

OLIGOCENE VICKSBURG SANDSTONES OF THE TIJERINA-CANALES-BLUCHER FIELD:
A SOUTH TEXAS GEOLOGIC JAMBALAYA

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ABSTRACT

The Tijerina-Canales-Blucher (TCB) Field of Kleberg and Jim Wells Counties, Texas, has produced significant amounts of hydrocarbons from Oligocene Vicksburg sandstones at depths of 7800 feet to 11,800 feet. TCB Vicksburg sandstones were deposited in deltaic to shallow marine environments as evidenced by various sedimentological and biological indicators. Diapirism of Jackson shelf muds coupled with syndepositional growth faulting generated highly faulted rollover elongate anticlines. These faulted, elongate highs along with a stratigraphic variability form the main traps in TCB Field.

Detailed examination of cores from five different Vicksburg sand-shale intervals in Sun Exploration & Production Company's Canales portion of TCB Field aided in delineation of a complex diagenesis related to depositional environment, lithology, burial, and thermal history of the field region. The sandstones vary in lithology from lithic to feldspathic lithic arenites and wackes. A volcanic source during Vicksburgian time is indicated by the presence of high percentages of volcanic rock fragments. This over-abundance of labile constituents is the prime factor that resulted in the "jambalaya" of diagenetic complexities.

Porosity in the TCB Vicksburg sandstones is almost entirely secondary and was generated predominantly by the dissolution of feldspars, volcanic rock fragments, and calcite cement. Permeability was greatly enhanced by dissolution and recrystallization of clayey matrix and carbonate cement. An overall smectite-illite signature pervades the vertical section with an extremely well developed authigenic imprint of highly crystalline kaolinite, chlorite, and illite and many other

mineral species superimposed onto the primary signature, especially with depth. The best TCB reservoirs have the largest average grain size and had the greatest amount of feldspars and volcanic rock fragments prior to diagenesis. Evolution of secondary porosity is suggested to be directly related to the generation and migration of hydrocarbons through the Vicksburg host rocks.

The most productive TCB Vicksburg reservoirs are found to be analogous with distributary channel and channel mouth bar facies. Depositional environment facies mud to sand ratios were instrumental in the formation of the diagenetic imprints of the TCB Vicksburg sandstones. Sandstones with initial high detrital clay content stood less chance of becoming reservoir quality rock due to lower initial permeabilities which retarded fluid-rock interaction. The best reservoirs exhibit a high degree of authigenesis with well developed chlorite and/or kaolinite being developed in conjunction with the secondary porosity. Poor quality reservoirs do not exhibit this high degree of crystalline authigenesis.

INTRODUCTION

Tijerina-Canales-Blucher Field is located in the lower Gulf Coast Plain of South Texas in Kleberg and Jim Wells Counties approximately 55 miles southwest of Corpus Christi, Texas (fig. 1). TCB Field has produced significant volumes of hydrocarbons from Oligocene Frio and Vicksburg fluvial-deltaic-barrier bar-strand-plain facies. Frio and Vicksburg Formations' cumulative production from Sun Exploration & Production Company's Canales portion of TCB Field is 14.7 million barrels of oil (MMBO) and condensate; 231 billion cubic feet (BCF) of gas and 9.1 million barrels of water (MMBW). The Oligocene Vicksburg reservoirs have produced 3.8 MMBO, 149 BCF of and, and 1.2 MMB of water. The Vicksburg production thus far translates to 65% of total gas production and 26% of total oil/condensate production. The main purpose of

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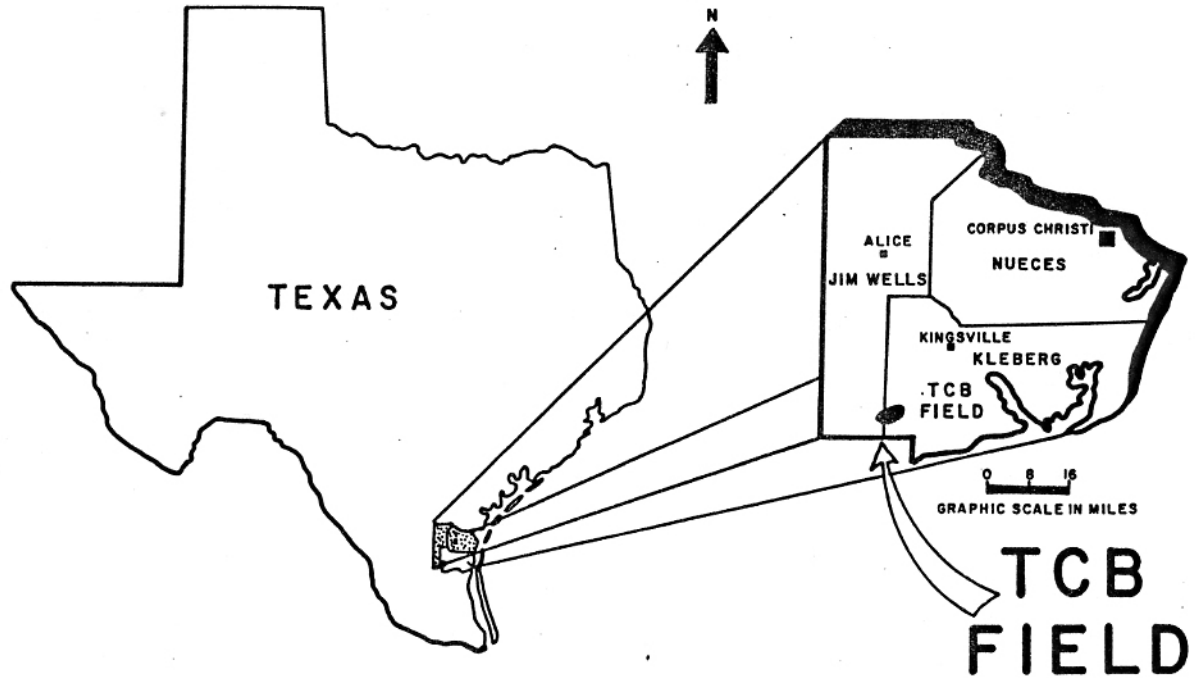
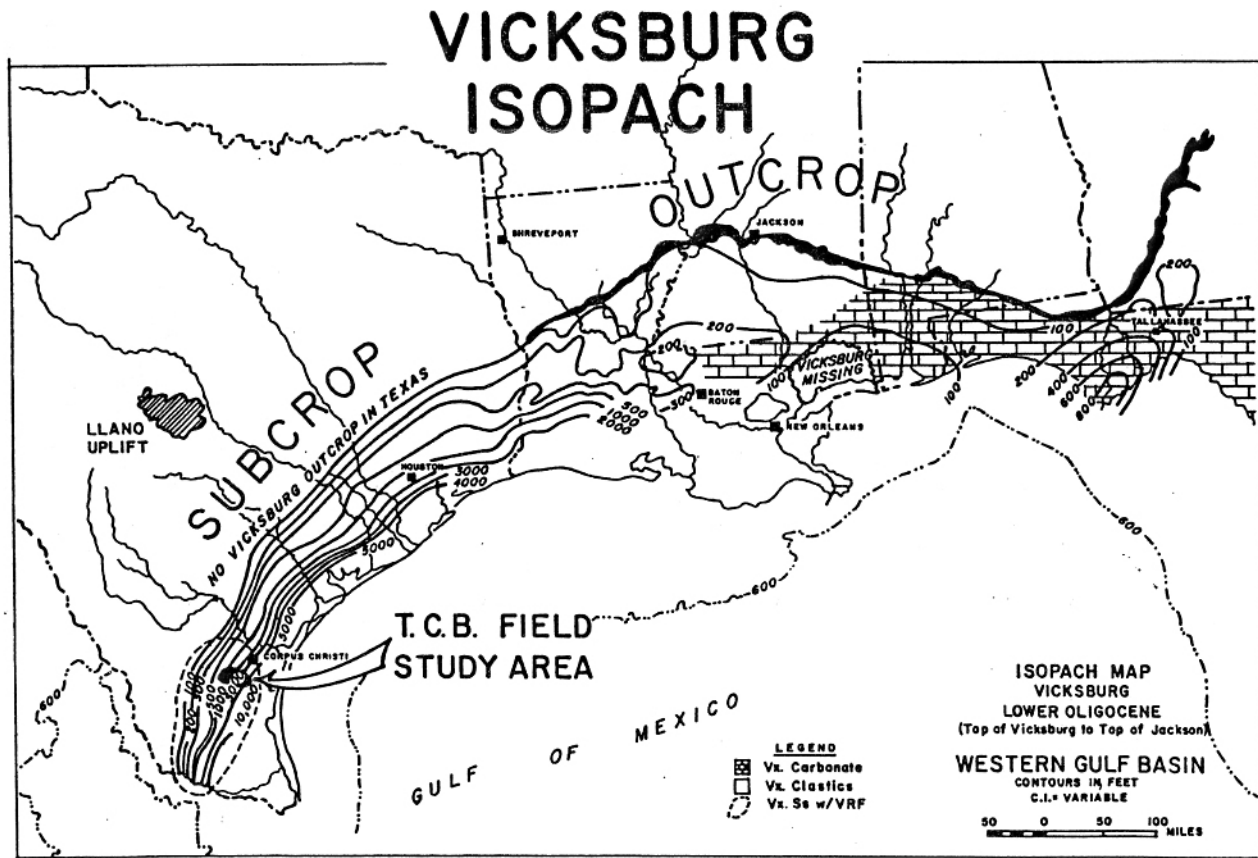


Figure 1. Location of Tijerina-Canales-Blucher Field (TCB) in South Texas.



Modified From: Tipword (1969), Hunter (1979), Han (1981)

Figure 2. Vicksburg isopach map showing outcrop, subcrop, lithologic variation and location of TCB study area within volcanoclastic anomaly. Modified from Tipword (1969), Hunter (1979) and Han (1981).

this investigation was to determine the relationship between petrology, diagenetic imprint, depositional environmental facies and structural geology to the excellent cumulative production evidenced in the Canales portion of TCB Field.

METHODS OF INVESTIGATION

Five different conventional whole cores from five different Vicksburg sandstone-shale intervals were slabbed and studied in detail. Most observable rock properties were studied both macroscopically and microscopically. After detailed sedimentological logging coupled with Core Lab prepared porosities and permeabilities, samples were selected from reservoir and non-reservoir rock for thin sections, X-ray diffraction, and scanning electron microscopy. The five cores were taken from the Canales portion of TCB Field, four of which represent productive reservoir rock and one of which represents non-productive poor reservoir quality rock. The integration of data from the above mentioned analyses coupled with standard subsurface petroleum geology information demonstrated the relationship between observed parameters and the productive or non-productive qualities of Vicksburg sandstones. The cored sandstone shale intervals were taken within the geopressure envelope of TCB Field between the depths of 8890 feet and 10,820 feet. Average pressure gradient through the stratigraphic interval that was cored was .85 psi/ft.

REGIONAL STRATIGRAPHY AND TCB FIELD PRODUCTION STRATIGRAPHY

The Vicksburg can be found as a mappable lithologic entity in several Gulf Coast states from Florida to Texas and varies in thickness from 100 to 800 feet in Florida to 10,000 feet in South Texas (Han, 1981) (fig.2). Lithologies vary from different types of carbonates to calc-arenites to feldspathic lithic arenites to shales. The Vicksburg does not outcrop in Texas and occurs only as a subcrop which is sandwiched between the Eocene and the Oligocene Frio Formation. The change from a stable, non-clastic platform in Florida to an area of unstable, rapid clastic deposition in South Texas is a dramatic example of stratigraphic variation in the Gulf Coast. Stratigraphic subdivisions are simple in the South Texas

subsurface with the Vicksburg Formation being divided into Upper, Middle and Lower (fig. 3). Since correlation in South Texas is limited to fault block trends due to structural-stratigraphic complexities, subdivisions of Upper, Middle and Lower are usually by local subsurface field names and/or local subsurface depth names. The Canales portion of TCB Field was subdivided into Upper, Middle and Lower Vicksburg based on repetitive cycles seen in electric log signatures and seismic sections. Delta fringe to delta front seems to be the common associative and repetitive cycle seen in the Vicksburg section within the study area. The main Vicksburg sands encountered within the area of investigation include the following:

Upper Vicksburg	Cumulative Production
Nowacek Sand	466,966 BC, 20.8 BCF
Wilson Sand (7800 Sand)	142 BC, 23.5 BCF
8025 Sand (7900 Sand)	4,762 BC, 23 MMCF
8500 Sand	31 BC, 11 MMCF
8520 Sand	4150 BC, 169 MMCF
8650 Sand*	Non-Productive

Middle Vicksburg	Cumulative Production
8800 Sand*	1,726,731 BC, 72.6 BCF
9000 Sand	29,562 BC, 754 MMCF
9400 Sand	56,234 BC, 2.2 BCF
9550 Sand	13,189 BC, 479 MMCF
9900 Sand	99,742 BC, 3.4 BCF

Lower Vicksburg	Cumulative Production
10,250 Sand*	850,015 BC, 30.8 BCF
10,500 Sand*	155,634 BC, 3.4 BCF
10,600 Sand*	217,560 BC, 7.4 BCF
11,000 Sand	148,381 BC, 4.5 BCF
11,600 Sand	7,300 BC, 16 MMCF
11,800 Sand	3,847 BC, 22 MMCF

All of the above sands with the exception of the 8650 Sand are main field producers. The 8650 Sand was perforated, but did not produce. Asterisks indicate studied core intervals from the Upper, Middle and Lower Vicksburg.

The type log for the Canales portion of TCB Field demonstrates typical repetitive electric log signatures from the Lower Vicksburg through the basal Frio (fig. 4). The Vicksburg producing sands are in the condensate rich window of hydrocarbon production in the area.

VICKSBURG STRATIGRAPHIC NOMENCLATURE

		TEXAS	LOUISIANA	MISSISSIPPI ALABAMA	FLORIDA	
MESOZOIC	VICKSBURG FM	Anahuac Fm	Anahuac Fm	Tatum Limestone Member ?		
		Frio Fm	Frio Fm	Chickasawhay Fm	Suwanee Limestone	
		U M L			VX GROUP Bucatunna Clay ? Byram Fm. Glendon Ls Mint Spring Marl/ Marianna Ls	?
			Nash Creek Fm/ Rose Field Fm Sandel Sand Mosley Hill Fm		Forest Hill Fm/ Red Bluff Fm	Marianna Ls
						Bumpnose Ls
CENOZOIC	JACKSON	Whisett Fm				
		McElroy Fm	YAZOO GROUP Danville Landing Beus Verda Tullos	YAZOO GROUP Shubuta Member Pachuta Marl Member Cocoa Sand Member Northtwistwood Cr. Mem.	OCALA GROUP Crystal River Fm	
		Caddell Fm			Williston Fm	
		Moody Branch Fm		Moody Branch Fm	Ingis Fm	

HAN (1981)

Figure 3. Vicksburg stratigraphic nomenclature showing subdivision in South Texas into Upper, Middle and Lower; from Han (1981).

