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INTEGRATED METHODOLOGY FOR CONSTRUCTING A QUANTIFIED HYDRODYNAMIC MODEL FOR APPLICATION TO CLASTIC PETROLEUM RESERVOIRS

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INTEGRATED METHODOLOGY FOR CONSTRUCTING A QUANTIFIED HYDRODYNAMIC MODEL FOR CLASTIC PETROLEUM RESERVOIRS

By M. M. Honarpour, R. A. Schatzinger, M. J. Szpakiewicz,

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ABSTRACT

A comprehensive, multidisciplinary, stepwise methodology is developed for constructing and integrating geological and engineering information for predicting petroleum reservoir performance . This methodology is based on our experience in characterizing shallow marine reservoirs, but it should also apply to other deposystems. The methodology is presented as Part I of this report.

Three major tasks that must be studied to facilitate a systematic approach for constructing a predictive hydrodynamic model for petroleum reservoirs are addressed: (1) data collection, organization, evaluation, and integration; (2) hydrodynamic model construction and verification; and (3) prediction and ranking of reservoir parameters by numerical simulation using data derived from the model.

The main building blocks for the integration process are core descriptions, petrophysical analyses, structural analyses, petrographical analyses, rock-fluid interaction analyses, well tests, wireline log analyses, production/injection data analyses, pressure histories, drive mechanisms, and information from analogous reservoirs, outcrops, and modern deposits.

The scale, quality, and quantity of data critical to the successful development of a predictive, quantitative hydrodynamic model are outlined for characterizing shallow marine reservoirs. Timing and sequence of data collection relative to the stepwise development of the model are discussed. Data integration consists of combining a facies map with petrophysical and petrographical data and wireline logs to produce flow unit maps of a reservoir. Further integration of flow unit maps with well test data, structural maps, and analogous outcrop data will provide predictive interwell information on flow unit continuity, preferential fluid paths, transmissivity, anisotropy, and distribution of hydrocarbon trapping.

Three-dimensional hydrodynamic models show the distribution of reservoir properties and the intercommunication within a reservoir in a correct spatial position. They are used in simulators to predict formation fluid movement under an imposed hydraulic gradient and, in turn, to evaluate production strategies and predict reservoir performance.

Mathematical simulations incorporate information from the three-dimensional models at the level of detail required for the stage of production studied. Predictions by use of the models are compared with field data for validation. Various production strategies are examined and compared for their effectiveness in oil recovery.

An expert system was developed to help the user collect and organize geological and engineering data to establish reservoir models for mathematical simulations. This manual driven program organizes the reservoir characterization procedure into a structured and easily followed approach.

This integrated approach provides a comprehensive guide for optimum data collection, integration, construction of an hydrodynamic model with predictive capabilities, and performance of simulation for field development and production strategies.

Part II of this report addresses criteria for the recognition of five types of shoreline barriers (spits, shoals, barrier islands, barrier peninsulas, and barrier bars); three genetic groups (aggradational, propradational, and transgressive); and tide or wave domination of the coastline. A barrier island field at Bell Creek Field, MT, was selected to exemplify the application of the methodology in characterizing a barrier island reservoir.

PART I: INTEGRATED METHODOLOGY

I. INTRODUCTION

The purpose of this report is to present a multidisciplinary approach to detailed reservoir characterization with emphasis on obtaining quality data and providing an integrative outline for defining fluid distributions and pathways in petroleum reservoirs. This is achieved by constructing a predictive hydrodynamic model. The resulting model is used to manage reservoirs more systematically and efficiently, to determine where hydrocarbons are located, and to forecast production performance.

NIPER has applied an interdisciplinary team approach to the integrated analysis of a clastic reservoir and several related outcrops as part of a DOE-sponsored geoscience research program. Through integrated analysis, depositional, diagenetic, structural, and interstitial fluid models have been assembled and used to construct a quantitative geological model which has been integrated with an engineering model for the same reservoir. This combined geological/engineering model has been used to identify various scales of heterogeneities in a reservoir.

Based on the results of 3 years of research, it is concluded that improved reservoir characterization is only possible through multidisciplinary integration and analysis of data on a specific depositional system. As part of this project, a generic, comprehensive, stepwise methodology with abundant interconnection among disciplines has been organized in a format that is adaptable to an expert system technique for effective and efficient reservoir characterization.

The purpose of reservoir characterization is to outline and integrate reservoir geological, petrophysical, diagenetic, rock-fluid , and production features which dictate fluid flow paths and trapping of fluids in reservoirs. Integration can be defined as a coordinated study to construct a unified picture of a reservoir which is compatible with all sources of information.[1] Integration is obtainable through synthesizing information about rock and fluid properties from various sources obtained at various scales at different locations and orientations, with variable accuracy and resolution. The experience we have gathered is based on analysis of shallow marine clastic reservoirs. The complex methodology that is developed is captured in an expert system.

Methodology for reservoir characterization consists of applying geological, geochemical, petrophysical, statistical, pressure, and production/injection analysis to subsurface reservoirs and their ancient/modern analogs for prediction of hydrocarbon production performance (fig.1). Statistical and mathematical methods are applied to analyze, rank, and correlate the data. An integrated geological/engineering model containing geological and engineering characteristics is constructed based on partial models of the reservoir. Application of various geostatistical and mathematical simulation techniques outline reservoir performance under various modes of operation. Any diagnostic study should begin with the construction of a geological/engineering model and selection of appropriate tools to identify problems and recommend solutions.

Knowledge of the depositional origin of a reservoir provides fundamental information about original reservoir dimensions, geometries, continuities, thickness pattern, and pore geometries.[2-3] Cross sections and maps are constructed after the environment of deposition has been identified. Comparison is then made with generalized models of that environment. Postdepositional modifications should be identified and integrated into a reservoir model. Statistical averaging must be performed for the same rock type within the same depositional environment and facies to subdivide the reservoir into its component parts. Location of pilot projects and well spacing should also be examined on the basis of geological continuity and other reservoir specific features.

A hydrodynamic model describes fluid flow in a reservoir based on pressure distribution, saturation, fluid properties, and reservoir heterogeneities manifested by permeability variations and boundary conditions. This model is derived from the integration of information from static partial geological models -- depositional, diagenetic, structural, and fluid characteristics. Pressure distributions, fluid-fluid, and rock-fluid interactions must be superimposed for each recovery stage to add a dynamic component to a model. Hydrodynamic models are used in simulators to predict the formation fluid movement under an imposed hydraulic gradient and, in turn, to evaluate production strategies and predict reservoir performance.

II. CRITICAL HETEROGENEITIES AND REQUIRED DATA FOR CHARACTERIZATION

Geological heterogeneities may be grouped primarily into four categories: sedimentological, diagenetic, structural, and formation fluid characteristics. Sedimentological heterogeneities result from depositional processes and indicate the original framework/architecture of a reservoir. Subsequent diagenetic processes resulting from geochemical alterations of reservoir rock or fluids improve and/or deteriorate reservoir quality through generation of clays, cementation, and leaching processes. Structural features such as faults and fractures are superimposed on the primary framework and may interact with diagenetic processes by acting as channels/barriers for fluid migration. Formation fluids consist of formation water and hydrodynamically induced water and hydrocarbons. These fluids have interacted with the rock over 10's of millions of years and have reached an equilibrium state in closed systems or a semiequilibrium state in deep dynamic systems. The implementation of recovery processes creates man-induced alterations which may present additional complications in the system and may be deleterious to subsequent production.

These heterogeneities have variable effects on reservoir performance depending on the stage of production; therefore, they must be characterized separately at different levels of detail at each stage of production and for each implemented process. The characterization should encompass nonproductive formations overlying and underlying producing sections, as well as aquifers in hydraulic contact with the reservoir.

Major heterogeneity types based on geological origins are listed in table 1. These critical heterogeneities are important to all hydrocarbon reservoirs and must be quantified for reservoir modeling. These heterogeneities are manifested in the following fluid flow characteristics and distributions:

(1) formation thickness (pay/nonpay), spatial distribution of pay and nonpay intervals, and reservoir dip (attitude);
(2) compartmentalization/continuity;
(3) permeability contrast (layering) and anisotropy;
(4) fluid, fluid-fluid, rock-fluid interactions;
(5) drive mechanism/gas cap/aquifer size, shape (irregular/tilted connection to other reservoirs with gas-cap drive) and its characteristics; and
(6) volumetrics, fluid distribution.

Critical heterogeneities for various stages of production may be summarized as follows:

Primary - net formation thickness
compartmentalization
type of drive mechanism
volumetrics/fluid distribution
fluid properties, relative permeability.

Secondary - compartmentalization/continuity,
permeability contrast (channeling),
anisotropy, rock-fluid interaction
(wettability, relative permeability),
clay type(swelling/migration),dip.

Tertiary - volumetrics/fluid distribution
compartmentalization/continuity,
permeability contrast (channeling),
anisotropy, rock-fluid interaction
(wettability, relative permeability),
temperature, dip (table 2).

The importance of these critical heterogeneities to sweep and displacement efficiencies and the tools for their characterization are shown in table 3.

Reliability of geological/engineering models depends on the quality of the basic data, the type of averaging/interpolation technique used, and the basic assumptions made. Measurements should be representative of in situ reservoir conditions for specific rock types even though some unavoidable irreversible (physicochemical) changes may occur during coring, recovery, and testing. Rock type means a suite of rocks with similar mineralogy, texture, diagenetic history, pore geometry, throat size distribution, porosity, permeability, capillary pressure, and similar wettability behavior. Rock type characteristics are inherited largely from the time of deposition. However certain postdepositional factors such as compaction, cementation, solution, and rock-fluid interaction can modify the characteristics of a formation significantly.[4] Defining a rock type primarily by porosity, permeability, or lithology alone is inadequate for reservoir characterization.

Systematic data collection must be concerned with the following major points:[5]

(1) optimum coverage of the reservoir,
(2) consistency of procedures and providing enough details for comparative purposes,
(3) data quality more than quantity,
(4) objective or final usage, and
(5) maximum usage of available data.

The answer to the question of "how much" data are required to reduce the level of uncertainty in input data to an acceptable level for a given process must be determined through simulator sensitivity studies for that process. This answer depends on the degree of variability in reservoir properties and the error bars associated with varying amounts of data. Given the intrinsic probablistic nature of any reservoir description, sensitivity studies should aim at establishing a relationship between quantity and quality of reservoir data and uncertainity in the simulation predictions. This would assist in deciding on the type of reservoir data needed to reach an acceptable confidence level in predicted results. The results of sensitivity analysis for a given process should be a relationship between the input data needed for an acceptable predictability confidence level.

Information concerning primary and secondary production performance as well as all man-made alterations should be taken into account for reservoir characterization for enhanced oil recovery (EOR). A sensitivity study will rank critical reservoir parameters according to their importance to fluid flow. Interwell continuity resulting from depositional, erosional, diagenetic, and structural processes is, to a large degree probablistic. Other parameters which can be probablistic include the distribution of petrophysical properties and shale laminae. Simulation should be used to fine-tune these probablistic parameters and not the deterministic parameters. Geologists provide guidelines for engineers to fine tune their models for history-matching with consideration of characteristics of geological parameters.

The determination of each input parameter and its representativeness is an integrative process and is scale-dependent because no single tool is capable of measuring all necessary parameters on the scale of a simulator grid block.

There are four levels of information about a given reservoir. These sources include (1) the target reservoir; (2) analogous reservoirs, aquifers, mines, and outcrops; (3) modern depositional systems; and (4) regional setting. Comprehensive reservoir characterization should incorporate all these sources of information.

III- TOOLS REQUIRED FOR RESERVOIR CHARACTERIZATION AND DATA SYNTHESIS

The objective of this reservoir characterization research is to construct a geological-engineering model for reservoirs based on hard and soft data. Hard data are obtained from direct or indirect measurements, whereas soft data are based on model construction and interpretation. Data obtained from cores, wireline logs, well tests, and seismic have their own area/volume coverage, resolution (figs.2-3), accuracy, and cost. Often a combination of tools is needed for characterization of heterogeneities. Because these tools provide measurements at various scales, integration of data requires a substantial effort. Data acquisition, timing, and an optimum suite of tools for characterization of various heterogeneities at various stages of production are shown in figure 4.

A. Core Description and Analysis

Information derived from core studies and physical properties of samples can be divided into three categories: (1) data for geological parameters, including geological core descriptions and petrographic analysis, (2) data for well completions; and (3) data for engineering calculations. Core analysis provides information often not available by any other technique. It does not, however, stand alone, but rather supplements and is the basis for integration with information provided by other reservoir characterization tools.

A whole core provides the most reliable, continuous, direct information regarding quality and type of reservoir rocks, confining strata, and in situ fluids. Cores are used specifically for identification of depositional environments, facies, subfacies, erosional events, dip angles and azimuths. In addition, cores provide petrologic, petrophysical, mechanical, and geochemical data of reservoir rocks and interstitial fluids. Cores are also used for determination of rock-fluid interaction parameters and as a necessary reference for log interpretation. Such information is critical, particularly during advanced stages of production; e.g., during design of waterflooding or enhanced oil recovery (EOR) projects. Well scout tickets, workover reports, wireline logs, production/injection data, well test data, results of previous investigations of rocks and fluids (core analysis reports), and early photographs of core sections are extremely helpful during detailed cores investigations. Criteria for selection of representative samples from cores are outlined in appendix A.

Geological Core Description

There are four major steps in the geologic description of a core: (1) estimation of core quality (physical condition of cores) and selection of the best and/or most informative cores for detailed analysis; (2) identification of the lithostratigraphic sequence and sedimentology of the environments of deposition (facies, and subfacies); (3) documentation of postdepositional processes and their products (cements, fractures, and erosional cuts); and (4) design of a sampling program and sampling procedure.

1. An evaluation score sheet for determining core quality is shown in figure 5. Geologic information from cores with low scores can be used in areas of special interest or where other data are not available. Poor quality cores, those scored below 50 points, may only be used as an indication of continuity of certain lithostratigraphic units. Cores selected for detailed investigation should represent the entire spectrum of depositional and diagenetic features observed.

2. A complete core description starts with a microscopic, foot-by-foot comparative measurement of the dominant grain size and a visual estimation of mineralogic and textural features such as composition and percentage of dominant, secondary, and accessory minerals, sorting, grain shape, and their arrangements. In addition, mineralogical and textural measurements should be taken from intervals above and below the unconformities, sedimentary contacts, and from diagenetically affected zones. Such features provide information about provenance, energy, and distance of sediment transport which are characteristic of certain facies and environments of deposition.

Documentation of the types and quantities (e.g. volume percent) of various characteristics such as lithologies, physical structures (e.g. crossbedded, rippled or reworked layers), biogenic sedimentary structures (e.g. bioturbation), and contact type provide the essential basis for identification of depositional environment, facies, subfacies, occasional sedimentary episodes, and erosional events.

The geologically described vertical profile is constructed. Geologic features identified in the core are described in quantitative terms for individual zones and layers.

An example of the sedimentologic data sheet adapted for barrier island deposits is shown in table 4. An example of sedimentologic interpretation of cores from well W-16 in Bell Creek field is presented in figure 6. Facies are interpreted on the basis of sedimentologic criteria. The confidence levels and an occasional alternative interpretation are given.

3. Postdepositional processes and their products may strongly affect original rock properties and fluid flow paths. Their manifestation in cores provides guidance for taking additional samples for special laboratory analysis. Erosional cuts may vary from shallow and narrow scours (washouts) to deep valley cuts extending laterally for hundreds or thousands of feet. In a few-inch-diameter core they may not be readily distinguishable; however, erosional cuts are usually filled with lithologically and genetically different sediments than that of the eroded facies. Erosional phenomena need to be carefully documented and interpreted in a described core because they may negatively affect the original petrophysical properties of the reservoir rock.

The degree of lithification, color, change of type, magnitude and distribution pattern of cementation occurring in layers, laminae, lenses, patches, or nodules indicates exposure of deposited material to certain physical and chemical processes. The relationship of postdepositional changes to sedimentary structures provides valuable information regarding the timing of diagenetic processes. Chemical diagenesis (precipitation/dissolution/alteration of minerals) results from rock-fluid interaction in a specific environment defined by the pH, Eh, temperature, pressure, and chemical composition of migrating interstitial fluids. Matrix porosity and permeability measured on core samples reflects both depositional and diagenetic effects. Crystallization in pore spaces, stylolites, dewatering and degassing structures, and oil staining need to be identified and carefully documented for core description.

Particular attention should be given to any manifestation of natural fractures. Fracture width, length, density, true orientation, continuity, roughness, and type of infilling or scaling should be measured, described and photographically documented.

4. After sedimentological description, cores are sampled for a variety of further studies such as petrographic examination, paleontologic studies, thermal maturity and isotopic analysis, and routine and special core analyses.

Petrographic Analysis

Petrography is that branch of petrology which is concerned with the study, description, and classification of rocks. Petrology is the general term that refers to the study of the natural history of rocks, including their origin, constituent components, original and present conditions, and their alterations. Petrographic analysis for reservoir characterization generally refers to the microscopic description of mineralogy; rock textures and fabric; the abundance, distribution, and relative timing of diagenetic components; and the abundance, size, distribution, and bounding mineral phases that define the evolving pore system. Comprehensive diagenetic studies must also account for the types and amount of diagenetic fluids that have migrated through the pore system, for these provide the vehicle through which diagenesis occurs. Many of the tools available to the petrographer and their applications are listed in figure 7.

Petrographic analysis can provide a link between rock-derived data, such as that determined by core analysis, and data obtained from wireline logs. The petrographer is often in a unique position because direct observations of textural features can often explain apparent discrepancies such as those that commonly occur between log and petrophysical data.

Textural information provided by standard thin section or scanning electron microscope (SEM) analysis is generally not available elsewhere. These data may help to explain fluid flow or rock-fluid problems not explained by abundance data (e.g. mineral occurrence, porosity, or pay thickness).

Petrographic analysis can determine the type, amount, morphology, distribution, and reactivity of clays and other potentially problematic mineral or organic phases to waterflood and EOR methods. Stable or unstable isotope analysis, atomic absorbtion, CT scanning, and differential thermal analysis complement thin section analysis, X-ray diffraction, and scanning electron microscopy.

Routine and Special Core Analysis

Reservoir characterization without core description and analysis is inaccurate and incomplete because there would be no basis for calibration between various techniques, nor would there be a reference or standard for many reservoir parameters (fig. 8). There are four areas of concern in obtaining high quality core information: (1) the problem of selecting representative samples; (2) to minimize wettability alteration; (3) minimizing any changes in pore structures; and (4) selection of laboratory techniques for closer to true measurements of reservoir properties. The process of coring, selection of coring fluid, and preservation methods should be designed to minimize changes in cores relative to in situ conditions during and after core recovery. CT scanning can be used to monitor possible changes in cores. [7]

Great care must be taken during the core-handling process because changes in the core are often essentially irreversible.[8] During routine core analysis of some reservoir rocks, miscible cleaning and critical point drying techniques may be required to avoid changes in the pore structure. In addition, it may sometimes be better to omit measuring air permeability and to determine liquid permeability in uncleaned cores.

Mechanical, electrical, and sonic property measurements provide input for hydraulic fracture analysis and wireline log analysis. Caprock analysis sometimes is performed to evaluate the adequacy of the rock as a stratigraphic barrier.

Rock, fluid, and rock/fluid interaction characterization is an important initial step in screening for secondary recovery and EOR methods in a reservoir. Some of the rock-fluid interaction parameters that are critical to various EOR processes are included in table 2.

B. Downhole/Interwell Measurements

1. Geophysical Analysis

Geophysical methods for reservoir characterization may be divided in three categories: open-hole logging, cased hole logging, and surface/borehole seismic. Cased hole logs play a major role in locating bypassed hydrocarbon zones.

The purpose of wireline log analysis' where cores are absent or incomplete, is to provide a basis for extrapolation and interpolation between cored wells, and to obtain in situ and continuous measurements for various reservoir parameters where the log/core calibration has been established (fig. 9). Unfortunately, the vertical resolution of most logs is not fine enough for characterization of thin, high-porosity streaks. Therefore, porosity calculations from logs are lower, than the actual porosity where thin highly porous layers are present.

All downhole log readings are indirect measurements that must be converted to required parameters through some empirical models. These models have been based on measurements conducted on core samples. Because logs do not measure any properties related to permeability, a transform is often used to equate log measurements to reservoir permeabilities.

Geophysical techniques, especially seismic, can be of great help in reservoir description and characterization. The principle that allows seismic reflections to be of use is that a sonic pulse will reflect from each lithologic layer and the acoustic contrast between layers will determine how much of the energy is reflected (its recorded strength). Because sediment types, velocity, and density are more similar within than between layers, seismic reflections show patterns of strata. Seismic interpretation is, therefore, mainly concerned with three areas: recognition of stratigraphic patterns, application to well log interpretation (particularly sonic log), and specialized studies such as high resolution seismic.

Recognition of stratigraphic patterns includes definition of the attitude, geometry, and limits of individual reservoir beds and the location, vertical and lateral orientation, and distribution of faults. Seismic techniques may be useful in delineating drainage blocks bounded by faults, in determining the extent of an aquifer, particularly in off-structure positions with little well control, and in locating the distribution of reservoir facies Finally, seismic data can sometimes be used to help map fluid contacts, especially gas-oil or gas-water contacts.

The vertical resolution of seismic reflections is limited when compared to core or well log data. The lateral resolution obtained from 3D seismic is more detailed. The correlation of seismic and sonic log data by downhole velocity surveys, or vertical seismic profiling (VSP) may be of great value for pinpointing geological features and providing information about direction of stress, anisotropy, and fractures.[9] Because borehole data and seismic information are not interactive, the two types of data may may not be easily reconciled. However, comparison of the two techniques at different stages of production enhances reservoir characterization. Lateral continuity and interwell data provided by seismic logs can help improve structural maps, depositional trends, and location and direction of pinchout. Limitations of processing seismic data may be due to stacking procedures, effects of low velocity layers, surface terrain, sea bottom, water reverberations, multiples, refraction, and dip migration.[9]

Geophysical interpretation must be conducted by someone who is well versed in the specific techniques, and just as importantly, the interpreter must have insight about the geological features that the geophysical data reveal.[10] Other mapping techniques for characterizing reservoir properties of interwell areas and their changes with time include microseismic, geotomography, and CSAMT. All of these techniques may require baseline surveys. Contrasts indicated by these techniques include changes in temperature, mineralogy, water saturation, and electrical conductivity of fluids in the reservoir.

For these techniques, resolution of a few 10s of feet can be obtained. At this time, most of these mapping techniques are in their infancy and are not stand-alone diagnostic tools.[11]

2. Well Test Analysis

Regular, systematic, and consistent production and pressure monitoring and testing allow a balanced injection/production strategy. Initial production and pressure distribution provide valuable information about major depositional, erosional, diagenetic, tectonic, and rock-fluid interaction, and fluid contacts within a reservoir (fig. 10).

Front monitoring through production/observation wells and mapping of fluid movements provide knowledge that can guide well placement and balance production and injection to improve recovery efficiency and reduce bypassing and channeling. Pressure profile, areal pressure, watercut, GOR, water-gas contacts, fluid properties, and saturations should be determined and plotted and/or mapped with time.

Single-well and well-to-well pressure transient tests measure the average properties in the drainage area of a well and between wells. Often the effective permeability of a heterogeneous system is adequately described by the geometric average of individual values with the arithmetic and harmonic averages representing the extreme highs and lows. The proper determination of effective permeability requires knowledge of the spatial distribution (in a statistical sense) of various rock types and performance of numerical simulations.[12] Uncertainity in analysis of single- well, pressure-transient tests exists under a condition of multiphase flow. In heterogeneous reservoirs, well-to-well pressure-transient tests may not provide a correct estimate of interwell transmissivity.[13] Well-to-well tracer tests indicate the variability that comprises averages obtained from pressure transient tests. They also provide useful information for mapping fast-moving fronts and are unique in identifying sources and excess production of injected fluids. Transient pressure responses are found to be insensitive to the degree of layering and permeability contrasts, whereas tracer test responses are found sensitive to both the degree of layering and permeability contrasts.[14] Therefore, well-to-well transient and pressure tests complement each other.[15] Tracers include inorganic salts, soluble dyes, or radioisotopes. Some of the shortcomings of tracer methods include safety considerations, adsorption, incompatibility of tracers with produced fluids, precipitation or partitioning of tracers into oil, loss or alteration of tracers in reservoirs, susceptibility of the analytical technique to chloride ion interference, wellbore condition, and adverse mobility ratio. Nonarrival of tracer at an observation well does not indicate lack of transmissivity, but could simply be due to pressure distribution in the reservoir.

3. Wellsite Formation Evaluation

Some useful information about reservoir characteristics can be obtained by relatively inexpensive techniques such as wellsite formation evaluation. Wellsite formation evaluation can provide information about petrophysical properties (including hydrocarbon shows), mineralogy (including thin shale laminae), thief zones (high permeability or fracture indications), pressure, and type of fluids present. Wellsite evaluation is based on examination of drilling data, drill cuttings, mud logging, core, log, and DST analysis (fig. 11).

4. Fluid Analysis

Fluid analysis consists of crude oil characterization which includes PVT analysis, oil composition, and formation/injection water analysis. Additional fluid analysis is required for various EOR processes (fig. 12). Design of the sampling program is a critical step in the fluid characterization process.

Bubblepoint pressure measurements obtained from PVT analysis in saturated reservoirs should correspond with initial pressures at GOC. Bubblepoint pressures of samples obtained at various vertical positions in a reservoir may not form linear correlations with depths. This is specially true in reservoirs with large oil column where fluid properties may show substantial variation with depth.[16]

The role of the geochemist is to provide information about the type, history, source, and movement of formation fluids. This information is used to predict rock-fluid and fluid-fluid interactions.

C. Data Synthesis and Determination of Reservoir Properties

Commonly, the purpose of data collection is only to meet the requirements of available simulators. Data collection is not based on any geologic model. Nonreservoir rock distribution within a reservoir and associated aquifer and gas-cap characterizations are often ignored. Furthermore, systematic collection and reconciliation of various data are to a large degree ignored. Vast amounts of information available on analogous outcrops and reservoirs are not used. Appropriate scaleup is not applied, and geological models, even when available, are not integrated with engineering models. Data collection is not systematic, quality assurance is not given adequate attention, and consistency in measurements is ignored.

Some reservoir properties such as PVT, pore volume, and rock compressibility are not scale independent, whereas others such as permeability, and relative permeability are scale dependent and have directional characteristics.

Porosity can be measured from cores or determined by log interpretation. It defines reservoir capacity. Porosity tests measure total or effective porosities. The difference could be negligible in high-quality rocks. Direct porosity measurement is obtained from core analysis. The Boyle's law method for pore volume and mercury immersion for bulk volume measurements is the most reliable laboratory technique, except for highly heterogeneous samples (e.g., vuggy core, fractured core, or core with very large average pore size). Appropriate porosity corrections should be made to account for in situ stress conditions in order to be able to correlate core-determined porosity to that log-determined porosity. Furthermore, different wireline logs measure porosities which may be different than those measured in the laboratory (fig. 13). However, the volume of rock that is measured is different depending on the technique used (thin-section, core-plug, sonic, density, or neutron log). For example, the volume of investigation by sonic log is 5 times larger than the volume of whole core, and it is 1,000 times greater then that of a core plug.[17] Table 5 summarizes the investigation depth, angular coverage, and rock volumes for wireline tools.[18]

Absolute permeability is generally measured with air on extracted plugs in laboratories that in the past have not provided proper standards and procedures. Additional corrections to air permeability measurements should be made for slippage or turbulence. These values often are not representative of the ability of reservoir rock to transmit a single phase fluid because of inappropriate core-cleaning procedures that may well have changed the pore structure through the collapse or removal of clays or other fine particles. Such changes in pore structure are not consistent throughout a reservoir or even within a single core plug; therefore, air permeability values cannot be easily corrected. The result is that laboratory-derived air permeability values are almost always greater than the permeability to fluids under reservoir conditions. Furthermore, maximum and transverse permeability values reported are highly subjective because no effort is usually made to orient the core other than rotating it 90 degrees from a randomly chosen first direction.[19] This means that the K_{max} reported may not actually be the maximum permeability.

Layering, bedding, and lamination, as well as lateral permeability variations due to changes in depositional energy, diagenetic effects, structural factors and rock-fluid interactions create directional reservoir properties.[20] Therefore, determining a permeability distribution/profile in a reservoir based on data obtained from wells requires a reliable geologic model to allow interwell rock property prediction and description of lateral and vertical communication. Orientation of samples with respect to bedding is sometimes difficult to achieve in heterogeneous, anistropic, and layered/dipping formations. Vertical permeability has an effect on the coning, gravity drainage, crossflow, and perforation density requirements.

