CONSOLIDATION OF GEOLOGIC STUDIES OF GEOPRESSURED-GEOTHERMAL RESOURCES IN TEXAS: COLOCATION OF HEAVY-OIL AND GEOTHERMAL RESOURCES IN SOUTH TEXAS

1991 Annual Report

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Prepared for the U.S. Department of Energy
Advanced Technologies Division
under Cooperative Agreement No. DE-FC07-85NV10412

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February 1992

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ABSTRACT

In a five-county area of South Texas, geopressured-geothermal reservoirs in the Eocene Wilcox Group occur below heavy-oil reservoirs in the Eocene Jackson Group. This colocation warrants consideration of the use of geothermal fluids for a thermally enhanced waterflood. Geothermal fairways comprise thick deltaic sandstones within growth-fault-bounded compartments containing geopressured water in excess of 250°F. Geothermal reservoirs occur at depths of 11,000 to 15,000 ft in continuous sandstones 100 to 200 ft thick. Permeability ranges from 1 to 150 md, and porosity from 12 to 24 percent.

Updip pinch-out of shallowly buried (200 to 2,000 ft) barrier-bar/strandplain sandstones largely controls the distribution of heavy-oil reservoirs. Subtle structure, small faults, and sand-body pinch-outs form lateral barriers of the reservoirs. Structural, depositional, and diagenetic variations affect reservoir compartmentalization. The heavy-oil reservoirs are typically porous (25 to 35 percent), permeable (100 to 1,000 md), slightly clayey fine to medium sand. Calcite-cemented zones of low porosity (>5 percent) and permeability (0.01 md) compartmentalize reservoirs.

Injection of hot (300°F), moderately fresh to saline brines will improve oil recovery by lowering viscosity and decreasing residual oil saturation. Matrix clays are smectites, which could swell and clog pore throats if injected waters were fresh. The high temperature of injected fluids will collapse some of the interlayer clays, thus increasing porosity and permeability. Reservoir heterogeneity resulting from facies variation and diagenesis must be considered when siting production and injection wells within the heavy-oil reservoir. The suitability of abandoned gas wells as geothermal production wells and their long-term well productivity also affect the economics of geothermally enhanced hot-water flooding.

Keywords: geopressured-geothermal reservoirs, heavy-oil reservoirs, hot-water flood, Jackson Group, Mirando trend, South Texas, thermally enhanced oil recovery, Wilcox Group

INTRODUCTION

In the State of Texas, geothermal resources are largely untapped despite their wide distribution. Three regions in the State that contain geothermal resources include the (1) geopressured-geothermal zone along the Texas Gulf Coast, (2) rift-associated hydrothermal area of the Trans-Pecos, and (3) fault-associated hydrothermal area of Central Texas (fig. 1). Geothermal resources could provide an auxiliary source of energy for diverse applications, and at some localities, a possible supply of potable water. Low-temperature hydrothermal resources associated with the Balcones and Mexia-Talco Fault Zones have experienced the most, albeit limited, development in Texas (Woodruff, 1982). Geopressured-geothermal resources along the Texas Gulf Coast have received the most study (Meriwether, 1977; Bebout and Bachman, 1981; Dorfman and Morton, 1985; Negus-de Wys, 1990, 1991) because they possess the highest temperatures and have associated chemical and kinetic energy. In the 1970's, preliminary optimistic estimates indicated that vast energy resources were associated with the geopressured-geothermal fluids that might be suitable for generation of electricity and production of natural gas (Jones, 1976; Wallace and others, 1979). Subsequent resource estimates, using data gathered from geopressured-geothermal research programs, drastically shrank the resource base (Gregory and others, 1980). The changing price structure of oil and gas resources also had a negative impact on the economics of geothermal resource utilization (Wrighton, 1981). Without price or tax incentives, generation of electricity through production of geopressured-geothermal energy is unlikely to be economic, given the current price for competitive energy sources such as oil and gas.

Texas geothermal waters range in temperature from <100° to >350°F but are not hot enough for direct generation of electricity utilizing steam-driven turbines. Texas geothermal resources may be suitable for binary cycle conversion in which the geothermal fluids vaporize a working fluid (freon, isobutane, isopentane) that would then drive a turbine generator. The technology for commercial use of moderate temperature geothermal fluids for generation of

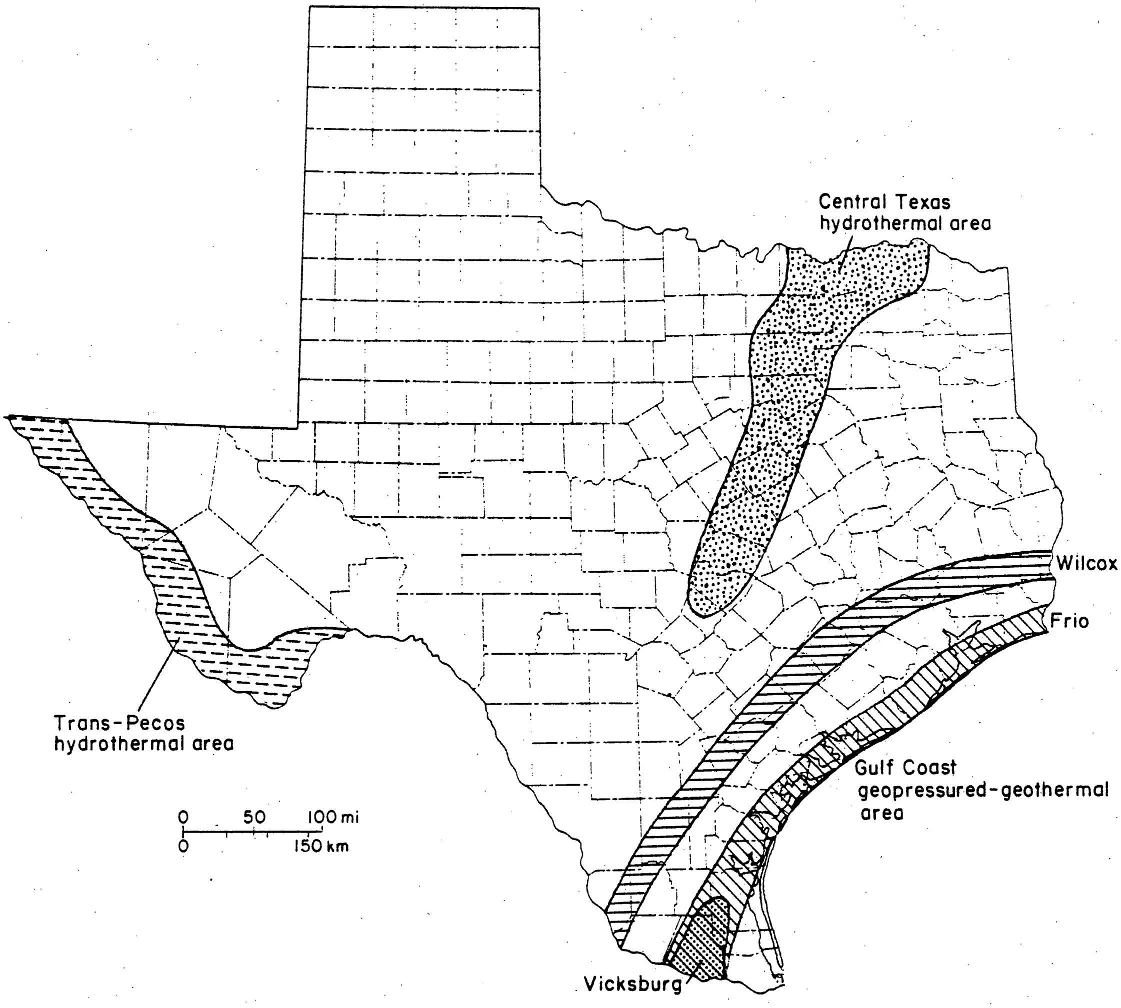


Figure 1. Map of areas containing geothermal resources in Texas and geopressured-geothermal corridors along the Texas Gulf Coast (Bebout and others, 1978, 1982; Gregory and others, 1980; Woodruff and others, 1982).

electricity has been proven both in California and elsewhere and has been successfully tested for a geopressured-geothermal well in Texas. Generation of electricity from geopressured-geothermal resources is complicated by the necessity for utilizing all the multiple components of the resource stream such as thermal energy (hot water), chemical energy (dissolved natural gas), and kinetic energy (hydraulic power), each of which is uneconomic to exploit on its own. A major drawback inhibiting the development of geothermal resources is the large front-end investment needed to exploit a relatively low-value commodity. In Texas, the commercial success of such a procedure is currently hampered by uncertainties in the size and productivity of individual geothermal reservoirs, low prices for natural gas and electricity, higher rate of return from competing resources such as oil and gas production, high costs of geothermal well drilling and completion, high costs of customized plant design and fabrication, and high costs for disposal of spent fluids. Economic considerations dictate that geothermal fluid must be produced very cheaply and in large quantities. The economics are especially sensitive to the flow rate and productive life of individual wells which are best determined on the basis of long-term flow tests. Unfortunately, a large number of variables can affect well productivity, and the flow rates and reservoir performance must be determined for each well individually. However, direct use of geopressured-geothermal fluids may have a higher probability of near-term utilization by employing a variety of applications with varying temperature requirements (Lunis and others, 1991).

Direct Use of Geothermal Resources

Direct uses include space heating or other industrial processes that require moderate temperatures, such as agriculture, aquaculture, or thermally enhanced oil recovery (TEOR). Enhanced recovery of heavy oil by injecting geopressured-geothermal fluids for hot-water flooding is one type of direct use with particularly attractive economic factors. Because of the difficulty of conserving the geothermal heat energy during long-distance transport (Hannah, 1975), geothermal and heavy-oil resources must be located in physical proximity. In the Gulf Coast region, geothermal and heavy-oil resources are colocated in South Texas where a geothermal fairway in the Eocene Wilcox Group occurs 2 to 3 mi below an overlying shallow Mirando heavy-oil trend. Geothermal fluids produced from the deeply buried Tertiary geopressured-geothermal reservoirs could be injected in shallow oil reservoirs to supply both the heat energy and fluid for enhanced oil recovery by steam or hot-water flooding (fig. 2). Although the incremental gain in production resulting from injection of hot water is substantial when compared to that gained from injection of cold water in a typical waterflood, such improvements are significantly less than those gained from injection of steam (Burger and others, 1985). A TEOR process would result in energy savings and resource conservation by maximizing the efficiency of oil recovery and by eliminating the standard practice of heating the injection fluids through combustion of hydrocarbons. Where steam injection is impractical or uneconomic, injection of geothermally heated water may offer an economically attractive alternative. Negus-de Wys and others (1991) suggest that TEOR geopressured-geothermal fluids could be economically viable in South Texas on the basis of colocation of geothermal resources below heavy-oil reservoirs, the size of the heavy-oil and geothermal resources, and optimistic assumptions on well productivity, price structure, and dissolved gas content.

Objectives

This report characterizes geothermal resources and heavy-oil reservoirs where colocated in South Texas and investigates the feasibility of using geothermal brines for thermally enhanced recovery of heavy oil. The report is organized in three sections. The first section provides background information on types of geothermal resources and reviews geologic and engineering characteristics of the geopressured-geothermal resources in Texas. The second section examines use of geothermal fluids for thermally enhanced waterflood. The third section characterizes the colocation of heavy-oil reservoirs and geopressured-geothermal resources in South Texas.

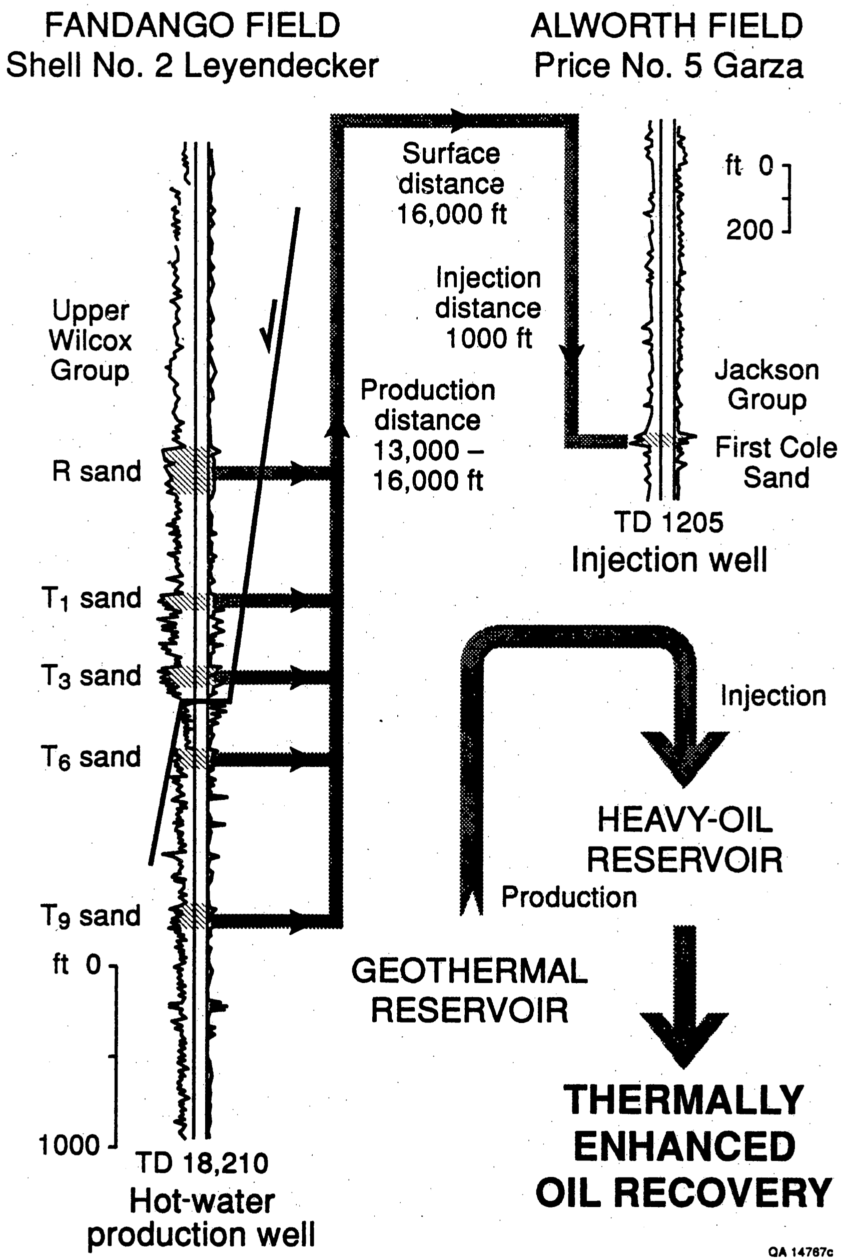


Figure 2. Flow chart illustrating a geothermally enhanced oil-recovery method utilizing geothermal water from reservoirs in the Wilcox for injection into shallow heavy-oil reservoirs in the Jackson Group.

Special attention is directed toward characterizing aspects of potential heavy-oil reservoirs that would affect use of geopressured-geothermal fluids in a TEOR program. The focus of the colocation study is a five-county area of South Texas (Duval, Jim Hogg, Starr, Webb, and Zapata Counties) where known geothermal fairways in the deep Wilcox Group (Gregory and others, 1980; Bebout and others, 1982) are favorably colocated below the shallow Mirando trend of heavy-oil reservoirs (Galloway and others, 1983; Hamlin and others, 1989; Seni and Walter, 1990).

GEOTHERMAL RESOURCES

Geothermal resources are locally abundant at many places in the Western United States, such as southern California (Imperial Valley), northern California (Geysers), Wyoming (Thermopolis and Yellowstone), and Utah (Roosevelt Hot Springs). Geothermal utilization is most advanced in California owing to exceptionally hot fluids and a favorable tax structure. Electricity is produced from geothermal energy in three regions of California: (1) northern California (district G1), (2) the Geysers (district G2), and (3) southern California (district G3) (California Division of Oil and Gas, 1988). More than 2,750 Mw of electricity is currently generated by geothermal energy in the western states (DOE, 1990). At the Geysers in northern California, geothermal steam is used directly to generate 2,043 Mw of electricity (Barker and others, 1991). In the Imperial Valley, southern California, electricity is also generated by direct flashing of geothermal brines to steam and by using various binary cycle turbine systems. At some of these California reservoirs (East Mesa and Heber in southern California and Casa Diablo in northern California), temperatures of the geothermal brines are roughly equivalent to temperatures of the hottest reservoirs along the Texas Coast. In a wide area of northwestern California, Idaho, Utah, New Mexico, and Nevada, geothermal fluids, primarily hot water, are used for district and local space heating, aquaculture, agriculture, and enhanced oil recovery.

Idaho is the largest user of low-temperature geothermal waters as a result of extensive use of geothermal waters for waterflooding in the Williston Basin (Lunis, 1990).

When spent fluids are disposed of properly, geothermal resources are relatively benign environmentally, especially when compared to the generation of electricity through the combustion of fossil fuels. Electrical generation through production of geothermal energy releases little or no greenhouse gases such as CO_2. One advantage of binary cycle generation over direct flash is that CO_2 emissions are minimized because the geothermal fluids are kept in a closed loop and injected into the geothermal reservoir to maintain reservoir pressure and prevent escape of solution gases.

Types of Geothermal Resources

Geothermal resources can be divided into categories on the basis of the nature of the resource and the origin: hydrothermal, petrothermal (hot-dry rocks), and geopressured-geothermal. The heat energy for the first two categories is generally supplied by a large body of hot rock or magma. In a hydrothermal system, ground water becomes heated or is vaporized through contact with surrounding hot rock. Such resources are considered renewable if ground water is replenished by seasonal rainfall or snowmelt. The energy content of hot rocks is extremely large, but not inexhaustible. The phase of the geothermal fluid depends on depth and pressure and may include hot water, steam, or a mixture of the two. The Geysers, California, is an example of a vapor-dominated system that provides electrical power at relatively low cost because the single steam phase contains no liquids that need to be separated.

The Basin and Range province of Trans-Pecos Texas contains many hot springs and typifies hydrothermal systems associated with an ancient rift system that is still characterized by high heat flow. Dorfman and Kehle (1974) and Culver (1991) schematically illustrate how surrounding hot rocks heat descending meteoric water (fig. 3). The heated water expands and

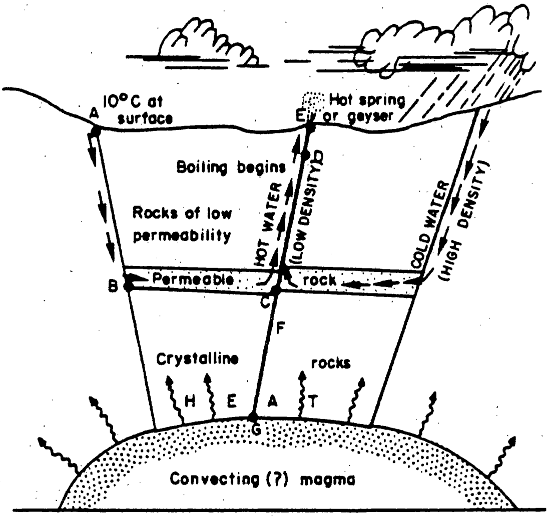


Figure 3. Schematic model of a hydrothermal geothermal system (Dorfman and Kehle, 1974).

because its density is lowered, it moves buoyantly upward through fractures (fault-plane hydrothermal model) or by lateral migration in porous and permeable strata (lateral leakage hydrothermal model) (Culver, 1991). Although many of these systems derive their heat from magma (molten rock) or hot, crystallized plutons, others show no association with recent plutonic activity, but instead derive their heat from deep circulation along fault zones in area of high thermal gradients.