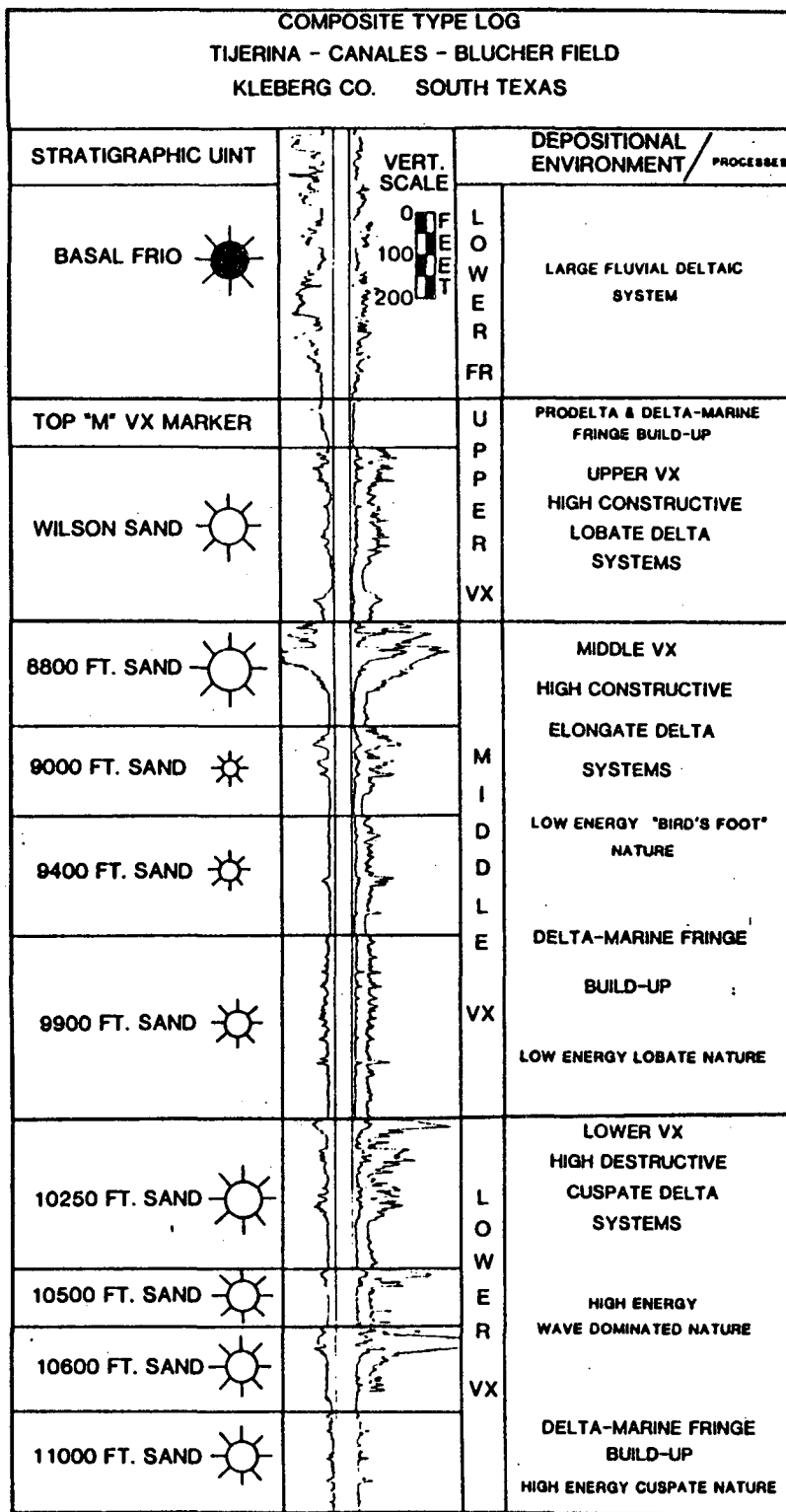


Figure 4. Composite type log for Canales portion of TCB Field demonstrating repetitive electric log signatures. Basal Frío is in the oil window and Vicksburg is in the condensate window.

STRUCTURAL STYLE AND GENERAL ENVIRONMENTS OF DEPOSITION

The general structural style of TCB Field is best demonstrated by the dip oriented seismic cross-section C-C' (fig. 5). This migrated seismic line transverses the main structural high and hydrocarbon sweetspot in the Canales portion of TCB Field and parallels the dip oriented electric log cross-section A-A' (fig. 6). Both the seismic cross-section structural interpretation and the electric log cross-section structural interpretation are in agreement.

The general structural style of TCB Field is that of large syndepositional listric normal growth fault and resulting migrational "roll-over" elongate anticlines. Structure contour maps are shown for the four productive cored intervals that were studied, including the 8800 Sand (fig. 7a) 10,250 Sand (fig. 7b), 10,500 Sand (fig. 7c) and the 10,600 Sand (fig. 7d). Structural mapping indicates a migration of the structural crests or axis of folding toward the northwest from Lower Vicksburg times to Frio times. The same structural axis migration can be observed in the cross-sections.

The anticlinal closures are complicated by older listric normal faults and associated antithetic faults. The downbending into the syndepositional fault plane generated the dip reversals for formulation of the anticlinal closures which are the main hydrocarbon traps in TCB Field (Stanley, 1970). The dominant youngest listric normal fault in TCB Field tends to parallel the ancient and modern shorelines of the Gulf Coast with maximum displacements of 200 feet to 400 feet. Displacements seem to vary along with fault plane with different degrees of movement being in direct proportion to the mass of sediments being deposited on shelfal or interdistributary bay muds. The greater the volume and mass of sediments being deposited at a specific location at a specific time, usually the greater the thickening in the downthrown block.

The TCB listric normal growth faults have dip angles that vary from 70° to 30° due to the curvilinear nature of the faults. High angles of dip on the fault plane are noted near the upward terminus and the lower dip angles are

noted with increasing depth as the faults die into the bedding plane or surface that separates the Eocene from the Oligocene. Average dips in midportions of the listric normal fault planes appear to fall in the range of 45° to 55°. The upper terminus of the main TCB Field fault dies before entering the Frio and even though the Frio is not cut by the dying growth fault, a structural low or sag is exhibited in the Frio over the maximum folding in the deeper Vicksburg (fig. 5).

The antithetic normal faults demonstrate similar geometry to the listric normal growth faults except that they are concave toward the paleoshoreline. These antithetic faults typically show less displacement, less definition, steeper dip angles and often die out in the Middle or Lower Vicksburg before intersecting the main listric normal growth fault.

TCB Field is located approximately 18 miles east/southeast of the most northwesterly trace of the Sam Fordyce-Vanderbilt Fault. The structural implications of the area are tied heavily to the depositional environments that were operating in the area throughout past geologic time. The Vicksburg of TCB Field is characterized by a series of deltaic progradations separated by minor transgressions from Lower Vicksburg through Upper Vicksburg. In the area of investigation, the Oligocene Vicksburg overlies the Eocene Jackson shale. The Jackson appears to be the main surface of decollement on which the Vicksburg was deformed or faulted. Subsurface percent sand maps by Fisher, et al (1970) indicate an open shelf mud system as the predominant Jackson facies in the TCB Field area. The Vicksburg of TCB Field is overlain by the Frio which is interpreted by Nanz (1954) and Shelton (1973) to be deposited in a fluvial-alluvial environment in the updip Seeligson Field area. Mapping by Sun Geologists in the downdip TCB portion of the Frio indicates a change from dip oriented sand bodies to strike oriented sand bodies occurring in the northwestern and central portion of TCB Field. From these in-house structure and isopach maps, it is inferred that the TCB Frio was probably deposited in a fluvial-deltaic-strandline environment.

By integrating electric log signatures, sedimentology from whole cores, in-house net

STRUCTURAL STYLE OF T. C. B. FIELD

DIP ORIENTED SEISMIC CROSS SECTION, C - C'

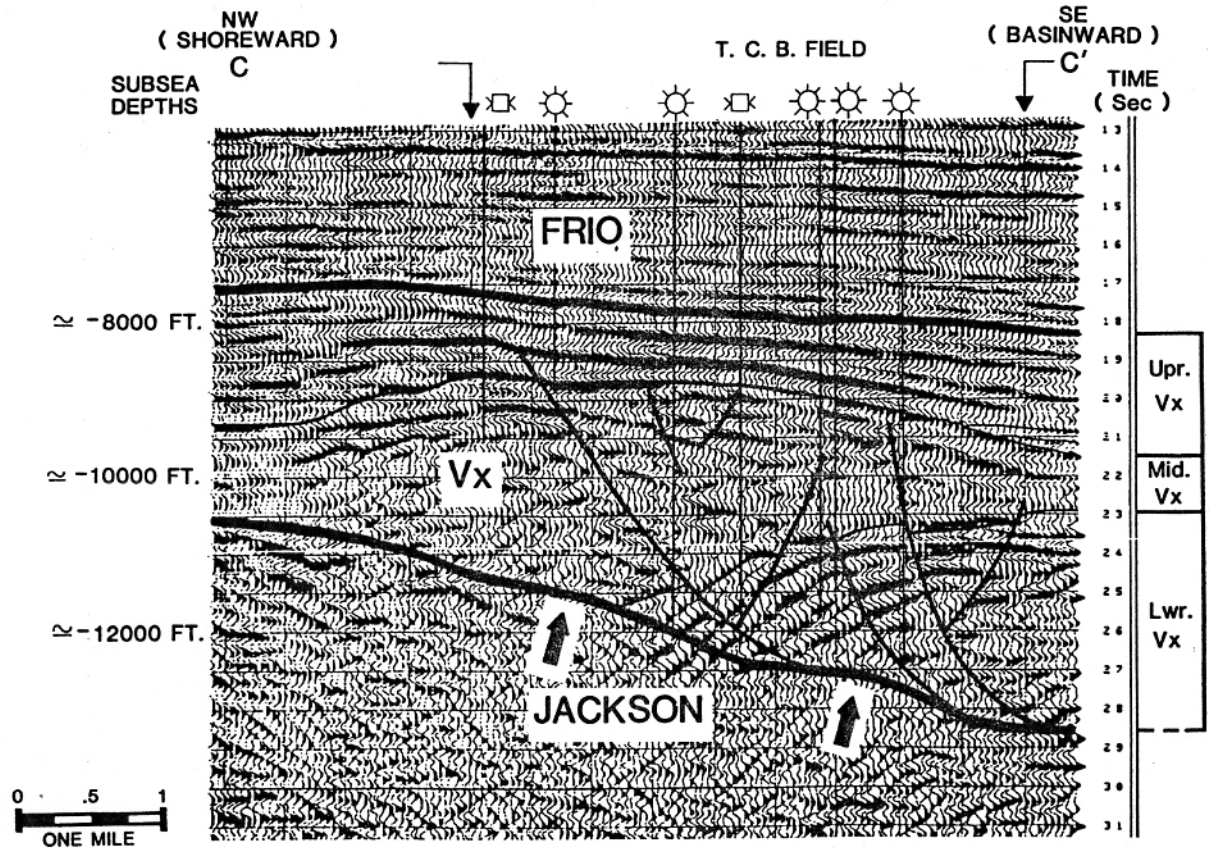


Figure 5. Dip oriented migrated seismic cross-section C-C' demonstrating typical structural style for TCB Field.

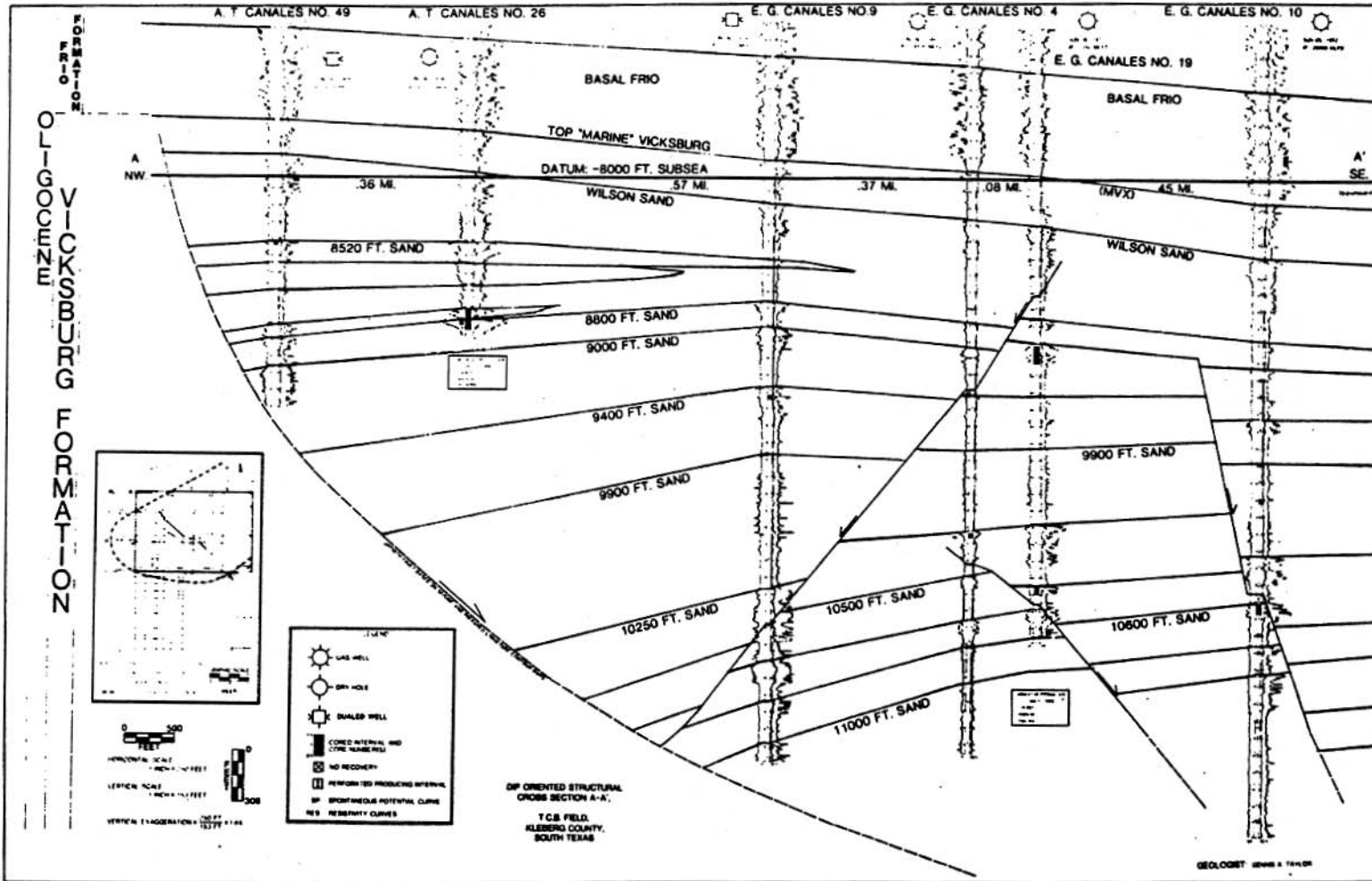


Figure 6. Dip oriented electric log cross-section A-A' demonstrating agreeing parallelism with seismic cross-section C-C'.

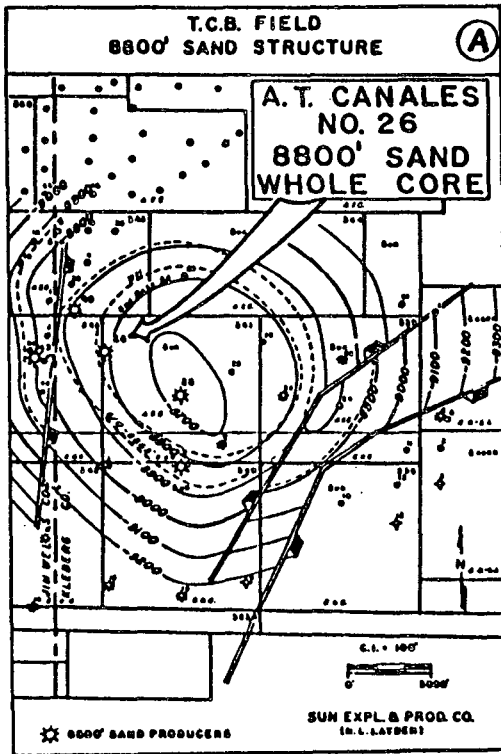


Figure 7a. Structure contour map for Middle Vicksburg 8800' Sand exemplifying structural style and location of cored A. T. Canales No. 26.