Permeability is generally measured relative to the plug orientation without consideration of sedimentary structures or facies boundaries. Vertical permeability obtained from plugs is often inadequate in defining the vertical movement of fluids because of the small volume of core plugs. Values obtained from whole core measurements are expected to be more representative because larger rock volumes can contain more barriers to vertical flow. The presence of isolated shales (depending on their lateral dimensions and frequencies) can have drastic effects on the vertical permeability of the formation. However, most of the single-phase flow is in the bedding direction.[21] The presence of isolated shales may not have severe effects on gravity drainage of oil from zones invaded by water or gas. The advantage of a two-phase flow mechanism decreases as the lateral extent of the shale increases because the drainage rate is related to the inverse of the length squared.[22]

Characterization of clay clasts and thin laminae can be conducted at the core level, and their in situ effects can be deduced from pressure transient data and fluid monitoring. This information can be integrated into a geological model to allow prediction of clasts and laminae lateral distribution. This means that the distribution of nonreservoir rock is an integral part of reservoir characterization because multiphase flow, immiscible/ miscible displacement, frontal advance, and coning are controlled and shaped by the distribution of reservoir to nonreservoir rocks.[23] Based on these observations, calculated Dykstra-Parsons coefficients (a measure of permeability variability) could be highly misleading because they ignore the sequence of layers and vertical permeability values and violate the fact that in reservoirs, streamlines do not cross in viscous flow.[24] Miller and Lent have recommended that identifiable correlative members of a formation should be averaged separately for assigning permeabilities to layers.[24]

Permeability values obtained from one-dimensional (1-D) fluid flow measurements on a core sample provide harmonic averages of various segments of the core. Fluids follow the path of least resistance and are influenced by gravity forces in reservoirs. It is not surprising that standard techniques of permeability averaging often may not be applicable for simulation of fluid flow in reservoirs. To compute effective interwell permeabilities one has to obtain both average permeabilities for each rock-type and a statistical representation of the spatial distribution of the various rock types in the reservoir.

Water saturation defines net pay, water-oil contact (WOC), and has a bearing on cementation and saturation exponents. Its distribution in a reservoir is controlled by geological structure, dynamics of the system, gravity, pore geometry/capillarity, and wettability. The dynamics of the aquifer as well as man-made alterations may also have a strong effect on water saturation distribution. The concept of irreducible water saturation can be misleading. Recent work[25] has shown that water saturation can be reduced to extremely low values as the result of successively higher displacement pressures. Water saturation distribution should be a product of the integration of capillary pressure measurements on preserved cores (native-state) under reservoir conditions, electrical log analysis, and repeat formation tests. In addition, capillary pressure characteristics of various rock types should be identified for correlative purposes. Capillary pressure data define transition zones in a reservoir. The accurate description of a transition zone affects hydrocarbon-in-place calculations, breakthrough times, and fluid injection/production performances.

Determination of oil saturation is also an integrative process. It is obtained by input from various coring, logging, well testing, tracer, and material balance techniques. The lateral extent of the distance of investigation for determination of ROS from various tools and associated advantages and limitations are summarized in table 5.

Systematic saturation measurement discrepancies among core, log, tracer, material balance calculation, and well test techniques exist. One of the main reasons for discrepancies among various methods of saturation measurement is due to the different volumes of investigation. For example, ROS measurement by chemical tracer tests, induction log, thermal decay tool, microlaterolog involves volumes of 5,000,000, 200,000, 2,000, and 100 times, respectively, the volume determined from a standard core plug.[26] Various methods of laboratory measurement of capillary pressure should be compared and more reliable values should be selected for reconciliation with DST, RFT, and wireline log data. Selection of effective ROS determination techniques should be based on the formation and wellbore conditions. Comparison of various methods of ROS measurement techniques has shown that PNC-LIL, C/O log, and single-well tracer tests provide similar ROS measurements. The resistivity log tends to give higher than average ROS measurements, and pressure coring tends to give lower than average ROS values. EPT and NML show large deviations from other methods. In most cases the average ROS determined by core/log/test wells in waterflooded areas are measurably less than those calculated by material balance calculations.[27] The reliability of various ROS measurement techniques is summarized in table 2 of Chang et al.[28]

Net pay is used in volumetric reserve calculations and predictions of flow performance. Net pay often is determined by establishing a cut off criteria such as porosity, water saturation, and/or shale content from logs and crossplots, and/or mercury capillary pressure data. These criteria are often based on regional experience or can be based on cumulative transmissivity distribution, and/or production logging data. Establishing too low cutoff values may mean that both viscous and capillary forces are important. Therefore, in flow performance predictions, capillary pressure should be included. Otherwise, flow performance predictions will be based on viscous forces alone resulting in higher cumulative oil production.[16] In primary production, net pay may not be economically as important as in tertiary production when expensive chemicals are to be injected as a percent of pore volume. Net pay is a variable parameter that is continually being redefined and is measured differently by different tools. Net pay also depends on the recovery process that is being applied and the economics of the reservoir.

Two types of errors can often affect the results of core analysis: random errors caused by measurement inaccuracies and systematic errors due to techniques or calibration. Quality control (internal laboratory evaluation relative to standards) and quality assurance (continuous critical review of procedures) are necessary for generating accurate and reliable data for reservoir characterization. There must be on-site quality control checks and assurance for the entire coring program, well testing, wireline logging, field monitoring, and fluid sampling and analysis.

Logging measurements sometimes are influenced by calibration errors, adverse borehole conditions, and associated borehole signals, and statistical fluctuations. It is recommended that, in a few strategic wells, thorough comparisons should be made between core and log data to resolve discrepancies. The accumulated log data base should also be used to predict reservoir properties in a well for which core analysis and description are available for quality assurance.

The quality control program maximizes data quality at extra cost, but it certainly saves money in the long term. In core analysis, comparison of grain density with lithology provides an opportunity to identify inaccurate porosity data and cementation exponents that are used in log analysis for saturation determination. When authigenic clay minerals are abundant, a comparison of grain density with lithology in cores may not provide much help in determining errors in porosity measurement from cores. According to Thomas and Pugh,[29] air permeability measurements of low-permeability samples are less accurate than those of high-permeability samples. The accuracy of measurements obtained from cores depends on the range of rock permeabilities. Porosity/permeability crossplots are a useful method for identifying suspect porosity/permeability data. However, significant scatter in such a plot may be due to differences in texture (grain size, sorting), clay content, or sample preparation. For example, sorting in one rock type may not be distinguished from the effect of pore geometry or grain size in another rock type and each of these parameters may cause scatter in porosity vs. permeability data.

Sample size/dimension affects the accuracy and precision of laboratory data because it is involved directly or indirectly in the calculation process and in scaling of laboratory measurements. In general, the largest possible plug or whole core should be used for measurement, especially in a highly heterogeneous formation or one that is fractured.

Relative permeability data are essential for almost all calculations of fluid flow in hydrocarbon reservoirs. The data are used in making engineering estimates of productivity, injectivity for different fluids, prediction of the course of displacement, sweep efficiency, mobility ratio, pressure distribution, and ultimate recovery from a reservoir for evaluation and planning of production operations. The pore geometries that control reservoir petrophysical properties can also affect the relative permeability characteristics.[30] Rock texture, fabric, mineralogy, and surface area control pore geometry and pore connectivity. Therefore, a study of these four parameters must be included to predict relative permeability.[30]

Laboratory relative permeability measurements should be conducted under simulated reservoir conditions on carefully selected and preserved cores. The use of preserved cores ensures that further alteration of wettability will be minimized after core recovery. The direction of saturation changes should duplicate as close as possible those that were encountered in the reservoir's production history. This is important because many interstitial fluid distributions are possible for each level of saturation -- relative permeability is path dependent and is also influenced by aspect ratio. Thus, by not recognizing the nature of the distribution of fluids, the wrong set of relative permeability curves and capillary pressure data may be used for simulation of a reservoir.

To be consistent, measurements of relative permeability, capillary pressure, and electrical properties should all be taken from the same core following the same path of saturation change as experienced by the reservoir.

Measured relative permeabilities should be checked against well test data, tracer tests, and field performance to provide an integrated approach and to identify any possible discrepancies. Permeability values from well tests having much higher values than the average from core data may indicate the presence of fractures, whereas having much lower values than the average values from a core may indicate lack or reduction of lateral continuity. Thus, well test data may predict arithmetic or geometric or some other average permeabilities depending on the flow models that are used for calculation. Different deposits may require special models for interpretation of well tests.

Core analysis and wireline log analysis often provide different values due to the nature of measurements, volume averaging, and operator dependency. Running averages of core porosity should be considered for correlating with log porosity values because of the limitations in log resolution due to smoothing bias introduced by the logging technique, type and scale of heterogeneities in the system, and sampling density. The distance that the running average is taken is dependent on the type of logging tool, the heterogeneity of the formation, and core sampling pattern. In addition, disagreements between core porosity and log porosity may be due to inaccuracy of core porosity measurements or usage of inappropriate porosity log or parameters. Core spectra gamma-ray logs provide the means to adjust core depth to log depth during core-log correlation. For core-log correlation, core, representativeness must be taken into account. Wellbore effects can also keep the logs from representing actual conditions of a formation. Less variance is expected in a data set as the volume of the sample increases for a given type of heterogeneity. This means that core porosity should show more variance about the mean than log-derived porosity because logs tend to consider a larger volume of rock. Core-log correlation should be integrated with pore geometry, lithological, and stratigraphic factors derived from geological core description and petrographic analysis. Core porosities are generally considered to be more accurate and precise than log values but should be corrected for in situ reservoir conditions in order to correlate with log data. Before core measurement, the quality of a core must be ensured: the coring process and handling procedures must be taken into account to insure that the physical condition of the core has not been altered. Microdevices can provide additional information about the location of permeable zones. Porosity alone cannot be used to predict permeability. Predictive equations may be developed for estimation of permeability values from wireline logs. Discriminant and multiple regression analyses have been used[18] to include grain size, cement, gravel content, type, and amount of clay in estimation of permeability from porosity. Hearn, Hobson, and Fowler[19] used statistical models based on core and log data for identification of facies and flow units. The discriminant models were constructed by characterizing facies and flow units in cores, in terms of corrected and normalized data from several log curves. The model utilized volume of shale based on gamma-ray log, corrected FDC porosity, and SP wireline curve data. In some cases, facies or rock type has been successfully distinguished by log crossplots after proper core-log calibration has been performed. Grain size and electrical resistivity values are often directly related when sorting is not an important factor or if fine grained rocks are more well sorted than the coarse grained rocks.[20] Shaley, silty, or cemented rocks have higher electrical resistivity than clean or uncemented rocks of equivalent grain size.

The separation of sonic and neutron logs due to their responses to gas is sometimes used to detect gas-oil contact (GOC). This information can be checked against gradient survey and used for calculation of gas-cap gas volume to be used in material balance calculations. Application of core-log correlations for identification of facies, flow units, and other heterogeneities should be checked against available geological models to see if the patterns and trends make sense.

The core, log and production data from each well need to be stored in a data base for ease of access and updating. A good data base package should allow easy manual input of data from other file formats (ASCII, spread sheets, data bases) by importing. The facility for performing fast searches (simple and complex) is essential for finding the geological or engineering data of interest. It should be able to output data in various formats such as reports, tables or maps. It should handle stratigraphic, lithologic, structural, log, production, well history, well test, geochemical and other data related to the reservoir. It should also allow flexibility in both geological and engineering processing by performing rapid calculations of structure, isopach, stratigraphic sequences, unconformity adjustments, univariate and multivariate statistics, regression analysis, and user defined algorithms. Good plotting software is essential in helping to quickly verify existence of relationships between various geological and engineering data. The use of a spread sheet format for display should allow quick data editing, sorting and various mathematical computations. The main goal of the data base is to allow the geologist and engineer to quickly extract data of interest and to study various relationships between these data. Thus, ease of use, flexibility and doumentation as well as available technical help are important factors. A detailed comparison of a number of PC-based data bases together with user's guide/to the study was given in recent issues of Geobyte.[31-33]

According to Davis,[34] three classes of data are present in geological investigations:

1. Data in which the sequence of observations is important in either time or distance series (such as in well logs or stratigraphic sequences).

2. Data in which spatial relationships between data are important as in mapping, surface trend analysis, kriging, etc.

3. Multivariate data in which the order and location of observation is not important. This category studies clustering classification and various other interrelations among data sets.

Much of reservoir characterization consists in finding parameters which have a major influence on oil location and its production. This is done by investigating the relationships between the types of data listed above, which is done by using various statistical and mapping programs. It is essential that the file formats for the various programs be compatible, otherwise an inordinate amount of time can be spent just changing file formats. The mapping software should allow flexibility in geological interpretation in both data selection and algorithm selection. For example, the software should map conformable surfaces present within a stratigraphic framework, should allow the existence of unconformities and faults correctly, and should handle points belonging to various populations, as well as preserving the proper trend in the absence of data in some conformable surfaces.

An important feature of the algorithm is to be able to project values outside of the values encountered in the control points. All the algorithms that use averaging techniques cannot do this. Thus, peaks and ridges present between the control points cannot be mapped by such algorithms even if the control values would otherwise point toward such features. These projections could be forced by using polynomials with universal kriging. Other important features of computer mapping software include the correct handling of zero-thickness values such as in pinch-outs, and the ability to perform grid operations such as addition, subtraction, basetop and truncation.

A more detailed discussion of the above topics with various mapping problems and their solutions using computer mapping software is given by Jones et al.[35]

IV. MODEL CONSTRUCTION

There are many types of models in the field of reservoir characterization including physical, conceptual, and mathematical. The type of models referred to in this section are concerned with the distribution of reservoir properties (sedimentological, diagenetic, and structural models, etc). The mechanisms used to portray the models include 1, 2, or 3-dimensional displays (cross sections, maps, or tables).

A. Sedimentological Model

Sedimentological characterization begins with identification of the depositional environment based on examination of cores, log signatures, stratigraphic sequence, thickness maps, and regional settings (fig. 14). Knowledge of the environment of deposition and distribution of facies of a productive formation is always a key toward improving predictions of three-dimensional (3-D) reservoir properties[2] because sampling is inherently inadequate to describe a reservoir in the detail necessary for performance prediction.

After depositional facies have been identified and located within a stratigraphic and environmental setting, data from analogous outcrops, other reservoirs, and modern environments can be used to supplement a depositional/erosional model. Once a depositional system has been confidently identified, the internal and external depositional and diagenetic or structural boundaries must be defined. At this time, petrophysical data and geochemical-diagenetic, structural, and engineering models must be consulted to provide sufficient data for quantification of a geological model. The concept of grouping facies into genetic associations is used for predicting geometry, continuity, and determination of properties of reservoir units representing similar transmissivities.

Stacking of sedimentary cycles and the position of aggradational deposits, or marine and alluvial erosional cuts can be defined by facies analysis in cored wells and predicted in the areas between core control on the basis of log signatures interpreted in accordance with geological rules.

Accurate mapping of external boundaries (pinching out, deep and low relief cuts, etc.) enables identification of potential localized hydrocarbon traps as injected water banks the hydrocarbons.

B. Geochemical Model

Geochemical characteristics encompass the mineralogy of reservoir rock, geochemistry of original formation fluids and their origin, and solid, liquid, colloidal and gaseous products of the rock-fluid interaction (fig.15).

Changes in geochemical environments create precipitation of cements, recrystallization, leaching, and universal alteration. These diagenetic processes result in reequilibration between rock and fluid systems through geological time. At the time of hydrocarbon entry into the reservoir, diagenesis ceases or is significantly slowed,[36] and new equilibrium conditions are achieved. Man-induced alterations of formation fluids and minerals take place during decades of production and reservoir stimulation.[37] Very few aspects of these processes are quantified in petroleum reservoirs except for compatibility between formation water and injected fluids.[38]

Undesirable geochemical effects, which are commonly encountered in hydrocarbon reservoirs, such as formation damage, plugging of slotted intervals, scaling and corrosion of casing and production pipes, and channeling of injected chemicals may result from incomplete geochemical characterization.

Isotope geochemistry has been available for more than 25 years as an indispensable tool for geochemists. However, it has not commonly been used for solving certain geochemical and hydrodynamic problems in hydrocarbon reservoirs probably because of the lack of information transfer from science to technology and because of general unfamiliarity with their usefulness of the isotopic tool among practitioners.

Stable and radioactive isotope analyses of $^{18}O/^{16}O$; D/H; and $^{87}Sr/^{86}Sr$ in reservoir rocks and formation brine have proven useful in characterizing interformational communication between reservoir and nonreservoir strata.[39] Carbon isotopes have also proven useful in determining the genetic source of oil and the identification of the environment of deposition of the source rock.[40]

C. Diagenetic Model

The diagenetic history of a reservoir must be taken into account during reservoir development and production because diagenetic processes influence the amount, type, origin, and distribution of porosity; pore shape and size distribution; wettability and surface area; and the resulting permeability and interwell continuity of flow units.

Diagenetic studies and model construction have applications to drilling-completion-stimulation, log analysis, and injection-fluid/ rock interactions (fig. 16). Timely identification of sensitive minerals and their distribution can be used as the basis for recommendations of drilling and completion fluids that are compatible with reservoir rocks.

Petrographic and core analysis data generally available to log analysts provide an improved basis for interpretation of the composition, pore volume, depositional environment, and fluid saturation within a reservoir rock pore system. Other information such as quantitative mineral abundance, mineral distribution, and other textural parameters can be used to supplement and to calibrate log interpretation models. Once calibrated, such information allows a continuous prediction of the mineralogy within the units of interest. More accurate log-derived determination of lithology and mineral distributions, including clays, ensures more accurate volumetric calculations, pore descriptions, and lithologic characterizations.

Diagenetic studies allow more accurate prediction of reservoir behavior through improved evaluation of reservoir properties during core analysis. Geological description of the rocks, including petrographic studies, should coincide with or precede a detailed core analysis program, particularly if sensitive minerals such as clays, carbonates, sulfates, or sulphides may be present.

Applications of diagenetic studies for different stages of production differ mainly in their emphasis. A more detailed discussion of diagenetic characterization may be found in appendix B.

D. Structural Model

Structural characteristics comprise the disruptive and nondisruptive products of tectonic processes such as faulting and/or folding that affect depositional continuity, geometry, and distribution of internal stresses (fig. 17). The scale of these effects varies from a microscopic scale in the case of grain rearrangement and microcracking (brittle, cleavage, and shear fractures) to a megascopic scale (subsidence, uplifting, regional dip, tilting of tectonic blocks, faulting, fracturing, folding, flexuring or overthrusting).

The general tectonic pattern within a field is often characteristic for the entire region. Small-scale features; e.g., minor faults or fractures, are site-specific and depend largely on local depositional and diagenetic characteristics. Development of reservoir rock deformation and stress distribution information also depends on the position of the reservoir with respect to larger scale tectonic features such as folds or salt diapirs.

Saturation of reservoir rock by pore fluids has a tremendous effect on rock susceptibility to deformation and failure.[41] Fluid withdrawal in the area of compressive stress may result in fracture closing, while in the tensile stress area a widening of fracture aperture may take place. Channeling of formation or injected fluids and divergence of flow directions may result when fractures are open. Open fractures or faults acting as conduits for formation fluids may promote diagenetic alterations (dissolution/precipitation/recrystallization) to the rock matrix in an adjacent area. Mineral precipitation or fines migration in fractures may block the conduits to fluid movement, and the original open fractures may become baffles in the hydraulic system.[37] A reverse process (dissolution) may take place when strongly undersaturated fluids enter the system. Thus, the role of fractures as fluid conduits depends on the actual state of chemical equilibrium between the formation fluids and rock.

The hydraulic role of filled fractures depends on the permeability contrast between the fracture-filling material (authigenic or detrital) and the adjacent rock matrix. When the permeability of a filling material is similar to permeability of adjacent rocks, the fractures may not be detected by downhole tools until acidization or another dissolution process creates greater contrast .

Fluid withdrawal or injection into a system may result in either a drastic decrease or an enhancement of fracture permeability. In extreme cases, nonlaminar flow conditions may be induced.

A study of a naturally fractured reservoir consists of four major steps: (1) detection of fractured zone distribution, (2) identification of superimposed fracturing episodes and their spatial distribution, (3) quantification of fracture characteristics, and (4) modeling of fluid storage and transport through fractured media and estimation of the fracture contribution to the fluid flow pattern and to production performance.

The general tectonic outline of a hydrocarbon reservoir can be inferred from regional tectonic maps and seismic profiles. The site-specific features, however, need to be studied individually for a field or production unit based on geologic, geophysical, and well test indications. Analogous outcrops located in the same tectonic region provide valuable information regarding rock deformation patterns.

E. Application of Outcrop Data to Reservoir Characterization

Depositionally analogous outcrops are an excellent source of quantitative geological information at the level of detail necessary for interwell characterization. Outcrops provide laterally continuous exposures which enable closely spaced sampling at scales from inches to hundreds of feet --information not readily available from subsurface cores, logs, and well tests of seismic lines.

Outcrops have traditionally been a source for determining sedimentological and structural information, vertical sequence of facies, facies geometry and dimensions, direction of depositing currents, underlying and overlying lithologies and environments of deposition, presence and scale of unconformities, diastems, transgressive surfaces, and sequence boundaries (fig. 18). Recent quantitative studies of outcrops have characterized reservoir properties such as shale dimensions[42] and sandstone lense geometries[43] and have indicated that these features are a function of depositional environment.

Structural information on the orientation, spacing, relative timing of fractures and faults and the angle and orientation of regional dip can also be readily obtained through outcrop studies. Outcrop permeability data are a potentially rich resource for determining the spatial distribution of permeability contrast in a given system and for closely spaced permeability values for scaling-up studies.[44-46] However, the degree of applicability of outcrop permeability values to subsurface reservoirs must be demonstrated to wisely apply this information to the subsurface.

Comparisons of permeability data from three outcrop-reservoir pairs: (1) Upper Cretaceous Shannon sandstone outcrops around Salt Creek anticline and Teapot Dome field, Wyoming, located 5 miles from the outcrops; (2) Shannon sandstone outcrops around Salt Creek anticline and Hartzog Draw field, located 40 miles from the outcrops; (3) the Lower Cretaceous Muddy formation outcrops in northeastern Wyoming near New Haven and Bell Creek fields, located 40 miles from the outcrops in southeastern Montana, show substantial similarities. Outcrop permeabilities were measured from 1-inch-diameter core plugs drilled horizontally into the outcrop. Subsurface permeabilities were from conventional core analysis.

In all three cases, detailed sedimentological analysis was performed to assure similar depositional environments and similar locations within the deposystem.

Case I. Shannon sandstone -- outcrops around Salt Creek anticline and Teapot Dome field reservoir (depth of approximately 280 ft). The Shannon sandstone was deposited as shelf sand ridge complexes on the midshelf of the Upper Cretaceous Seaway. Comparison of outcrop permeabilities from the High Energy Ridge Margin facies in the Lower Shannon and subsurface permeabilities from the High Energy Ridge Margin Facies in the Upper Shannon indicate a strong similarity between the two permeability populations.

Case II. Shannon sandstone -- outcrops around Salt Creek anticline and Hartzog Draw field reservoir (depth of approximately 9,500 ft). Outcrop and subsurface permeabilities differ between the two sample populations by two orders of magnitude and reflect increased diagenetic alteration and compaction in Hartzog Draw field. Although the magnitude of permeabilities differ, similar general relationships exist between permeability and facies and stratification types. The similarity is that permeability decreases through generally the same sequence of facies and stratification types and that decreasing permeability corresponds to decreasing depositional energy.

Case III. Muddy formation outcrops in northeastern Wyoming and Bell Creek field reservoir (depth of approximately 4,500 ft). Permeability frequency distributions and cumulative distribution functions from outcrop middle shoreface and subsurface foreshore facies are from the same population. Other similarities in outcrop and subsurface samples include grain size frequency distribution, k/ø slopes, and paragenetic sequence.

The results suggest that outcrop permeability measurements may be useful for deriving such parameters as spatial correlation lengths, covariance functions, determining the spatial distribution of permeability values and for conducting scaling up exercises, provided that care is taken to establish the similarities in properties.

F. Synthesis of the Geological Models: Transmissivity and Flow Unit Concepts

Major problems associated with attempts to characterize reservoirs include the uncertainty associated with identification of hydrodynamic units, assigning average properties to hydrodynamic units, and interpretation and extrapolation of physiochemical properties between control points.[19,26,47] To divide a reservoir into hydrodynamic units, average properties must be assigned. This may be accomplished by obtaining "representative" properties from various size samples. Because some reservoir properties are scale-dependent, a decision must be made about sample size that best balances the theoretical and practical aspects of characterization. The theoretically determined size/volume and dimension/shape of samples required for characterization are related to the property and rock type to be evaluated.

As a step in constructing a hydrodynamic model of the reservoir, it is necessary to determine the capacity of various rock types to transmit a fluid. The flow unit concept was used [47] in Hartzog Draw (WY) reservoir to identify zones which had the greatest contribution to flow of injected and produced fluids. A flow unit was defined as a reservoir zone that is continuous laterally and vertically, and has similar permeability, porosity, and bedding characteristics. Consistent patterns of continuity of flow units were detected on numerous crosssections, although average properties of each of the flow units varied areally. In the studied shelf ridge environment of deposition, the identified flow units corresponded with gamma-ray log signatures.

Ebanks[48] defined flow unit as "a volume of total reservoir rock within which geological and petrophysical properties that affect fluid flow are internally consistent and predictably different from properties of other rock volume, i.e. flow units." Unfortunately, Ebanks did not propose a method forquantification of the flow units which "uniquely subdivide reservoirs into volumes and approximate the architecture at a scale consistent with reservoir simulation." The flow unit concept has been utilized for reservoir sublayering into facies associations based on sedimentological criteria such as sedimentary structures, lithology, color, grain size, and bioturbation. Slatt and Hopkins[49] used a depositional model as a basis for subdivision of a reservoir into five layers corresponding with five flow units and providing "the best input for simulation models" based on integrated geological and petrophysical characteristics. Szpakiewicz et al.[50] used the traditional concept of transmissivity coefficient to determine the flow units in the Muddy formation of Bell Creek (MT) field. Division of layers was based on the integration of detailed sedimentologic (facial), diagenetic, structural, and petrophysical characteristics. No attempt was made to average reservoir data for the entire productive intervals. Three or more flow units were distinguished vertically and interpreted laterally in the up to 30-foot-thick Muddy reservoir.

A flow unit has been defined as a section of reservoir rocks with a transmissivity coefficient (kv) range that is significantly different than the kv range of adjoining intervals in a profile. Distribution of formation transmissivities and hydrostratigraphic flow units becomes more reliable when several lines of evidence point toward similar conclusions related to permeability values, effective thickness (net pay), and continuity of facies. These features are dictated by depositional, diagenetic, structural and erosional factors. The transmissivity coefficient used in this manner to define flow unit distribution and continuity (in two or three dimensions) provides the best available and most practical static interpretation of formation properties for simulation of dynamic behavior of the reservoir.

G. Engineering Model

Engineering characterization concerns itself with multiphase flow of fluids and/or heat, mass transfer in porous and permeable rocks, rock-fluid interactions, barriers and conduits to flow, influence of geological heterogeneities on flow, and scale of flow properties. In contrast, geological characterization deals with spatial distribution of static properties of rocks and fluids in reservoirs and sometimes with single-phase-flow behavior in aquifers. The construction of an engineering model and its integration with a geological model provides critical information for selecting, planning, and implementing logical recovery processes. Engineering characterization can be described in three components: (1) hydrocarbon fluids, fluid-fluid, and rock-fluid characterization; (2) evaluation of well performance; and (3) determination of reservoir volumetrics/fluid distributions (fig. 19). Reservoir engineers depend on laboratory determinations of rock, fluid, and rock-fluid interaction data for predictions of reservoir performance. This information can be compared with production/injection monitoring, transient well testing, and tracer testing. Well performance is evaluated based on actual production/injection, pressure transient testing, and log analysis and is compared with expected performance based on petrophysical and rock-fluid interaction properties. Hydrocarbons in place are calculated by a volumetric method using kriged maps of porosity, saturation, and reservoir thickness. Well data including dip information and surface seismic are used for structural control. The volumetric calculation of hydrocarbon in place is compared to the value obtained by the material balance method. Residual oil saturation may be found in the water zone due to tectonic movements or a change in the hydrodynamic regime after oil accumulation. Drive mechanisms, their variations during the life of the reservoir, and their role at various stages of production; irregularity/tilting of WOC due to hydrodynamics; capillary effects or variations in fluid properties, and directional aquifer strength should all be characterized because of their effect on hydrocarbon-in-place calculations and their role in providing reservoir energy.

H. Integration of Geological and Engineering Models

Integration of models for construction of a geological/engineering model (fig. 20) starts with individual parameters from the critical heterogeneity table (table 1), and identifies the level of detail needed at each stage of production based on the sensitivity of the production stage, the process, and the analysis of production performance in all previous stages of production. The critical scale of heterogeneities at each stage of production should be determined, and geostatistical methods should be applied to identify reservoir zonation and data requirements. To account for the actual structure and geometry of a reservoir, a simulator must include the minimum number of layers necessary to represent three-dimensional properties of that reservoir. Three-dimensional representation of the geometry and subdivisions of the reservoir will identify areas in need of more detailed evaluation. Verification of this level of integrated model is provided by production-pressure history and well tests. Thus, each stage of production provides useful information for the next stage of production.

