79	24.0
15668	16.70	17.75	19.58	19.32	18.25	25.8	12.30	15.6	16.24	20.6

(Jogi et al., 1981)

Table 11. Comparison of log-derived & measured uniaxial compaction coefficients & formation factors.

	Uniaxial Compaction Coefficient ($x10^{-6}psi^{-1}$)						Formation Factor		
	Laboratory Data				Log Data		Laboratory Data		Log-Derived Value
	Static		Dynamic		Sonic & Density	Mechanical Properties	Maximum Effective Stress	Minimum Effective Stress	
	Maximum Effective Stress	Minimum Effective Stress	Maximum Effective Stress	Minimum Effective Stress					
CCO-DOE #2									
2-1-14696	.285	.87	.17	.21	.168	.177	32.35	27.60	6.2
14699	.185	.42	.185	.212	.193	.195	26.75	22.9	12.0
14702	.285	.73	.20	.26	.179	.151	27.4	23.75	9.85
14703	.310	.84	.18	.22	.179	.155	28.15	24.1	7.38
14711	.230	.52	.20	.24	.183	.187	19.25	18.1	5.23
14712	.29	.84	.20	.26	.184	.187	25.8	23.3	5.29
2-3-15665	.30	.80	.21	.24	.175	.167	23.63	21.15	13.35
15668	.19	.48	.20	.25	.170	.176	29.25	25.5	18.5

(Jogi et al., 1981)

Table 12. Comparison of log-derived & lab-measured values of Young's modulus & Poisson's ratio.

	Young's Modulus (10^6 psi)			Poisson's Ratio		
	Lab Data (Static)			Lab Data (Static)		
	Maximum Effective Stress	Minimum Effective Stress	Log-Derived Data	Maximum Effective Stress	Minimum Effective Stress	Log-Derived Data
CCO-DOE #2						.277
2-1-14696	2.95	0.3	4.596	.355	.35	.293
14699	3.72	1.45	3.880	.321	.30	.307
14702	1.95	0.45	4.917	.372	.41	.300
14703	2.47	0.85	5.03	.291	.19	.287
14711	2.31	0.95	4.12	.281	.25	.287
14712	2.4	0.80	3.99	.321	.23	
2-3-15665	2.37	0.95	4.875	.312	.251	.250
15668	3.77	1.20	5.193	.331	.225	.230

(Jogi et al., 1981)

Alteration Mineralogy

Capuano (1988) calculates the effects of geopressuring and kerogen decomposition on mineral-fluid equilibria in order to predict the diagenetic--alternative mineralogy produced in equilibrium with kerogen-rich, geopressured sediments. She notes that several processes specific to kerogen-rich geopressured sediments contribute to the development of a characteristic alteration mineralogy. These processes are: 1) the upward flow of fluids in geopressured sediments, in contrast to the generally downward flow of fluids in normally-pressured sediments; 2) the coincidence of the depths of geopressuring with the geothermal temperatures necessary for CO_2 and CH_4 releases; and 3) the opposing rates of sediment burial and CO_2 and CH_4 transfer into the upward-flowing fluids, which result in the geopressured pore fluids becoming enriched, and in some cases saturated, with respect to CO_2 and CH_4. As a result three patterns of mineral deposition during diagenesis of kerogen-rich geopressured sediments are predicted:

1) Authigenic quartz deposition should occur at the top of the geopressured zone and decrease rapidly with increased depth as a result of the decreased upward fluid flow with increased depth;

2) Carbonate deposition should occur above the zone of CO_2 release from kerogen degradation as a result of the upward flux of CO_2-saturated fluids and subsequent decreases in fluid temperature, pressure and CO_2 solubility; and

3) Kaolinite-carbonate could deposit within and above the zone of CO_2 release from kerogen as a result of silicate dissolution by CO_2-rich acid pore fluids, followed by the potential for albite-carbonate deposition upon CO_2 depletion.

These mineralogic relationships compare favorably with observed relationships in the kerogen-rich geopressured sandstones of the Frio Formation from the Texas Gulf Coast. Capuano (1988) makes the following conclusions:

"Chemical and hydrologic conditions present within kerogen-rich geopressured sediments during diagenesis are uniquely different from those present within normally-pressured or kerogen-poor sediments. In geopressured sediments compaction-driven flow dominates such that fluids are transported upward to regions of lower temperature and pressure. In contrast, flow in normally-pressured sediments is generally gravity-driven and therefore downward to regions of higher temperature and pressure. Calculation of the magnitude of fluid flow in geopressured sediments resulting from burial compaction and fluid thermal expansion indicates that the greatest magnitude of upward flow is at the top of the geopressured zone, decreasing rapidly with increased depth."

"Kerogen present within geopressured sediments decomposes releasing CO_2 and CH_4 at temperatures over 194 to 212°F (90 to 100°C), temperatures generally present in the upper portions of the geopressured zone. Calculation of the opposing rates of sediment burial with subsequent CO_2 and CH_4 release, and absorption of these gases by the upward flowing fluids indicates that this process can result in gas enrichment to or near to saturation in geopressured fluids within petroleum-source rock. Gas saturation is further enhanced by the temperature and pressure decreases in gas solubilities experienced by the fluids as they move upward. In kerogen-poor geopresssured sediments, pore fluids generally lack a source of CO_2 and CH_4 and, therefore, do not become enriched in these gases."

Fluids

Geopressured-geothermal fluids are nominally hot brines of varying salinity and chemical composition. Typically, sodium and calcium compounds predominate, with other dissolved salts in lesser quantities. Also dissolved in the brines are methane, other light hydrocarbons, other organic chemicals, and other gases. Their variety is indicated by the tables in the Appendix to this report. The overriding chemistry of geopressure-geothermal fluids relates to the brines, but the contributions of other dissolved materials to the overall development and behavior of the reservoir have not been appraised separately.

Certain radioactive elements may be present in some geopressured-geothermal reservoirs. While these elements do not, at present, appear to assist in historical interpretations, activity measurements for radon and radium can be a very useful technique for monitoring some aspects of reservoir behavior during long-term production.

Origin and Sources of Brines

D. L. Graf (1982) examines the origin of subsurface brines. Calculations using recently tabulated values of density and osmotic coefficient for NaCl-H_2O indicate that overpressuring is more than adequate to overcome chemical osmosis and drive reverse chemical osmosis in sedimentary sequences. In the Gulf Coast area contributions from salt layers (halite) to the brines in the Houston-Galveston area are recognized, but not in the Corpus Christi area. Graf concluded that the strongest arguments for the importance to present-day brine compositions of membrane concentration of sea-water solutes are: 1) the correlation of dD values of water molecules of pore fluid with those of local meteoric water, and 2) the need for major sources of Mg^{2+} and Cl^- in apparently evaporite-free basins. Reverse chemical osmosis operates to leak relatively dilute water. The membrane effect of the shale beds of the Gulf Coast in developing a salinity gradient (high on the bottom near the geopressured reservoir and low at the top of the shale after the fluid passes through the shale vertically) is described by Graf.

Macpherson (1991) addresses "Regional Variations in Formation Water Chemistry: Major and Minor Elements, Frio Formation Fluids, Texas." The definition he uses for geopressure is that, within the geopressure regime, fluid pressures increase at the rate of at least 16 MPa/km (0.7psi/ft). Macpherson notes three origins that have been considered seriously for Na-Ca-Cl waters. These are as follows: 1) membrane filtration of altered seawater, 2) fluids from which the Louann Salt was deposited, and 3) halite dissolved by water and recrystallized. None of the three is adequate in answering all the questions relative to formation of the formation waters. In south Texas, the fluid chemistry suggests that 1) these fluids may have been emplaced before geopressure was established in the region (2-3 m.y.), and 2) river systems (probably ancient systems active during pluvial periods) may have removed Ca-rich fluids from other parts of the section. This interpretation applies only to the south Texas region and does not preclude earlier interpretations that clay-dehydration reactions dilute formation waters (Macpherson, 1991). See Figure 31.

Some experimental work attempts to quantify and correlate the effects of salt, gas, temperature, and pressure on the compressibility and formation volume factor of water.

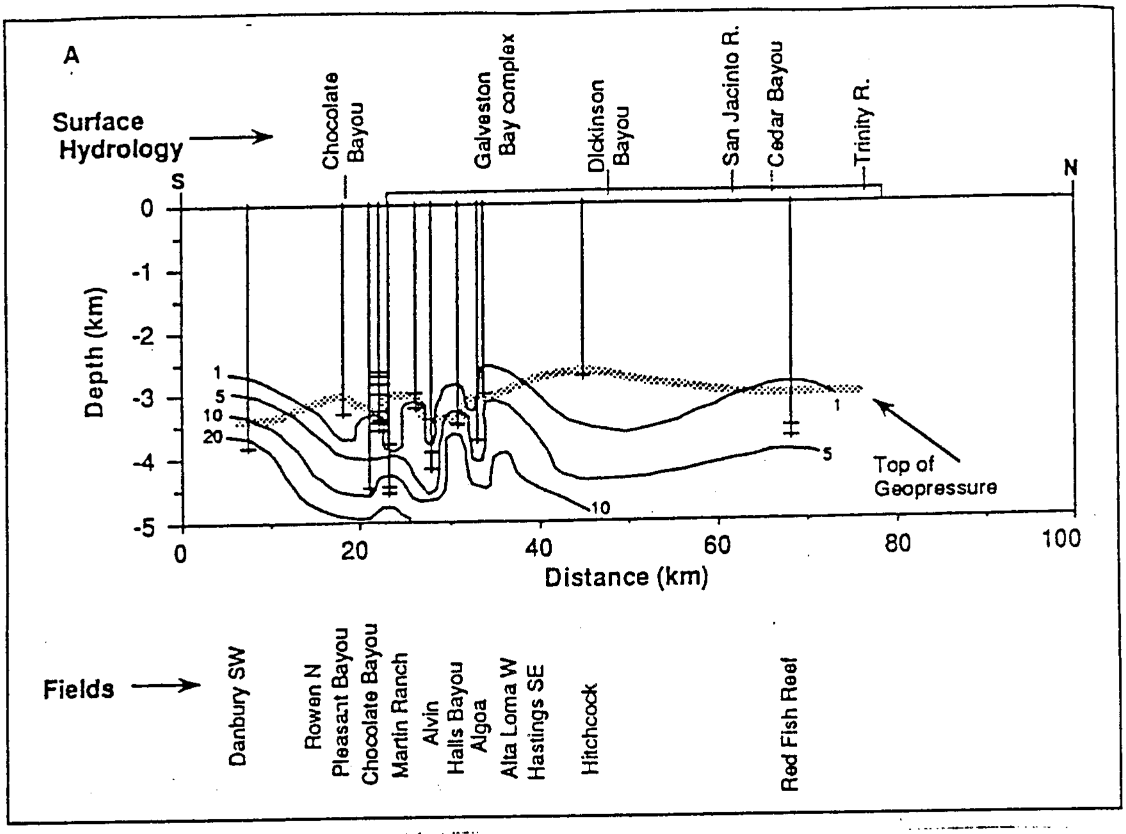
Osif (1985) reports on compressibilities and formation volume factors of water-sodium chloride-gas systems measured as a function of temperature 200 to 270°F (93 to 132°C), pressure (up to 20,000 psi), and composition (up to 34.5 SCF gas/bbl and up to 200 g sodium chloride/L). Plots of the reciprocal of compressibility versus pressure are linear for water and brines. The slopes of these plots are all the same but the intercepts are linearly dependent on the temperature and salinity. Dissolved gas has no effect on these compressibilities at gas-to-water ratios (GWRs) of 13 SCF/bbl. Even at GWRs of 34.5 SCF/bbl, dissolved gas probably has no effect, but certainly causes no more than a 5% increase in the compressibility of brine. Dissolved gas does have an effect on formation volume factors. Table 13 shows the system compositions evaluated by Osif, and Table 14 summarizes his data development.

Table 13. System Compositions.

System	Composition
1	Water
2	Brine, 100.5 g NaCl/liter
3	34.5 SCF Methane/bbl water
4	34.5 SCF Methane/bbl brine, 99.5 g NaCl/liter
5	35.1 SCF "natural gas"/bbl brine, 100.0 g NaCl/liter
6	12.8 SCF "natural gas"/bbl brine, 100.1 g NaCl/liter
7	12.9 SCF "natural gas"/bbl brine, 199.7 g NaCl/liter
8	32.9 SCF "natural gas"/bbl brine, 29.9 g NaCl/liter
9	Water
10	Brine, 199.9 g NaCl/liter
11	Brine, 29.9 g NaCl/liter
12	348 SCF "natural gas"/bbl brine, 99.6 g NaCl/liter
13	Brine, 100.4 g NaCl/liter
14	34.6 SCF "natural gas"/bbl water
15	14.1 SCF "natural gas"/bbl water
16	12.8 SCF "natural gas"/bbl brine, 30.0 g NaCl/liter

"Natural gas" = 89.749 mole % methane, 9.240 mole % ethane, 0.913 mole % propane, and 0.098 mole % n-butane.

(Osif 1985)



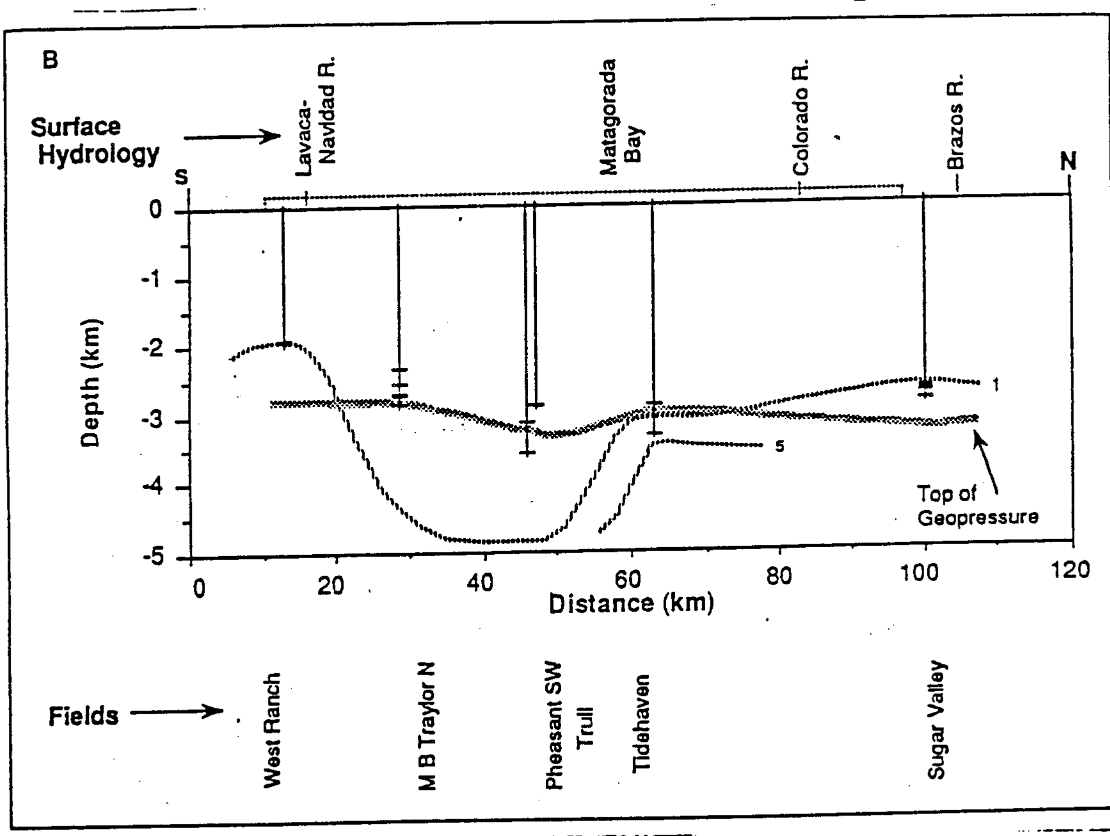
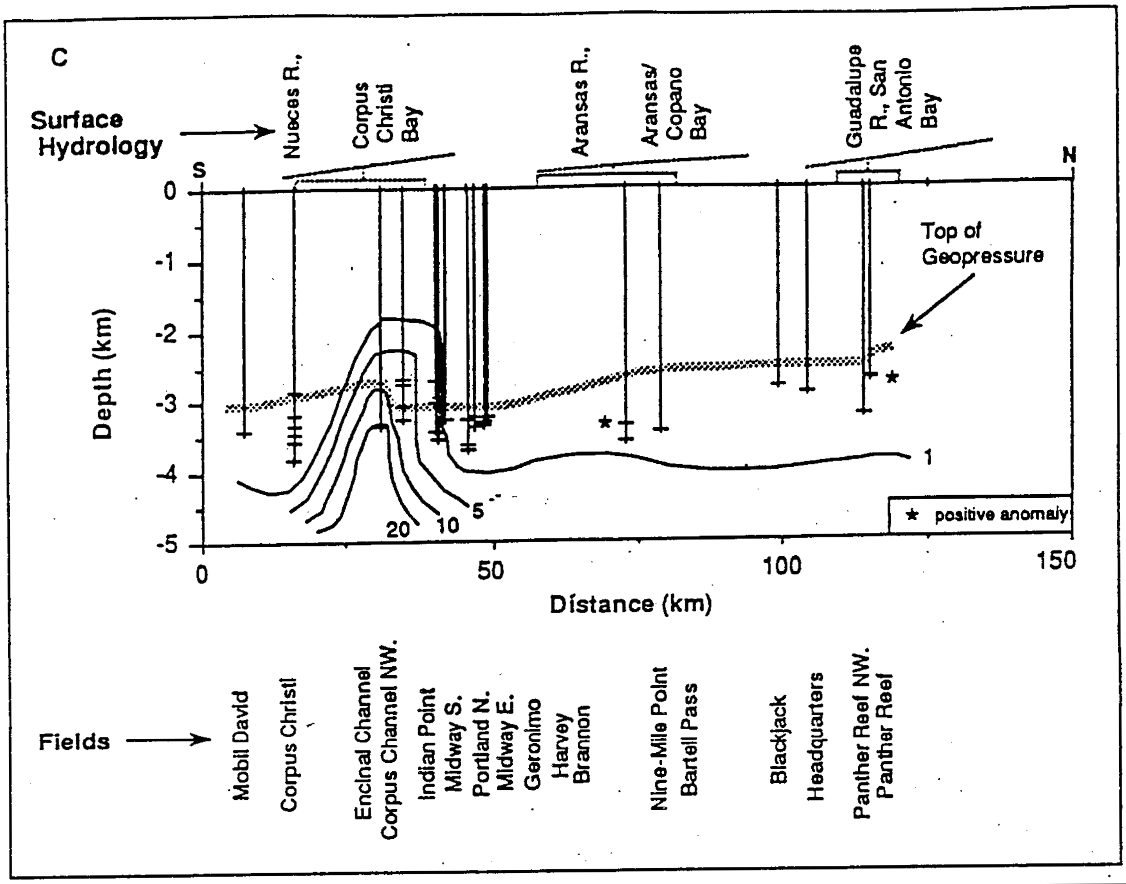
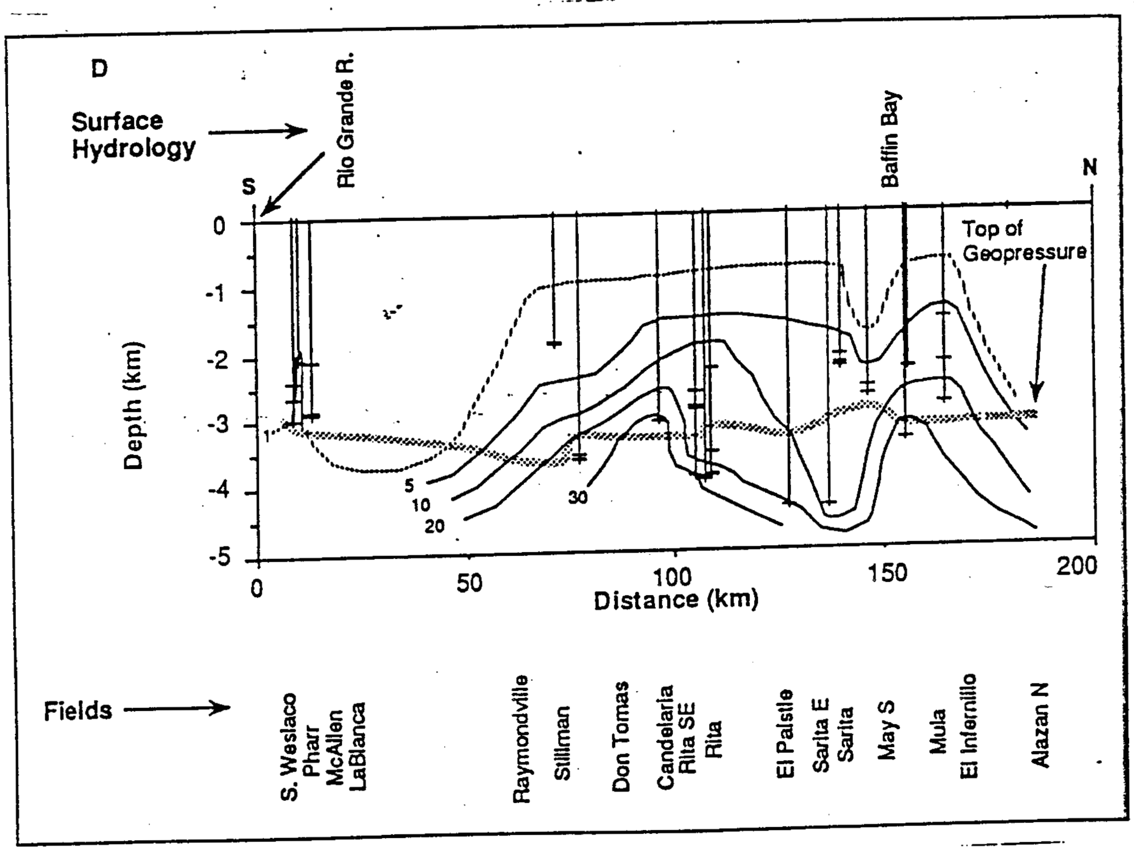


Figure 31 Contours of Ca++ content (g/L) in coast-parallel cross sections for various fields in (a) north coastal Texas, (b) northern half of central coastal Texas, (c) southern half of central coastal Texas, and (d) south Texas.


C
Surface Hydrology
Nueces R.,
Corpus Christi Bay
Aransas R.,
Aransas/ Copano Bay
Guadalupe R., San Antonio Bay
S
N
Top of Geopressure
Depth (km)
0
-1
-2
-3
-4
-5
1
5
10
20
* positive anomaly
0
50
100
150
Distance (km)
Fields
Mobil David
Corpus Christi
Encinal Channel
Corpus Channel NW.
Indian Point
Midway S.
Portland N.
Midway E.
Geronimo
Harvey
Brannon
Nine-Mile Point
Bartell Pass
Blackjack
Headquarters
Panther Reef NW.
Panther Reef


D
Surface Hydrology
Rio Grande R.
Baffin Bay
S
N
Top of Geopressure
Depth (km)
0
-1
-2
-3
-4
-5
1
5
10
20
30
0
50
100
150
200
Distance (km)
Fields
S. Weslaco
Pharr
McAllen
LaBlanca
Raymondville
Stillman
Don Tomas
Candelaria
Rita SE
Rita
El Paistle
Sarita E
Sarita
May S
Mula
El Infernillo
Alazan N

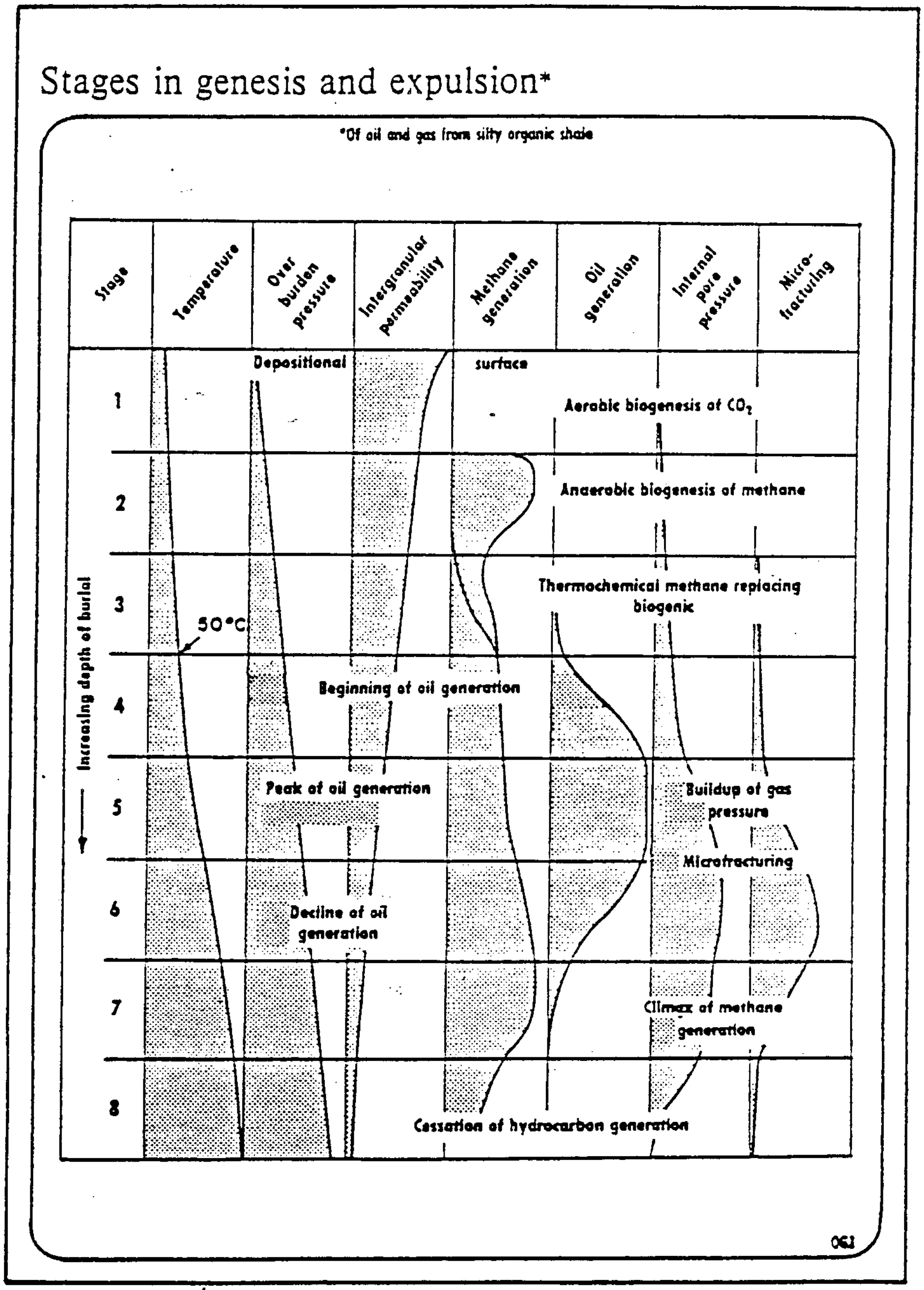


Figure 32. Stages in hydrocarbon genesis and expulsion (Hedberg, 1979).

Table 14. Parameters for calculating compressibilities of water and brines containing dissolved gas.

Equation: $-1/C + (AI)(P) + (A2)(S) + (A3)(T) + A4 = 0$

C = compressibility in units of psi^{-1}
P = pressure in psi
S = salinity in g/liter of solution
T = temperature in °F

I	AI	Variance	Standard Deviation
1	0.7033 E+1	0.2996 E-2	0.5473 E-1
2	0.5415 E+3	0.1430 E+2	0.3781 E+1
3	-0.5370 E+3	0.9509 E+2	0.9752 E+1
4	0.4033 E+6	0.5965 E+7	0.2442 E+4

Number of observations 420
Variance of the function of unit weight = 0.3331 E+8
Standard deviation of the function = 0.5771 E+4
Number of residuals greater than 2.5 std. dev. = 5

This equation was fitted for pressures between 1000 and 20,000 psi, salinities from 0 to 200 g NaCl/liter, and temperatures from 200 to 270°F. Compressibilities are independent of dissolved gas species.

(Osif 1985)

Origin and Sources of Hydrocarbons

Hydrocarbons in geopressured reservoirs include dissolved gases, oil and condensate. One or more phases may be represented depending on the chemical and physical conditions and constituents of the reservoir.

Deep basinal organic-rich sediments, high in terrestrial kerogen, are believed to be the source beds for many of the Gulf Coast hydrocarbon accumulations, both oil and gas, generated through thermal maturation and migrated up dip and across faults into offshore and onshore structural and stratigraphic traps. This process of thermal maturation is ongoing. With burial and compaction, the organic material passes deeper and deeper into the thermal regime required to generate oil and gas and then to crack the oil, forming additional gas and lighter hydrocarbons. The migrating hydrocarbons seek paths of least resistance, of higher permeability and porosity, and thus, frequently end up in sandstones, fractures, and fissures. The buildup of oil and gas continues in a trap as long as there is a maturing and migrating supply of hydrocarbons, and the trap seals hold the increasing pressure.

The hydrocarbons may spill out of an oversupplied trap or burp out of an overpressured compartment filled beyond the sealing capacity of its boundaries. See Figure 32 and the section on Hydrocarbon Generation under Causal Agents.

Water Chemistry

Dissolved salts in geopressured waters are often present in large amounts. Examples of their variety and relative concentrations are provided by the tables in the Appendix. Dickey (1988) addresses regional variations in formation water chemistry in the Frio Formation in the Texas Gulf Coast. Three different types of water from four different areas exist along the Texas Gulf Coast. Two of these types fall into the chloride-calcium class, except that one has very high calcium with respect to sodium. The third type belongs to the bicarbonate sodium class. Waters of similar chemical composition are found in many parts of the world. The bicarbonate sodium class has been considered to be, at least in part, of meteoric origin. Morton and Land (1987), whose work Dickey discusses, account for high salinity by molecular diffusion from the underlying salt bed and from salt diapirs; abnormally low salinities are accounted for by the expulsion of lattice water from the conversion of smectite to illite, and its rise and escape from the geopressure zone. High-calcium water is believed to come from deeper formations. Dickey agrees with Morton and Land that the popular explanation of reverse osmosis is impossible.

Pore water in shales contains much less other dissolved solids and much more sulfate and bicarbonate (alkalinity) than the water in the immediately adjacent sands. The different composition of the shale pore water shows that cross-formation flow cannot occur except locally along faults. The growth faults of the Gulf Coast are usually pressure barriers where they cut oil and gas fields. The very existence of the geopressures and the different water compositions associated with them suggest that cross-formation flow is not occurring or at least is extremely slow. Long-distance lateral and vertical diffusion of sodium chloride is unlikely and large-scale cross-formation flow also seems unrealistic, according to Dickey (1988).

On the basis of the work by Dickey (1988) and Morton and Land (1987), the concept that shale dewatering is recharging the DOE Gladys McCall and Pleasant Bayou Wells is not substantiated by the brine chemistry which has remained essentially unchanged after 4-5 years of flow testing. Further the high total dissolved solids (TDS) in the Louisiana wells suggests deep vertical water sources rather than freshening by shale dewatering.