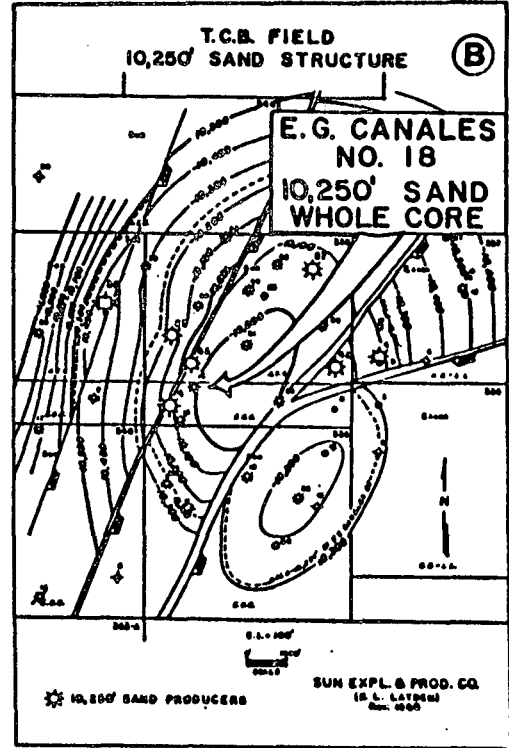


Figure 7b. Structure contour map for Lower Vicksburg 10,250 Sand exemplifying structural style and location of cored E. G. Canales No. 18.

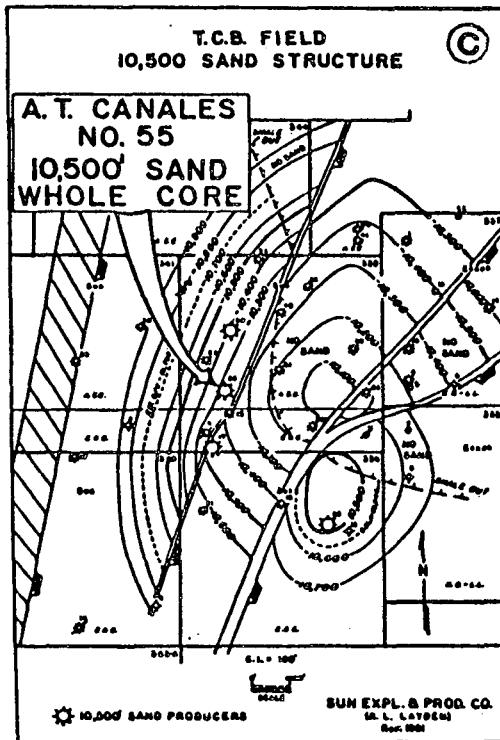


Figure 7c. Structure contour map for Lower Vicksburg 10,500 Sand exemplifying structural style and location of cored A. T. Canales No. 55.

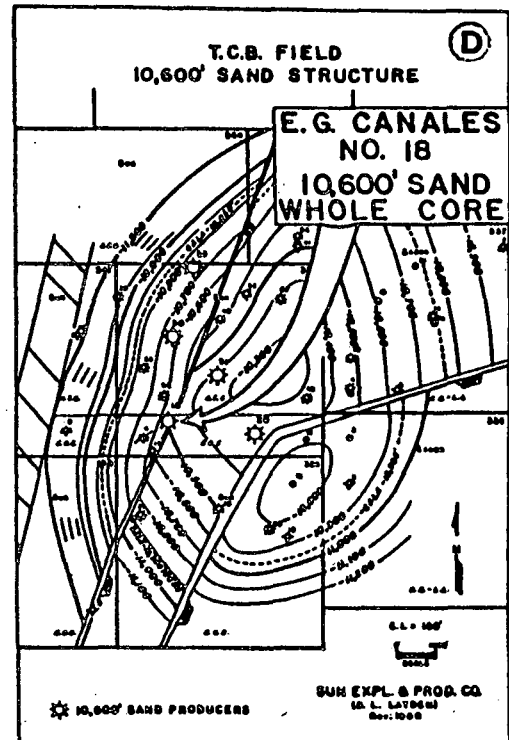


Figure 7d. Structure contour map for Lower Vicksburg 10,600 Sand exemplifying structural style and location of cored E. G. Canales No. 18.

sand isopach maps and biological indicators, the general theme incorporated for depositional environment for the Vicksburg in the TCB Field range from wave dominated deltas in the Lower Vicksburg to fluvial dominated deltas in the Upper and Middle Vicksburg (fig. 8). Net sand isopach maps which show generalized geometries for three example Vicksburg reservoirs demonstrate the change from strike oriented geometries to more dip oriented geometries from Lower Vicksburg through Middle Vicksburg (fig. 9).

By comparing the real rock data with electric logs, mapping, electric log cross-sections and the seismic C-C' section, a seismic stratigraphic interpretation was formulated demonstrating the repetitive character of seismic events related to general depositional environments (fig. 10).

ENCOUNTERED PRODUCTIVE AND NON-PRODUCTIVE FACIES

Approximately six different facies can be identified in the five cores studied. Core logs from the A. T. Canales No. 26 (fig. 11a) and the E. G. Canales No. 18 demonstrate most of these facies (fig. 11b). These facies fall into a typical occurrence sequence in almost all cases and are represented by coarsening upward log signatures and blocky style log signatures as demonstrated in electric logs from the A. T. Canales No. 26 (fig. 12a) and the E. G. Canales No. 18 (fig. 12b). The facies encountered, in order of normal occurrence, include prodelta and/or interdistributary shale facies, soft sediment deformation facies, beginning progradational delta fringe facies, channel mouth bar facies, distributary facies, and bioturbated facies. Only the sand facies including channel mouth bars and distributary channels are lucrative producers. The other facies are typically non-productive for various sedimentologic and diagenetic reasons.

Prodelta and/or interdistributary bay shale facies are found at the top and bottom of sand sequences. They are typically laminated to non-laminated gray shales with a high concentration of carbonaceous material and wood fragments. Sometimes whole plant stems and leaves are preserved within these shales. Few

body fossils were found, but the shales were sometimes bioturbated. Due to the high percentage of organic remains, it is possible that many of these shales may have acted as source beds for the generation of hydrocarbons into the Vicksburg reservoirs.

Soft sediment deformation facies are generated due to loading by prograding channel mouth bars and especially distributary channels. Convolute bedding is generated which mixes sand and mud and destroys the possibility for reservoir quality rock in the first delta deposited sand bodies. The base of the whole core from the E. G. Canales No. 18 10,600 Sand demonstrates loss of porosity and permeability due to the mixing of sand and mud in deformed convolute bedding (fig. 13). This type of facies is only found at the base of sand sections.

Progradational delta fringe facies develop at the base of channel mouth bars as deltaic progradation occurs. Loading may not occur as quickly as with encroachment of a large distributary channel, therefore, soft sediment deformational facies are not as prevalent. These progradational delta fringe facies represent the base of the coarsening upward sequence and still have enough organic and clay fines mixed with the sand that reservoir rock quality will be lacking. Delta fringe facies can sometimes be cleaned up by longshore currents and wave action to generate reservoir quality rock although this was not observed in the available studied cores, but may have occurred in the 9900 Sand which is interpreted to be a productive delta marine fringe buildup. No cores were available in the 9900 Sand for this extremely thick section of alternating sands and shales.

Channel mouth bar facies are characterized by medium scale cross bedding, lower percentages of carbonaceous material, and slight bioturbation. Grain size is variable from fine to medium grained and there is a low initial mud to sand ratio associated with this facies. Due to high initial permeabilities, the chance of generating reservoir quality rock due to diagenetic alteration is high in Vicksburg channel mouth bar systems. The photo from 10,177.6 in the 10,250 Sand of the E. G. Canales No. 18 shows a cross bedded channel

INFERRED VICKSBURG DELTAIC SYSTEMS

T. C. B. FIELD

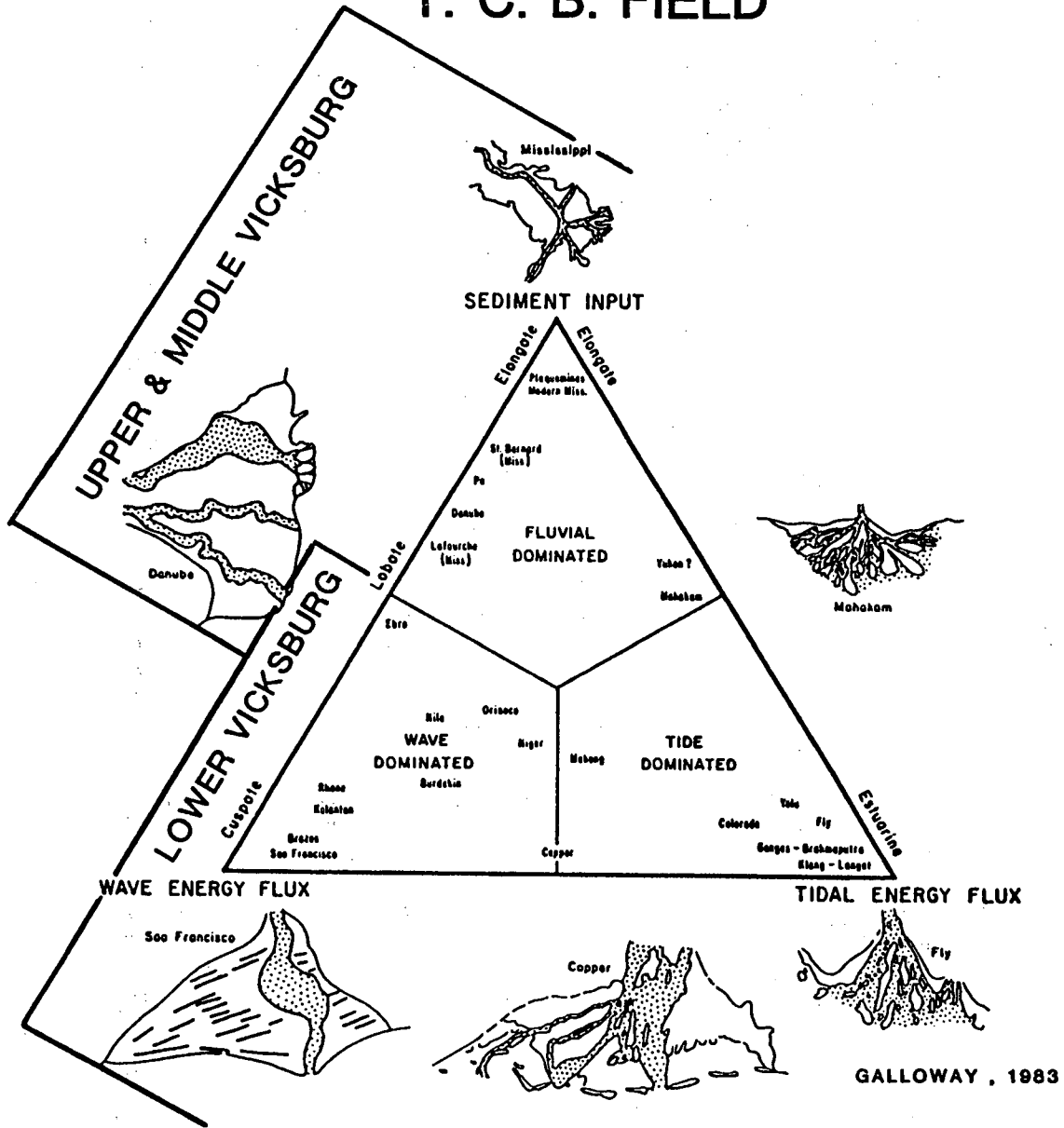


Figure 8. Inferred types of Vicksburg deltaic systems in TCB Field. Classification scheme from Galloway (1983).

NET SAND ISOPACHS GENERALIZED GEOMETRIES

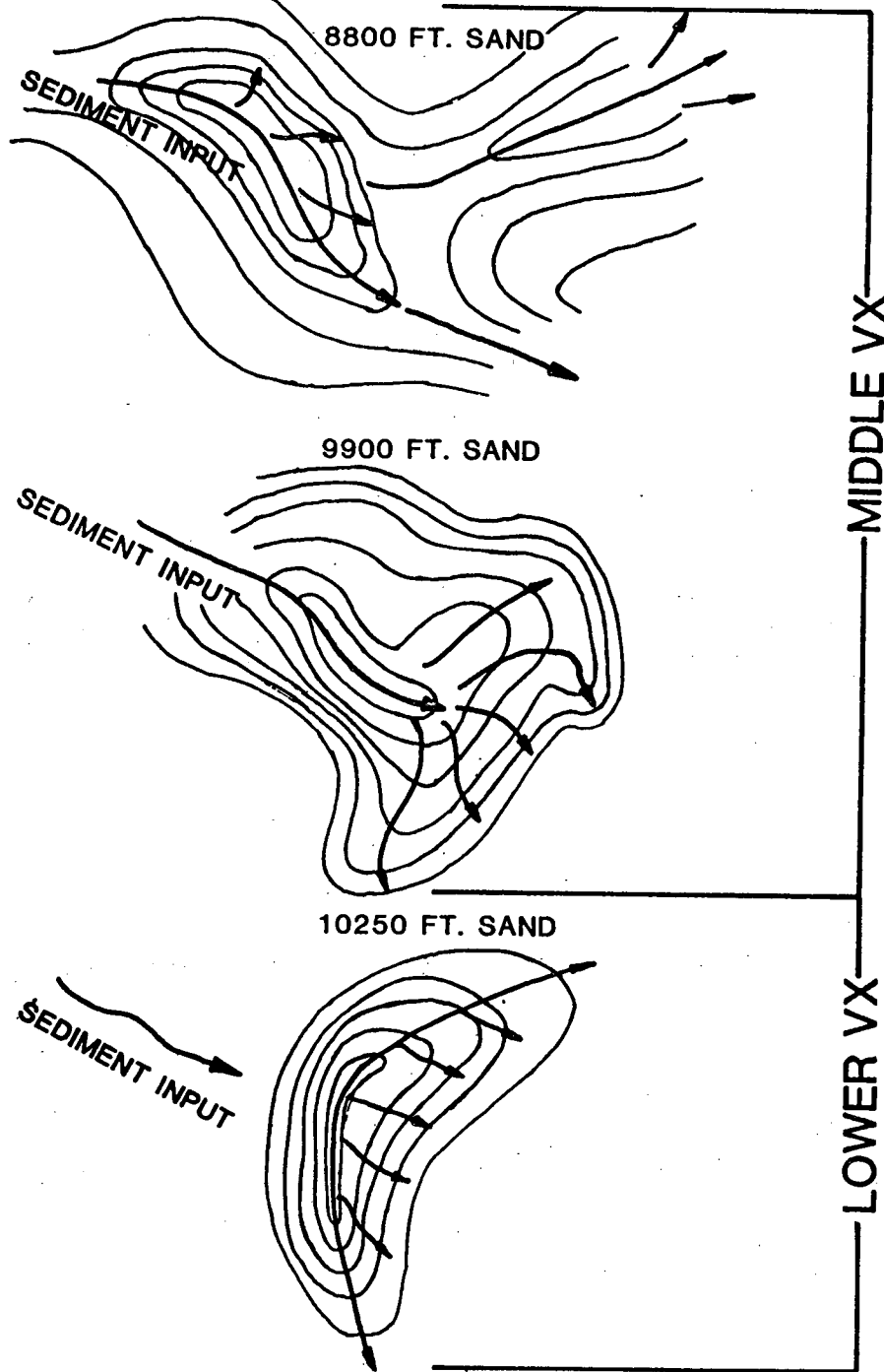


Figure 9. Net Sand isopach maps showing generalized geometries and sand dispersal systems for Lower and Middle Vicksburg productive intervals.