The initial production rate distribution reflects the location and combined effects of major depositional, erosional, and to some extent tectonic and diagenetic features within the reservoir. Therefore, the location of major reservoir heterogeneities can be identified from the first several hours of production rate potential. This information provides guidance for later stages of production.

V. SIMULATION

A. Conventional Simulation

Reservoir parameter sensitivity analysis by simulation can be used to study the impact of uncertainty in data and the influence of various parameters on performance. Sensitivity studies to investigate the effect of layer thickness and clay type on simulation results are desirable. An example of the effects of clay type on micellar-polymer flooding recovery in a three-layer reservoir is shown in table 6.

Although the available reservoir simulators have a high degree of mathematical sophistication, often the results of simulation are not realistic and have to be "history matched" to be brought into agreement with observed field data. Saleri[16] gives a detailed critique of the state-of-the-art in performing reservoir simulations by stressing that the lack of standards in performing simulations (the choice of the grid size, history match quality, scaleup procedures and model suitability) affects the reliability of simulator predictions. He also explains how inadequate reservoir description contributes to reduction in the reliability of simulator predictions.

Permeability Layer Model

A simple layer model based on geologic facies provides the basis for calculating reservoir volumetrics, forecasting field and well performance, and the framework for a subsequent, more detailed flow unit model, (figs. 21 and 22). Slatt and Hopkins[49] outlined the following three criteria: (1) the model should be simple, consisting of relatively few layers, (2) there should be a geologic basis for the choice of layers, and (3) layers should exhibit different average reservoir properties.

Facies provide a logical division for distinguishing the layers, because a strong relationship between sedimentary facies and reservoir quality often exists. This relationship has been demonstrated in a number of depositional environments.[45-54] Statistical tests can be performed to determine whether permeability and porosity distributions from one facies are significantly different from those of other facies. Environments with similar permeability and porosity distributions can then be combined into a single layer.

One technique[55] suggests the use of k/ø plots to develop reservoir layering to be used in a simulator for performance prediction. This approach is not universally applicable, and it has not proved successful in some high quality reservoirs.

Kyte and Berry[56] and Jacks et al.[57] have suggested the scaleup of one-dimensional (1-D) laboratory relative permeability and capillary pressure data to two-dimensional (2-D) grid size for the purpose of using areal models instead of three-dimensional (3-D) simulation. This method can be used for gas-oil as well as water-oil systems; however, rock-types, the presence of transition zones, mobility ratio variations, number of blocks, block sizes, and rates should be taken into account. The shortcoming is the fact that vertical distribution patterns of pressure, saturation, etc. will be different from the values obtained from an areal simulation. In addition, vertical discontinuities cannot be accounted for.

B. Geostatistics/Conditional Simulation

Conventional simulators have inherent uncertainities in input data; therefore, they should be considered as a probabilistic tool, more like weather forecasting, instead of a deterministic tool, as in a chemical process simulator.

Because reservoir rock properties are known only at the well bore and at scales determined by selected methods of measurement, (core, log, well test) one has to rely on theoretical schemes for calculating "effective" values to be used in simulator grid blocks (scaleup) and to generate grid block values for interwell regions.

If a reservoir exhibits a gradual change in rock properties between wells, one can rely on average interpolation methods such as using powers of inverse distance or kriging. The kriging approach, although more computer intensive has the advantage that it generates a map of error variances which are dependent on the location of control points. These variances can be used to determine the range of variability of input data.

The main tool of geostatistics in examining existing structures in geological data is the variogram. A variogram is computed based on average values at well locations (the control points). It can describe only structures present at distances larger than the well-to-well interval. This can be useful in understanding variations in reservoir parameters (net pay, average porosity, permeability, fluid saturations) at the field scale and to generate kriged maps of the parameters and their variances. A variogram defines a zone of influence beyond which the regionalized variables studies are no longer correlated.

If the reservoir has large variations in rock properties at the interwell scale, such as when stochastic shales are present, one has to generate a realistic distribution of these properties to obtain correct front movement and dispersion. [58] When similar heterogeneities exist at various scales, meaning that the reservoir has a fractal nature, then interwell variograms can be constructed based on reservoir heterogeneities at well locations.[59-60] A basic assumption is that fractal behavior observed at wells from analysis of vertical profiles (logs, cores) is also maintained laterally due to the common processes which determine both vertical and lateral rock distribution. After measuring the fractal dimension for porosity from sonic logs, and permeability from cores or transformed porosities from logs, cross sections have been generated and used in simulations to compute the fractional flow relations for these reservoirs.[59] When these fractional flows were used in stream tube models, a good match was obtained with the field data without having to adjust any of the simulator parameters.

Conditional simulations, by respecting both the control data and the correlation relationships, allow the generation of a spectrum of output data. By finding the relationship between the simulator input and output distributions, one can evaluate the importance of the uncertainty of various reservoir parameters and thus evaluate the risk associated to a project for a given range of uncertainites of simulator input parameters.

Fractal analysis combined with conditional simulations can be used also for scale up by first constructing statistically correct representations on a very fine grid (0.5 ft to 1 ft size) and averaging over these blocks by means of simulation to predict effective values for permeability or relative permeability for coarser grid blocks to be used in a field simulation.[59]

VI. EXPERT SYSTEM FOR RESERVOIR CHARACTERIZATION

The development of the expert system, a technique of artificial intelligence (AI), provides a tool to use the knowledge base from reservoir characterization research by users who have little background in the integrative approach to reservoir characterization.

An expert system is a computer program that solves problems in much the same manner as human experts. It was not until the late 1970s that AI scientists began to realize that the problem-solving power of a program comes from the knowledge it possesses, not just from the formalism and inference schemes it employs. This realization led to the development of special-purpose computer programs that were expert in some narrow problem area. The process of building an expert system involves an "extraction" from human experts of their procedures, strategies, and rules of thumb for problem solving and building of this knowledge into a computer program. The heart of an expert system is the powerful knowledge that accumulates during system building. The knowledge is explicit and organized to simplify decision making. Compared to human expertise, artificial expertise in an expert system is permanent, consistent, affordable, easy to transfer, and easy to document.

Many knowledge-based expert systems are now feasible for several domains of expertise. Some of these systems are described in appendix C.

A. NIPER's Reservoir Characterization Expert System

The methodology for constructing a reservoir model for mathematical simulations was converted into a computer program or an expert system in this study. This program advises users about geological and engineering data required, sources to acquire them, and a sequence of data collection.

1. Logical Flow of NIPER's Expert System

Basic procedures for establishing and improving a reservoir model using an expert system are shown in figure 23. The system starts by establishing the stage of recovery and proposing a recovery mechanism to be modelled for the target reservoir. The reservoir data collection falls into two major categories: geology and engineering.

The reservoir characterization expert system considers geological data based on the following priorities: real reservoir data, previous information about the formation of interest from the literature, data of nearby reservoirs in the same formation, nearby analogous outcrop data, and information about depositionally analogously deposits in modern environments. After the depositional environment is identified, the geological model is constructed if core and other hard data are adequate to characterize the level of reservoir heterogeneity. Any inadequacy in the model requires a search for additional information.

Engineering data are collected to identify rock-fluid, and fluid properties for use in mathematical simulation. This engineering model is then integrated with the geological model to form the hydrodynamic flow model. A mathematical simulator is used as a tool in this expert system to verify or improve the hydrodynamic flow simulation. Discrepancies identified between the production history and simulation results require further improvement of the flow model. The model could be revised by collecting additional core data and engineering tests to better define the nature and magnitude of the responsible heterogeneities. The above model verification and refinement is continued, based on the field production performance, until a satisfactory model is obtained. This model can then be used to predict fluid production and residual oil saturation distribution based on alternative production schemes.

2. Features of Developed Expert System

To make this expert system versatile, the program was written in basic language for use with an IBM personal computer. The program implements a series of simple "yes" or "no" questions. Based on answers received, the user might be asked different questions to construct, integrate, or verify the reservoir model. At the end of the program run, conclusions will be made, and suggestions will be provided. Rules of thumb are provided for certain cases in which real data are difficult to obtain. Examples are published correlations of relative permeability curves, capillary pressures, and fluid pressure-volume-temperature (PVT) properties based on informations of fluids and rocks. The detailed methodology for collecting geological and engineering data can be referred to previous sections of this paper.

Different from the standard rule-based expert system, the system developed in this study uses a conventional deterministic algorithm to reach the conclusion. A "help" session is added in the program to explain certain key terms in the expert system that may not be familiar to users. The program can be interrupted whenever users wish to use the "help" session. This "help" session explains geological and engineering terms such as depositional environments, diagenesis, PVT properties, and hydrodynamic flow models.

VII. SUMMARY AND CONCLUSIONS

1. Methodology for construction of a comprehensive model, which provides a guide for reservoir management and input into a simulator for more realistic predictions is outlined in this report.

2. Knowledge of the resolution, coverage area of various tools, data quality, and representativeness is necessary for incorporation into the fluid dynamic model.

3. Models constructed from geologic and engineering data for each stage of production increase predictability of features that affect performance.

4. Sensitivity analysis is used to rank important data (parameters) and geostatistical analysis is used to define the regions where more data are required to improve reliability of models.

5. The integration of information from various disciplines is a stepwise, iterative process that is dependent on the sequence and timing of data collection. No single discipline can provide adequate information for proper characterization of a reservoir.

6. The emphasis of our methodology is on the sequence, timing, and quality of data collection which is designed to guide data collection management and to facilitate coordination of information from various disciplines. Geostatistics and sensitivity analysis are used to identify important data (parameters) and their distribution (density) to improve reliability of model. This is a continuous process during each stage of reservoir development.

7. Each stage of production requires a different level of detail in engineering and geological information and different scales of features which are crucial to production performance.

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APPENDIX A. -- CRITERIA FOR SELECTION OF REPRESENTATIVE SAMPLES

The following sampling criteria were formulated for cores from the Muddy formation at Bell Creek field:

A. Sedimentologic criteria:

1. Sample sandstone units of each identified facies for representativeness at bedding and sedimentologic boundaries, anomalous zones if uniform sedimentologically and no indication of permeability contrasts, sample every 3 feet; two samples from predominant bedding types, and one sample from each other common bedding.

2. If apparently uniform sedimentologically but permeability contrasts exist sample every identified contrasting zone.

3. If nonuniform sedimentologically, sample each subfacies, but preferably no more than one sample per foot.

4. If significant variation of grain size occurs (e.g. 100 - 175μ), sample major contrasting zones.

5. Take minimum of three samples below each identified unconformity and 2 or 3 samples above unconformity.

6. Take at least two samples from the nonbarrier "upper" sandstone (in Muddy cores).

Note: Sample no closer than 6 inches from unit's contacts.

B. Diagenetic criteria:

1. If pores are plugged (authigenic clays, carbonates, sulphates, sulphides, oxides, silica, compaction, etc.,) take at least one sample every foot from the diagenetically affected zone and one sample above and below.

2. If pore size has been enhanced (dissolution, recrystallization, etc.) take two samples 6 inches apart. If not readily identifiable under field microscope, choose the highest permeability zones (from core analyses reports) .

3. If major differences in magnitude of cementation are identified, sample each major zone but no more than one sample per 6 inches.

Note: Sample no closer than 6 inches from diagenetic zone contact.

C. Guidance by logs, core analyses reports and indications from engineering tests:

1. Sample zones where log responses cannot be related to those features visible on core; take minimum of two samples from each "anomalous" zone.

2. Permeability contrast from core analyses reports are covered by (1) and (2).

3. Increase number of samples from cores identified by engineering tests such as DST, RFT,. as "barriers" or "thief zones," or intervals of anomalous production (either higher or lower than expected).

Similar sampling procedures can be applied to other fields and different clastic environments of deposition.

For each sample taken, the exact log and core depth, lithology, sedimentary structure, and observed type of cementation should be indicated on a separate list. Size of samples must be adequate for the requirements of specific analytical procedure. In addition, the position of each sample should be marked on the geological profile.

APPENDIX B. -- APPLICATION OF DIAGENETIC CHARACTERIZATION

Diagenesis refers to the postdepositional physical, chemical (including biologically induced) processes that sediments undergo prior to metamorphism.[61] Processes include compaction, hydration/dehydration, cementation, recrystallization, leaching, alteration, and replacement, among others .[62] The driving force for most diagenesis is metastability of minerals within sediments with respect to interstitial waters.[63] The immediate rewards of the study of diagenesis include improved porosity and permeability prediction (both in terms of type and quantity), improved ability to manage and predict rock-fluid interactions within the reservoir, and a stronger, more realistic base upon which to simulate primary, waterflood, or enhanced oil recovery processes.

Pore geometry, which can best be studied by direct petrographic methods, influences the type, amount, and rate of fluid production.[64] The geometry of pore and pore throat types changes during diagenesis: they may become larger or smaller, more or less complex, they may become well connected or they may become disconnected, and all of these changes in porosity and permeability are related to increasingly or decreasingly complex mineralogy depending on the type, source, and volume of fluids that migrate through the potential reservoir rocks. It is through the development of diagenetic and geochemical models that these changes are cataloged and their influences on reservoir quality are evaluated.

Because the results of petrographic study are so dependent on rock samples selected for analysis, it cannot be overemphasized that samples must be representative of the units under study. They must include average, maximum, and minimum values for features within these units, and they must include the 'uncommon' features within these units as well (such as thin, cemented zones within clean sandstones, clay clasts, or clay laminae). Only general conclusions about the diagenetic characteristics of a reservoir can be made with a small number of samples (one to five per pay zone). Conversely, numerous samples chosen at regular intervals may not adequately represent the dynamic range of characteristics found within the studied horizons.

Results of petrographic study are integrated to determine the paragenetic history of reservoir rocks. Paragenisis is used to describe, interpret, and extrapolate the effects of diagenesis on reservoir properties. The diagenetic effects on individual reservoir horizons are mapped and combined with information provided by sedimentological, geochemical, and tectonic models. The paragenetic sequence is basically determined by mineralogical and textural cross-cutting relationships. Independent techniques such as isotopes, fluid inclusion analysis, or stratigraphy are needed to calibrate the scale and timing of changes in the geochemical environment. These results can be quantified, and they are used to improve prediction of current petrophysical properties.

Paragenesis (sequence of diagenesis) of the reservoir rock is of more than academic interest to the drilling and production engineers because of the information it conveys about continuity, sensitive minerals, pore system evolution, and the relationship between diagenetic features, depositional environment and tectonic stresses.

The major contributions of a diagenetic model to reservoir characterization are toward drilling, completion, and stimulation applications, log analysis, and injection-fluid/rock interactions. These contributions should be taken into account for each stage of production (primary, waterflood, EOR) in terms of the engineering model of a given reservoir. Diagenetic characterization is part of the larger geological model and is closely related to (and often included with) geochemical studies through fluid and core analysis.

I. Applications to Drilling/Completion and Stimulation

Log, core, and petrographic analysis each provide critical information to drilling/completion and stimulation operations. Timely identification of sensitive minerals and predictions of rock-fluid interactions are necessary to minimize formation damage. Aspects of petrographic analysis that can be of use during drilling and stimulation procedures include bulk composition, amount, and distribution of framework, matrix, and diagenetic minerals, their susceptibility to being dislodged or mobilized throughout the pore system, anticipation of subsequent pore bridging, pore filling, or throat blocking by migrating fines, and expected chemical reactions with the injected borehole fluids. Identification of the specific varieties of clay minerals, and their reactivities are frequently critical to efficient completion and stimulation.[65]

II. Applications to Log Analysis

Because of the direct evaluation of pore and framework geometry, petrographic analysis is ideally suited to provide the calibration for log-derived pore description. which in turn influences the formation factor. The cementation factor is a function of shaliness, clay type, and grain sphericity. Optical, thin section analysis, X-ray diffraction (XRD) and scanning electron microscope (SEM) analysis can provide information about each of these aspects. Finally, increased water saturation may be due to increased interparticle (free) water or to increased residual (bound) water saturation. Increased residual water saturation is frequently controlled by the type or amount of clay minerals and microporosity present in the rock.

The most commonly used rock characterization methods for wireline log calibration include core description, quantitative thin section, XRD, and SEM analysis. Thin section analysis provides the log analyst information about mineral types, abundances, polymorphs, and distribution, as well as grain size, sorting, shale (actually clay) content, and distribution of fine-grained materials. Geometrical effects can induce error into thin section analysis; for example, the geometry of interparticle pores in addition to micropores (too small to be accounted for by optical microscopy) create thin section derived porosity values greater than true porosity. Because of this tendency, thin section porosity should not be used alone for log analysis calibration. The strength of thin section analysis, lies in the ability to distinguish specific mineral phases with the same chemical composition (polymorphs) for grains down to about 10-20 microns in size, and in the description of textural features that are available through no other source.

X-ray diffraction is of particular use in distinguishing clay mineral species. X-ray diffraction, however, has the limitation of measuring only minerals with a crystalline structure. This technique cannot distinguish mineral aggregates such as eroded rock fragments, or colloids, and it yields no information about rock texture or porosity. Scanning electron microscopy can be used in a qualitative sense to provide information about the geometry of pores and constituent rock components including mineral cements found within or lining the pore system. Because of the high magnification available with SEM, microporosity can often be evaluated. This is of particular interest to the log analyst and engineer who may have to explain how rocks with high water saturations can produce water-free hydrocarbons. With the presence of an energy dispersive X-ray analysis system (EDX) on the SEM, minerals with very small crystal size can be qualitatively identified in their natural position within the rock. Therefore, the SEM/EDX system can provide insight about the effect of specific mineral phases that line the pore system or are found within pore throats. Despite the inherent differences between these techniques, the results obtained should be relatively close and will provide basic information about the composition and mineralogical heterogeneity of the reservoir rock.

Truman and others [66] have outlined a method for utilizing rock characterization data to improve well log interpretation. Their technique involves digitizing core analysis results which are then depth shifted to match well log data. Core analysis results are compared with the available well log data and samples are selected so that the entire range of log responses are represented. Quantitative petrographic data are compared with the log data in a preliminary evaluation to insure that the petrographic samples are representative. The petrographic data must be grouped and displayed in a manner that is compatible with the well log response. Core analysis and petrographic data are then plotted against well log data to determine calibration parameters. The calibration parameters must then be analyzed for applicability.

Of particular concern to the log analyst is the evaluation of shaley sandstone reservoirs and associated net pay. The presence of clay minerals in the reservoir sandstone is known to have a strong detrimental effect on the calculation of water saturation. Furthermore, because more than one clay mineral type is frequently present within the reservoir rock no single parameter can be consistently used to characterize argillaceous rocks. With the Waxman-Smits model,[67] reliable formation water saturations can be determined for reservoirs with a wide range of clay types. Critical to the Waxman-Smits model are cation exchange capacity (CEC) values. CEC and hydrogen indices are derived from density, neutron, and natural gamma ray spectral data. Core-derived CEC and petrographic analysis of clays should be used at this point in the log analysis to check and calibrate the log derived values.

III. Applications to Core Analysis

A systematic approach such as suggested by Heaviside and Salt[68], should reduce the variability that is sometimes seen in core analysis results. Core studies that lack a systematic approach often fail to adequately account for inhomogeneities in reservoir and nonreservoir rock properties.[20] Petrographic analysis of depositional and diagenetic features can help by providing basic information about pore size distribution, pore geometry, pore type and complexity, pore lining materials (including clays) and their grain size, abundance, and morphology, framework and depositional matrix, mineralogy, grain size distribution, sorting, compaction, other textural features, and the mineralogical and textural history of the rock.

The recently expanding field of computer-assisted petrographic image analysis allows rapid and accurate measurement of geometrical dimensions of pores and grains in thin sections. Besides providing accurate shape and size data for classification of various rock types, it can be used to predict porosity and permeability from small rock samples.

Perhaps one of the most useful applications of petrographic analysis is to explain apparent petrophysical anomalies revealed during special or routine core analysis. To be applicable, petrographic analysis must be based on carefully selected samples that must correlate with samples used for core analysis.

The single, most important application of petrographic studies to core analysis is the quantitative identification of framework, depositional matrix, and diagenetic mineralogy. This is done through thin section point counts and with X-ray diffraction supplemented by SEM studies. At this stage of analysis, any potentially sensitive minerals should be distinguished, and their effects on primary, waterflood, or

EOR recovery processes should be evaluated. The pore system is then defined in terms of volume, pore size distribution, aspect ratio, genetic type and geometry, microporosity, and mineral or organic coatings, fillings, and throat blocking. These tasks are readily completed using reflected and transmitted light, cathodoluminescence, and ultraviolet fluorescence.

Scanning electron microscopy enhanced by energy-dispersive X-ray analysis is necessary to evaluate the morphology and distribution of clay-size fine materials that are found on the margins of most pore systems.[69] Petrophysical parameters can be significantly affected by textural properties of clay minerals. For this reason reservoir rocks must be evaluated in terms of clay mineral texture and morphology as well as the "standard" volume and distribution values.

Reservoir heterogeneities that are dependant on diagenetic processes can be ranked (critical, important, negligible) and scaled (microscopic, bedding, interwell, field wide) in order to assess their relative importance to field production through reservoir simulation studies. Petrographic studies can also be used to indicate where further sampling and special core analysis is required. The results of petrographic investigations of the diagenesis of reservoir rocks should be passed on in the form of recommendations for each mode of operation.

IV. Stages of Production

The study of reservoir diagenesis can be of particular use in waterflood applications. Petrographic studies comprise part of the laboratory studies that can be used to predict waterflood performance. They must be undertaken before waterflood implementation[70] to help improve design of well patterns and prevent drastic formation.[71] Petrographic studies for waterflood performance prediction concentrate on the basic questions of compatibility of injection water and formation water, and the compatibility or reactivity of injection water with the reservoir rock. Detailed knowledge of the chemical composition of the reservoir rocks and the injection water is paramount to the prediction of chemical reactions between the two media.

Petrographic applications to waterflood production require a more detailed knowledge of the mineralogy of the reservoir rock, particularly the potential water-sensitive minerals. Maps of sensitive mineral distribution for each productive horizon should be made and compared with available production data. Frequently, production will correlate with gross features such as the amount of clay in the producing unit, the amount of authigenic (diagenetic) clay, or the dominant type of clay in the pore system. In some instances, however, the morphology of the clay size minerals or the distribution of the fines within the pore/throat system is more important.[71] Such relationships are difficult to quantify, but this does not mean that they should be ignored. In order to determine the effect of morphology or distribution of clays in their original relationship to the pore structure, preserved core samples should be miscibly cleaned and dried using the critical point drying technique, and examined with the scanning electron microscope. If even a tiny amount of diagenetic clay had a tendency to precipitate in the throat regions, or if clays precipitated in a loosely arranged network within the pores their effect would be significantly different on the petrophysical properties of the rock than if the clays formed just on the pore walls.[72] The effect of clay collapsing onto the walls of the pore system in unpreserved or mishandled samples is significant, but often ignored during core analysis.

Just as the potential reactions between water-water and water-rock are considered for waterflood, the potential reactions between EOR injection chemicals and the reservoir rock composition must be evaluated. Theoretical considerations based on a thorough knowledge of the chemical composition and reactivity of injection fluids with reservoir minerals should be supplemented by laboratory tests on cores under reservoir conditions prior to chemical injection into the reservoir.

Diagenetic effects are frequently ignored in many EOR projects.[73] At the very least, the chemistry of framework minerals and authigenic or detrital clays must be characterized. Transformation of clay minerals through geological time, and through the production life of a field, are related to changes in temperature, pressure, interstitial water ionic composition, ion activity, and pH-Eh relations.

Polymorphs (morphological varieties of the same mineral) of clay minerals, particularly authigenic clays found within the pore system, may react to EOR chemicals, preflush fluids, interformation, or intraformation waters in drastically different ways. For example, the swelling properties of halloysite and kaolinite, or glauconite and illite are drastically different. Non-clay minerals can also create potential problems during chemical EOR processes, such as the water sensitive nature of anhydrite, the high cation exchange capacity of crystobalite, or the induced precipitation of colloidal materials.

Thorough geochemical characterization of the potential reactions between injection fluids and the reservoir rock must also account for caustic consumption[74] and must anticipate precipitation of solid phases within the pore system after reaction with hydroxide. Caustic injection fluids may be consumed by the siliceous framework of the reservoir sandstone[74] and therefore laboratory tests, petrographic analysis, and geochemical studies, and even structural geology studies may be required to determine the effective distance enhanced by caustic fluid injection. The types of clay and their mixtures within the reservoir rock must be characterized for micellar/polymer flood because it has been show that these characteristics can be related to recovery efficiency.[75] Mineralogical characterization is equally as essential in the case of fireflood. The presence of coal, pyrite, or vermiculite in the sediments affected by the fireflood may have a significant effect upon its ultimate success.

APPENDIX C. -- EXPERT SYSTEMS RELATED TO RESERVOIR CHARACTERIZATION

Some of the better-known expert systems have been used for diagnostic tools in the medical profession, chemical analyses, criminal investigations, and various applications in military strategy. An example of an earth science oriented expert system is PROSPECTOR[76] which acts as a consultant to aid exploration geologists in their search for ore deposits. Given field data about a geological region, it estimates the likelihood of finding particular types of mineral deposits there. Other expert systems developed in earth science include DIPMETER ADVISER,[77] Elas, [78] HYDRO,[79] LITHO,[80] XEOD,[81] PLAYMAKER,[82] and an unnamed expert system approach.[83] Schlumberger's DIPMETER ADVISER infers subsurface geological structure by interpreting dipmeter logs and measurements of the conductivity of rock in and around a borehole as related to depth below the surface. Teknowledge's DRILLING ADVISER diagnoses the mostly likely causes of sticking and recommends a set of treatments to solve that problem. AMOCO's ELAS gives advice on how to control and interpret results from an interactive program for well log analysis and display. NL Baroid's MUD helps engineers maintain optimal drilling fluid properties. It does this by diagnosing the causes of problems with drilling fluids and suggesting treatments. The University of Alabama's XEOD determines clastic depositional environments based on the associations between 166 observable features and 58 environmental facies and subfacies. A set of features from a single bed or facies yields a set of possible environmental interpretations, ranked by likelihood based on certain values computed from the rules. UCD'S COREXPERT[84] is a system to assist in the accumulation, manipulation, synthesis, and interpolation on Cenozoic sediments of the open oceans.

Texas A&M University[86] developed a system for correlating geological horizons between wells from two log traces. This system converts log data into symbolic representation and recognizes log shapes from traces before identifying, characterizing, and correlating geological zones. The University of Alberta's WLAI[87] helps geologists to identify formations and sedimentary facies from well log data. Wlai emphasized the entirety of geological interpretation and emulated the reasoning of geologists by a string-to-string comparison algorithm. Stanford University's Pettj and Jrial are used to classify mineralogic analysis of open-hole logs and Bedform analysis of raw dipmeter data. Pictorial justification is provided through ternary and slab plots.

Identifying a pressure transient test model that describes the reservoir behavior is a fundamental and difficult problem which is dependent on the skills and experience of the interpreter. Texas A&M University has developed a knowledge-applicable interpretation model. A diagnostic plot generating module facilitates the interpretation procedure and a history matching algorithm is used to verify the interpretation model.[86] Similarly, Stanford University has developed a system to identify a well test interpretation model using the derivative of well test data. It involves extraction of features present on the data derivative, construction of interpretation models, and test results matching.

A rule-based system from The University of Texas at Austin[88] estimates clay distribution, morphology, and formation damage in reservoir rocks using information from thin-section, X-ray, and SEM analysis of core samples. The content of different clay types is calculated by solving a system of linear simultaneous equations.

Other recently developed expert systems applicable to reservoir description include geostatistical reservoir characterization, formation damage, reservoir simulation, and database management.