In petrothermal systems, magma or hot, dry rock lies relatively close to the earth surface. However, subsurface water or ability to transmit the water (permeability) is severely restricted. Water or other fluid must be injected into the hot subsurface, permeability pathways must be created, and then the heated fluid must be recovered in order to extract the geothermal energy. Petrothermal systems are typically located in desert climates where surface and ground water are scarce. Recovery of geothermal energy from petrothermal systems is currently uneconomic.

In geopressured-geothermal systems, water trapped within a subsurface sand reservoir is heated by pressure and surrounding hot strata during rapid burial of sediments within young sedimentary basins (Dorfman and Kehle, 1974; Bebout and others, 1978) (fig. 4). The geopressured-geothermal reservoir is sealed by relatively impermeable shale and faults. Insulating layers of thick shales encase the reservoir sandstones and retain heat within the geopressured reservoirs. The high temperature of the geopressured fluids is a result of the normal increase in temperature during burial. The geothermal gradient in the Gulf of Mexico region is low to normal (1.5° to 3.0°F/100 ft). The fluids become overpressured by partially supporting the weight of the overlying column of rock during continued burial. In a normally pressured area, fluid pressure increases with increasing depth as a function of the weight of the overlying column of water; this is referred to as the hydrostatic zone. In the Gulf Coast region the normal hydrostatic pressure gradient is 0.465 psi/ft. Limited fluid circulation within the overpressured interval causes the pressure gradient to increase to between 0.7 and 1.0 psi/ft. Geothermal fairways are typically characterized by temperatures more than 300°F, fluid

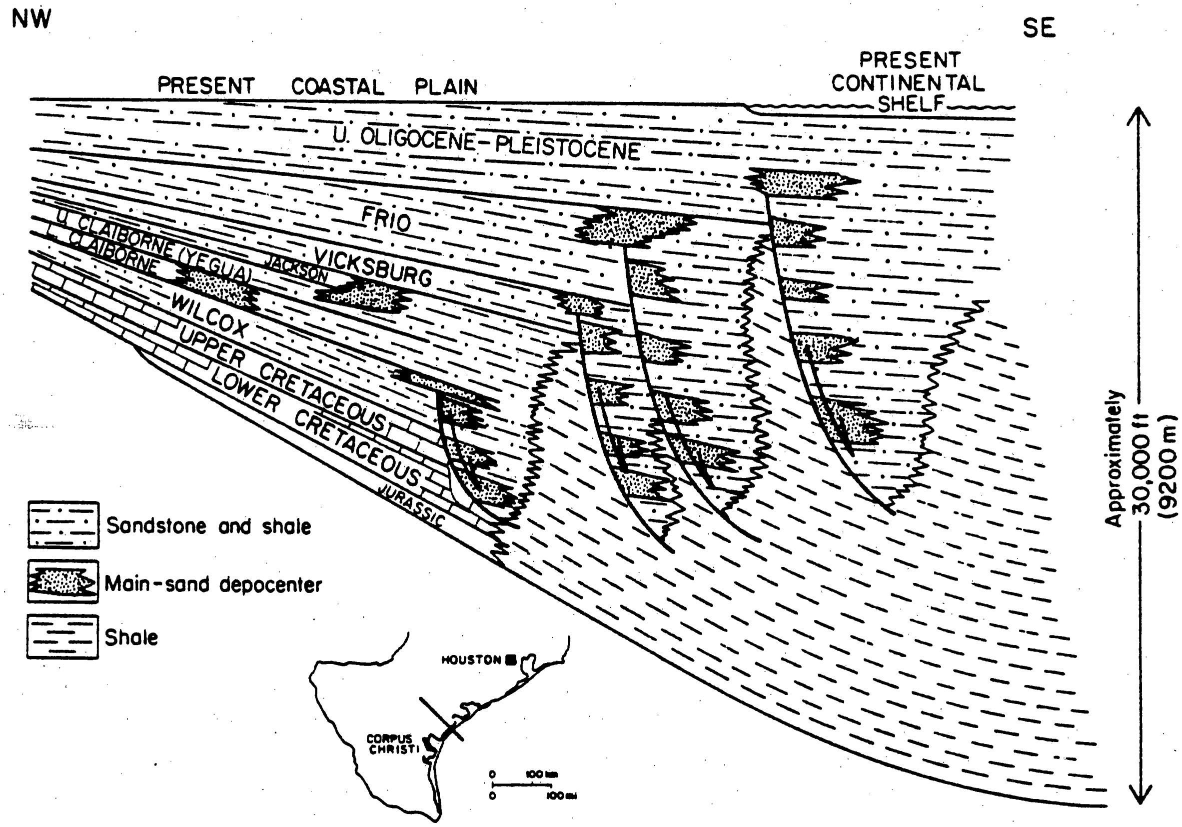


Figure 4. Schematic model of depositional and structural style of Cenozoic strata along the Texas Gulf Coast (modified from Bruce, 1973).

pressures more than 0.7 psi/ft, and sandstone thicknesses exceeding 300 ft. Because geopressured-geothermal fluids are sealed within deep reservoir strata, they should be considered nonrenewable resources similar to oil and gas. Although geopressured-geothermal resources are best known in the northern Gulf of Mexico basin, geopressured basins are common in the United States and worldwide (Fertl and others, 1976).

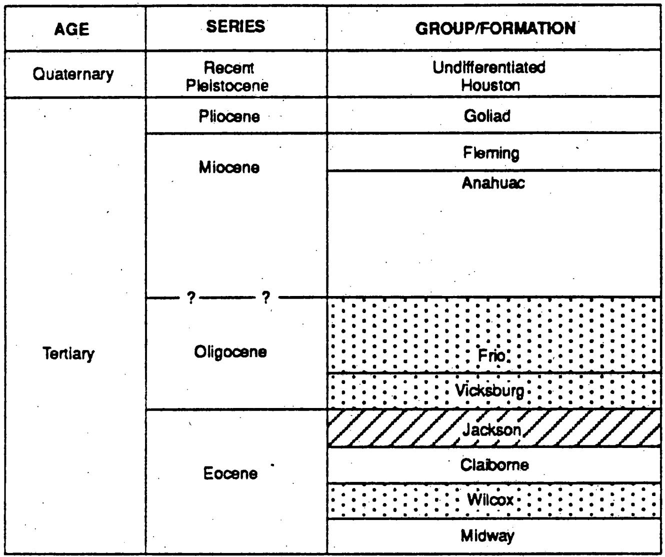
Geopressured-Geothermal Resource

The University of Texas (Bureau of Economic Geology and the Center for Geosystems Engineering) has participated in a long-term research program funded by the Department of Energy (DOE) to evaluate geopressured-geothermal resources in Texas (Dorfman and Deller, 1975, 1976; Podio and others, 1976; Bebout and others, 1978, 1982; Dorfman and Fisher, 1979; Gregory, and others, 1980; Bebout and Bachman, 1981; Dodge and Posey, 1981; Morton and others, 1983; Dorfman and Morton, 1985). Similar programs have been funded by the DOE to evaluate geopressured-geothermal reservoirs in Louisiana (Bebout and Gutierrez, 1981; McCulloh and Pino, 1981; Snyder and Pilger, 1981). As a result of this research program, a substantial body of information is now available concerning the location, distribution, and productivity of the resource. The initial research focus was on assessing the potential for electrical generation from the deep subsurface brines in onshore Tertiary strata. The primary goals were to locate prospective reservoirs that met the following specifications: fluid temperatures of 300°F or higher, pressure gradients higher than 0.7 psi/ft, reservoir volume of 3 mi^3, and minimum permeability of 20 md (Bebout and others, 1978; Morton, 1981). The recognition that geothermal brine contained substantial dissolved natural gas focused research on quantifying the chemical energy component. Initial optimistic projections suggested brines contained up to 40 to 120 scf/bbl. However, gas solubility was found to be a function of the salinity of the brine; high salinities reduced gas solubility (Blount and others, 1979; Gregory and others, 1980). Long-term well tests of geothermal wells indicated gas content of the brines ranged from 20 to 34 scf/bbl (Negus-de Wys and others, 1991). More detailed information on regional assessment and site selection studies for Tertiary formations from the Texas Gulf Coast is summarized for the Frio, Vicksburg, and Wilcox strata (Bebout and others, 1975a, 1975b, 1976, 1978, 1982; Gregory and others, 1980; Loucks, 1979; Edwards, 1981; Morton and others, 1983; Winker and others, 1983).

Geothermal Corridors

Broad geopressured-geothermal corridors within Tertiary formations in the Gulf Coast of Texas and Louisiana (fig. 1) contain localized geothermal fairways or prospects that are characterized by the coexistence of high subsurface fluid temperatures (<250°F) and thick permeable sandstones. Thick sandstone bodies provide the necessary large reservoirs for the geothermal fluids. In the Gulf Coast Basin, such corridors typically occur where deltaic, shoreline, and shelf-margin sandstones accumulated syndepositionally on the downthrown side of regional growth faults (fig. 4). Belts of growth faults were formed by large-scale basinward sliding of the unstable shelf edge and by salt and shale tectonics (Ewing, 1986). Geopressured-geothermal aquifers result when thick sandstone bodies are hydraulically isolated by subsidence and rapid burial within fault blocks (Winker and others, 1983). In addition to thick reservoir sandstones and high temperature of geothermal fluids, permeability constitutes a third major limiting factor that must be examined to characterize first-order geothermal prospectivity (Bebout and others, 1978).

Around the northern arc of the Gulf of Mexico depositional basin, reservoirs of geopressured-geothermal fluids occur in major sandstone-rich Tertiary sequences including: (1) the Eocene Wilcox Group, (2) the Eocene Yegua Formation, (3) the Oligocene Vicksburg Group, (4) the Oligocene Frio Formation, and (5) Miocene formations (fig. 5). Yegua and Vicksburg strata contain less favorable geothermal resources because reservoir sands at suitable depths are areally restricted or have low permeability (Loucks, 1979). In Texas, Miocene strata



AGE	SERIES	GROUP/FORMATION
Quaternary	Recent Pleistocene	Undifferentiated Houston
Tertiary	Pliocene	Goliad
	Miocene	Fleming
		Anahuac
	— ? — ? —	
	Oligocene	Frio
		Vicksburg
	Eocene	Jackson
		Claiborne
		Wilcox
		Midway

Figure 5. Cenozoic formations and groups, Texas Gulf Coast. Geopressured-geothermal units are in stippled pattern (Bebout and others; 1978). Heavy-oil reservoirs are most common in Jackson Group (lined pattern).

have not been buried to sufficient depth to host favorable geothermal resources. In Louisiana however, Miocene strata have been buried more deeply and a DOE geothermal design well—Gladys McCall No. 1—has been completed in Miocene strata. Both the Wilcox and Frio depositional units in Texas contain the thick sandstone-rich corridors that delimit potential geothermal fairways at the appropriate depth and structural setting to produce exceptionally large reservoirs necessary for the development and production of geothermal fluids (Bebout and others, 1978, 1982). Within these broad corridors are smaller geothermal fairways or prospects that contain thick potential reservoir sandstones with elevated reservoir temperatures and pressures.

Wilcox Geothermal Fairways

The Wilcox Group together with the underlying Midway Group constitutes the oldest thick sandstone/shale wedge within the Gulf Coast Tertiary System. The faulted downdip section of the Wilcox Group constitutes the Wilcox geothermal corridor. Sediments within the updip part of the Wilcox wedge were deposited primarily by fluvial processes. Large delta systems deposited thick sandstone rich sequences in the lower and upper Wilcox. Marine processes reworked some deltaic sediments and redistributed sediments longshore in barrier bar/strandplain environments. Growth faults developed between the shoreline and shelf margin of the larger delta lobes where thick deposits of sand and mud accumulated over unconsolidated offshore mud of the underlying sediment wedge. Subsidence along these faults isolated thick sandstone sequences that prevented escape of pore fluids during burial. Six geothermal fairways are identified within the corridor on the basis of sandstone distribution and temperature maps (fig. 6). These six geothermal fairways are simplified into two Wilcox reservoir models (Gregory and others, 1980; Bebout and others, 1982). Table 1 summarizes characteristics of the reservoir models.

A.

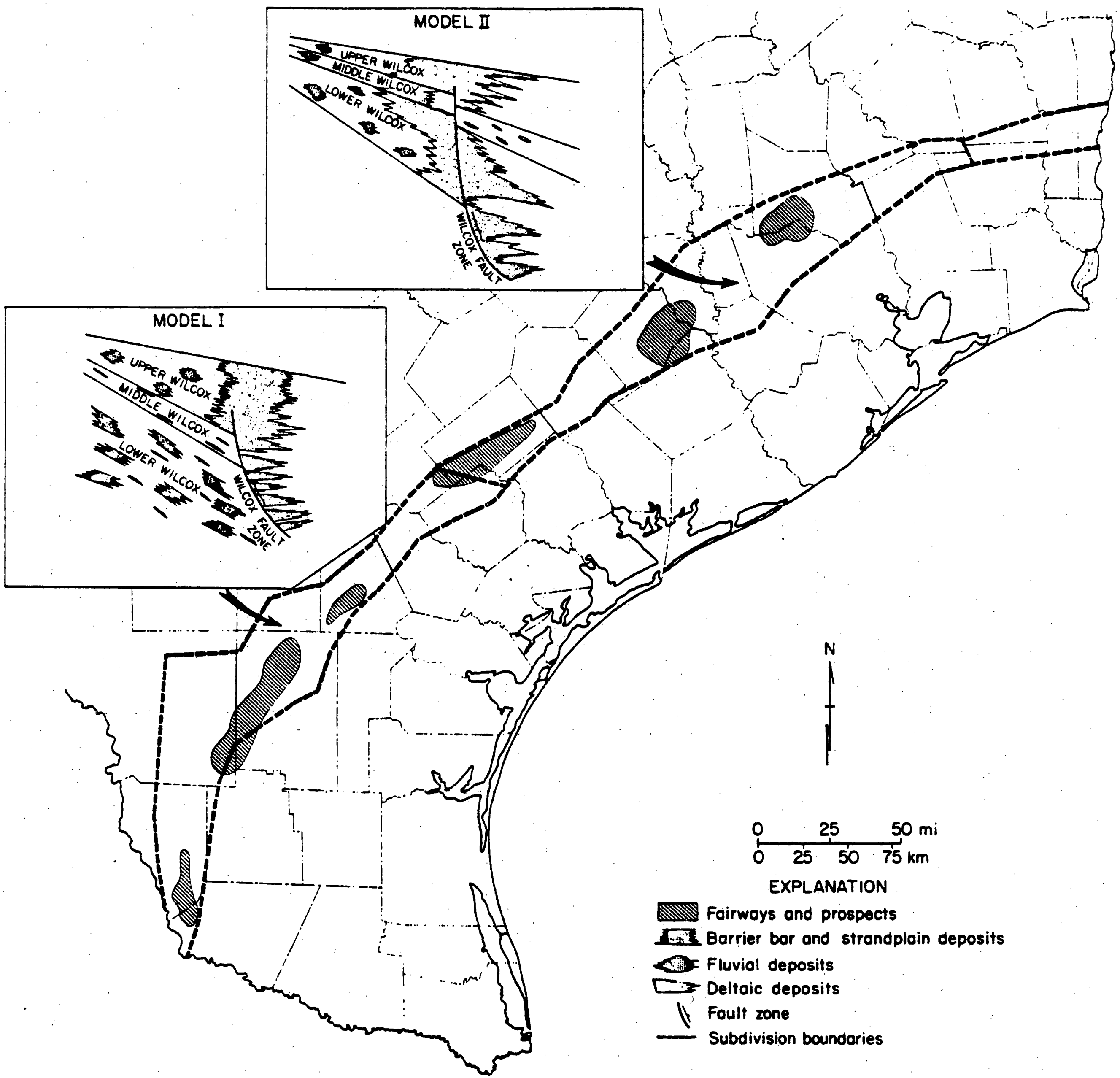


Figure 6. A. Wilcox geopressured-geothermal reservoir models (Gregory and others, 1980).

B.

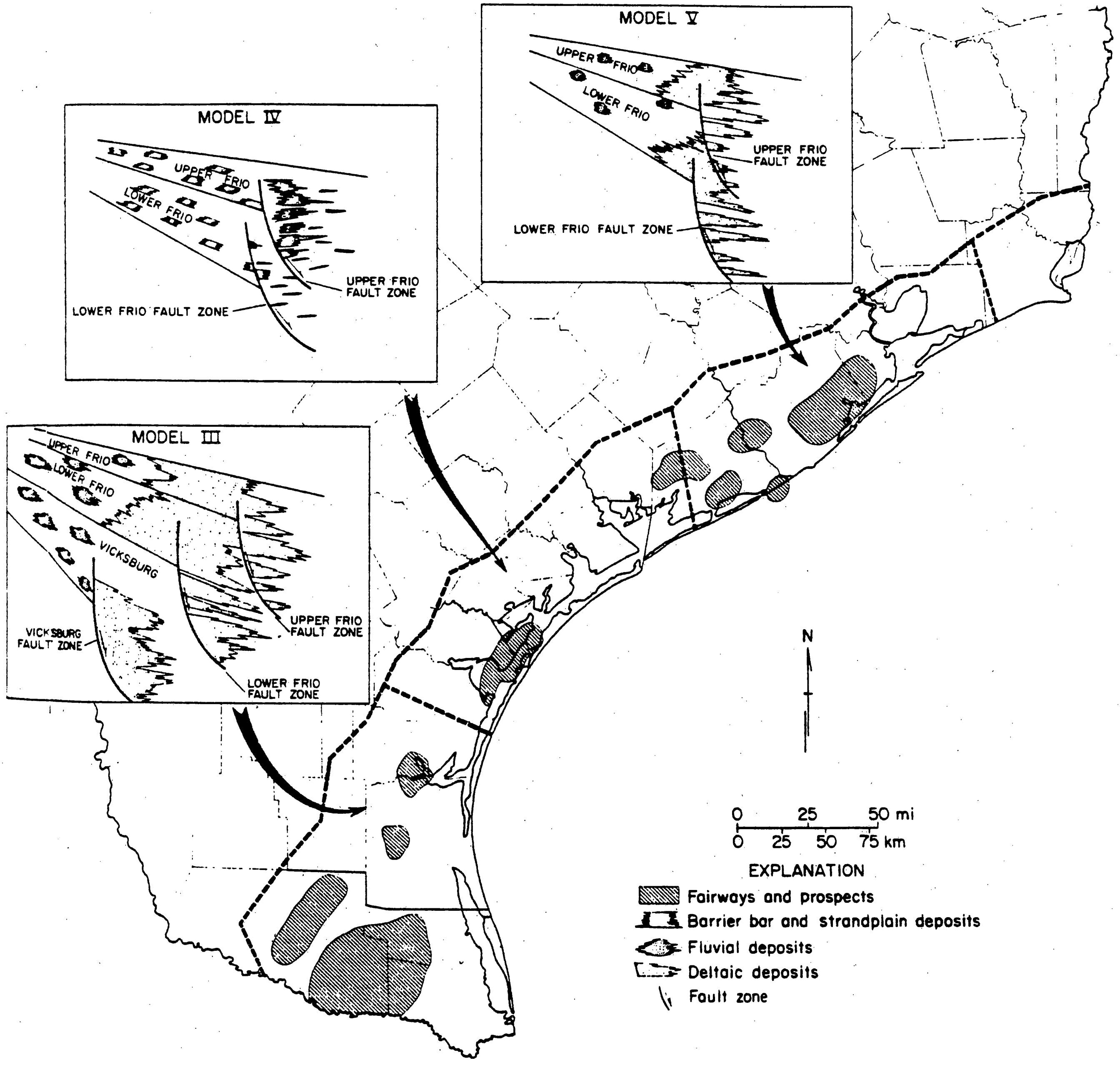


Figure 6. B. Frio geopressured-geothermal reservoir models (Bebout and others, 1978).