SEISMIC STRATIGRAPHY AND DEPOSITIONAL SYSTEMS

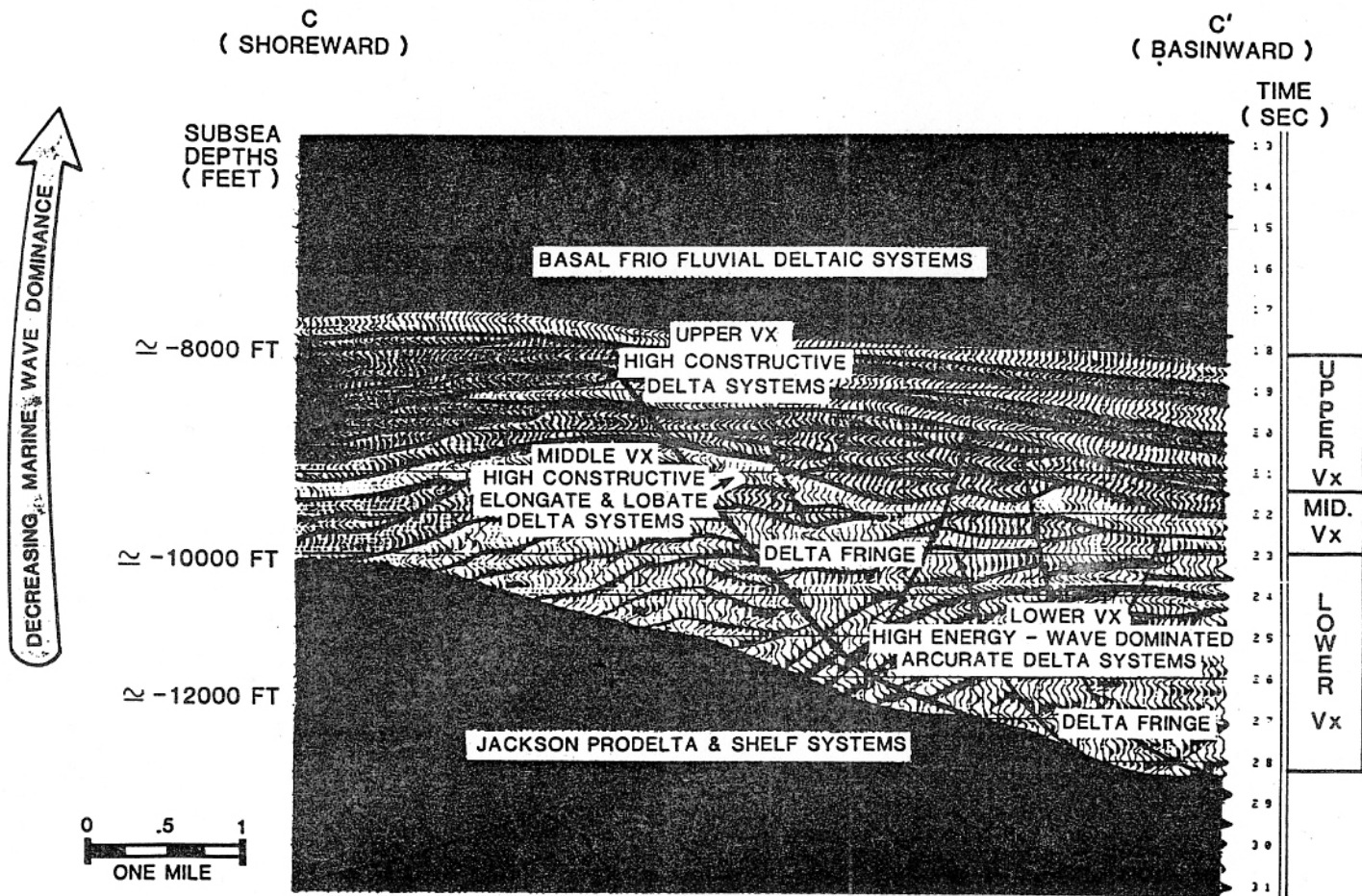


Figure 10. Seismic stratigraphy and depositional systems demonstrating repetitive character of seismic events in TCB Field.

CORE LOG

A. T. CANALES NO. 26

T. C. B. FIELD

SUN EXPL. & PROD. CO.

(A)

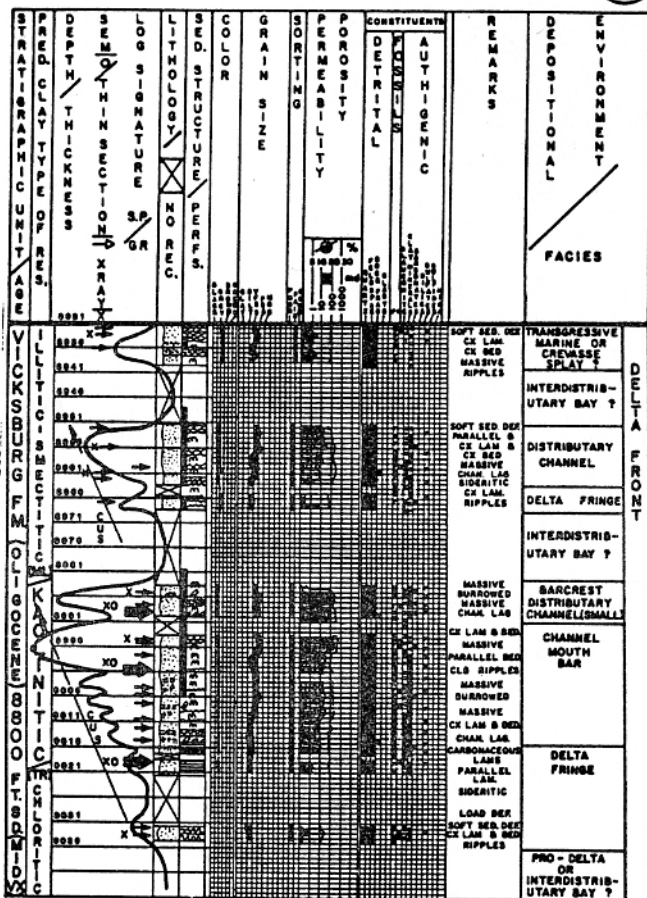


Figure 11a. Core log of 8800 Sand from the A. T. Canales No. 26 demonstrating delta front sequence of facies and subfacies typical of all cores studied. 8800 Sand of Middle Vicksburg section has been the best Vicksburg producer in TCB Field.

CORE LOG

E. G. CANALES NO. 18

T. C. B. FIELD

SUN EXPL. & PROD. CO.

(B)

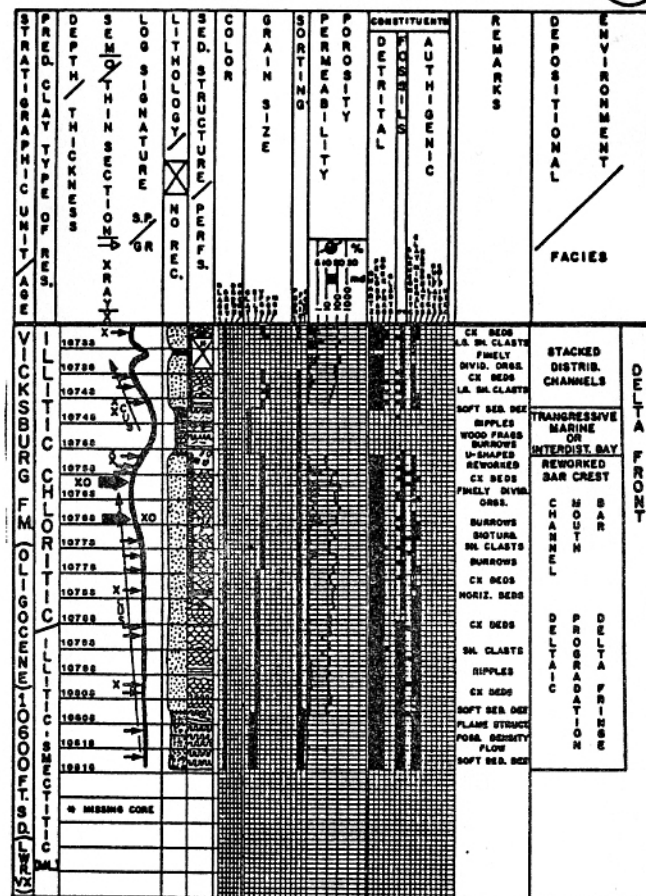


Figure 11b. Core log of 10,600 Sand from the E. G. Canales No. 18 demonstrating a delta front sequence with stacked distributary channels over a channel mouth bar. Note soft sediment deformation subfacies at base of sand and bioturbated facies on bar crest. Both of these facies are poor reservoir quality.

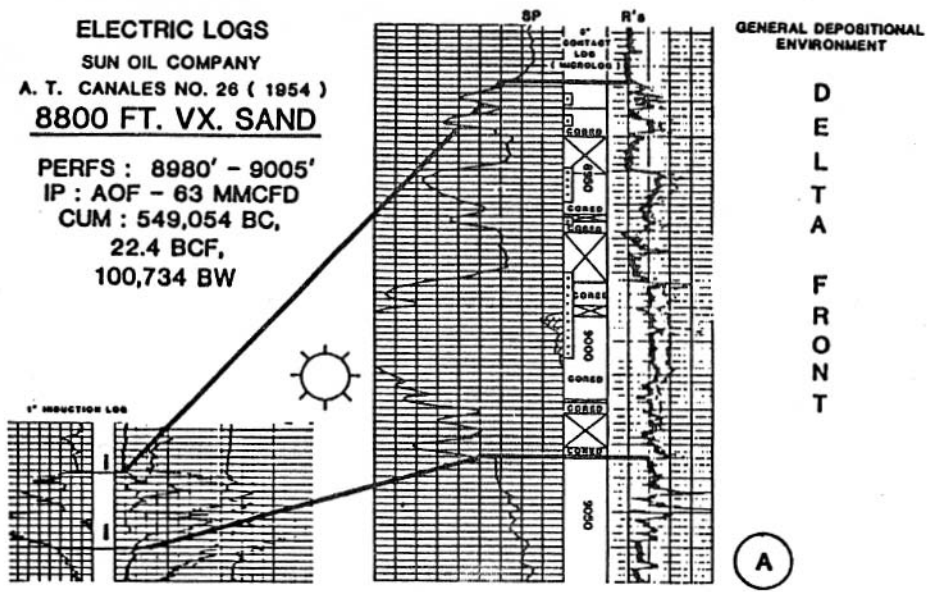


Figure 12a. Contact microlog and induction log showing electric log character, cored intervals, and perforations in the 8800 Sand of the A. T. Canales No. 26.

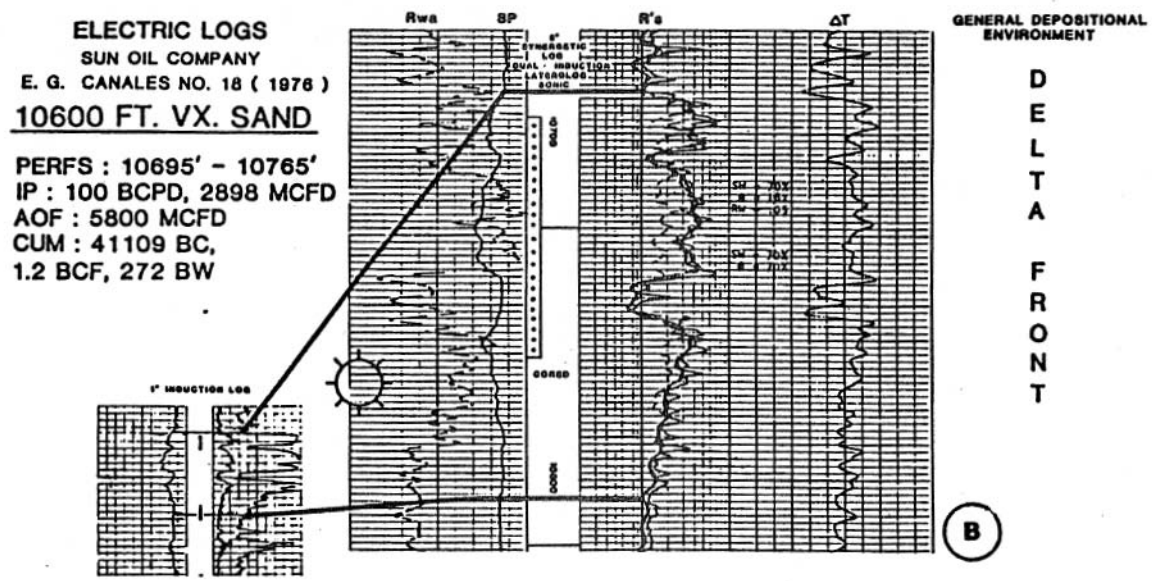


Figure 12b. Dual-induction-laterolog-sonic showing electric log character, cored intervals, and perforations in the 10,600 Sand of the E. G. Canales No. 18.

mouth bar facies (fig. 14). Channel mouth bar facies are extremely productive with good porosities and permeabilities. These facies are usually associated with the upper portion of the coarsening upward sequence evident from electric log signatures. Quite often, distributary channels are found stacked directly over channel mouth bar sequences.

Deltaic distributary channels are characterized by massive bedding usually with associated channel lag found at the base of the channel sequence. Grain size varies from fine to medium in Vicksburg distributary channels and there is a reduced percentage of organics and detrital fines since current velocities would keep fines flushed from the system. Distributary channels have the lowest mud to sand ratio at the time of deposition and are therefore capable of generating excellent reservoir quality through diagenesis in the Vicksburg. The best production from the Vicksburg comes from distributary channels in TCB Field. The 8800 Sand of the Middle Vicksburg in the A. T. Canales No. 26 produced 549,054 barrels of condensate and 22.4 BCF of gas from a distributary channel. The photo from 8987.6 in the 8800 Sand of the A. T. Canales No. 26 demonstrates an excellent distributary channel facies with massive bedding and channel lag (fig. 14). Porosity is approximately 26% and permeabilities range from 100 to 600 millidarcies. These channel facies are difficult to differentiate from channel mouth bars since both facies grade laterally and vertically into one another. Typically, distributary channels have blocky log signatures and are found at the top of coarsening upward sequences. They represent the best reservoir facies that should be explored for in the South Texas Gulf Coast subsurface. Several distributary channels are often stacked in series prior to switching of the main sediment axis on a deltaic lobe.