TABLE 1. - Outline of major heterogeneity types based on their geological origins

HETEROGENEITY TYPE manifestations	FUNDAMENTAL CAUSES (PROCESSES)		
	SEDIMENTOLOGIC	GEOCHEMICAL/DIAGENETIC	TECTONIC
VARIATIONS IN CONTAINER (External Geometry) Pay Thickness Dimensions Continuity Attitude (Dip)	Deposition, Erosion	Leaching, Cementing	Faults, folds, flexure, monocline
BARRIERS/ COMPARTMENTALIZATION	Erosion (Reservoir cut out) Shale Layers	Compacted Zones Tightly Cemented Zones	Sealed Faults Sealed Fractures
BAFFLES	Shale / Siltstone Layers Variations in grain size and Sorting Bioturbation	Compacted Zones Partially Cemented Zones	Partially Opened Faults and Fractures
CHANNELS (Thief Zones)	Coarse Grained, Layers, Well Sorted Layers	Leached Zones	Open Faults, Open Fractures
SPATIAL VARIATIONS OF RESERVOIR ROCK PROPERTIES Vertical Lateral	Environment of Deposition Variations in Grain Size. Sorting, Minerology, Biogenic Activity	Compaction Cementation / Leaching	
SPATIAL VARIATIONS OF RESERVOIR ROCK-FLUID PROPERTIES	Fluid Origin	Thermal Maturation, Geochemical Environment, Rock Fluid Interaction	

TABLE 2. - Rock/fluid interaction for various EOR processes

	Polymers	Surfactants	Alkaline	CO_2	N_2	Steam	In situ combustion
Clay mobility or swelling	C	C	C	-	-	C	C
Ion exchange	C	C	C	-	-	C	-
Dissolution	C	C	C	C	-	C	-
Precipitation	-	C	C	C	-	NK	-
Reaction	-	-	C	C	-	-	-
Adsorption	C	C	C	-	-	-	-
Wettability	-	C	C	C	NK	NK	-

C = Critical
NK = Not known

TABLE 3. - The relationship between critical geological heterogeneities and their effects on reservoir properties

Critical geological heterogeneities related to:	Effect on sweep efficiency	Effect on displacement efficiency	Tools for identification/ measurement of tools	Effectiveness of tools
Depositional environments	Strong	Moderate/ Minimal	Core description	1
			Log interpretation	1
			Well tests	1-2
			Seismic	2
			Analogous outcrops/reservoirs/ aquifers/mines/modern deposits	
Flow units superposition/geometry/ continuity, storage capacity, transmissivity	Strong	Minimal	Core analysis/core description	1
			Log interpretation	1
			Well tests	1
			Analogous outcrops/reservoirs/ aquifiers/mines	3
Internal baffles or barriers to flow	Strong	Minimal	Core analysis	1
			Well tests	1
			Log interpretation	1-2
			Analogous outcrops/reservoirs/ aquifiers/mines	2
Thief zones/internal channels to flow	Strong	Minimal	Well tests	1
			Core analysis	1
			Log interpretation	1-2
			Analogous outcrops/reservoirs aquifiers/mines	3
Fluid saturations/volumetrics/ composition/properties/contacts	Strong	Strong	Log interpretation	1
			Fluid analysis	1
			Core analysis	1
			Geochemical data	
Rock-fluid interaction processes and products	Strong	Strong	Core analysis	1
			Fluid analysis	1
			Well tests	2
Non-distruptive tectonic effects (Dip/folds/flectures)	Strong	Minimal	Regional seismic	1
			Log interpretation	
			Well tests	3

1 - Critical
2 - Important
3 - Supplemental

TABLE 4. - Sedimentologic data sheet adapted for the barrier island deposits

Unit

Core Depth:
Log Depth:

Lithology ______

1 Sandstone (%) ______
2. Siltstone (%) ______
3. Shale (%); a) Laminated; b) Clasts ______
4. Siderite (%); a) Laminated; b) Clasts ______
5. Glauconite (%); a) Disseminated; b) Laminated ______
6. Organic material (%); a) Disseminated; b) Laminated ______

Physical Structure

1. High angle cross-bedding (20^{o}+); a) Troughs; b) Planar-tabular; c) Planar-tangential; d) Curved-tangential (trough) ______
2. Moderate angle cross-bedding (10-20^{o}); a) Troughs; b) Planar-tabular; c) Planar-tangential; d) Curved-tangential (trough) ______
3. Subhorizontal to low angle bedding (<10); a) Trough; b) Planar-tabular; c) Planar-tangential; d) Curved-tangential; e) Planar ______
4. Horizontal laminations; a) Sandstone; b) Shale ______
5. Rippled; a) Sandstone; b) Shale; c) Current; d) Wave ______
6. Ripples superimposed on troughs ______
7. Ripples superimposed on troughs ______
8. Reworked: a) By waves & currents; b) Bedding destroyed massive; c) soft sediment deformed; d) clasts ______

Biogenic Sedimentary Structures

1. Identified burrows; a) *Asterosoma*; c) Chondrites; d) "Donut burrows" (Terabellina); g) Gastropod tracks; p) Plural curving tubes; s) Skolithos; t) Teichichnus; th) Thallasinoides ______
2. Distinct burrows; a) <1/8"; b) 1/8"-1/4"; c) 1/4"-1/2"; d) >1/2"; 3) Silt filled; f) Clay filled; g) Sand filled; h) Silt lined; i) Clay lined; j) Spreiten; k) Vertical; l) Oblique; m) Horizontal ______
3. Burrowing (non-bioturbated) (%) ______
4. Bioturbated, 75% (+) burrowed (%); % burrowed; a) Distinct, b) Mottled ______
5. Total interval burrowed (%, footage) ______
6. Diversity (Number of burrow types); 1-4 low, 4-8 moderate; >8 high ______

Cemented Intervals; a) Siderite; b) Calcite ______

TABLE 4. - Sedimentologic data sheet adapted for the barrier island deposits - Continued

<u>Contact Relations</u> (core contacts)

1. Upper; a) Very sharp (<0.05' transition); b) Sharp (0.05-0.1' transition); c) Transitional (0.1-0.3' transition); d) Gradational (>0.3' transition); e) Contact, erosional (truncated) angular; f) Contact erosional parallel; g) Covered or not covered ______
2. Lower; a), b), c), d), e), f), g) ______

TABLE 5. - Depth of investigation for ROS Tools

Tools for ROS Measurements	Investigation Depth
Conventional	<10 in. (25 cm)
Pressure	<10 in. (25 cm)
Sponge	<10 in. (25 cm)
Tracer test	25 to 40 ft (7.5 to 12 m)
Logging	
Resistivity	
Conventional	2 to 50 ft (0.6 to 15 m)
LIL	2 to 50 ft (0.6 to 15 m)
NML	
Conventional	2 ft (0.6 m)
Inject log	2 ft (0.6 m)
Dielectric constant	
Conventional	1 to 2 ft (0.3 to 0.6 m)
EPT	
Conventional	2 ft (5 cm)
PNC	
Conventional	7 to 24 in. (17.5 to 60 cm)
LIL, water	7 to 24 in (17.5 to 60 cm)
LIL, chemical	7 to 24 in (17.5 to 60 cm)
LIL, chlorinate oil	7 to 24 in (17.5 to 60 cm)
C/O	
Conventional	9 in. (23 cm)
LIL, water	9 in. (23 cm)
LIL, chemical	9 in. (23 cm)
Gamma ray log	
LIL, water/chemical	2 to 4 in. (5 to 10 cm)
Gravity (conventional and LIL)	50 ft (15 m)
Well Test Methods	
Effective permeability	Well drainage area
Interwell ROS	
Resistivity	Well-to-well distance
Well-to-well tracer	Well-to-well distance
Oil displacement	Well-to-well distance
WOR	Well drainage area
Material Balance	Whole reservoir
Production Simulation	Whole reservoir

TABLE 5. - Depth of investigation, angular coverage, and rock volumes for wireline tools--Continued

Tools	Vertical resolution (in)	Radial depth of investigation depth, (in)	Angular coverage, (degrees)	Rock volume investigated, (in^3)
Density	15	5	20	245
Neutron (Mandrel)	24	16	360	28,952
Micro electrical log	2	1.5 (50%)	30	7
Induction (6FF-40)	20	4	N/A	75
Gamma ray	6	15	360	21,676
Dipmeter (1 button)	0.5	6 (90%)	14	5
Borehole televiewer	0.3	0.0	360	-

TABLE 6. - The effect of different clay types on recovery in a simulated 3-Layer System

Clay Content			Absorption		Oil
			Surfactant	Polymer	Recovery
Layer 1	Layer 2	Layer 3	ml/ml PV	wt % PV	%
0	0	0	0	0	37.6
1%M[1]	0.5%K[2]	0.1%M+0.5%K	0.0022	0.0051	30.5
5%M	2.5%K	0.5%M+2.5%K	0.0049	0.0155	20.5
15%M	7.5%K	1.5%M+7.5%K	0.00590	0.0294	14.9

[1] M = montmorillonite

[2] K = kaolinite

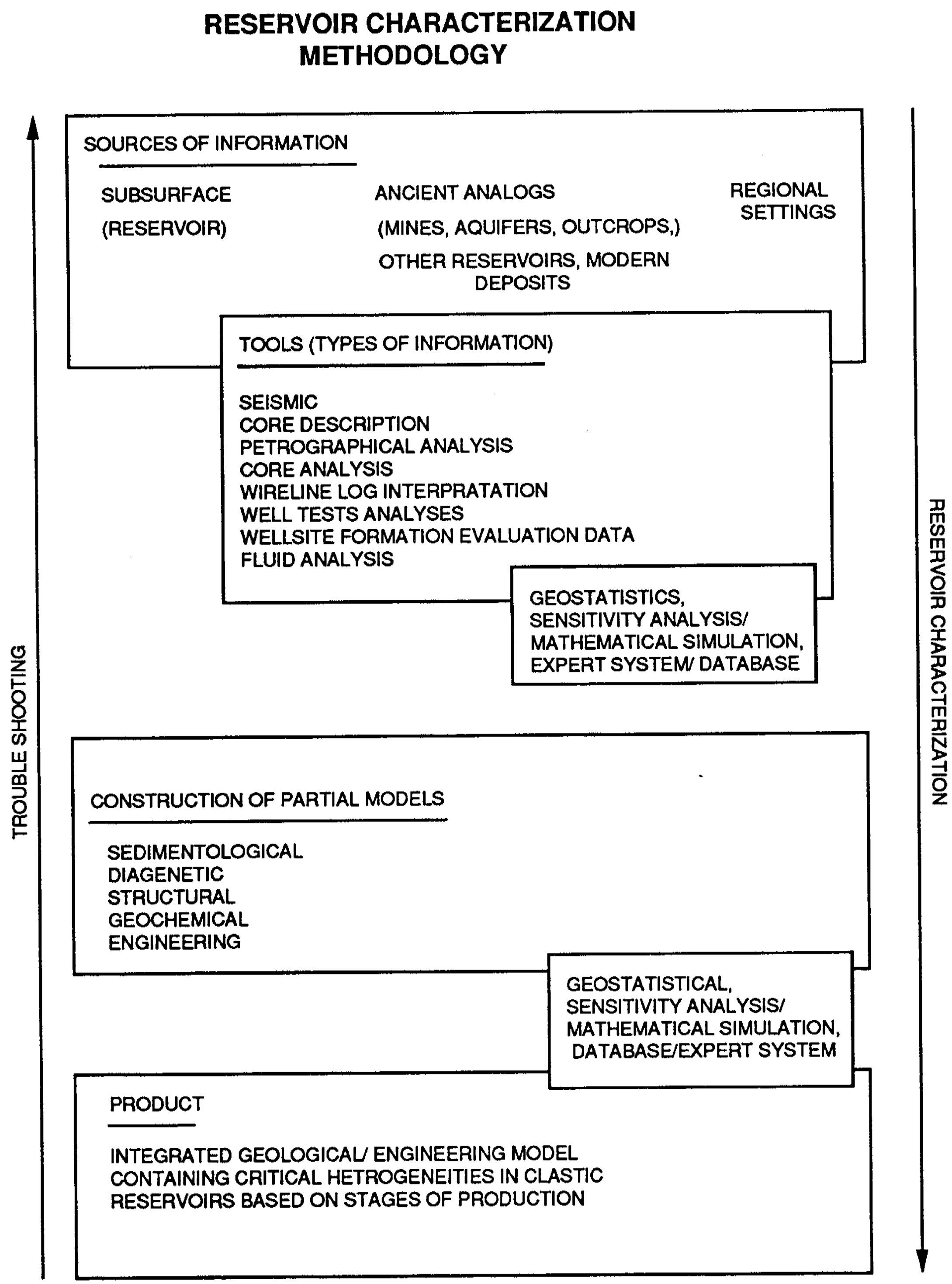


FIGURE 1. - Sources of information, tools, and partial models for reservoir characterization.

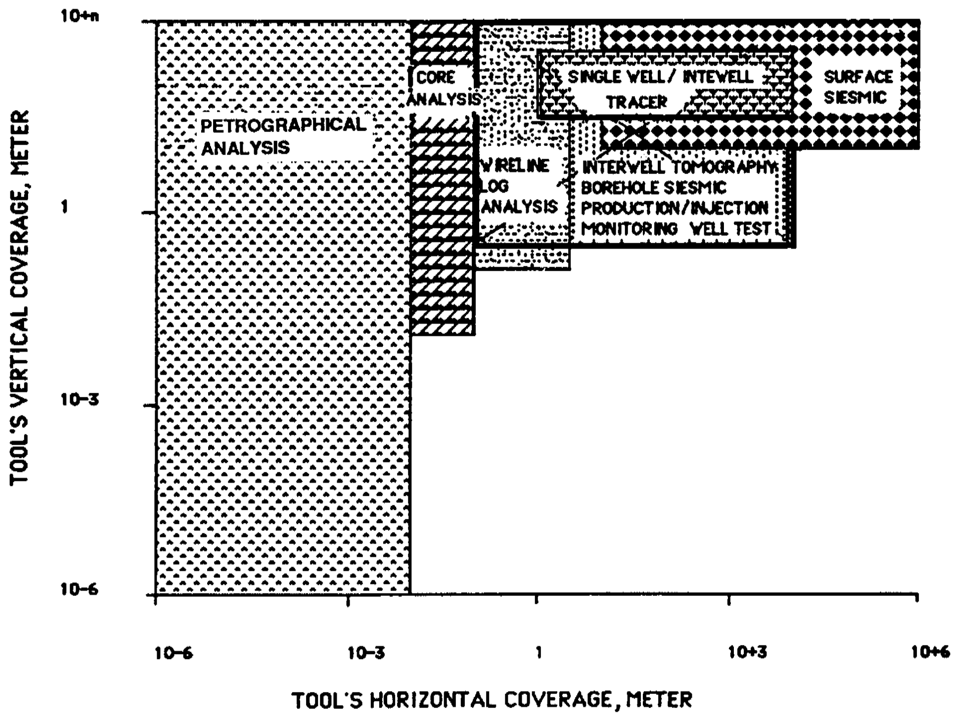


FIGURE 2. - Vertical and horizontal coverage of various tools.

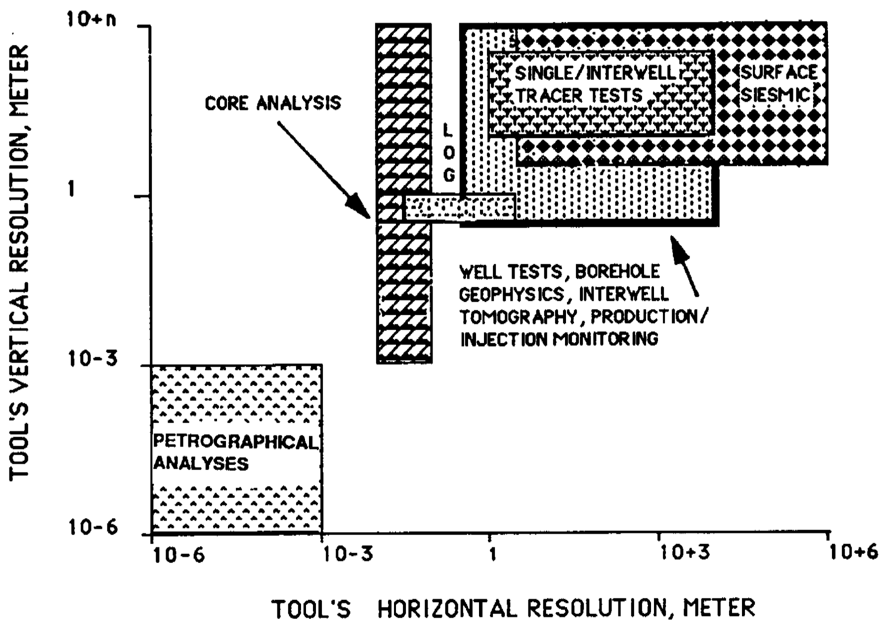


FIGURE 3. - Vertical and horizontal resolution of various tools.

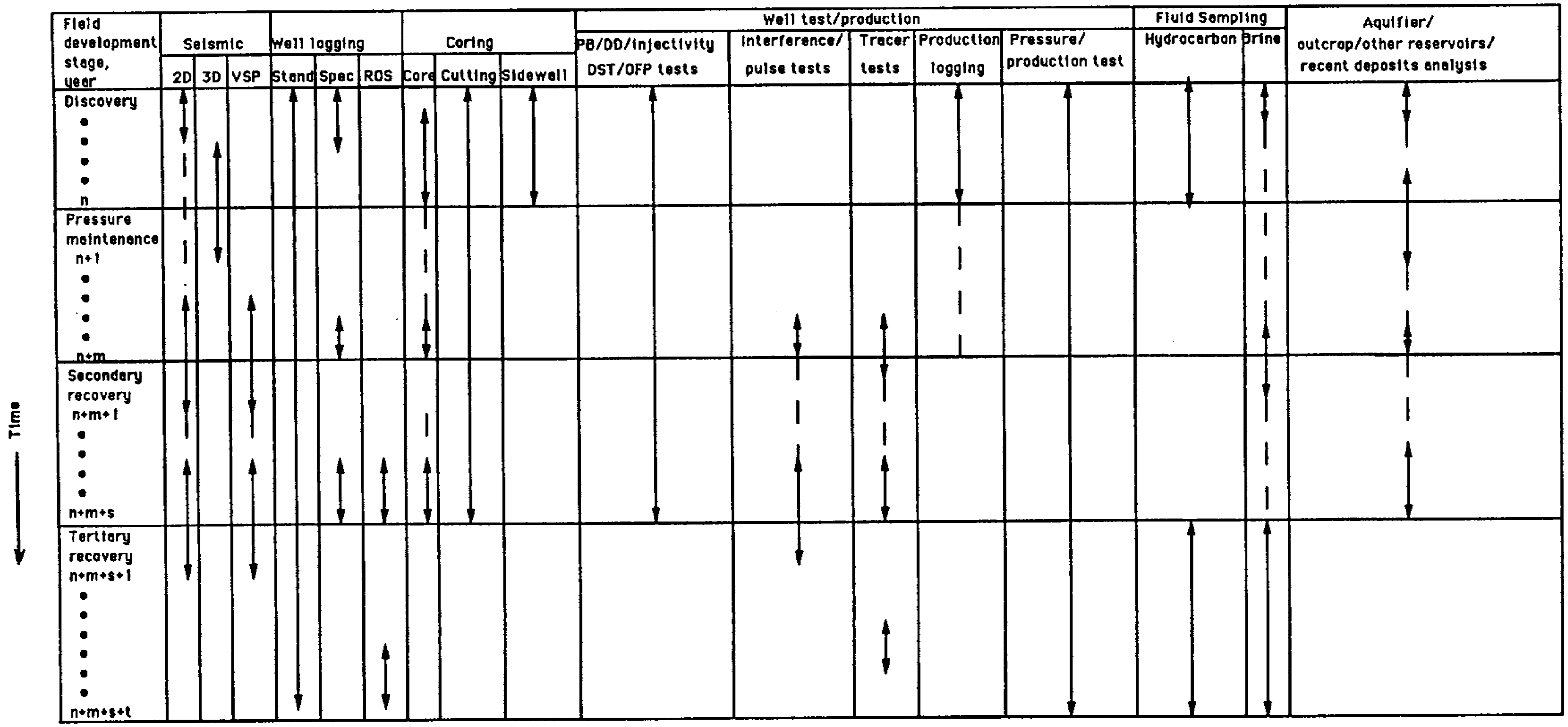


FIGURE 4. - Type, sequence, and timing of data gathering for reservoir characterization. Modified after Weber.[6]

Well Name Gary P-2 Location: 660 E. NW Corner

Sec. 26 T 8S R 54E Date 6/24/86

County: Powder River State: Montana

Interpreter Tillman

Core			Points*	
1.	Complete reservoir sand includes in core		30	30
	A.	More than 10' of reservoir sand	15	__
	B.	5 to 10' of reservoir sand..................................	10	__
	C.	Less than 5' of reservoir sand.........................	-10	__
2.	Unit(s) above reservoir; feet of rock in core			
	A.	More than 5'..	20	20
	B.	2 to 5'...	10	__
	C.	2' or less...	15	__
3.	Unit(s) below reservoir; feet of rock in core			
	A.	More than 5'..	15	__
	B.	2 to 5'...	10	10
	C.	2' or less...	5	__
4.	% of cored interval remaining			
	A.	More than 95% of core remains........................	20	__
	B.	90% of core remains..	15	__
	C.	75-90% of core remains....................................	10	10
	D.	Less than 75% of core remains.......................	0	__
5.	Core slabbed			
	A.	1/2 or 1/3...	15	15
	B.	Thin slab (less than 1/3 of core)....................	10	__
	C.	Unslabbed		
		(1) Unable to slab...	0	__
		(2) Potential to slab...	10	__
			Subtotal	85
Supplemental Information				
6.	Logs			
	A.	Logs (2 or more)...	20	20
	B.	Log (only one available)....................................	10	__
7.	ϕ and K data available...		20	20
8.	Previously described by:			
		(1) Tillman...	10	5
		(2) Berg and Davies..	5	__
9.	Grain size analysis available..................................		5	2
			Subtotal	47
		Subtotal from P-1		85

*Choose single best description under each number.

FIGURE 5. - Sample of core quality index.

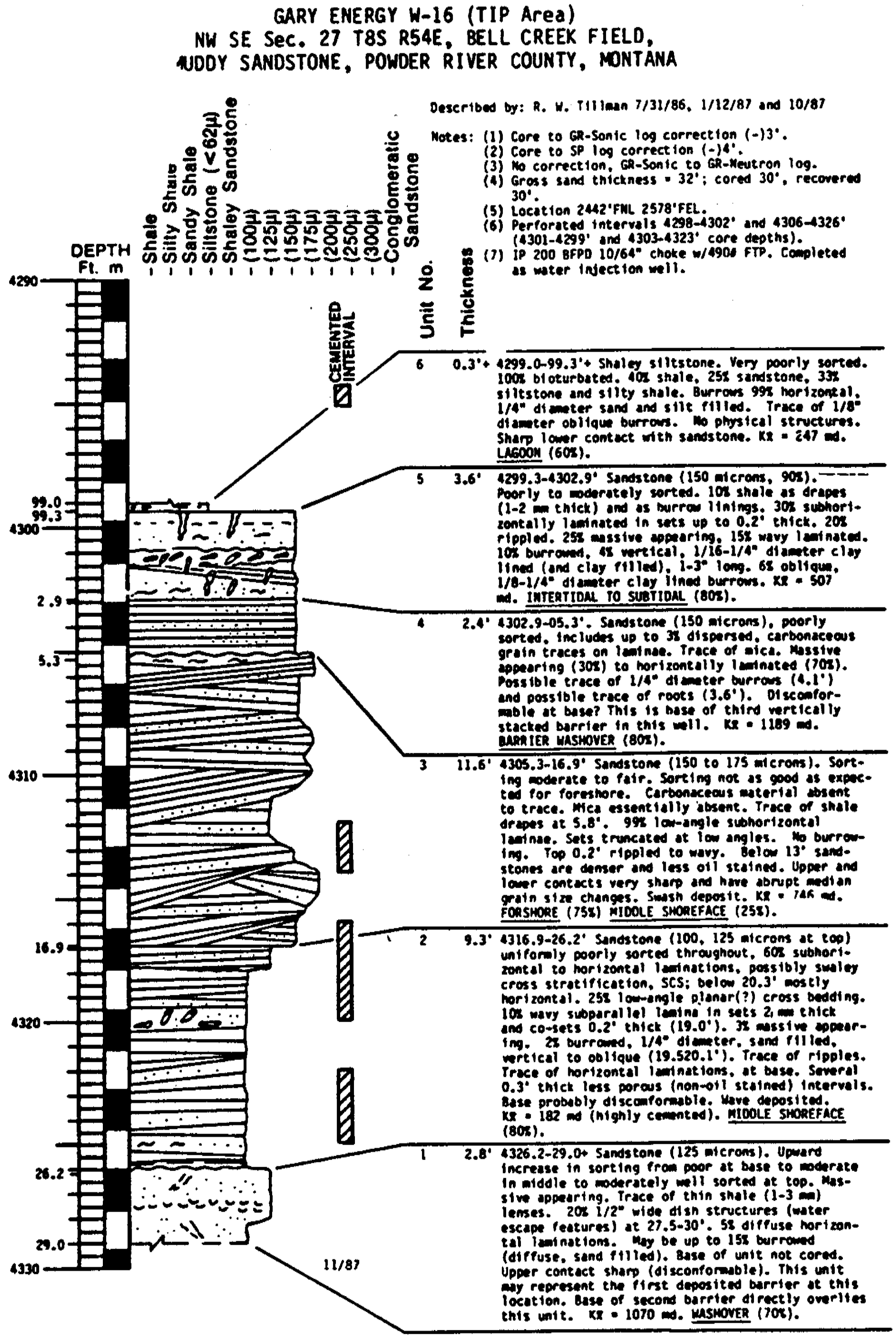


FIGURE 6. - Sample of geological core description.

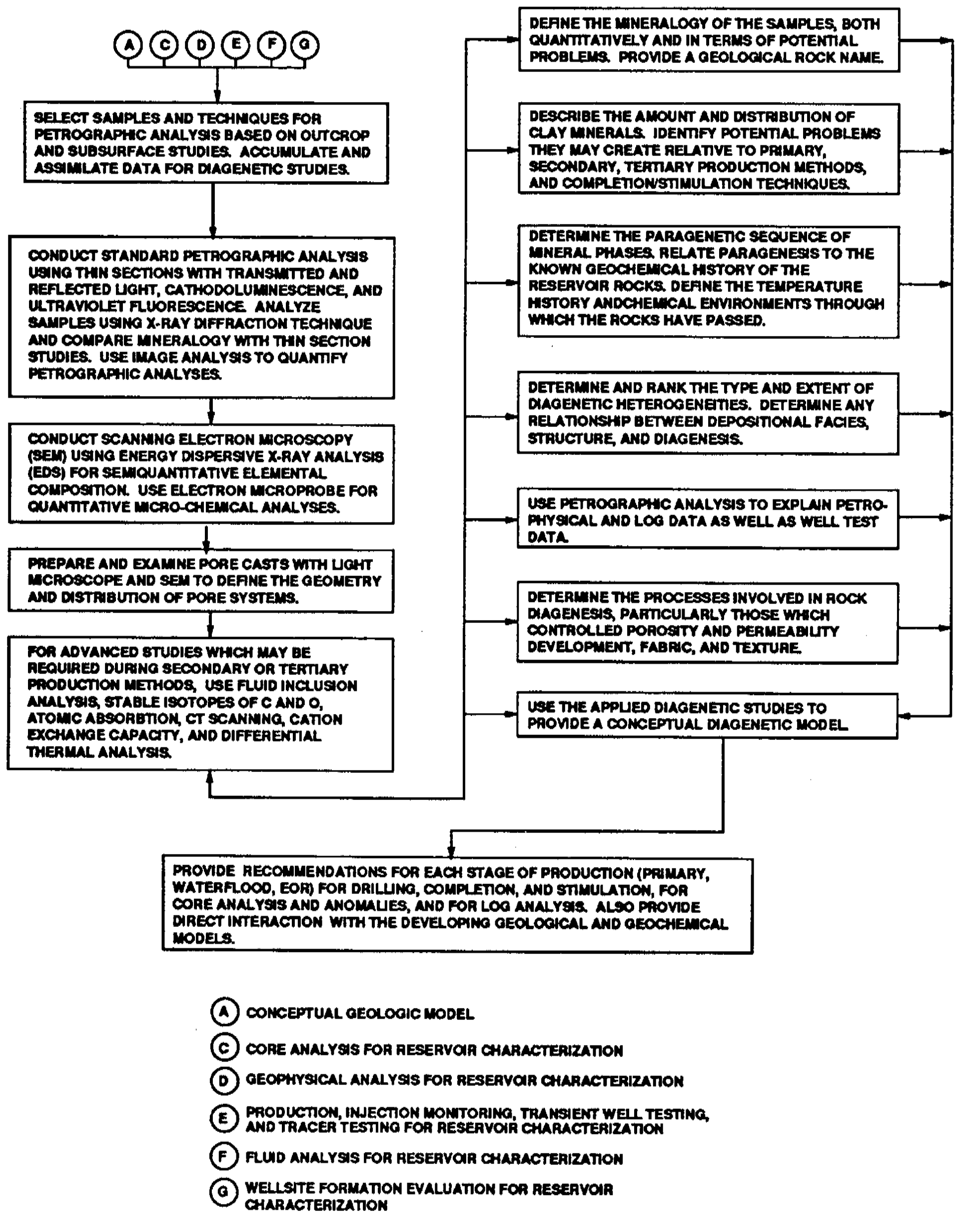


FIGURE 7. - Petrographic analysis for mineralogical characterization.