Several investigators comment on freshening of highly saline waters. "Theories advanced to explain the existence of abnormally pressured (geopressured) sandstones in the coastal regions of Texas and Louisiana propose a freshening of the saline waters by expulsion of essentially deionized water from adjacent shale beds as a result of the transformation of montmorillonite to illite. Resulting salinities are decreased by 50,000 mg/liter or more from values otherwise to be expected at such depths. Several examples are reported of salinities less than 30,000 ppm in geopressured zones at depths greater than 10,000 ft" (Jones, 1969). In the South Texas area, the Upper Wilcox Formation fluids show 3,260 ppm TDS. This would be in the fresh end of brackish water (Negus-de Wys, 1991). An abrupt decrease in total dissolved solids at 10,000 ft in sandstones in the Manchester Field, Calcasieu Parish, Louisiana was reported from 170,000 to about 20,000 mg/liter. See Figure 33.

"If the reservoir fluids in such a situation are simply diluted by fresh water from the shale beds, it can be anticipated that the principal ions in solution will be those of sodium and chlorine. The other major cation will probably be calcium, with magnesium and potassium in lesser amounts. Other major anions will probably be bicarbonate and sulfate, with iodide and bromide in lesser amounts. The solubility of calcium sulfate increases with decreasing temperature and should be little affected by decreasing pressure. The solubility of calcium carbonate similarly increases with decreasing temperature, but the evolution of a vapor phase as a result of decreased pressure would shift the carbonate-carbonate equilibrium to favor precipitation of calcium carbonate. If the magnesium and bicarbonate contents of the water are high, a similar tendency to precipitate magnesium carbonate may exist" (Silberberg, 1976).

Schmidt (1973) investigates interstitial water composition and geochemistry of deep Gulf Coast shales and sandstones. He states: "Interstitial water from shales and sandstones shows a contrast in concentration and composition. Sidewall cores of shales were taken every 500 ft between 3,000 and 14,000 ft in a well in Calcasieu Parish, Louisiana, which encounter abnormally high fluid pressures just below 10,000 ft. Significant differences between the total dissolved solids concentrations in waters from normally pressured sandstones (600 - 180,000 mg/l) and highly pressured sandstone (16,000 - 26,000 mg/l) were noted. Shale pore water has a lower salinity than the water in the adjacent normally pressured sandstones, but the concentrations are more similar in the high pressure zone. Shale water generally has a concentration order of $SO_4 = >$

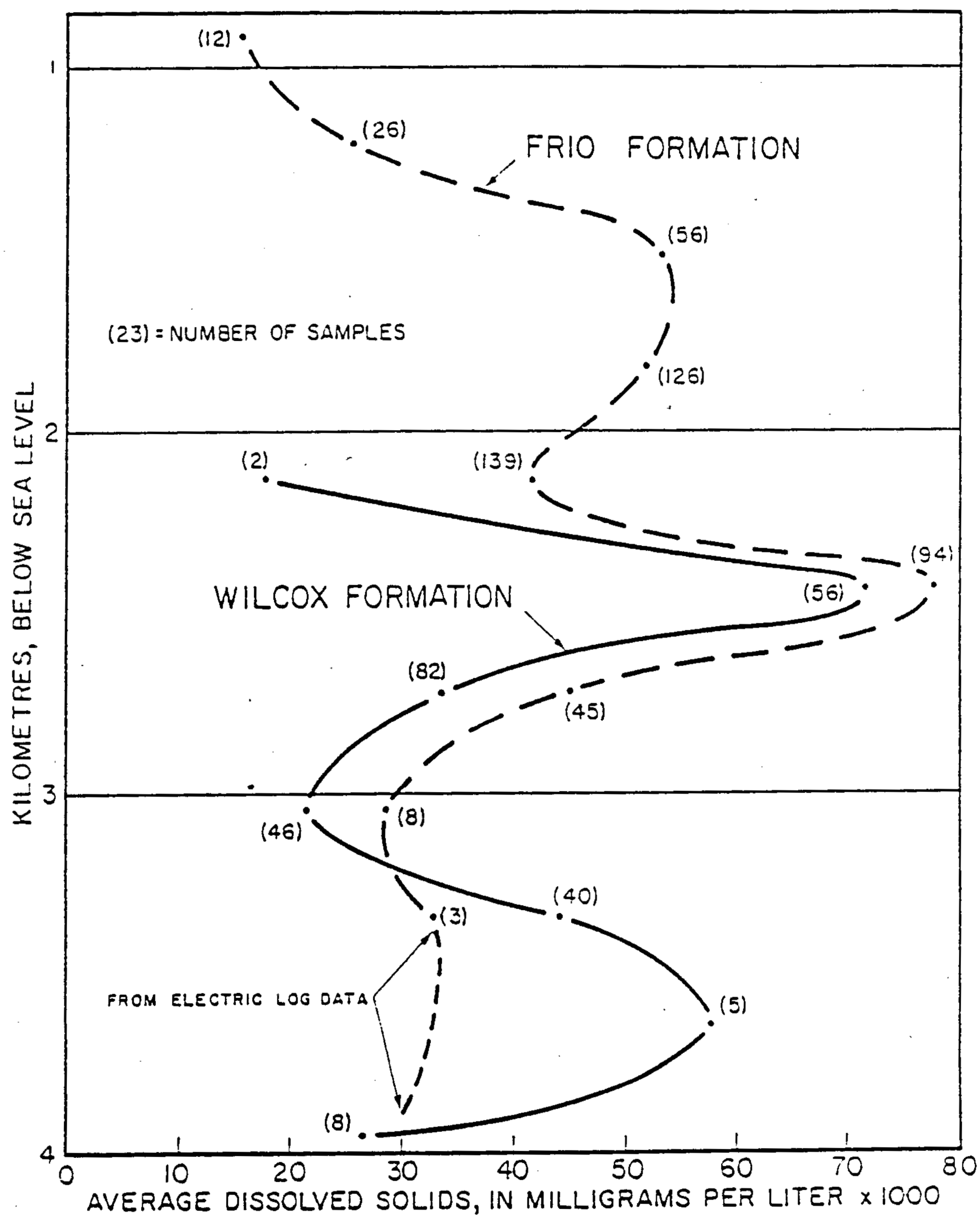


Figure 33. Salinity change with depth and geologic formation in south Texas Coastal Plain based upon the average salinity of waters from aquifers in depth intervals of 330 m (1,000 ft) (Jones, 1975).

HCO_3^- > Cl^-, whereas water in normally pressured sandstone has a reversed concentration order.

"Conversion from predominately expandable to nonexpandable clays accelerates near the top of the high pressure zone, which appears correlative with a major temperature gradient change, and increase in shale porosity (decrease in shale density), a lithology change to a massive shale, an increase in shale conductivity, an increase in fluid pressure, and a decrease in the salinity of the interstitial waters. The data suggest that the clays subjected to diagenetic change release two layers of deionized water and that this released water may be responsible for the lower salinity of the water found in the high pressure section."

Hanor (1981), in the context of waste water reinjection, presents the calcium, barium, alkalinity, and sulfate for hydropressured water and geopressured waters in south Louisiana as a function of chloride.

As a result of his studies, Hanor concludes that "it is safe to assume that the following compatibility problems are likely to occur if untreated waste water is injected into hydropressured sands in south Louisiana:

1. Precipitation of Ca, Sr, and Ba sulfates and carbonates,
2. Precipitation of iron minerals if dissolved oxygen is entrained in the injected fluid, and
3. Migration or swelling of clays if there are large salinity differences between injected and native fluids."

Hanor suggests that, presumably, any of these problems can be alleviated at cost by suitable chemical pre-treatment of the injection horizon and injected wastes.

Similar problems could be encountered in using geopressured-geothermal fluids in thermal-enhanced recovery of medium to heavy oil where the reservoir to be flooded is shallow and of similar chemical composition. However, chemical pre-treatment could be the solution (Hanor, 1981).

After 5-6 years of re-injecting hot geopressured brines into shallow aquifers (~6,000 ft), the DOE Geopressured-Geothermal Program has observed no precipitation problems, migration or swelling of clays.

Mazor and Kharaka (1981) address gases produced from geopressured-geothermal and natural gas wells in the northern Gulf of Mexico Basin. They report Ne, Ar (masses 36 and 38), Kr and Xe having atmospheric-like isotopic compositions and concentrations ranging over two orders of magnitude and, yet, having "simple" abundance patterns varying between those of free air and air-saturated sea water. "Assuming that these gases originated from degassing of brine (connate water) initially equilibrated with air, the authors calculate that a minimum of 1 to 5000 volumes of brine are required to provide the noble gases in one volume of natural gas produced. Comparisons of these volumes with the actual volumes of brines produced are used together with the abundance patterns for noble gases to indicate the presence and the relative size of separate natural gas phases in the reservoir rocks. The ratios of nitrogen to noble gases indicate up to 98% loss of the original atmospheric nitrogen." Radiogenic ^{4}He and ^{40}Ar excesses seem to reflect medium to young ages, in line with the Oligocene to Miocene age of the reservoir rocks (Tables 15 and 16).

Table 15. Noble gases and nitrogen (in mole ratios) from geopressured and gas wells.

Sample #	80-GG-202	79-GG-250	77-GG-54	77-GG-7	77-GG-13	77-GG-17
Well #	Pleasant Bayou #2	Beulah Simon #2	Edna Delcambre #1	E. Dugas #7	Cowell #B-2	S/L 3320 #2
Field Name	T. Martin	Cossiniade	Tigre Lagoon	Tigre Lagoon	Horseshoe	Lake Sand
Producing zone	Frio Sand	Camerina A	Sand #3	Planulina 8	Roblus LSA	Operc-8RA
Temperature, °C	138	131	114	105	120	137
Pressure, psi (atm.)	11,400(776)	13,020(886)	10,990(748)	11,600(789)	9,285(632)	12,070(821)
Depth, meters	4,462	4,486	3,926	4,330	4,251	5,007
TDS, mg/L	132,000	92,000	130,000	122,000	120,000	22,400
Gas, SCF/day	2.1×10^5	2.5×10^5	1.2×10^5	2.3×10^6	6.0×10^6	1.6×10^6
Gas, m^3/day	5.6×10^3	5.7×10^3	1.1×10^4	6.0×10^4	1.6×10^5	4.3×10^4
Brine, barrels/day	1.0×10^4	1.0×10^4	6.0×10^3	1.6×10^3	118	83
Brine, m^3/day	1.6×10^3	1.6×10^3	1.0×10^3	256	19	13
N_2, 10^{-2} of gas	0.57	0.26	0.29	0.16	0.53	0.31
He, 10^{-5} of gas	7.14	8.9	16.7	9.8	9.0	5.9
Ne, 10^{-6} of gas	0.014	8.7	10.4	42.8	39.3	7.4
Ar, 10^{-3} of gas	0.032 total	3.6	4.6	17.6	15.5	3.3
	0.014 atm.			27.9	22.1	3.2
Kr, 10^{-7} of gas	0.044	5.3	5.9	27.4	19.1	6.5
Xe, 10^{-8} of gas	0.21	4.8	8.8			
Brine/gas (cc/cc)	0.27	0.24	0.09	0.004	0.0001	0.0003
Volume brine required to produce one volume argon: a. min.[1]	0.04	10.3	13.1	50.3	44.3	9.4
b. high[2]		1030	1310	5030	4430	940

1 Minimum values obtained by dividing atmospheric Ar by 3.5×10^{-4} cc STP Ar/cc sea water. Assumes complete degassing of brine which started as sea water saturated with noble gases at 10°C.

2 High values obtained by (a) multiplied by 100. Abundance patterns for these samples show about 1% degassing only (see text).

(Mazor and Kharaka, 1981)

Table 16. Noble gas isotopic and elemental ratios.

Sample	80-GG-202	79-GG-250	77-GG-54	77-GG-7	77-GG-13	77-GG-17	air	air-saturated sea water
^{20}Ne/^{22}Ne	-	11.3	10.1	10.1	10.1	10.2	10.3	
^{22}Ne/^{22}Ne	-	34.6	35.3	34.4	34.0	34.4	34.5	
^{40}Ar/^{36}Ar	691	286	277.4	285.7	285.5	297.5	295.5	
^{36}Ar/^{38}Ar	-	5.36	5.39	5.32	5.46	5.21	5.35	
^{32}Kr/^{34}Kr	-	0.19	0.20	0.20	0.20	0.20	0.203	
^{33}Kr/^{34}Kr	-	0.20	0.21	0.20	0.20	0.20	0.203	
^{36}Kr/^{34}Kr	-	0.31	0.31	0.30	0.30	0.30	0.305	
^{233}Xe/^{132}Xe	-	0.09	0.06	0.04	0.08	0.06	0.071	
^{129}Xe/^{132}Xe	-	0.98	0.97	0.98	1.00	0.97	0.974	
^{130}Xe/^{132}Xe	-	0.17	0.15	0.13	0.16	0.15	0.151	
^{131}Xe/^{132}Xe	-	0.80	0.78	0.77	0.78	0.72	0.789	
^{134}Xe/^{132}XE	-	0.39	0.37	0.37	0.35	0.38	0.391	
^{136}Xe/^{232}Xe	-	0.33	0.32	0.31	0.29	0.32	0.332	
Ar/Ne x 10^{3}	2.3	0.41	0.44	0.41	0.39	0.45	0.51	1.9
Kr/Ne x 10^{-1}	3.1	0.31	0.57	0.65	0.56	0.43	0.63	4.5
Xe/Ne x 10^{-1}	1.5	0.55	0.85	0.64	0.49	0.88	0.47	6.4
Kr/Ar x 10^{-4}	1.6	1.47	1.28	1.59	1.43	0.97	1.22	2.4
Xe/Ar x 10^{-5}	6.5	1.33	1.91	1.56	1.23	1.97	0.92	3.4
Xe/Kr x 10^{-1}	4.8	0.91	1.49	0.98	0.86	2.03	0.75	1.4
N_2/Ar atm.	410	0.7	0.6	0.1	0.3	0.9	83	48
He/Ne	5100	10.2	16.1	2.3	2.3	8.0	0.28	0.23

(Mazor and Kharaka, 1981)

Table 17. Decay scheme of ^{232}Th and ^{238}U. α or β symbol indicates mode of decay, half-life of isotope indicate under arrow.

$$^{232}\mathrm{Th} \xrightarrow[1.4\mathrm{x}10^{10}\mathrm{yr}]{\alpha} {}^{228}\mathrm{Ra} \xrightarrow[5.7\mathrm{yr}]{\beta} \cdots \longrightarrow {}^{208}\mathrm{Pb}$$

$$^{238}\mathrm{U} \xrightarrow[4.5\mathrm{x}10^{9}\mathrm{yr}]{\alpha} {}^{234}\mathrm{Th} \xrightarrow[24.1\ \mathrm{day}]{\beta} {}^{234}\mathrm{Pa} \xrightarrow[1.18\mathrm{min}]{\beta} {}^{234}\mathrm{U} \xrightarrow[2.48\mathrm{x}10^{5}\mathrm{yr}]{\alpha} {}^{230}\mathrm{Th} \xrightarrow[7.5\mathrm{x}10^{4}\mathrm{yr}]{\alpha} {}^{226}\mathrm{Ra} \xrightarrow[1601\mathrm{yr}]{\alpha} {}^{222}\mathrm{Rn} \xrightarrow[3.8\mathrm{day}]{\alpha} \cdots \longrightarrow {}^{206}\mathrm{Pb}.$$

(Kraemer, 1981)

Radioelements

Kraemer (1985) reports on natural radioelement behavior in geopressured aquifers, based on rock and fluid produced from United States Department of Energy-sponsored geopressured-geothermal tests wells that have been analyzed for naturally occurring uranium and thorium series radioelements.

Uranium is found in very low concentrations in formation water produced from geopressured aquifers. Concentrations of from 0.003 to 0.054 μg/L have been observed. Chemical modelling indicates that these formation waters are in equilibrium with the uranium minerals uraninite and coffinite.

Radium dissolved in geopressured formation water is observed to vary directly with the salinity of the water. This relationship indicates that the ionic strength of the formation water is important in determining how readily the water can remove radium from the solid matrix grains. Radon was also determined in the geopressured formation waters. In low salinity waters, dissolved radon activity is greatly in excess of the radium activity, indicating radon exhalation from matrix grains is taking place. In high salinity waters (>100 g/L TDS) where dissolved radium activity is higher, the dissolved radon activity is approximately equal to the radium activity, indicating no significant exhalation from the matrix grains. The most likely reason for this is that most of the radium is leached from the outer rims of the matrix grains and is now found in solution, so little radon is formed in the outer part of the grains and is now found in solution where exhalation generally originates (Kraemer, 1985) Tables 17-23.

Keeley (personal communication, 1992) emphasizes the significance of radon decay:

$$\bullet\bullet\bullet\ {}^{226}\mathrm{Ra} \xrightarrow[1602y]{\alpha} {}^{222}\mathrm{Rn} \xrightarrow[3.8d]{\alpha} {}^{218}\mathrm{Po} \xrightarrow[3.05m]{\alpha} {}^{214}\mathrm{Pb} \xrightarrow[26.8m]{\beta^-} {}^{214}\mathrm{Bi} \xrightarrow[19.7m]{\beta^-} {}^{214}\mathrm{Po} \xrightarrow[1.64\mathrm{x}10^{-4}s]{\alpha}$$

$${}^{210}\mathrm{Pb} \xrightarrow[20.4y]{\beta^-} {}^{210}\mathrm{Bi} \xrightarrow[2.6\mathrm{x}10^{6}y]{\beta^-} {}^{210}\mathrm{Po} \xrightarrow[138d]{\alpha} {}^{206}\mathrm{Pb}\ \text{(stable)}$$

Variations in the activity of radium and radon have been observed during a number of aquifer flow tests on geopressured reservoirs (Kraemer, 1981). Possible reasons for these variations include, for radium, differences in uranium and thorium concentration at various locations in the aquifer and shale dewatering, and for radon, the presence of free gas within the aquifer (Table 15). The presence of radium and radon may be useful in evaluating properties and performance of geopressured-geothermal aquifers. The radium behavior reported may be valuable in determining whether shale dewatering is taking place in long-term well production periods. The radon behavior should be useful in detecting the initial presence of a subcritical free gas saturation in an aquifer and the development of a free gas saturation in an aquifer due to pressure reduction by water removal. The only likely explanations for the decreasing radium 226 activity with length of production at Pleasant Bayou are: 1) progressive decreases in uranium content of the aquifer matrix away from the well bore, and 2) water from another source. Since there is no evidence for a decrease in the total dissolved solids content of the produced brine during the period of testing, shale dewatering that would freshen the brine does not appear likely.

The radon activity of the gas equates to the radium activity for the water in the geopressured DOE-sponsored wells tested. "The radon activity of the produced HC gas did not start to decline until gas/water ratios in excess of solution values were produced. This implies that the free gas came to the well bore as a thin layer, migrating down along the roof of the aquifer. As more free HC gas with low radon activity entered the well bore and mixed with the exsolved solution gas the radon activity of the produced HC gas decreased. The radon activity of the HC gas at the end of the test, when the well was producing over 10^6 ft^3/day (2.8 x 10^4 m^3/day) of gas, is probably close to the radon content of the free HC gas phase. This hypothesis is in agreement with the conclusions of Eaton Operating Company's final report (1981) that the oil and gas produced by this well came from the "coning--in" of an up-dip conventional hydrocarbon reservoir" (Kraemer, 1981).

Table 18. Uranium concentration and results of chemical equilibrium modelling of geopressured-geothermal formation waters.

Well	U µg/L	$\Delta G^{diff}_{UO_2(s)}$	$\Delta G^{diff}_{USiO_4(s)}$
#1 F. F. Sutter	0.030	0.86	0.94
#1 Amoco Fee (Zone 5)	0.003	0.77	0.58
#2 Pleasant Bayou	0.003	-0.03	0.18
#1 G. McCall (Zone 9)	0.003	-----	----
#1 L. R. Sweezy	0.003	-0.76	-0.39
#1 Prairie Canal	0.030	-0.19	-0.85
#2 Crown Zellerbach	0.007	-1.44	-1.79
#1 Girouard	0.011	-0.67	-0.75
#1 Koelemay	0.054	1.08	0.64
#2 Saldana	0.044	0.76	0.43
#1 E. Delcambre (Zone 3)	0.010	0.29	0.43
#1 E. Delcambre (Zone 1)	0.005	-0.12	-0.02
Average		0.00	-0.09

(Kraemer, 1985)

Table 19. Comparison of $^{228}Ra/^{226}Ra$ activity ratios of formation water with Th/U activity ratios of the host matrix.

Well	Formation water $^{228}Ra/^{226}Ra$ activity ratio	Matrix Th/U activity ratio
#2 Pleasant Bayou	0.9	1.4
#1 L.R. Sweezy	1.2	1.7
#1 Amoco Fee (Zone 3)	0.8	0.9
#1 Gladys McCall (Zone 8)	0.6	1.3

(Kraemer, 1981)

Table 20. ^{222}Rn activity of solution-gas produced from geopressured-geothermal test wells.

Well	^{222}Rn (dpm/L gas)
#1 F. F. Sutter	517
#1 Amoco Fee	
Zone 5	283
Zone 3	253
#2 Pleasant Bayou	351
#1 G. McCall	
Zone 9	122
Zone 8	91
#1 L. R. Sweezy	211
#1 Prairie Canal	129
#2 Crown Zellerbach	75
#1 Girouard	45
#1 Koelemay	265-68
#2 Saldana	18

(Kraemer, 1985)

Table 21. Radon and radium activity in formation water produced from test wells.

Well	Approx. Salinity (mg/L)	^{226}Ra, diss. (dpm/L of water)	^{222}Rn, diss. (dpm/L of water)	$\frac{^{222}Rn}{^{226}Ra}$ (activity ratio)
#1 F. F. Sutter	190.000	1742	2098	1.20
#1 Amoco Fee				
Zone 5	165,000	1402	1003	0.72
Zone 3	165,000	1130	900	0.80
#2 Pleasant Bayou	132,000	1537	1375	0.89
#1 G. McCall				
Zone 9	95,000	517	521	1.01
Zone 8	95,000	446	463	1.04
#1 L. R. Sweezy	95,000	422	751	1.78
#1 Prairie Canal	42,600	224	1033	4.61
#2 Crown Zellerbach	36,000	124	400	3.23
#1 Girouard	23,750	72	817	11.4
#1 Koelemay	15,300	23	1415	61.5
#2 Saldana	12,800	70	158	2.26

(Kraemer, 1979)

Table 22. Mole percent CO_2 of the total dissolved gas (column 3) and as absolute concentration (column 4) dissolved in brines for various geothermal wells.

Well	Temperature °F	Mole % CO_2	CO_2 SCF/Bbl	Salinity mg/L
Leer	260	18.3	7.0	15,000
Fairfax-Sutter	270	18.4	4.8	190,900
Prairie Canal	294	17.0	7.6	44,000
Riddle	300	28.9	15.4	32,000
Pleasant Bayou	308	22.9	6.8	120,000
Crown Zellerbach	327	38.0	14.8	18,200

(Kraemer, 1985)

Table 23. Solubility of methane in Pleasant Bayou brine at various temperatures and pressures, as well as calculated values for an equivalent NaCl concentration (130,000 mg/l).
(NA, not applicable)

Temperature °F	Pressure psi	Experimental solubility SCF/Bbl	Calculated solubility SCF/Bbl
201.6	12,016	20.4	21.9
196.3	9,126	19.8	18.8
198.2	5,076	13.4	14.0
198.2	2,021	8.3	8.5
198.7	1,059	4.2	NA
248.1	12,024	24.8	25.8
248.0	11,950	24.1	25.7
248.0	11,893	25.2	25.7
249.8	9,083	22.3	22.5
250.3	5,018	17.5	16.2
	2,060	9.9	10.0
250.3	2,002	9.4	9.9
	1,001	5.7	NA
301.1	12,300	29.3	32.6
301.1	12,040	27.2	32.2
302.8	9,040	25.0	28.0
299.5	5,076	19.6	20.1
301.1	2,002	12.2	11.9
299.7	1,004	7.7	NA
301.1	507	3.9	NA
3013	260	3.4	NA
300.2	104	1.3	NA

(Blount et al., 1979)

Hydrodynamic Flow

Neglia (1979) examines the migration of fluids in sedimentary basins. "A possible way of removing oil from a source rock, in addition to the colloidal or true solubilization in water or the flow in a three-dimensional oil-wet kerogen network, is through its solubilization in high-pressure gas generated in the deeper part of the basin and coming up through preferential paths such as faults and fractures." Neglia makes the following conclusions:

1. Compacted shales microfracture and can be faulted easily during tectonic events. Microfractures and faults represent an easy escape for gas generated in the deeper part of the basin. Little-compacted shales are plastic and can hold gas and oil columns provided that displacement pressure threshold is not reached.

2. Salt layers and overpressured shales commonly are not continuous. The thicker part of the section grows at the expense of the thinner. On the flanks of a salt or shale dome or between ridges or walls, a direct communication between the lower and upper layers will be established where the salt is lacking and thin shale layers compact and break.

3. Natural gas is continuously generated in the deep hot part of a sedimentary basin provided that the organic matter still contains hydrogen.

4. A solubilization process of liquid hydrocarbons in highly pressured gas is thought to be the main mechanism for the extraction of oil from a source rock. Gas percolates through source rocks along microfractures.

5. Differences in the displacement pressure of the oil and gas columns will separate the gas that can disperse through the caprock from the oil that will remain below it.

6. Degradation processes generally occurring in hydropressured layers will gradually transform the condensate into heavy oil.

Chemical geothermometers should not be applied to chemical analyses of waters from gas wells as these waters are often diluted by condensed water vapor produced with natural gas. Mazor and Kharaka (1981). Kharaka et al. (1985) show that chemical analyses from many gas wells, especially those from geopressured-geothermal systems, are diluted and do not represent the true chemical composition of formation water from that production zone. The criteria to distinguish such samples are given by these authors, but temperatures calculated from these samples are erratic and generally lower than the measured temperatures (Kharaka and Mariner, 1989).

Powley (1990 b) addresses pressures and hydrogeology in petroleum basins. His work reflects studies of global basins by Amoco since 1980 and recognition that all of the basins studied in the United States showed evidence of overpressure except the Illinois Coal Basin which is underpressured as a result of uplift. Powley concluded that, "in most deep sedimentary basins in the world there is a layered arrangement of at least two superimposed hydrogeological systems. The shallowest hydrogeological system can extend to great depth; however, in many basins it extends from the surface down to only about 10,000 ft greatest historical depth of burial."

Bradley and Powley (1990) make the following observations: "The deeper hydrogeological systems usually are not basin-wide in extent and exhibit abnormal pressures. They generally consist of a layer of individual fluid compartments which are sealed off from each other and from the overlying system. In some basins, mainly in the onshore U.S., there is an even deeper, near normally pressured noncompartmented section. The compartmented layer in those basins generally is in the sequence of rocks which were deposited during the period of most rapid deposition. The underlying noncompartmented layer, where present, usually is in prebasin shelf deposits and basement rock. The uppermost noncompartmented layer usually is in rocks which were deposited during the last 10,000 ft in basin filling."

"Correlations of petroleum in reservoirs with the rocks from which the petroleum was generated has imposed a system of mainly upward paths for the first several thousand feet of migration of petroleum from source rocks largely within the compartmented layer to pools generally in the shallow hydrogeological system. The migration paths of petroleum and water may not be coincident."

"The shallow hydrogeological systems generally are basin-wide in extent and exhibit normal pressures. The pore water apparently is free to migrate approximately in accordance with the theory of fluid migration proposed by Munn (1909) and quantified by Hubbert (1940 and 1953)."

As the basin sediments with kerogen-rich shales are buried more deeply with geologic time, the hydrocarbon source rocks begin to generate oil, condensate, and gas, increasing the pore pressures. The hydrocarbons migrate vertically up fractures and faults in 30% of the world's conventional reserves, but in the overpressured compartments Hunt (1990) postulates that the seal is periodically broken every few thousand years and the hydrocarbons leak into the normally pressured shallower reservoirs. Most commonly, oil is produced from the overpressured compartments in the Vermillion area in the Gulf Coast. Hunt envisions numerous separately sealed overpressured compartments in a given basin. Because external fluids from the surface cannot penetrate the overpressured compartments, the compartmentalized oils cannot be biodegraded. In the geopressured sediments of the Louisiana coastal parish, hydraulic flow directions are nearly vertical, upward (Hunt, 1990). See section on Hydrocarbon Generation.

The DOE Pleasant Bayou Site

The saline fluid flow and hydrocarbon migration and maturation as related to geopressure in the Frio Formation, Brazoria County, Texas, is reported by Tyler et al. (1985). The Department of Energy's Pleasant Bayou geopressured-geothermal test wells in Brazoria County, Texas, display a prominent thermal-maturity anomaly in the Oligocene Anahuac and Frio Formations. "Highly geopressured, more-mature shales are interbedded with hydro-pressured to moderately geopressured sandstones in the upper Frio and Anahuac. In contrast, shales and sandstones in the lower Frio, including the Andrau geopressured-geothermal production zone, are highly geopressured but exhibit lower thermal maturities" (Tyler et al., 1985).

"Vitrinite-reflectance data, supported by hydrocarbon-maturation data and anomalous concentrations of C5 to C7 hydrocarbons at Pleasant Bayou, indicate that the upper Frio was subjected to an extended period of hot, extremely saline, basinal fluid flow which caused the above thermal anomaly. Regional salinity studies suggest that regional growth faults were the conduits for vertical basinal brine movement at depth. At shallower levels the upwelling waters migrated laterally through permeable sandstone-rich sections such as the upper Frio. Anomalously mature gasoline-range (C5-C7) hydrocarbons were introduced into the upper Frio by this process. Fluid influx in the lower Frio was probably limited by high geopressure; consequently maturity in the deep Frio section (greater than 14,000 ft) remained consistent with the regional geothermal gradient" (Tyler et al., 1985). See Figures 34 and 35.

Tyler et al. make the following conclusions: "Thermal-maturity profiles, supported by hydrocarbon maturation data and anomalous concentrations of C5 to C7 hydrocarbons in the T3 to T5 section in the Pleasant Bayou area, strongly suggest that the upper Frio (between present depths of 10,000 and 14,000 ft) was subjected to an extended period of hot basinal fluid flow. Thermal-maturity values in the lower Frio are consistent with the extant geothermal gradient, subsidence history, and maturity values observed elsewhere on the Gulf Coast, indicating that the geopressured lower Frio was insulated, and isolated, from this thermal event."