Table 1. Characteristics of geopressured-geothermal reservoir models (Gregory and others, 1980).

Model I	Sand geometry	Temperature	Pressure	Salinity	Methane solubility	Porosity & permeability	Factors limiting reservoir potential
J. Wilcox	thick, laterally extensive sands	moderate to high	moderate to high	low to moderate	low to moderate	low	low to moderate methane solubility, low porosity and permeability
L. Wilcox	thin, areally extensive sands	high	high	low	high	very low	thin sands, very low porosity and permeability
Model II							
U. Wilcox	moderately thick sands, moderately continuous	low to moderately	low to moderate	low to high	low to moderate	low	low porosity & permeability, low pressure in updip areas
L. Wilcox	thick, laterally extensive sands	high	high	high	high	low, locally high in DeWitt fairway	low porosity & permeability
Model III							
U. Frio	thick, areally limited sands	moderate to high	moderate to high	low to moderate	high	low	areally limited sands, low porosity & permeability

Table 1 (continued)

Model I	Sand geometry	Temperature	Pressure	Salinity	Methane solubility	Porosity & permeability	Factors limiting reservoir potential
L. Frio	thin, basal sands, laterally continuous	very high	very high	low to moderate	high	very low	low porosity & permeability
Vicksburg	thick, areally limited sands	high	high	low to moderate	high	very low	areally limited sands, low porosity & permeability
Model IV							
U. Frio	thick, areally extensive sands	low	low	high	low to moderate	high	low to moderate methane solubility, low pressure
L. Frio	thin, areally limited sands	moderate to high	moderate to high	low	moderate to high	low	areally limited sands, low porosity & permeability
Model V							
U. Frio	thin to moderately thick sands, areal extent variable	low to moderate	low to moderate	moderate to high	low to moderate	high	low to moderate methane solubility & pressure, low tota sand volume
Frio							
Matagorda Fairways	thin, areally limited sands	high	moderate to high	high	moderate to high	high	thin, areally limited sands
Brazoria Fairway	thick, areally extensive sands	high	moderate to high	high	moderate to high	high	thin, areally limited sands

Model I—South Texas upper Wilcox Fairways

Model I represents upper Wilcox geopressured-geothermal reservoirs in South Texas. High constructive lobate deltas of the upper Wilcox are growth faulted along the lower Wilcox shelf margin, forming vertically continuous reservoirs of delta-front sandstones (Edwards, 1981). Zapata, Duval, and Live Oak Fairways represent major sand depocenters associated with three delta lobe complexes. In the Zapata Fairway, more than 1,500 ft of net sandstone accumulated in growth faulted compartments (Seni and Walter, 1990). The maximum thickness of individual sand bodies is 200 ft. To the north, in the Duval and Live Oak Fairways, individual sandstone bodies are thinner, and net sandstone packages are 300 to 700 ft thick. Reservoir temperatures are moderate to high (250° to 471°F) as a result of high geothermal gradients and substantial reservoir depth. Reservoir sandstones in the upper Wilcox are relatively continuous along strike, but dense growth faults restrict continuity in a dip direction. Average porosity in Model I fairways ranges from 17 to 22 percent. However, permeability is the limiting factor restricting geothermal reservoir potential in the upper Wilcox. At depths where geothermal reservoirs are developed, average permeabilities are very low, ranging from 0.01 to 0.5 md. Core analysis indicates that the low porosities and permeabilities will limit production from potential geopressured-geothermal reservoirs (Bebout and others, 1982).

Model II—Lower Wilcox De Witt, Colorado, and Harris Fairways

Model II represents potential geothermal reservoirs in the lower Wilcox along the middle and upper Texas Coastal Plain (Gregory and others, 1980; Bebout and others, 1982). The sandstone geometry and structure in De Witt, Colorado, and Harris Fairways are characteristic of this model. High-constructive, lobate lower Wilcox deltas were extensively growth faulted when they prograded across the underlying Cretaceous carbonate shelf margin. Delta-front sheet sands accumulated to great thicknesses in growth fault zones. Reservoir size is limited by restricted dip extent and lateral facies changes. In the De Witt Fairway, from 400 to 1,000 ft of net sandstone accumulated. A thick section of sandstones having net-sandstone values of 1,200 to 1,600 ft occurs in the lower Wilcox in the Colorado Fairway. Maximum net-sandstone values with thicknesses of more than 2,000 ft occur in the lower Wilcox in the Harris Fairway. Available core data show that most permeabilities of sandstones in the deep subsurface are less than 1 md. Locally permeabilities are highest in the De Witt Fairway where permeabilities range from less than 2.1 to >100 md. The highest permeability is typically at the top of sandstone-bearing intervals in thick channel fill sandstones.

Frio Geothermal Fairways

Five geothermal fairways that occur within the Frio geothermal corridor along the Coastal Zone of Texas are simplified into three reservoir models (Bebout and others, 1978; Gregory and others, 1980) (fig. 6). The geothermal fairways occur where contemporaneous growth faults promoted the accumulation of thick deposits of sandstone to a depth currently characterized by high subsurface temperature and pressure. The Frio contains a substantial amount of data associated with the analysis of geothermal resource. Reservoir-specific information relevant to the production of geothermal energy in the Frio Formation of Texas has been evaluated in one DOE design well (Morton, 1981; Morton and others, 1983; Winker and others, 1983).

Model III—Corpus Christi-Matagorda Fairways

The Corpus Christi and Matagorda Fairways both contain high-temperature geothermal waters in the range of 300° to 340°F. Updip strandplain sandstones grade downdip across closely spaced fault zones into thin sandstone beds separated by thin shales beds representing shelf and slope deposits. Although sandstone-prone zones are 400 to 900 ft thick, individual sandstone beds range in thickness from 1 to 10 ft. Limited core data indicate that porosities range from 9 to 22 percent and permeabilities average <5.3 md. Local zones of high permeability (80 to 300 md) occur at the top of some sandstones. The size of reservoirs in the Corpus Christi-Matagorda Fairway is relatively small. Reservoir size is limited by restricted original distribution of sands and by syndepositional and later faulting.

Model IV—Hidalgo-Armstrong Fairways

The Hidalgo and Armstrong Fairways in South Texas contain geothermal waters with temperatures from 250° to >300°F. The fluid temperatures in the Armstrong Fairway are relatively low. Thick, extensive sandstones characterize both fairways. Total net sandstone of more than 300 ft occurs over an area of 50 mi^2 in the Armstrong Fairway. Numerous thick sandstone reservoirs of adequate size occur at depths greater than 13,000 ft in the Hidalgo Fairway. However, both fairways are limited by extremely low permeabilities. In the vicinity of the Frio Hidalgo Fairway, the underlying Vicksburg Formation is also characterized by low permeabilities (Loucks, 1979). Swanson and others (1976) analyzed fields producing from the geothermal zone, and they found that most sandstone permeabilities are 1 md or less.

Model V—Brazoria Fairway

Along the upper Texas coast in Brazoria and Galveston Counties, thick, porous and highly permeable sandstones accumulated in the Brazoria Fairway. Bebout and others (1978) mapped and identified the Brazoria Fairway as the most favorable site for testing geopressured-geothermal resources in the Frio Formation in Texas (fig. 7). Geological characterization of potential Tertiary geopressured-geothermal reservoirs led to the selection of the Austin Bayou Prospect within the Brazoria Fairway as a site for the first DOE design well. Subsequently, the

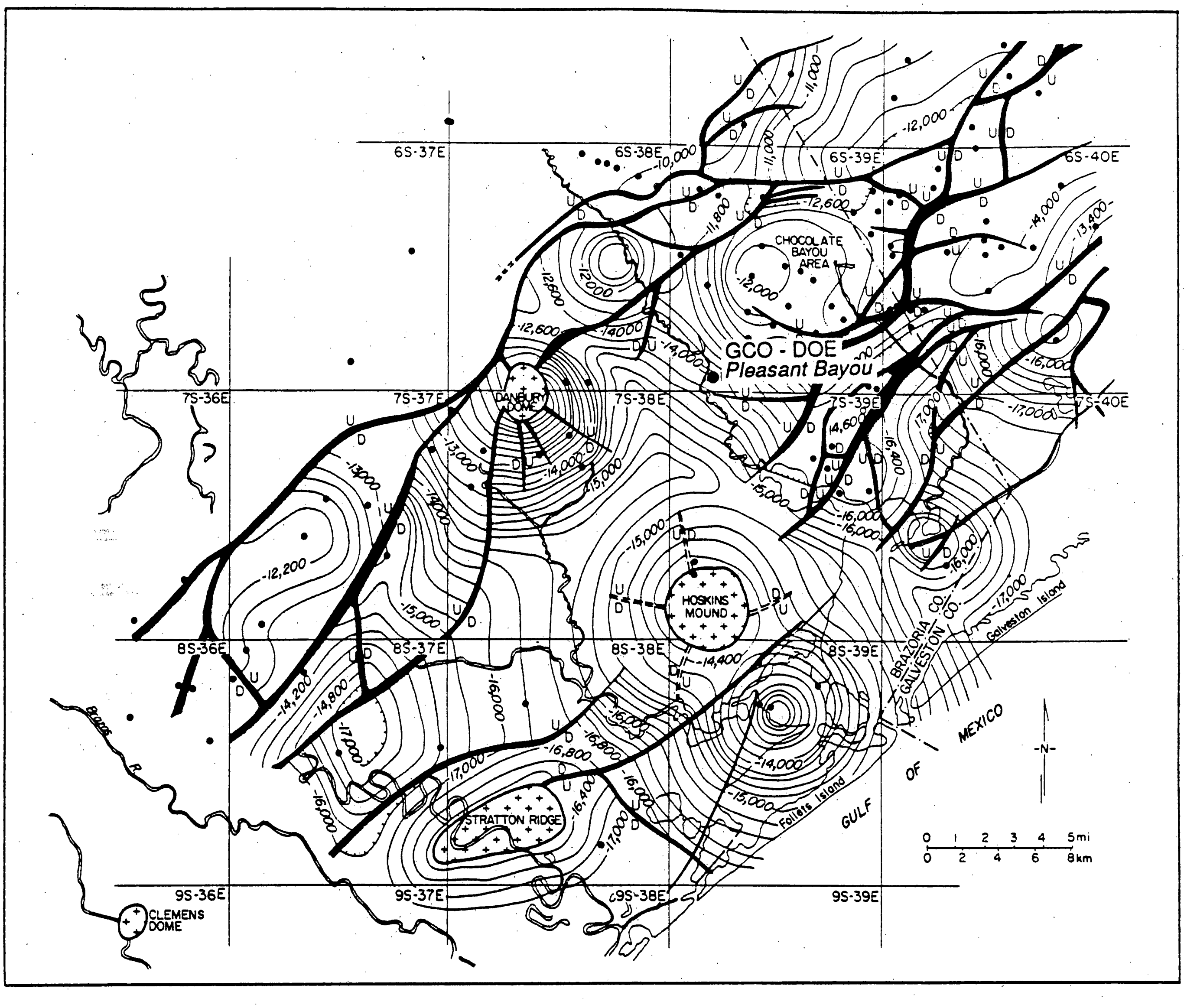


Figure 7. Location of General Crude Oil/DOE Pleasant Bayou Nos. 1 and 2 geopressured-geothermal test wells and structure on T5 marker (Morton and others, 1983).

first DOE design well to evaluate the geopressured-geothermal energy resource was completed in 1979 in the Brazoria Fairway.

The structural style in the Brazoria Fairway represents the interaction among deltaic sedimentation, growth faulting, and dome growth. Thick reservoir sandstones accumulated in a large salt-withdrawal basin that is bounded on the updip side by a major regional growth fault. Several hundred feet of potential geothermal reservoir sandstones contain fluid temperatures of higher than 300°F. Permeability values for cores of sandstone units in the Brazoria Fairway range from less than 0.1 md for cores with low porosities less than 15 percent to several hundred millidarcys (140 to 1,050 md) when porosity exceeds 20 percent. The generation of secondary leached porosity within the deep zone of reservoir development has improved the permeability of Frio sandstones in the Brazoria Fairway (Loucks and others, 1980, 1981).

DOE Geothermal Well Testing Program

A series of geopressured-geothermal wells have been drilled in Texas and Louisiana to gain information on various potential geothermal reservoirs (Gould and others, 1981; Morton and others, 1983; Pritchett and Riney, 1983; Clark, 1985; Durrett, 1985; Garg and Riney, 1985; Rogers and Durham, 1985; Rogers and others, 1985). The wells include oil and gas wells drilled by industry and used for short-term tests ("Wells of Opportunity program") and DOE geothermal wells designed for long-term reservoir testing, characterization, and fluid production (Design Well program) (fig. 8). The short-term and long-term tests have been designed to (1) document reservoir conditions, (2) define the productivity and life of the geothermal reservoir, (3) analyze geothermal fluids and dissolved gases, and (4) demonstrate potential for technical transfer to private companies.

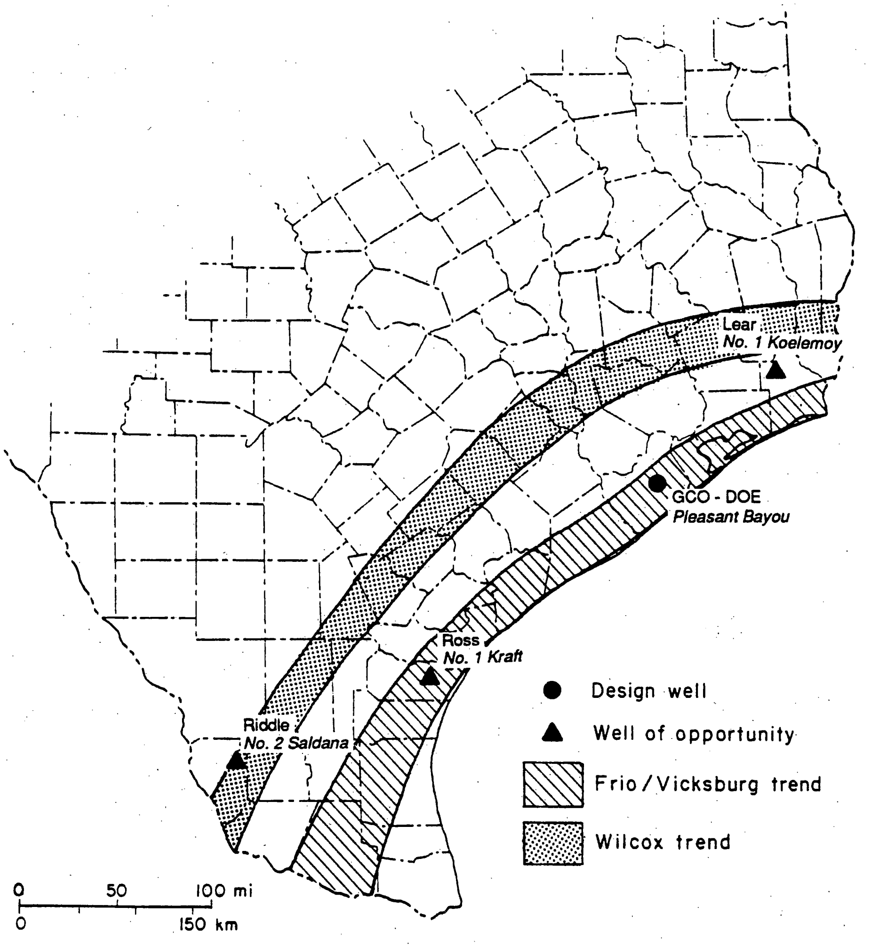


Figure 8. Location of geothermal corridors and test wells, Texas Gulf Coast (Morton and others, 1983).

DOE Design Well Program

Four design wells have been drilled and tested (Lombard, 1985) (table 2). An additional well was drilled as a gas well and was transferred to DOE. The first design well, the General Crude-DOE Pleasant Bayou No. 1, was drilled in 1978 and completed as a disposal well after drill pipe became stuck in the objective geothermal section. Pleasant Bayou No. 2 was offset 500 ft and successfully completed to 16,500 ft (Bebout and others, 1978; Morton and others, 1983). The Pleasant Bayou DOE geothermal test well in Brazoria County, Texas, is the only well in the geothermal-geopressured program that has successfully produced electrical power from an experimental 1 MWe hybrid power system (Hughes and Campbell, 1985; Eaton Operating Company, 1991) utilizing isobutane. Natural gas was separated from the brine and this gas powered an engine to contribute exhaust gas heat to the heat exchanger assembly, or the gas was sold to a pipeline. Net power was 955 kw after parasitic power reduction. The long-term test extended from September 1989 to June 1990. The DOE Pleasant Bayou No. 2 design test well sustained production of 20,000 to 23,000 bbl/d of brine at a wellhead temperature of 268°F. Approximately 20 MMbbl has been withdrawn and 39 MMscf of gas were extracted from the well's estimated 7.8 Bbbl reservoir. The test facility successfully demonstrated power generation from a geopressured-geothermal aquifer. However, the costs of electricity and gas produced from the test were not economically viable when compared to that produced from conventional energy resources.

DOE Wells of Opportunity Program

The DOE Wells of Opportunity program economically utilized existing oil and gas wells for short-term reservoir tests. Six conventional oil and gas wells that were tested in the DOE Wells of Opportunity program during 1980 and 1981 sustained fluid production rates that ranged

Table 2. Characteristics of geopressured-geothermal test wells. A. DOE design wells. B. DOE wells of opportunity. Modified from Klauzinski (1981), Morton (1981), Morton and others (1983), Clark (1985), Garg and Riney (1985), Peterson (1985), Negus-de Wys and others (1990), and Eaton Operating Company (1991).