Bioturbated facies are often one of the last facies in the sequence before minor marine transgression or distributary channel abandonment. Quite often the top of the channel mouth bar or distributary channel has been bioturbated as the area changed to shelf facies or interdistributary bay facies. This bioturbation usually occurs in the upper 1 to 5 feet of the bar crest and, unfortunately, works fines

back into the relatively clean sand destroying permeabilities. Usually, the heavily bioturbated portions of the bars are poor quality reservoir rock. The photo taken at 10,755.4 in the 10,600 Sand of the E. G. Canales No. 18 is an example of a heavily bioturbated bar crest that covers about 4 to 5 feet of sandstone facies (fig. 16). This is an *Ophiomorpha* U-shaped feeding burrow which is often considered possibly indicative of a shallow marine environment. Unfortunately, the burrowing destroyed the possibility of generating reservoir rock through diagenesis by reducing initial permeabilities. Han (1981), in his studies well to the south of TCB Field in the Rincon-North Rincon Field area, also observed the feeding trace fossil *Ophiomorpha* in association with channel mouth bars and distributary channels. In some cases, increased bioturbation throughout a delta front sequence may indicate greater marine dominance or interdistributary dominance on a particular sedimentation input. In the case of the only non-productive core studied in the Upper Vicksburg 8650 Sand, almost the entire delta front sand sequence has been heavily bioturbated and, as a result, poor reservoir quality rock was induced and maintained. The photo taken at 8896.6 in the 8650 Sand of the E. G. Canales No. 8 demonstrates this heavy bioturbation (fig. 17).

TCB VICKSBURG PETROLOGY

The Vicksburg rocks of TCB Field are not typical sandstones. They contain less quartz and more feldspar and rock fragments than would be expected in normal clastic reservoir rocks. Grain sizes vary from fine grained to medium grained with most averaging fine grained. Framework grains are moderately to poorly sorted and are subangular to subrounded. At the time of deposition, the TCB Vicksburg sandstones typically contained large amounts of volcanic rock fragments and feldspars (Hunter and Davies, 1979). This was especially true for Lower and Middle Vicksburg reservoirs. This concentration of labile volcanic rock fragments and feldspars occurs almost exclusively in the Rio Grande Embayment south of the San Marcos Arch (fig. 2) with possible volcanic source areas in the southern Rockies, Trans-Pecos Volcanic Field, and the Sierra Madres (Winker, 1982).

The lithologic detrital compositions for the Vicksburg sandstones of TCB Field are feldspathic lithic in nature. Data points were taken from each studied cored interval within channel mouth bar and distributary channel facies. The sandstone facies that had the most potential for becoming reservoir quality rock were sampled for percentages of quartz, feldspar and rock fragments. Percentage samples were normalized to 100% and plotted on a QRF ternary diagram (Folk, 1968). The TCB sandstones vary in lithology from lithic arenites to feldspathic lithic arenites (fig. 18). The average composition for channel mouth bar and distributary channel facies is 16% quartz, 10% feldspar and 30% rock fragments. The Upper Vicksburg non-productive core was more quartz rich than the Middle or Lower Vicksburg productive cores. The Middle Vicksburg core was more feldspathic than the Lower Vicksburg cores and the Upper Vicksburg core. The Lower Vicksburg cores plotted with a higher lithic or rock fragment content than the Middle and Upper Vicksburg cores. The original compositions of all Vicksburg sandstones before diagenetic alteration were probably more lithic arkosic in nature. As alteration of feldspars occur, the entire field of plotted points would have migrated toward more quartz rich feldspathic regions of the QRF diagram.

DIAGENETIC COMPONENTS AND SEQUENCE

There has been intense diagenesis within the South Texas Vicksburg Formation and as a result of this geochemical alteration, the Vicksburg microfabrics of the sandstones have become one of the very important keys to successful exploration, completion and production in the Vicksburg, especially in South Texas. The TCB Field falls within a stratigraphic lithologic anomaly of abnormally high volcanoclastic rock composition. It was this high concentration of labile fragments that resulted in a volatile geochemical system which generated tremendous secondary porosities and enhanced permeabilities capable of storing and releasing enormous volumes of hydrocarbons. Evolution of these microfabrics has been controlled by diagenesis which has created a very complex diverse mixture or "jambalaya" of reservoir characteristics. Because of varying degrees of complexity of this Vicksburg "jambalaya" a diagenetic paradox often exists

within the Vicksburg Formation. Diagenesis created the porosities that have become our Vicksburg reservoirs, but at the same time, diagenesis within the Vicksburg destroyed porosities and/or caused severe inherent formation problems capable of hindering the successful completion of an otherwise highly prospective well. This diagenetic alteration has taken place over a given amount of time as the Vicksburg was subsided toward the basement. The diagenetic alteration of sand-shale packages is a function of many different parameters throughout geologic time including:

- 1) Depositional environments facies and subfacies.
- 2) Original grain sizes.
- 3) Original primary porosities and permeabilities.
- 4) Original mud to sand ratios within varying facies and subfacies.
- 5) Original sandstone mineralogy and geochemical composition.
- 6) Original shale mineralogy and geochemical composition.
- 7) Structural-tectonic setting.
- 8) Rates of subsidence.
- 9) Geothermal gradients.
- 10) Hydrocarbon migration.
- 11) Geochemical composition of migrating fluids, past and present.

The diagenetic sequence encountered in TCB Field Vicksburg sandstones was very similar to that identified in a general Gulf Coast Tertiary model by Loucks, Bebout, and Galloway (1977) (fig.19). The deep zone of reservoir development associated with a second stage of feldspar, volcanic rock fragment, and calcite dissolution occurring between 8000 and 11,000 feet corresponds with TCB Vicksburg secondary porosity reservoirs. The best Vicksburg production thus far has occurred in the 8800 Sand between 8000 and 9000 feet. The studied Vicksburg core intervals fall well within the geopressure envelope with an average pressure gradient of .85 psi/ft (fig. 20). Good porosity, good permeability and good production can occur associatively with increased geopressures in TCB Field to certain depths.

Porosity in all productive cores studied was almost entirely secondary and was generated by the dissolution of feldspars, volcanic rock fragments, and calcite cement. Development and

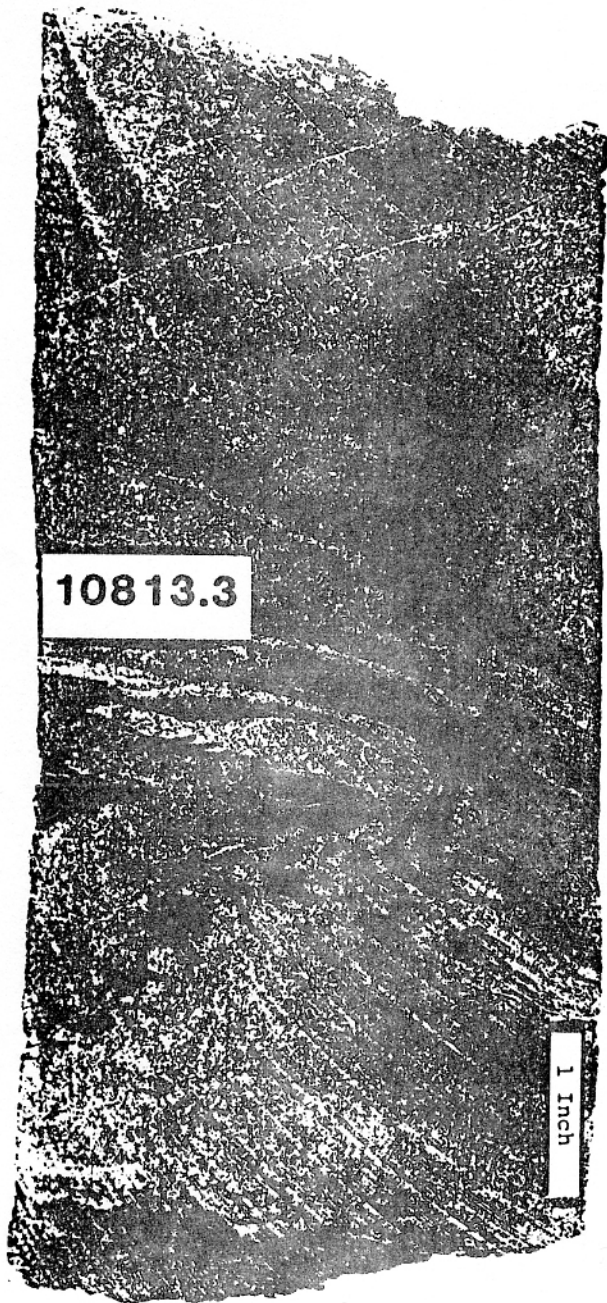


Figure 13. Soft sediment deformation facies at 10,813 feet from 10,600 Sand of the E. G. Canales No. 18. Poor quality non-reservoir facies due to mixing of mud and sand.

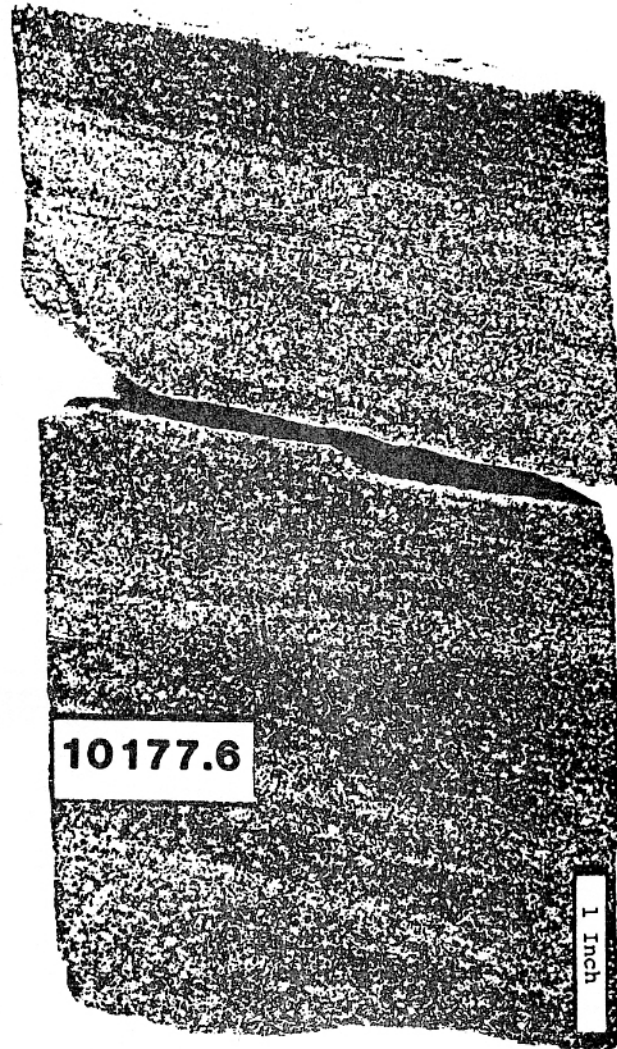


Figure 14. Cross-bedded channel mouth bar facies from 10,177 feet in the 10,250 Sand of the E. G. Canales No. 18; good quality reservoir rock with 22 percent porosity and 10 md permeability.

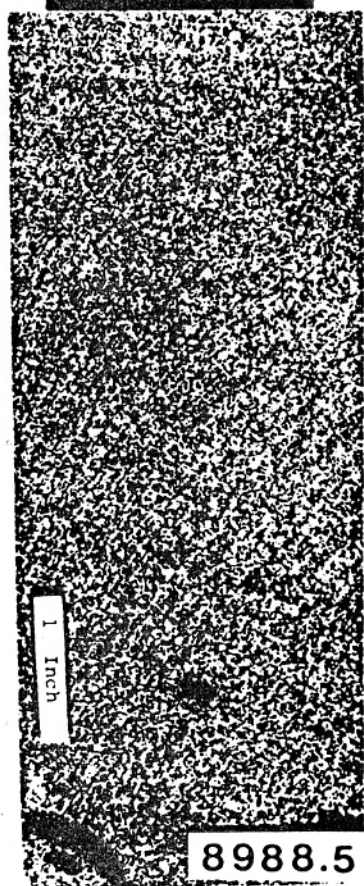
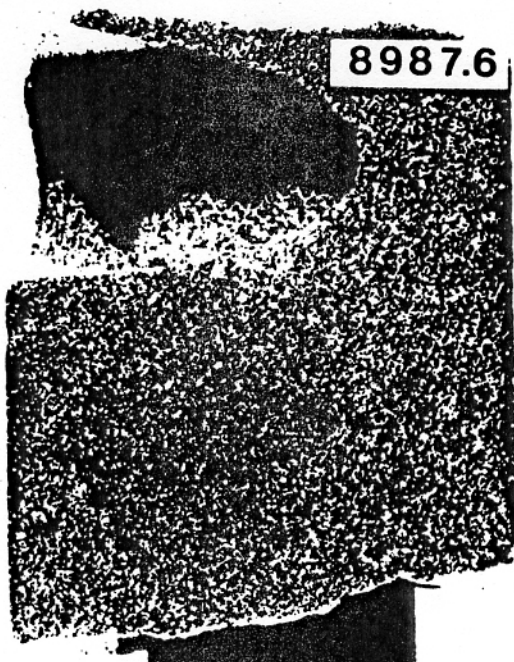


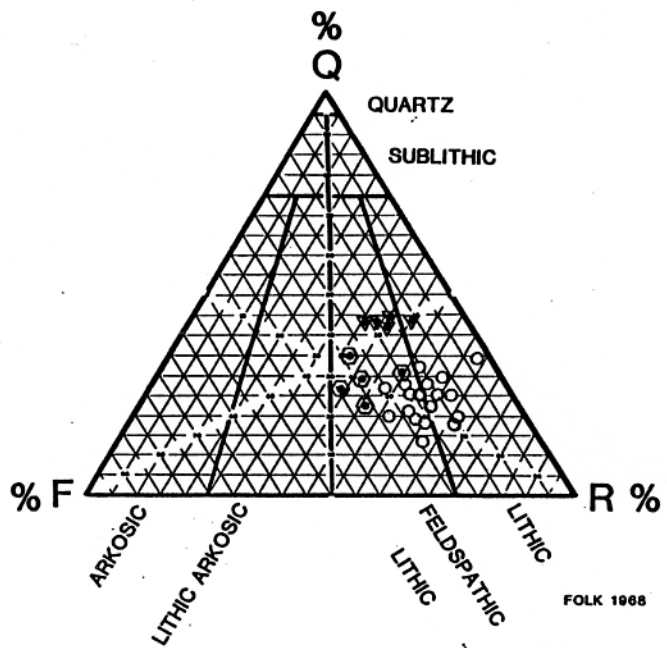
Figure 15. Massive distributary channel facies with channel lag from 8987 feet in the 8800 Sand of the A. T. Canales No. 26; excellent quality reservoir rock with 26 percent porosity and 100 to 600 md permeability.



Figure 16. Bioturbated bar crest facies with Ophiomorpha U-shaped feeding burrow from 10,755 feet in the 10,600 Sand of the E. G. Canales No. 18; poor quality non-reservoir facies.



Figure 17. Bioturbation in a delta front sequence destroyed most initial permeabilities in the 8650 Sand at 8896 feet from the E. G. Canales No. 8.