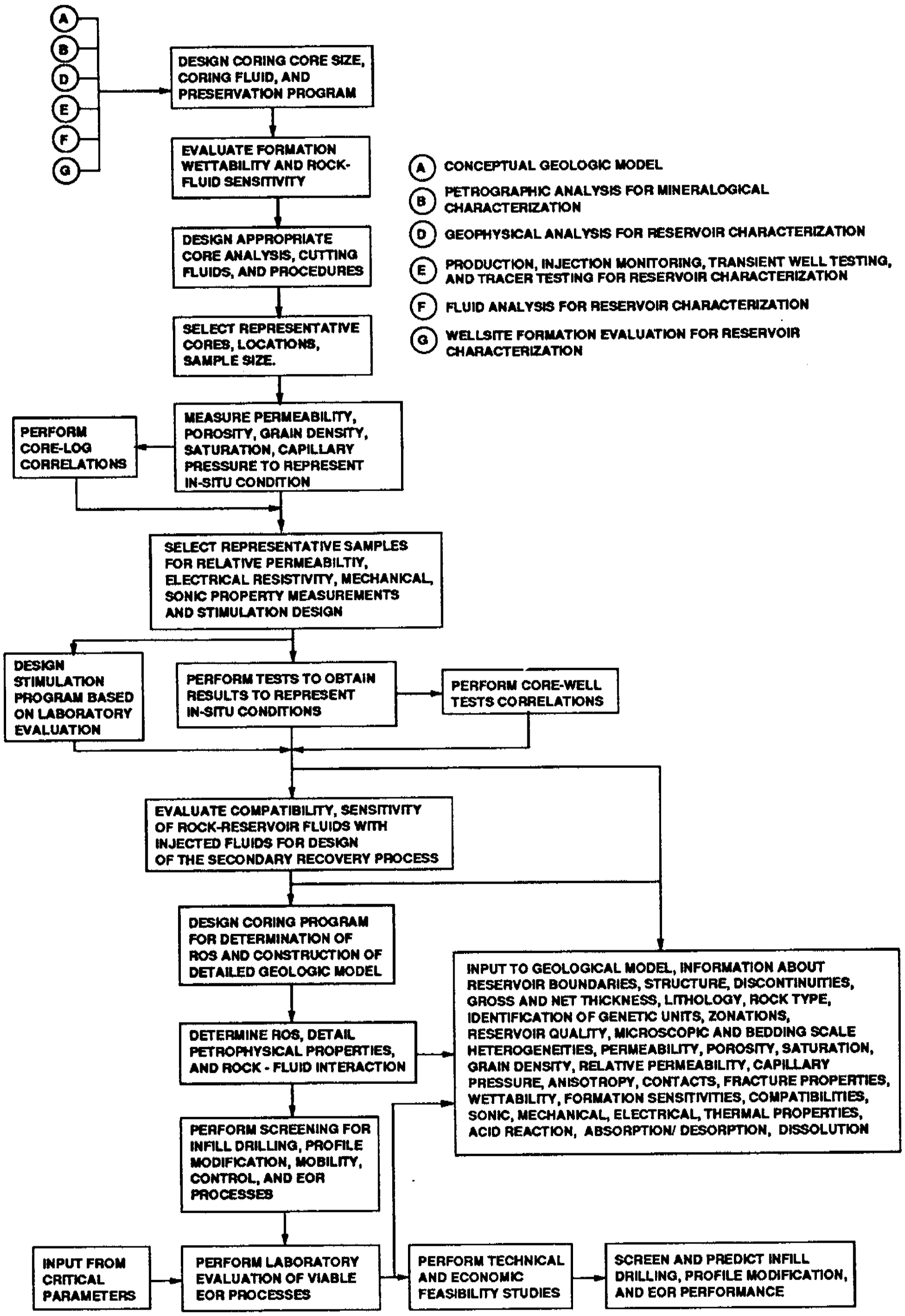


FIGURE 8. - Core analysis for reservoir characterization.

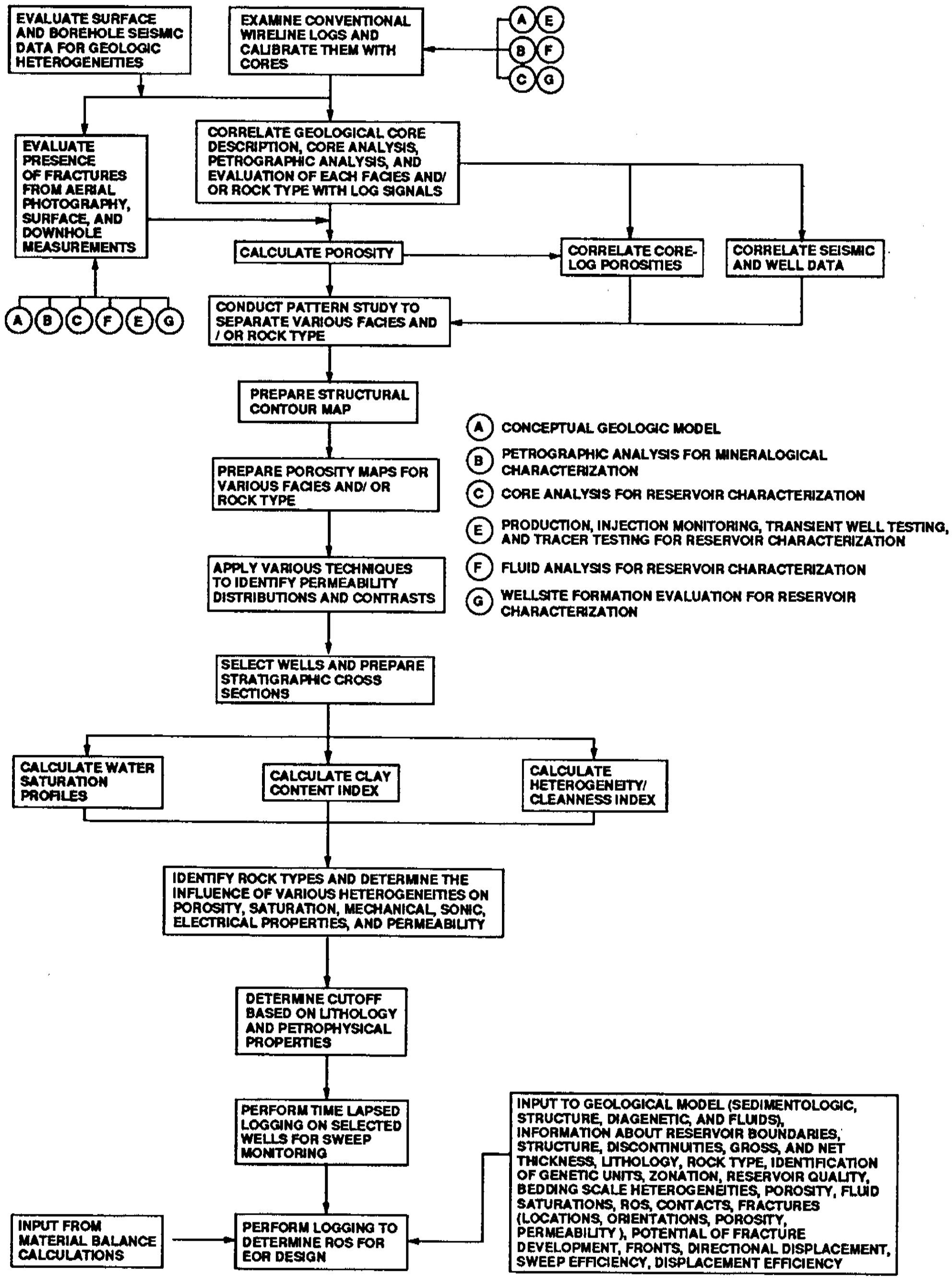


FIGURE 9. - Geophysical analysis for reservoir characterization.

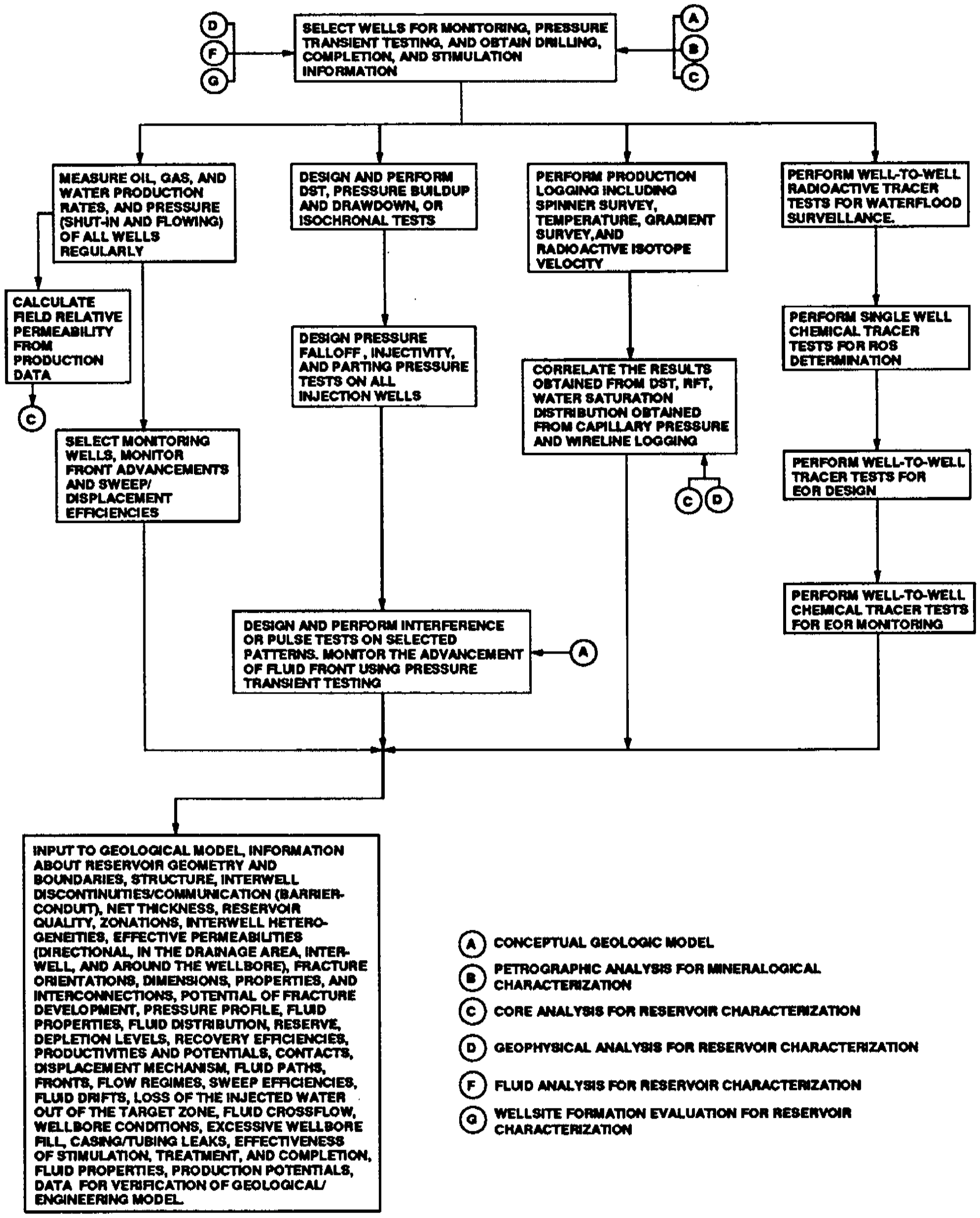
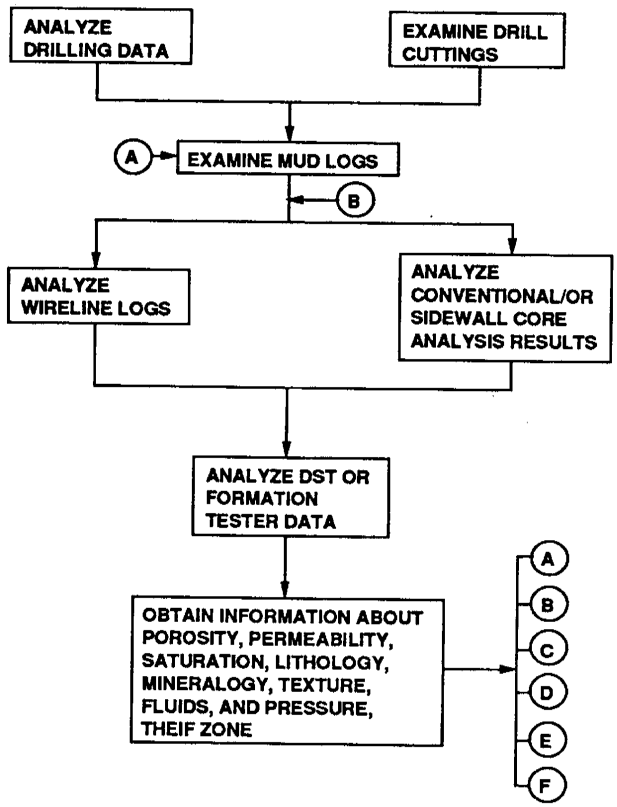


FIGURE 10. - Production, injection monitoring, transient well testing, and tracer testing for reservoir characterization.



(A) CONCEPTUAL GEOLOGIC MODEL

(B) PETROGRAPHIC ANALYSIS FOR MINERALOGICAL CHARACTERIZATION

(C) CORE ANALYSIS FOR RESERVOIR CHARACTERIZATION

(D) GEOPHYSICAL ANALYSIS FOR RESERVOIR CHARACTERIZATION

(E) PRODUCTION, INJECTION MONITORING, TRANSIENT WELL TESTING, AND TRACER TESTING FOR RESERVOIR CHARACTERIZATION

(F) FLUID ANALYSIS FOR RESERVOIR CHARACTERIZATION

FIGURE 11. - Wellsite formation evaluation for reservoir characterization.

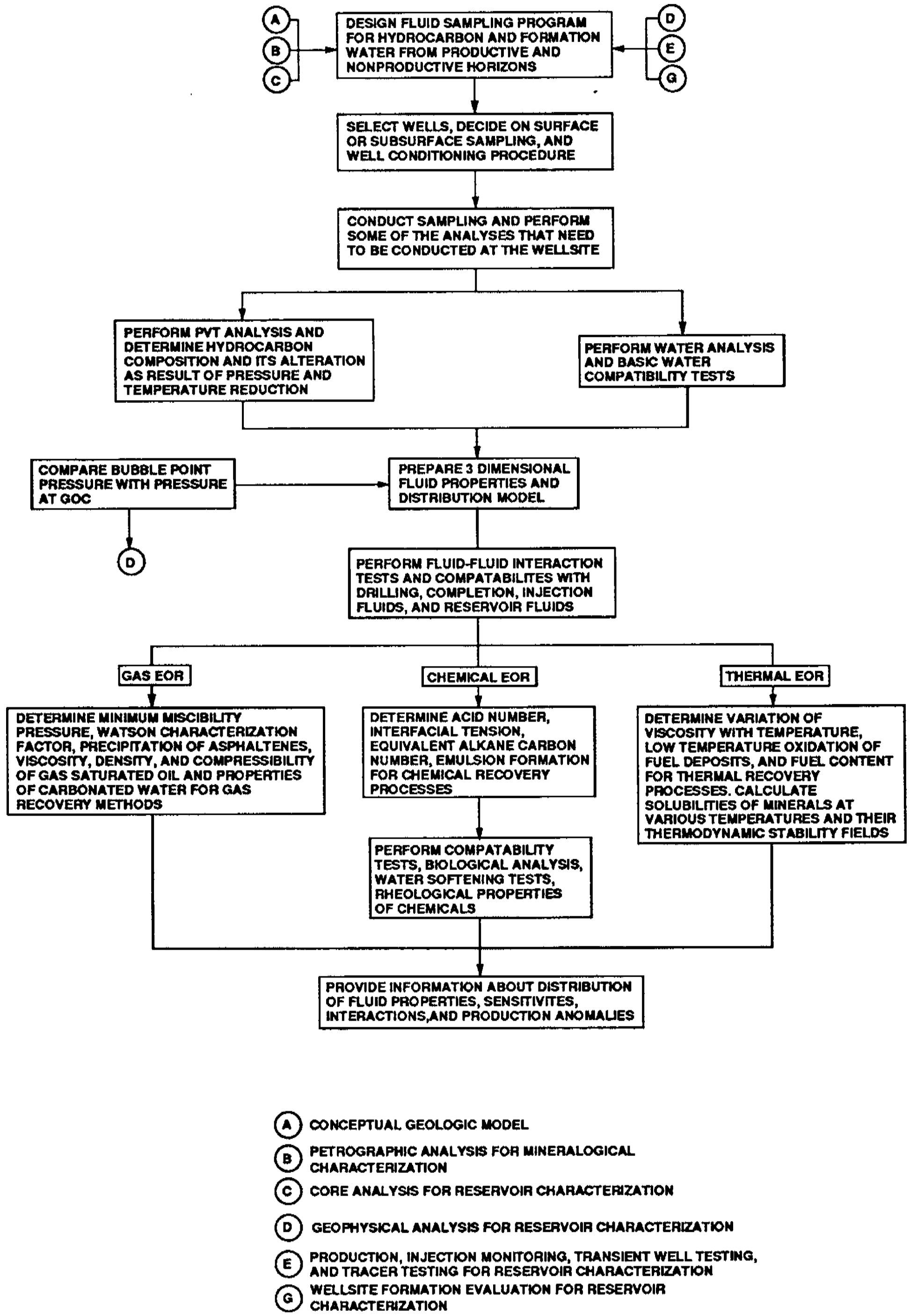


FIGURE 12. - Fluid analysis for reservoir characterization.

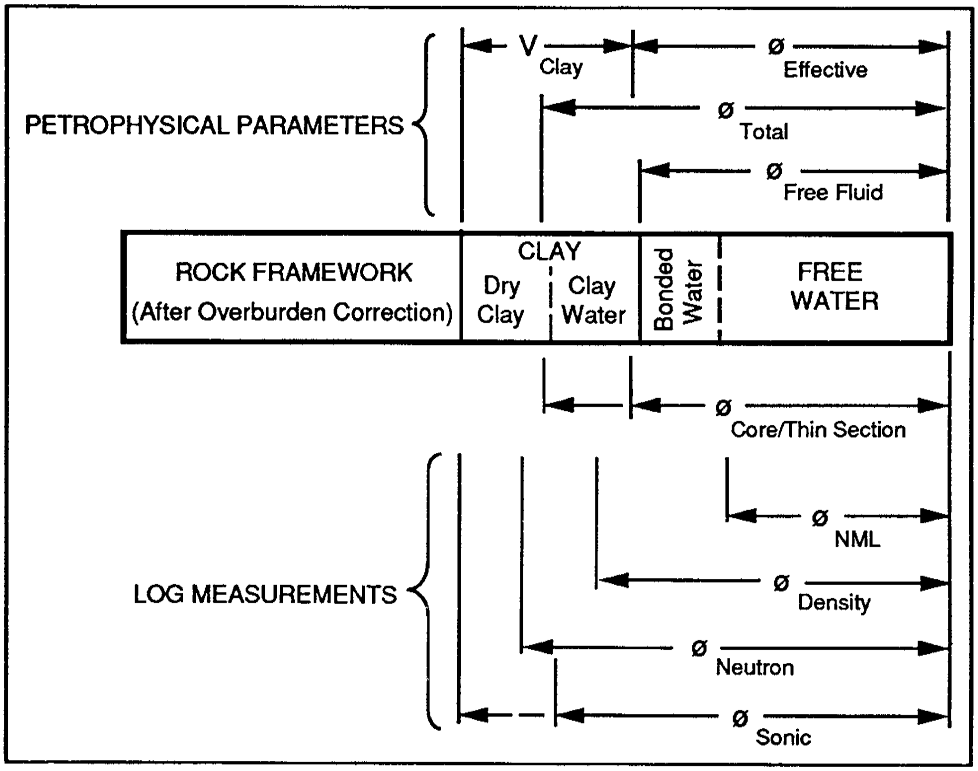


FIGURE 13. - Log and core measurements of various aspects of porosity. Modified from Bassan et al., 1988.

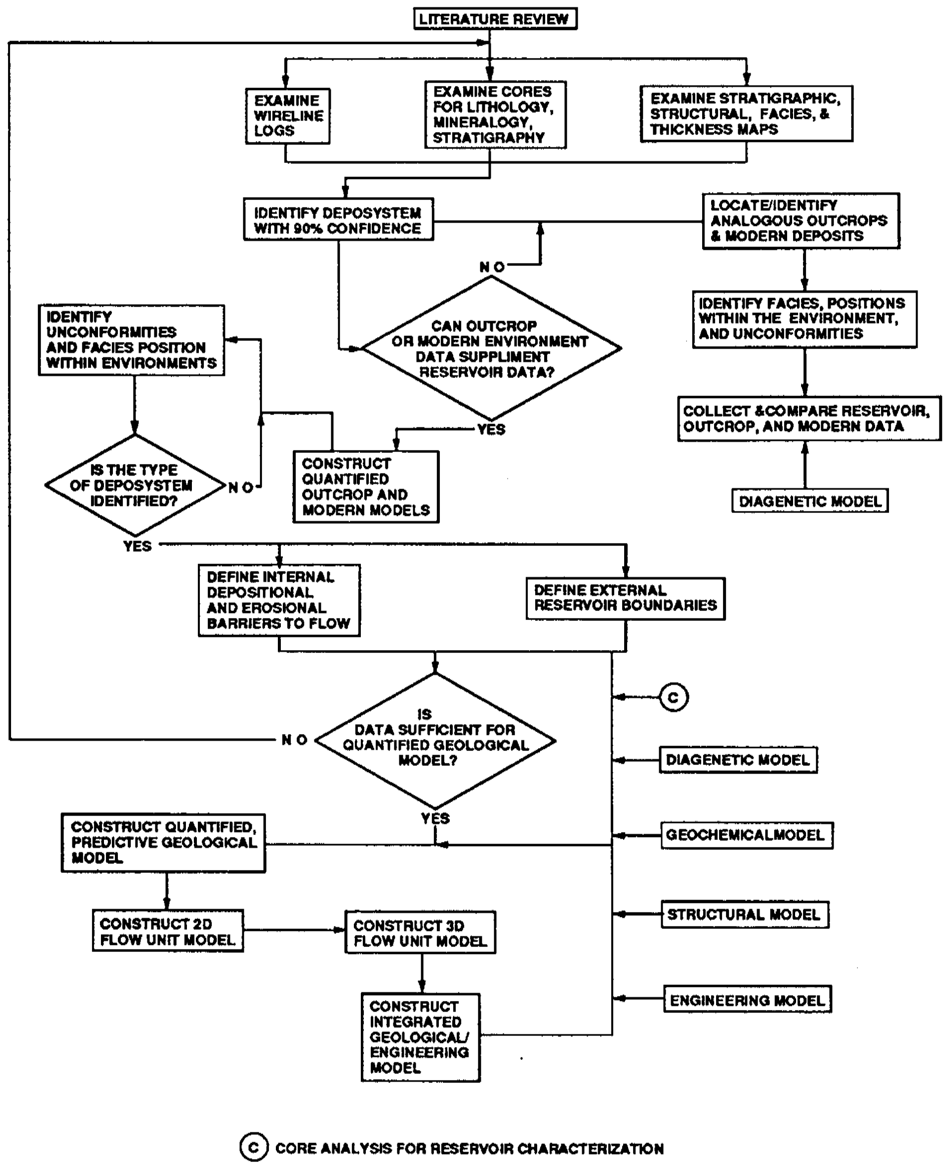


FIGURE 14. - Procedures for sedimentological model development.

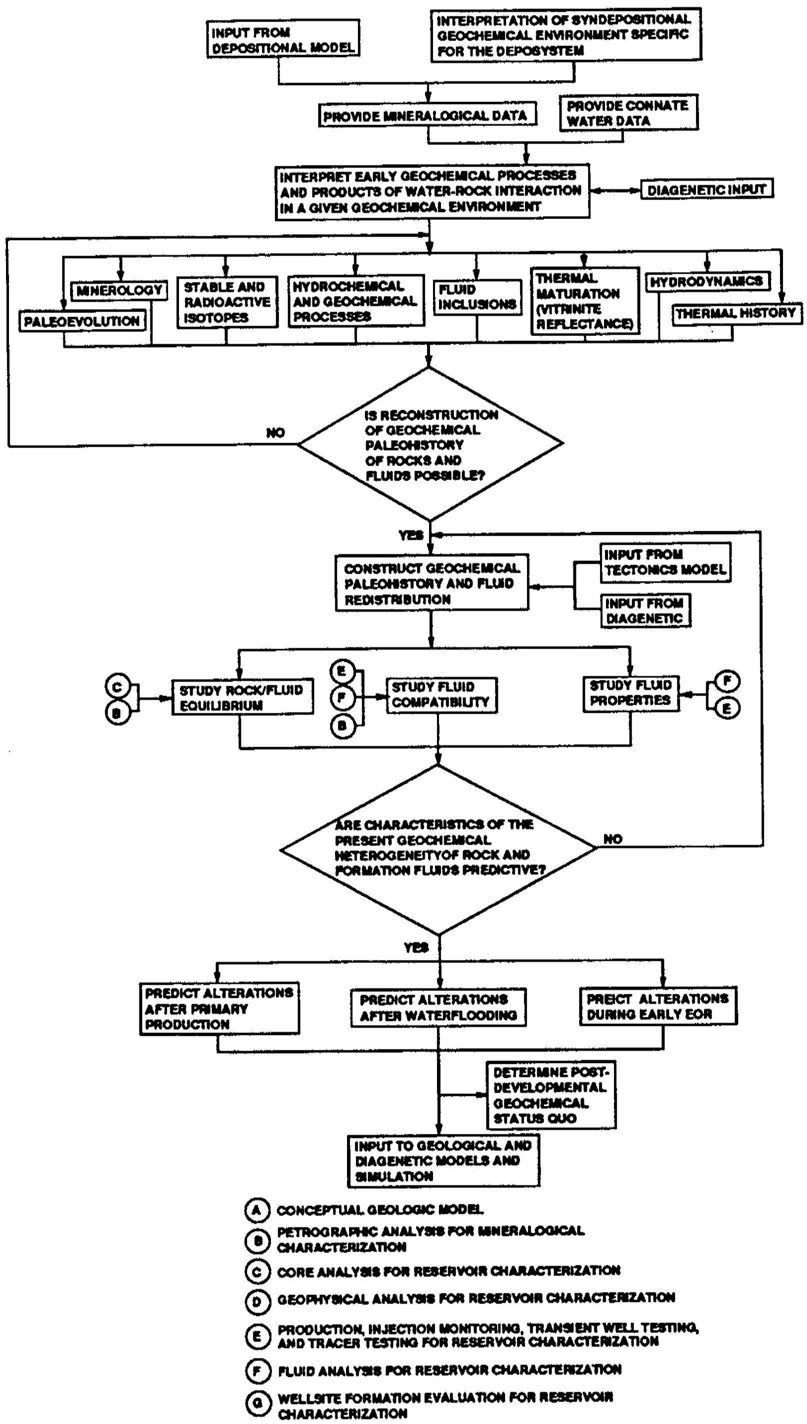


FIGURE 15. - Procedures for geochemical model development.