A

WELL	General Crude/DOE	Technadril-F and S/DOE	Dow/DOE	Gulf-Technadril/DOE	Superior Oil Co.
NAME	#2 Pleasant Bayou	#1 Gladys McCall	#1 L. R. Sweezy	#1 Amoco Fee	#1 Hulin
AGE/FORMATION	Oligocene/Frio	Miocene/lower Miocene	Oligocene /Anahuac	Oligocene/Frio	Oligocene/ Frio
UNIT	T5 Sand	#8 Sand	Cibicides jeffersonensis	Miogypsinoides (sand # 5)	Miogypsinoides
DEPTH (ft)	16500	15158-15490	13340	15387-15414	21546
THICKNESS (ft)	60	300	50	27	500
BOTTOM HOLE PRESSURE (psi)	11050	12783	11410	12052	18500
FLOWING PRESSURE (psi)	3000	2000		4749	3500
BOTTOM HOLE TEMPERATURE (F)	301	298	237	279	360
SURFACE TEMPERATURE (F)	292	268			330
GAS/WATER RATIO	23.7	27	17.5	20.9	34
PERCENT METHANE	85	85			93
PERCENT CO2	10.5	10	10		4
RESERVOIR SIZE	8 billion bbls	4 billion bbls			14 billion bbls
TOTAL DISSOLVED SOLIDS (mg/l)	131320	95000			195000
Cl (mg/l)	70000	57000			115000
POROSITY (%)	19	23.8	27	20	
PERMEABILITY (md)	200	64	6-1526 (817 on buildup)	42-140	
SUSTAINED FLOW RATE	20000	19837	9800	2046-2648	15000
LONG TERM PRODUCTION	19.5 million bbls	27.3 million bbls		1.1 million bbls	
LIMITING FACTORS	well sanding when		well sanding when	high production rates	no long term tests
	production > 20,000 bbls		production > 10,000 bbls	not sustainable;	
				reservoir barriers	

Table 2 (continued)

B

WELL	Riddle	Lear	Ross	Wainoco Oil and Gas
NAME	#2 Saldana	#1 Koelemay	#1 Kraft	#1 P. R. Girouard
AGE/FORMATION	Eocene/upper Wilcox	Eocene/Yegua	Oligocene/Frio	Oligocene/upper Frio
UNIT	1st Hinnant	Leger Sand	Anderson Sand	Marginulina texana
DEPTH (ft)	9745-9835	11590-11729	12750	14720-14827
GROSS SAND THICKNESS (ft)	90	139	120	107
NET SAND THICKNESS (ft)	79	77	109	91
BOTTOM HOLE PRESSURE (psi)	6627	9450	10986	13203
SHUT-IN SURFACE PRESSURE	2443	4373	9507	6695
BOTTOM HOLE TEMPERATURE (F)	300	260	263	274
GAS/WATER RATIO	47-54	30 (plus gas cap)		40 (estimate)
TOTAL DISSOLVED SOLIDS (mg/l)	13000	15000	23000	23500
POROSITY (%)	20	26	23	26
PERMEABILITY (md)	7	85	39	
SUSTAINED FLOW RATE	1950		34	15000
LIMITING FACTORS	tight	restricted reservoir	damaged reservoir	restricted reservoir

from 1,950 to 15,000 bbl/d for conventional $2\frac{3}{8}$- to $3\frac{1}{2}$-inch tubing (Klauzinski, 1981). Riddle No. 2 Saldana, from Martinez field, Zapata County, South Texas, is a Well of Opportunity that has tested the First Hinnant sand, which correlates with the Live Oak delta complex in McMullen and Live Oak Counties (Morton and others, 1983). This well provides the most direct data on the geothermal well productivity of the upper Wilcox in South Texas. The sand has good reservoir continuity and poor to excellent reservoir quality. Average porosity from the sonic log was 16 percent, average permeability was 7 md, salinity was 13,000 ppm TDS, and maximum temperature was 300°F (Morton and others, 1983). Maximum flow rate was 1,950 bbl/d.

Average permeability data have been tabulated from previous geopressured-geothermal research programs in figure 9 (Swanson and others, 1976; Bebout and others, 1978, 1982; Loucks, 1979; Klauzinski, 1981; Morton and others, 1983). The data represent permeabilities derived from diamond core, sidewall core, pump tests, and median values averaged from many samples. These undesirable variations in measurement techniques impose an additional scatter to data that characteristically have a wide natural dispersion. Despite the scatter in the data, there is a clear distinction between the relatively low permeability values represented by Vicksburg, Frio, and Wilcox permeabilities in South Texas and the extraordinarily high permeabilities measured in the Frio in the Pleasant Bayou Fairway. In the South Texas area, where Wilcox and younger Tertiary strata are deeply buried (11,000 to 14,000 ft) in the hot geothermal zone, typical permeabilities range from less than 0.01 to 1 md. For instance, Morton and others (1983) report that average permeability was 7 md in the First Hinnant sand (17 measurements) over a depth range of 9,720 to 9,840 ft at the Riddle No. 2 Saldana. In contrast, at Pleasant Bayou No. 2 average permeabilities are 230 md in the Andrau Sand (27 measurements) over a depth range of 14,484 to 14,766 ft (Morton and others, 1983, p. 54–57). Rosita field in Duval County is an upper Wilcox gas field that has abundant porosity/permeability data showing that for the deepest and hottest reservoirs, the preponderance of permeability values fall in the range of from less than 0.1 to 1 md (fig. 10). Permeabilities from the Frio Pleasant Bayou No. 2 geothermal well in Brazoria County are compared to those from

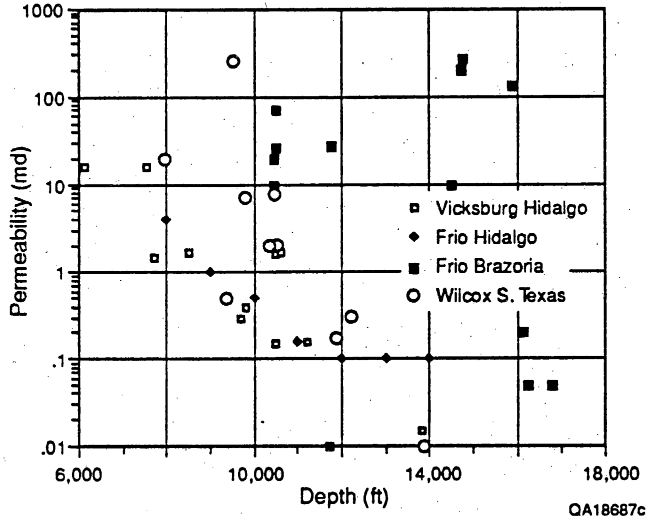


Figure 9. Average permeability plotted as a function of depth for various Texas geothermal corridors (Wilcox-Klauzinski, 1981; Bebout and others, 1982; Morton and others, 1983; Vicksburg-Swanson and others, 1976; Loucks, 1979; Frio-Bebout and others, 1978; Morton and others, 1983).

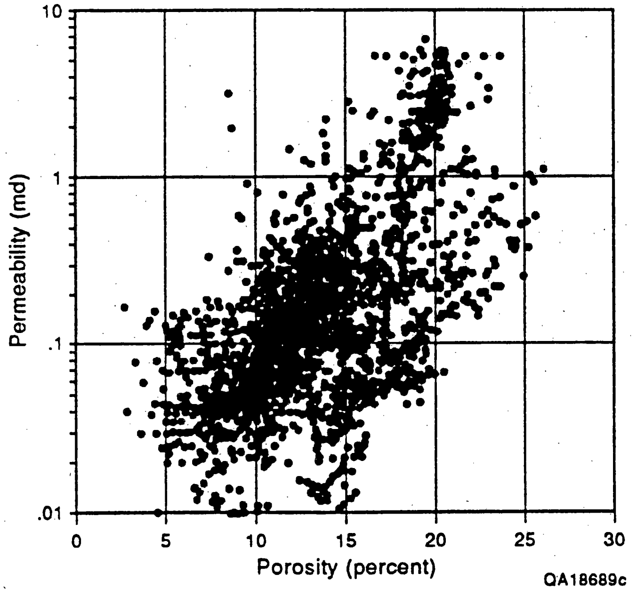


Figure 10. Permeability (unstressed air permeability) versus porosity, Rosita field gas wells, Duval County, Texas.

the upper Wilcox Fandango field in Zapata County (fig. 11). For a given constant porosity, Frio permeabilities are typically one to two orders of magnitude greater than those in the upper Wilcox at Fandango field (fig. 11).

Summary of Geopressured-Geopressured Resources in Texas

The thick reservoir sandstones and locally high porosity and permeability identify reservoirs of Model V in the Frio Formation of the central Texas Gulf Coast as the most favorable that has been evaluated for production of geopressured-geothermal resources in Texas. Both the Frio Formation and the Wilcox Group contain sandstone reservoirs of sufficient thickness and temperature to be viable geothermal resources. Maximum temperatures of thick reservoir sands in the Frio are approximately 300°F. Locally in Model I, thick, upper Wilcox reservoir sands contain geothermal fluids in excess of 450°F and thick reservoir sandstones. The favorable trend of high brine temperature, low brine salinity/high gas saturation, and thick reservoir sandstone must be balanced against the consistent trend of decreasing porosity and permeability with depth. The limiting factor affecting geothermal productivity is the characteristically low permeability of potential reservoir sandstones. Low permeability is endemic for South Texas fairways including the Frio Formation (Bebout and others, 1978), Vicksburg Group (Swanson and others, 1976; Loucks, 1979), and Wilcox Group (Bebout and others, 1982). Comparison of porosity/permeability relationships between South Texas Wilcox reservoirs and ideally favorable Frio reservoirs indicated that the Frio reservoirs at similar reservoir depth typically has permeability that is 1 to 2 orders of magnitude greater than that in Wilcox strata in South Texas. The abundance of unstable volcanic rock fragments in South Texas favors a burial diagenesis pathway that results in reduction of original primary porosity by cementation. Along the middle Texas coastal area, secondary porosity by feldspar dissolution in the deep subsurface (Loucks and others, 1980, 1981; Milliken and others, 1981) has enhanced porosity and permeability of deeply buried sandstones.

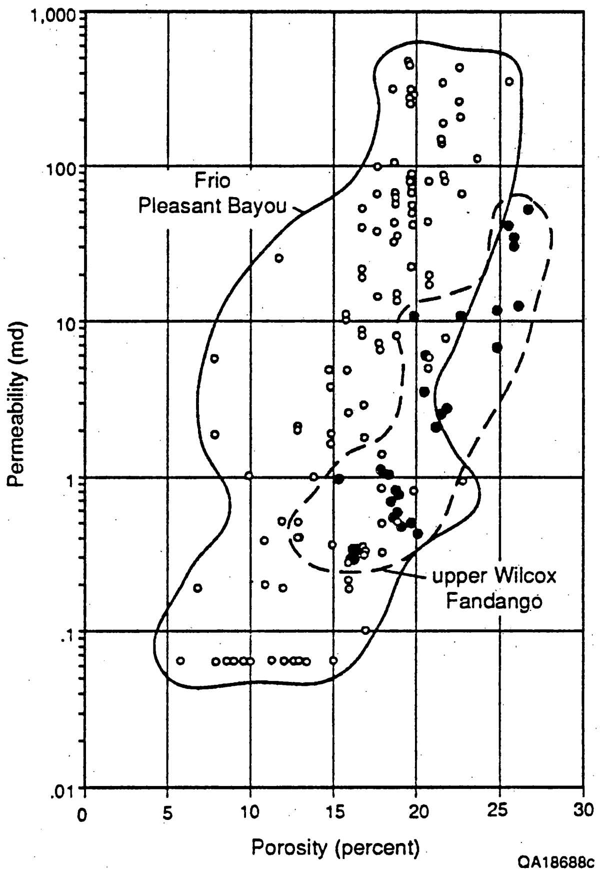


Figure 11. Permeability (unstressed air permeability) versus porosity, Frio Chocolate Bayou field, Brazoria County, Texas (Phillips No. 1 JJ), and upper Wilcox Fandango field (Shell Muzza No. 2 and Garza No. 2).

DIRECT USE OF GEOTHERMAL FLUIDS FOR IMPROVED OIL RECOVERY

The role of hot-water flooding in the mobilization of heavy oil is poorly documented (DuBar, 1990) and there have been relatively few field applications designed to assess the effectiveness of hot-water floods to mobilize heavy crude. Important exceptions are the pilot test in Schoonebeek field, the Netherlands (Dietz, 1972), and Loco field in southern Oklahoma (Martin and others, 1972). According to DuBar (1990), these two tests demonstrated that, although the process was more complicated than originally anticipated, hot-water flooding could increase heavy-oil production. Currently, Amoco is using geothermal fluids in a hot-water flood of oil reservoirs in Wyoming (Lunis, 1990).

Hot-Water Flooding

Raising reservoir temperature is the primary method employed by thermal recovery techniques for reducing in-situ viscosities and increasing production. Hot-water flooding is one method of heating the reservoir to reduce the oil viscosity and thus improve the displacement efficiency over that obtainable from conventional water floods (Craig, 1971). Hot-water flooding is basically a displacement process in which both hot and cold water mobilize oil. A hot-water flood, whether geothermal or conventional, involves the flow to two phases: water and oil. Steam and combustion processes include a third gaseous phase. The displacement efficiency of hot water is greater than that of cold water, but much less than that for steam (fig. 12). Hot water has a lower transport capacity and sweep efficiency than steam injection (Burger and others, 1985).

Prats (1986) showed how (1) thermal expansion, (2) viscosity reduction, (3) wettability, and (4) oil/water interfacial tension affect displacement efficiency of crudes of increasing oil density (fig. 13). Qualitatively, viscosity reduction is the most important mechanism displacing

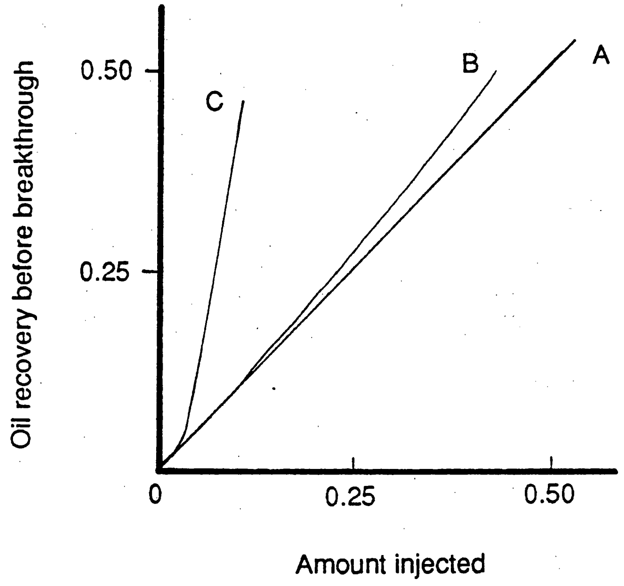


Figure 12. Oil recovery before breakthrough of water versus the amount of water injected: Curve A–conventional isothermal water flood, Curve B–hot water flood, and Curve C–steam flood (Burger and others, 1985).

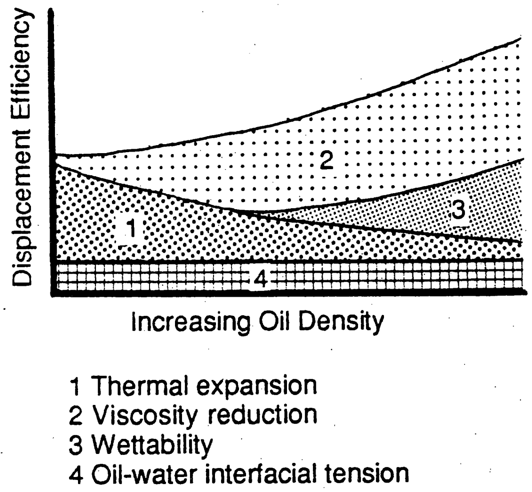


Figure 13. Contribution of recovery mechanisms to displacement efficiency during injection of hot water of oil as a function of density (Prats, 1986).

heavy crudes, whereas thermal expansion is more important in light crudes. Burger and others (1985) recognized three principal zones that develop in a reservoir flooded by hot water (fig. 14). *Zone 1*: At each point in the heated zone, the temperature increases with time, which reduces the residual oil saturation. In addition, expansion of fluids and matrix leads to a reduction of the specific gravity of the oil left in the pore space at the same saturation. *Zone 2*: Oil is being displaced by water that has cooled to the temperature of the formation. The oil saturation at any point in the zone will decrease with time and under certain conditions may reach residual saturation corresponding to the prevailing temperature in the zone. *Zone 3*: Reservoir conditions in Zone 3 are consistent with those prior to injection of hot fluids. In contrast, Burger and others (1985) recognize four zones during steam injection: (1) the steam zone, (2) the condensation zone, (3) the hot-water zone, and (4) the unaffected zone.

The colocation research program has focused on heavy-oil reservoirs because literature and lab data indicated these reservoirs would exhibit a greater viscosity reduction during hot-water flooding than would light-oil reservoirs (Tissot and Welte, 1984; Negus-de Wys and others, 1990). Traditionally, oil is classified primarily by its API gravity, and a heavy oil has a ≤20° API gravity (Lane and Garton, 1935; Smith, 1968; Tissot and Welte, 1984). According to Tissot and Welte (1984), API gravity is strongly correlated with log viscosity (correlation coefficient of 0.916). According to Negus-de Wys and others (1991), for 20° API-gravity oil at a reservoir temperature of 86°F, viscosity can be reduced by an order of magnitude to 5 to 10 centipoise, if reservoir temperature can be increased to 212°F. The practical difficulty is in distributing heat throughout the reservoir and avoiding channeling of injected heated fluids. The disadvantages of hot-water flooding are substantially mitigated if there is an ample supply of naturally heated water near a heavy-oil reservoir.

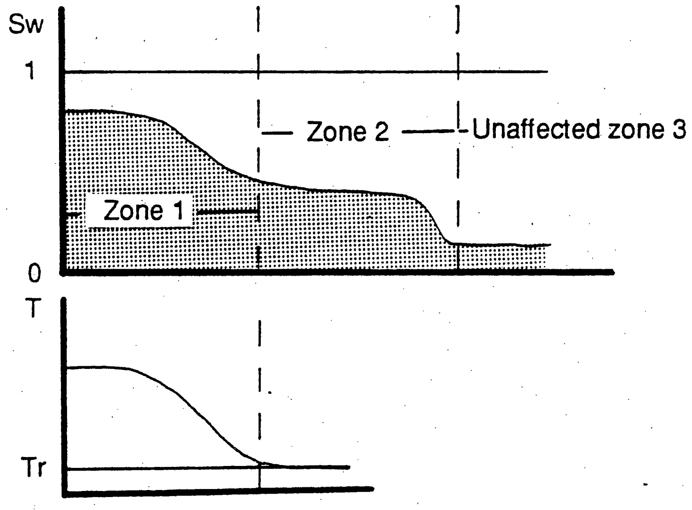


Figure 14. Water saturation and temperature profiles during one-dimensional displacement of oil during hot water injection without vaporization of the light fractions of the oil: Zone 1–heated zone, Zone 2–cool zone, and Zone 3–unaffected zone.

COLOCATION OF HEAVY-OIL AND GEOTHERMAL RESOURCES

South Texas is the best region in Texas to test the viability of using geopressured geothermal fluids to improve oil recovery because here abundant heavy-oil reservoirs of the Mirando trend are colocated above geothermal fairways. For this report the South Texas Wilcox geothermal corridor is defined by the area where the base of the upper Wilcox is deeper than 8,000 ft (fig. 15). The corridor is downdip of the 250°F temperature contour in the upper Wilcox and is associated with thick net sandstones in the deep upper Wilcox (Gregory and others, 1980; Hamlin and others, 1989) in the five-county area of Duval, Jim Hogg, Starr, Webb, and Zapata Counties. Well control and locations of cross sections are shown on figure 16. The Mirando trend contains the greatest concentration of heavy- and medium-oil reservoirs in Texas and produces from shallowly buried (100 to 3,000 ft) reservoirs in the Eocene Jackson Group in Duval, Jim Hogg, McMullen, Starr, Webb, and Zapata Counties. Mirando trend heavy-oil reservoirs are well suited for testing improved recovery using TEOR because they have generally excellent porosity and permeability but are characterized by low recovery efficiency as a result of high oil viscosity.