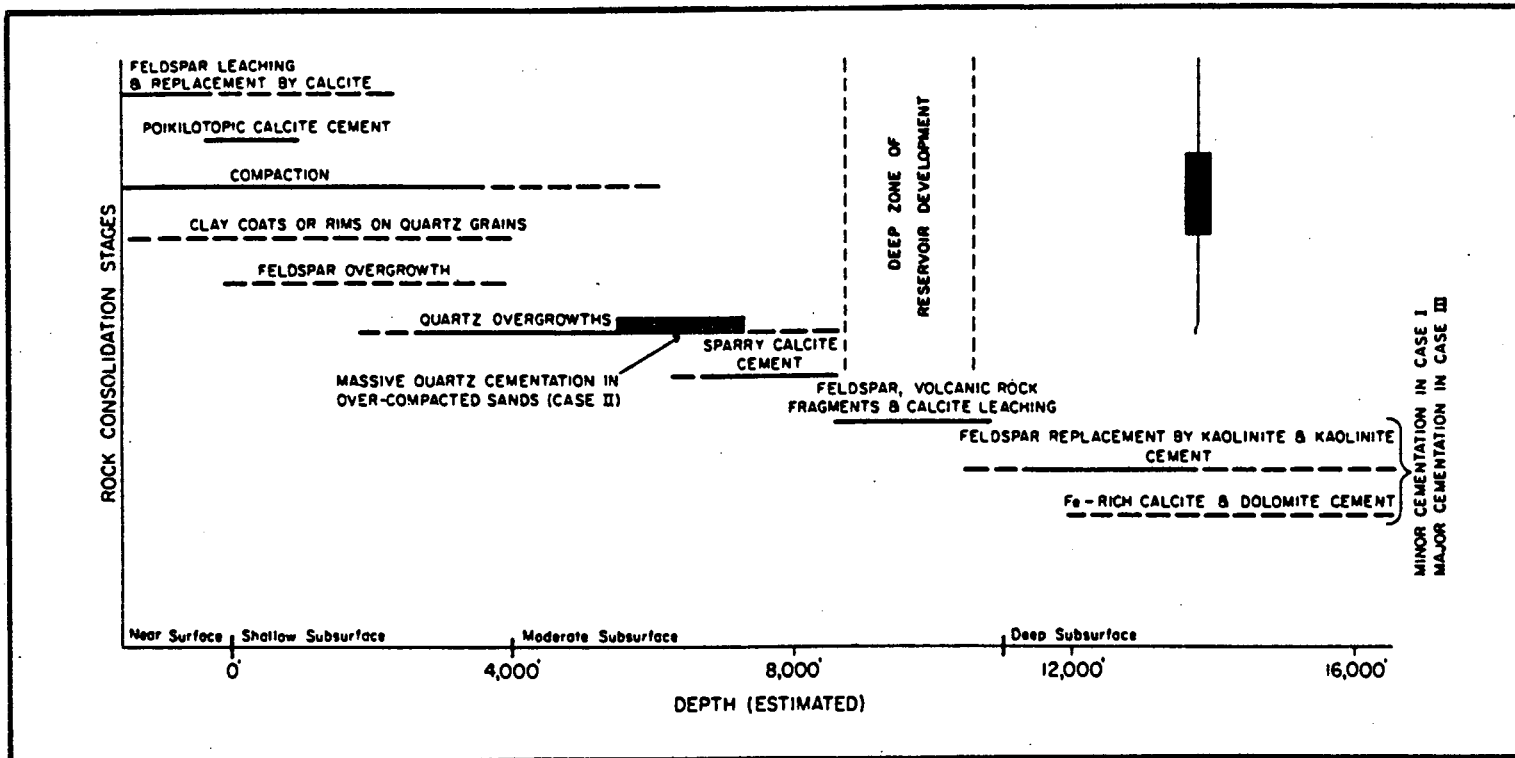


**DETRITAL COMPOSITIONS
T. C. B. FIELD
VICKSBURG SANDSTONES**

- ▼ UPPER VICKSBURG
- MIDDLE VICKSBURG
- LOWER VICKSBURG

Figure 18. Quartz to feldspar to rock fragments (QRF) diagram indicating feldspathic-lithic nature of TCB sandstones. From Folk's (1968) classification scheme.

DIAGENETIC SEQUENCE

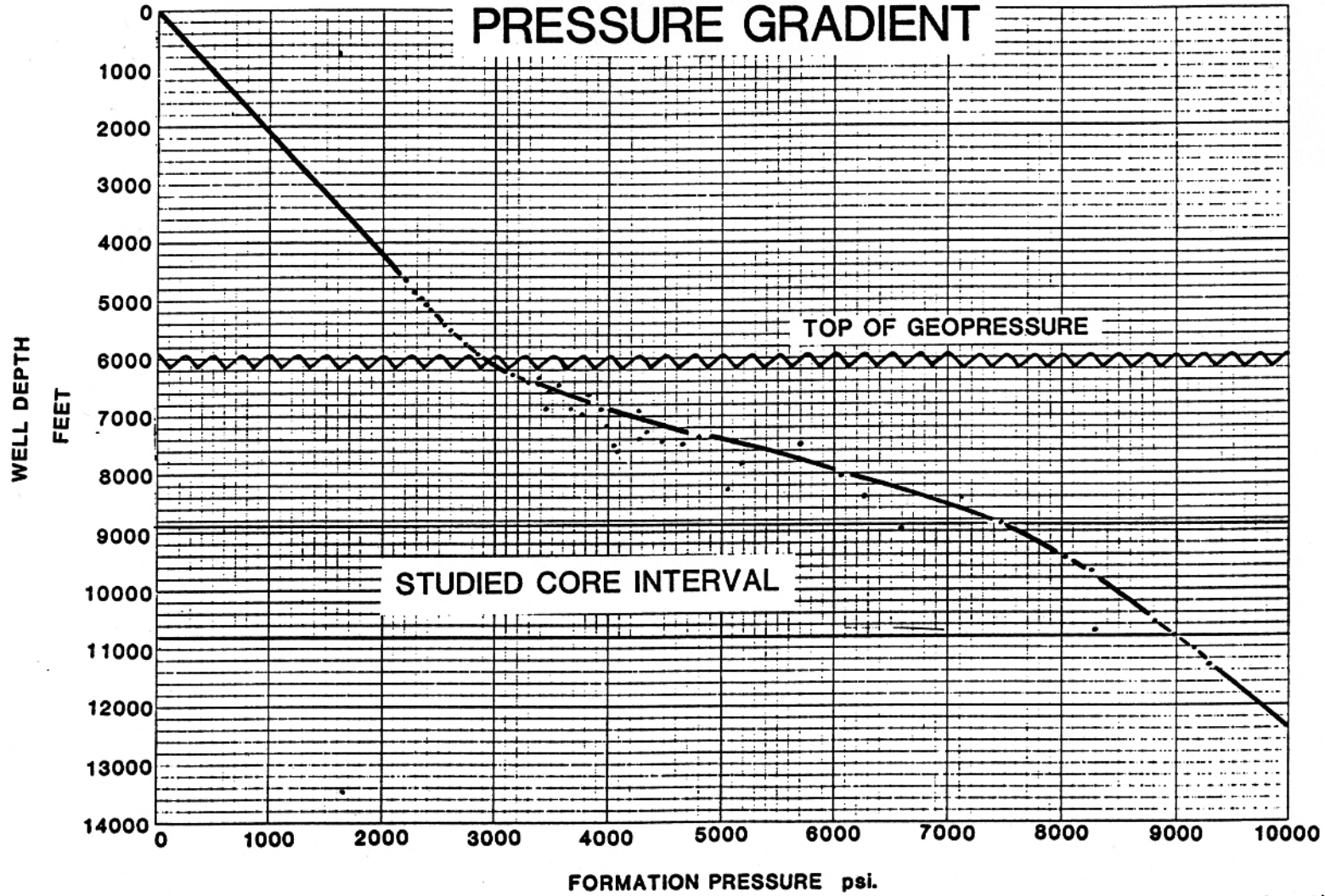


LOUCKS, BEBOUT, & GALLOWAY

1977

Figure 19. Diagenetic sequence model developed by Loucks, Bebout, and Galloway (1977) parallels TCB diagenetic events.

T. C. B. & SEELIGSON FIELDS PRESSURE GRADIENT



MODIFIED FROM B. BRIM (1980)

Figure 20. Changes in geopressure with depth in the TCB and Seeligson Field areas. Modified from Brim "in-house" (1980).

preservation of secondary porosity with associated enhanced permeabilities are the key diagenetic alteration features linked to successful petroleum reservoir development in South Texas. The two most productive Vicksburg reservoirs thus far in TCB Field include the 8800 Sand of the Middle Vicksburg and the 10,250 Sand of the Lower Vicksburg. Scanning electron microscopy of channel mouth bar-distributary channel samples from both of the above-mentioned reservoirs demonstrate excellent visual secondary porosities exceeding 25% (fig. 21a and fig. 21c) through regular intergranular porosity (fig. 21b), over-sized (fig. 21d) pores and grain molds (fig. 21e). Similar secondary porosity style was also observed by Klass, et al (1981) in the McAllen Ranch area. Feldspar "crystal city" dissolution is a common feature in the best of reservoir facies (fig. 21b and fig. 21d). Preferential dissolution of more unstable end members has occurred leaving behind more stable end members of the feldspar solid solution series.

Most TCB Vicksburg reservoir rocks have secondary porosities ranging from 15% to 26%, but permeability seems to be just as critical to have a producible reservoir. Permeabilities of most reservoir rocks ranged from 1 millidarcy to 600 millidarcies. Permeability observed in thin sections and scanning electron microscopy samples appeared to be greatly enhanced by dissolution of clayey matrix and carbonate cement.

Clay mineral assemblages are probably the second most important diagenetic alteration feature linked to successful petroleum reservoir development in South Texas. The geometry of pore spaces and pore throats in association with authigenic mineral assemblages within the secondary porosity voids is critical to the successful completion of many wells. Clay mineral assemblages and degree of authigenesis can also serve as indices for good reservoir quality rock versus poor reservoir quality rock. By observing clay mineral estimated percentages from thin sections, X-ray diffraction and scanning electron microscopy, relative percentages of clay in each core interval from Lower to Upper Vicksburg were compared in a kaolinite, illite-smectite, chlorite (KISC) ternary diagram (fig. 22). Surprisingly, the

different reservoir rocks classified by authigenic clay mineral types fall in anomalous regions to reservoir quality. The two most productive cores in TCB Field plotted in very similar regions on the KISC diagram. Distinct clay mineral variations from reservoir to reservoir were evident especially with depth. Each studied Vicksburg reservoir had its own distinct diagenetic imprint in TCB Field. All Vicksburg reservoirs are not alike and the diagenetic imprints can even vary from facies to facies within the same core. Diagenetic imprints appear to be extremely composition, depth and facies dependent.

Each core studied had a particular clay mineral assemblage. The 10,600 Sand in the E. G. Canales No. 18 was the deepest core studied in the Lower Vicksburg and could be described as an illitic-chloritic reservoir as indicated by scanning electron microscopy (fig. 23a) and X-ray diffraction (fig. 24a). There is abundant authigenic pore bridging illite and authigenic iron chlorite blades and rosettes. The 10,600 Sand is very tight with permeabilities averaging less than one millidarcy. The low permeability is probably the result of high percentages of late stage authigenic ferroan calcite and pore bridging illite. This core also has scattered bloturbation throughout the main sand facies which may have reduced initial permeabilities which in turn reduced alteration effects. The 10,600 Sand core plotted low on the KISC diagram in a similar region as the 10,500 Sand, but with a greater relative percentage of illite (fig. 21).

The 10,500 Sand could be described as an iron chloritic-slightly illitic reservoir as indicated by scanning electron microscopy (fig. 23b) and X-ray diffraction (fig. 24b). Sharp X-ray diffraction peaks indicate the high degree of crystallinity of the chlorite. The iron chlorite rosettes have extreme authigenic character and are associated with authigenic microquartz (fig. 23c). Permeability is better in this reservoir and approaches 10 millidarcies in the upper distributary channel facies. The 10,500 Sand also plotted low on the KISC diagram, but with less illite than the 10,600 Sand (fig. 22). Both the 10,500 Sand and the 10,600 Sand are good Vicksburg reservoirs, but their associated high iron chlorite content should require special care in completion.

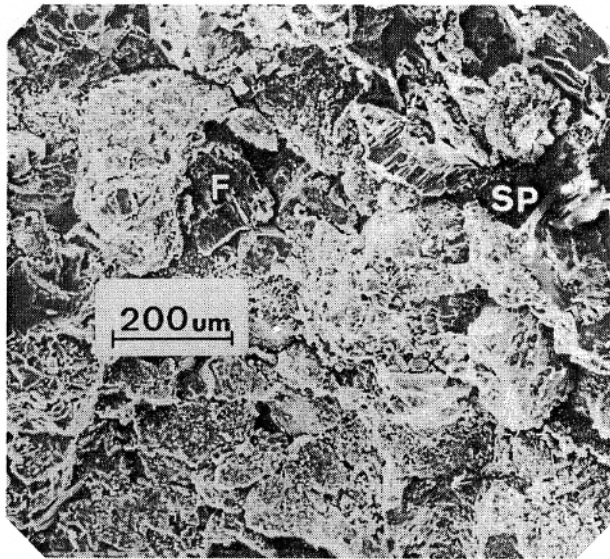


Figure 21a. Scanning electron photomicrograph of excellent secondary porosity at 8999.5 in the 8800 Sand of the A. T. Canales No. 26; F is preferentially dissolved feldspar with intergranular porosity, SP is secondary porosity in an over-sized pore.

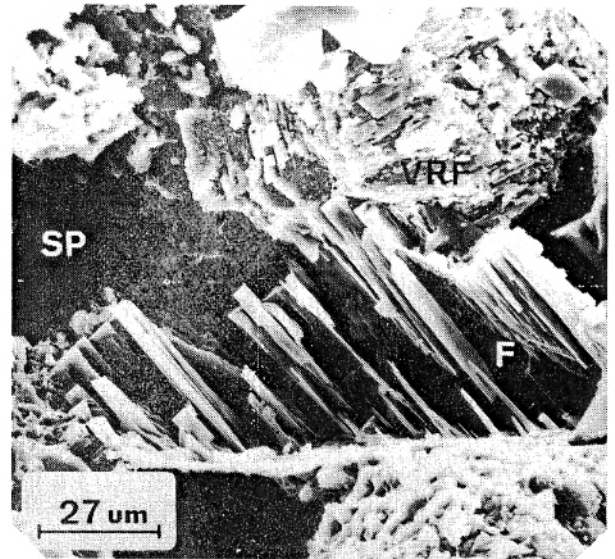


Figure 21b. Scanning electron photomicrograph higher magnification of 8988.5 in the 8800 Sand of the A. T. Canales No. 26; F is "crystal city" preferential dissolution of feldspar, SP is secondary porosity in an over-sized pore, VRF is a volcanic rock fragment.

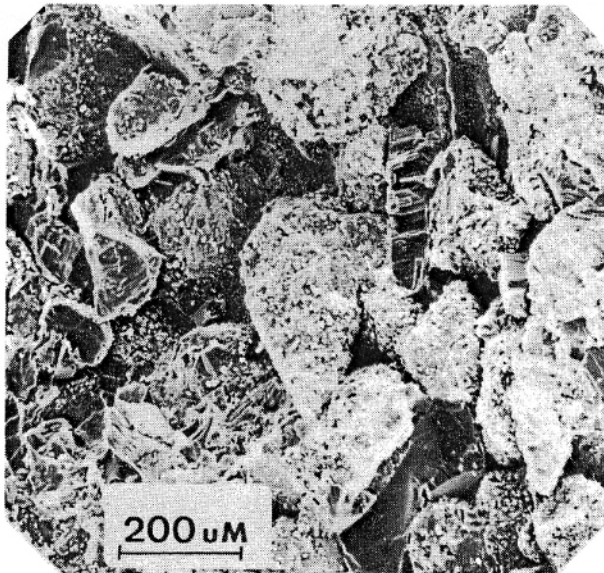


Figure 21c. Scanning electron photomicrograph of excellent secondary porosity at 10,180.0 in the 10,250 Sand of the E. G. Canales No. 18.