"Methane and gasoline-range hydrocarbons contained in upper Frio sediments display isotope, relative-age, and thermal-maturity characteristics of a deep source, probably Vicksburg and lower Frio marine slope shales at depths of 20,000 ft and greater. Dewatering of these geopressured shales provided the hot water that transported heat and mature hydrocarbons to shallower levels. As the thermal fluids migrated upward, interaction with salt domes and mounds produced high salinities, elevated chlorine-to-bromine ratios and modified-marine connate water compositions. Evidence of the high salinity of the brines is present in formation waters in the geopressured interval where salinities of 129,000 mg/L have been recorded. At higher levels the brines were diluted during intrusion into sediments containing water produced by clay mineral

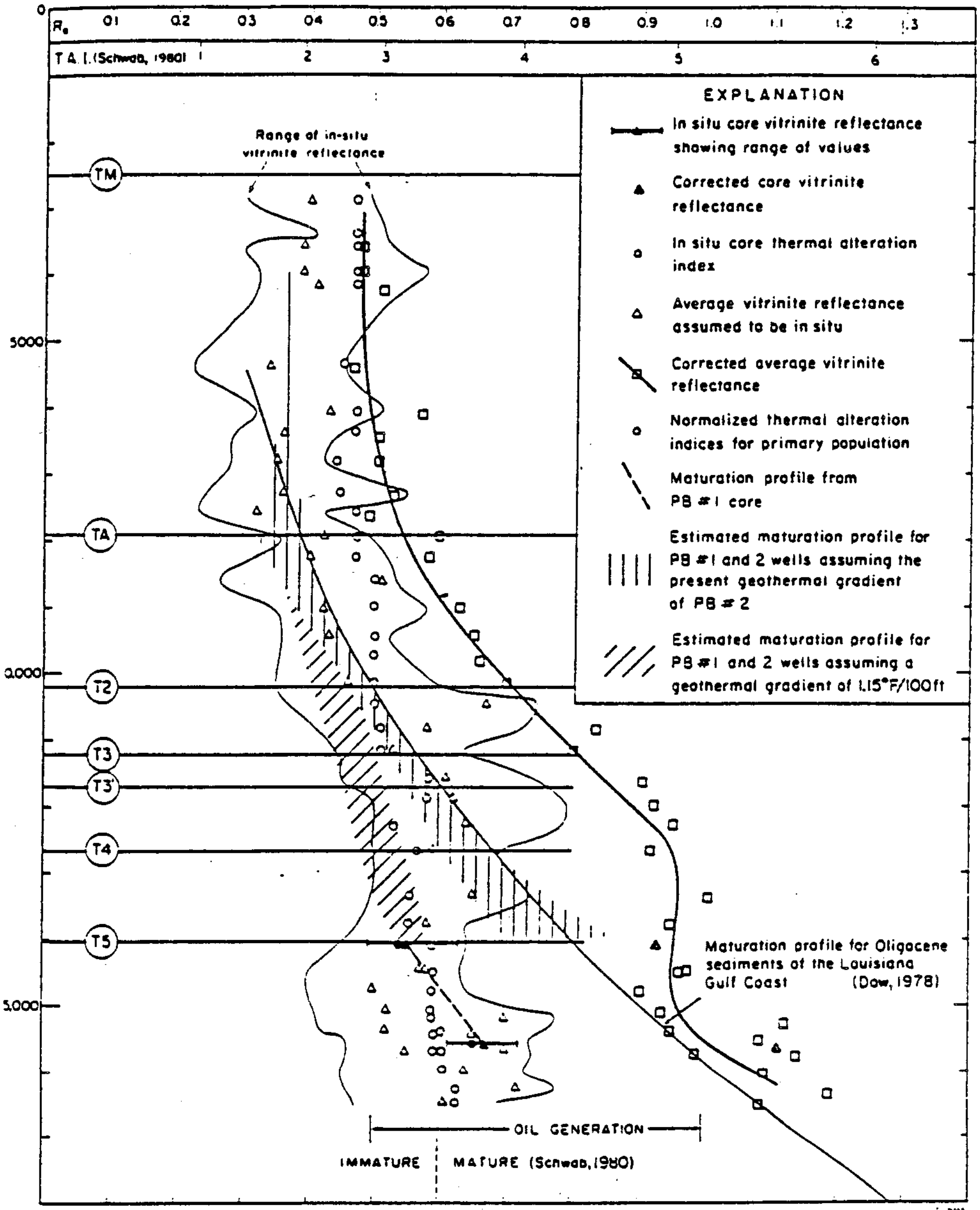


Figure 34 Vitrinite relectance and thermal alteration index profiles for the Pleasant Bayou No. 1 well (Brown, 1980; Schwab, 1980). The reflectance profile is compared to the regional reflectance (Dow, 1977) and to calculated profiles using the present-day geothermal gradient at the test well and low gradient of 1.15°F/100ft. Vitrinite-reflectance data were corrected to be comparable with Dow's and with Robertson Research data. Modified from light and other (in prep.) (Tyler et al., 1985)

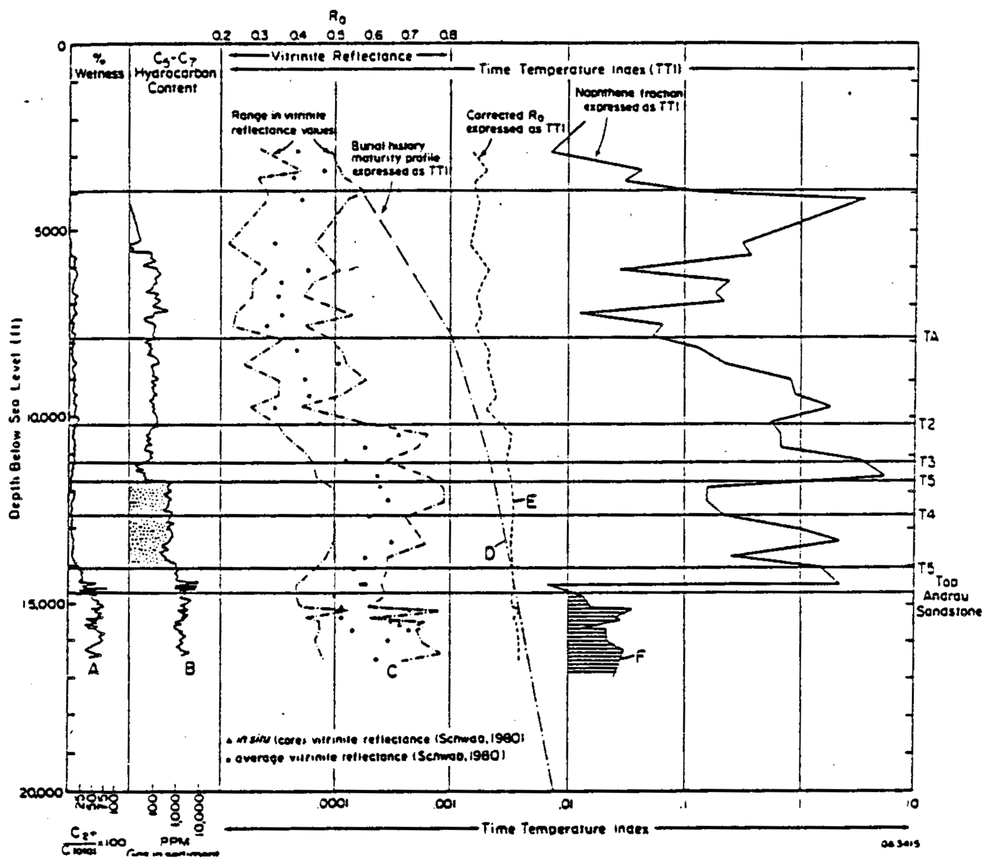


Figure 35 Naphthene fraction expressed as time-temperature integrals (TTI) vs. depth for the Pleasant Bayou No. 1 well compared with the burial history maturity profile and the corrected vitrinite reflectances, both expressed as time-temperature integrals (TTI). The uncorrected vitrinite reflectance, percent wetness, and C_5 to C_7 hydrocarbon content in 1 million volumes of sediment versus depth is shown for comparison. Stipple pattern represents a zone containing anomalous concentrations of C_5 to C_7 hydrocarbons; lines pattern indicates zone containing hydrocarbons consistent with depth and thermal gradient (Tyler et al, 1985).

"Migration pathways of the upwelling fluids are indicated by regional and local salinity studies to be major faults at deeper levels. At shallower levels lateral migration takes place along sandstone-rich intervals; vertical movement continues along faults. Anomalous maturity values and aberrant C5 to C7 contents in the T3 to T5 interval, when compared with the remaining Frio stratigraphic column, suggest that the T3 to T5 sandstones composed a major migration pathway for hot saline brines and the contained hydrocarbons up and out of the basin. The T3 and T4 sandstones are thick and display good lateral continuity throughout the Pleasant Bayou area. The T3 sandstone corresponds approximately to the boundary between normally pressured and geopressured sandstones. Based on a burial history model that incorporated isotopic dating of digenetic minerals, the extensive flushing of the upper Frio sandstones began 14 million years ago. The temperatures recorded in the Pleasant Bayou No. 1 well over this interval are significantly higher than would have been predicted from the geothermal gradient deduced from the second well, suggesting that basinal fluid upwelling and lateral migration is currently active." See Figure 36.

"By contrast, the lower Frio (T5 and deeper) displays no evidence for extensive hot water invasion. The vast bulk of the upwelling geothermal brines clearly bypassed this sandstone-rich geopressured section, migrating vertically along major faults. High salinities indicate that small amounts of brine penetrated the geopressured interval but probably did so at much slower rates. The inferred limited water invasion of lower Frio sediments suggests that they were geopressured as early as 14 million years ago (Tyler et al., 1985; Morton et al., 1981, Kharaka et al., 1980; Ewing et al., 1984; Stahl, 1977).

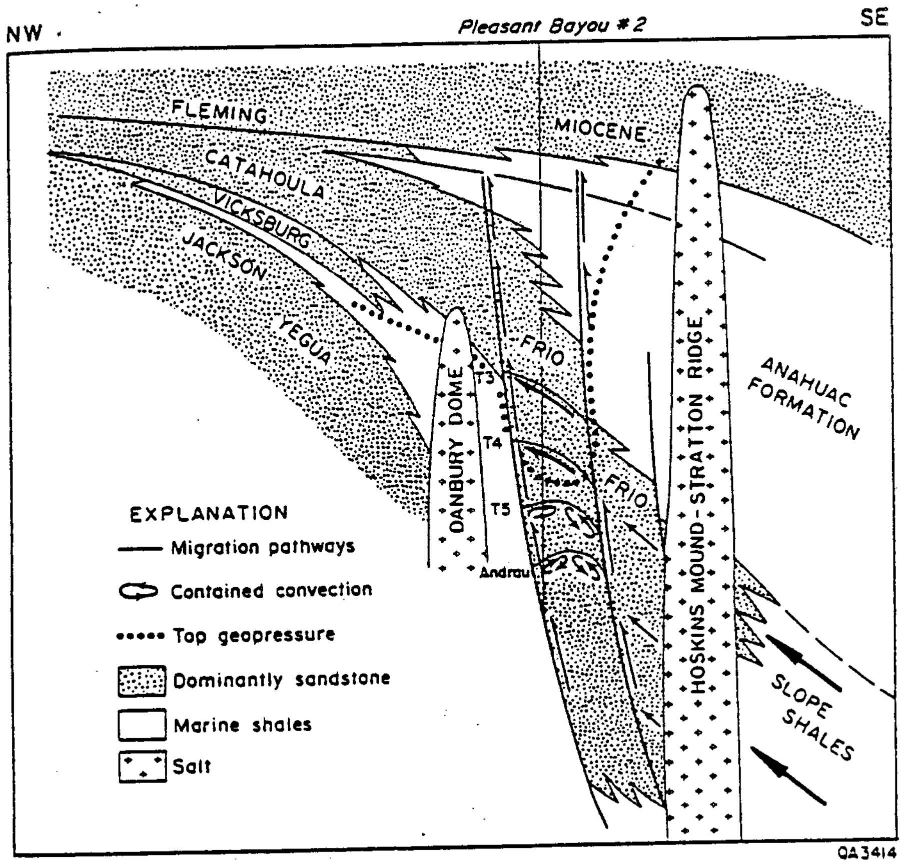


Figure 36. Schematic cross section illustrating fluid migration pathways in the deep Frio Formation (Tyler et al., 1985).

SEALS

Formation Processes, Characteristics, and General Behavior

In order to develop a geopressured compartment, there must be seals and boundaries to prevent the loss of excess pressure as fast as it begins to build up. The pressures can begin to build in sandstone reservoirs simply because the porosity and permeability are usually more attractive to the migrating gases. However, the compartment will soon need additional seal besides such a differential. Jansa and Urrea (1990) suggest that the cause and the development of overpressures, seals, and secondary reservoirs are diagenetically driven. In a study of the "Diagenetic History of Overpressured Sandstone Reservoirs in the Venture Gas Field, Offshore Nova Scotia, Canada," numerous overpressured gas and condensate-bearing sandstone reservoirs are found within normally compacted shales. The volumetric increase achieved by kerogen-to-petroleum-gas conversion and hydrocarbon expulsion are believed to be the main driving forces for Venture overpressures. Formation of dynamic diagenetic barriers within the zone of peak gas generation, Jansa and Urrea believe, helps to retard the diffusive migration of hydrocarbons and other fluids expelled during shale diagenesis, resulting in pressure buildup. These Venture-type diagenetic overpressures are not associated with undercompacted sediment and thus cannot be predicted from compaction trends during drilling

"Seal" has been described by Bradley and Powell (personal communication, 1991) as follows: "A capillary seal, which restricts the flow of hydrocarbons, is formed when the capillary pressure across the pore throats (a function of the surface tension between the wetting fluid and the migrating hydrocarbon) is greater than or equal to the buoyancy pressure of the hydrocarbons (a function of the height of the hydrocarbons and the density difference of the fluids). Pore throat size reduction, which increases the capillary pressure, may be due to deposition, diagenesis, deformation (including faulting) or some combination. Fluid can move through the interconnected pore system of a capillary seal.

"A pressure seal which restricts both hydrocarbon and brine, is formed where the pore throats become effectively closed, i.e., the permeability approaches zero. A leaking pressure seal, called a "rate seal," occurs when the pressure/flow caused by subsidence-sedimentation or uplift-erosion is greater than the seal leakage. When the internal fluid pressure exceeds the fracture pressure (PF = sigma 3 + P + T), the seal will fracture and fluids will escape from the compartment." See Figures 36 and 37.

A pressure compartment is described by Bradley and Powell as follows: "A pressure compartment, which is a closed hydraulic and closed chemical system, is defined only by deviation of pressure, either high or low, as compared to normal hydrostatic pressure. No timing or duration for the compartment is implied. An open hydraulic and chemical system exists within the compartment. The seals of a pressure compartment may act as a trapping mechanism."

Seals do not have consistent lithologic properties other than extremely low across-the-seal permeability. Recognition is from indirect evidence such as well log indicators, measured pressures in local reservoirs encased in seal rock, and from pressure measurements indicating obviously, hydraulically separated reservoirs (Powley, 1990 a and b).

Seal characteristics are described by Powley (1990 a and b): "Seals may have thin internal permeable rock layers which contain water or oil and gas pools. The transition of pressures across the total thickness of top seals in clastic rocks is essentially linear with increasing depth wherever data have been obtained. The rate of pressure change across seals ranges from 15 psi/ft in shale to 25 psi/ft in sandstone.

"Seals may have calcite and/or silica mineralization within the seals or in the lower pressured rocks exterior to the seals, probably precipitated as water seeps through the seals. Such calcite precipitation is very common in southwestern Louisiana. When the infill is silica it is easily recognizable by drastically reduced drilling rates as the seal is penetrated."

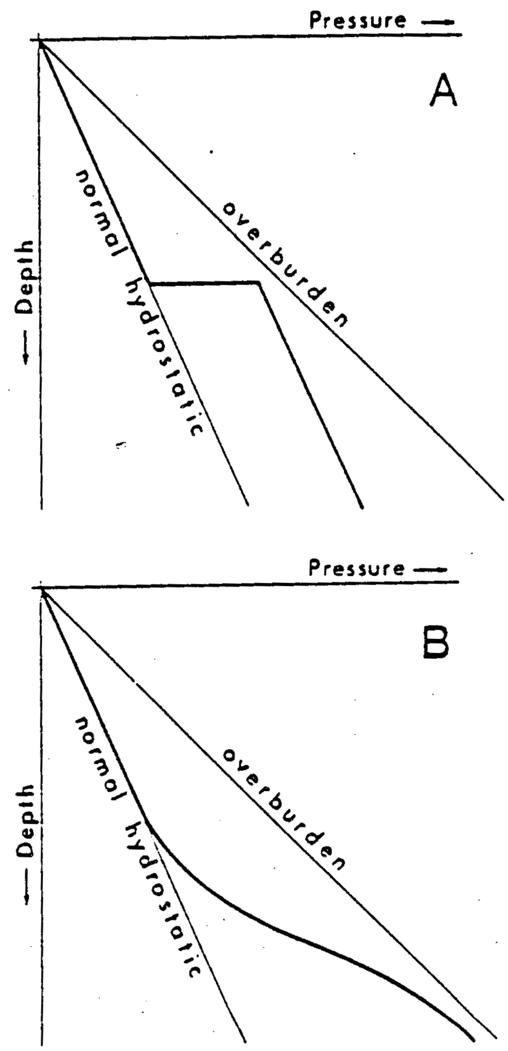
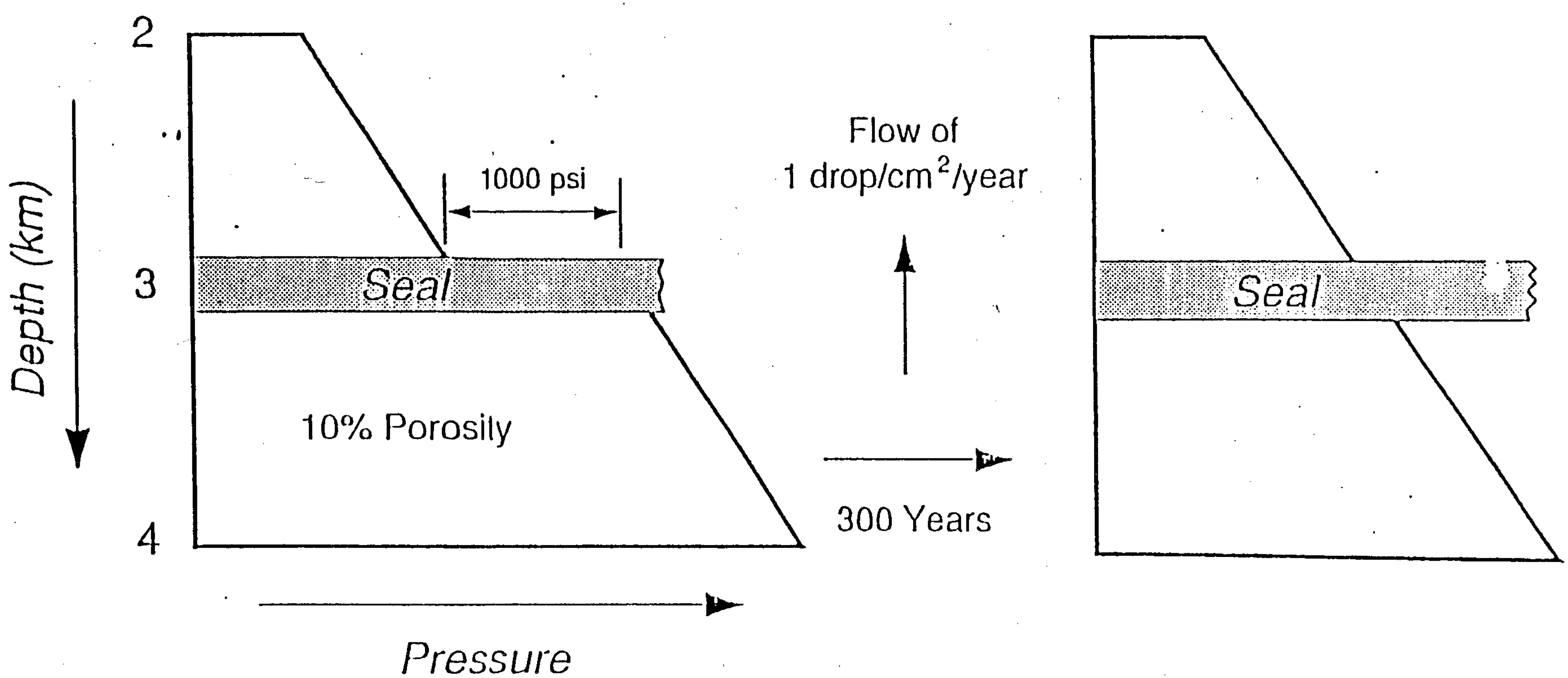


Figure 37. A. Pressure-depth relation in shale below perfect seal. B. Pressure-depth relation implied by drilling and borehole logs in transition zone.



FLOW REQUIRED TO EQUALIZE A 1000 PSI PRESSURE DIFFERENCE

Figure 38. Calculated time required to equalize a 1,000 psi pressure difference across a seal (Bradley and Powley, 1990).

Top seals in clastics-dominated sections range in thickness from 150 ft to over 3000 ft, with the majority about 600 ft. Seals in carbonate-evaporite sections are generally thinner, with salt and anhydrite beds as thin as 10 ft forming effective seals.

When the compartmented layer overlies a noncompartmented layer, the basal seal usually follows a single stratigraphic horizon (Powley, 1990 a & b).

Lateral seals are usually vertical or near vertical and range in thickness from less than 1/8 mile to about 6 miles, with the majority 1/8 mile or less in width. These seals tend to be straight, suggesting that they follow faults. In wells that have penetrated lateral seals, the rocks are found to be slightly fractured and the fractures infilled with calcite and/or silica. When fractures are locally open they can yield limited oil and gas. The fractures in underpressured through slightly overpressured Cretaceous and older rocks are nearly closed in most basins. However, the fractures are open enough to cause prominent reductions in overall interval sonic velocities in overpressured rocks. This can also lead to mud loss which starts at the base of the top seals (examples: Hanna Basin and the deep basin area of the Alberta Basin). The fractures are less than 1 inch long.

Matrix rocks may exhibit remarkably different porosity values. Sandstone porosities are in the 20-35% range in the overpressured Cretaceous Tuscaloosa sandstone reservoir in the False River Field in Louisiana and can be less than 10% in the Paleozoic Goddard sandstone reservoir in the Fletcher Field in Oklahoma at about the same depth and pressure (Powley, 1990 a & b).

Bradley and Powley (1990) suggest that fluid release from compartments may be oscillatory, proceeding via a cycle of seal fracturing and healing. Ghaith et al. (1990) set forth a simple mathematical model of the phenomenon. Hunt (1991) echoes Bradley and Powley in suggesting a possible geological cyclicity to compartment burping. If the generation of hydrocarbons is contributing actively to the overpressuring of a sedimentary basin, it would be reasonable to expect a stress point to be reached where fractures or the bounding seal would be broken to release some pressure. The pressure reduction and continued availability of calcium and silica in brine would then tend to reseal the rupture until the necessary stress was again built up by continued generation of hydrocarbons, and whatever other mechanism is contributing to buildup of the overpressure. See Figure 38.

Waples (1991) suggests that the need for sedimentation rates in excess of 100 m/m.y. for overpressuring may explain why top seals commonly are found at similar depths (about 3000 m or 10,000 ft) in many basins. Rupture of the top seal occurs when the fluid pressure reaches 70-90% of lithostatic pressure. This pressure is reached in the range of about 3500-5000 m (11,000-16,000 ft) in several areas studied by Mann and MacKenzie (Waples, 1991). When rupture of this original seal occurs, the mineral-laden hot fluids from the overpressured zone will move vertically until they encounter a permeable stratum at an acceptably lower pressure. The fluids will then enter the permeable stratum and precipitate carbonates and silicate according to the temperature, pressure and saturation conditions.

The new seal will thus be nearer the surface than the original seal. Seals equal to pressures of 60% of lithostatic pressure may occur at about 3000 m (10,000 ft). As sedimentation continues and these strata are buried more deeply, this rupture-cementation process would be repeated. The net effect would be to keep the top seal at approximately 3000 m (10,000 ft). (Waples, 1991). See Figure 38.

By using biomarkers it can be proved that oil has moved vertically out of the overpressured compartments into the overlying normally pressured rocks. "But we cannot establish the dominant cause of overpressures except in some cases." To fully understand and evaluate the various causes of overpressures in each basin, the cause and timing of seal formation must first be understood. Multiple seals that eliminate essentially all permeability have been observed in well cores by oil company geologists (Hunt, 1991a). See Figure 39.

In 1988, the Gas Research Institute initiated a research program on deep basin compartments and seals, an outgrowth of the Amoco work over more than 20 years (Powley and Bradley, personal communication, 1991).

The program has resulted in conference proceedings covering the studies in at least four basins. Weedman et al. of The Pennsylvania State University reports on studies on analysis of pressure data, and initial investigation of the seismic signature of overpressured rocks and the acoustic and chemical properties of seals. This work utilizes data from the Tuscaloosa trend onshore Louisiana, the Frio trend onshore south Texas, the Devonian of the Appalachian Basin, and the deep basin of Alberta. Laboratory work focuses on kinetics of the smectite-illite transition, kinetics of quartz cementation, and kinetics of calcite dissolution and precipitation (Weedman et al. 1991). See Figure 39.

From an analysis of pressure data in the Powder River basin, Surdam and Heasler at the University of Wyoming conclude that numerous pressure compartments on the scale of oil and gas fields exist in the Minnelusa, Dakota, Muddy, and Frontier formations (Surdam and Heasler, 1991).

A variety of top seals were identified in the Anadarko Basin. One common denominator of all the cored-seal intervals is the characteristic banded structures observed in various lithofacies including sandstones, siltstones, shales, and argillaceous mudstones. Cored intervals of the same stratigraphy and lithology above the top seal zone show no evidence of banding. The banding represents diagenetic events that progress with burial and increased temperature. Following an initial calcite cementation phase the rocks enter the liquid window (thermal maturation of hydrocarbons) and the seal is essentially completed (Al-Shaieb et al., 1991).

Vandrey et al. (1991) at the University of Wisconsin-Madison, characterize the diagenetic seals in the St. Peter Sandstone of the Michigan Basin. They find that the diagenetic seals closely correlate with packages containing intense stylolitization as well as intergranular pressure-

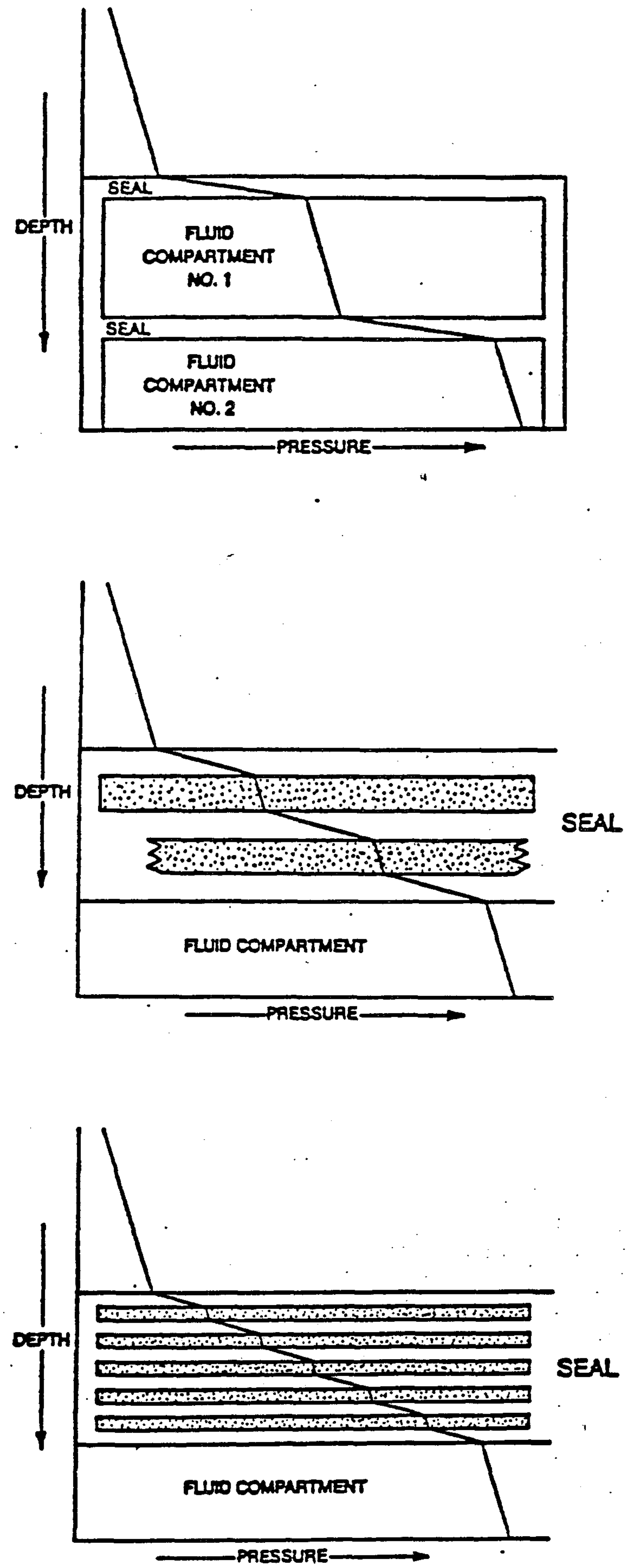


Figure 39. Multiple seals have been observed in well cores.

solution, and packages with recurring well- and poorly-cemented bands or alternating bands with different cement types. Each band is up to 2 cm thick. Packages of pressure-solution and diagenetic banding form tight horizons with porosity = 0 to 3% and K = 50 μd. Thickness ranges from one to several meters and both types may be present within the same core-interval. Stylolites post-date all previous diagenetic phases. The bulk of cementation occurred at temperatures of 194 to 329°F (90 to 165°C).

Weedman et al. (1991) at The Pennsylvania State University examine the transition zone from hydrostatic pressure to overpressure at about 5.5 km depth in the Lower Tuscaloosa Formation, Louisiana. They find local high secondary porosity zones and late chlorite cement. The researchers propose that the tight highly compacted rocks, resulting from compaction after secondary porosity formation, may act as pressure seals within deep shale-poor reservoirs.

Lin and Logan (1991) at Texas A&M University report on fault zones as seals and conduits to fluid flow. Grain communication produced by mechanical shearing in fault zones increases the path for fluid migration.

Ortoleva and Al-Shaieb (1992) and Sonnenthal and Ortoleva (1992) at Indiana University examine the theory of banded seals. The authors explain the internal layered structure of seals by a quantitative model accounting for mechanical, chemical and transport processes. Banding types described include stylolite arrays, differentiated compaction/cementation alternations, carbonate cementation bands in sandstones, and matrix- collapse comminution bands. Some of the conclusions reached are as follows:

1. The coupled mechano-chemical dynamics allow for the destabilization of the uniform state of compaction and the genesis of well-localized layers of compaction or cementation;

2. Due to intense overgrowth or other precipitation, some layers may develop such low permeability that they collectively form a very efficient barrier to flow normal to their plane;

3. Grain size, mineralogy, clay or other coatings, the state of grain-grain contacts (clean or dirty, smooth or corrugated), rate and depth of burial, thermal history and fluid composition all are influential factors; and

4. Quantitative mechano-chemical models of layered seal genesis can predict conditions favorable for the genesis of diagenetically layered seals.

Wheland et al. (1991) at Woods Hole Oceanographic Institution examine sediments from zones going through normally to overpressured zones in two wells from the Louisiana Gulf Coast, using pyrolysis, pyrolysis-gas chromatography mass spectrometry (Py-GCMS), organic petrographic techniques, and by latroscan (a technique for quantifying amounts of asphaltenes). A gradient of C7 to C14 hydrocarbons through the overpressure ("seal") zones of both wells was shown by Py-GCMS, with the lightest and most mobile hydrocarbons concentrating near the top of the zone and the heavier near the bottom. Higher concentrations of all components are detected below the seal zones of both wells. In one well the vitrinite reflectance profile through the seal shows a smooth peak in maturation within the seal.