Previous regional studies documented the sheetlike geometry and strike-orientation of strandplain/barrier-bar sands in the Jackson Group of South Texas (West, 1963; Fisher and others, 1970; Kaiser and others, 1978, 1980) and characterized specific oil fields and reservoirs (Galloway and others, 1983; Hopf, 1986; Schultz, 1986; Hyatt, 1990). Sandstone-rich sequences in the Jackson Group in South Texas are informally referred to as the Mirando, Loma Novia, Government Wells, and Cole Sands. They form a sand-rich belt, 20 to 25 mi (32 to 40 km) wide, bounded by mudstone both updip and downdip (fig. 17). The Government Wells and Cole sands occur within the upper Jackson, whereas the remaining sands occur in the lower Jackson.

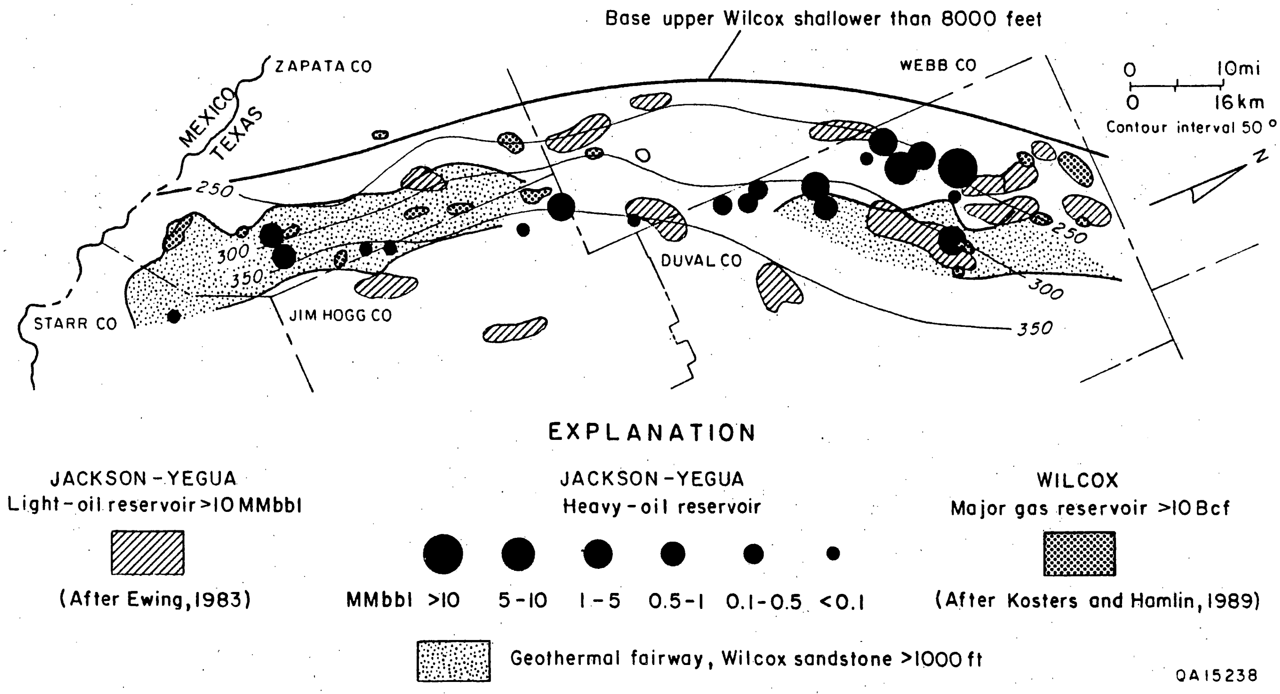


Figure 15. Map showing geopressured-geothermal corridor of the deep upper Wilcox in South Texas (Gregory and others, 1980; Hamlin and others, 1989) and the distribution of heavy- and large medium-oil reservoirs (Galloway and others, 1983). Heavy-oil reservoirs are represented by solid circles whose size is proportional to the size of the reservoir. Updip of the corridor, the base of the upper Wilcox is shallower than 8,000 ft. The corridor includes the area downdip of the 250°F isotherm in the upper Wilcox. Two geothermal fairways (stippled) are associated with net sandstone in the upper Wilcox thicker than 1,000 ft.

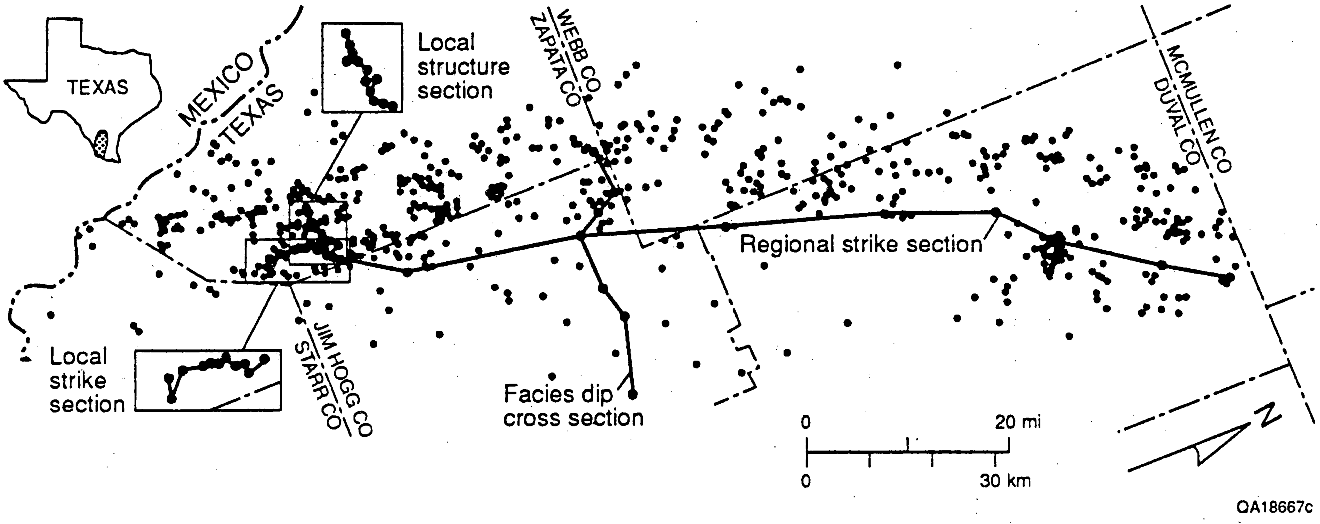


Figure 16. Well control and location of cross sections, South Texas.

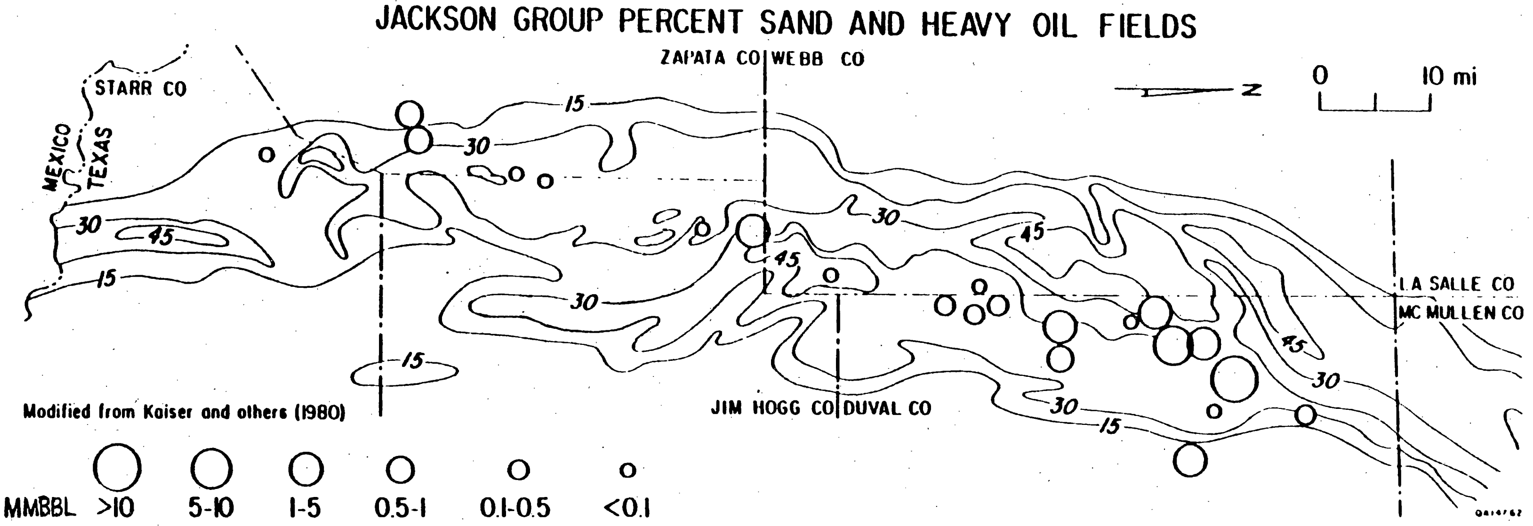


Figure 17. Percent-sand map of the lower Jackson Group in South Texas (Kaiser and others, 1980). The Cole sands occur in the upper part of the Jackson Group and are not represented on the percent-sand map, which emphasized the distribution of Mirando sands.

Jackson Group Oil Distribution

Two classes of oil reservoirs were analyzed in the Jackson Group in South Texas (1) all heavy-oil reservoirs (26) with ≤20° API gravity colocated within the South Texas geothermal corridor and (2) all large oil reservoirs (15) with ≥10 MMbbl cumulative production (Galloway and others, 1983) (fig. 15, tables 3 and 4). Not all of the large oil reservoirs lie within the geothermal corridor. Original oil in place of only the large reservoirs in the Jackson Mirando trend is 1.1 Bbbl (Galloway and others, 1983). Recovery efficiency using primary and secondary recovery for the largest reservoirs is only 38 percent (Galloway and others, 1983). The largest reservoirs in the trend (Government Wells—cumulative production through 1988 of 97 MMbbl and Loma Novia—cumulative production through 1988 of 55 MMbbl) produce from medium-gravity reservoirs. Only two of the largest reservoirs contain heavy oil (Lundell and Seven Sisters). However, the largest reservoirs have an average API gravity of 26°, which is a relatively heavy, medium-gravity oil. The 20° API boundary between heavy- and light-oil reservoirs is arbitrary, and the group of medium-oil reservoirs is relatively heavy.

In the South Texas geothermal corridor, each of the 21 heavy-oil fields (26 reservoirs) has a minimum cumulative production of 1,000 bbl (table 4). The heavy-oil reservoirs comprise a resource target with original oil in place of 110 to 330 MMbbl over the South Texas geothermal corridor (fig. 15). Recovery efficiency of the heavy-oil reservoirs is estimated at 10 to 30 percent (C. Kimmell, personal communication, 1990). Total cumulative production from the heavy-oil fields is 33 MMbbl. Lundell (first Cole) is the largest heavy-oil field and has cumulative production of 10 MMbbl through 1988). Heavy-oil reservoirs constitute 9 percent of the cumulative production of the major medium-oil reservoirs in the Mirando trend in the five-county area.

The stratigraphic and geographic distribution of oil reservoirs in the South Texas Mirando Trend indicates that oil reservoirs are segregated among the various Jackson Group sand bodies

Table 3. Characteristics of large, medium-heavy oil reservoirs in the Mirando trend (Galloway and others, 1983).

RRC Dist	Field and Reservoir	Disc. Date	Lithology	Trap	Drive	Depth (ft)	Oil Col. (ft)	Por. (%)	Permeability Avg. (md)	Permeability Log Range		H_2O Sat.	API Grav.	Init. Gor.	Init. Pres.	Temp. (ft)	Production Technology	Unit Date	Well Spacing (acres)	Ros (%)	OIP (MMbbl	CUM Prod. (MMbbl)	ULT Recov. (MMbbl)	Rec. Eff. (%)
4	Aviators, Mirando	1922	SS	UPP	SG + WD	1700	51	32	357	1	3	.37	21		700	107	WF	1966	10	25	37	10.1	10.3	28
4	Colorado, Cockfield	1936	SS	UPP	SG	2600	300	28	800	2	3	25	45	287	1125	145	WF		10-40	31	52	21.7	21.8	42
4	Conoco Driscoll, U.1GW	1937	SS	NPP	GCE	2800	54	31	458			32	33	139	1290	153	PMG	1937	20	9	69	20.0	23.7	34
4	Escobas, Mirando	1928	SS	NPP	SG	1200	70	30	500	1	3	40	23		575	100	WF,T		10	30	28	12.8	12.9	46
4	Govt. Wells, North G.W.	1928	SS	UPP	SG + WD	2200	60	32	800	2	3	30	21	800	875	114	WF,P,T		10	36	150	77.3	78.0	52
4	Govt. Wells, South G.W.	1928	SS	UPP	SG	2300	89	30	600	2	3	35	21	880	850		PMG,WF		10	20	40	16.6	18.0	45
4	Hoffman, Dougherty	1947	SS	NPP	SG	2000	250	34	757			40	23	85	795	131	WF,P		16	18	55	20.5	21.0	38
4	Loma Novia, Loma Novia	1935	SS	UPP	SG	2600	240	26	800	1	3	25	26	40	1003	114	WF,PMG		10	35	176	47.7	48.0	27
4	Lopez, First Mirando	1935	SS	UPP	Combined	2200	70	35	250	1	3	40	22		780	111	PMG,WF,T	1955	10	25	75	30.4	33.0	44
4	Mirando City, Mirando	1921	SS	UPP	Combined	1600	35	33	1600	2	3	40	21	125	665		WF,T			25	46	12.1	12.1	26
4	O'Hern, Pettus	1930	SS	NPP	SG	2700	200	28	286	1	3	20	28		990	136	PMG,WF,T	1957	10	20	83	22.2	30.0	36
4	Piedre Lumbre, G.W.	1935	SS	NPP	WD + SG	1900	65	30	300	1	3	30	22		820	100	PMG,WF,LPG		10	25	95	20.7	22.0	23
4	Prado Middle, Loma Novia	1956	SS	UPP	SG + GCE	3700	65	32	850	1	4	26	40	600	1407	109	PMG,WF	1957	10	30	38	10.4	23.7	62
4	Seven Sisters, G.W.	1935	SS	NPP	SG + WD	2330	75	28	225	1	2	55	20		1150	132	PMG,WF		10	15	142	35.0	56.0	39
					m	2273	1110	31	613			34	26	370	930	121				25	Σ 1086	367.5	440.5	39

Table 4. Characteristics of heavy-oil reservoirs in the South Texas geothermal corridor.

RRC Dist	Field and Reservoir	Disc. Date	Lithology	Trap	Drive	Depth (ft)	Oil Col. (ft)	Por. (%)	Permeability Avg. (md)	Permeability Log Range	H_2O Sat.	API Grav.	Init. Gor	Init Pres	Temp (ft)	Production Technology	Unit Date	Well Spacing (acres)	Ros (%)	OIP (MMbbl	CUM Prod. (MMbbl)	ULT Recov. (MMbbl)	Rec. Eff. (%)	Producing SS
4	Alworth, Cole Sand	1965	SS	Comb.	WD	1040	6	29	511		31	19		191		WF		63			.078			Cole
4	Bruni, S.	1944	SS			1804		31	600			19									.001			Cole
4	Bruja Vieja, Cole Sand	1950	SS			1755						18									001			Cole
4	Cedro Hill	1938	SS	Strat	SG + WD	1440	12	31	700		42	19		400		WF			13.65		6.569			Cole
4	Charco Redondo	1913	SS	Strat	SG	339	14	33	1659	518-2900	25	17		30		AF			7.7		.659			Cole
4	Colema	1936	SS	Strat	SG + WD	1500	20	32	650		40	19		600		WF					3.868			Cole
4	Dinn	1949	SS	Strat	WD	1805	5					19									.319			Cole
4	Edlasater, W., Cole 950	1968	SS			950						20									.013			Cole
4	El Puerto, N., O'Hern	1965	SS			760						20									.001			4th Mirando
4	Govt. wells, N., 900 Sand	1948	SS			918						20									.315			Cole
4	Govt. wells, N., 1000 Sand	1950	SS			1062						19									.080			Cole
4	Govt. wells, N., 1150	1978	SS			1167						20									.023			Cole
4	Govt. wells, No., 1550	1949	SS			1547						20									.030			Cole
4	Govt. wells, S., Hockley 1900	1965	SS			1919						19									.030			Taracahuas
4	Hoffman, E.	1950	SS	Strat	SG	2038	20					20									1.387			Taracahuas
4	Joe Moss, 500 Sand	1952	SS			500						20									.557			2nd Mirando
4	Kohler, NE., Mirando #2	1980	SS		S	2633						19									1.217			Cole
4	Las Animas-Lefevre	1937	SS	Strat	SG	1793	20	31	800		35	19		620		WF			3.600		3.402			Cole
4	Lopez, N., (Lopez)	1951	SS	Strat	SG	2064	10	35	428		33	20		960		WF					2.225			Cole
4	Lundell	1937	SS	Strat	SG	1528	10					19		700		WF					10.358			Cole
4	Orlee	1949	SS	Strat	WD	1697	10	25	200		35	20		765							.266			1st Cole
4	Peters, N., Cole First Sand	1959	SS	Fault		1746						20									.042			Cole
4	Rancho Solo	1937	SS	Comb.		1849						19									.465			1st Cole
4	Rancho Solo, Cole Second	1959	SS	Fault		1840		31				20									.030			2nd Cole
4	Rancho Solo, Extension	1939	SS	Strat		1836						19									.520			Cole
4	Richardson	1944	SS			1784						18									.147			Cole
				m		1512	12.7	31.	694		34	19		533						Σ	32.92			

21 Fields
26 Reservoirs

(fig. 18). Seventy-nine percent of the oil in the largest reservoirs is in the Government Wells and Mirando sands. In contrast, 84 percent of the heavy oil is in the Cole sands. The Cole Sand contains no medium-oil reservoirs with cumulative production greater than 10 MMbbl. The shallow Cole sands contain many small heavy-oil reservoirs, whereas the medium-oil reservoirs in the Mirando and Government Wells sands are much larger.

A plot of API gravity versus depth illustrates depth dependency of the large and heavy-oil reservoirs (fig. 19). The large oil reservoirs show two trends of API gravity with depth: (1) shallow trend of relatively consistent API gravity (average API gravity = 21°) over a depth range of 1,000 to 2,500 ft and (2) a deep trend of increasing API gravity with increasing depth over a depth range of 2,500 to 4,000 ft. The heavy-oil reservoirs show a relatively constant gravity (average API gravity = 19.3°) over a depth range of 200 to 2,500 ft. Heavy-oil reservoirs are significantly shallower than major light-oil reservoirs (mean depth of 1,512 ft for heavy reservoirs versus 2,273 ft for light reservoirs). Interestingly, the overall trend of API gravity of both populations of reservoirs illustrates relatively constant gravity (average API gravity = 20°) for reservoirs at a depth of 200 to 2,500 ft and then increases with increasing depth.

The consistently low API gravity of the shallow reservoirs is interpreted to result from water washing and bacterial degradation that was particularly active above a depth of 2,500 ft (Tissot and Welte, 1984). The processes that result in heavy-crude oil include biodegradation, water washing, loss of volatiles, and oxidation (Philippi, 1977; Tissot and Welte, 1984). Fresh water invasion in Jackson Group sands is indicated by electric logs that show reversal of the SP curve occasionally to a depth of 2,000 ft. Deeper than 2,300 ft the API gravity increases with depth as a function of increasing temperature with depth and lack of fresh water and bacteria.