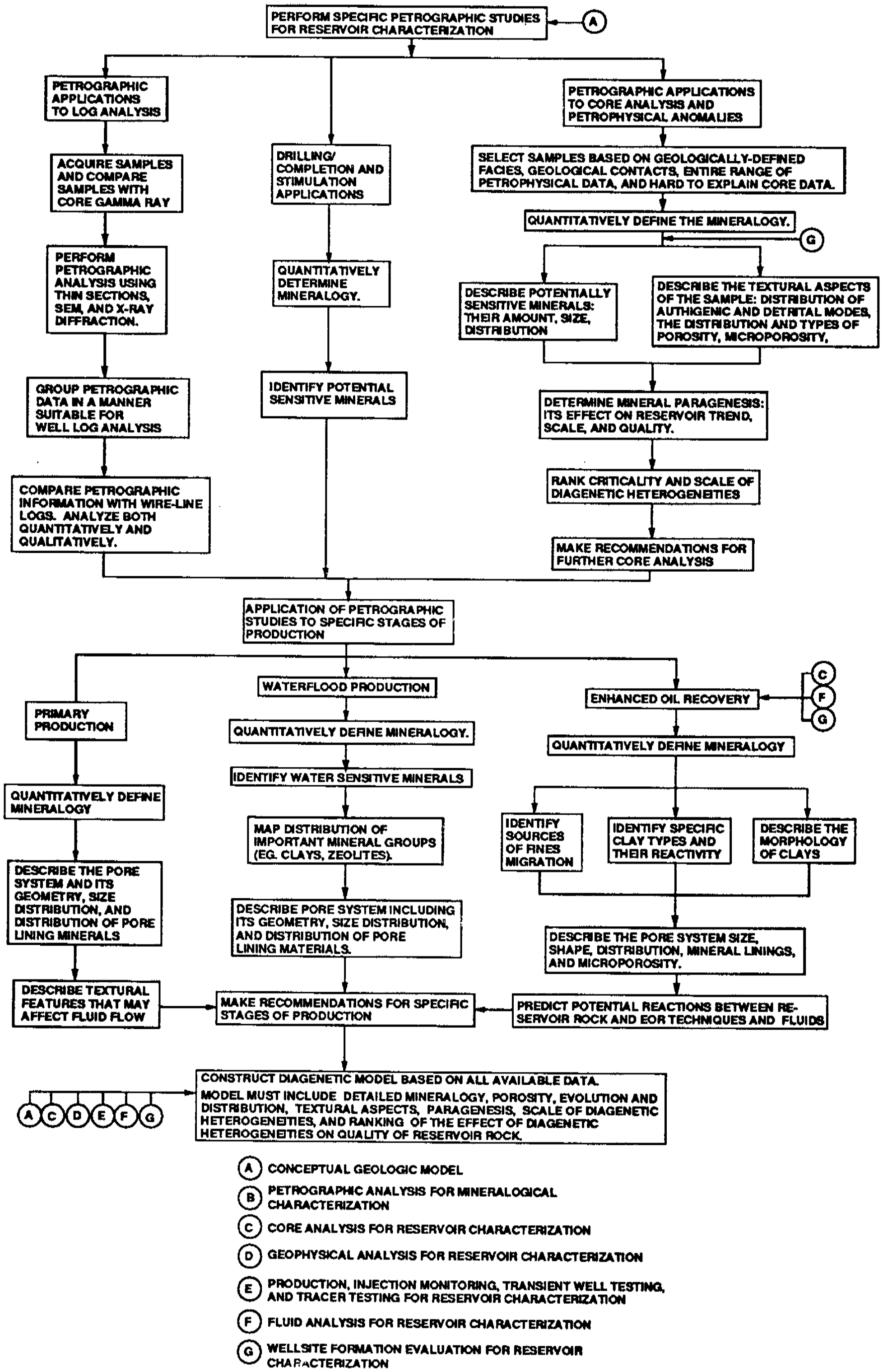


FIGURE 16. - Procedures for diagenetic model development

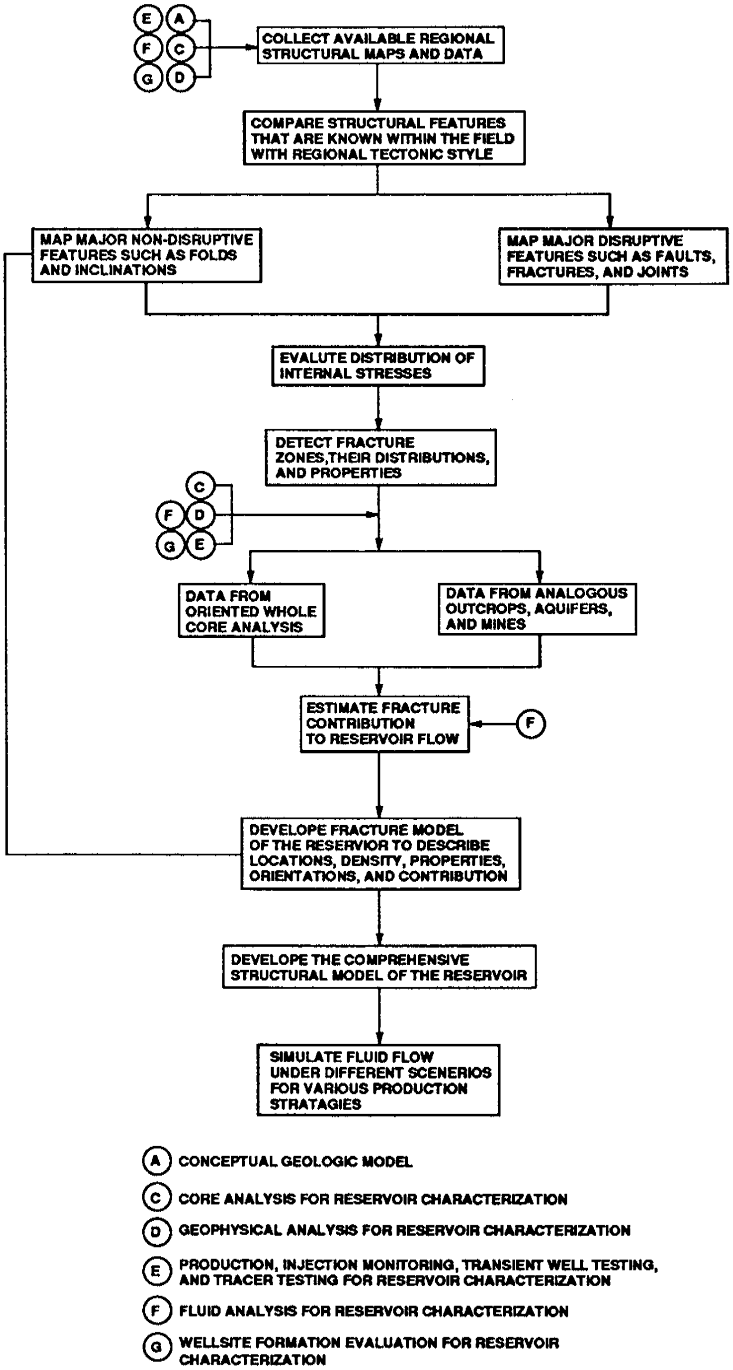


FIGURE 17. - Procedures for structural model development.

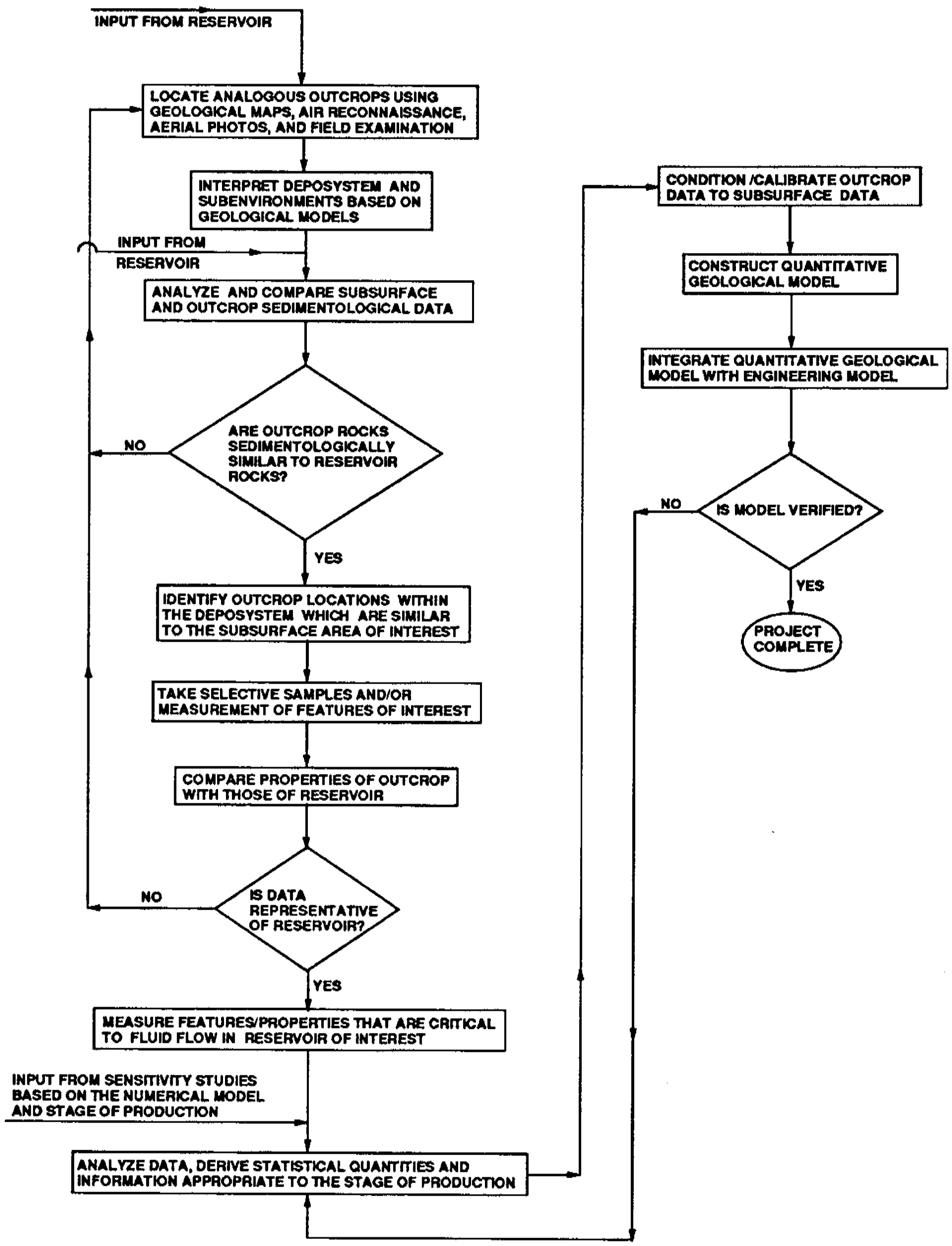


FIGURE 18. - Procedure for outcrop characterization.

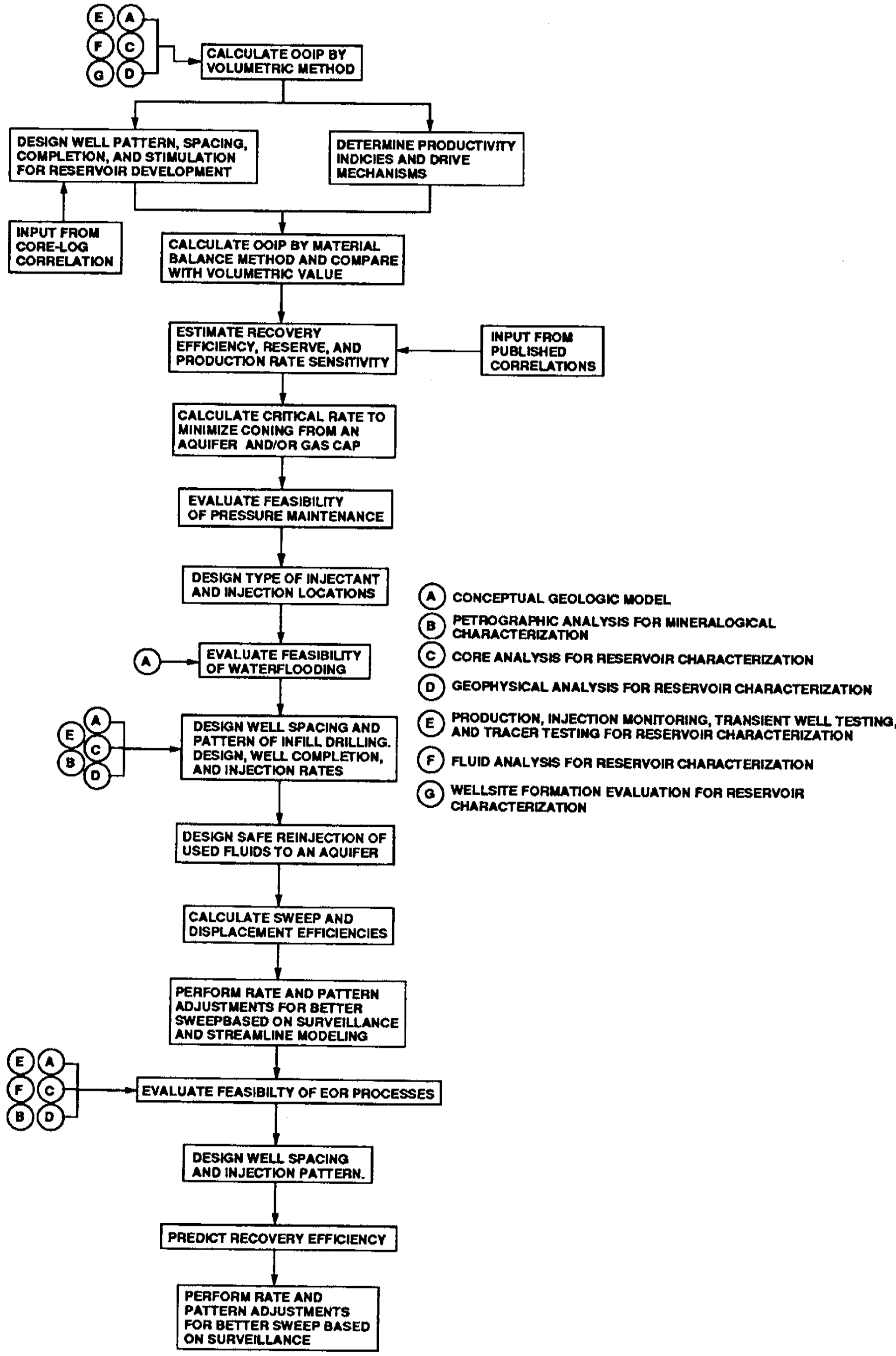


FIGURE 19. - Procedure for reservoir engineering calculations.

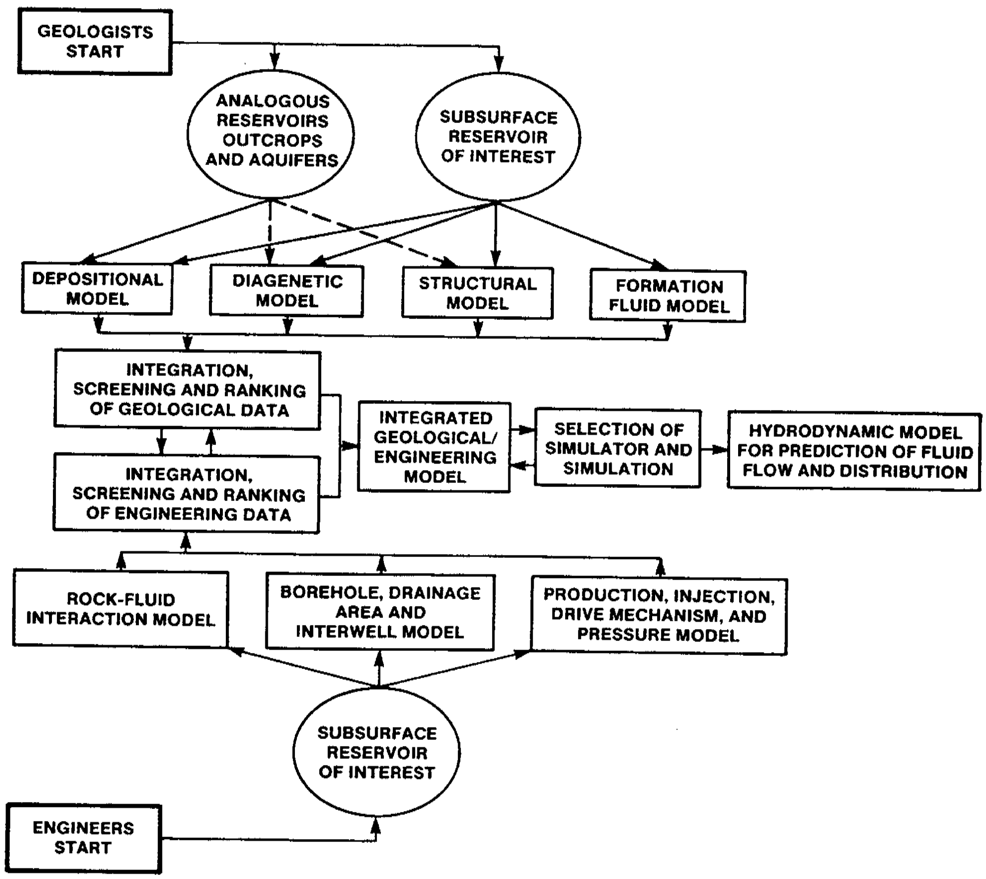


FIGURE 20. - Procedure for integrating geological and engineering studies.

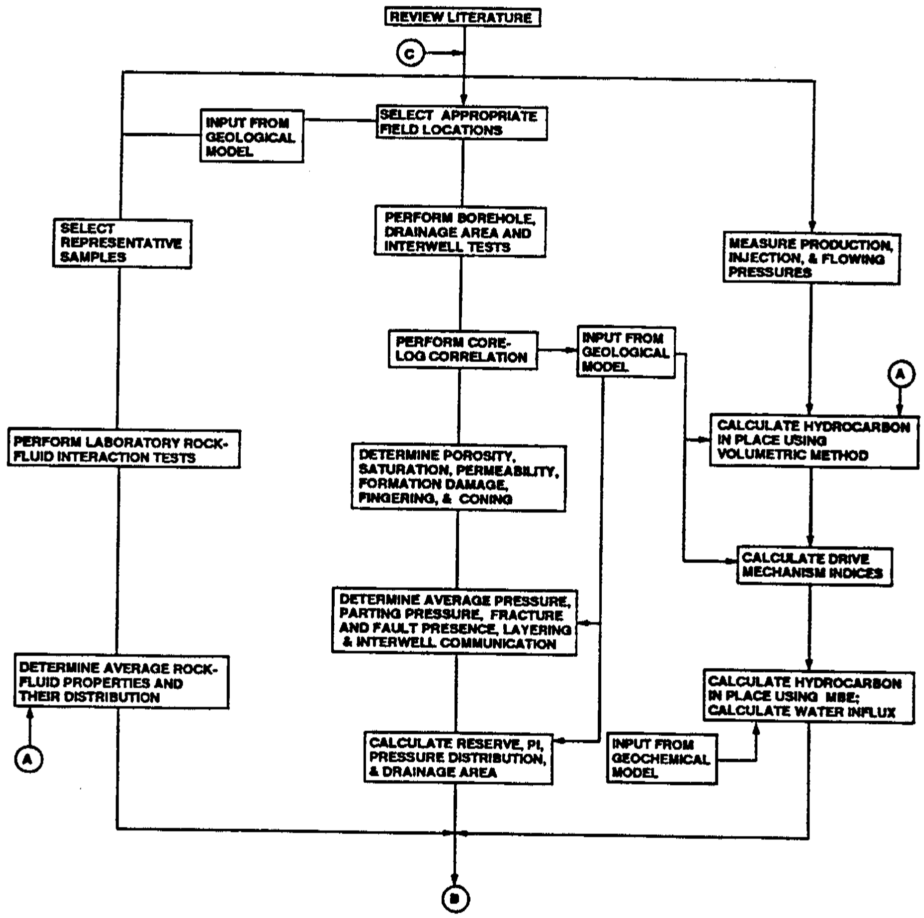


FIGURE 21. - Development of engineering model and performance of simulation. Part A. Input data preparation.

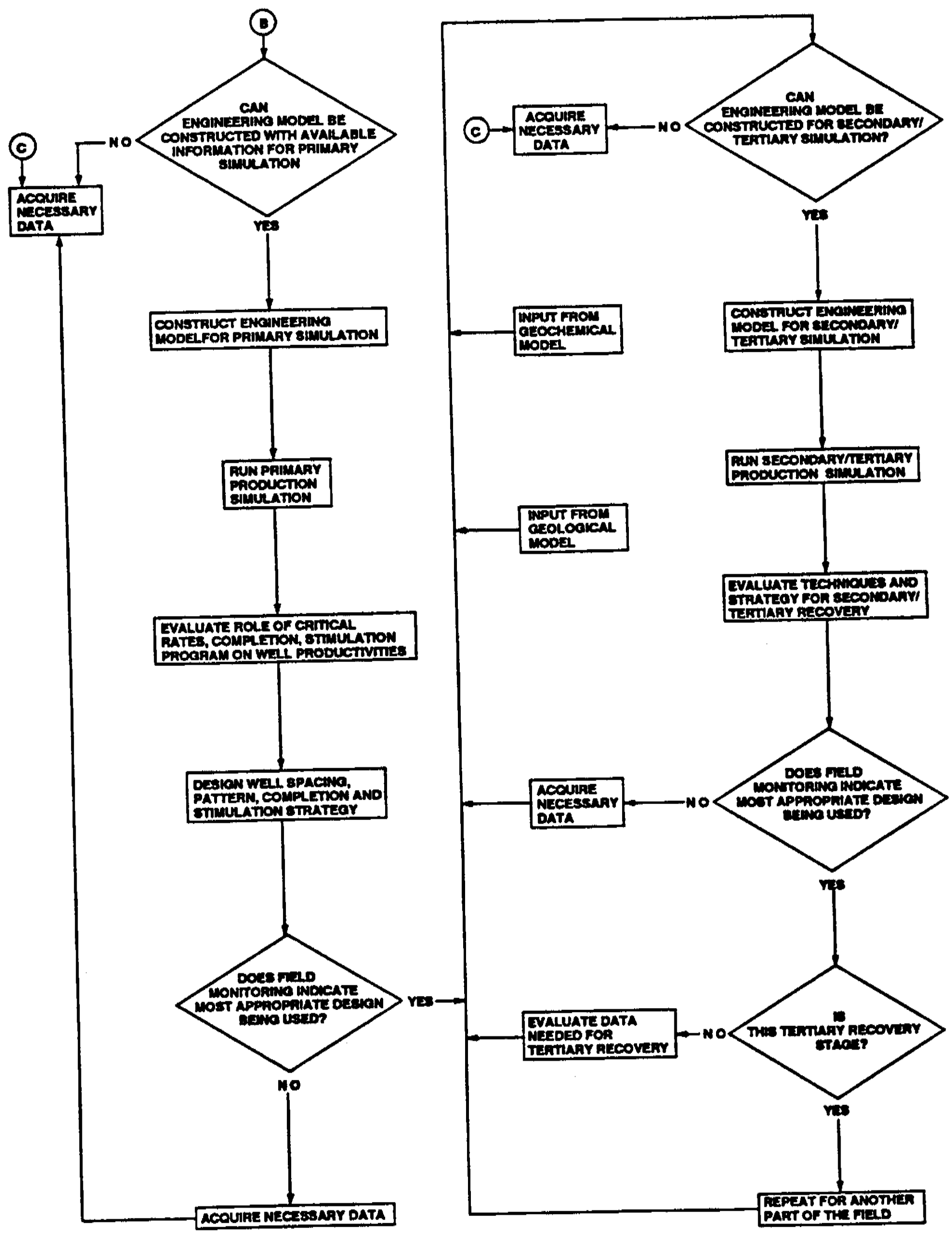
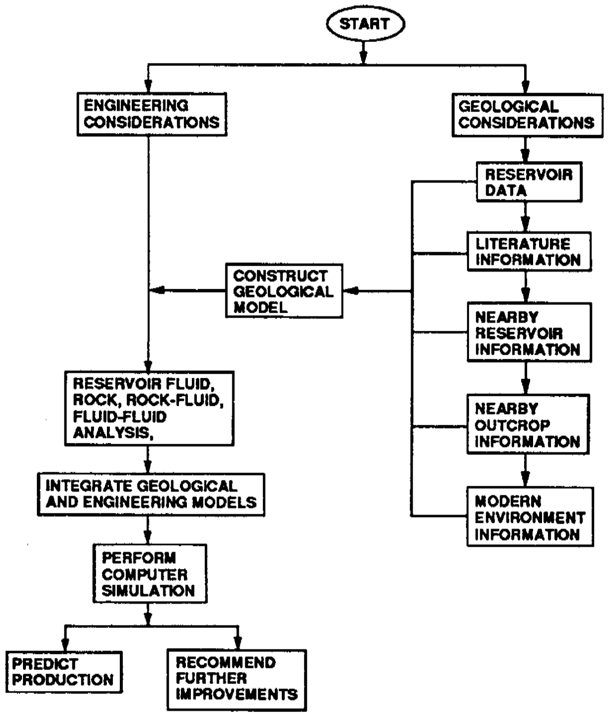


FIGURE 22. - Development of engineering model and performance of simulation. Part B. Simulation.



FIUGRE 23. - Expert system flow chart for reservoir characterization.

PART II. APPLICATION OF THE METHODOLOGY

I. INTRODUCTION

Five types of shoreline barriers (spits, shoals, barrier islands, barrier pennisulas, and barrier bars) and three basic genetic groups (aggradational, progradational, and transgressive) have been destinguished in modern and ancient barrier sediments. All the shoreline barriers are strongly affected by the dynamics of wave or tide dominated coasts. They differ significantly in their external dimensions, internal structures, sequence of facies and thickness of sand bodies. Therefore, each genetic type of shoreline barrier may have different storage capacity and flow unit distribution.

Examples presented in this part will be from an integrated, geological and engineering study of the Lower Cretaceous Muddy formation in Unit 'A' of Bell Creek field located in southeast Montana. Information from analogous outcrop exposures located 40 miles south near New Haven, Wyoming was also used. The models presented herein were developed for the Tertiary Incentive Project (TIP) area, which was a pilot micellar-polymer project implemented after 10 years of line-drive waterflooding.

The Muddy formation in Unit 'A', Bell Creek field produces oil primarily from a 30-foot-thick (maximum) barrier island sandstone stratigraphic trap reservoir. It is unconformably overlain by a valley fill complex of poorly productive channel sandstones and marginal to non-productive estuarine siltstones and shales. In places, the valley cuts entirely remove the barrier island sandstone, creating hydraulic barriers within the field and defining production unit boundaries with different oil-water and gas-oil contacts.[1]

II. GENERAL CHARACTERISTICS OF A BARRIER ISLAND

At least three types of information are required to construct a generic classification of diverse types of shoreline barriers which include spits, shoals, barrier peninsulas, barrier islands, and barrier bars. The first type is the relative direction of growth or migration of the barrier (progradational, aggradational, or transgressive). Secondly, whether the shoreline is (or was) tide- or wave-dominated must be determined. Thirdly, the tidal range at the site of deposition must also be determined (microtidal, mesotidal, macrotidal). Shoreline barriers generally do not form in macrotidal conditions. In microtidal and mesotidal conditions, barrier complexes form parallel or oblique to the coastline and have distinctive facies geometries and lateral extents. Only through comparisons and contrasts of truly analogous types of barrier deposits can a generalized model be constructed. The effects of diagenesis on parameters commonly used to define depositional facies, such as grain size or sorting, are also considered in the following sections.

III. COMPARATIVE CHARACTERISTICS OF MODERN SHORELINE BARRIERS AND HYDROCARBON PRODUCTIVE ANCIENT ANALOGS

In this part of the comparative study leading to generalization of the external and internal geometries, dimensions, and petrophysical properties of barrier island deposystems, a broader relationship between recent and ancient shallow marine sandy shoreline barriers is addressed. Before meaningful comparisons and conclusions regarding generalized features can be made, it is necessary (1) to define various shoreline barriers; (2) to determine how they are formed, by which depositional processes and in what setting; (3) to compare similarities and differences among various types; and (4) to compare similarities between various types.

A. Types of Shoreline Barriers

Shoreline barrier island depositional settings encompass a variety of sandbody types. Shoals, spits, barrier peninsulas, barrier islands sensu stricto, and sandy barrier bars attached to the mainland at both ends are subtypes of shoreline barriers formed by long-shore currents and modified by wave and/or tide action (fig. 24). They can be transformed from one to another during coastline evolution or even destroyed before their burial.

Most barrier bars are parallel or oblique to the coastline. Some may be attached to the shore at one end (spits, peninsulas), and others may be separated from the mainland and submerged (shoals) or emerged and breached by tidal channels (barrier islands). Strand plains, delta mouth bars, tidal sand ridges, and shelf ridges (offshore bars) are excluded from this discussion even though they may possess certain common features with nearshore barriers.

Generally, typical modern coastal barrier sand bodies are 10 to 25 miles long, 2 to 4 miles wide, and 30 to 50 feet thick.[2] The inner shelf shoals are typically 20 to 22 miles long, 1 to 6 miles wide, and 7 to 23 feet thick.[3]

B. Information Required for a Genetic Classification of Shoreline Barriers

There are three major genetic groups of modern shoreline barriers: aggradational (build upward, sometimes called stationary); progradational (migrating seaward); and transgressive (migrating landward),[3] which differ substantially in their external dimensions, internal structures, sequence of facies, and thickness of sand bodies (fig. 25). These types of barriers must be identified in the subsurface to ensure adequate predictions of reservoir geometry, petrophysical properties and distribution of facies in uncored areas, and for selection of optimum strategy for reservoir development. Modern transgressive barrier islands are 20 to 47 miles long, 1 to 1.5 miles wide, and only 7 to 16 feet thick.[4] An excellent description of evolutionary stages of the transgressive barrier shorelines of the Mississippi delta plain is given by Boyd and Pennland, 1984.[5] Fast marine transgression and rapid subsidence favors preservation of most barrier island sediments. Slow subsidence during transgressive periods results, however, in the reworking of most sequences, and only remnants of original facies have a chance to survive.[6] Numerous depositional models of shoreline barrier deposits indicate that continuity of sand bodies is usually excellent and petrophysical properties are relatively constant parallel to depositional strikes for all three major barrier types.[1] In the dip direction, however, the vertical profile is often disrupted, and petrophysical properties may vary greatly in aggradational and transgressive types (fig. 25).

For a generic classification of barrier type, two additional features which need to be defined are the paleodirection of shoreline currents which formed the reservoir body and determination whether the paleocoast was tide- or wave-dominated. After these features are identified, a third major question must be addressed - whether the ancient shoreline was formed in a micro- or mesotidal environment. That the morphology of modern barrier islands and the type of sedimentation significantly differ in these two environments have been well documented.[7] In microtidal coasts (<1 m of tidal range) long, narrow barriers with numerous washovers and few inlets are formed. Padre Island, 110 miles long and 1/2 to 4 miles wide, which was aggradational for most of its history but which recently became transgressive[8] is a good example of a barrier island formed on a microtidal coast. Along mesotidal coasts; e.g., East Frisian Isles (1 to 3.5 m tidal range), the barrier islands are short in the direction of the depositional strike (rarely exceeding 10 miles length), wide in the dip direction, and are characterized by numerous inlets. In macrotidal coasts (>3.5 m tidal range), barriers are absent although shoals and supratidal islands perpendicular or oblique to the mainland can be formed (fig. 26).