Martinsen and Jaio (1991) at the University of Wyoming address characteristics of unconformities and their possible role in the development of pressure compartments in clastic reservoir/source rock systems. The researchers find that a soil zone in the Lower Cretaceous rocks in the Rocky Mountain region (one of many) provides top and lateral seals to overpressured zones in marine sandstones beneath the unconformity and bottom and lateral seals to anomalously pressured compartments within the valley fill deposits overlying the unconformity. Abundant evidence suggests reservoir quality of sandstones both above and beneath the soil zone is diagenetically improved by porosity-enhancing fluids. However, these fluids are unable to penetrate into the soil zone and reduce its sealing effectiveness. The soil zone develops as a result of regional sub-areal exposure and erosion and thus can be at the top, within, or at the base of the Muddy Sandstone, making it appear that seals separating pressure anomalies "cross stratigraphy." The zone is 3 to 20 ft thick, regionally extensive, with evidence of roots 8-10 ft down from the unconformity. It contains numerous small siderite concretions, and a relatively high percentage of clay matrix, up to 50% by volume. The clays consist of kaolinite, smectite-illite and chlorite. From core analyses the porosities in the soil zone range from 5 - 15%, and permeabilities are less than 0.1 millidarcies.

Al-Shaieb et al. (1991) examine completely sealed gas-bearing pressure compartments in the Upper Morrow Fan-Delta chert conglomerate in the Cheyenne and Reydon Fields. These Upper Morrowan Chert Conglomerate reservoirs in Roger Mills County, Oklahoma, and Wheeler county, Texas, have produced gas volumes exceeding 1.0 Tcf.

The reservoirs are overpressured, with pressure gradients of about 0.98 psi/ft and potentiometric heads in excess of 20,000 ft. Thick shales in the Upper Morrowan interval seal and isolate the individual productive chert members. The southern lateral seal for the chert wedge is formed by extensive cementation which has completely occluded porosity.

Sonnenthal and Ortoleva at Indiana University (1992) model the development of pressure compartments. Modeling results demonstrate that a basin naturally is separated into the classical, hydraulically connected upper region and the compartmented lower region proposed by Powley and Bradley. The following categorization of compartments emerges from the researchers' modeling work:

1. Megacompartments and their nested (internal) and satellite (neighboring) smaller scale compartments;
2. Columnar or other bottomless compartments; intra-stratum compartments; and
3. Small-(cm to m) scale compartmentation.

Modeling accounted for coupled reaction, transport, and mechanical processes, and could predict the following:

1. The types of compartments that may form;
2. The dynamics of abnormal pressuring within compartments;
3. The nature and dynamics of the transbasinal, migrating top seal;
4. Episodic fluid release from compartments via a fracture/healing cycle; and,
5. The factors of basin history and stratigraphy that promote the formation of compartments and their likelihood for containing petroleum.

The authors conclude that the basin at depth is divided into hydrologically isolated domains on a wide range of scales from basin to cm.

Anderson et al. (1991) include studies on the topography on the top of geopressure offshore Louisiana. In most basins the top of geopressure is encountered at about 3 km depth and temperatures of 194°F (90°C). "This relatively constant elevation in basins such as the Gulf of Mexico Basin where up to 2 km of sediments have been deposited in the last million years suggests that the top of geopressure moves upward with time." The top of geopressure in the Gulf has substantial topographic relief, suggesting that the movement is irregular. Changes in elevation of over 6000 ft in a few miles are common." Modeling shows that seals must have permeabilities less than about 100 nanodarcies in the areas investigated in the Gulf for overpressures to be retained. The development of overpressure arrests compaction. The authors conclude that the abnormally high porosities observed at and below the top of the geopressure surface in the Gulf constrain both the permeability of the seal and the depth at which it initially formed.

MacGowan and Surdam (1991) at the University of Wyoming study implications of variations in formation water chemistries to pressure compartmentalization in the Powder River Basin.

Formation of some pressure compartment seals relies on precipitation of diagenetic cements. Diagenetic pathways are critically controlled by formation water chemistry. Reactions occur at the interface between waters of differing chemical compositions. Thus, knowledge of variations in formation water chemistries within a stratigraphic interval can contribute to the understanding and identification of pressure compartmentalization.

Using the Amoco Powder River Basin formation water database consisting of 10,000 analyses (donated to the University of Wyoming), the researchers were able to identify trends in formation water chemistry that are regular and mappable (at least in the Muddy Sandstone) and that coincide with pressure compartments and seals. For the Muddy Sandstone the Total Dissolved Solids (TDS) varies from 3,000 ppm to greater than 30,000 ppm. The alkalinity (bicarbonate) varies from 300 ppm to greater than 2,500 ppm. The pH varies from 6.2 to 8.5.

Drzewiecki et al. (1991) compare hydrodynamic versus static models for Michigan Basin Pressure Anomalies. Evidence from high fluid potentials and repeat formation test data suggests a transient hydrodynamic system in which pressures are responding to recent or past changes in the boundary conditions or sources.

Maucione et al. (1991) at the University of Wyoming evaluate the seismic response of abnormally pressured zones in the Powder River Basin. Numerous zones of abnormal pressure have been documented from an extensive and ongoing analysis of drill stem tests (DSTs) throughout the Powder River Basin. In ongoing work, the authors set out to characterize the geophysical signature of abnormal pressure and evaluate exploration strategies and techniques.

Well logs are used in the first phase to indirectly estimate subsurface pressure variations. The study focuses on the Amos Draw and Kitty fields in the northern part of the basin and the Powell Field in the south. Both areas produce hydrocarbons from overpressured Cretaceous formations. The results from well log interpretation correlate well with DSTs. The variations in P-wave velocity and density across the Amos Draw and Kitty pressure compartments were mapped from well log data. The P-wave velocity is dependent on changes in subsurface pressure and is quantified by the study reported. The seismic response across the model is simulated by finite difference and ray tracing methods. The results will be used to test the utility of various techniques such as pattern recognition and AVO (amplitude versus offset) in identifying anomalies associated with abnormal pressure. Actual field data will be compared to the synthetic seismic data.

Moline et al. (1991) at the University of Wisconsin-Madison characterize pressure seals through the use of wireline logs, using a multivariate statistical approach. The study addresses the compartmentation in the St. Peter Sandstone of the Michigan Basin. Discontinuities in the pressure gradient are commonly used to identify the existence of pressure compartments. Direct measurements of permeability from in-situ well tests and core plug evaluations are not readily available for the St. Peter. Wireline logs provide an alternative means for estimating permeability. Over 500 wells with wireline logs are used to correlate electrofacies with lithofacies descriptions and hydraulic parameters from core analyses. The electrofacies associated with very low permeabilities are then used to identify "tight" zones in individual wells and to develop the vertical and lateral distribution of potential seal zones throughout the basin.

D'Onfro et al. (1991) at Conoco report on fault sealing in sandstone. Faults in sandstone can act as permeability conduits or seals, or any position in between. The work is based on laboratory experiments, field observations of natural faults, and critical state concepts as adapted from soil mechanics. The researchers use stress path and critical state concepts to suggest how burial and tectonic histories may play a key role in the formation of sealing faults in sandstones.

Serebryakov (1991) at the University of Wyoming describes abnormal pressure regimes in the USSR Basins. The areas where oil and gas fields show abnormal pressures are western, eastern, and northern Siberia; the Crimea; the Caucasus; the Caspian Basin; in regions of the Middle Asian Republics; Ukraine; and the Island of Sakhalin, to name a few.

Meshri (1991) at Amoco addresses the evolution of porosity in the context of thermal and paleohydrologic evolution. Computer codes that could be added to basin modeling are the focus of this report.

Iverson and Evers (1991) at the University of Wyoming discuss drill stem test identification of pressure compartments. "Drill stem tests (DST) are used to measure formation pore pressure in the Powder River Basin in northeast Wyoming. Horner analyses are used commonly to extrapolate recorded pressure to an estimated reservoir pore pressure. Formation permeability is also estimated by the slope of the extrapolation. Alternatives to Horner analysis, such as multirate, pressure derivative, and gas pseudo-pressures are applied to various DSTs. The high kh (permeability x thickness) yields large quantities of recovered fluid. Pressure seals support extremely large pressure gradients, irrespective of the actual pressure magnitude within the seal. Permeability appears extremely low (<0.01 μd) yet a finite quantity, indicating that leakage through the seal is possible when only a single fluid phase is present in the seal."

Weedman et al. (1991) at The Pennsylvania State University examine chemical and stable isotope analyses of a sedimentary section through a pressure seal in the deep Tuscaloosa Trend in the Gulf Coast. Rocks in and below the pressure seal tend to be depleted in carbonate carbon and sulfur; the seal appears to have lost up to 80% of its original sulfur content. Similar sulfur depletion was previously observed in an ancient seal zone in the Appalachian Basin and might be characteristic for seal-forming diagenetic processes. Weedman et al. make the following conclusions:

1. Hydrocarbons are the fluid-pressuring phase, although water may be locally produced with the oil or gas. Temperature-caused hydrocarbon generation is the origin of the overpressuring. When water is produced, it comes from a few high-water-saturation reservoirs interbedded with the primary hydrocarbon-producing rocks. Initial gas-well or oil-well completions may be water-free but, following pressure drawdown, water may be

produced. Rarely do overpressured reservoirs have discrete gas-water or oil-water contacts.

2. Present temperatures of most rocks are at least 200°F (93°C) ± 10°F (23°C), suggesting that present or near-present temperature is a factor in pressure maintenance caused by active hydrocarbon generation;

3. For a few wells, available data suggest a pressure leakoff rate;

4. Organic-rich source beds still capable of hydrocarbon generation must be present. The richer the source beds, the more easily the pressure can be maintained even if the reservoir temperature has significantly decreased from its maximum;

5. Regionally overpressured rocks generally have minimum vitrinite reflectance values of approximately 0.6% in oil-prone source beds and 0.7% in gas-prone source beds. High pressure is generally not present if the rocks contain little or no organic matter;

6. The maximum pressures encountered are about equal to the lowest fracture gradient of the rocks in a particular succession. However, the maximum pressures can be influenced by rock and fracture permeability, and therefore may be much lower than the expected fracture gradient. Limited data suggest that high pore pressure can cause natural vertical fractures and may be a major mechanism to move hydrocarbons and water through the reservoirs. Fracture gradients seem to be generally higher in mudstones and shales, and lowest in sandstones. If correct, this relationship implies that organic-rich clay rocks can have a pore pressure considerably above that in adjacent sandstone. When failure occurs in the clay rock, the gas or oil can rapidly enter the adjacent sandstone at pressures well above the sandstone fracture gradient, initiating or enlarging vertical fractures; and

7. Classical hydrodynamic concepts involving groundwater movement are not very applicable in the analysis of pressure variations in deep Rocky Mountain basins because the pressuring phase is not water and the hydrocarbon generation is a very dynamic condition. Pressure differentials caused by variable rates of hydrocarbon generation and leak-off can cause rapid changes in pressure.

Gulf Coast Seals

Faulting in conjunction with structural closure provides the trapping mechanism for large volumes of hydrocarbons in the Louisiana Gulf Coast salt basin. A close interrelation exists between faulting and hydrocarbon distribution in many of the oil and gas fields in the basin. A study by Smith (1980) was undertaken: 1) to determine the different situations of fault entrapment of hydrocarbons in Tertiary sediments of the Gulf Coast salt basin, and 2) to investigate the role of juxtaposed sediments in a sandstone-shale sequence in creating sealing and nonsealing faults. Smith makes the following conclusions:

1. Many fault traps exist in which hydrocarbon-bearing sandstone is in lateral juxtaposition with a shale formation. Proof is not available that the reservoir rock is actually in contact with the juxtaposed shale formation. The reservoir boundary may be the juxtaposed shale formation or fault-zone material;

2. The faults are nonsealing to lateral migration where parts of the same sandstone are juxtaposed across the faults. The two fault segments have a common accumulation if the hydrocarbon column extends below the spillpoint of juxtaposed sandstone. Nonsealing faults indicated from the distribution of hydrocarbons are substantiated by reservoir performance in a limited number of cases analyzed. Sealing faults with parts of the same sandstone juxtaposed may be present in the Gulf Coast, but none were found in the field examples studied;

3. Some faults are sealing and others are non-sealing to lateral migration where sandstone bodies of different ages are juxtaposed. Some faults are sealing to lateral migration at one level and nonsealing at another. In the fields studied, faults sealing to lateral migration are much more common than nonsealing faults where sandstones of different ages are juxtaposed;

4. Juxtaposition of reservoir rock with shale across a fault is not necessary to form a fault trap. Boundary fault-zone material is indicated along some faults, trapping hydrocarbon accumulations in upthrown sandstones that are juxtaposed with younger water-bearing sandstones; and

5. The boundary fault-zone materials creating the sealing faults have not been identified, but the possibilities include materials resulting from both mechanical and chemical processes related directly or indirectly to faulting. This distribution as well as the displacement pressure of the boundary material will govern the maximum thickness of hydrocarbon column that can be trapped at a fault.

The importance of the smectite-to-illite transition has long been recognized by the petroleum industry because the transition provides a large volume of water during diagenesis. This water may be available for the potential transport of hydrocarbons within the rock. Also recognized early by researchers in petroleum migration was the coincidence of the top of the geopressured zone with the main migration zone of hydrocarbons. Powers (1967) notes that this transition of smectite to illite may be related to abnormal fluid pressures at depth, which in turn could be important for the generation of geopressured-geothermal energy (Bebout et al., 1978).

Freed and Peacor (1989) address the sealing effect of the smectite-to-illite transition in geopressured shale. The major objective of this paper is to describe an observed transition model and to suggest a relationship between clay transformation and abnormal fluid pressure in two Gulf Coast regions, Brazoria and Hidalgo Counties, Texas, and further, to show how this transformation leads to textural relationships that may provide a geopressure seal in clay-rich sediments. It is generally agreed among clay researchers that smectite and illite coexist within Tertiary Gulf Coast sediments, and that illite represents about 20% of the illite/smectite composition prior to transition to smectite. Transition results in about 80% illite composition. The transition is documented by x-ray diffraction techniques and occurs over a range of temperatures. The change is independent of sediment age and burial depth, and only proceeds from smectite to illite.

The reported research involves examination, by transmission electron microscopy (TEM) techniques, of Frio and Vicksburg (Tertiary) overpressured shales from Brazoria and Hidalgo Counties, Texas. The initial domination by smectite in subparallel packets contributes to permeability. As transition proceeds to illite packets, pathways are restricted, and a loss in local permeability results in a rise in the fluid pressure gradient. Illite packets coalesce with increasing transition, causing further restriction in hydraulic continuity with the surface and resulting in a more efficient geopressure seal.

The Brazoria County samples are from Pleasant Bayou Well #1. Those samples show about 50% illite composition at the top of the geopressured zone at about 11,000 ft, 241°F (116°C). The fluid pressure gradient at this depth increases to 0.7 psi/ft from the normal 0.45 psi/ft. The 0.7 psi/ft gradient is commonly used as a marker because resistivities change dramatically and electric logs can be used to identify this depth.

The conclusion reached by Freed and Peacor is that the geopressure seal is a result of clay mineral textures developed by the smectite-to-illite transformation.

Pressure Release

If pressure seals are broken or trap boundaries are exceeded, the pressure compartment will burst forth into the next available compartment, path, or reservoir. The hydrocarbons may spill out of an oversupplied trap or burp out of an overpressured compartment filled beyond the sealing capacity of its boundaries. Hunt (1991 a and b) suggests that the pressured compartments periodically burp as the pressure continues to build up, and that a geologic cyclicity could be anticipated throughout the life of hydrocarbon generation that may be supplying the pressure source. Once the source of the added pressure buildup is depleted the compartment or basin could become normal or even underpressured through subsequent leakage or uplift and erosion. However, in the Gulf Coast area with an extensive deep hydrocarbon-generating basin, much of which is still in early thermal maturity with extensive hydrocarbon-generating potential remaining, a geopressure driving mechanism could be anticipated to continue for many years, in a geological time frame.

Recharge

Hunt (1990) discusses Bradley's 1975 calculation that the flow required to equalize a 1,000 psi pressure difference across a seal separating two 1-km-thick rocks with 10% porosity is equivalent to one drop of water per square centimeter per year for only 300 years. Based on length of bounding faults, the thickness of the perforated reservoir, the estimated reservoir volume, the volume of brine produced, and the pressure buildup on the DOE Gladys McCall and Pleasant Bayou Wells, less than one-half to one drop per square inch per 24 hours could recharge both the reservoirs in question by brine leaking up dip and across the downdip faults.

Anderson et al. (1991) find thermal buildup and restricted fluid flow are associated with the top of the geopressured zone, which hydraulically isolates the deeper compactional system within the basin. They assume that hydrothermal fluids are periodically expelled from the geopressured "chambers" and are documented to migrate both laterally and vertically for considerable distances. In modelling the fluid flow history in the Gulf Coast sediments using a data cube, the authors find the most important dynamic boundary in the Gulf of Mexico is the top-of-geopressure surface. The transition zone from hydrostatic pressures above to those approaching lithostatic contains most of the hydrocarbon accumulations in the Gulf. This transition zone varies in thickness from a few hundred feet to several thousand feet and is not a flat surface. It may have several thousand feet of relief in the data cube area. The movement of hot fluids from the geopressured chambers upward along the faults is likely to be a significant distributor of heat and hydrocarbons in the area, according to Anderson et al. (1991). The convective heat flow anomalies from the completely independent geothermal data set correlate strongly with both the locations of major offsets in the top-of-geopressure surface and the major locations of oil and gas accumulation in the data cube area.

From the data and model the authors conclude that the volumes of fluid transport required to sustain the thermal anomalies are too great for steady-state dewatering. Thus, they infer the fluid flow must have occurred episodically, as "bursts" from the geopressured shales deep within the data cube area. That is, these very high fluid flow velocities can be maintained only with episodic opening of very high permeability pathways along the growth faults as a result of hydraulic fracturing.

Preexisting fault zones can be hydraulically opened only when geopressures build to values that exceed the fracture reopening pressure in the data cube (the minimum compressive stress magnitude). Rapid bleeding off of the geopressure quickly closes the faults again, but large volumes of hot fluid will have been released into the sand-shale sequence above, thus the correspondence between hot spots and faults.

Bernard (1987) studies pressure and production data on about 100 abnormally pressured reservoirs. Most were experiencing water-drive, as evidenced by water production and/or a maintenance of reservoir pressure. He eliminates obvious water-drive reservoirs from the study to avoid complications of active water influx. Bernard begins with the classic method of analyzing depletion-drive gas reservoirs, plotting the average reservoir pressure divided by the gas deviation factor, p mean sub cap R/Z, versus the cumulative gas production, G sub p. This is commonly referred to as a "P/Z plot". The plot is a straight line if there is no appreciable influence from water and rock compressibility. With the influence of a fairly strong water drive, the P/Z plot may be straight during the early life, but a non-linear flattening of the plot may ultimately develop. Bernard found that if an abnormally pressured reservoir is undergoing depletion drive, the P/Z plot will be straight during the early life, but will usually curve downward during the later stages of depletion. Several investigators have suggested reasons for the non-linear behavior of the P/Z plot for abnormally pressured reservoirs. These include a rock collapse theory and shales supplying water (dewatering). Water influx can explain most cases. Bernard concludes that a combination of water influx from small steady-state aquifers, water influx from surrounding shales, and the effects of normal rock and water compressibilities explain the observed phenomena. Water influx could, of course, include fault leakage.

OCCURRENCE AND EXAMPLES

United States

Texas and Louisiana

Bebout et al. (1978) publish in-depth descriptions of the Gulf Coast Geologic Framework. "The Tertiary section along the Texas Gulf Coast comprises a number of off-lapping and basinward-thickening wedges of sand and shale. The thin, updip part of each wedge consists dominantly of shale with thin, discontinuous sand bodies deposited in a fluvial system. Gulfward of the fluvial system is the main sand depocenter characterized by thick sands separated by thick shale sections and deposited in a deltaic system or by thin sands separated by thin shales and deposited in a strandplain or barrier-bar system. Finally, the downdip part of the wedge is characterized by a thick shale section containing thin, laterally restricted sand bodies deposited in a prodelta or shelf system. An understanding of the general processes which controlled the deposition of these wedges along the Gulf Coast was developed more than 20 years ago by petroleum geologists from outcrop data. See Figures 40-43.

"Growth faults, which develop from loading along the main sand depocenter, allow abnormally thick sections of sediment to accumulate. The displacement of sand bodies against shales along growth faults contributes to the trapping of fluids within the sediments." See Figure 44.

"At least eight sand/shale wedges are easily recognized on regional electrical-log cross sections. These cycles reflect changes in the ancient shoreline resulting from variations in sediment supply, rate of subsidence, and position of sea level. In general, in the updip end of the wedge the main sand depocenter is in the lower part of the section and downdip it is progressively higher in the section, thus describing a progradational cycle.

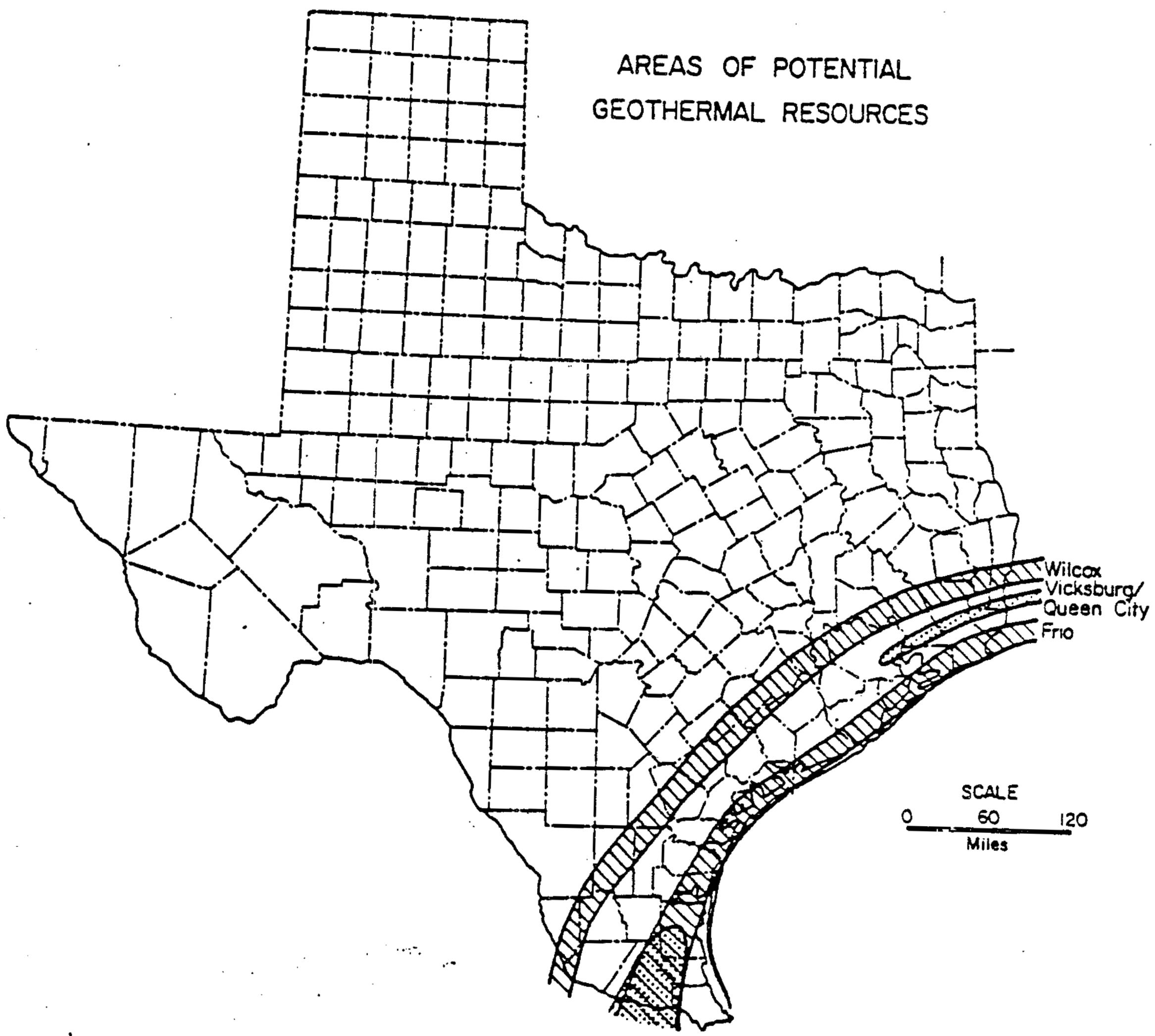


Figure 40. Geothermal corridors of potential fairways (Bebout 1976).

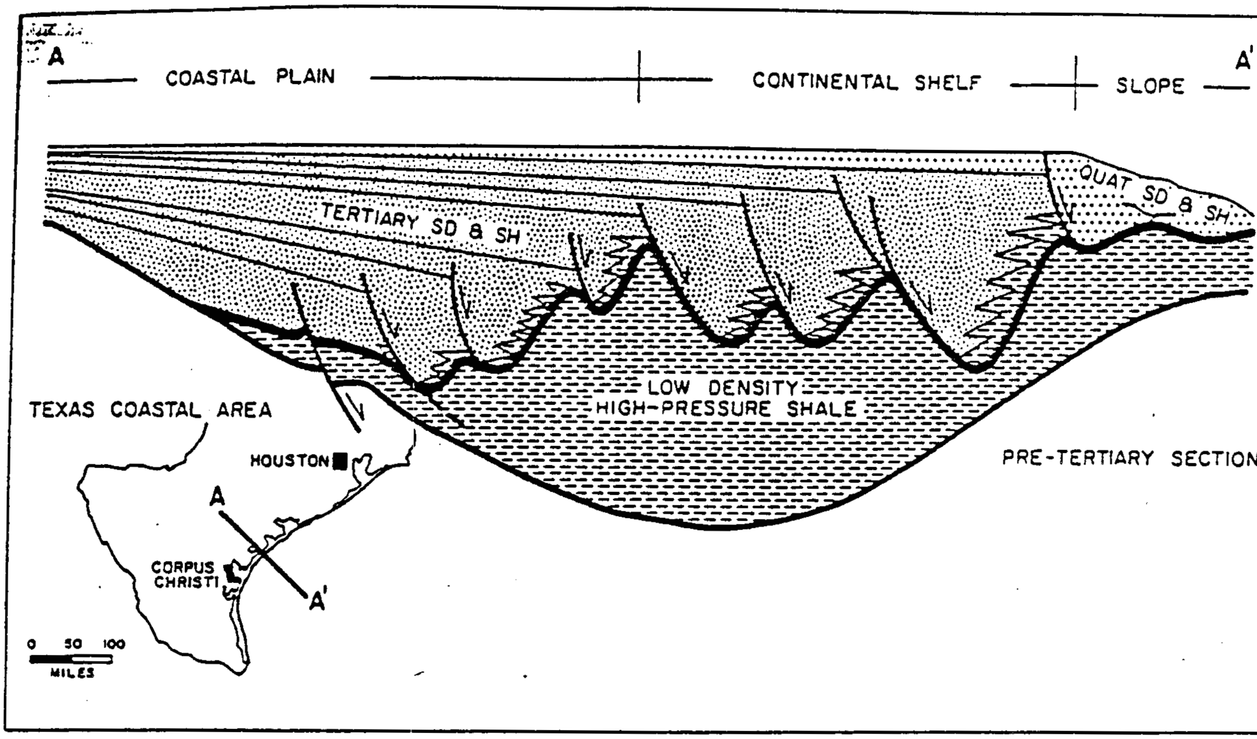


Figure 41. Depositional style of the Tertiary along the Texas Gulf Coast (Bruce, 1984) (Bebout 1976)

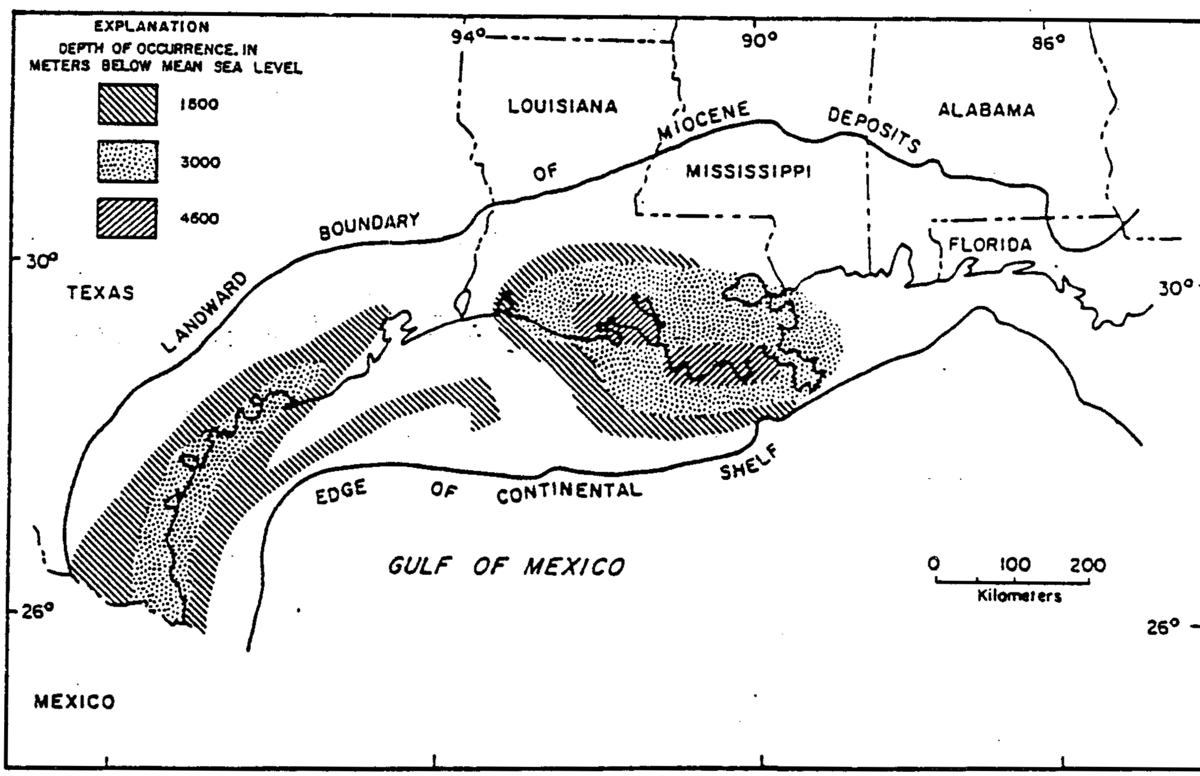


Figure 42. Location and depth of occurrence of the geopressured zone in the northern gulf of Mexico basin (Jones, 1969) (Knapp and Isokrari, 1976).