Jackson Group Sand-Body Geometry and Depositional Facies

A dip-oriented cross section of the Jackson Group in Zapata County illustrates the typical structural setting and stratigraphic relationships for the Jackson Group across the deep Wilcox

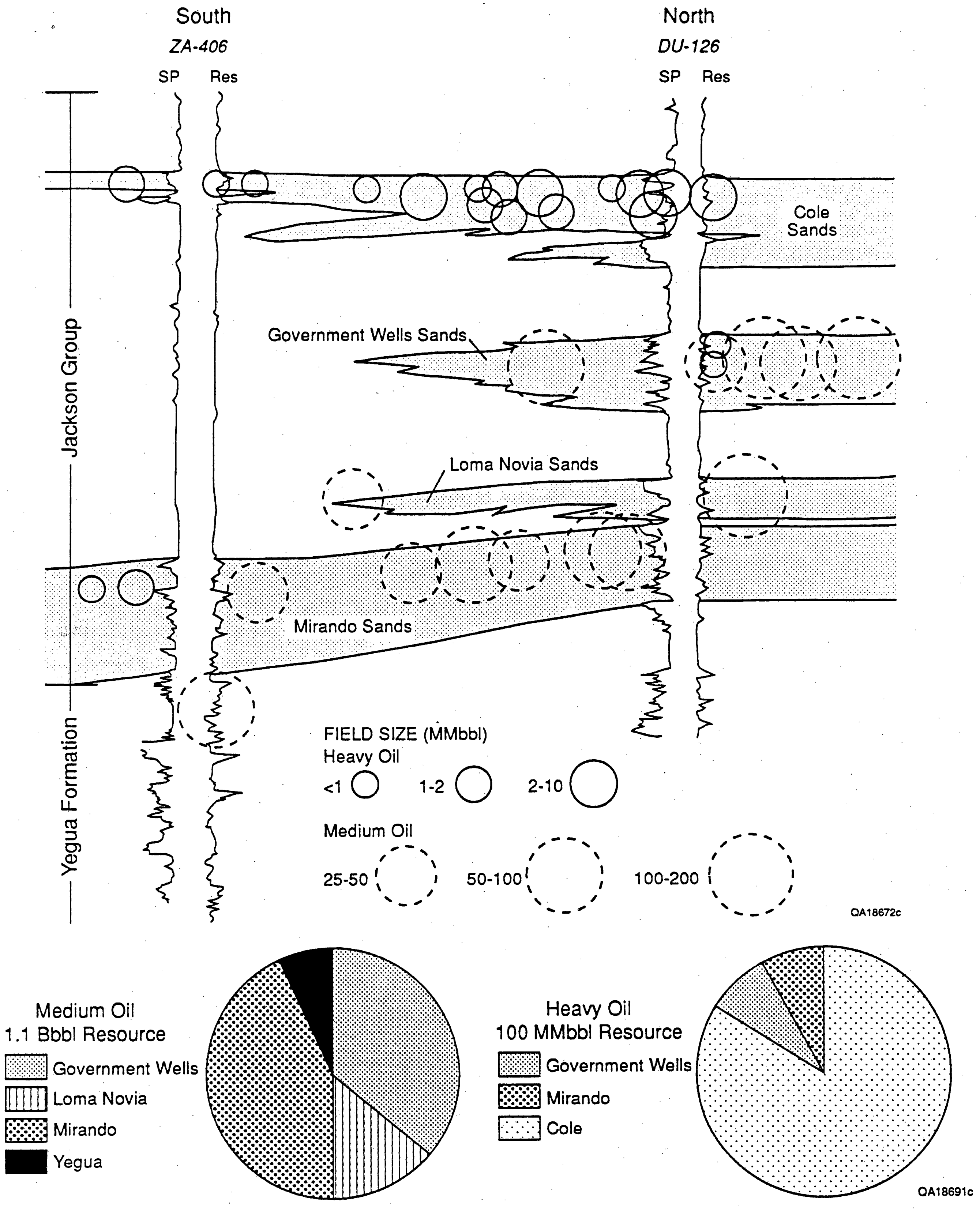


Figure 18. Cross section illustrating distribution of heavy-oil reservoirs (API ≤20°) and of large reservoirs in Jackson Group (from Galloway and others, 1983) along strike from Zapata County (south) to Duval County (north) and by stratigraphic horizon. Pie diagrams show stratigraphic distribution of reservoirs. Heavy-oil reservoirs are concentrated in Cole sands, whereas large medium-oil reservoirs are concentrated in Government Wells and Mirando sands. Wells are located at southern and northern end of regional strike section on figure 16.

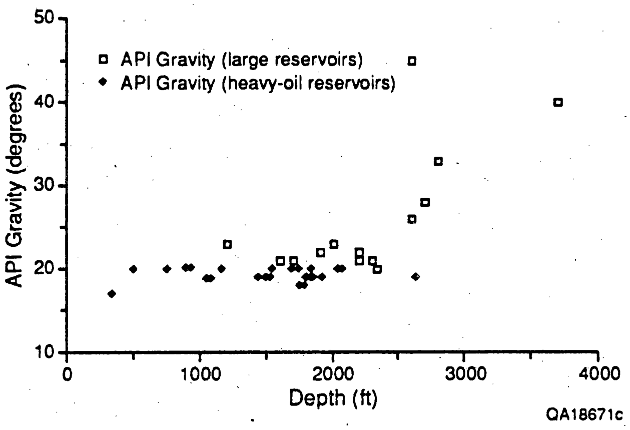


Figure 19. Plot of API gravity as a function of depth, Jackson Group reservoirs, South Texas.

geothermal fairway and the association of oil reservoirs with the updip pinch-out of sheet sandstones (fig. 20). The influence of faulting on regional patterns of hydrocarbon entrapment is relatively insignificant. However, small faults do form local barriers to lateral migration. The gulfward dip of Jackson strata ranges from 125 to 250 ft/mi and has enhanced the gravity segregation and updip migration of hydrocarbons toward updip porosity pinch-outs.

A strike-oriented cross section from Zapata to Duval Counties illustrates the lateral continuity of sands in the Jackson Group of the South Texas colocation area (fig. 21). To the north in Duval County, the Jackson is sand rich where Loma Novia and Government Wells sands are thick. The Mirando and upper Cole Sand sands are continuous across the area; however, the Loma Novia, Government Wells, and lower Cole sands pinchout to the south.

A sand-percent map of the lower part of the Jackson Group illustrates the strongly linear strike orientation of the sandstone belt (fig. 17) (Kaiser and others, 1980). A net-sandstone map of the upper Jackson (fig. 22) (including the Cole and Government Wells sands) shows a similar strike-orientation of net-sand thickness. Government Wells and Cole sands thin to the south, indicating longshore sand transport from the north. The axis of thickest net sandstone in the upper Jackson sands has prograded seaward 15 mi in the northern part of the study area from the location of the axis for the lower Jackson. However, little seaward progradation of the axis of thick net sandstone occurred in the southern part of the study area, where the Jackson Group is thicker.

The updip and downdip pinchouts of a single Cole sand body in Jim Hogg and Zapata Counties can also be demonstrated within a vertically restricted stratigraphic section. The thickness of the first Cole Sand ranges up to 100 ft and the width of the first Cole Sand is approximately 8 to 10 mi (fig. 23). A dip-oriented facies cross section illustrates lateral relationships among depositional facies and indicated that the sand body was deposited in a variety of sand-rich depositional environments (fig. 24). Both thickness relationships and log character were used to identify depositional facies. Sand-body thickness is greatest in the barrier-core sands that are characterized by progradational base and blocky tops. Barrier-core

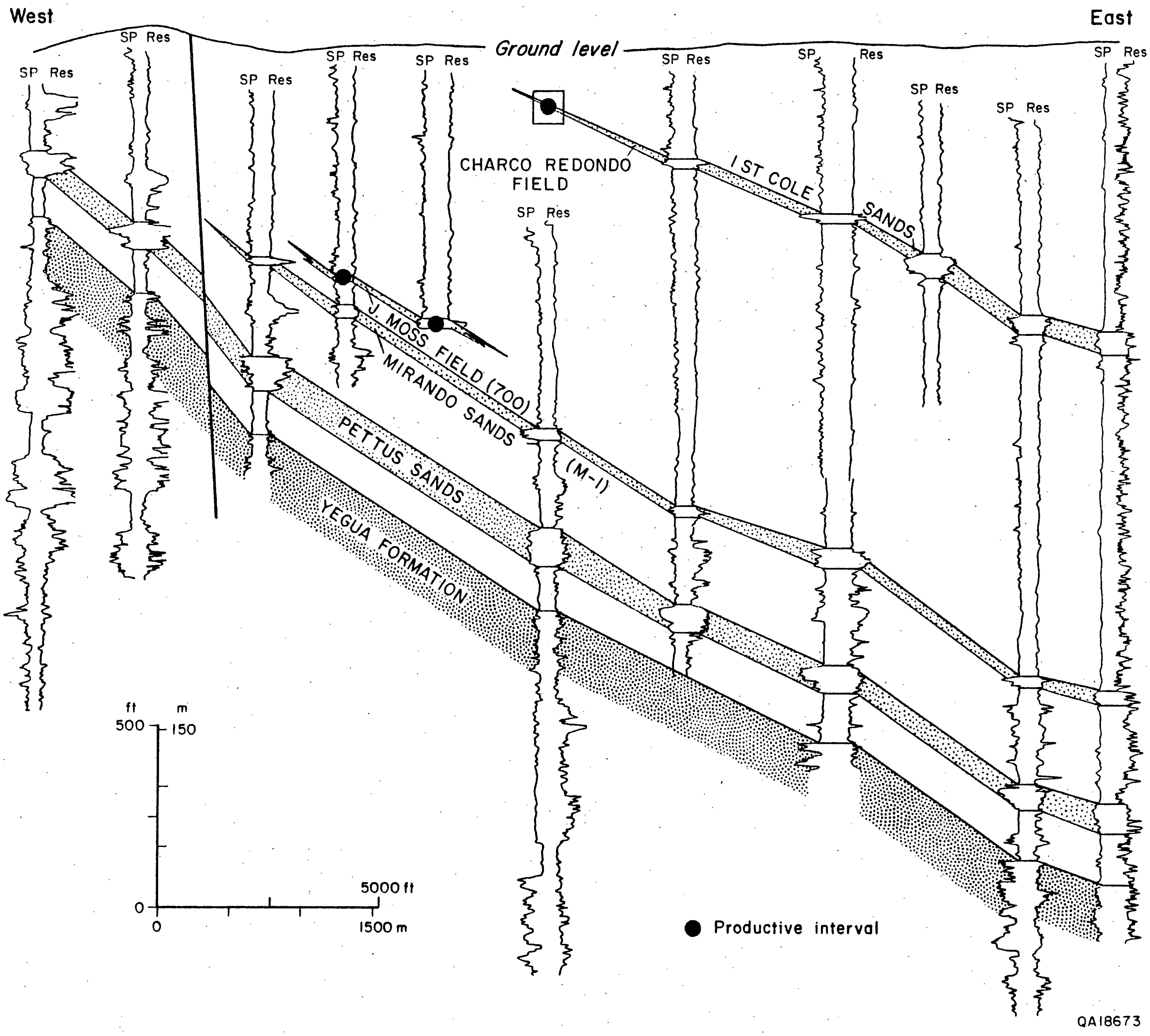


Figure 20. Dip-oriented structural cross section illustrating structure of Jackson Group and updip pinch-out of upper Jackson Group sandbodies. Section is labeled local structure section on figure 16.

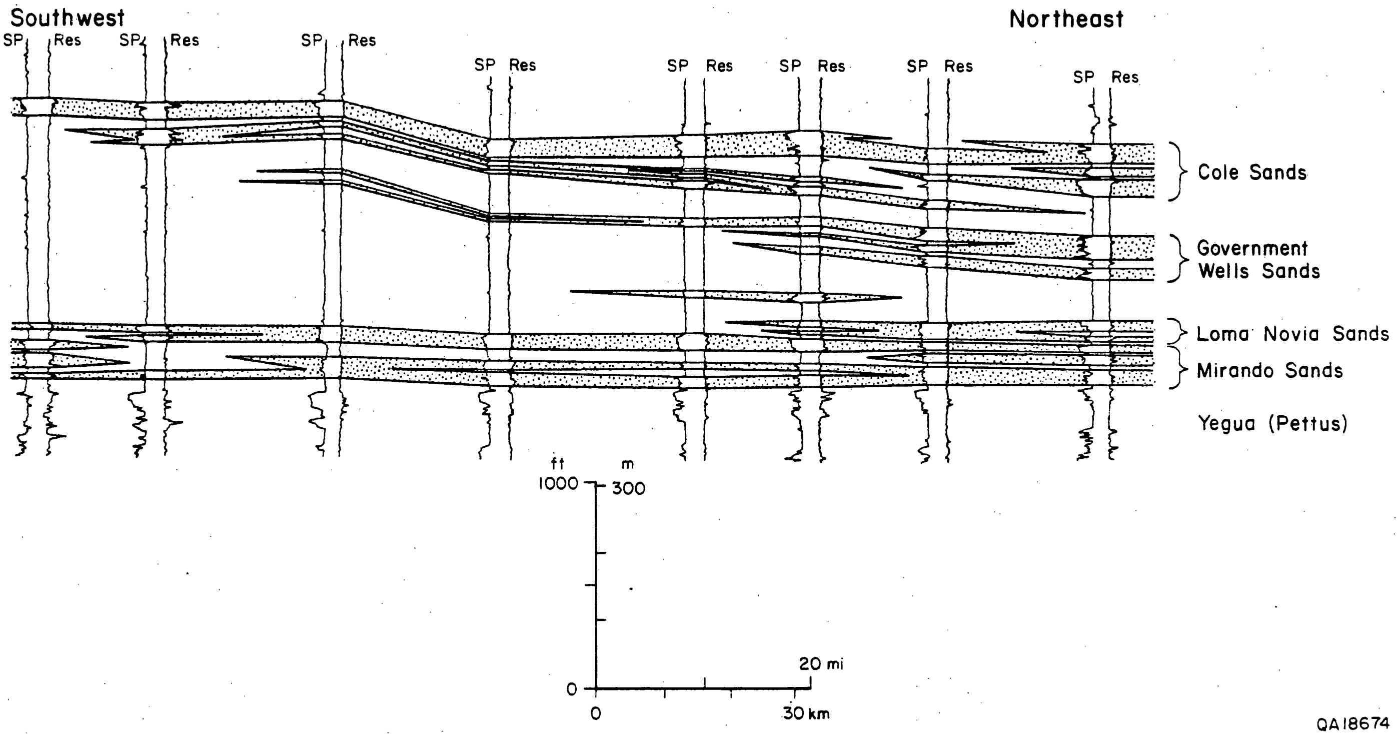


Figure 21. Strike-oriented cross section illustrating lateral continunity of Jackson Group sand bodies. Section is labeled regional strike section on figure 16.

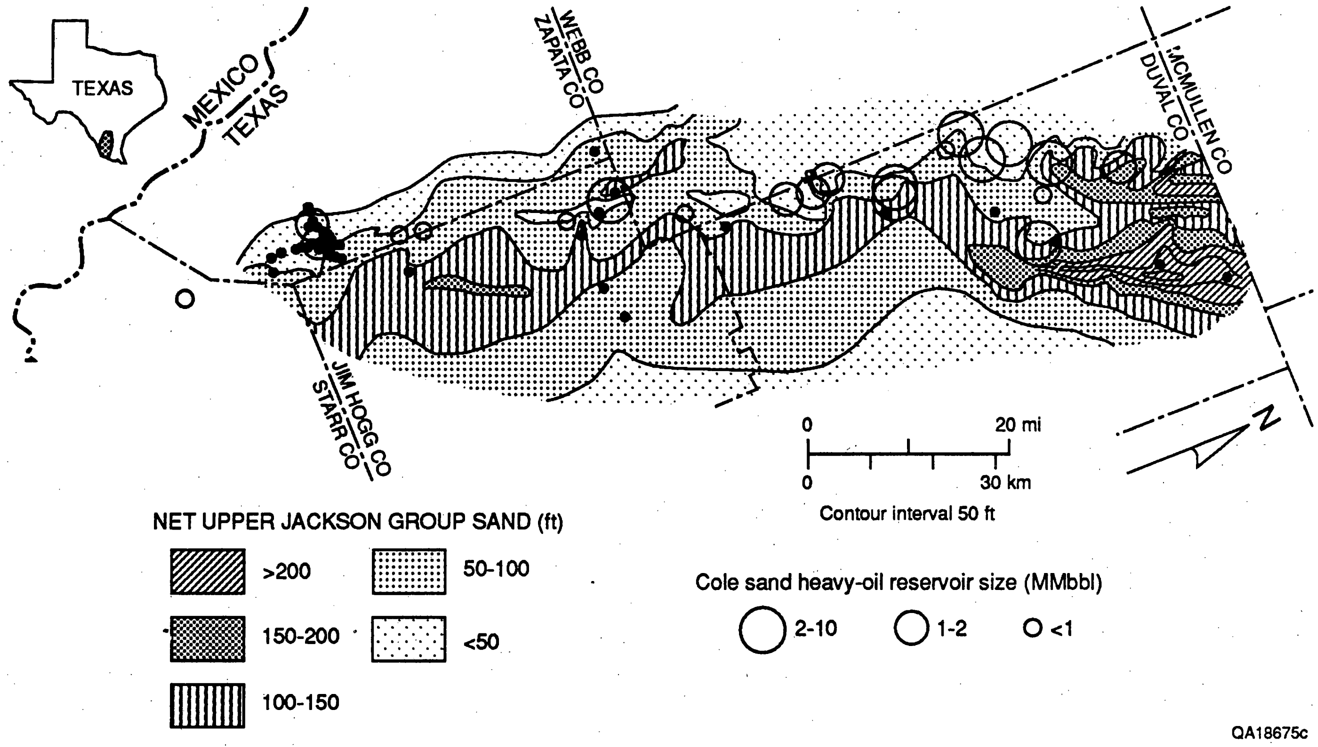


Figure 22. Net-sand map, upper Jackson Group, including the Cole and Government Wells sands.