C. <u>Examples of Reservoirs and Their Modern Analogs</u>

Critical geological information such as genetic barrier type, dimension, geometry, petrophysical properties, trapping mechanism, depth of occurrence, and oil, gas, or condensate reserves has been evaluated for several hydrocarbon reservoirs producing from shoreline barrier deposits in different geologic settings of the United States. In some cases, reservoir characteristics are quite similar to their modern analogs. Identification of such genetic types with analogous facies dramatically improves understanding of reservoir behavior and facilitates improved predictions of reservoir properties for advanced stages of development. For example, the sedimentary pattern of the closely located group of south Texas oil fields producing from the Eocene Reklaw formation in Atkinson (barrier island), Hysaw, and Flax fields (distributary mouth bar prograding seaward) and Burnell, Hondo Creek, and Runge West fields (broad delta-front sheet sand deposited further downslope) reported by Bulling and Breyer[9] is similar to the modern sedimentary system of the Vistula barrier bar on the Baltic Coast, Poland, studied by Szpakiewicz.[10] Another example of a strong analogy with a modern generic type of barrier comes from characteristics of the Pilot Sandstone reservoir of the Upper Cretaceous lower Tuscaloosa Group (Cenomanian) in South Carlton and Pollard fields of southwestern Alabama. The Pilot Sandstone is considered[12] to be similar to the transgressive shoreline barrier sands associated with the modern Mississippi River delta plain in Louisiana, as described by Penland (1985).[4]

West Ranch field, a prolific oil and gas field with multiple pay zones in the Frio formation barrier island/strand plain system (fig. 27), would provide a natural laboratory for comparative study of the three major types of barrier islands: (1) aggradational (Greta reservoir), (2) progradational (41-A reservoir), and (3) transgressive (Glasscock reservoir). Ward and 41-A reservoirs of West Ranch field represent the strand plain type of sedimentation.[11] The Glasscock reservoir is the thinnest of the three and contains the least oil-in-place. The progradation 41-A reservoir consists of barrier core, inlet fill, and flood tidal delta facies. The barrier core and inlet fill sediments are the best producers and occur in comparable proportions. The distribution of permeabilities, however, is very different in the two systems; in the barrier core, permeability increases upward and the highest permeabilities occur at the top of the section, whereas in the inlet fill, the highest permeabilities occur at the base and gradually decrease upward. The field may be considered for a more detailed comparison of nearshore marine reservoirs.

D. Bell Creek Depositional Setting

Characteristics of Bell Creek (MT) field resemble, to a much lesser degree, characteristics of progradational Galveston Island in Texas, that were suggested by previous workers.[12-13] Moslow[3] observed that an isopach map of Bell Creek sandstones is similar in morphology to that of a modern transgressive barrier island chain. The arcuate-shaped sandstone body that extends updip (paleo-landward) into lagoonal shales is interpreted as a series of transgressive storm washover deposits. Spontaneous potential log (SP) signatures from the Galveston Island barrier front, backbarrier, and across the tidal channel[14] are different from those of Bell Creek field, i.e. the SP is decreasing at the top of the Bell Creek barrier section but it is increasing at the top of the Galveston Island barrier. In consideration of examples discussed here, a generalization of properties of shoreline barrier deposits, in their variety of forms, must be based on thorough comparative studies of numerous reservoirs, outcrops, and modern sediments. Only parameters from reservoirs that can be confidently assigned to a specific type of barrier should be used for such a comparison or generalization. For identification of genetic barrier type represented by the Bell Creek reservoirs comparative studies of cores from numerous parts of field (different production units) is required.

Rock, fluid, and reservoir properties from 67 barrier island/strand plain reservoirs were collected and analyzed. These reservoirs were mainly located in Texas,[15] and they were produced under various drive mechanisms such as solution gas, pressure maintenance, and/or water injection. Average reservoir properties of Unit 'A' of Bell Creek (MT) field, a barrier island reservoir, are listed for comparison in Table 7 with other barrier island reservoirs. Bell Creek field, Unit 'A' average properties consistently fell within the range of properties found in other reservoirs of the same environment of deposition.

IV. GEOLOGICAL MODEL

Construction of the geological model required information from the following partial models: 1) depositional model, 2) diagenetic model, 3) structural model, and 4) geochemical (rock and fluid) model. Information resulting from this composite model is the identification of field-scale features such as the reservoir boundaries, laterally extensive shales or cemented zones which act as barriers to fluid flow, erosional features or thinning of the reservoir due to depositional or erosional processes, and major compartments within the reservoir. For each reservoir, the geological features which most affect reservoir quality and production must be identified, ranked, and incorporated into the model.

A. Depositional Model

The depositional model provides the framework of reservoir architecture and serves as the basis for subsequent fluid flow models. After the depositional processes are identified and the sequence of depositional events are reconstructed, the spatial distribution, geometry, and dimensions of facies are determined or predicted.

In the Muddy formation, nine major reservoir sandstone facies were distinguished on the basis of grain size, texture, sedimentary structures, and type and amount of biogenic structures.[16] Information from 26 cores in the northern part of Bell Creek field as well as information from outcrop exposures of the Muddy formation was used to define the facies and reconstruct the depositional and diagenetic history.[16] A 3-D conceptual model was developed for Bell Creek field, which includes the interpreted location of Unit 'A' within the deposystem[16-17] (fig. 28).

The foreshore facies and middle and upper shoreface facies represent deposition by marine processes, and these facies were grouped together into one layer because they contain similar reservoir properties. These facies exhibit the highest quality reservoir rock and comprise the main part of the reservoir. Distinct sedimentological and reservoir properties were noted for the lower shoreface facies. The paralic facies of washover, lagoon, estuarine, tidal channel, and tidal delta exhibit variable reservoir quality characteristics, with the washover facies exhibiting the best reservoir quality. The distribution of overlying valley fill deposits was controlled primarily by alluvial processes, and these deposits consist of both reservoir sandstone and finer grain marginal to non-reservoir sediments. A typical vertical profile of facies with associated petrophysical characteristics is presented in fig. 29.[18] Figure 30 presents the spatial distribution and thicknesses of these facies in the TIP area. In places, the thickness of the foreshore and the upper shoreface facies is reduced by about 30% (10 feet) by overlying valley fill deposit.

The sequence of depositional events in the Muddy formation in Unit 'A' in Bell Creek field was as follows: 1) deposition of a barrier island sandstone; 2) a transgression and an associated shoreface retreat which preserved only back-barrier remnants of the first barrier deposit in wells 27-14, W-16, and C-10 (fig. 30); 3) deposition of a second regressive (progradational) barrier island sandstone which comprises the major reservoir interval in Unit 'A'; 4) continued regression which resulted in local erosion of the second barrier sand by fluvial channel systems; and 5) transgression which filled the upper parts of the paleovalleys with estuarine deposits and subsequently deposited the marine Shell Creek and Mowry shales. The regional sea level curves which support this sequence of depositional events have been presented by Szpakiewicz, et al.[16]

The initial production rate potential in Unit 'A' in Bell Creek field is controlled to a large extent by the distribution of the reservoir marine facies and the valley cuts (fig. 31). On the eastern (landward and updip) side of the barrier, primary production rate potential deteriorates very rapidly away from the barrier axis, where reservoir quality sand pinches out and interfingers with back-barrier, lagoonal deposits. On the western (seaward and downdip) side of Unit 'A', barrier island reservoir sandstones are truncated by low-permeability valley fill deposits (fig. 31), which form hydraulically isolated units and reduce production over the distance of one well spacing, (1,320 feet).

B. Petrographic/Diagenetic Analysis

The major diagenetic phases established for Unit 'A' were determined from thin sections of samples primarily from the TIP area.[16] Table 8 outlines the major diagenetic phases identified within the barrier island facies and their potential effect on porosity and permeability. Leaching occurred very early in the paragenetic sequence and significantly increased the pore space in the reservoir by creating intraparticle secondary porosity and oversize pores.

Virtually all subsequent diagenetic phases, which include siderite cementation, compaction, silica overgrowths, calcite cementation, later leaching, and clay cementation, reduced the transmissivity of the reservoir rock.

The effect of clay content on permeability can be seen in histograms of permeability from the foreshore facies, where two distinct permeability distributions occur: a relatively sharp-peaked population occurring from 0 to 1,500 md and a broader population from 1,500 to 4,800 md (fig. 32). The samples which comprise the higher permeability population are from wells which contain less than 1% clay cement, whereas those samples in the lower permeability population are from wells which contain greater than 1% clay cement. Statistical tests (Kolmogorov-Smirnoff) indicate that these two populations are distinct and illustrate the diagenetic overprint on the primary depositional permeability fabric.

The spatial variations in the distribution of the clay cement (and therefore permeability) within the TIP area tend to occur laterally rather than vertically and are shown in figure 33. Interwell changes in the amount of clay cement tend to correspond with the faults present. Crossplots of distance to the nearest fault versus diagenetic clay (fig. 34) also show a positive correlation (correlation coefficient of 0.812); and indicate that in some cases, faults have provided pathways for diagenetic fluids which resulted in the precipitation of diagenetic clay.

Different clay assemblages are associated with barrier and valley fill deposits and can be shown to greatly affect chemical EOR production. X-ray diffraction analyses of Muddy formation samples indicate that the barrier island sandstones contain a 2:1 ratio of kaolinite to illite. Total clay comprises less than 15% of the volume of barrier sandstones based on point counts, whereas in valley fill sandstones and mudstones, montmorillonite and kaolinite dominate the clay assemblage.[16]

Sensitivity studies using a three-dimensional chemical flood simulator, UTCHEM, modified for heterogeneous distributions of salinity, adsorbtion and cation exchange parameters[19] indicate that the adsorption of surfactant and polymer increases with the amount of montmorillonite in the reservoir rock, (Table 9) and that the calcium released due to ion exchange with sodium ions causes precipitation of the surfactant . Oil recovery after waterflood varied from 38% in clay-free reservoirs to 35% in low-clay reservoirs and down to 15% recovery in clay-abundant areas of the reservoir.

1. Comparison of Rock Composition and Textural Factors

a. Quartz Composition and Grain Size

Although the recognition of general rock types, vertical sequences, and distribution of major depositional facies used for field development are frequently based on log signatures alone, much more diagnostic information can be obtained if cores are also available. Facies characteristics, rock compositions, textural parameters, and diagenetic history can only be calibrated with core or outcrop samples. Of these parameters, grain size and sorting are often valuable indicators of depositional environment because the detrital mineralogy and grain size distribution reflect the imprint of the environment of deposition. The sediments comprising shoreline barriers tend to be quartzose, and each detrital component has its own unique size distribution.[21] Therefore, grain size must be summarized only for the quartz fraction.

Cross plots of quartz size versus quartz content cannot generally be used to discriminate diverse environments of deposition.[22] However, compositional and textural data from samples collected within the same general environment and from within the same basin can be used to segregate subenvironments or facies as long as there is no change in source of the material and the diagenetic histories are identical. For example, bivariate plots of quartz size and quartz content collected from recent sediments along the Galveston barrier complex yield data that discriminate the major subenvironments (lagoon, lower shoreface, middle shoreface, upper shoreface-beach, and dune). A crossplot of quartz size and quartz content (fig. 35) shows a positive correlation with a reasonably high correlation coefficient ($R = 0.71$). Further, data for each facies tend to cluster in the expected order, with dune and upper shoreface-beach being the coarsest and having the greatest quartz content. In contrast, lagoonal and lower shoreface samples are the finest grained and contain the least quartz.

The close interdependence between quartz content and quartz grain size has also been reported[13,22] for samples from the Muddy formation of the Powder River Basin. The data by Davies and Etheridge[22] were not subdivided by facies. They concluded that an environmental identification must be made before any quantitative assessment of the interdependence between grain size and quartz content can be made. They reasoned that the positive relationship between grain size and quartz content reflects that those environments (or facies) characterized by the most winnowing are significantly enriched in quartz.

Berg and Davies[13] agreed that grain size is related closely to energy of depositional environment. Their plot of grain size and quartz content for samples from Bell Creek field showed a positive correlation, and the data were segregated into four distinct groups including beach and upper shoreface, middle shoreface, lagoon (with washover), and lower shoreface and lagoon.

Results of ongoing petrographic studies also indicate a visual relationship between quartz content and grain size; however, the correlation coefficient is not high ($R = 0.51$). In a crossplot of quartz content versus grain size (fig. 36), higher energy barrier facies show a tendency to be coarser grained, whereas lower energy barrier and lagoonal facies tend to be more fine grained. A major difference between our data and that of Berg and Davies[13] is the degree of scatter among the facies. A plot (fig. 36) of NIPER data clearly shows more scatter for individual facies with virtually no clear segregation of data into groups based on facies.

Discrepancies between our data and that of Berg and Davies[13] may result from one or more of the following conditions.

1. Bell Creek data were selected from representative samples of each facies from cored intervals. As such, these data may be expected to illustrate more accurately the natural variability within each facies.

2. There may be some variation due to the spatial distribution of the data. NIPER data (fig. 36) are exclusively from wells within only four sections located within Unit 'A'. Berg and Davies data were selected from wells along the entire length of the field.

3. Great differences in rock composition, grain size, matrix, clay cement, and related petrophysical properties have been documented on a well by well basis in Unit 'A'. Such differences may indicate differing intensities of diagenetic processes. Plotting data from wells with divergent properties on the same chart would naturally lead to greater scatter, even for data from equivalent facies.

b. Permeability and Grain Size

Permeabilities may be expected to vary according to grain size and sorting, therefore, according to depositional environment in recent settings. Berg and Davies[13] found a positive correlation for log permeability versus quartz grain size in their study of the Muddy formation at Bell Creek field but unfortunately did not report a correlation coefficient. In their figure 7, the finest grained samples have the lowest permeabilities and represent lower shoreface and lagoonal environments. Cleaner sandstones were segregated according to permeability so that four permeability-grain size categories were recognized: beach and upper shoreface, middle shoreface, lagoonal-washover, and lower shoreface-lagoonal. Although they found good environmental discrimination, Berg and Davies noted that segregation according to environment is not complete. They concluded that the principal type of variation in the permeability-grain size plot was caused by variations in the amount of matrix and cement.

NIPER data from the barrier island facies at Bell Creek field, Unit 'A' (fig. 37) indicates that there is no statistical correlation between permeability and grain size ($R = 0.27$).

Another way to look at the relationship between permeability and grain size is to consider a single mean value for each facies. This relationship, based on NIPER Bell Creek thin section data, is illustrated in figure 38. Although there is a general increase in grain size and permeability in the higher energy facies, the grain size and permeability are anomalously low for the dune facies. Finer mean detrital grain size from modern dune sediments has been reported at Mustang Island, TX,[22] along the Atlantic Coast,[23] at New South Wales,[24] and at Padre Island, TX.[25] In contrast, coarser dune sediments have been reported at Galveston Island, TX.[26] The finer grained dune sediments recorded for the Muddy formation at Bell Creek (this report) are in line with most recorded modern settings.

The data in figure 38 also illustrate the danger of blindly comparing barrier island settings in terms of their petrophysical, textural, or compositional parameters. In addition to the data from Bell Creek, data from the literature are also presented in figure 38 for two other barrier island reservoirs. Note that the average grain size is distinctly different in Bell Creek and the two other fields and that permeability values do not overlap. Both Lockhart field and Livingston field, reservoirs in the Frio formation, Texas Gulf Coast, are at 10,000 ft, whereas Bell Creek is about 4,500 ft. The effect of increased depth is probably the most likely reason for the significantly lower permeabilities in the deep Gulf Coast reservoirs. Different diagenetic histories for two reservoirs could also produce equally dramatic differences.

c. Composition and Sorting

Plots of mean grain size versus sorting are not adequate indicators of environment[26]; however, because quartz content is environmentally sensitive, plots of quartz content versus sorting should provide environmental discrimination for modern samples. As a test of this relationship for ancient settings, the available data (based on thin section analyses of Bell Creek samples) were plotted. The results (fig. 39) show no trend and no grouping of data by facies. Scattered data are most likely the result of strong diagenetic changes in the Bell Creek samples since the time of deposition. Furthermore, petrographic examination indicates that some wells have been diagenetically altered more than other wells. The effects of diagenesis can mask or destroy trends that were present within sediments at the time of deposition. The data in figure 39 serve as a warning not to make direct comparisons of parameters from barrier island reservoirs, or facies within the same reservoir, that have not been subjected to the same diagenetic history. Comparisons of average values from barrier island/strand plain reservoirs, such as those presented in table 1, may be of some comparative value, but can be misleading if both the genetic type of barrier and the diagenetic histories are not similar. Many of these properties may be related to the basin/age rather than to the depositional environment.

C. Structural Analysis

Recognition of the presence and location of faulting in the TIP area in Bell Creek field resulted from the integration of information from various sources. The first indication of the possibility of faulting was from the inspection of faulted and fractured outcrop exposures. The discrepancy between the actual depth of the Muddy formation in Bell Creek field and calculations of the expected depth based on regional dip, suggested that faults may be present in and around Bell Creek field.[27]

Although not reported in the abundant literature on Bell Creek field and not found in the cores examined, construction of wireline log cross sections indicated the presence of faults with displacements up to 40 feet but generally from 10 to 20 feet.[16] Pressure-pulse and falloff testing as well as the waterfront advancement rate supported the identified fault locations.

The faults identified in Unit 'A' in Bell Creek field are discontinuous, commonly strike 50 degrees northeast and 140 degrees northwest, and are parallel to the NW and NE trending lineaments recognized throughout the Powder River Basin. The similarity of azimuths obtained from regional stress orientations,[28] major lineaments identified from landsat imagery, and seismic interpretation[29] suggests that the structural framework is common for the entire area.

Faulting within the reservoir produced a mosaic of small tectonic blocks (fig. 40).[16] Downthrown tectonic blocks would be expected to produce less oil but high total fluids because of the natural tendency of oil to concentrate in structurally high areas in the reservoir. Based on a comparison of fluid production of well P-14 (structurally low) and well P-11 (structurally high) these expectations are born out.

The effects of structural features on production in Unit 'A' are variable, depending on the stage of production. Studies in the TIP area indicate that the influence of dip and faults on primary production was generally low to negligible; however, greater oil accumulation was found in uplifted tectonic blocks (horsts).[1]

Secondary production was dominantly influenced by structural dip, but not faulting. Wells located updip of the water injection linedrive pattern showed increasingly higher cumulative production eastward where the oil bank moved updip against a stratigraphic pinchout of the reservoir.[1] Tertiary production was moderately to highly affected by faulting where the disrupted continuity of flow units in places, adversely affected sweep and displacement efficiencies.

D. Geochemical Analysis

After two decades of reservoir development, including the implementation of two EOR projects, the origin of formation fluids in the productive horizons in Bell Creek field remains unknown. The enhanced geothermal gradient and a much lower than expected formation water salinity based on a normal hydrogeochemical gradient, strongly indicate a hydraulically dynamic system. However, the variability of chemical and isotopic composition of formation water and oil in the Muddy formation is poorly understood.

Analysis of oil gravity data indicates that in the northern part of Bell Creek field (Units 'A' 'B', 'C', and 'D'), oil gravity varies from 28° to 42° API (fig. 41). There is no obvious relationship between oil gravity and structural dip of the Muddy formation. Except for an isolated area of heavier oil (28° API), 30.5° to 32° API gravity oil exists in the central and central-southern part of Unit 'A', while in the northern part of Unit 'A', as well as in Units 'B', 'C', and 'D'; lighter oil (33°-34° API) predominates. The reason for such a pattern of oil gravity distribution is not clear. There is, however, a possibility that the effects of variable formation temperature, water washing and biodegradation may have influenced the gravity near a network of documented faults.

V. PERMEABILITY LAYER MODEL

The geological model presented above provided the framework for the subsequent, quantitative permeability layer model and the flow unit model.

Permeability layers were based primarily on sedimentological facies divisions and exhibit distinct average reservoir properties such as permeability, porosity, variability of permeability (Dykstra-Parson's coefficient), and the ratio of vertical to horizontal permeability (table 10). This relatively simple reservoir model provides the framework for calculating reservoir volumetrics as well as forecasting field and well performances.

Non-parametric (Kolmogorov-Smirnoff) statistical two-sample tests[30] indicated that three distinct permeability distributions occur in the Muddy formation in the area studied. One group includes the higher-energy deposits; a second group includes the lower energy barrier island deposits of lower shoreface, and the third group includes the lowest energy lagoon and marine valley fill deposits. The permeability groups are presented in figure 42, which presents the permeability means and ranges for the barrier facies in 19 wells from the TIP area.

Figure 43 presents a 3-D permeability layer model of the TIP area. The datum for the fence diagram is the base of the Muddy sandstone and the top of the diagram is the top of the upper sand in the Muddy formation. Layer 1 corresponds to the lower shoreface facies; layer 2 to the foreshore, upper and middle shoreface facies; layer 3 to the lagoonal facies and layer 4 to the valley fill facies. Although tests indicated that the permeabilities of the lagoonal facies and valley fill facies were from the same distribution, they were distinguished on the diagram because of their very different depositional origins and different clay-type contents.

The ratio of vertical permeability to horizontal permeability indicates that layer 2 is essentially isotropic, while layer 4 has the lowest vertical permeability. Dykstra-Parsons coefficients indicate low heterogeneity values for layer 2 and high heterogeneity values for layers 3 and 4, whereas layer 1 exhibits intermediate values.

A. Application of Outcrop Data

Justification of the lateral continuity of the permeability layers came from outcrop permeability data, where similar permeability averages and vertical profiles extend over 2,000 feet and 1.6 miles (fig. 44).

Comparison of subsurface and outcrop permeability cumulative distribution functions from the the outcrop middle shoreface facies and the subsurface foreshore facies and the outcrop and subsurface lower shoreface facies is presented in figure 45. Statistical (Kolmogorov-Smirnoff) tests indicate these permeabilities to be from the same population. The comparison of the middle shoreface to the foreshore permeability is valid, based on the similar geologic and petrophysical characteristics observed in both outcrop and subsurface.

Other similarities in outcrop and subsurface samples include grain size frequency distribution and paragenetic sequence. Grain size distributions calculated by image analysis of thin sections indicate similar distributions for outcrop middle shoreface and subsurface upper and middle shoreface facies (fig. 46). Petrographic studies based on thin sections indicate a similar paragenetic sequence for outcrop and subsurface barrier island facies. A plot of the natural logarithm of permeability vs. porosity shows similar slopes for outcrop and subsurface data, with outcrop porosity slightly (2%) higher.

Major differences between outcrop and subsurface characteristics documented in this study are the spatial distribution of diagenetic cements. In outcrop, a carbonate-cemented zone in the top of the sandstone sequence (foreshore facies) is present which extended laterally for 1000's of feet. The absence of this laterally extensive cement in the reservoir suggests that it may have originated at or near the present surface due to subaerial exposure to meteoric waters. A second difference is the absence of clay-cemented zones in outcrop, which in the reservoir, appear to affect the entire reservoir section and vary over lateral distances of approximately 1,500 feet.

VI. FLOW UNIT MODEL

A flow unit model incorporates all pertinent, detailed geologic and petrophysical information available and provides a detailed reservoir description which retains the complexities of reservoir architecture and variations in reservoir parameters. It is most useful in predicting production performance of secondary and tertiary recovery processes.

A flow unit has been defined by Hearn, et al.[31-32] as a reservoir zone that is continuous laterally and vertically and has similar averages of those rock properties that affect fluid flow, and has similar bedding characteristics. Ebanks[33] similarly defined a flow unit as a "volume of rock subdivided according to geological and petrophysical properties that influence the flow of fluids through it."

Parameters used by previous workers[32, 34-35] to distinguish flow units include permeability, the product of permeability and thickness (kh), porosity, pore-size distribution determined by mercury-injection and air-brine capillary pressure data, kv/kh ratios, oil saturation, sedimentary structures, lithology, color, grain size, and amount of bioturbation.

In Bell Creek field, it was found that the previously constructed permeability layer model based on sedimentologically defined facies provided an acceptable basis for a more detailed flow unit model of the TIP area in Unit 'A'. Permeability, porosity, sedimentologically defined units as well as kv/kh ratios, Dykstra-Parsons coefficients, cation exchange capacities, and capillary pressures indicated different rock properties for the layers distinguished (table 10).

The flow unit model constructed for the TIP area in Unit 'A', Bell Creek field is presented in figure 47. Layers were subdivided laterally on the basis of average permeabilities, and porosities, at each well. The resulting model of the study area is one of a mosaic of flow unit blocks where lateral changes in average permeability values generally correspond to fault locations and diagenetic clay content (fig. 33). Fault locations (shown) and transmissivities (not shown) should also be included in the model.

Variogram analysis of average permeability per well indicates an isotropic, nested pattern consisting of two ranges of correlation lengths: 0.25 and 1.5 to 2.5 miles (fig. 48a). The shorter range, is about the distance between wells and reflects permeability variations within the flow unit.

The longer range is reflected in the permeability layer model, and is on the order of the width of the sandstone body in Unit 'A'. This correlation range is consistent with the outcrop permeability variation observed, where similar permeability averages and vertical profiles extend over at least 1.6 miles. This range is significantly larger than the 2,500-ft upper limit observed by Dubrule and Haldorsen[36] for a fluvial braided-stream environment, which forms smaller-scale sandstone units than barrier island-shoreline environments.

The variogram of initial production rate potential also indicates an isotropic nested pattern with ranges in correlation lengths similar to those of average permeability (fig. 48b). This similarity suggests a dominant control of permeability on initial production.

VII. LOG-DEFINED FACIES UNITS

The lithologic and petrophysical properties within each barrier island facies or a group of facies tend to be fairly distinct. Because of the relative uniformity of depositional processes in subenvironments, some uniformity in the distribution of petrophysical properties in these facies may be expected. The predictability of fluid production from barrier island reservoirs can, therefore, be augmented by an understanding of the spatial distribution of thicknesses and variations of petrophysical and fluid flow properties in each facies. Subsequent to deposition of sandstones, diagenesis or tectonic events may severely affect the distribution of flow properties in the different facies. Nevertheless, the distribution of depositional characteristics is frequently related to reservoir quality.

Two crossplot techniques based on interpretation of log data which can effectively distinguish some of the barrier island and associated nonbarrier island sandstone facies have been described.[37] From examinations of a large number of crossplots, it was concluded that barrier and nonbarrier sandstone deposits at Bell Creek could be grouped into three log facies which have similar petrophysical and fluid flow characteristics. Kolmogorov-Smirnoff (K-S) statistical, two-sample tests conducted on permeability and porosity data also indicate the presence of three distinct permeability distributions for the Muddy sandstone in the study area. The three log facies and the corresponding geological facies they represent may, therefore, be summarized as follows:

a. "high productive facies" consisting of foreshore, shoreface, the upper part of middle shoreface, and washover;

b. "upper sand facies" consisting of paralic facies of estuary, lagoon, or marsh, nonbarrier channel or valleyfill deposits; and

c."lower shoreface/lagoonal facies" consisting of poorer reservoir quality sediments which include a and b.

In this investigation, variations in thickness and geometry of the different facies groups have been studied based on fieldwide log-derived facies maps. The distribution of other important properties critical to the determination of productivity of sandstones; i.e., porosity, permeability, water saturation, etc. in the various facies groups, was also investigated. Because clays have an important effect[1,19] on fluid production at Bell Creek the distribution of total clays within different facies has also been investigated.

A. Distribution of Geometry and Petrophysical Properties in Different Log Facies of the Barrier Island Sandstone at Bell Creek Field

1. Facies Geometry Distribution

Based on porosity, resistivity and the porosity, gamma ray crossplots developed for facies discrimination, two stratigraphic cross sections, XX' and YY', one along the dip and the other along the strike direction of the barrier island deposit, were constructed (see fig. 49 for location). The variation in thickness of the different facies along the strike and the dip directions, the interfingering of facies, and the presence of valley cuts filled with low-permeability sediments, are shown in figures 50 and 51

2. Porosity Distributions

Good estimates of reservoir porosity may be obtained from interpretation of density logs from Bell Creek field. Included on the stratigraphic cross sections are density-log-calculated average porosities over vertical intervals having fairly uniform porosity values (figs. 50 and 51).