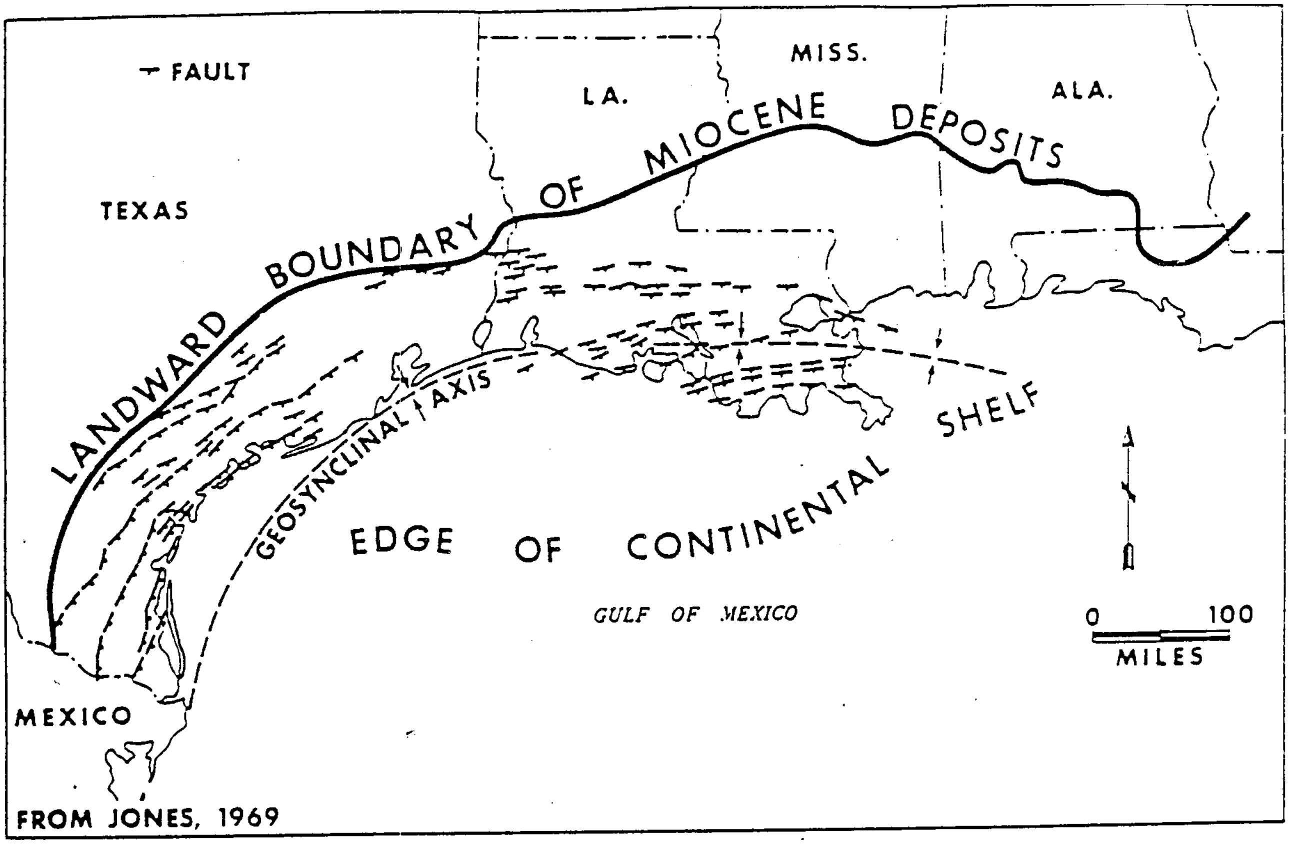


Figure 43. Principal regional normal faults in Neogene deposits of the Gulf Coast geosyncline.

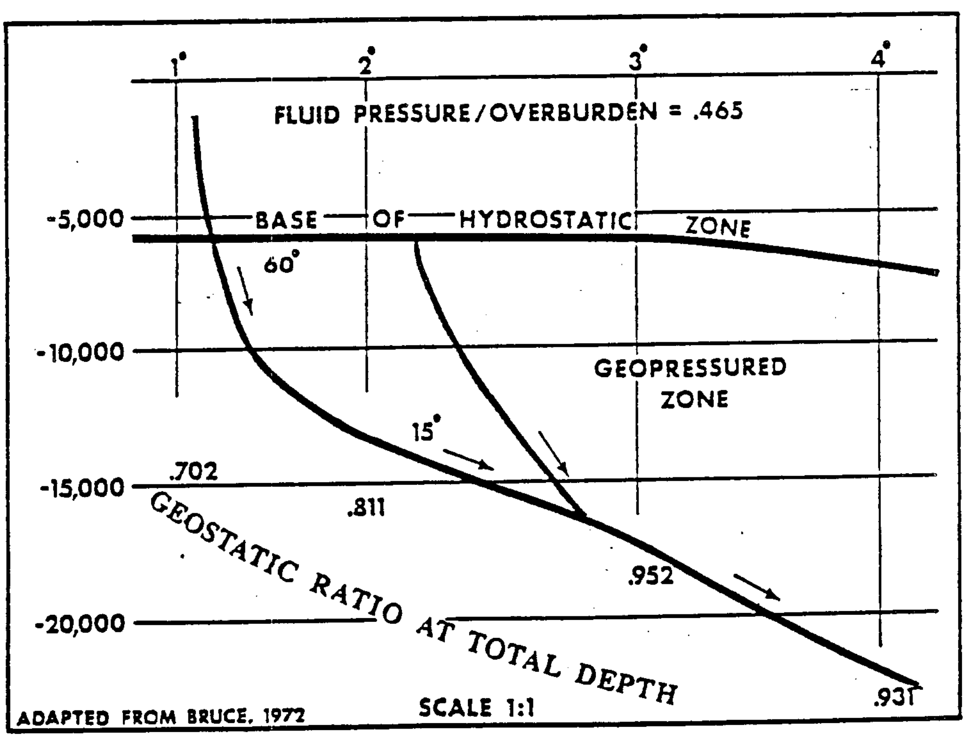


Figure 44. Relation of dip angle of contemporaneous faults to pressure gradient in geopressured shale, south Texas Coastal Plain (Jones, 1975).

"When basinward progradation was far enough that sand facies of a later wedge migrated Gulfward over the soft, earlier-deposited offshore-mud facies of the previous wedge, large growth faults developed. However, in each of these wedges the main sand depocenter is rarely geopressured and only the more seaward-reaching sand bodies are prospective as geothermal reservoirs. These sand bodies thus occur at greater depths and are enveloped by thick shale sections. Three Tertiary wedges prograded in this manner and were found to contain significant thicknesses of sand within the geopressured zone - the Wilcox, Vicksburg, and Frio Formations. The DOE Pleasant Bayou Well produces from the Frio in Brazoria County from a deltaic depositional sequence." See Figure 45.

"From the cross sections studied, parts of select wedges can be readily outlined which do or are expected to contain thick sand bodies deeper than 10,000 ft below sea level in the geopressured zone. On the cross sections which show little or no control in the geopressured zone the prospective areas were outlined using other nearby sections. Broad corridors expected to contain geothermal fairways can thus be delineated. The inland-most corridor is that of the Wilcox Formation which extends from eastern Zapata and western Starr Counties on the south to southern Jasper and Newton Counties on the northeast. The band along the present-day Gulf Coast is the Frio corridor which extends from Hidalgo and the western Cameron Counties on the south to southern Jefferson County on the northeast. The Vicksburg corridor is in two parts: the southern part overlaps with the Frio corridor in Hidalgo, the western Cameron part occurs between the Wilcox and Frio corridors from southern Harris County on the south to northern Orange and southern Newton Counties on the north.

"....all of the Tertiary oil-producing basins of the world are geopressured. They exhibit the same general geothermal-gradient characteristics. They exhibit the reversals of the salinity gradient within the geopressured zone, and the oil and gas occurrences

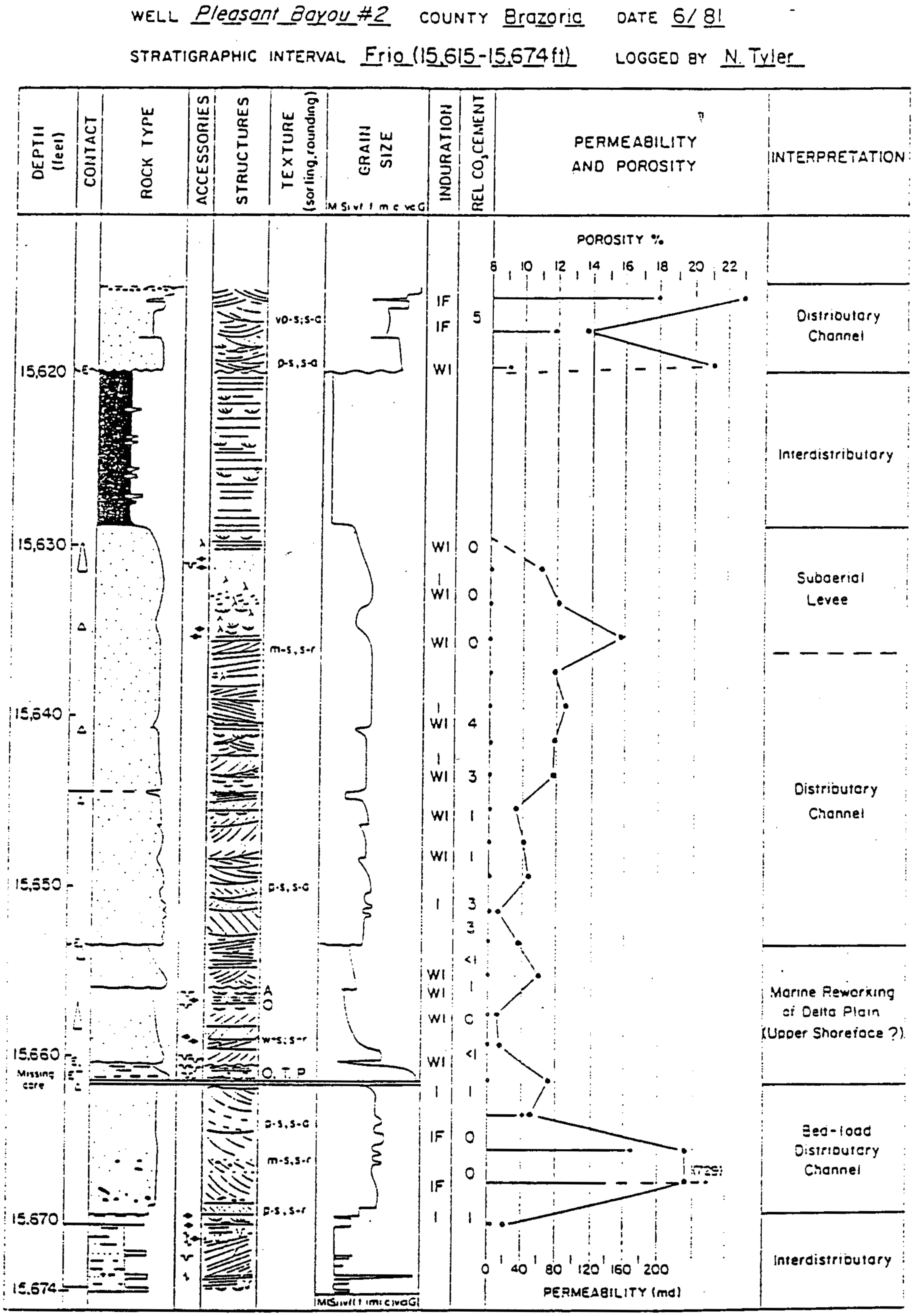


Figure 45. Detailed core description, pore properties, and interpretation of the lower part of the Frio F correlation interval (T5 unit). This composite sand stone shows a central decrease in porosity. Large-scale crossbeds (15.670 to 15.661 ft and 15.620 to 15.616 ft) have higher porosities and permeabilities than do small-scale crossbeds (15.653 to 15.640 ft). Trace fossils in the marine-reworked interval: *A-Arenicolites, O-Ophiomorpha, T-Thalassiroides,* and *P-Planolites* (Morton et al., 1981).

are tied in with the pressure-temperature-salinity regime in the basin. This represents 28 countries around the world" (Jones, 1975).

Knapp and Isokrari (1976) develop a geological framework of information on geopressured geothermal reservoirs in preparation for their work on numerical simulation of future performance of geopressured-geothermal reservoirs.

"Geopressured reservoirs are deep sedimentary basins filled with sand and clay or shale and are generally undercompacted below depths of 7,000 to 25,000 ft, and, as a result, the interstitial fluid pressure carries a part of the overburden load.

"These reservoirs occur generally in regions where the normal heat flow of the earth is trapped by insulating impermeable clay beds in a rapidly subsiding geosyncline or downward bend of the crust. Pressures at depth are significantly in excess of hydrostatic and may approach lithostatic. The aquifers are often compartmentalized by regional faults into horizontal blocks.

"Geopressured deposits are hotter than normally pressured deposits because upward loss of the included water has been essentially stopped for millions of years. Water is a poor conductor of heat compared to the associated minerals, and undercompacted clay is an excellent thermal insulator. The specific heat of water is about five times that of the associated minerals. Thus, geopressured deposits reduce the thermal flux above them, compared to that below, and store geothermal energy until a steady temperature is reached. The temperature gradient is sharply increased at the top of the geopressured zone.

"Because the solubility of hydrocarbon gases in water increases with decreasing dissolved solids, and because the high temperature and pressures have resulted in a natural cracking of the petroleum hydrocarbons, the geopressured reservoir fluid often contains 10 to 40 scf (standard cubic feet) of natural gas per barrel of fluid. These dissolved hydrocarbon gases would be a valuable by-product of fluid production" (Knapp and Isokrari, 1976).

Abnormal pressures in the Lower Vicksburg, McAllen Ranch Field, south Texas, were studied by Berg and Habeck (1982). They found the entire section of 2000 ft of shale and 4000 ft of interbedded sandstones and shales to be abnormally pressured, with gradients to 0.94 psi/ft. Identification was by estimation of pressures from conductivity logs and by extrapolation of shut-in buildup pressures. The hydrodynamic flow is thought to be taking place from areas of high pressure to an underlying major listric normal fault, and then updip along the fault plane. The top of abnormal pressures occurs at a depth of 7,500 ft and at a temperature of about 210°F (99°C), where there is an abrupt decrease in smectite within the mixed-layer illite-smectite clays. Berg and Habeck conclude that the abnormal pressures are largely the result of clay transformation, perhaps accompanied by pressuring due to hydrocarbon generation. Aquathermal pressuring was ruled out because pressure increase with temperature does not follow isodensity lines for water.

A zone in the lower Frio Formation was found to have gradients to 0.74 psi/ft beginning at about 5000 ft. In this zone, pressure increase with temperature follows isodensity lines for water, and the authors thus conclude that aquathermal pressuring is the major cause of abnormal pressures. Shale densities suggest that nonequilibrium compaction may also have played a minor role in creating abnormal pressures in the Frio.

Jackson and Light (1987) (through Dorfman (1991) private communication) address "Estimated percentage of wells producing from Geopressured Reservoirs along the Texas Gulf Coast." They state that in 1983, there were 50,938 actively producing oil and gas wells along the Texas Gulf Coast. Of those wells, an estimated 989 gas wells and 35 oil wells were producing from geopressured reservoirs, or 2% of the total number of producing wells. However, the 2% estimate certainly includes wells that do not penetrate economically viable geothermal reservoirs.

To make their estimate, Jackson and Light began by tabulating the number of wells producing from Tertiary reservoirs below 10,500 ft, the average depth to top of geopressure in major Tertiary sand units (Miocene, Frio, Vicksburg, Yegua, and Wilcox sands; see Bureau of Economic Geology publications by Bebout and others, 1978). Wells penetrating the Cretaceous section also were tabulated though there are few, if any overpressured Cretaceous reservoirs. Wells in the Tertiary section below 10,500 ft were separated into categories by 1) Texas Railroad Commission district (Districts 03, 02, and 04); 2) type of production (oil or gas); and 3) depth interval of production. The tabulation is given in Table 24. The source of this information was the International Oil and Gas Development Yearbook, Review of 1982-1983 published in 1984 by the International Oil Scouts Association.

Bebout et al. (1978) demonstrate that the top to geopressure is actually closer to 12,000 ft in southeast Texas (District 03). Thus, in District 03, Jackson and Light estimate that there were 208 wells producing from geopressured reservoirs in 1983 (208 being the sum of oil and gas wells in the Tertiary section below 12,000 ft, as of oil and gas wells in the Tertiary section below 12,000 ft, as listed in Table 24. In the other two districts (the middle and South Texas Gulf Coast) the top to geopressure averages about 10,500 ft. Thus, for all three districts combined, an estimated total of 1,024 wells produce from geopressured reservoirs along the Texas Gulf Coast. This represents 2.0% of all wells (50,938) producing along the Texas Gulf Coast during 1983.

The estimate of the percentage of wells producing from the geopressured section could be improved. Jackson and Light (1987) use the average top to geopressure as the cut-off point. However, an accurate estimate would require initial bottom hole pressures for each well. While this data is available at the Texas Railroad Commission, additional funds and perhaps two months of time would be needed to complete the task of compiling the information.

It should also be noted that of the approximately 1,024 geopressured wells, a much smaller number of wells are capable of producing significant quantities of water (and co-produced gas) from extensive, permeable reservoirs. The areas where such reservoirs exist have been identified in previous Bureau of Economic studies, and it would be possible to estimate the number of producing wells in these areas (Light et al. 1987).

Table 24. Distribution, by depth, of the number of Texas Gulf Coast oil and gas wells producing during 1983.

DISTRICT 03 - SOUTHEAST TEXAS GULF COAST DEPTH INTERVALS IN THOUSANDS OF FEET

		<10.5	>10.5	10.5	11	12	13	14	15	>16
GAS		5963	856							
	TERT		693	121	377	119	53	13	7	3
	CERT		163	1	108	42	2	1	0	9
OIL		15310	66							
	TERT		54	25	16	9	3	1	0	0
	CERT		12	2	3	5	2	0	0	0

DISTRICT 02 - MIDDLE TEXAS GULF COAST DEPTH INTERVALS IN THOUSANDS OF FEET

		<10.5	>10.5	10.5	11	12	13	14	15	>16
GAS		5778	277							
	TERT		143	57	48	22	9	3	1	3
	CRET		137	39	0	0	83	8	2	5
OIL		5414	5							
	TERT		3	3	0	0	0	0	0	0
	CRET		2	2	0	0	0	0	0	0

DISTRICT 04 - SOUTH TEXAS GULF COAST DEPTH INTERVALS IN THOUSANDS OF FEET

		<10.5	>10.5	10.5	11	12	13	14	15	>16
GAS		10610	652							
	TERT		651	186	222	133	61	24	20	4
	CRET		1	0	0	0	0	8	0	0
OIL		.7563	19							
	TERT		19	10	4	3	2	0	1	0
	CRET		0	0	0	0	0	0	0	0

As a follow-up on this information Dr. Myron Dorfman states that by law in Texas all wells must be plugged and abandoned when activity has ceased. This involves a cement plug at the bottom and at the top. Thus, to obtain useable geopressured wells from the oil and gas industry, it is necessary to locate prospects during production or just prior to plugging and abandoning (Dorfman, personal communication, 1990).

Mississippi

Parker (1974) presents a classification of overpressures not based on seals but on driving force. Under geopressure, Parker includes inflated pressure, phase pressure, load pressure, and tectonic pressure. Parker states that for geopressure, the driving force is the weight of the water-filled overburden. As defined by Stuart (1970), changes in overburden are implied. It is expanded to include any case in which fluid is actually supporting overburden in excess of its normal buoyancy; e.g., deep overpressures in the Gulf Coast Tertiary. Varieties caused by in-situ fluid generation and loading or unloading include the following:

1. Inflated pressure - originates when fluids migrate from adjacent or deeper overpressured strata. For example, Germann and Ayres (1938) conclude that thermal decomposition of impure limestone can account for the high subsurface pressures and large volumes noted in carbon dioxide reservoirs. These reservoirs often have been inflated from deeper zones via faults.

2. Phase Pressure - the origin is a mineral phase change such as increased pressure resulting from the release of water during a gypsum-to-anhydride transition, dehydration of serpentine, or dehydration of montmorillonite as it converts to illite clay. The last is considered by Burst (1969) to cause some of the overpressuring in the Gulf Coast Tertiary. "Phase pressure" considers that the geopressure origin is geochemical fluid production rather than rapid physical deposition of overburden as in "load pressure" below.

3. Load pressure - the origin is increased overburden weight without fluid escape in the sense used by Stuart for "geopressure." Often, rapid deposition as in the Gulf Coast Tertiary accounts for this geopressure because the underlying fluids are in rocks with relatively low transmissibility, but given enough time these pressures should eventually equalize to hydrostatic pressure.

4. Tectonic pressure - implies origin through sealing and loading by a tectonic force. For example, a moving thrust sheet can generate regional overpressures (Hubber and Rubey, 1956). Finch (1969) credits overpressuring in a single structure in North Dakota to tectonic forces during structural growth. Berry (1983) explains geopressure in the Central Valley (Great Basin) of California by tectonic pressure.

Deep Smackover geopressures differ from those in the Gulf Coast Tertiary. Shale porosity variations, usually in a leaky transition zone, reveal geopressures in the Gulf Coast Tertiary. In the deep Jurassic where there is no shale seal and where porosity, if any, is erratic, there exists a more complex rock package dominated by quartzites, carbonates and evaporites. The Buckner anhydride often marks the boundary between hydropressures and geopressures in much of the salt roller structural province. The overpressures rise stratigraphically in a basinward direction. Tight crystalline limestones within the Smackover can separate pressure regimes. Geopressures below these crystalline seals are abrupt and give no warning to drillers. This type of pressure can be predicted through seal analysis and underlying porosity prediction.

Deep Jurassic geopressures have diverse origins, which include inflation, mineral or hydrocarbon phase changes and evaporite-related seals. Many of these origins involve late geologic events and migrant acid gases or fluids that apparently have dissolved available soluble minerals, thereby creating late secondary porosity.

Geopressuring in the south Mississippi salt basin is associated with hydrothermal phenomena which appear to be directly related to igneous activity. See Figures 46 and 47. The possibility that igneous intrusions at depth could be occurring in the Gulf Basin is based on the

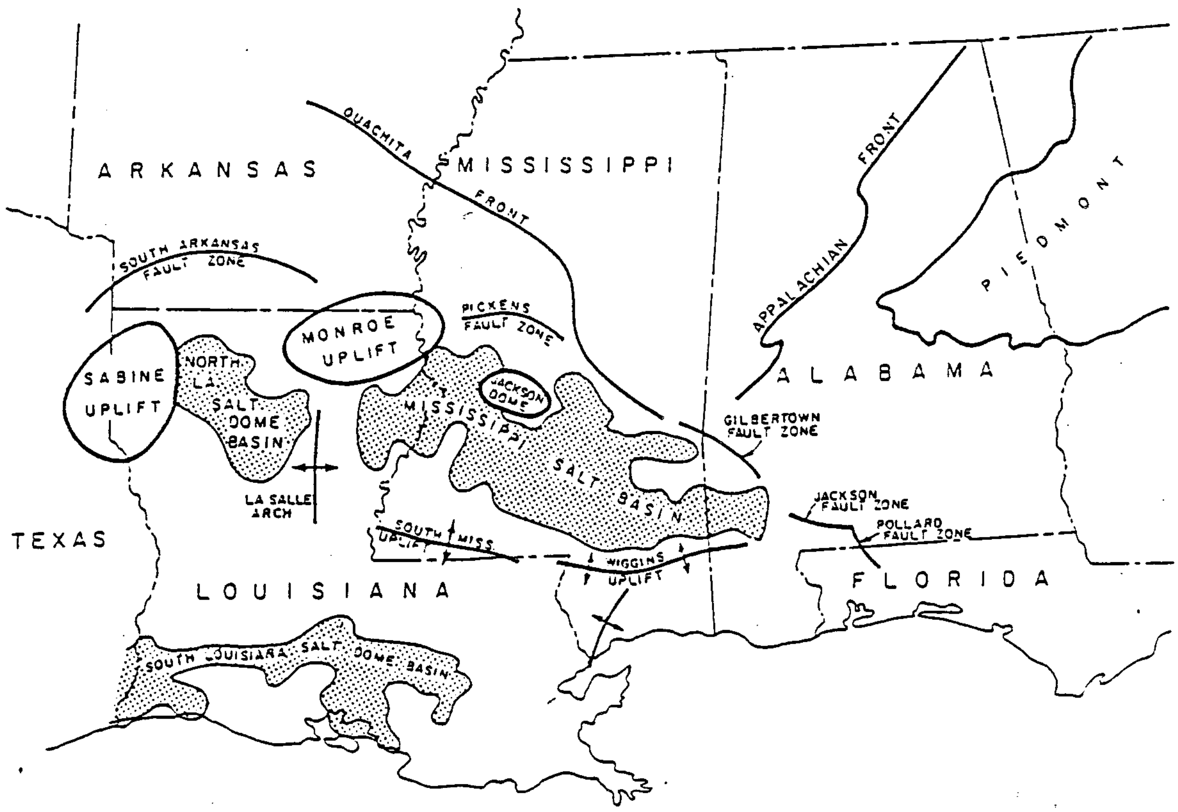


Figure 46. Tectonic Index Map (Reprinted from J. Plate Tectonics, August 1973).

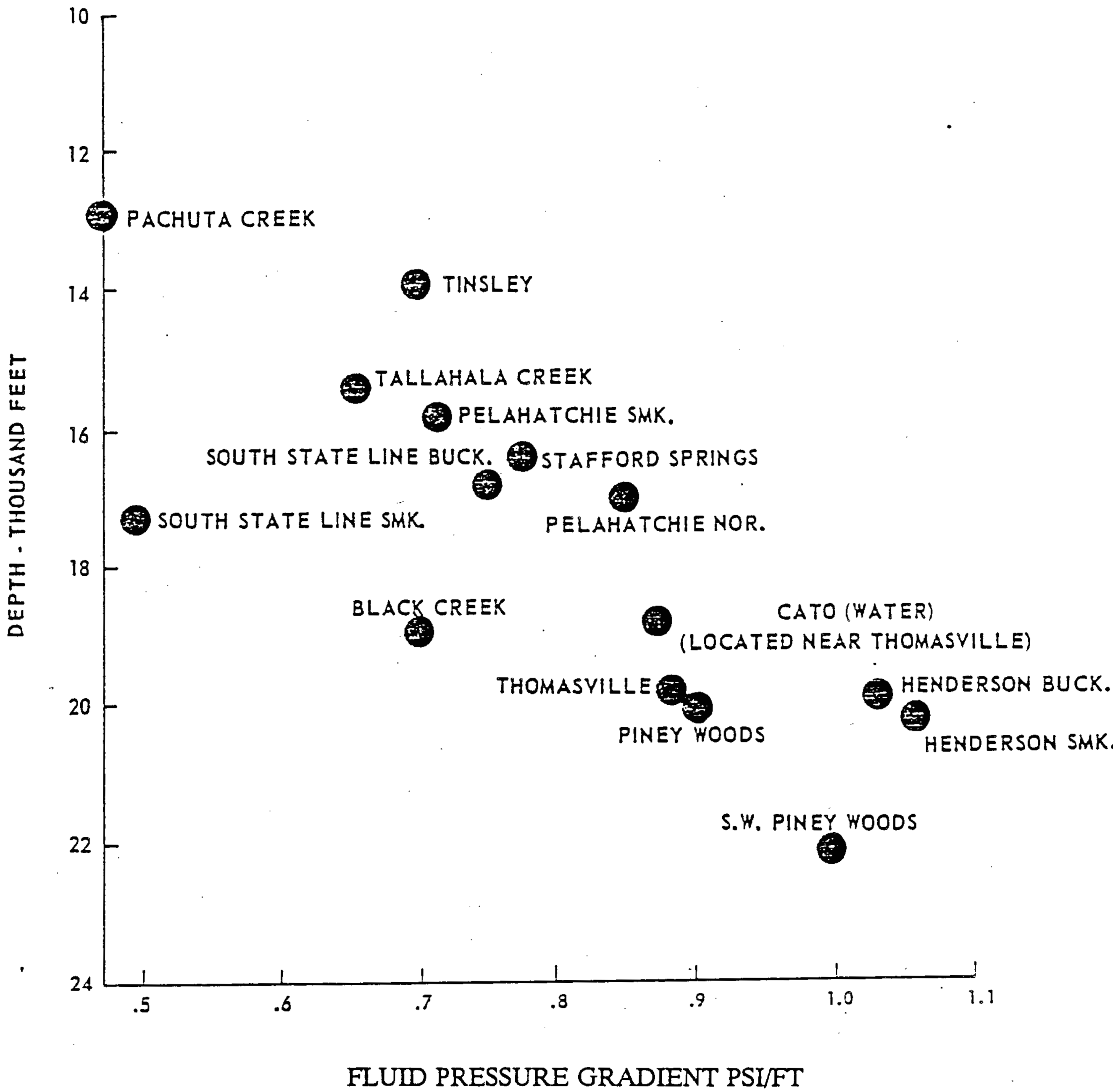


Figure 47. Plot of pressure gradients with depth, Mississippi interior basin (Parker, 1986).

temperature distributions in the basin and the conclusion that mass transfer of both solid salt and liquid water from very great depth was sufficient to produce thermal halos that dehydrated shale throughout vast areas of enormous thicknesses.

California

Berry (1973) reports on high fluid potentials in California Coast Ranges and examines their tectonic significance. Berry uses data based on fluid pressures determined principally from direct measurements made during drill-stem tests on individual wells, and extrapolation of pressures taken from actual drill-stem-test pressure charts to infinite time by the method outlined by Horner (1951) to obtain the most accurate determination of the undisturbed static fluid pressure within the given sedimentary zone. See Figures 48-53.

Pressures are near-lithostatic (1.06 psi/ft). Examples of flow rates are:

1. The Clear Lake Well in Franciscan sandstones which hit a fracture channel at 1,630 ft and flowed 30,000 to 35,000 bbls of hot water 210°F (99°C) and 50,000 to 70,000 lb of steam per day. The water is in a liquid phase within the reservoir; steam was generated by flashing associated with production. The well is within the area of high heat flow in the northern California Coast Ranges, and

2. California Department of Water Resources second deep well in the Eel-Glenn River Diversion project (EG-I). At 3,300 ft the well penetrated low-grade metamorphosed shale (graphitic phyllite). Very high pore fluid potentials were registered in the metashale below the more shallow silicified rock. Berry concludes that "within the Franciscan, local areas or zones of near-hydrostatic fluid potentials within fractured rocks have been found, and others may be expected to exist. Presumably, abnormally high fluid potentials bound such zones both laterally and at depth, but such zones should be common within the extensively fractured Franciscan and related rocks."