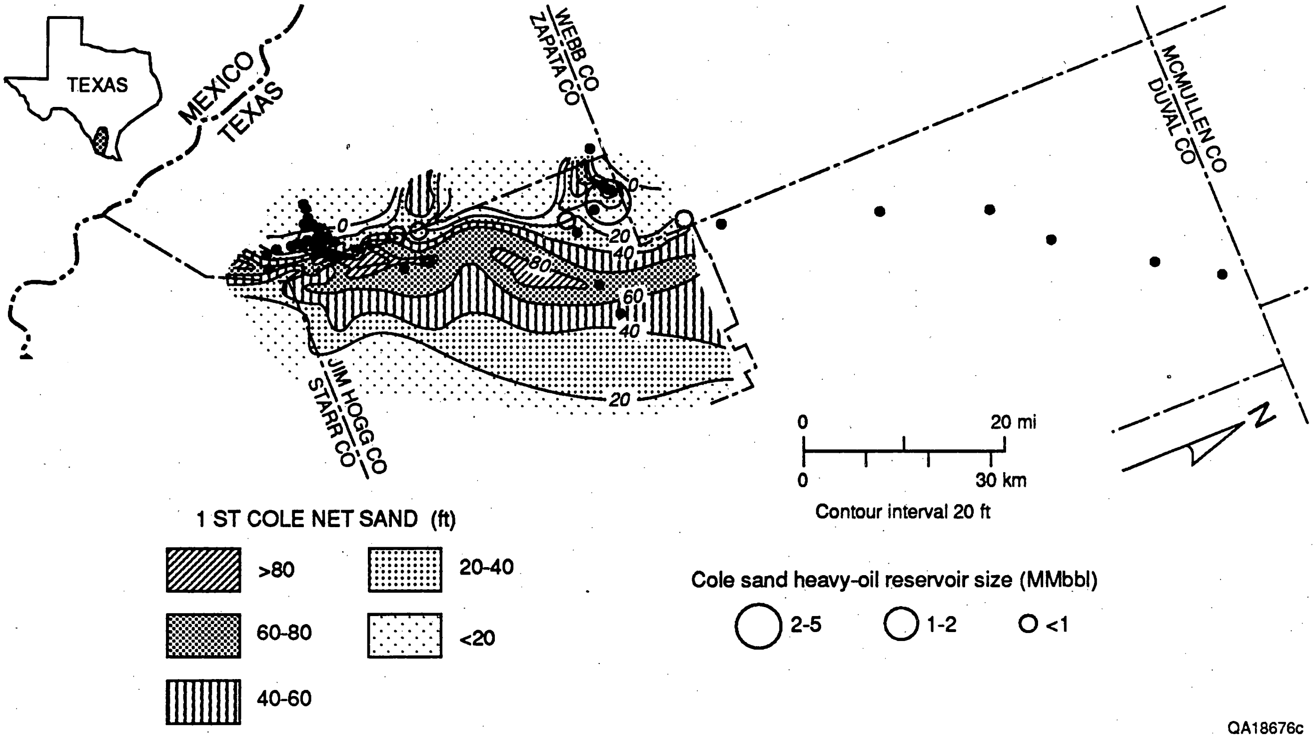


Figure 23. Net-sand map, first Cole Sand, Jim Hogg and Zapata Counties.

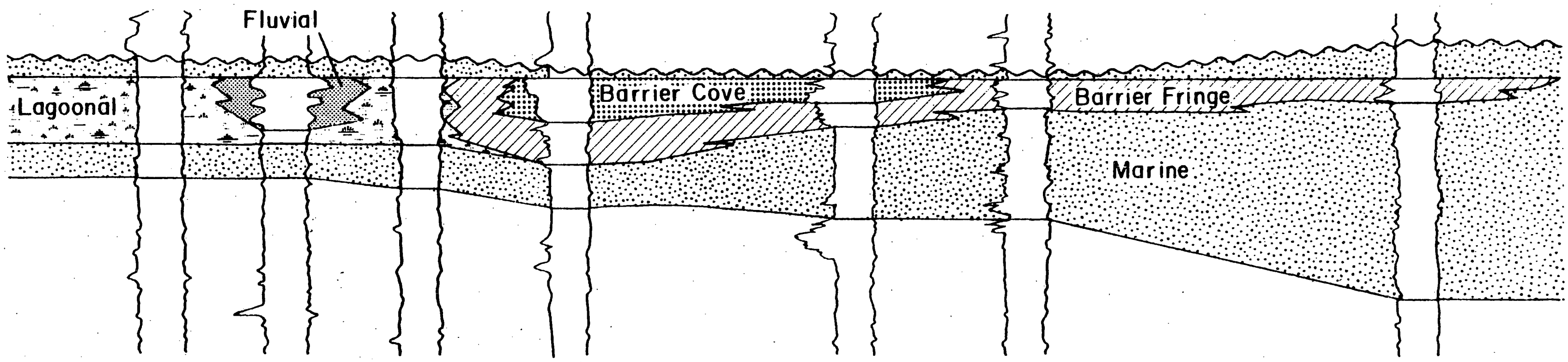


Figure 24. Facies cross section, first Cole Sand. Section is labeled facies dip cross section on figure 16.

and back-barrier sandy facies rapidly grade updip into sand-poor lagoonal facies. Lagoonal mudstones occur updip of barrier-strandplain sandstones. Fluvial facies are isolated within muddy lagoonal facies on the landward updip margin of the sand-rich belt. Within the lagoonal mudstones are isolated, dip-oriented fluvial-deltaic sandstones consisting of thin upward-coarsening packages at the base and multiple upward-fining packages at the top. Fluvial-deltaic sandstones apparently did not prograde across the extensive lagoonal mudstones and breach or feed the barrier/strandplain. In a seaward direction, barrier-fringe sandstones thin gradually and are replaced by offshore mudstones and siltstones.

The availability of abundant core allowed the characterization of reservoir texture and mineralogy at Charco Redondo field, which is associated with the updip pinchout of the first Cole Sand (figs. 20 and 25). The reservoir at Charco Redondo field is typically a friable, uncemented, clean fine sand that coarsens upward as the percentage of fine silt and clay declines (figs. 25 and 26). Fabric has been destroyed by drilling or burrowing. Textural analysis indicates that the reservoir sands are poorly sorted to well sorted, strongly fine skewed, medium- to fine-grained and contain 75 to 95 percent sand and 1 to 7 percent clay. Burrowed, oyster-bearing, fine sandy mudstones overly and underlie the reservoir. The surrounding mudstones are very poorly sorted and fine skewed and are a subequal mixture of fine sand and silt with 15 to 22 percent clay. Thin calcite-cemented zones within the reservoir are tight and apparently affect the distribution of the oil (figs. 25 and 26).

Swelling smectite clays occur in mudstones that encase the reservoir (fig. 27). Standard oriented clay mineralogy slides were analyzed with X-ray diffraction, glycolated, and heated to confirm mineral identification. Reservoir sandstones at Charco Redondo field contain a relatively low percentage (1 to 7 percent) of swelling smectite clays. The occurrence of smectite clays in other heavy- and medium-oil reservoirs in the Jackson Group is likely to be common owing to the similar depositional and diagenetic history. The percentage of clay minerals in a given reservoir is expected to depend on the location of the reservoir with respect to sandbody pinchout and to depositional facies.

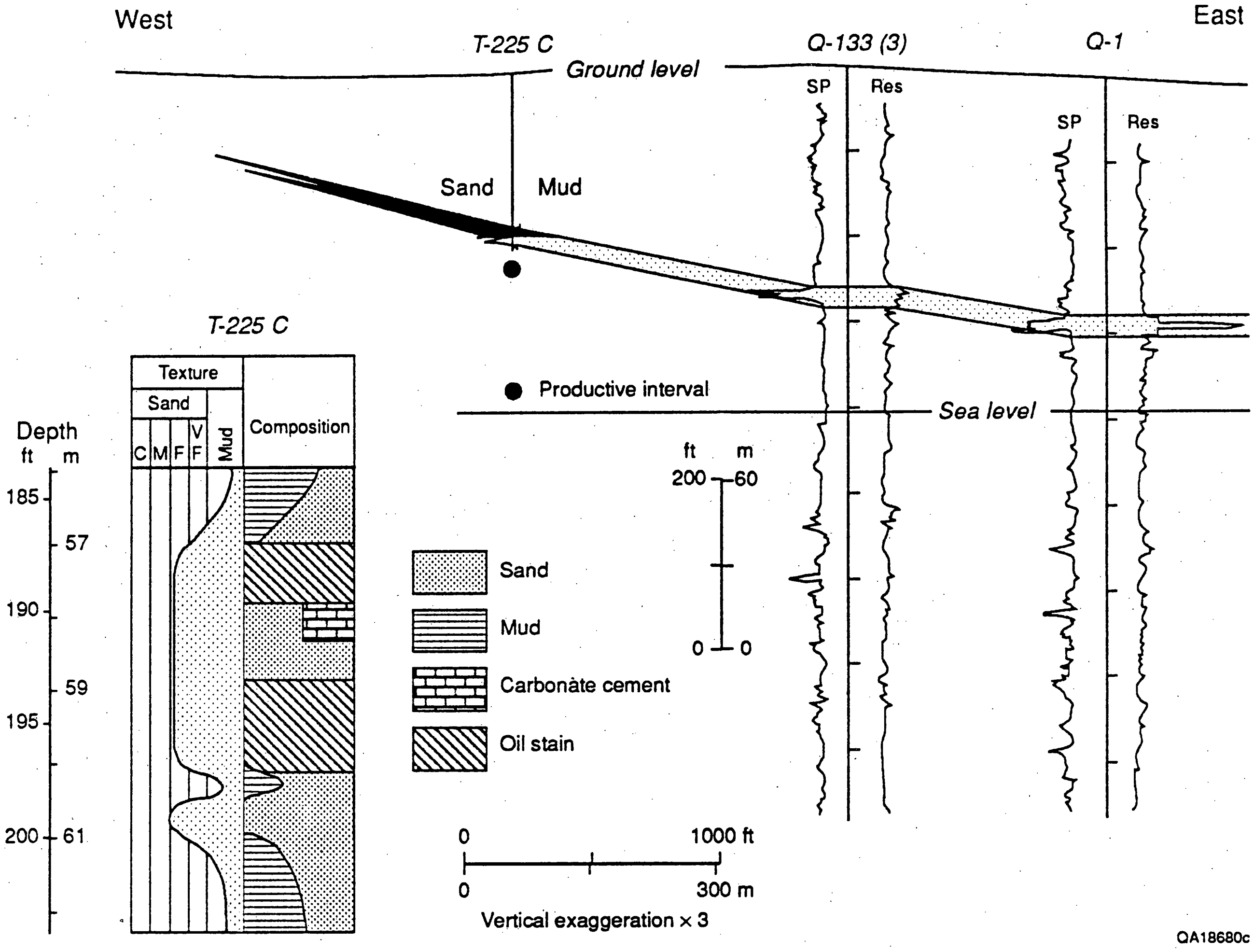


Figure 25. Structural cross section, Charco Redondo field, showing updip pinch-out of first Cole Sand at Charco Redondo field. Textural and compositional variations based on description and analysis of core from Charco Redondo field.

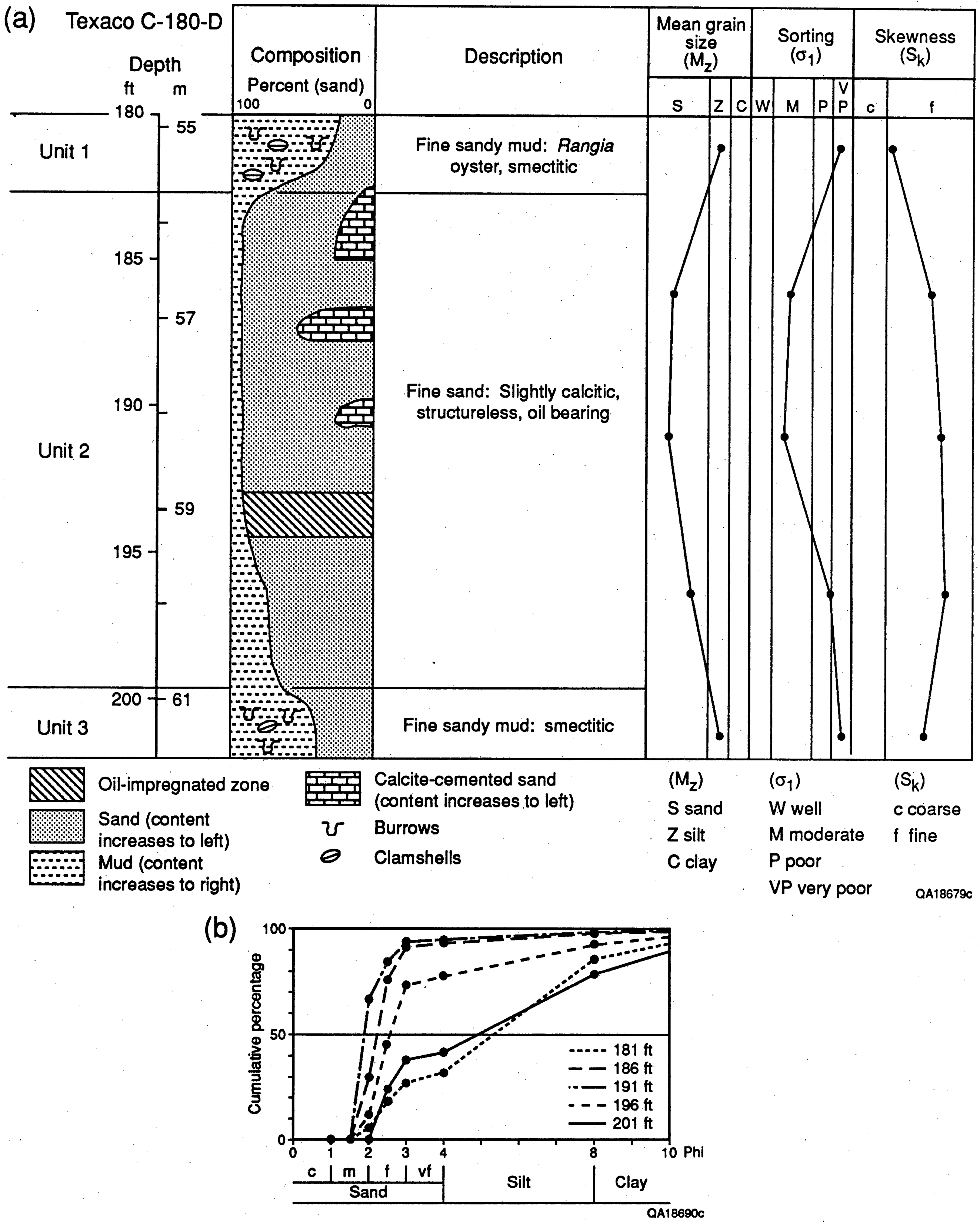


Figure 26. Well description, Texaco C-180-D, Charco Redondo field. A. Description of upper Jackson Group first Cole Sand from Charco Redondo field, Zapata County. B. Textural data based on wet sieve analysis. Compositional variations are based largely on variations in the percentage of matrix clay and silt that is admixed with the abundant fine to medium sand.

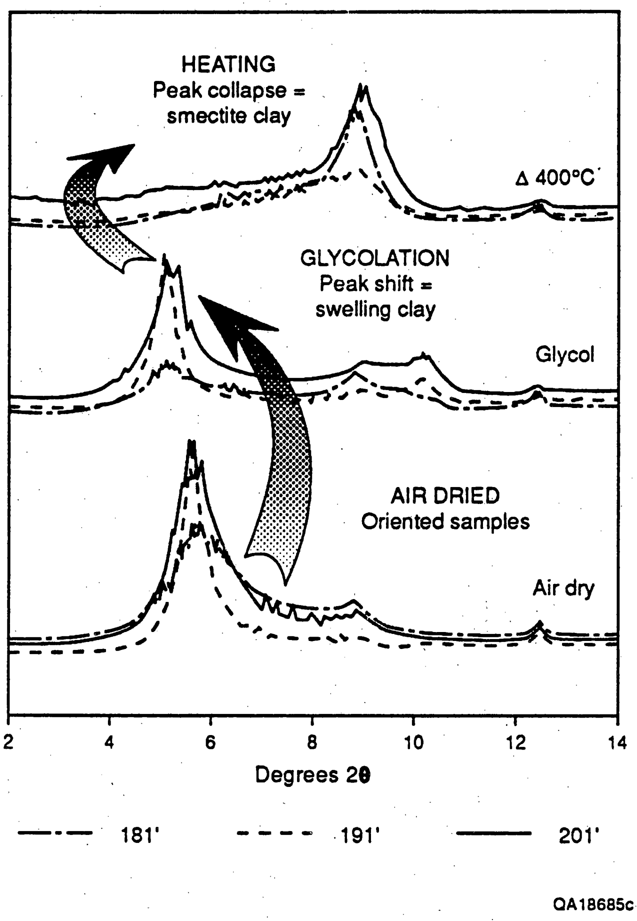


Figure 27. Clay mineralogy, Texaco C-180-D, Charco Redondo field, Zapata County.

Facies Control on Heavy-Oil Reservoirs

A depositional facies map (fig. 28) of the first Cole sand was derived from well log character and a net-sand map (fig. 22) reveals facies relationships and alignment of heavy-oil reservoirs. Heavy-oil reservoirs at Charco Redondo, Ed Lasater, Alworth, Bruja Vieja, Las Animas-Lefevere, and Bruni South fields are located along the updip pinchout of barrier-fringe facies against lagoonal mudstones. At Charco Redondo field the upper Cole Sand is 10 to 20 ft thick. Reservoir traps form in updip facies by loss of porosity through (1) sand-body pinchout and (2) increasing percentage of clay in the sand body.

A detailed cross section based on closely spaced cores (50 ft) reveal diagenetic heterogeneities related to low permeability zones of calcitic sandstone segment heavy-oil reservoirs at Charco Redondo field (fig. 29). An offlapping series of calcite cemented zones occur in the upper part of the sand body in a updip position, dip basinward, and extend to the lower parts of the sand body in a downdip position. These zones apparently formed along accretionary-grain surfaces that dip across the sand body. Porosity/permeability plots for reservoirs in the upper Cole sand at Charco Redondo and 76 West fields indicates zones with high porosity (25 to 35 percent) and permeability (100 to 3,000 md) are separated by calcite-cemented zones with low porosity (5 to 15 percent) and permeability (0.001 to 10 md) (fig. 30). The distribution of low-permeability, calcite-cemented zones segments the reservoirs. Such compartmentalization could interrupt reservoir drainage and affect pathways of injection fluids.

DISCUSSION

The colocation of heavy-oil reservoirs and geothermal corridors is a necessity for using geothermal fluids in a geothermally enhanced oil recovery process. However, colocation alone

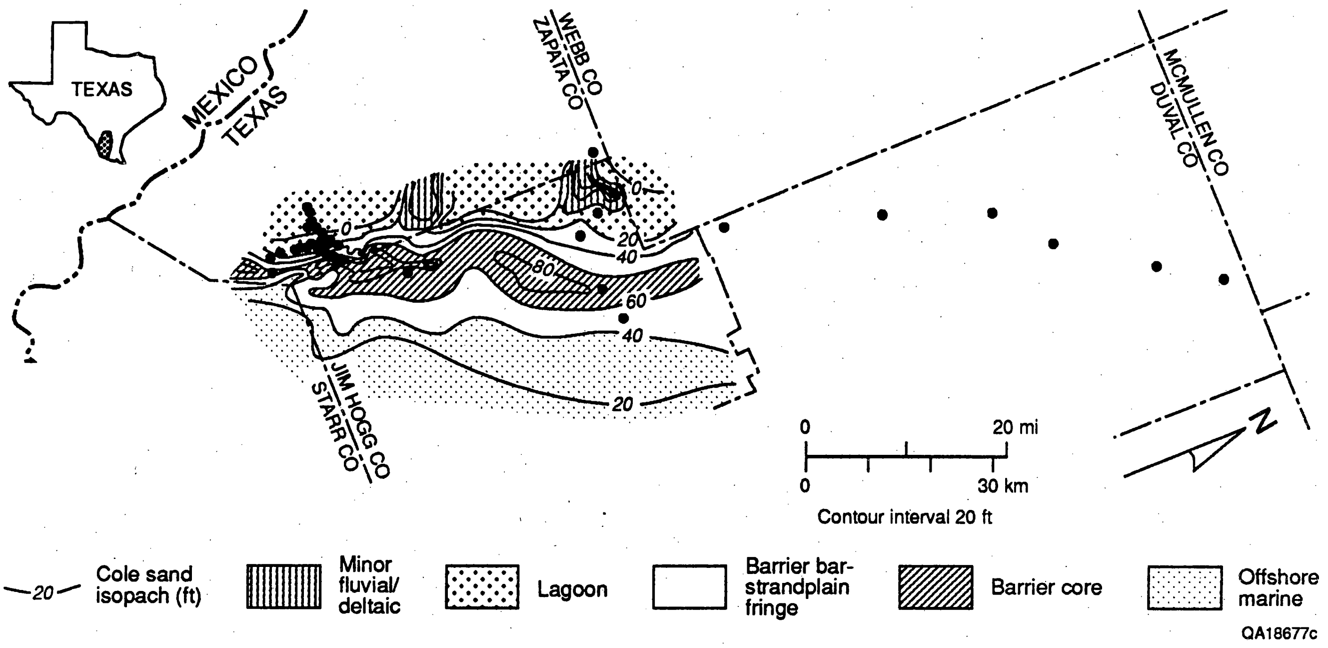


Figure 28. Facies map of first Cole Sand and distribution of heavy-oil fields, Jim Hogg and Zapata Counties.