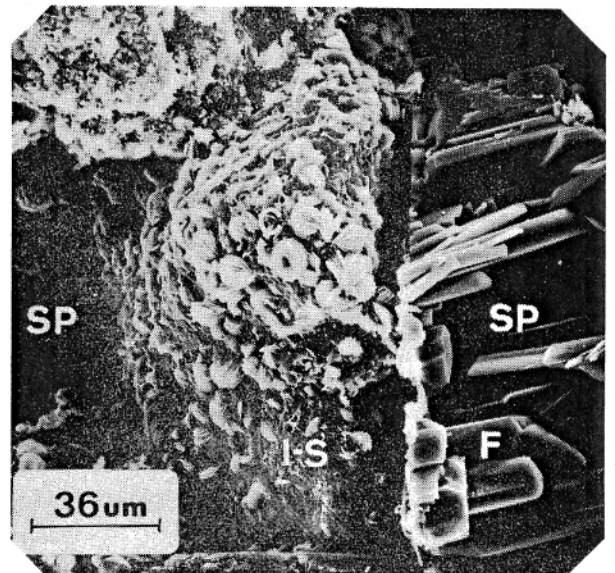


Figure 21d. Scanning electron photomicrograph higher magnification of 10,180.0 in the 10,250 Sand of the E. G. Canales No. 18; C is iron chlorite rosettes, I-S is illite-smectite, F is preferentially dissolved feldspar, SP is secondary porosity both over-sized pores and intergranular.

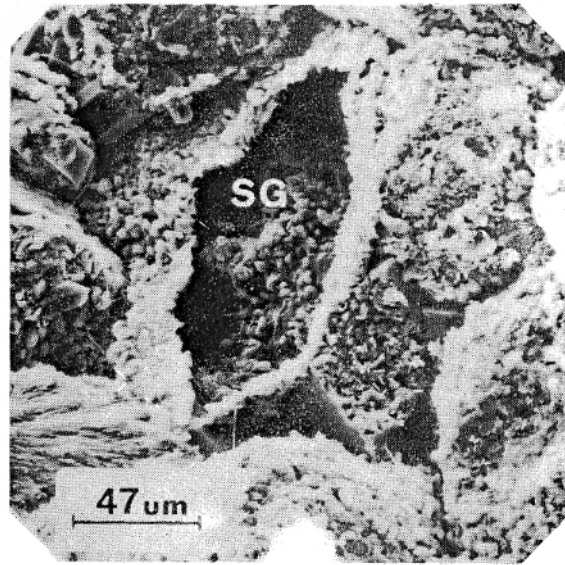
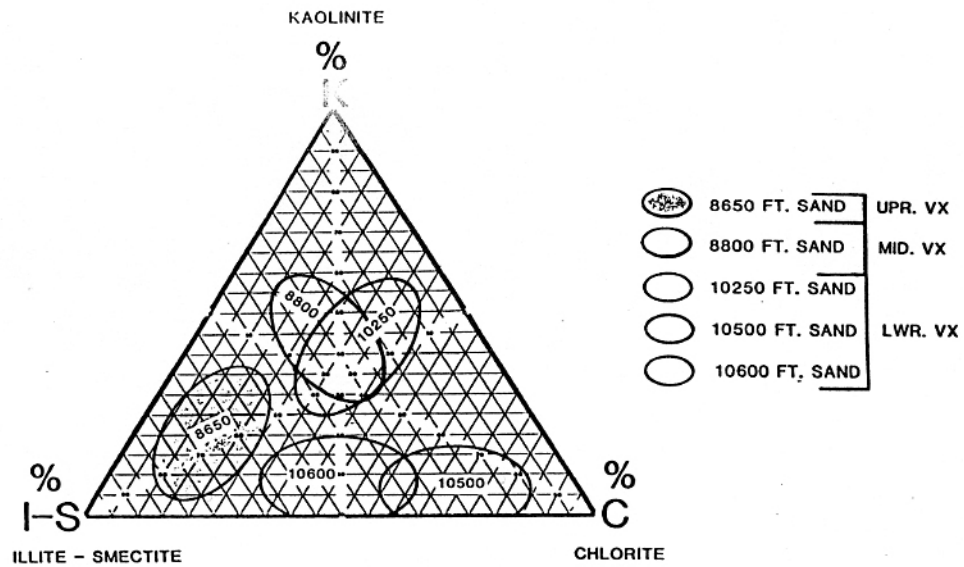


Figure 21e. Scanning electron photomicrograph of secondary porosity demonstrated by a skeletal grain or grain mold at 10,518.8 in 10,500 Sand of the A. T. Canales No. 55; SG is skeletal grain or grain mold.



RELATIVE % OF CLAYS
 T. C. B. FIELD
 VICKSBURG SANDSTONES

Figure 22. Kaolinite to illite-smectite to chlorite (KISC) diagram used to indicate relative clay mineral assemblage in TCB Vicksburg sandstones.

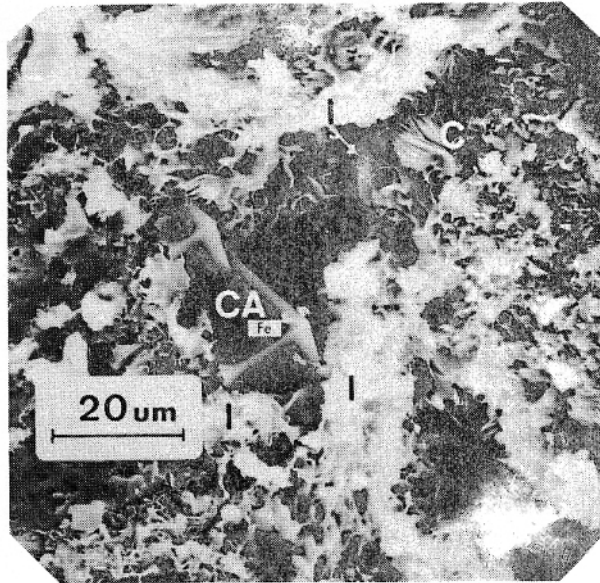


Figure 23a. Scanning electron photomicrograph of illitic-chloritic clay assemblage in the 10,600 Sand (10,767.3 feet) of the E. G. Canales No. 18; I is authigenic illite, C is iron chlorite rosettes, CA is late stage ferroan calcite.

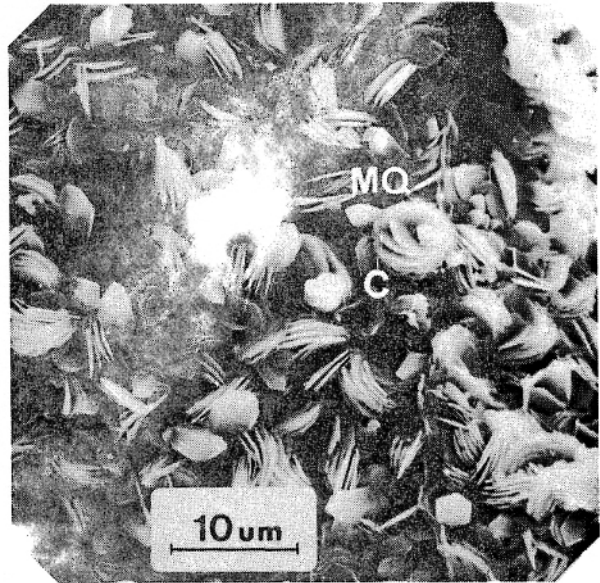


Figure 23b. Scanning electron photomicrograph of iron chloritic clay assemblage with microquartz in the 10,500 Sand (10,518.8 feet) of the A. T. Canales No. 55; C is iron chlorite rosettes, MQ is microquartz.

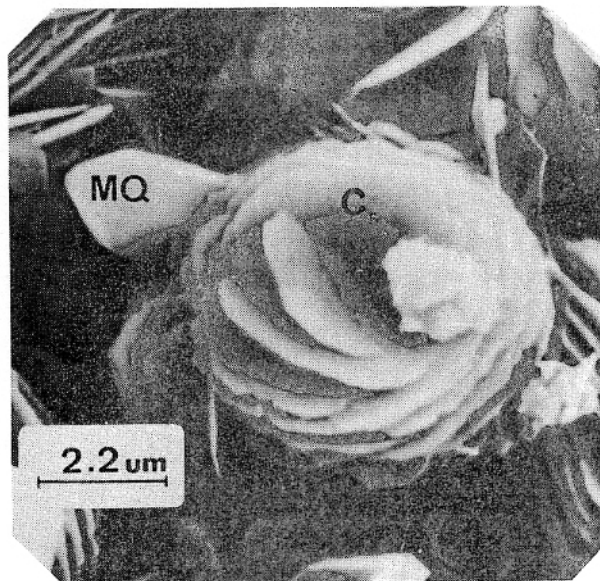


Figure 23c. Scanning electron photomicrograph higher magnification of iron chlorite rosette with microquartz in the 10,500 Sand (10,518.8) of the A. T. Canales No. 55.

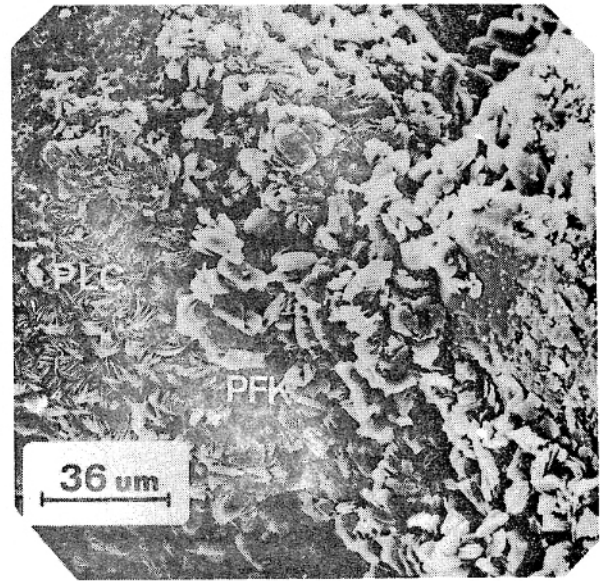


Figure 23d. Scanning electron photomicrograph of kaolinitic-chloritic clay assemblage in the 10,250 Sand (10,180.0) of the E. G. Canales No. 18; PFK is pre filling kaolinite, PLC is pore lining chlorite.

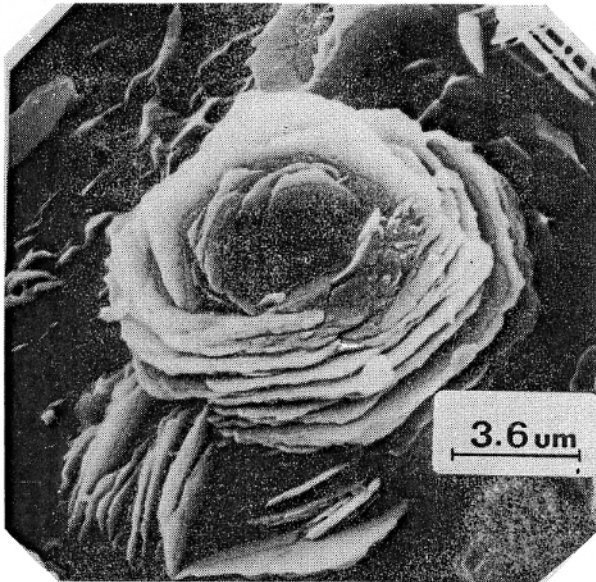


Figure 23e. Scanning electron photomicrograph demonstrating extremely authigenic iron chlorite from 10,250 Sand (10,180.0) of the E. G. Canales No. 18.

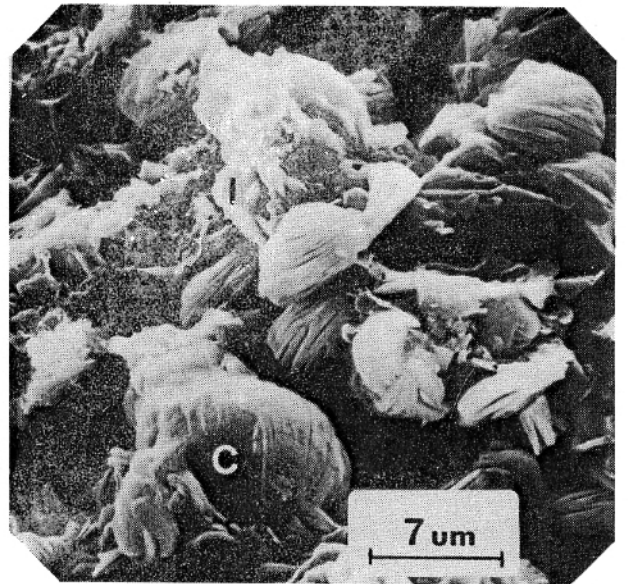


Figure 23f. Scanning electron photomicrograph of "cabbage head" chlorite in the 8800 Sand (9001) of the A. T. Canales No. 26; C is iron chlorite, I is illite.

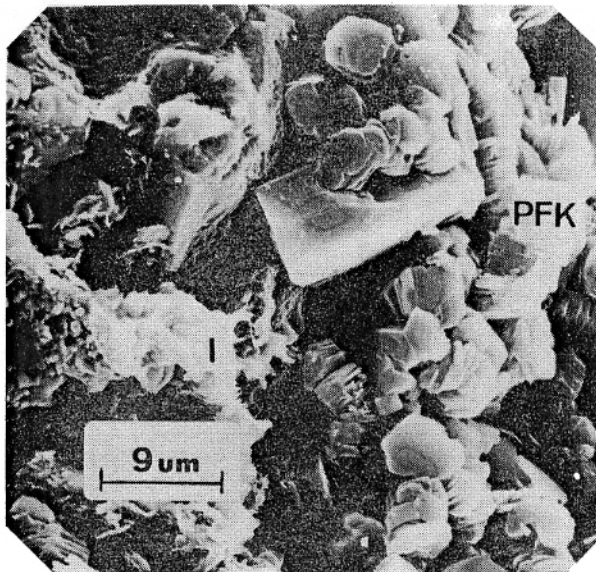


Figure 23g. Scanning electron photomicrograph showing pore filling kaolinite and illite in the 8800 Sand (9001) of the A. T. Canales No. 26; PFK is pore filling kaolinite, I is illite.