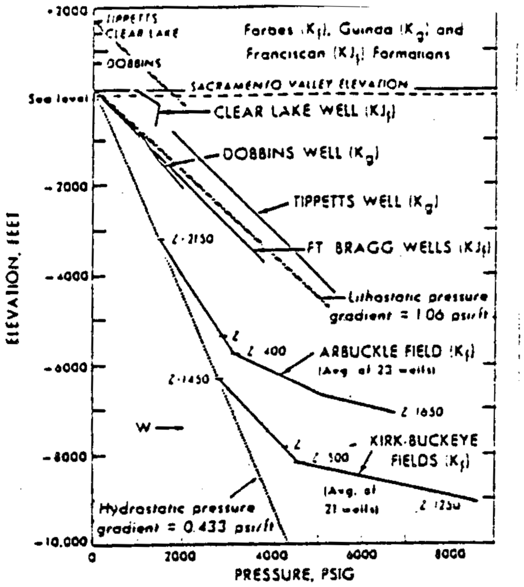


Figure 48. Pressure versus depth plot in Sacramento Valley, California. Pressure-depth lines plotted for Arbuckle and Kirk-Buckeye gas fields are composite lines derived from series of pressure determinations in several wells. Formations from which fluid pressures were determined are indicated. "Z" is stratigraphic marker in Forbes Formation. Reference lithostatic and hydrostatic gradients are plotted from average surface elevation of Sacramento Valley (+50 ft). Surface elevations of Dobbins, Clear Lake, and Tippetts wells are indicated and reference lithostatic gradient is plotted from Tippetts surface elevation (Berry, 1973).

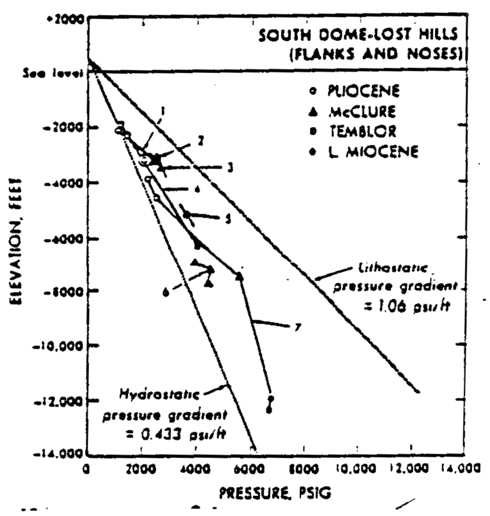


Figure 50. Pore-fluid pressures plotted with respect to elevation below sea level for wells drilled along flanks and at ends of noses of South Dome-Lost Hills anticline. Surface elevation is approximately +400 ft from which reference hydrostatic and lithostatic gradient lines are plotted. Numbered lines represent: (1) Standard of California 59 Cahn; (2) Standard of California 4-148 Cahn; (3) Texas Co. 1 Martin; (4) Buttes Gas and Oil 1 Vaughey-Occidental Lands; (5) California Lands 2 Occidental Lands; (6) Standard of California 3 Lost Hills Extension; (7) Standard of California 45 Van Sicklin. (Berry, 1973)

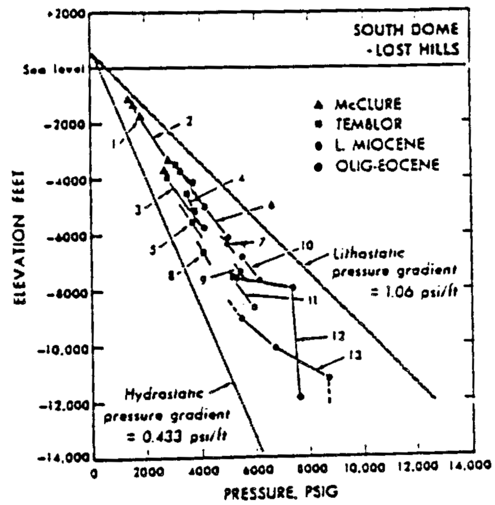


Figure 49. Pressure versus depth plot of axis of South Dome-Lost Hills anticline, showing distribution of pore fluid pressure with respect to elevation below sea level for various wells. Hydrostatic and lithostatic gradients are plotted from surface elevations of about +400 ft. Slope of lines with only one point is estimated. Lines represent wells: (1) Texas 2 Overall; (2) Lincoln 1-A Theta; (3) Tidewater 1 Williamson; (4) Universal Consolidated 49; (5) Standard of California 58-4 Cahn; (6) General Petroleum 33-11; (7) Standard of California 16; (8) Ohio Oil 1 Smith; (9) Continental Oil 28-7 Gatchell; (10) Universal Consolidated 265; (11) Occidental Petroleum 131x-2 Hellman; (12) Standard of California 4-2; (13) Occidental Petroleum 27-27. (Berry, 1973)

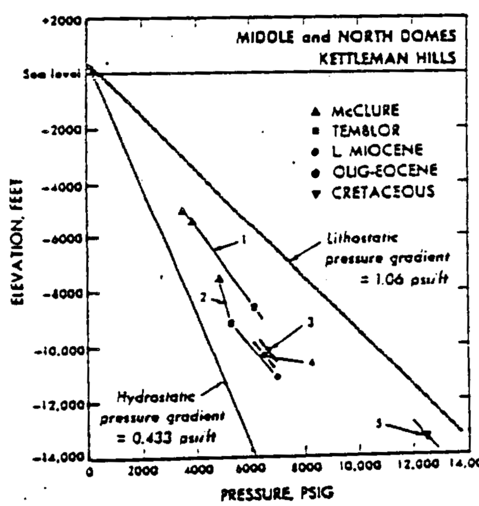


Figure 51. Pore-fluid pressures plotted with respect to elevation below sea level for wells at Middle Dome and one well at North Dome. Surface elevation is approximately +500 ft from which reference hydrostatic and lithostatic gradient lines are plotted. Numbered lines represent, on Middle Dome: (1) Petroleum Securities 1; (2) Standard of California 613; (3) Middle Dome 38-19V; (4) Standard of California 68-4; on North Dome; (5) Kettleman North Dome 423 (Berry, 1973).

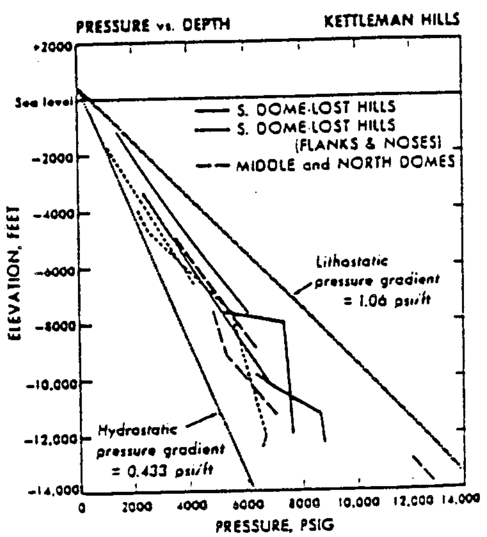


Figure 52. Composite pressure versus depth plot at South Dome-Lost Hills anticline. Middle and North Domes. Reference hydrostatic and lithostatic gradient lines are plotted for average surface elevation of +400-500 ft (Berry, 1973).

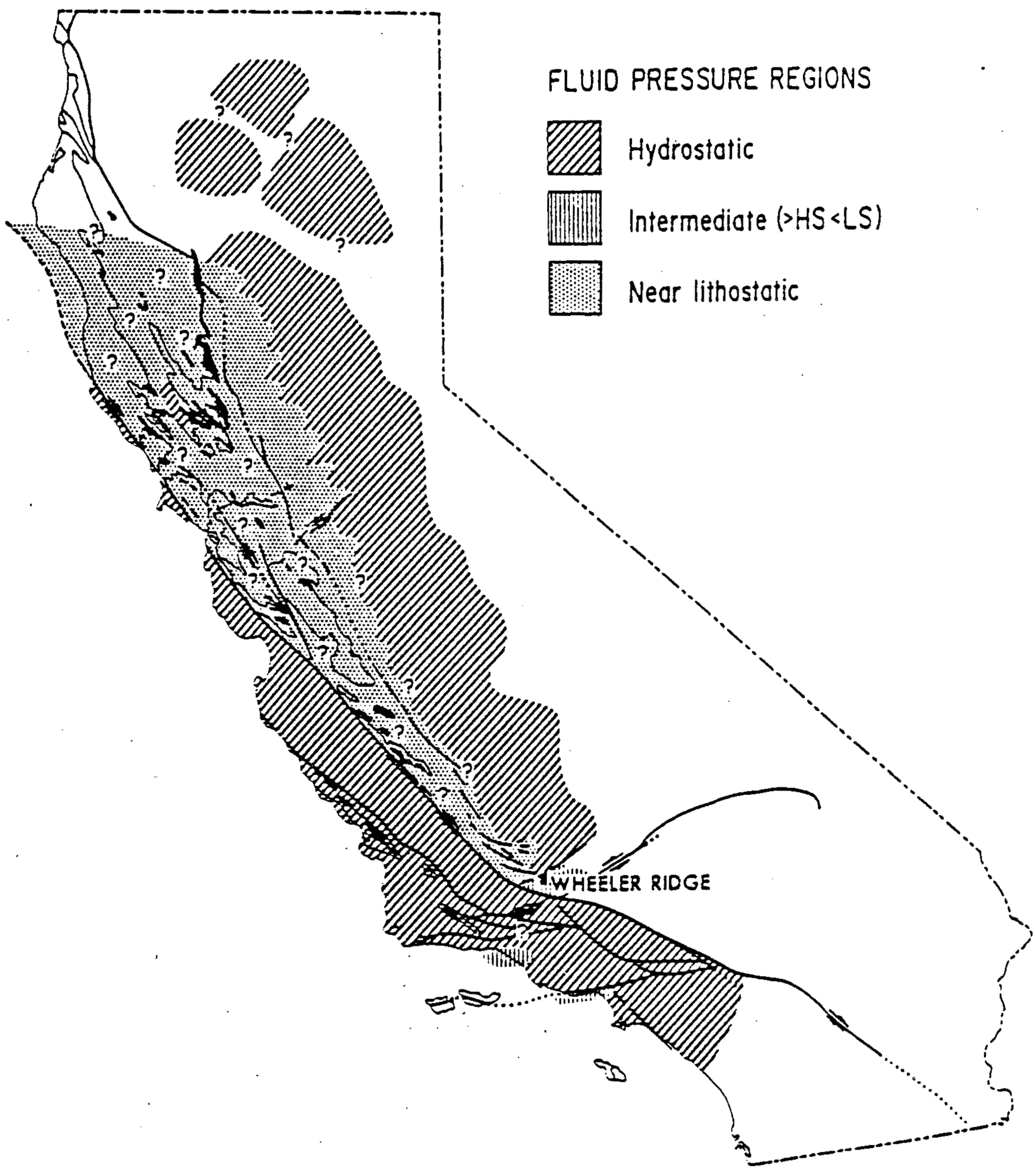


Figure 53. Geographic distribution of fluid-potential zones in California. Principal faults are indicated (Berry, 1973).

In the San Joaquin Valley, "the most convincing evidence that the Cretaceous sedimentary section has high fluid potentials stems from the chemical similarity of water from the Tertiary rocks to that of water from the Great Valley sequence in the Sacramento Valley. In general, the Great Valley sequence waters possess all the characteristics associated with membrane-effluent waters and probably are derived from tectonic compaction of the shales."

The waters of an effluent origin have a low total concentration (TDS) and relatively high content of NH_4+, B, I, and HCO_3 with respect to either Na or Cl compared with seawater. The waters also have a relatively low Ca/Na ratio and a relatively high pH compared with most deep subsurface waters. Berry uses analyses of 32 representative samples of subsurface water. The lower Tertiary waters of the San Joaquin Valley possess a striking similarity in chemical composition to water in the Sacramento-Great Valley sequence. The San Joaquin waters have a low total concentration (TDS) which decreases with depth; chemical content is typical of membrane-effluent waters. Berry concludes they are expelled pore waters derived principally by tectonic compaction of the underlying Great Valley sequence and driven upward into the overlying relatively high-permeability lower Tertiary rocks where they have been mixed with meteoric water.

The Kettleman Hills area, South Dome, and Lost Hills have average pore fluid pressure gradients of about 0.7 psi/ft. The water chemistry is similar to the Cretaceous waters of the Sacramento Valley. The waters of the Leda Sandstone, a lense at the Oligocene-Miocene boundary, are interpreted to be membrane-hyperfiltrated water from the chemical composition characteristics. The total dissolved solids (TDS) are 70,000 ppm, much higher than those above (20,000 ppm) and lower (8,000 ppm). The fluid potential may in part be due to chemical osmosis resulting from the semipermeable membrane properties of shales.

Other areas with high fluid potential identified by Berry (1973) are the Ventura Avenue anticline, the Wheeler Ridge anticline and the Los Angeles basin.

Berry also addresses "how long can an unbalanced fluid pressure be maintained?" He states that the limiting factor is the permeability of the shales, and estimates that tens or hundreds of thousands of years are probably the limit, based on the range of shale permeabilities (10^{-3} to 10^{-9} μd). Most of the various phenomena caused by the near-lithostatic fluid pressures are related to rheological properties of rocks with such fluid pressures. "Such rocks will behave as near-perfect plastic materials" (Berry, 1973). Pore-fluid pressures can serve as sufficiently sensitive strain gauges to permit detection of minor dilatational effects, such as those created by tides and seismic waves (Bodvarsson, 1970, in Berry, 1973).

Rocky Mountain Region

Spencer (1986) reports that overpressured reservoirs are present in the deeper parts of most basins in the Rocky Mountain region. In age the rocks range from Devonian to Tertiary and are associated with low-permeability reservoirs. Most overpressuring is related to organic-rich Cretaceous or Tertiary rocks, where oil and gas generation is still ongoing. Nearly all overpressured reservoirs and source rocks have temperatures of approximately 200°F (93°C) or higher and vitrinite reflectance values of 0.6% or greater in oil-prone strata or 0.7% or greater in gas-prone strata. Most overpressured gas-bearing strata have vitrinite reflectance values of 0.8% or greater. Hydrocarbon-water contacts are generally absent and the optimum depths for exploration are usually the upper 1,000-2,000 ft of the overpressured section.

Basins which have gas-saturated sections exhibit characteristic pressure profiles. They may be subnormally or supernormally pressured, but never normally pressured. The pressure profiles of numerous gas-saturated sections in North America have been documented by constructing pressure-depth plots. Examples of supernormally pressured Tertiary and Upper Cretaceous rocks of Wyoming are presented. Overpressured areas discussed are the Red Desert Basin, Wyoming, and the Green River Basin, Wyoming.

A pressure-depth plot of the Red Desert Basin indicates a normally-pressured water profile and a supernormally-pressured gas profile. The oil and gas fields in the updip area fall on the normally-pressured system and have downdip-associated water. The gas fields downdip fall in the supernormally-pressured system. Formation water has not been found in this pressure profile. Several gas columns are seen in the supernormal pressure system, a probable result of poor reservoir continuity in the gas-saturated area.

The sediments in the Green River Basin dip to the east at approximately 200 ft/mi. The pressure-depth plot shows two basic pressure regimes: A normally-pressured water system and a supernormally-pressured gas system below that. On the normally-pressured system, oil and gas are trapped in structural and/or stratigraphic accumulations. Below approximately 500 ft, or 152.4 m (subsea) a supernormally-pressured profile is observed. The oil and gas fields on the normal pressure system have associated downdip water. The gas fields in the supernormally-pressured system have no downdip water associated with them. The different gas columns that occur in the supernormal pressure profile suggest very poor reservoir continuity in the gas area, which is probably due to the depositional environment of these sands. These rocks are deltaic, fluvial, and shallow marine in both the Red Desert and the Green River Basins. Spencer makes the following conclusions:

1. There are many gas-saturated basins that are characterized by a large areal extent of pervasive gas saturation with no downdip water.

2. These pervasive gas sections can be described on a pressure-depth profile and may be subnormally or supernormally-pressured in relationship to the regional water profile.

3. Such accumulations are always associated with low-permeability formations although high-permeability areas may occur within the gas-saturated section.

4. The use of pressure-depth plots may help in identifying similar hydrocarbon occurrences in other petroleum provinces.

5. Much oil and gas in conventional reservoirs may have been originally generated in overpressured source beds and migrated vertically and laterally into the closest available high-permeability reservoirs where they then migrated updip by buoyancy in a continuous oil or gas column. Conventional reservoirs generally have normal to

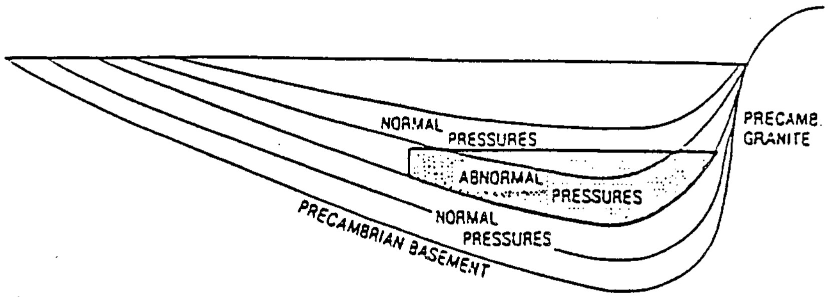


Figure 54. Cross section of the hydrogeological systems in a typical Rocky Mountains basin (Powley, 1990).

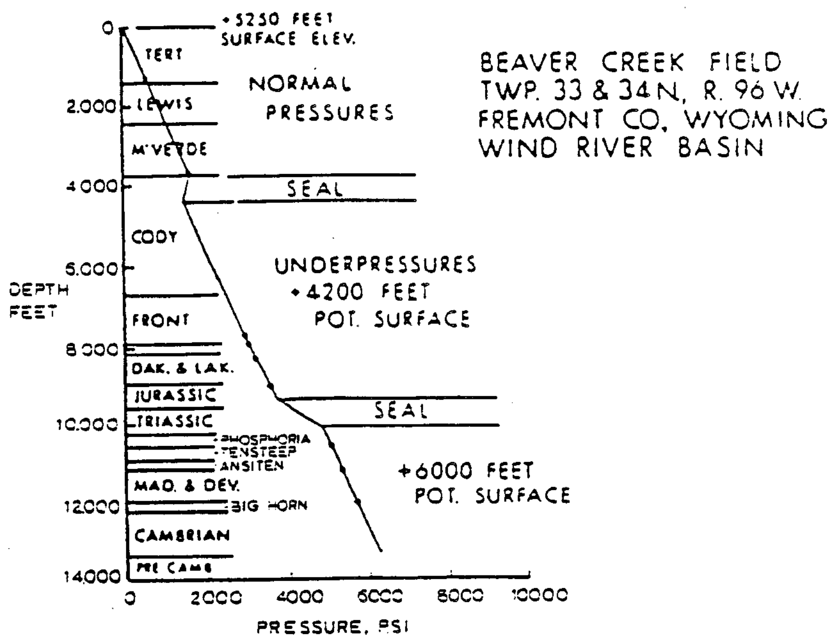


Figure 55. Typical pressure/depth profile in a Rocky Mountains basin.

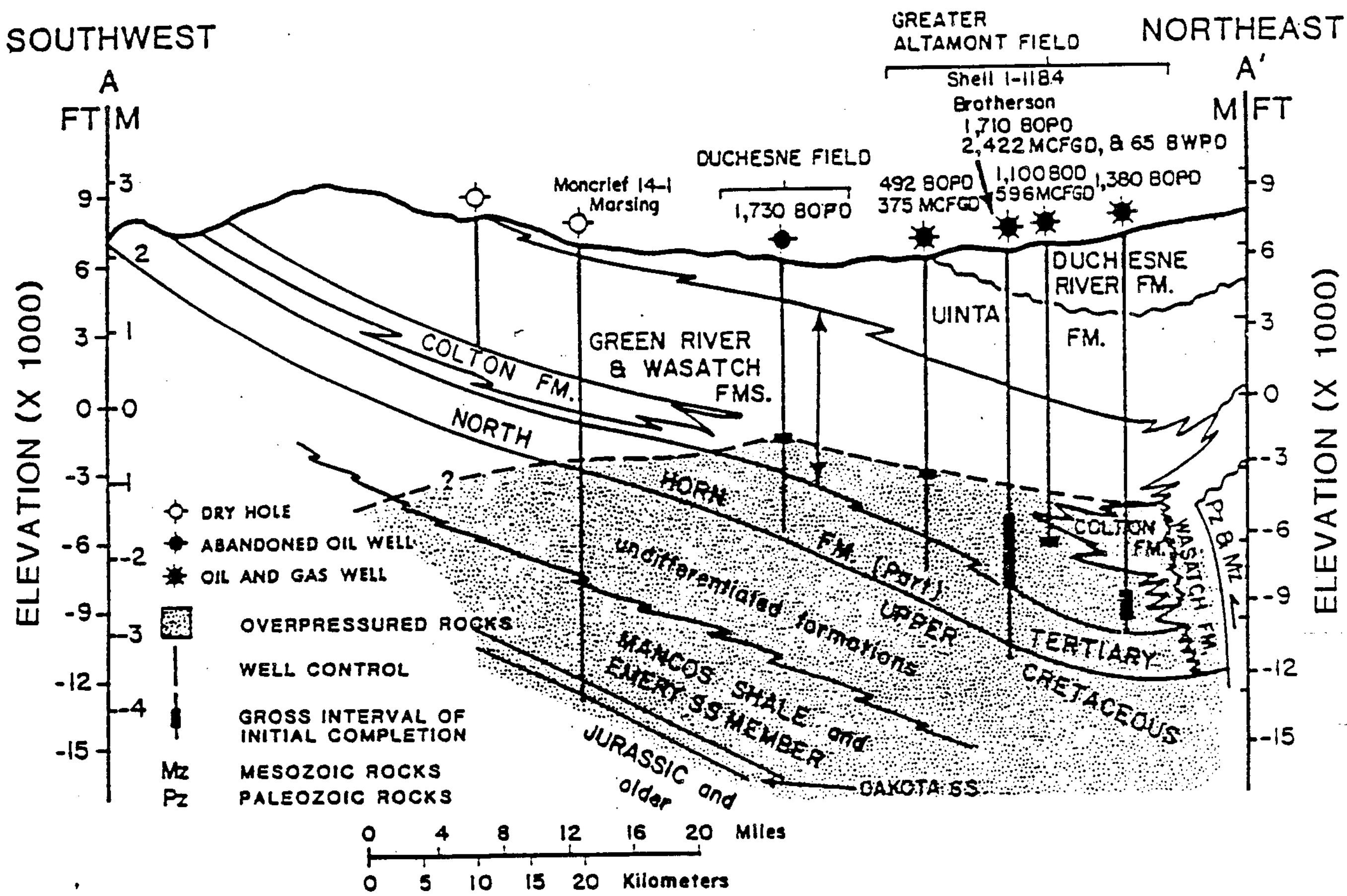


Figure 56. Cross section AA' across Uinta basin through Greater Altamont field, modified from Fouch (1975), Interpretation of overpressured section from present study is shown. Data are lacking to determine base of overpressure. Initial potential and producing interval from Fouch (1981). Some wells have been recompleted in other intervals (Spencer, 1986).

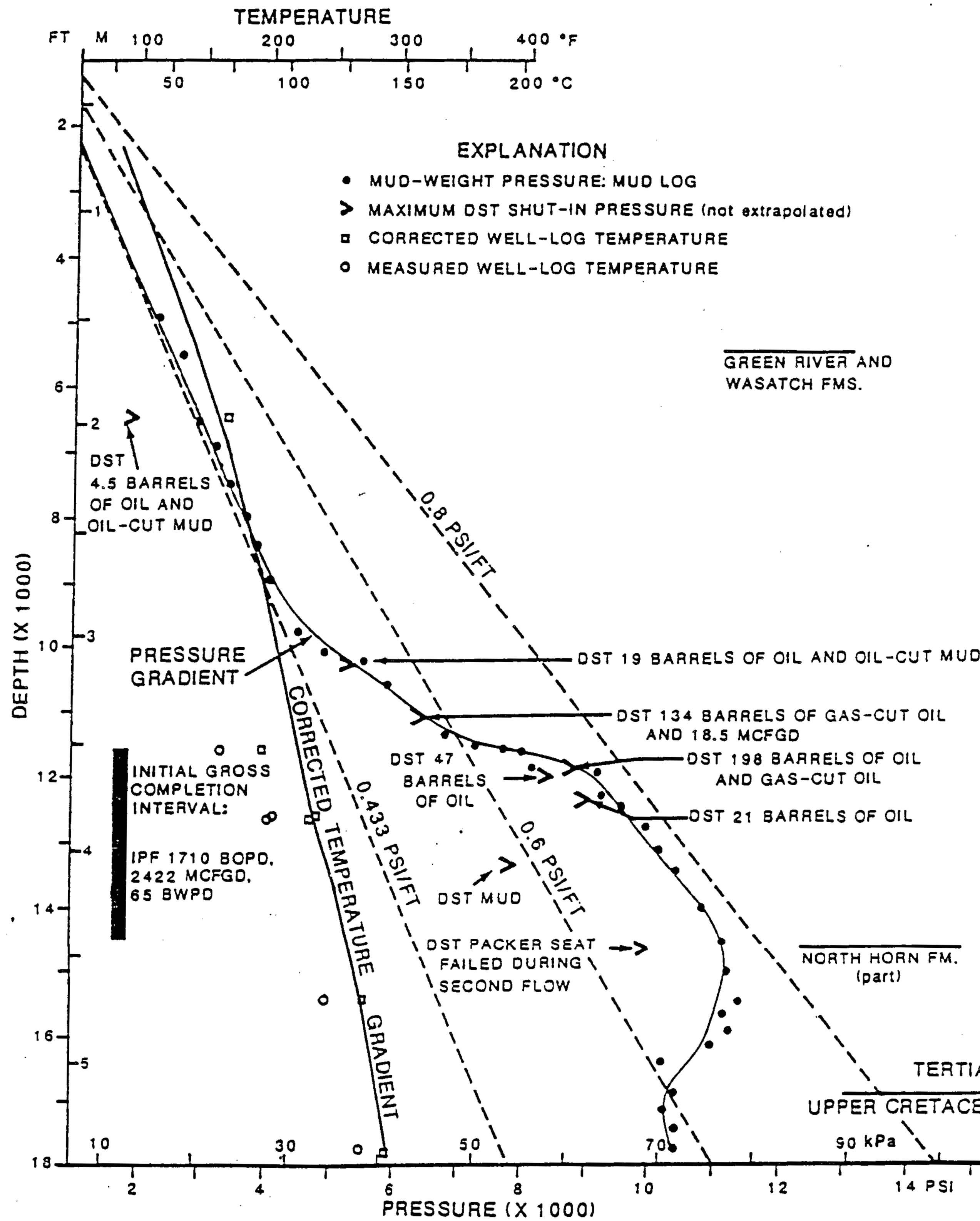


Figure 57. Pressure profile of Shell 1-11B4 Brotherson well (Sec. 11, T2S, R4W, Duchesne County, Utah), Uinta basin. Gradients are nearly 0.8 psi/ft (28.1kPa/m) and decrease in less organically rich Upper Cretaceous rocks. DST recoveries from DST reports. DSTs deeper than 10,000 ft (610 m) also recovered water cushions (Spencer, 1986).

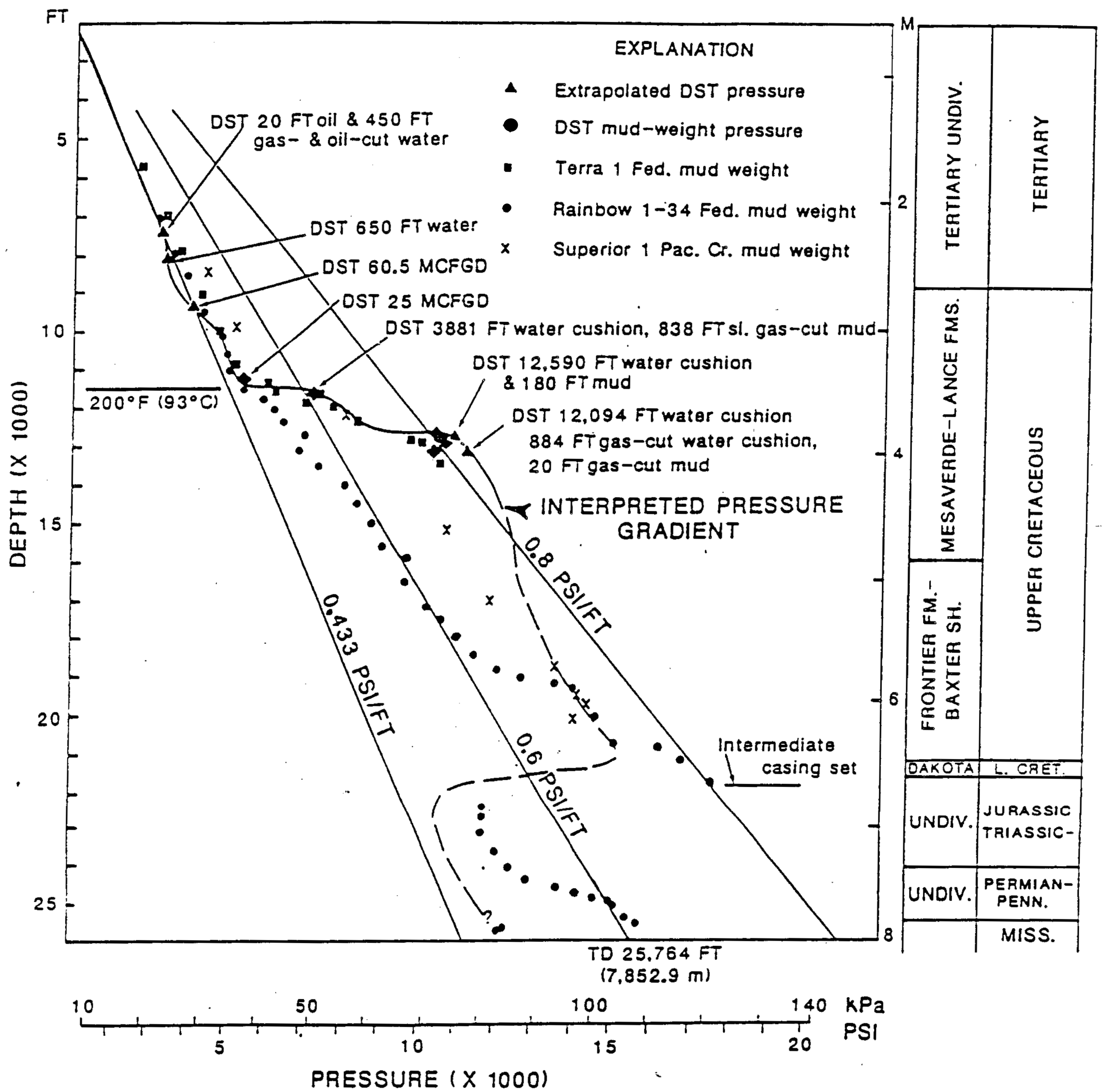


Figure 58. Pressure profile for wells in Pacific Creek area using extrapolated drill-stem test (DST) and mud-weight pressure, gas shows, and drilling-time data. Profile is dashed where uncertain (Spencer, 1986).