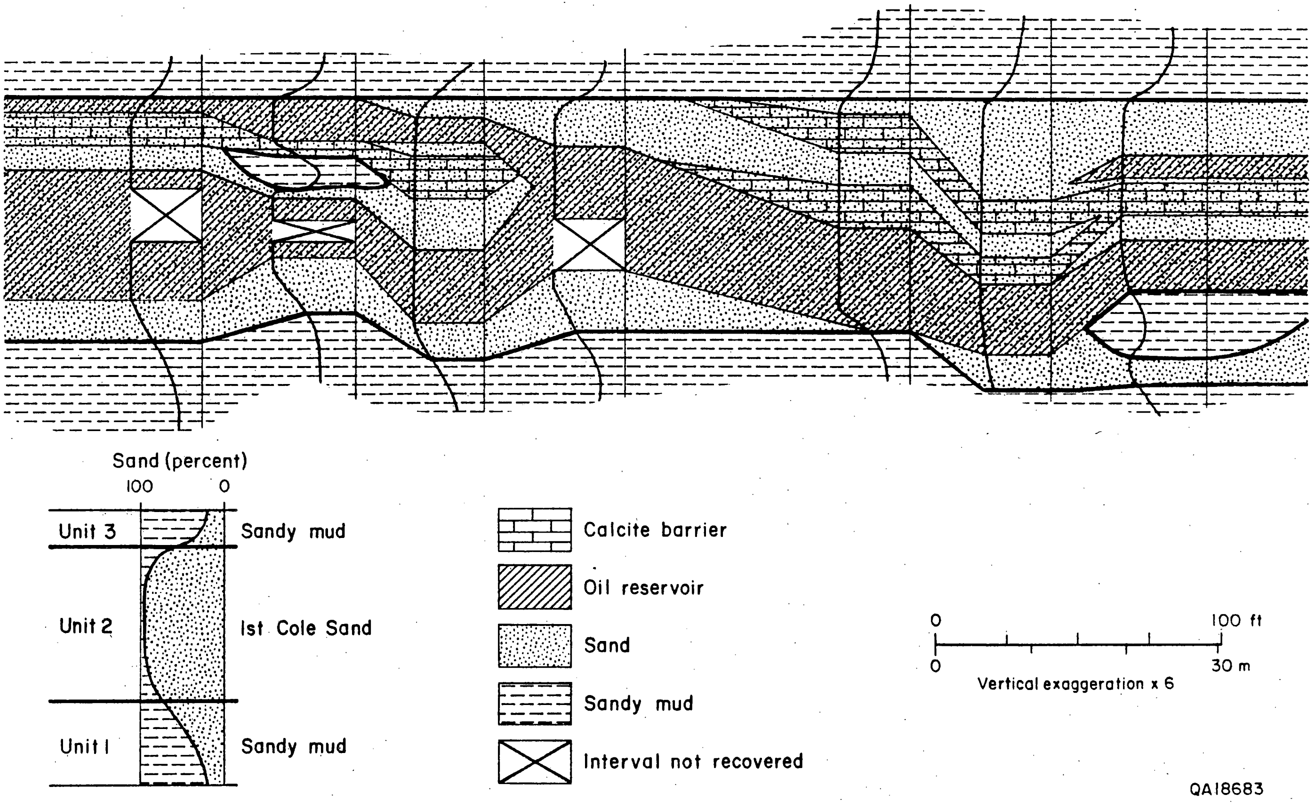


Figure 29. Cross section of Charco Redondo field utilizing core descriptions. Core consisted predominantly of disaggregated sand owing to the shallow depth of burial. Thin calcite-cemented sandstones appear to segment the reservoir into compartments.

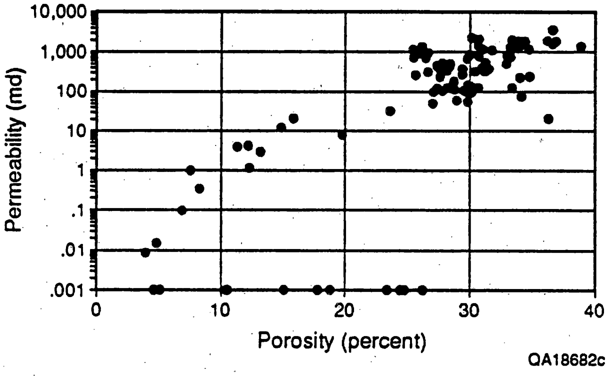


Figure 30. Plot of porosity and permeability, first Cole Sand.

does not necessarily mean the process is commercially or technically feasible. Characteristics of the potential target oil and geothermal reservoirs must be carefully considered. Conditions of special significance for possible geothermal enhanced oil recovery process in the South Texas area include (1) relatively shallow, thin heavy-oil reservoirs with thin oil columns, (2) generally excellent porosity and permeability complicated by low-permeability barriers, (3) swelling clays in oil reservoir, and (4) low permeability in the geothermal reservoir.

The shallow depths of heavy-oil reservoirs (mean depth of 1,512 ft) constrain the upper limit of injection pressures to prevent fracture of the reservoir. However, even at these relatively low pressures, injected geothermal fluids at 350°F will still be hot water and not steam. Although hot water is a less efficient mobilizing agent than steam, such inefficiency would be mitigated if an abundant and long-term supply of low-cost geothermal water were available.

A thin, blanket-type oil column in a thin reservoir that pinches out updip is an ideal geometry for favorable sweep efficiencies of conventional injected fluids. However, the thinness of the reservoir is unfavorable for hot fluids because of relatively high rates of heat loss (Martin and others, 1968). Although the laterally continuous character of heavy-oil reservoirs is generally favorable for minimizing reservoir compartmentalization, diagenetic calcite-cemented zones have compartmentalized the oil reservoir at Charco Redondo field. Such zones are suspected as being common in other heavy-oil reservoirs of the Mirando trend. A complete characterization of the genesis of such calcite-cemented zones would be prudent to avoid poor reservoir performance as a result of the unsuspected flow barriers.

A potential concern during injection of foreign fluids into an oil reservoir is undesirable reactions that could adversely affect oil production. A common undesirable reaction encountered during injection of fresh water or steam into a reservoir is plugging of pore throats as a result of swelling of smectite clays. Such plugging reduces porosity and particularly permeability. Smectite clays are susceptible to swelling when fresh water becomes bound into the clay structure. High-salinity fluids do not cause smectite clays to swell. Although smectite is present in Mirando trend reservoirs, the percentage clay in a given Mirando trend reservoir is going to be variable and primarily controlled by depositional facies distribution and relation of oil reservoir to updip porosity pinch-out.

The inability to predict salinity distribution in the deep upper Wilcox makes the potential problem of swelling clays difficult to assess. The salinity of formation waters is controlled by a complex and poorly understood interaction among local and regional geology, faults, compaction, clay diagenesis, temperature, fluid migration, salt tectonics, rock stress, and pressure (Fertl and Timko, 1970; Gregory and others, 1980). Along the Texas Gulf Coast, a plot of salinity versus depth indicates wide variations with generalized trends. Salinity typically increases with depth to the geopressured zone. In the geopressured zone salinity decreases. In the deepest zone, salinity trends become unpredictable. Generally, in the South Texas area, salinity is lower, in the range of <10,000 ppm to >80,000 ppm, than at comparable depth along the upper Texas coast (Gregory and others, 1980; Hamlin and others, 1989).

Potential geothermal fairways in Tertiary strata in the South Texas area, including the Frio, Vicksburg, and upper Wilcox reservoirs, were originally considered unfavorable for high volume production (20,000 bbl/d) of geothermal fluids owing to generally poor reservoir quality and low permeability in comparison to other geothermal fairways (Bebout and others, 1978; Loucks, 1980; Bebout and others, 1982). However, production rates from South Texas geothermal reservoirs are likely to range up to 2,000 bbl/d, which may be adequate for geothermally enhanced oil recovery.

Favorable Colocation Characteristics

A computerized data file at the Railroad Commission of Texas (RRC) was accessed to determine the status of existing wells in the South Texas area that might serve as suitable geothermal wells at a fraction of the cost of drilling a geothermal design well. Of the groups of well types examined, abandoned gas wells were considered most favorable because they are likely to be deep, to have intact casing, and to have an existing infrastructure of pipelines and other production facilities. Wells drilled before 1970 are not in the RRC computerized data file. The wells examined are from the inventory of well logs on file at the Bureau of Economic Geology (BEG). The South Texas well log data base at the BEG exceeds 700 wells, including shallow Jackson logs (100 to 3,000 ft) and deeper Wilcox penetrations. BEG has acquired logs from more than 90 percent of the wells in the South Texas area that penetrate through the upper Wilcox. The status of post-1970 wells in the BEG file (266 wells) is as follows: 44 percent (117) are current producers, 23 percent (60) are abandoned producers, 21 percent (55) are drilled and abandoned, and 12 percent (33) are not in the file. Pre-1970 wells with logs in the Wilcox interval (294 wells from the BEG well file) have an average depth of 7,238 ft, whereas post-1970 wells have an average depth of 12,836 ft. Abandoned gas producing wells have the deepest average depth, 14,765 ft.

Abandoned gas producing wells were plotted with a 2.5-mi radius around the wells in the South Texas colocation area to determine the extent of colocation among the wells and potential heavy- and medium-oil reservoirs (fig. 31). The boundaries of 38 heavy- and medium-oil fields in the Jackson Group contact or lie within a 2.5-mi radius around abandoned gas wells in the upper Wilcox in the South Texas colocation area. Approximately 35 abandoned gas wells occur within a 2.5-mi radius of a heavy- or large medium oil field. Fifty-two percent of the heavy-oil fields in the South Texas area occur within 2.5 mi of an abandoned well bore in the deep upper Wilcox, whereas 65 percent of the large (>10 MMbbl) reservoirs in the Jackson Group (Galloway and others, 1983) occur within the same radius. Clearly, strictly on the basis of surface distance, many deep abandoned gas producing wells are favorably located with respect to heavy- and medium-oil reservoirs.

The productivity of abandoned gas wells in terms of their water temperature or water production rates has not been addressed individually. However, averaged temperatures for a given depth can be calculated for South Texas Wilcox wells on the basis of a temperature-versus-depth formula (fig. 32) of corrected bottom-hole temperatures from all wells that

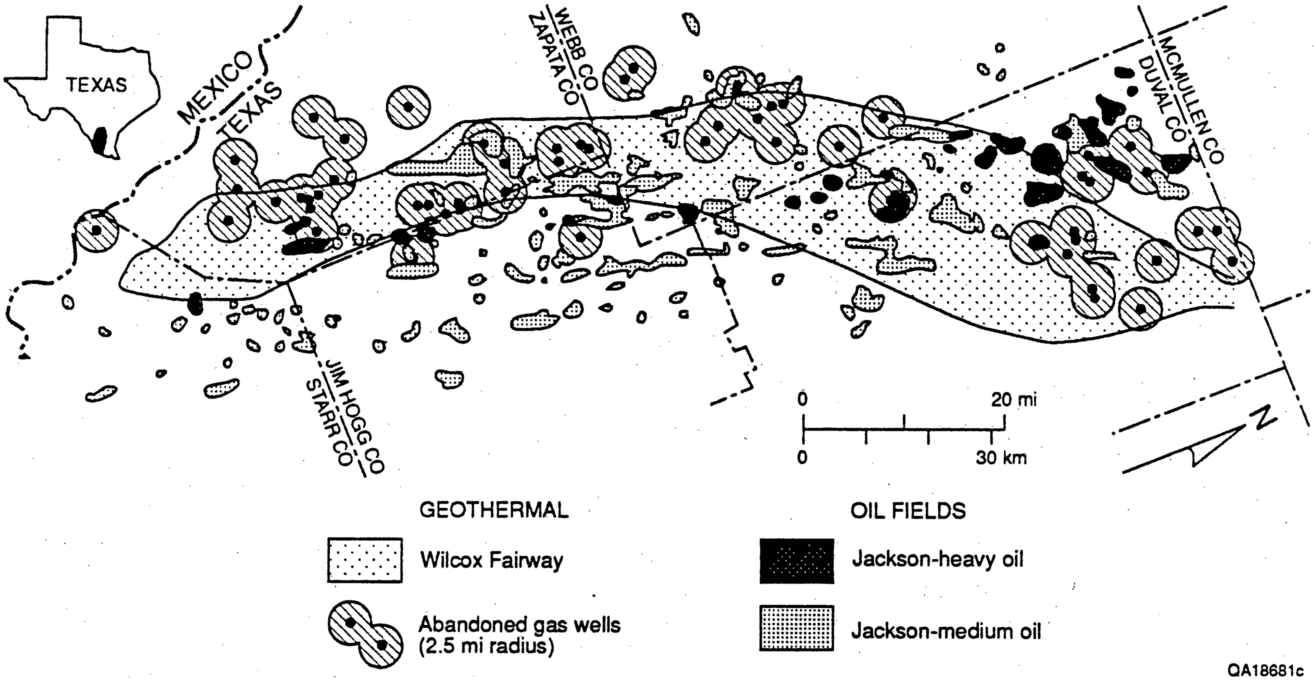


Figure 31. Map showing colocation of deep abandoned gas wells, heavy-oil fields in the upper Jackson, and the South Texas geothermal corridor.

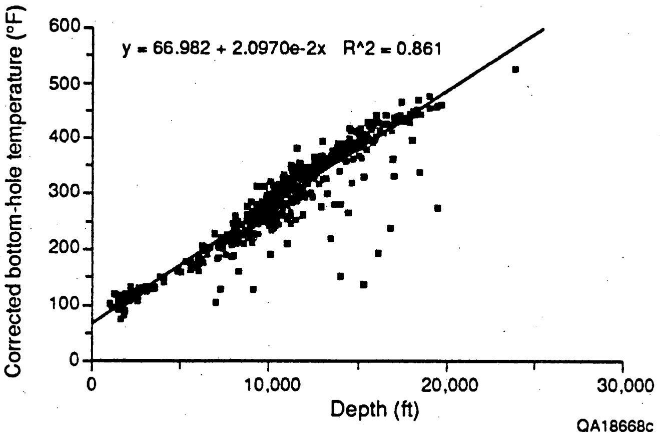


Figure 32. Plot of temperature versus depth, upper Wilcox gas fields.

penetrate the Wilcox in the South Texas BEG log file. At a depth of 14,765 ft the average temperature would be 376°F.

The conventional casing size for the deep upper Wilcox gas wells allows a tubing size of $3\frac{1}{2}$-inch or smaller $2\frac{3}{8}$-inch tubing inside $5\frac{1}{2}$-inch production casing. With conventional casing and tubing, production rates for geothermal fluids typically are limited to less than 20,000 bbl/d. The well productivity limits imposed by standard casing and tubing diameters should not be a significant constraint when the geothermal fluids are to be used for hot-water flooding. During conventional water flooding in Jackson Group oil reservoirs in South Texas, injection rates are 400 to 600 bbl/d for injection wells (RRC Hearings Files for 76 West field). A line of five injection wells with an injection rate of 500 bbl/d would require a single geothermal well producing 2,500 bbl/d.

Abandoned gas wells could comprise a cost-effective conduit for accessing geothermal reservoirs because as a group they are relatively deep and thus would contain relatively hot water. Geothermal well production rates of 2,500 bbl/d would provide sufficient geothermal fluids for five injection wells at the rate of 500 bbl/d.

CONCLUSIONS

(1) Approximately 35 deep upper Wilcox abandoned gas wells in the South Texas colocation area occur within 2.5 mi of heavy- and medium-oil fields in the overlying Jackson Group. With appropriate workover, abandoned gas wells may serve as cost-effective geothermal wells.

(2) In the South Texas colocation area, heavy-oil reservoirs are concentrated in the Jackson Group Cole sand, whereas medium-oil reservoirs are concentrated in the Mirando sand. Microbial degradation and fresh-water washing of light oil are inferred to have concentrated the heavy oil in the shallower Cole Sand reservoirs.

(3) Jackson Group sands in South Texas are characterized by a sheetlike geometry from deposition of strandplain/barrier-bar sands surrounded by lagoonal and shelf muds. Heavy- and medium-oil reservoirs in Jackson Group sands are trapped predominantly by porosity changes as a result of updip stratigraphic pinchout of barrier-fringe sands. Subtle structural influences such as nosing and small faults also assist in reservoir entrapment. Intrafield permeability barriers compartmentalize oil reservoirs in the Charco Redondo field.

(4) Swelling smectite clays surround and occur within Jackson Group reservoir sands. Smectite clays when exposed to fresh water will swell and could potentially interfere with reservoir performance through reduction in permeability.

(5) Deep geothermal fairways in South Texas contain geopressured-geothermal brines with temperatures locally exceeding 350°F, but are characterized by low permeability. In the South Texas geothermal area, Frio, Vicksburg, and Wilcox reservoirs exhibit characteristically lower permeabilities than the same units along the central Texas coastal plain.

Final Remarks

It is likely that upper Wilcox geopressured-geothermal reservoirs in the South Texas area will not produce fluids at the rate of 20,000 bbl/d as has occurred from the Frio Formation at the Pleasant Bayou geothermal test well in Brazoria County. However, production rates on the order of 1,000 to 2,000 bbl/d have been demonstrated in a production test from the upper Wilcox at Riddle No. 2 Saldana in Zapata County, South Texas. Such rates may be adequate (1) as a test of the technology for geothermally enhanced oil recovery, (2) to determine engineering data on South Texas geothermal reservoirs, and (3) to study interactions between geothermal fluids and heavy-oil reservoirs.

ACKNOWLEDGMENTS

This work was supported by the U.S. Department of Energy and managed through Idaho National Engineering Laboratory Geopressured-Geothermal Program. The authors thank the following individuals and organizations for their assistance; Mark Miller, Petroleum Engineering Department, The University of Texas at Austin; Ray Fortuna, U.S. Department of Energy, Washington; Jane Negus-de Wys, Idaho National Engineering Laboratory; Charles Kimmell, Fanion Production Company; and Shell Exploration and Production Company. Technical editing was by Tucker F. Hentz and Jay A. Raney. Tari Weaver, Patrice Porter, and Yves Oberlin drafted the figures under the supervision of Richard L. Dillon. Word processing was by Susan Lloyd, editing was by Amanda R. Masterson, text illustration photography was by David M. Stephens, and publication design was by Jamie H. Coggin.

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