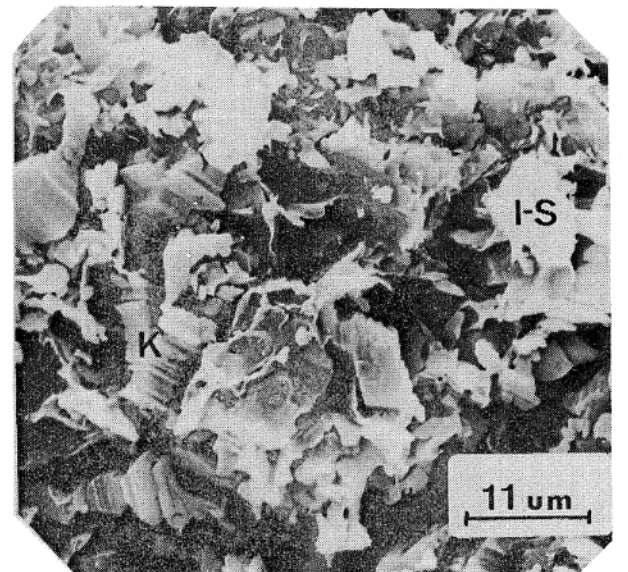
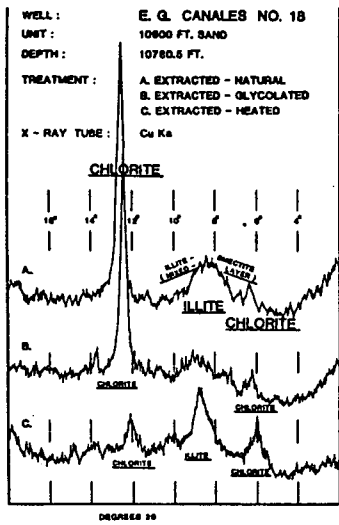
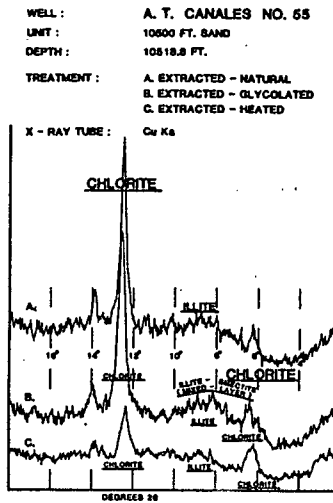


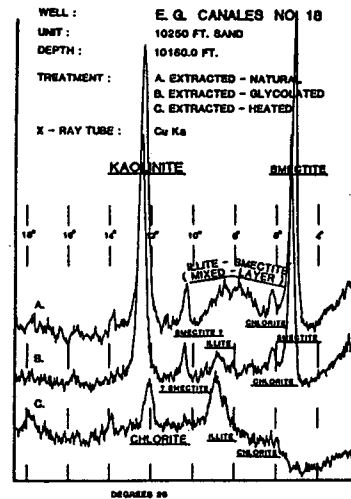
Figure 23h. Scanning electron photomicrograph showing illitic-smectitic-kaolinitic clay assemblage in the 8650 Sand (8905.3) of the E. G. Canales No. 8; K is "pagoda style" starved crystal of kaolinite, I-S is illite-smectite mixed layer clay.



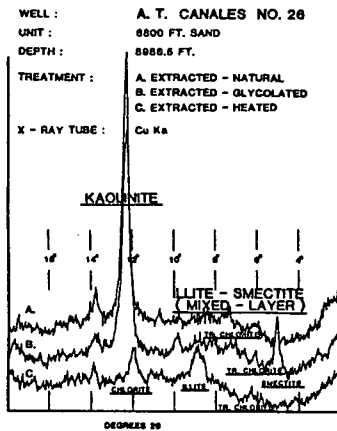
A



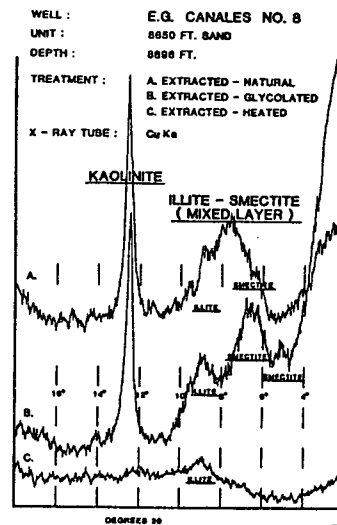
B



C



D



E

Figure 24a. X-ray diffraction peaks for clay mineral assemblage in the 10,600 Sand.

Figure 24b. X-ray diffraction peaks for clay mineral assemblage in the 10,500 Sand.

Figure 24c. X-ray diffraction peaks for clay mineral assemblage in the 10,250 Sand.

Figure 24d. X-ray diffraction peaks for clay mineral assemblage in the 8800 Sand.

Figure 24e. X-ray diffraction peaks for clay mineral assemblage in the 8650 Sand.

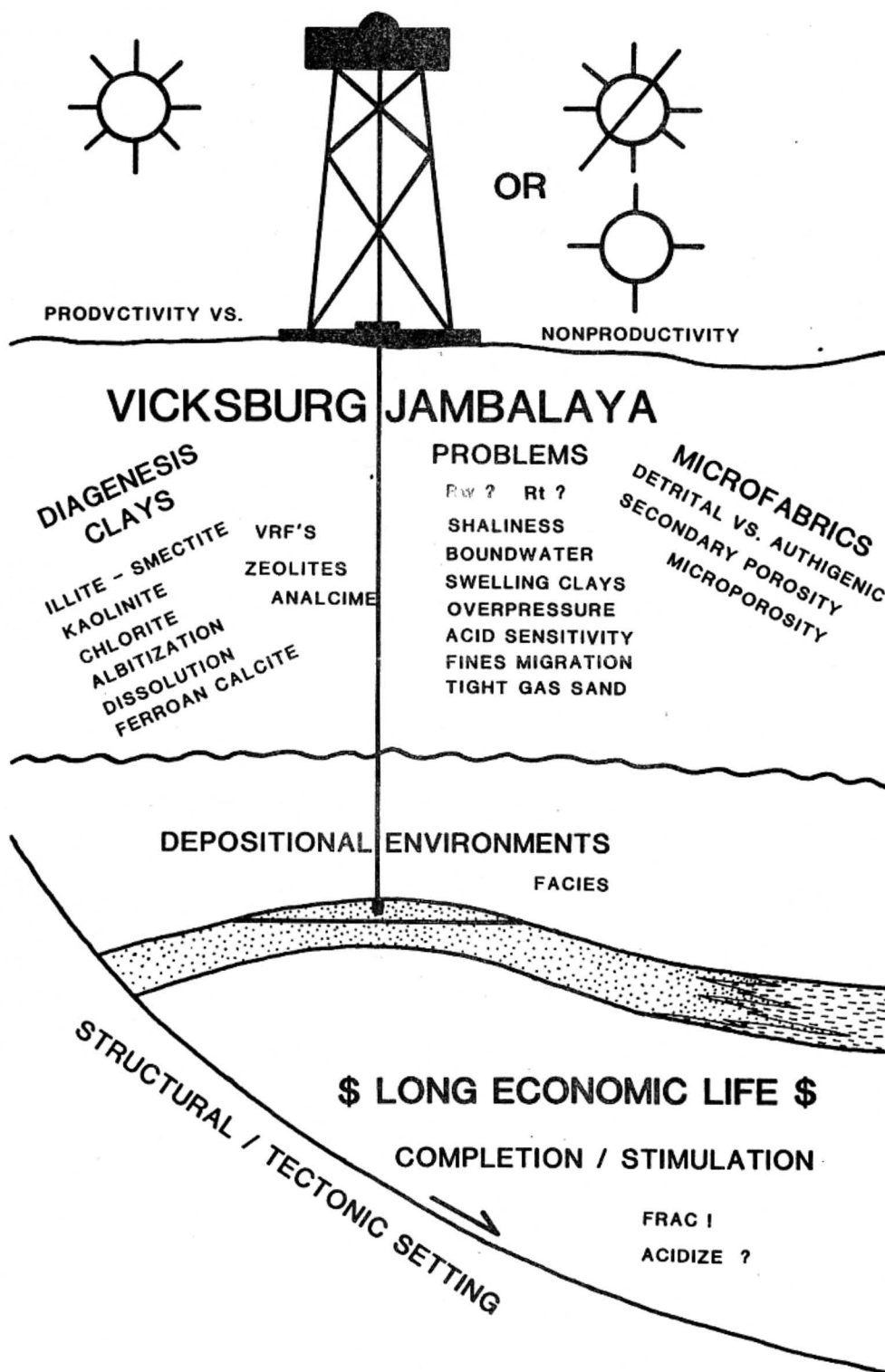


Figure 25. Important parameters to be considered in drilling and completion of Vicksburg wells in South Texas.

The uppermost core studied in the Lower Vicksburg was the 10,250 Sand which could be described as a kaolinitic-chloritic-illitic-smectitic reservoir by scanning electron microscopy (fig. 23d) and X-ray diffraction (fig. 24c). A rather complete clay mineral assemblage exists in the 10,250 Sand with excellent examples of pore filling kaolinite and pore lining chlorite (fig. 23d). This reservoir has an extremely high degree of authigenic crystallinity (fig. 23e) within secondary porosity; often the sign of an excellent reservoir. Permeabilities again approach 10 millidarcies. This reservoir is the second most productive Vicksburg reservoir in the Canales portion of TCB Field thus far. The 10,250 Sand plotted in a very similar region to the 8800 Sand on the KISC diagram with the 10,250 Sand having a higher chlorite content (fig. 22).

The 8800 Sand represents the uppermost Middle Vicksburg core studied and could be described as a kaolinitic-chloritic-illitic reservoir with tremendous porosity and permeability as indicated by scanning electron microscopy (fig. 23e and fig. 24f) and X-ray diffraction (fig. 24d). Pore filling kaolinite and "cabbage head" iron chlorite (fig. 23e) characterize the scanning electron microscopy photos. This is the best productive Vicksburg reservoir in the Canales portion of TCB Field. Porosities approach 28% and permeabilities exceed 500 millidarcies in the 8800 Sand of the A. T. Canales No. 26. The 8800 Sand did not have as high a chlorite content as the 10,250 Sand and the porosity and permeability was "cleaner" overall. This reservoir appeared to have had the greatest pure feldspar content at the time of deposition of any of the reservoirs studied. This may explain why the 8800 Sand plotted slightly more kaolinite-illitic on the KISC diagram (fig. 22). The 8800 Sand and the 10,250 Sand are both excellent Vicksburg reservoirs and both occur near localized unconformities at the top of the Middle Vicksburg and Lower Vicksburg, respectively.

The 8650 Sand was the only core studied in the Upper Vicksburg section. This section was perforated, but did not produce due to poor reservoir quality. The 8650 Sand could be described as an smectitic-illitic-kaolinitic poor reservoir quality rock as indicated by

scanning electron microscopy (fig. 23h) and X-ray diffraction (fig. 24e). Most of the channel mouth bar has been relegated to a bioturbate facies by "critters" (Friedman, 1985). The sand facies has a tremendous amount of detrital and some authigenic illite-smectite probably due to bioturbation. This core has decent porosities in the 18-20% range, but permeabilities run less than 1 millidarcy. Initial permeabilities were reduced by bioturbation and diagenetic alteration was retarded. The "pagoda style" kaolinites may represent starved crystals that lacked ion rich solutions due to reduced permeabilities. The 8650 Sand plotted in the high percentage illite smectite region of the KISC diagram reflecting the high percentage of detrital and authigenic illite-smectite contained in this core (fig. 22).

CONCLUSIONS

- 1) TCB Vicksburg sandstone were deposited in predominantly delta front environments with varying degrees of marine influence.
- 2) Lower Vicksburg is characterized by wave dominated cusped deltas; Upper and Middle Vicksburg are characterized by elongate and lobate high constructive deltas.
- 3) The most productive TCB Vicksburg reservoirs are within distributary channel and channel mouth bar facies; have the largest average grain size; have the greatest amount of altered labile fragments; and have strong highly crystalline authigenic imprints of kaolinite and/or chlorite and/or illite.
- 4) Diagenetic imprints of TCB reservoirs change with depth:
 - a) Relative percentages of kaolinite and illite-smectite decrease with depth.
 - b) Relative percentages of chlorite increase with depth.
 - c) The amount and degree of alteration of volcanic rock fragments increases with depth.
 - d) Secondary microporosity increases with depth.
 - e) Late-stage ferroan calcite cementation increases with depth and can destroy secondary porosity at shale-sand interfaces.

- f) Albitization increases with depth.
- g) Permeability decreases with depth.

- 5) Secondary porosity was generated due to dissolution of feldspars, volcanic fragments, early carbonate cements and clayey matrix which may be related to hydrocarbon migration (Al-Shaleb and Shelton, 1981) through Vicksburgian rocks.
- 6) Chloritization and presence of hydrocarbons may aid in preservation of secondary porosity.
- 7) Depositional environment facies and mud to sand ratios are instrumental in formation of the diagenetic imprints of TCB Vicksburg sandstones. Sandstones with initial high detrital clay content stood less chance of becoming reservoir quality due to lower initial permeabilities which retarded fluid rock interaction.
- 8) Lower Vicksburg reservoirs should require special completion techniques due to high percentages of authigenic iron-chlorite.

The Gulf Coast Province is classified tectonically as a "crustal collision zone-plate margin open" and the Mississippi Delta Province as a Tertiary to recent delta basin (Klemme, 1983). Klemme's study ranks 65 world petroleum basins and indicates that the Gulf Coast and the Mississippi delta were moderate size basins with volumes of 40,000 to 350,000 cubic meters, but with only 8 to 15% of their present basin reserves found in their five largest fields. This is an optimistic viewpoint for the business end of the oil and gas industry on the Gulf Coast since it implies that statistically more exploration and development wells will be needed to further delineate remaining reserves in these tectonic basin types where field size tends to be smaller and develop less reserves than fields classified in other types of tectonic basins. This characteristic parallels the structural complexities and diagenetic complexities associated with predicting trends in highly growth faulted over-pressured fluvial-deltaic-strandline-barrier bar clastic environments. In order to delineate these remaining reserves in the Vicksburg, it is essential that geologists consider carefully all critical geologic parameters (fig. 25) in

drilling and completing these delineation wells.

ACKNOWLEDGEMENTS

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This paper was presented to the South Texas Geological Society at the November Luncheon Meeting in 1986. The author, Dennis Taylor, is one of our newest members in the South Texas Geological Society.

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OLIGOCENE VICKSBURG SANDSTONES OF THE TCB FIELD:
A SOUTH TEXAS GEOLOGIC "JAMBALAYA"

Presented by

DENNIS A. TAYLOR

BIOGRAPHICAL SKETCH

Dennis Taylor is a geologist for Sun Exploration & Production Company in Corpus Christi, Texas. He was born in the Texas Panhandle in Levelland, Texas and in 35 years has seen six states as home including Texas, New Mexico, Oklahoma, West Virginia, Kentucky and Tennessee. Mr. Taylor was "raised" in the petroleum industry and was inspired at an early age by an Amerada geologist/-geophysicist from Tulsa, Oklahoma, Tommy Southgate, to become a geologist.

Mr. Taylor attended undergraduate school at Eastern Kentucky University in Richmond, Kentucky, and Oklahoma State University in Stillwater, Oklahoma, and received a BS degree in Geology in 1974. From 1974-1981 he taught geology, earth science, and science research for the gifted and talented in Okeene, Oklahoma. He attended geology graduate school at Oklahoma State University with an emphasis in petroleum geology. Since 1982, Mr. Taylor has worked for Sun Exploration & Production Company in Oklahoma City, Oklahoma, and Corpus Christi, Texas.

Professional topics of interest of Mr. Taylor include diagenesis, sedimentology, petrology, and porosity evolution of clastic reservoir rocks (in general), specifically sedimentology and diagenetic characteristics of the Jack Ford Sandstone Turbidite Sequence, Ouachita Mountains Overthrust; sedimentology, structural geology, petrology, depositional environments, and diagenetic characteristics of the Vicksburg sandstones of TCB Field, South Texas; petroleum geology of the Gulf Coastal Plain Province; petroleum geology of the Arkoma Basin; mineral associations and paragenesis of pegmatites of the Pikes Peak Granite and Mt. Antero Granite, Colorado.

Mr. Taylor is past President of the Oklahoma State University Geological Society and the Oklahoma State University AAPG Student Chapter. He is past member of the Oklahoma City Geological Society and a current member of the Corpus Christi Geological Society, and the American Association of Petroleum Geologists. Mr. Taylor has presented his paper entitled Oligocene Vicksburg Sandstones of the TCB Field: A South Texas Geologic "Jambalaya" at the National AAPG Convention in New Orleans, Louisiana, in March 1985, and the October 1985 Corpus Christi Geological Society noon meeting. The paper has been published in the 1986 GCAGS Transactions.