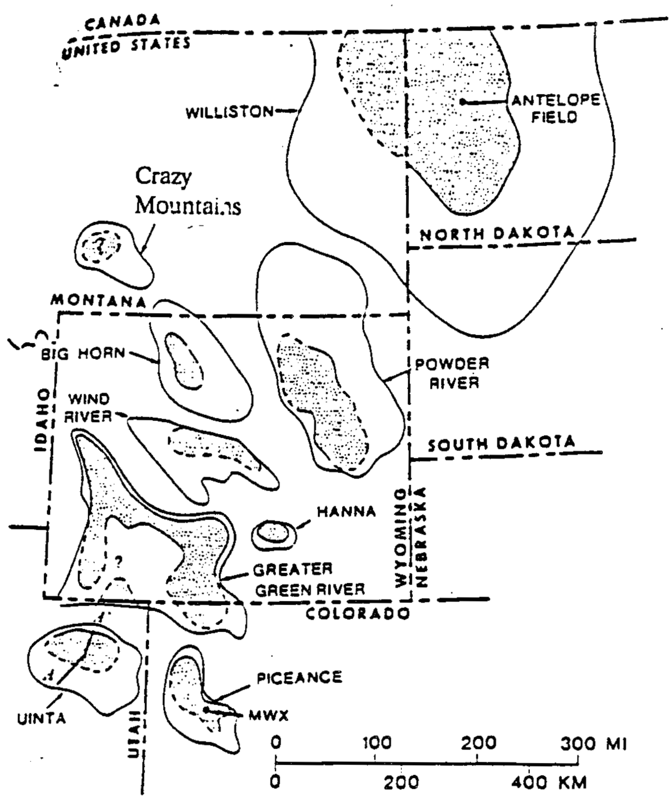


Figure 59. Index map showing Rocky Mountain basins. Shaded areas show interpreted areal distribution of overpressuring; boundaries dashed where uncertain. MWX = Multiwell Experiment site (Spencer, 1986).

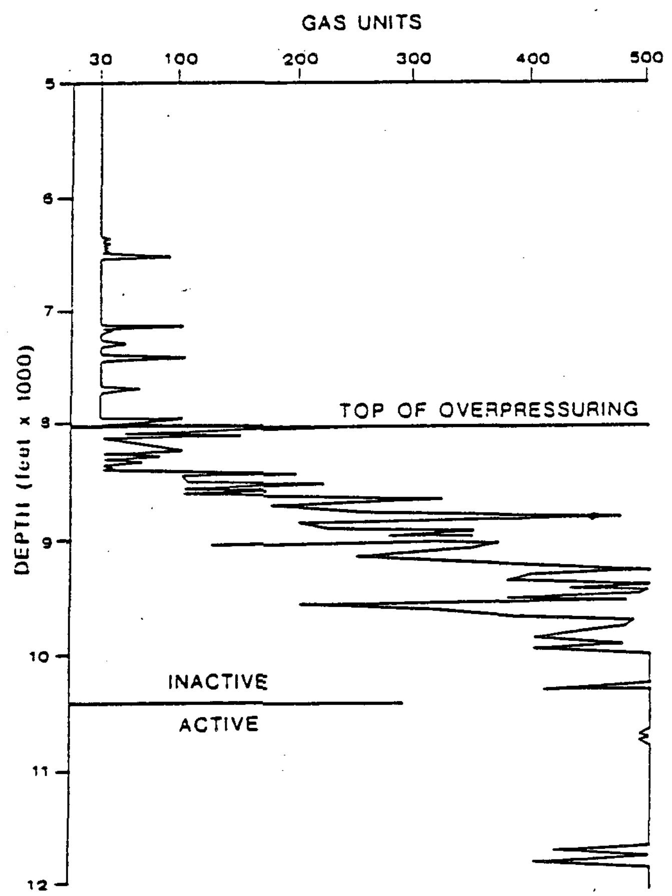


Figure 60. Modified part of mud log from El Paso Natural Gas 1 Wagon Wheel well showing relationship of gas occurrence to top of overpressured active and inactive zones (From Law and Dickinson, 1985).

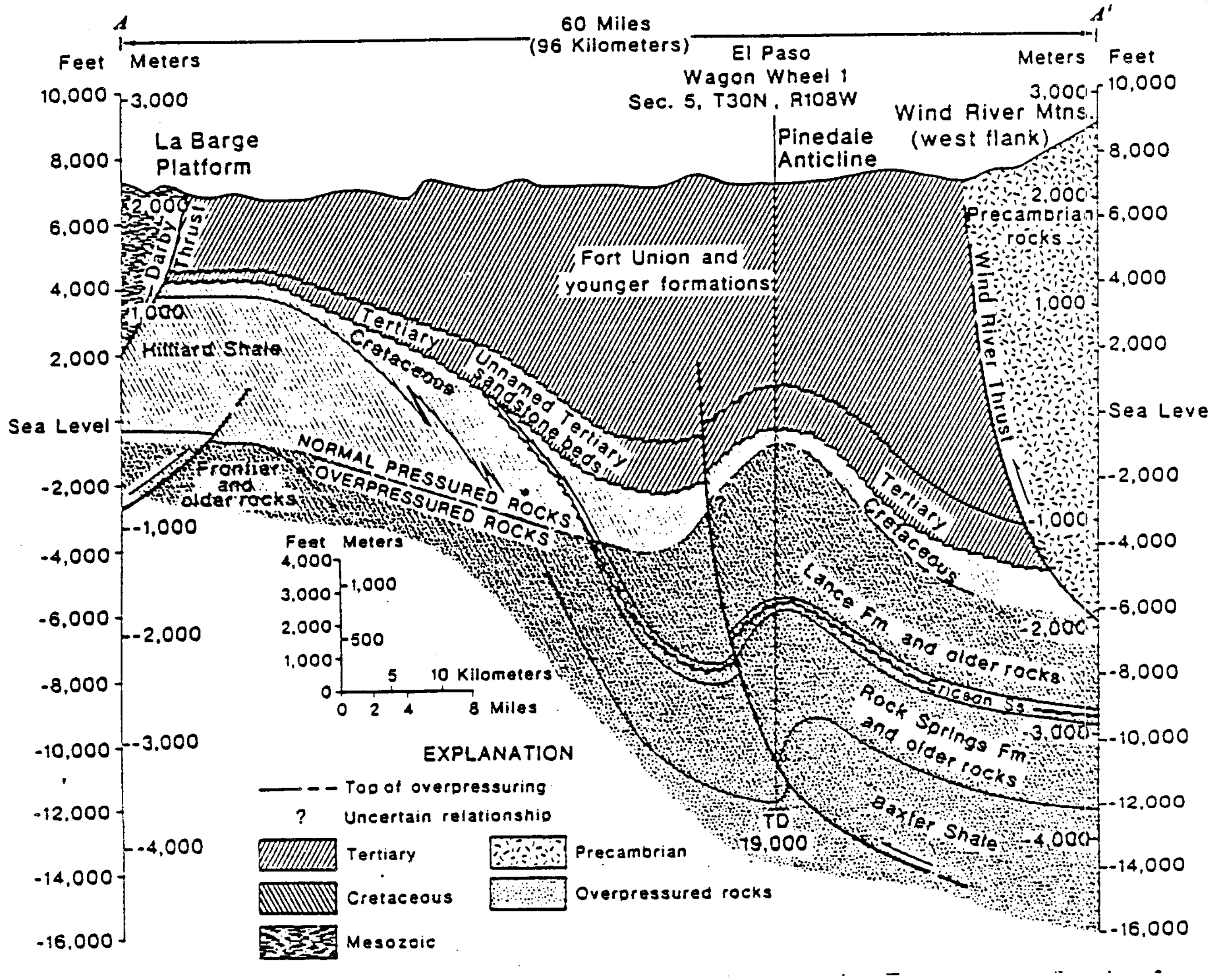


Figure 61. Cross section AA' showing relationship between structure and top of overpressuring (Law and Dickinson, 1985).

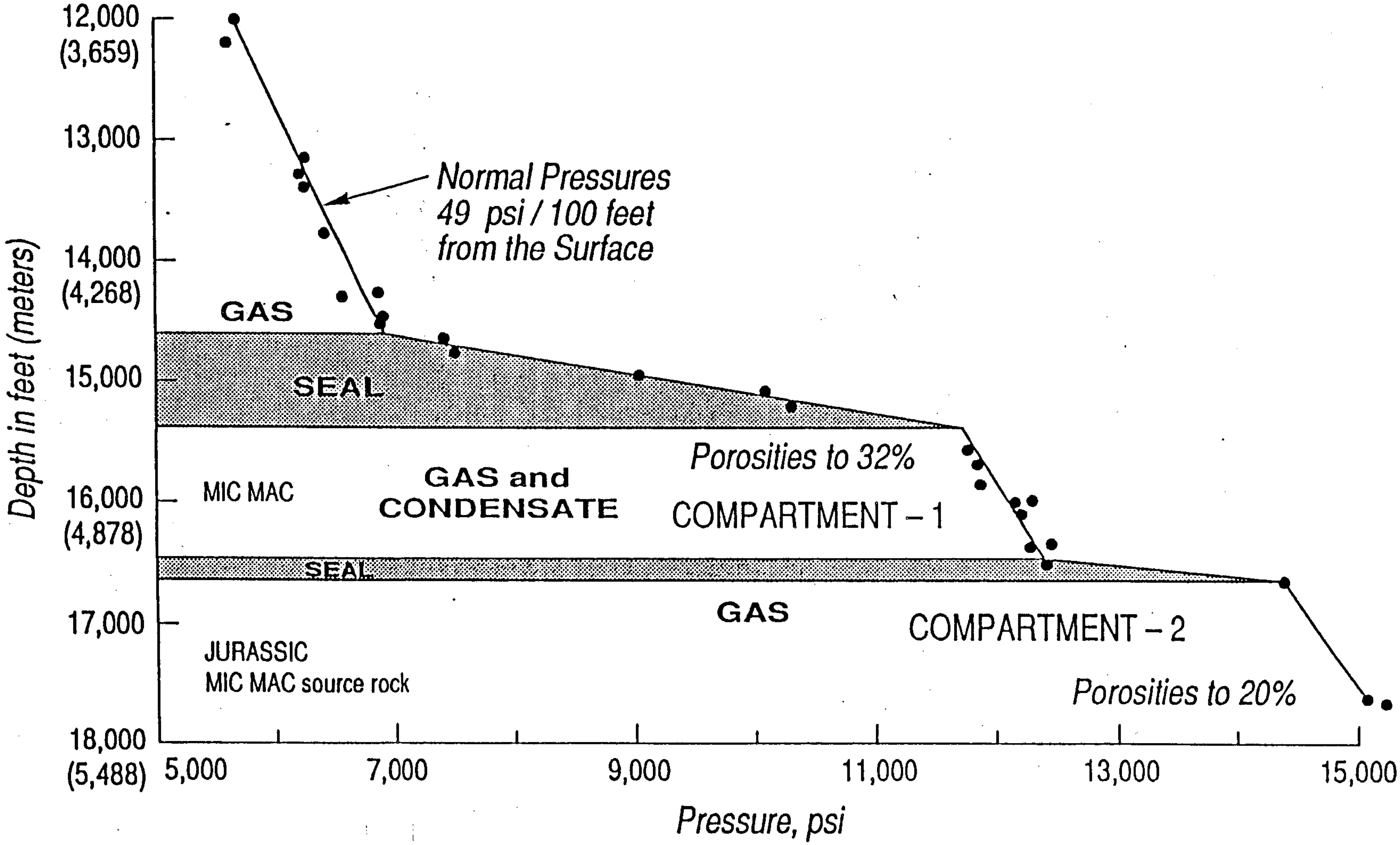


Figure 62. Pressure/depth gradient for Mobil wells B-13, B-43 and D-23 in the Venture gas field, Scotian shelf, Canada (data from G. S. Ward of Ward Hydrodynamics Ltd., Calgary, Alberta).

subnormal pressure. The permeability of tight oil and gas reservoirs is generally too low to permit migration by buoyancy; therefore, migration in these rocks occurs mostly by pressure differential.

6. The ability to predict the onset of abnormally high pressures can assist well operators in anticipating where to set intermediate casing strings and/or prepare for well kicks or blowouts.

7. Finally, the occurrence of abnormally high pressures in Rocky Mountain basins means a) the strata are oil- and/or gas-saturated, b) water should not be a major obstacle to production, c) reservoir energy is present to increase productive capacity, and d) for gas reservoirs, higher pressure means significantly more gas-in-place for a given percent of gas-saturated pore volume (Spencer, 1986).

In the Rocky Mountain Region the largest gas fields occur in abnormally pressured reservoirs. Basins containing overpressured gas accumulations are the result of the rates of thermogenic gas accumulation exceeding the gas loss. This causes the fluid (gas) pressure to rise above the regional hydrostatic pressure. The free water is forced out of the gas generation zone into overlying and updip normally pressured, water-bearing rocks. In the overpressured zone the gas accumulates in the resulting low-permeability (less than 0.1 md) reservoirs at rates higher than the gas is lost. Thus, although hydrocarbon accumulations are commonly sealed by a cap rock such as a shale, evaporite, or some other relatively impervious lithology, in the overpressured Rocky Mountain gas reservoirs the seal is the low porosity and permeability of the geopressured reservoir itself (Law and Dickinson, 1985). See Figures 54-62.

An example given by Law and Dickinson is the Greater Green River Basin. About 32,000 ft of Cambrian through Tertiary sedimentary rocks comprise the basin sequence in Wyoming and Utah. The Upper Cretaceous rocks are commonly overpressured, with the top of overpressure at 8,000 to 12,000 ft. Gradients exceed 0.9 psi/ft. The cause of abnormally high formation pressures has been attributed by many authors to the generation of gas from coal and carbonaceous source rocks interbedded with low-permeability reservoir rocks. The overpressured rocks are always gas bearing. In the northern part of the Green River Basin the Upper Cretaceous siliciclastic part of the overpressured rock sequence is about 10,000 ft thick, consisting of heterogeneous lithologies of fluvial-dominated environments. In the overpressured gas accumulation of Stage III, gas that is lost from the system is replaced by more gas, and water is unable to enter because of high pore pressure. In Stage IV pore pressures and capillary pressures are reduced permitting allowing water to enter the gas-bearing zone. Law and Dickinson interpret the underpressured basins as the later result of an earlier overpressured phase. Erosional unloading is cited as the mechanism for the development of the underpressure following an overpressure phase. In an example case, 60% of the gas must be lost from the overpressured reservoirs in order to evolve into an underpressured reservoir (Law and Dickinson, 1985).

The overpressured gas accumulations in the Rocky Mountain Basins that represent the largest gas fields in the region are commonly located in a basin-center position and down-dip from water-bearing rocks in low-permeability reservoirs. The conditions necessary for the occurrence are thermal generation of gas and low-permeability rocks, where gas accumulation rates are higher than rates of gas loss (Law and Dickinson, 1985).

In a later paper, Law et al. (1988) determine that the source of the gas in the Greater Green River basin of Wyoming, Colorado, and Utah in the overpressured low-permeability Cretaceous and Tertiary reservoirs is Type II organic matter in the interbedded coal and carbonaceous lithologies, and Types II and III organic matter in the interbedded marine shales. The overpressuring is confirmed to be coincident with the occurrence of gas-bearing reservoirs.

This correlation with depositional environment can be correlated with sea level advances and retreats, and could thus lead to the prediction of where, stratigraphically, overpressured conditions could be expected.

Meissner (1981) discusses the evolution of basinal conditions leading to overpressure and further development and evolution to near normal or underpressure. He attributes the abnormally high pore-fluid pressures to hydrocarbon generation from organic matter (kerogen) contained in "source rocks," and contributing processes such as 1) collapse of rock matrix as overburden-supporting solid kerogen is converted to non-expelled fluid hydrocarbons and 2) volume increases produced by the conversion of kerogen to hydrocarbons. As additional processes contributing to overpressure, Meissner considers volume increases associated with the thermally progressive conversion of oil to wet gas/condensate and to dry gas within the pores of either the source rock or associated isolated hydrocarbon-saturated nonsource rocks. He concludes that the occurrence, maintenance, and degree of fluid overpressuring appear to be dependent on time, temperature, volume of kerogen/hydrocarbons undergoing transformation, and the relative isolation of the rocks with respect to regionally extensive high-permeability rocks.

Overpressure is present as vertically and laterally restricted "cells" or "pods" centering around actively generating source-rock units in basin bottom positions. Hydrocarbons in most places appear to be the overpressuring fluid and the only initially producible fluid species present. Meissner's views appear to be concentrated on the Rocky Mountain basins, although that is not stipulated in his paper.

McPeek (1981) studies the developing giant gas supply from deep, overpressured Upper Cretaceous sandstones in the Eastern Green River Basin. He concludes that the undiscovered resources in the overpressured area are in the 10 to 40 Tcf (trillion cubic ft range).

Porosities in the Greater Green River basin geopressured sandstones range from 3 to 12%. The reservoirs are lenticular nonmarine and marginal marine sandstones. The more important factors related to gas generation and occurrence are source rock (quantity and quality), organic maturation, thermal history, formation pressure, and porosity and permeability variations (Law et al., 1986).

Alaska

Loss of porosity and permeability due to overburden stress, resulting from compaction, may be minimized by the presence of abnormal pore-fluid pressures (geopressures) that offset overburden pressure and reduce net confining stress. The presence of geopressures in the Point Thomson area suggests that such porosity preservation may be the case beneath the Alaska National Wildlife Reserve (ANWR) coastal plain also. In order to better predict the possibility of geopressures and concomitant porosity preservation in the Canning Formation beneath the coastal plain of the ANWR, more information is needed concerning the nature of the overpressuring and its relationship to basin evolution.

The effort to clarify the relationships between thermally controlled clay-mineral diagenesis and organic-matter transformations on the one hand and permeability, porosity, and abnormal fluid pressures on the other in thick, shaly sedimentary sequences represents a significant research frontier.

Studies of the shale-sandstone sequences in the United States Gulf Coast and elsewhere suggest a genetic relationship between thermal maturity for hydrocarbons and illitization of mixed-layer illite/smectite (I/S) clay. In the Gulf Coast, the principal transformation of smectite layers in I/S to illite layers occurs at a temperature of approximately 176 to 212°F (80 to 100°C). There is strong evidence that the illitization reaction is important in the development of geopressures (Kerr and Barrington, 1961; Freed, 1982; Bruce, 1984).

The North Slope basin near the ANWR in the Point Thomson area provides an additional setting in which to test the relationship between geopressures, organic-matter maturation, clay-mineral transformations, and porosity preservation.

Pressures were identified by acoustic logs, mud weights used during drilling, and by the pressure measurements made during formation tests. The point of departure of the acoustic curve from the trend line is generally interpreted as the top of the geopressured interval. Samples were collected from cuttings of Point Thomson wells, from normally pressured rock, the transition zone, and the zone of abnormally high pressures.

The apparent trend of decreasing smectite content with depth is similar to trends observed in the Gulf Coast region. The coincidence of the smectite decrease with the top of the geopressure zone is similar to trends observed in Texas and Louisiana.

The results of this study suggest that thermal maturation of organic matter sufficient for the onset of oil generation, mineralogical changes in I/S, and the development of overpressuring are coincident. Such coincidence suggests a genetic relationship and implies that overpressuring is to be expected in similar burial settings beneath the coastal plain of the ANWR. This, in turn, may provide some basis for optimism regarding porosity preservation in litharenite turbidities of the Canning Formation.

Canada

Formation waters of the Alberta Plains are inventoried in a report by Loveseth and Pfeffer for the Renewable Energy Branch, Energy, Mines and Resources, Canada. Water temperatures, salinities, depths, and the reservoir capacities of the enclosing rocks are included.

Temperature gradients (degrees Celsius per kilometer) range from over 45 to less than 10 and average about 30. Many excellent aquifers are present. The dissolved solids are usually 100,000 ppm or greater.

Global Occurrence

Bradley and Powley (1991, personal communication) catalogue pressure compartments on all continents except Antarctica. Hunt (1991 a and b) and Fertl (1976) also note a global recognition of overpressured sedimentary basins.

Carstens and Dypvik (1981) correlate abnormal formation pressure and shale porosity in an abnormally pressured Jurassic shale from the North Sea Viking graben. The fluid pressure-overburden ratio is 0.8 at 4,000 m and is associated with low porosity and high density. The authors describe the fluid pressure history in three stages.

Hunt (1990) observes that over half of the world's explored deep basins appear to have pressure compartments. Abnormal pressures have been identified in about 180 basins to date; some are listed in Table 25, and the extent of the world's geothermal regions can be seen in Figure 63.

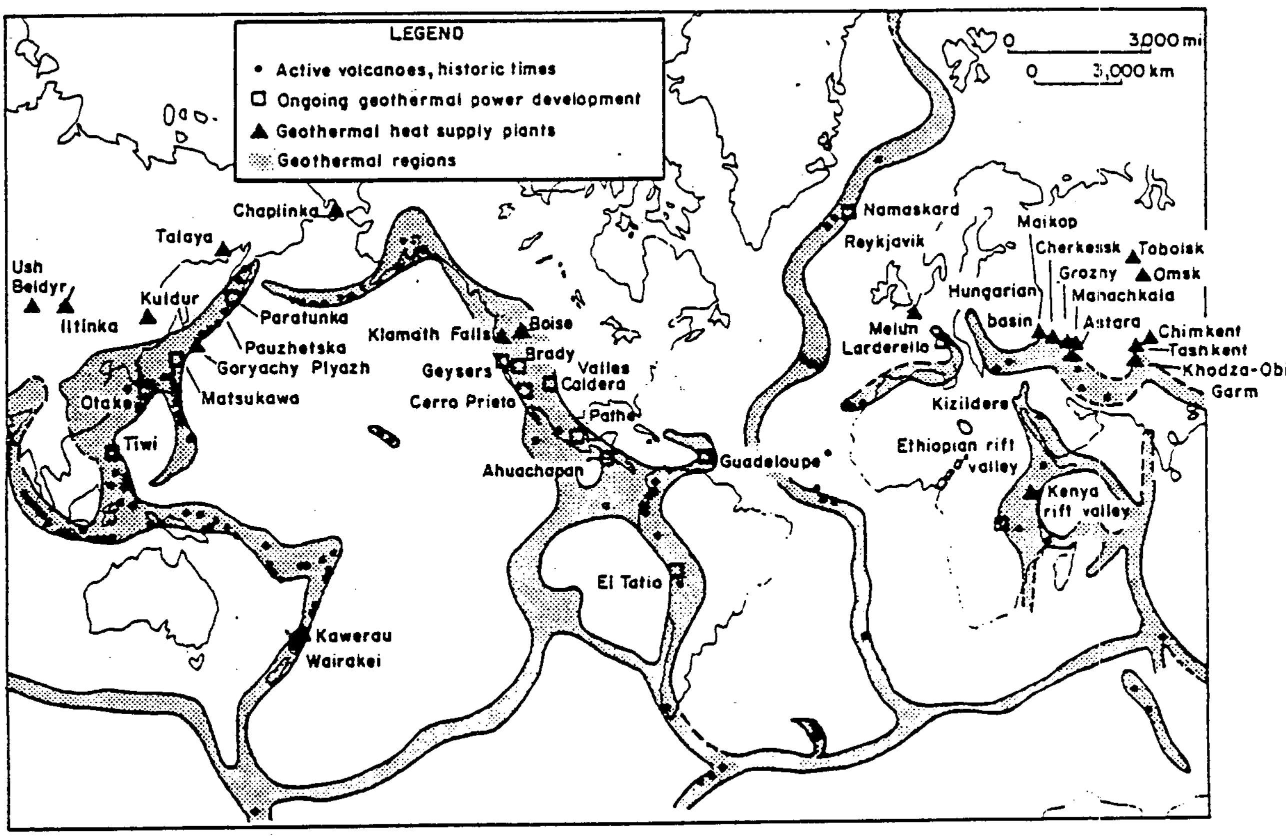


Figure 63. Geothermal regions of the world (Knapp and Isokrari, 1976).

Table 25. Some basins with abnormal pressure compartments in part of the basin.

Deltas
MacKenzie, Canada
Mahakam, Indonesia
Mississippi, United States
Niger, Africa
Nile, Egypt
Po, Italy
North American and South American Basins
Anadarko, United States
Columbus, Trinidad
Cook Inlet, United States
Gulf of Paria, Venezuela
Jeanne D'Arc, Canada
Lower Magdalena, Columbia
Mississippi Salt, United States
North Ardmore, United States
North Slope of Alaska, United States
Pacific Northwest, United States
Powder River, United States
Scotian, Canada
Southern Sacramento, United States
Texas and Louisiana Gulf Coast, United States
Uinta, United States
Williston, United States
Wind River, United States

Table 25. Some basins with abnormal pressure compartments in part of the basin (Continued).

African Basins
Gabon
Offshore Sinai, Egypt
Sirte, Libya
European Basins
Lower Saxony Trough, Germany
Molasse, Germany and Austria
North Sea
Pannonian, Hungary
Polish Trough
Pre-Caspian, USSR
South Aquitaine, France
South Caspian, USSR
Takzhik, Afghanistan
Transylvanian, Romania
Vienna, Austria
Western Siberian, USSR
Zechstein, Germany and Poland
Middle Eastern and Asian/Pacific Basins
Bengal, Bangladesh
Burma, Burma
Cambay, India
Dampier Sub-basin, Australia
Gulf of Bahai, China
Hsinchu, Taiwan
Mesopotamian, Iraq
Nepal, India

Table 25. Some basins with abnormal pressure compartments in part of the basin (Continued).

North Iran Jaya, Indonesia
Northland, New Zealand
North Sumatra, Sumatra
Northwest Shelf, Australia
Potwar, Pakistan
Sarawak (offshore)
South China Sea
South Papau Coastal, New Guinea
Tertiary Reefs, offshore Sumatra

(Hunt, 1990)

China

In a prepublication manuscript Zhang Quanxing (1991, personal communication) describes the Yacheng Gas Field in the South China Sea. The characteristics of the Yinggehai Basin are rapid subsidence, high temperature, high pressure and well developed mud diapirs. The source rock of Neogene age consists of 5,000 to 8,000 m of rich organic neritic-to-bathyl mudstones.

Oil and gas seepages along the coast of Yinggehai Village have been noticed for more than 100 years. As many as 32 seepages were located by the survey recently. The Ledong 30-1 turbidite sandbody in Ying-Huang Formations is located in the southeastern part of the Yinggehai Basin, and is the biggest reservoir sandstone found in the area - 468 km^2. The sandstone porosity is 17 to 23% with a permeability of 5 to 20 x 10^{-3} μm^2 based on the wireline log interpretation and conventional core analysis. Overpressure was encountered below a depth of 3,000 m with a pressure gradient of 18 to 22 kpa/m. The average thermal gradient of Ledong 30-1A well is 4.56°C/ 100 m, which is the highest in this area. High temperature and pressure drives hydrocarbons and fluids from the deep to the shallow and from the west to the east, through the Fault No. 1 and into the Yacheng structure where they form the gas reservoir. This is an example of aqueous migration of hydrocarbons as described by Light et al. (1987).

The authors make the following conclusions: The characteristic features of thick Neogene marine source rock in the Ying-Qiong Basins are: a) high percentage of mudstone lithologically dominated by terrestrial organic matter with submicroscopic resinites, and b) high hydrocarbon yield of about 50 - 120 mg/g. The geological setting of rapid thermal subsidence and deposition and high temperature and pressure created a special environment for mechanisms of generation, migration, and accumulation of hydrocarbons and resulted in hydrocarbon distribution dominated by a gas reservoir. As a result, the geopressure exists in the center of the Yacheng Gas Field.

The Yacheng Gas Field is known as an unusual geological case in that its condensate is the heaviest (34.39° API) and the most aromatic (49.8%) of the condensates in China, and its gas is the most aromatic of the natural gases there. Besides, the temperature of 304°F (151°C) at the top of the oil window of the field is the highest of China's basins. A fluid overpressure occurs below 4,748 m in the Ledong Well (Zhang Quanxing and Zhang Oiming, 1990 Geochemical Characterization of Petroleum Migration of Yacheng Gas Field, Offshore South China, Pergamon Press, printed in Great Britain, pp. 189-194, received by personal communication, 1991).

Ocean - Deep-Sea Vents

Deep-sea hydrothermal vents have been discovered at a number of places (Simoneit, 1989, personal communication). About 15 to 30% of the earth's released internal heat is lost through such vents (McClain and Schiffman, 1989). The National Science Foundation sponsors work on one such deep sea area, located along the Juan de Fuca Ridge, 200 miles off the coasts of Washington and British Columbia. Vents were found at depths of about 7,000 ft, with temperatures at about 752°F (400°C).

Another study, sponsored by the States of California and Oregon and the Minerals Management Service, was conducted along the Gorda Ridge, off the California and Oregon coasts. Here, vents were found at depths of about 9,000 ft, emitting water of about 500°F (260°C) temperature. Dissolved sulfides precipitate out of the hydrothermal waters, giving an appearance of dark smoke. The smoke is black in the Juan de Fuca Ridge area and gray in the Gorda Ridge area.

Simoneit video-recorded emissions of globular hydrocarbon masses from the vents while working with the Alvin sea probe. Samples were brought to the surface and were found to be petroleum. The material fluoresced at the depths of the vents. These characteristics suggest that the vents are associated with geopressured-geothermal conditions and hydrocarbon generation.

Paleo-overpressure

Law and Nuccio (1986) identify at least three linear segments in the mean vitrinite reflectance profile of a well in the southern Piceance Creek Basin, Colorado, showing evidence of previous high pore pressure. They interpret the data, in the framework of the work by Law and Dickinson (1985), to suggest that during the overpressured phase, the expulsion of relatively hot pore fluids from the top of abnormally high-pressured rocks into the overlying normal-pressured rocks raised the levels of organic maturation and steepened the vitrinite reflectance profile in the normal-pressured rocks. The bend in the profile at a vitrinite reflectance of about 0.80% represents the top of the earlier overpressured phase. Vitrinite reflectance values of this magnitude are commonly associated with the top of overpressuring in the adjacent Greater Green River basin of Wyoming, Colorado, and Utah.

IDENTIFICATION AND ASSESSMENT

Wallace, Taylor, and Wesselman (1977) examine the potential of using hydrogeologic mapping techniques for identifying geopressured-geothermal reservoirs in the Lower Rio Grande Embayment, Texas. Techniques used were based primarily on data obtained from electrical logs. Pressure, temperature, and salinity maps reflect variations in physical and chemical characteristics of subsurface fluids, mainly water, with depth. Interpretations based on this knowledge provide valuable insight into hydrologic, hydrodynamic, and hydrochemical processes occurring within the geologic framework of deep, young, sedimentary basins. The geologic framework, especially formation geometry, determines avenues and rates of fluid movement. Gross lithologic changes appear as broad upwarps or downwarps of the pressure, temperature, and salinity surfaces. Localized highs and lows on these surfaces near fault traces usually represent upward discharge of compaction effluents from greater depths along faults.

Exploration for overpressured reservoirs should concentrate in those areas and drilling depths having rich source beds, and temperatures of 200 to 220°F (93 to 104°C) or higher in Tertiary and Mesozoic rock and possibly slightly lower temperatures in Paleozoic rocks. The optimum areas will be those with a mixture of source beds, reservoirs, vertical seals, and natural fracture intersections. Very heavily fractured or faulted areas may have lost pressure and hydrocarbons The optimum depths for exploration in thick, overpressured successions are generally the top 1,000-2,000 ft of the overpressured succession because, in spite of overpressuring, there is a general trend of decreasing reservoir porosity and permeability with depth. Therefore, the shallow part of overpressured intervals generally should have better reservoir quality. A cursory review of worldwide pressure data suggests that, where regional overpressuring occurs, it is most common in rocks with temperatures higher than 200°F (93°C) (Spencer, 1986).

Bebout (1976) addresses subsurface techniques for locating and evaluating geopressured geothermal reservoirs along the Texas Gulf Coast and proposes semiquantitative criteria for reservoir conditions. "A potential geothermal reservoir along the Texas Gulf Coast should have a volume of at least 3 cubic miles (which translates into a cumulative sand thickness of greater than 300 ft and a real extent of 50 square miles), greater than 250°F (121°C) uncorrected subsurface fluid temperature, and permeability greater than 20 millidarcies." Based on analyses from actual water samples and interpretation from log analysis, deep-subsurface fluids are expected to have salinities lower than 20,000 ppm and perhaps as low as 5,000 ppm (Jones, 1975). Most well reports indicate that the water will be saturated with methane gas. A TDS as low as 3,200 ppm was measured at the Idaho National Engineering Laboratory on Upper Wilcox Formation fluids from the Rio Grande Embayment area.

Detection of overpressured low-permeability rocks is difficult (Law et al., 1986). The main criteria used are drilling mud weights and/or drill-stem tests. Temperature gradients, vitrinite reflectance (thermal maturity indicators), and gas accumulation can be used to interpret pressure gradients. The coincidence of a significant increase in the volume of gas (indicated by gas shows in mud log data) with the top of overpressure has been noted in numerous wells. The coincidence of reversed spontaneous potential (SP) curves and overpressuring was observed by Law et al. (1980). This has been shown to be a common occurrence in the Greater Green River Basin. The cause is suggested to be the freshening of formation waters caused by dewatering of organic matter and clay. The relationships of organic richness, organic maturation, subsurface temperature, and pressure gradient variations were observed in a cross section through the Wagon Wheel well to the Pacific Creek area (Law et al., 1986). Petrographic, diagenetic, and lithofacies studies can also be instrumental in predicting potential areas of deep subsurface secondary reservoir development (Jansa and Urrea, 1990).

Law et al. (1986) conclude that kinky vitrinite reflectance profiles are most likely due to perturbations of the thermal gradient caused by contrasting heat transfer processes associated with the development of abnormally high pressures. They interpret the intersection of the shallow and intermediate R sub m segments to mark the approximate original boundary between normal-pressured, water-bearing rocks and underlying overpressured gas- and water-bearing rocks and underlying overpressured gas-bearing rocks. However, the authors point out that because overpressuring is a transient condition that eventually evolves into normal pressuring or underpressuring, these intersections may not coincide with the present top of abnormal pressuring. Segmented vitrinite reflectance profiles occur in several Rocky Mountain basins of the United States and Canada.

Table 26 (Bebout, 1976) presents a general approach to location of geopressured-geothermal reservoirs by means of subsurface techniques and available data from applicable sources. Figures 65-70 illustrate some of the correlations and implications of these data.

Table 26. Subsurface techniques for locating geopressured-geothermal reservoirs.

Activity	Application of Data
Regional Statewide Survey	
Locate regional geothermal corridors	Regional electrical-log cross sections of the entire Tertiary section constructed using deepest penetrating wells aid in locating broad areas in which sands are expected to occur in the geopressured zone.
Regional Study of Specific Formation	
Well log-acquisition	Electrical logs are primary data source. Well spacing of 5-10 miles between wells is adequate for regional study.
Cross Correlation	
Correlation on formation cross section	The correlation fabric is established largely on micropaleontology and knowledge concerning location of major growth faults. Then well-log pattern correlation is used locally, aided by knowledge of sediment distribution of various depositional environments. Regional seismic lines aid at this stage.
Map construction	Sand-percent and net sand maps constructed from correlation units on formation cross sections.
	Isothermal maps from bottom-hole temperatures recorded on well-log headings.
	Top of geopressure calculated from well-log data.
	Based on the combination of sand, isothermal, and top-of-geopressure maps.
Geothermal fairway	
Fairway Study	
Detailed fairway studies	Detailed mapping of the reservoir interval using electrical logs from closely spaced wells. Incorporation or porosity-permeability data into the geologic model.
Site Selection	
Selection of geothermal well site	With a grid of dip and strike seismic sections correlate major events across prospective areas in order to understand structural configuration. With detailed velocity studies tie lithology for electrical-log sections into seismic sections.
	Using porosity-permeability, reservoir configuration, subsurface pressure and temperature, apply site-specific reservoir data to the reservoir-simulation model in order to estimate potential production capability.

(Bebout, 1976)

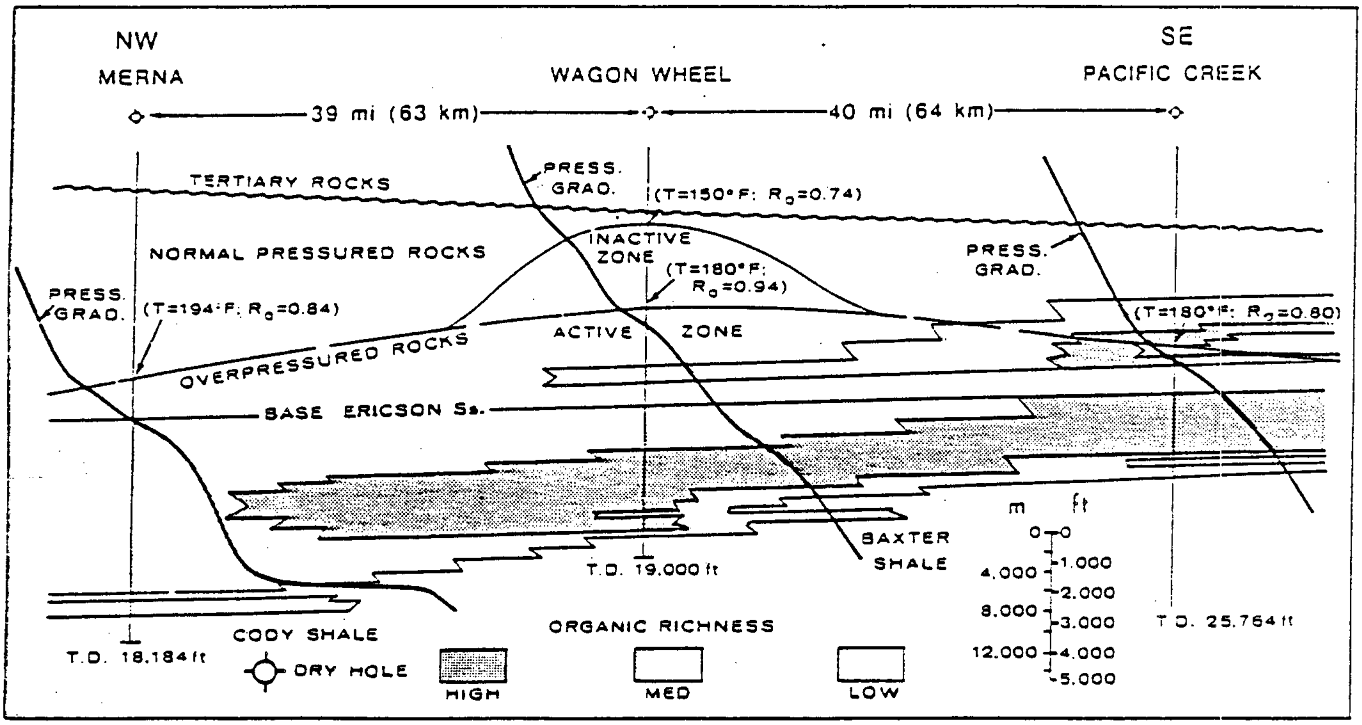


Figure 64. Stratigraphic cross section from Merna to Pacific Creek showing relationships among pressure gradients, organic richness, vitrinite values, and uncorrected temperature at top of overpressured rocks (after Law, 1984a). Pacific Creek pressure gradient has been modified with additional well data, but top of overpressure is still interpreted to occur at 11,600 ft (3,500 m) (Spencer, 1986).

CANADA

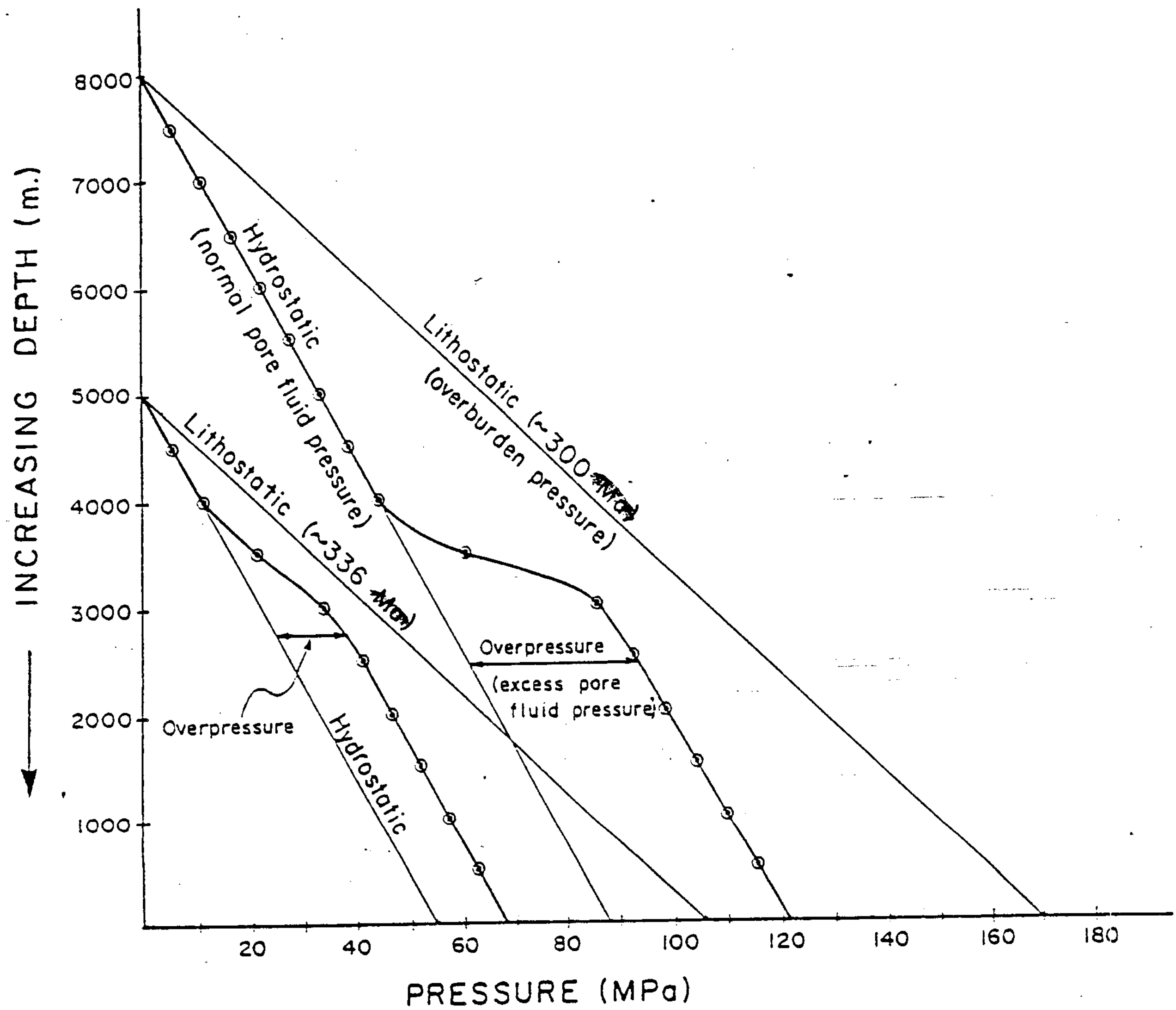


Figure 65. Pore fluid pressure and overburden pressure as a function of depth at two different times in the southern Magdalen Basin. For a given hydraulic conductivity distribution and sediment loading rate the excess pore fluid pressures shown are mathematically generated under the evaporite seal (Ravenhurst and Zentilli, 1987).

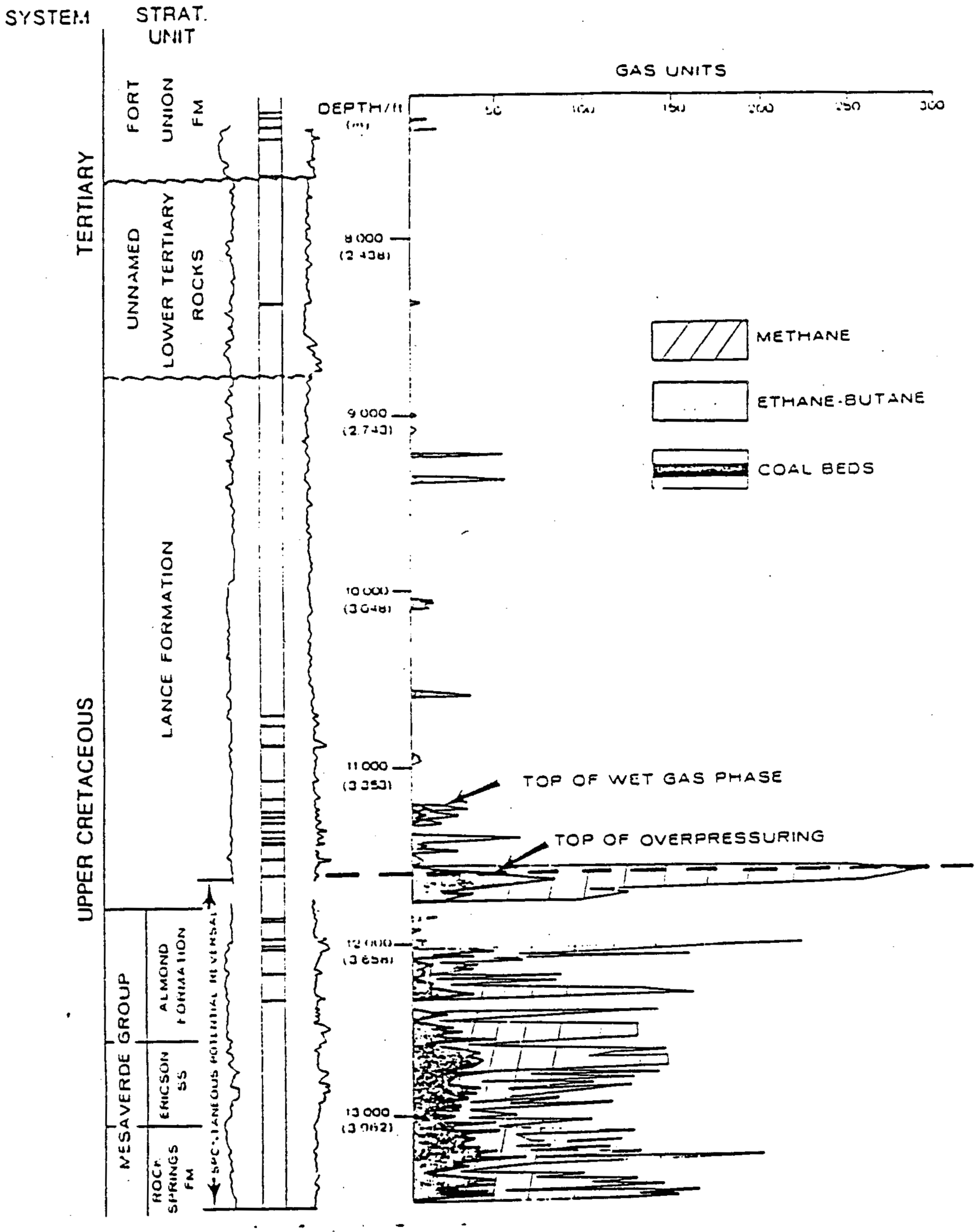


Figure 66 Electric log and gas mud log from the Terra Resources, et al. #1 Fed. well showing relationships of wet gas phase, overpressuring, and spontaneous potential reversal. Note large number of coals in or near top of wet gas phase (Law et al., 1980).

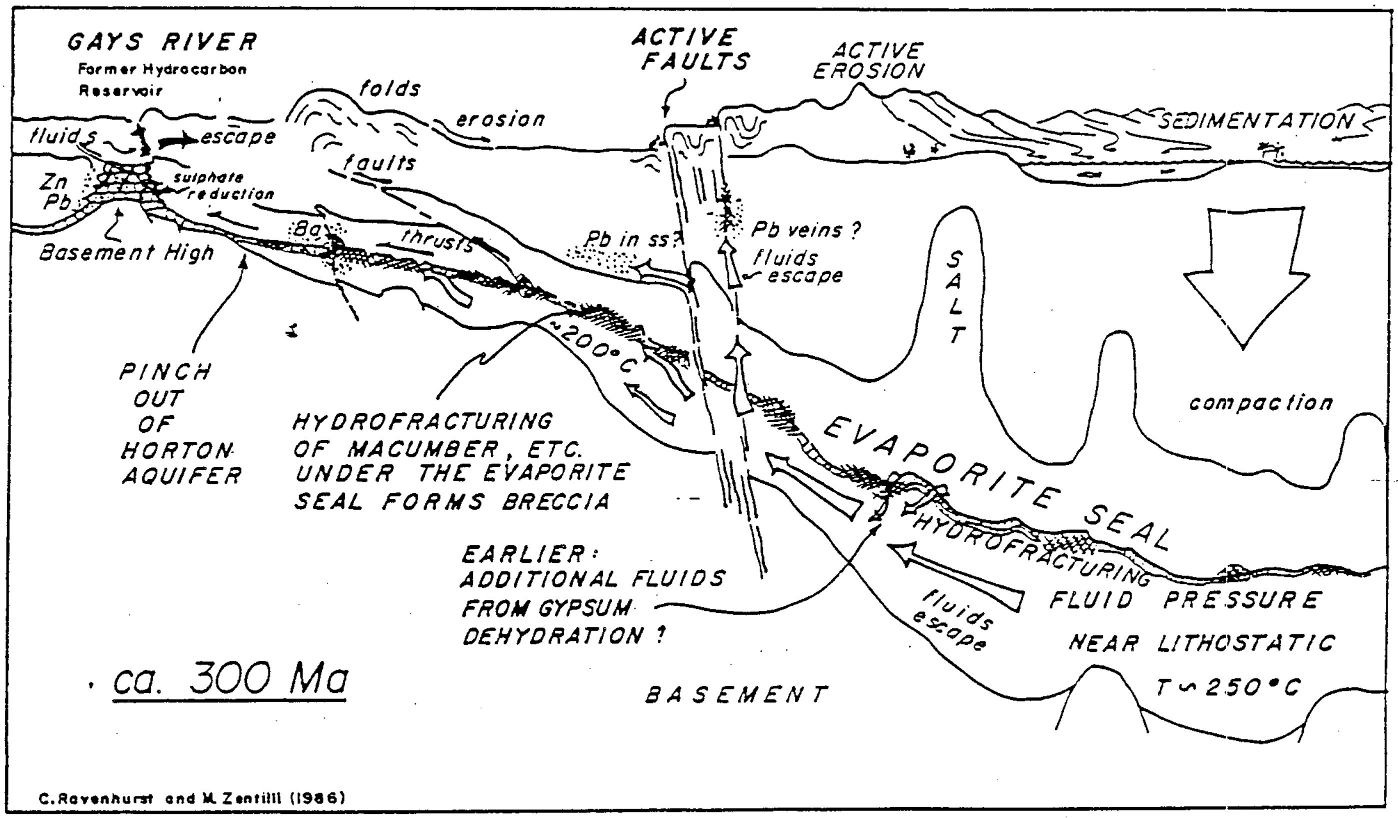


Figure 67. The conceptual mode. Overpressured fluids escape from deep in the southern part of the Magdalen Basin by a hydrofracturing mechanism. These hot, rapidly moving brines cause extensive brecciation and dissolution near the top of the aquifer-the Pembroke Breccia-under the evaporite seal. Deposits of Pb-Zn-Ba are formed at reducing sites at the margins of the basin by the hot mineralizing brines (Ravenhurst and Zentilli, 1987).

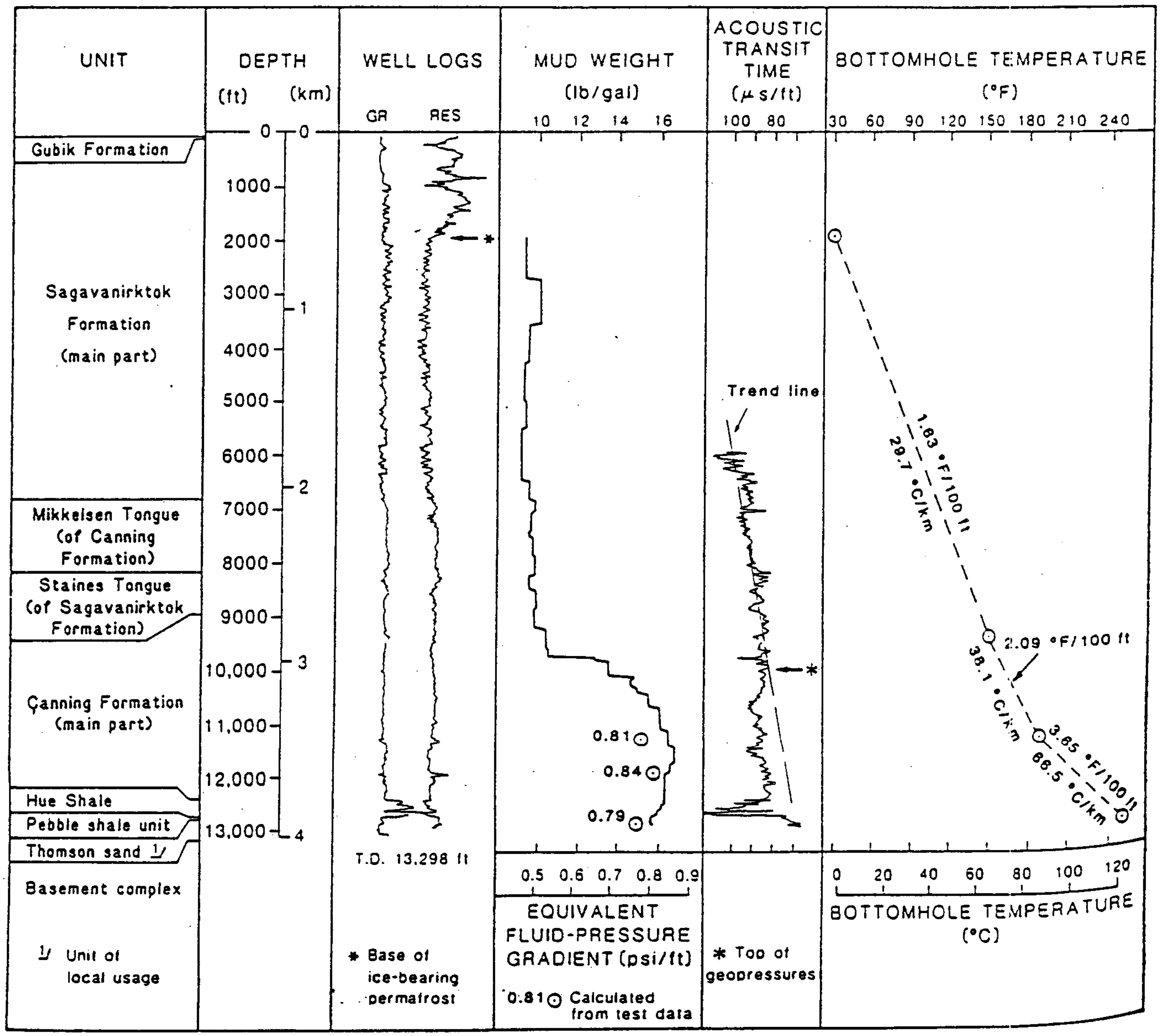


Figure 68. Gamma-ray (GR) and resistivity (RES) logs, mud weights used during drilling, acoustic transmit time, and corrected bottomhole temperatures of Point Thomason Unit-1 Well. T.D., total depth (Gautier et al., 1986)

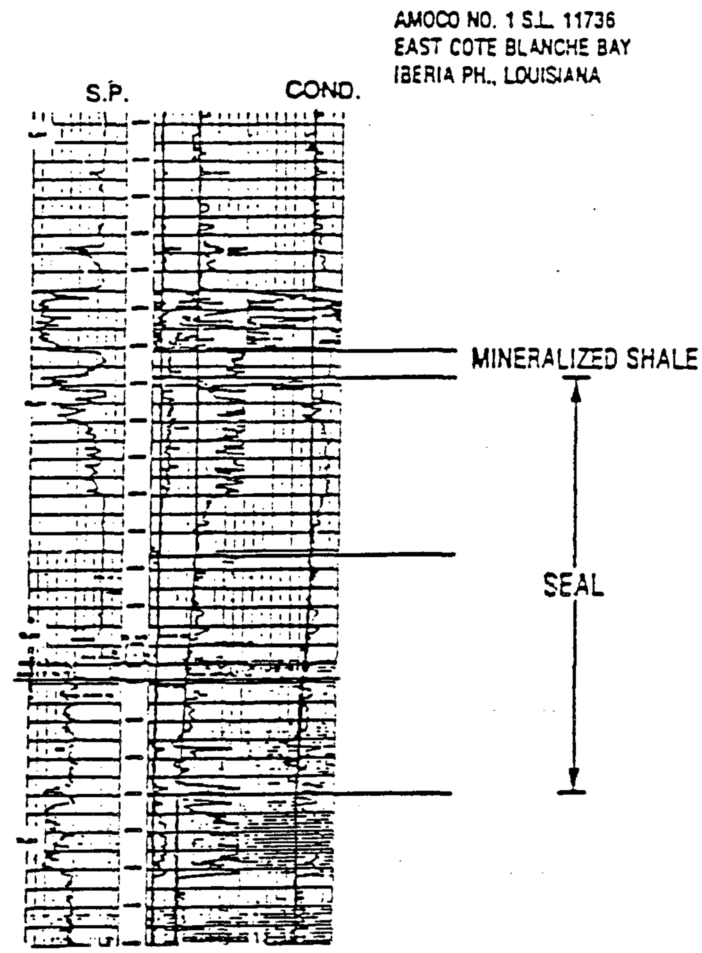


Figure 69. Typical electrical well log across a seal in the Gulf Coast basin.

Johnson and Nuccio (1986) use mud weights and pressure gradients from drill-stem tests in the Piceance Creek Basin to define possible overpressured zones. Overpressuring apparently occurs sporadically in rocks with present-day temperatures in excess of 200 to 250°F (93 to 121°C). A well defined geopressured zone similar to the one in the central part of the Uinta Basin is yet to be found in the Piceance Creek Basin.

Eight of nine Rocky Mountain area oil and gas fields surveyed by shallow geothermic methods show hot spots or positive shallow temperature anomalies at depths ranging from 500 ft to as shallow as 10 ft. The magnitudes of these anomalies generally range from 1 to 3°F, but in one case reached 16°F degrees at 500 ft. Similar shallow thermal anomalies associated with oil or gas fields are reported in Russian and other literature.

The primary cause of the observed temperature anomalies at and above oil and gas fields is unknown, but the writers believe that lateral and upward fluid movements through subsurface rocks are an important contributing factor.

Price et al. (1981) estimates abnormal fluid pressures from a dog-leg in the geothermal gradient and retardation of normal compaction in the Chevron R. G. Jacobs No. 1 Well in south Texas Goliad County. The porosity decreased from 43% at 68 m to about 20% at about 3,500 m. From 3,500 to 5,820 m the porosity remained roughly constant at around 20%. Deeper than 5,820 m porosity decreased with scatter to 5-10% at total depth of 7,546.8 m. The organic-geothemical data of this well are considered by Price et al. as the most significant for all the ultra-deep wells examined in their laboratories. For a framework of the conclusions, Table 27 shows relationships to temperature documented by numerous authors.

Table 27. Relationships of process to temperature.

Main phase hydrocarbon generation	60 - 120°C
Thermal destruction of organic matter	150 - 250°C
Heavy hydrocarbons are thermodynamically unstable and over geologic time graphite will form and the only stable hydrocarbon present will be methane.	over 200°C
Greenschist metamorphism occurs by R sub 0- values of 4.0, a point at which no hydrocarbon other than methane is stable	200 - 250°C

(Price et al., 1981)

However, Price et al. find that, in the well studied, kerogens with significant generating potential, high contents of C15+ extractable bitumen (up to 220 ppm) and high values of extractable bitumens normalized to organic carbon values (up to 367 ppm) are found in Lower Cretaceous rocks at present-day temperatures of 504 to 565°F (262 to 296°C). These temperatures are thought, by most petroleum geochemists, to be characteristic of greenschist metamorphism. The organic-rich zone of this well, as with others, is associated with high vitrinite values and low atomic H/C values, both of which are also attributed to greenschist metamorphism. The results conflict with concepts of hydrocarbon generation-maturation via carbon-carbon bond breakage. Price et al. expresses the opinion that the noted zones of intense hydrocarbon generation are due to breakage of much weaker bonds such as ketone, ester, ether, sulfide, disulfide, or other "N-S-O" bonds. Additionally, the zones could be due in part to destruction of the molecular hydrocarbon sieve properties of kerogen. Price et al. conclude that conventional concepts of the distribution of heavy hydrocarbons with increasing temperature and depth apparently require further review and revision.

Bradley and Powley note that numerous chemical parameters may imply or confirm compartmentalization, besides measured or inferred pore-fluid pressures. Major ion and isotope water chemistry may vary from compartment to compartment. Hydrocarbon chemistry may show variations. Mineralogy may reflect the variations in water chemistry. The chemistry of fluids in fluid inclusions has been shown to differ between compartments. The most direct indication Bradley and Powley conclude "is pore-fluid pressure measurements from drill stem tests (DST), repeat formation tests (RFT), and initial production tests (IP), all of which give a form of bottomhole final shut-in pressure (FSIP). Mud kicks and lost circulation will also indicate formation pressure when the formation depth and mud density are known. Less direct is the shale resistivity, which shows a reduction with an increase in pore pressure. The top of the resistivity break was found to be at a pressure gradient of 0.61 psi/ft and the bottom is assumed to be the bottom of the seal. The thermal gradient at about 0.75 psi/ft is similarly used as an indication of overpressures (Bradley and Powley, 1991, personal communication).

Sonic velocity logs may indicate overpressured compartments due to the reduced effective stress on the rock as the pore pressure increases or due to a lower density shale (Bradley and Powley, 1991, personal communication). Reflection seismology maps the top of overpressures as a low velocity interface. A seal is characterized by extremely low permeabilities, which imply low porosities and high bulk densities, and therefore should be seen on resistivity, sonic, and density logs. Thick seals are more difficult to see on logs. Micrologs (resistivity) or microsonic logs taken through the "transition" between normal and abnormal pressures can pinpoint the seal or seals. Thick dense (high velocity) top seals could possibly be mapped with high-frequency reflection seismology. The high frequency seismic is limited to relatively shallow targets because of the relationship between frequency, wave length (resolution), and depth (attenuation). A seal may be indirectly implied by a sudden decrease in drilling rate caused by the high-density, low-porosity seal lithology (Bradley and Powley, 1991, personal communication).

Hunt (1991 a and b) states that making a large number of accurate pressure measurements (using the Repeat Formation Tester (RFT) developed by Schlumberger) with depth in a single well, and plotting such data from several wells in overpressured rocks, gives a clearer picture of the position of the seals and the dimensions of the compartments. Hunt identifies the formation character and fixation of the compartment seals as a much needed research area.