3. Distribution of Total Clays

A reasonably good estimate of clay content (VCL) can be determined from interpretations of density and sonic log data from the following relationships:[38]

$$V_{CL} = \frac{\phi_s - \phi_d}{\phi_{ssh} - \phi_{dsh}}$$

where ϕs = porosity from sonic log, corrected for compaction

ϕd = porosity from density log

ϕssh = apparent sonic porosity in shale, corrected for compaction

ϕdsh = apparent density porosity in shale

The average total clay content in each facies was plotted at different well locations along profiles AA' and BB', coincident with the dip and strike stratigraphic cross sections (figs. 52 and 53). The east-west dip profile AA' (fig. 52) shows a sharp increase in clay content in all three facies in the southwestern part of the TIP area which is believed to be due to an increase in diagenetic clays, as indicated by detailed thin-section studies conducted in the area. From the central part, the average total clay content along profile AA' decreases in either direction. In the lagoonal side, in the eastern extremity of the profile AA', there is a 5.4% increase in average clay content in the higher productive (washover) facies. In the NE-SW profile BB' (fig. 53), the effect of diagenetic clays is noticeable in the southwestern part of the TIP area. The clay contents in all the three facies of this profile exhibit much less variation toward the northeast.

4. Distribution of Permeabilities

The lateral distribution of geometric means of air permeability in two barrier island sandstone facies (upper-sand and high-productive facies) in wells along the dip and strike directions of the deposit are shown in figures 54 and 55. Sufficient data were not available for calculation of geometric means of permeability for the lower shoreface/lagoonal facies. The sharp reduction in permeability of high productive facies in the diagenetically effected southwestern part of the TIP area (around wells W-16, W-14, and C-4) is clearly indicated in the two permeability profiles. The low permeability values in the upper sand facies, around well W-7 (fig. 55), are due to low porosity and clayey deposits in swamp and/or estuary. This trend is also noticed in the strike profile near well 23-11.

An estimate of the degree of permeability stratification in the different facies may be determined from the distribution of normalized standard deviations of air permeability values in different wells located along the dip and the strike profiles (figs. 56 and 57). In homogeneous sandstones with little or no stratification, normalized standard deviations will assume low values. As the permeability stratification increases, due either to depositional or diagenetic causes, normalized standard deviations will also increase. Figures 56 and 57 indicate a higher degree of permeability stratification in the high-permeability facies toward the lagoon, toward the basin, and also in diagenetically affected regions. There is a greater degree of intercollations between high- and low-permeability strata in the upper sand facies, and in certain parts (around wells W-7 and 23-11) the degree of stratification is quite extreme. These phenomena are believed to be the result of deposition of clay rich, low permeability, swamp or estuarian sediments along a north-south linear trend.

5. Distribution of Water Saturation

By application of Simandoux and Fertl's shaley sand models,[37-38] initial water saturations were calculated for each foot of pay thickness in wells 5-8, 23-3, 27-12, 27-1, 26-4, 14-16, and 6-14. The average initial water saturation in the high productive facies in these wells ranged between 15 and 40%. In the upper sand (mainly valley or channel fill deposits), the average calculated water saturation ranged between 25 and 60%, and water saturation was highest in the lower shoreface facies (around 30 to 75 %).

VIII. MODEL CONFIRMATION AND PERFORMANCE PREDICTION

To determine whether the quantified geological model developed was an accurate representation of the reservoir in the TIP area, the spatial distribution of flow units, log-defined units, primary reserves, and cumulative EOR production were compared. The model was also tested by comparing the spatial distributions of residual oil saturation (ROS) and front advancement rate from waterflood simulations of the model with ROS measured from cores taken after waterflooding and the waterfront advancement determined from production data.

Based on decline-curve analysis of primary production data, primary reserves were calculated for the wells indicated on the stratigraphic sections (figs. 50 and 51). A plot of primary reserves against storage capacity (product of porosity and thickness) was made from the crossplot data for each well. Figure 58 indicates a strong correlation between primary reserves and storage capacity (correlation coefficient, $R = 0.91$). This result is an indirect confirmation of the effectiveness of the crossplot technique in subdividing the producing Muddy sandstones into different units.

Comparison of cumulative EOR production and the permeability distribution shows similar patterns of distribution and indicates that the model is a reasonable representation of the reservoir (fig. 59). The similarity illustrates that EOR production is largely controlled by variations in permeability and diagenetic clays. Faulting may have affected the production in well P-12, where production is better than expected based on the permeability and clay content. The lower than expected production in well P-3 may be also attributed to reduced sweep efficiency by partially sealed faults.

Comparison of the spatial distribution of residual oil saturation obtained from simulation (fig. 60a) corresponds fairly well to that of core saturations measured after 10 years of waterflooding (fig. 60b).[1] In general, greater amounts of oil remained in the southwest part of the TIP where lower permeabilities and higher diagenetic clay contents prevented good sweep efficiencies. The high ROS values in the southwest part of the pilot may be a result of the presence of nearby faults. Because faults were not included in the simulation model, this area of high ROS is not present in the simulation prediction. Lower residual oil saturations occur in the central portion of the TIP area where permeabilities are higher and clay contents lower.

Comparison of the field and simulated waterfront advancements indicate similar front movement (fig. 61). The similar shapes of the fronts suggests that a one layer model adequately describes the waterflooding process. The main control mechanism for the front advancement is the slope of the reservoir, the location of injectors and major areal permeability variations.

IX. CORRELATIONS AND TRENDS OF PETROGRAPHIC, PETROPHYSICAL, AND PRODUCTION DATA AT BELL CREEK FIELD

Petrographic, petrophysical, and production data from Bell Creek (MT) field have been correlated and general trends in the data identified. This information will provide the basis for future comparative studies of barrier island types from different geological times and geographical locations with their ancient counterparts. This section is subdivided into two parts: a correlation of reservoir parameters indicated for the barrier island part of the reservoir at Unit 'A', Bell Creek field and a discussion of the recognized trends along and across the field.

A. Correlation of Critical Parameters

Available petrophysical, petrographic, and production parameters have been correlated for data from the barrier island reservoir interval at Unit 'A', Bell Creek field (table 11). Although much of the data is from the four-section area encompassing the Tertiary Incentive Project (TIP) we feel that the correlations are generally applicable to the barrier island reservoir section at Bell Creek.

The results of correlations summarized in table 11 are presented as correlation coefficients (R values) between given sets of data. Correlation coefficients have been corrected in the sense that wild points in the cross plots of parameters have been eliminated from no more than one well for each correlation. For example, in the cross plot of diagenetic clay versus distance to the nearest fault, the data lie near a statistically determined regression line except for a single point. That point was ignored when the high coefficient ($R = 0.812$) for that correlation was determined.

Nineteen correlation coefficients from this data set are high (greater than 0.70). The most significant of these correlations includes relationships among the following:

1. Average total clay of the barrier island facies in a given well versus distance to the nearest fault ($R = 0.850$). This relationship may indicate a structural control on diagenesis.

2. Average total clay of the barrier island facies in a given well versus average diagenetic clay (R = 0.911). This relationship reflects that, within the cleaner barrier island facies, total clay is a function of diagenesis, rather than depositional matrix.

3. Foreshore permeability versus maximum diagenetic clay (R = 0.874). This relationship basically reflects that the foreshore facies is very clean prior to diagenesis.

4. Foreshore permeability versus initial production rate (R = 0.869). This relationship indicates that initial producton rate is related to permeability through depositional facies. Unfortunately, not all facies are as directly related to initial production as is the foreshore; e.g., shoreface permeability versus initial production has only R = 0.509.

Major generic groupings of geologically defined facies (such as valley fill, or the barrier island group consisting of foreshore, upper, and middle shoreface) provide the basis for a permeability layer model of the Bell Creek reservoir (table 10). Each of the layers has distinctive characteristics such as average permeability, variability of permeability (Dykstra-Parson's coefficient), and the ratio of vertical to horizontal permeability. This rather generalized permeability layer model is useful for forecasting field and well performance.

Dykstra-Parsons coefficients (VDP) were calculated for individual facies in wells in the TIP area in Unit 'A' of Bell Creek field. The objective was to identify vertical variations in VDP and thereby predict variations in oil trapping. An increasing trend in the VDP occurs downward through the sequence of the foreshore, uppershoreface, and lower shoreface facies. Although the mean permeability is comparable for both the foreshore and upper foreshore facies, increased variability of values is indicated for the upper shoreface facies, which may lead to poorer sweep efficiency for that facies. The next step will be to compare the VDP to the oil saturation after waterflooding to determine how accurately the VDP can predict the location of trapped oil.

Vertical profiles of permeability and oil saturation were compared with the vertical sequence of facies to define units with similar fluid flow characteristics (flow units) and to determine fluid flow characteristics associated with each facies. A preliminary comparison of Dykstra-Parsons coefficients (VDP) and initial production indicated a good correlation between the two (R = 0.90), as shown in figure 62. Problems encountered in calculating VDP were due to the presence of several populations of permeability. In some cases, multiple populations produced curved lines on probability plots and prevented accurate graphical solutions. Among the three parameters, the Dykstra-Parsons coefficients, the product of geometrically averaged permeabilities and the net pay (K_GH) and the initial production rate,

K_GH, correlated (R = 0.75) the best with cumulative primary production. This may mean that initial production is strongly dependent on permeability stratification, whereas cumulative primary production is more related to K_GH. Other correlations among initial production rate, highest primary production rate, cumulative primary production primary reserve, transmissivity, and residual oil saturation were examined, and the results are presented in table 12. A strong correlation (R = 0.91) was also found between primary reserves and storage capacity (øH) calculated from log analysis.

B. Comparison of Infill and EOR Performance Between Pilot and TIP Projects, Unit 'A', Bell Creek (MT) Field

In Unit 'A', Bell Creek field 53% of the original oil in place was recovered during primary and waterflood stages of production (table 13). Because secondary production accounted for twice as much recovery as primary production, the linedrive waterflooding pattern was a very efficient strategy. Furthermore, infill drilling on a 20-acre spacing after completion of linedrive waterflood showed relatively poor performance in both the TIP and Pilot areas. We think this is attributed to the lack of effective compartmentalization within Unit 'A'. Tertiary production accounted for recovery of 11-15% of the original oil in place, or about the same amount as that produced by primary production. The micellar-polymer project located in the central part of Unit 'A' (the TIP area) was more successful than the northern Pilot project because of the higher quality of reservoir rock in the TIP area.

X. MODEL ELEMENTS AND GUIDELINES FOR FIELD DEVELOPMENT

The heterogeneities important for each stage of production in Unit 'A', were outlined by Honarpour et al.[1] The relationships between production performance and the various types of heterogeneities found in Bell Creek field may be used as a guide for elements to be included in reservoir models for other barrier island reservoirs.

In Unit 'A', it was found that primary production was dominantly influenced by large-scale depositional heterogeneities and moderately influenced by medium-scale diagenetic heterogeneities. The influence of structural features such as regional dip and faulting was low to negligible. Based on the Bell Creek field example, a sedimentological model including some diagenetic information adequately describes the reservoir for prediction of primary production performance.

Secondary production was dominantly influenced by regional dip, moderately to dominantly influenced by medium-scale diagenetic features and moderately influenced by large to medium-scale depositional features. A simple permeability layer model, as presented in this paper, which includes the dip of the reservoir and additional diagenetic information is necessary to design the waterflood pattern and predict waterflood performance.

Tertiary production was dominantly influenced by depositional features; locally strongly influenced by diagenetic heterogeneities; and moderately to locally strongly by faults. The comparisons of permeability and diagenetic clay content to EOR production presented in this paper indicate that a detailed model of these features accompanied by detailed diagenetic and structural descriptions is necessary to adequately predict EOR production performance and sweep efficiency.

The following guidelines for field development result from NIPER studies of Unit 'A', Bell Creek field and may be useful for developing other barrier-island reservoirs.

1. The best reservoir properties trend along the strike and in the central portions of the sandbody. Well spacings of 40 acres and greater may be applied along the strike of barrier islands, while spacings of 40 acres are adequate perpendicular to the strike for both primary and secondary recovery processes.

The scale of permeability variations from outcrop permeability data support these spacings and indicate that outcrop permeability data may be useful early in field development to determine the scale of permeability variations.

2. A linedrive waterflooding pattern, with injectors placed down-dip and along the strike of the barrier island sand body and moving the line of injectors updip is an effective recovery strategy. The saturation of the gas cap and invasion by the oil bank can be prevented by maintaining a high gas cap pressure.

3. Reservoir characterization for primary and secondary recovery needs to include the definition of external boundaries, lateral variations in reservoir thickness, and the dip and strike of reservoir. Only major divisions of facies groups with high permeability and kv/kh ratio contrasts are necessary. The importance of permeability contrasts less than twofold are negligible.

4. Important factors for reservoir characterization for EOR (chemical flooding) are directional permeability (anisotropy), spatial distribution of clay amount and type, and fault locations. A 20-acre spacing and five-spot pattern was adequate for micellar-polymer chemical EOR in the TIP pilot area.

5. Infill drilling on a 20-acre spacing after completion of linedrive waterflooding shows poor performance, whereas micellar-polymer flooding is much more successful at Unit 'A', Bell Creek field.

XI. SUMMARY AND CONCLUSIONS

Based on these studies and a survey of the literature the following conclusions have been made:

1. Shoreline barriers include spits, shoals, barrier peninsulas, barrier islands, and barrier bars. Although geologically similar, barrier island settings must be distinguished in order to compare of analogous reservoir deposits.

2. To make meaningful comparisons of barrier islands, three types of information must be known: (1) the direction of growth or migration (aggradational, progradational, or transgressive); (2) whether the shoreline is wave or tide-dominated; and (3) the tidal range at the site of deposition (microtidal, mesotidal, or macrotidal). Only by knowing which depositional processes created specific types of barriers can similarities and differences among and between them be compared and the scale and configuration of major reservoir sandbodies unpredicted.

3. The geometry of shoreline barriers is a function of their generic type. For example, typical modern coastal barrier sandbodies are 10 to 25 miles long, 2 to 4 miles wide, and 30 to 50 ft thick. Modern transgressive barrier islands, however, are 20 to 47 miles long, 1 to 1.5 miles wide, and only 7 to 16 ft thick. Inner shelf shoals, in contrast, are generally 20 to 22 miles long, 1 to 6 miles wide, and 7 to 23 ft thick.

4. Composition rather than grain size may provide first-order environmental discriminators for facies in a barrier island deposystem. At the time of deposition, each subenvironment leaves a strong imprint on the detrital mineralogy.

5. Composition, texture, and related petrophysical parameters inherent in barrier island subenvironments may be strongly altered through geological time by diagenetic processes. These changes can mask or completely destroy trends present at the time of deposition, even between closely spaced wells. Therefore, for valid comparisons between various generic types of barrier island reservoirs, it is necessary to account for the diagenetic history, to understand possible differences in original detrital mineralogy, to understand the subsidence history of the reservoir and to know the final depth of burial.

6. A sequence of model development is demonstrated which started with the geological model and is followed by a permeability layer model and a flow unit model. New additional information must be

integrated with the previously derived models to enhance the value of the continually changing reservoir model.

7. The geologic model is composed of four major partial models: a) a depositional model which identifies depositional environment and processes of deposition and erosion and facies and contains information on reservoir geometry and dimensions and internal architecture of facies; b) a diagenetic model, which outlines the paragenetic sequence, documents the stages of reservoir quality enhancement and degradation, and describes the presence of additional heterogeneities developed subsequent to depositional heterogeneities; c) a structural model which identifies the locations, geometries, and dimensions of faults, fractures, folds, and reservoir dip; and d) the geochemical model which contains information on the origin and type of formation fluids, rock-fluid, and fluid-fluid interactions.

8. The permeability layer model quantifies the sedimentological model by incorporating numerical values of petrophysical properties, which makes it useful for engineering calculations of reservoir volumetrics. In the area studied in Bell Creek field, genetically related groups of facies correspond well with distinct permeability populations.

9. A one-layer simulation model which contains lateral permeability variations, adequately predicted front movement and ROS distribution in the TIP area because there is little vertical variability within the major part of the reservoir. The greatest variability of permeability on the interwell scale occurred laterally on a scale of 0.25 miles, and was controlled by structural and diagenetic processes which, in places, significantly modified the depositionally related permeability pattern. The unmodified depositional pattern and related production characteristics can extend laterally on the order of a few miles.

10. The flow unit model incorporates all available information, and provides input for numerical simulation. The model developed for the TIP area in Bell Creek field illustrated how information from a number of different sources and different scales is combined to form a detailed picture of the reservoir fluid flow properties.

11. At Bell Creek field along the dip direction, the high-productive sandstones have maximum development in the central part and taper off toward the open sea and lagoonal directions. Thickness distributions in the upper sand are highly variable because of deep valley incisions in several areas. In the lower shoreface, the thickness variation is very small. In the strike directions, the thickness gradually reduces in all three facies groups, both in open sea directions and the lagoonal side.

12. Outcrop data is useful for identification of facies and permeability trends on inter-well scales, as well as important features such as faults and valley fill deposits. Outcrop permeability data compare well

with the subsurface data in the TIP area in characteristics such as permeability contrasts, lateral scale of variability grain size distribution, permeability/porosity relationships and paragenetic sequence. This agreement of properties suggests that outcrop permeability measurements may be used to approximate variations in the subsurface.

13. Two ranges of correlation length from variogram analysis appear to represent features resulting from diagenetic processes (shorter range) and depositional processes of barrier island formation and subsequent erosion by fluvial processes (longer range).

14. The model developed is confirmed by good agreement with cumulative EOR production data and comparison of the ROS distribution and waterfront advancement rate from simulation results and reservoir data.

15. The high correlation coefficient between ultimate primary recovery determined from decline curve analysis and storage capacity determined from analysis of Bell Creek crossplot data indirectly confirms the usefulness of subdividing barrier island sandstones into three major groups with distinct porosities for finding the storage capacity of various pay thickness. The initial production rate map agrees with the distribution of sandstone geometry, petrophysical properties, and clay content in different parts of the sandbody, as determined from this study. Compared to the second chemical flood project in the TIP area, the postwaterflood oil saturation in the first pilot was comparatively much lower, the amount of clays in the sandstone pore spaces was much higher, and the degree of intercollations between high- and low-permeability strata was much higher in the area of the first pilot. These factors adversely affected the chemical flood in the first pilot and account for the low oil recovery from the first pilot.

16. Infill drilling after completion of linedrive waterflood did not recover a significant amount of oil compared to the amount produced by micellar-polymer (EOR) technique.

17. The distributions of petrophysical properties (permeabilities, porosities, initial and postwaterflood oil saturations) in the high-productive facies at Bell Creek field, except in diagenetically affected regions, have the highest values along a zone in the central part of the deposit and decrease in all directions from central high areas. The decrease in properties is more gradual in the strike direction compared to that in the dip direction of the deposit.

18. In addition to grain size, both depositional and diagenetic clays had a dominant control on the distribution of porosity, permeability, and initial and postwaterflood oil saturations in the three log-defined facies groups at Bell Creek field. Sharp reductions in porosity and permeability due to diagenetic clays are most noticeable in the southwestern part of the TIP area.

19. Because of the varying effects of cementation, certain zones of the high-productive facies (like a part of washover facies in well 6-14) may be tight, and because of textural and diagenetic differences, part of lower shoreface/lagoonal deposits (like the storm deposit sequence in well 25-12) may have appreciable porosity and permeability.

20. Varying types and amounts of clay show significant effects on incremental oil recovery from micellar-polymer flooding as predicted by chemical simulation. For example, an increase in clay from 0 to 15% could reduce oil recovery from 35 to 15%.

VIII. ACKNOWLEDGMENTS

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TABLE 7. - Comparison of properties of 67 U.S. barrier island/strand plain reservoirs with those from Unit 'A' Bell Creek field

Reservoir Parameters	Texas Reservoirs Minimum	Texas Reservoirs Maximum	Texas Reservoirs Mean	Unit 'A' Bell Creek field, MT.
Depth, ft	1,200	10,000	5,051	4,500
Oil column thickness, ft	10	300	75	210
Absolute permeability, md	164	4,500	1,006	2,250
Porosity, %	21.5	38	29.7	28.5
Initial water saturation, %	13	55	31	26
Oil gravity, •API	20	49	31	32.5
Initial GOR, scf/stb	40	6,000	613	200
Initial pressure, psi	575	4,658	2,184	1,204
Reservoir temperature, °F	100	236	154	110
Residual oil saturation, %	9	50	25.8	35
Original oil-in-place, MM STB	18	549	84.6	127
Recovery factor, %	23	73	49	54

TABLE 8. Major Diagenetic phases identified within the Muddy formation Barrier Island Sandstone Facies. Phases are in Chronological Order From Earliest (top) to Latest (bottom) (after Szpakiewicz et al., 1989).

Diagenetic phase	Suggested cause	Effect
Dominant leaching creates secondary porosity, oversize pores, effects chert, feldspars, sed. rock fragments; early kaolinization	Meteoric water lens	Major ϕ increase
Siderite cement	Mixing of waters at low Eh	Insignificant ϕ decrease
Compaction increases rock heterogeneity; disjoints pore system; creates silt size detritus and pseudomatrix	Overburden pressure	Major k decrease
Silica overgrowths increase grain eccentricity, grain contact; reduce pore throats	Solution- reprecipitation	Minor ϕ decrease Minor k decrease
Calcite cement usually fills all porosity, stops compaction oversaturation	Deoxygenation, pH and/or temperature changes causing	Major ϕ decrease Major k decrease
Later leaching corrodes grains and prior cements	Reestablished meteoric water lens	Major or Minor ϕ increase Major k increase
Clay cement fills or lines pores blocks throats creates microporosity	changing subsurface water chemistry; new diagenetic fluids along faults	Minor ϕ decrease Major k decrease
Hydrocarbon migration forces	Hydrodynamic diagenesis	Retards or stops

TABLE 9. - Simulation Results of Micellar-Polymer Flooding with Various Clay Types and Quantities

Simulation run	Clay Content Layer 1	Layer 2	Layer 3	Oil recovery, fraction	Absorption Surfactant ml/mL PV	Polymer wt % PV
1	0	0	0	0.376	0	0
2	[1]1% M	[2]0.5% K	0.5% K+ 0.1% M	0.305	0.0022	0.0051
3	5% M	2.5% K	2.5% K+ 0.5% M	0.205	0.0049	0.0155
4	10% M	5% K	5% K+ 1% M	0.168	0.0057	0.0236
5	15% M	7.5% K	7.5% K+ 1.5% M	0.149	0.0059	0.0294

[1]M = Montmorillonite
[2]K = Kaolinite

TABLE 10. - Permeability Layer Model Characteristics

Layer	Facies	Grain size (microns)	Number samples[1]	Permeability, md			Porosity, %		kv/kh	Dykstra-Parksons coefficient	Cation-exchange capacity[1]
				Arithmetic Average	Geometric Average	Range	mean	range			meq/100g
4	Valley fill	100-200	21	193	42	0.6-1320	23	15-33	0.5 (N=16)[3]	0.90	3 (N=4)[3]
3	Paralic facies	75-125	13	256	82	1.3-746	23	14-30	0.87 (N=4)	0.93	[4]7/24 (N=6)
2	Foreshore, upper and middle shoreface	100-200	233	1662	859	0.01-7400	27	11-34	1 (N=26)	0.59	0.8 (N=7)
1	Lower shoreface	100-150	21	662	276	13-2694	23	9-30	no data	0.78	0.8 (N=1)

[1]for permeability and porosity from conventional core anlaysis
[2]from 3 wells - P-1, W-7, W-16
[3]N = number of samples
[4]from estuarine facies/lagoon facies

TABLE 11. - Correlation coefficients for petrophysical, petrographic, and production data from Unit 'A', Bell Creek (MT) field. Symbol* indicates that the value has been increased by omitting a well

	Ft. nearest fault	Ave. diag. clay	Max. diag. clay	Ave. total clay	Vdp (foreshore)	Vdp (formation)	Initial production	1980 ROS	Gross barrier sand	Shoreface k	Shoreface thickness	Foreshore k	Foreshore thickness	Shoreface kh
Ave. diagenetic clay	.434	-	-	-	-	-	-	-	-	-	-	-	-	-
Max. diagenetic clay	.812*	.896*	-	-	-	-	-	-	-	-	-	-	-	-
Ave. total clay	.850*	.911	.847*	-	-	-	-	-	-	-	-	-	-	-
Vdp (foreshore)	.662	.581	.378	.498	-	-	-	-	-	-	-	-	-	-
Vdp (formation)	.582	.452	.061	.457	.686	-	-	-	-	-	-	-	-	-
Initial production	.715*	.632*	.015	.712*	.371	.772*	-	-	-	-	-	-	-	-
1980 ROS	.392	.595	.382	.695*	.462	.612	.531	-	-	-	-	-	-	-
Gross barrier sand	.341	.393	.497	.159	.749	.087	.303	.082	-	-	-	-	-	-
Shoreface perm	.645	.531	.798*	.402	.329	.306	.509	.430	.136	-	-	-	-	-
Shoreface thickness	.675	.386	.218	.650	.224	.435	.563	.676	.325	.230	-	-	-	-
Foreshore perm	.615	.818*	.874*	.790*	.833*	.586	.869*	.449	.347	.559	.168	-	-	-
Foreshore thickness	.461	.108	.072	.107	.165	.265	.479	.393	.393	.358	.409	.525	-	-
Shoreface kh	.452	.719*	.314	.294	.351	.022	.179	.013	.404	.419	.769	.074	.348	-
Foreshore kh	.555	.635	.580	.635	.570	.494	.822*	.400	.313	.450	.021	.969	.687	.469

TABLE 12. - Calculated correlation coefficient, R, for different production parameters in the four central sections of Unit 'A'

	Initial production rate, STB/d	Highest production rate, STB/d	Cumulative primary production, STB	Primary reserve, STB	Arithmetically averaged permeability, md	Dykstra-Parsons coefficient	Residual oil saturation, %
Initial production rate, STB/d	–	0.30	0.45	0.35	0.61	-0.90	-0.43
Highest production rate, STB/d	0.30	–	0.71	0.43	0.20	-0.38	-0.40
Cumulative primary production, STB	0.45	0.71	–	0.84	0.71	-0.66	-0.52
Primary reserve, STB	0.35	0.33	0.84	–	0.55	-0.36	-0.43
Geometrically averaged permeability, md	0.65	0.36	0.70	0.38	0.83	0.74	-0.49
Residual oil saturation, %	-0.43	-0.40	-0.52	-0.43	-0.42	-0.57	–

TABLE 13. - Primary, secondary, and micellar-polymer production performance of TIP and Pilot projects Unit 'A', of Bell Creek (MT) field

Projects	Primary production	Primary reserve	Line-Drive secondary production	Infill/pattern waterflooding reserve	Tertiary production	Ultimate Average ROS
Production from TIP area, bbl	2,655,000	3,700,000	6,990,000	112,600	1,247,500	
Percent of OOIP	17.3	24.1	36.7	1.3	14.8	24
Production per well, bbl	177,000	247,000	466,000	5,600	62,400	
Production from Pilot area, bbl				29,000	164,000	
Percent of OOIP				2	11	

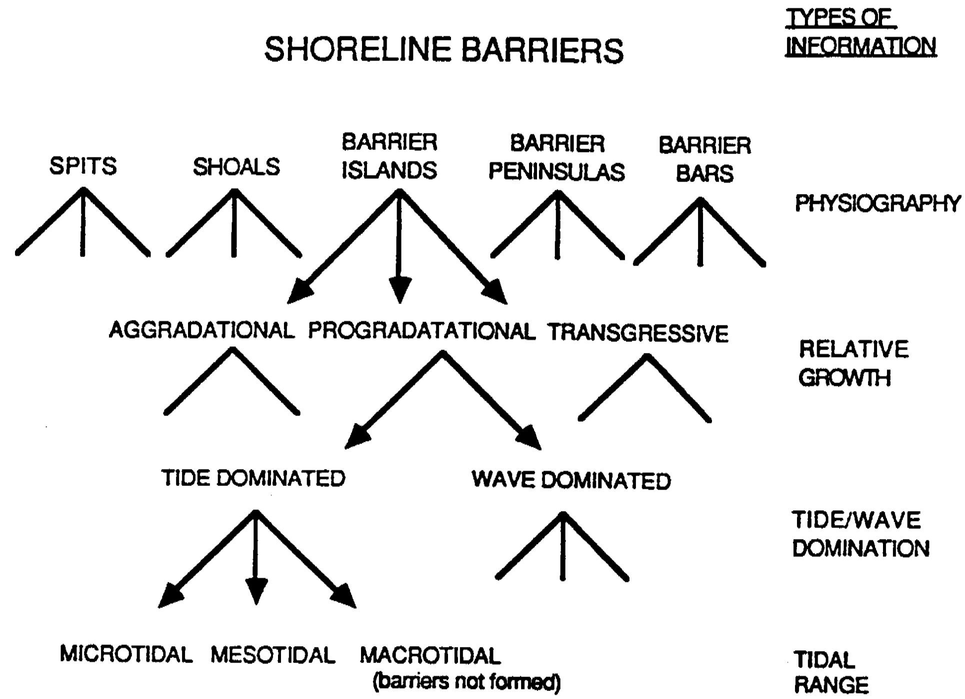

FIGURE 24. - Five major types of shoreline barriers may reveal different characteristics if formed in aggradation, progradational, or transgressive environment or if formed along tide or wave dominated coasts. Tidal range is another important factor responsible for shaping geometry, volume and facies distribution of shoreline barriers.

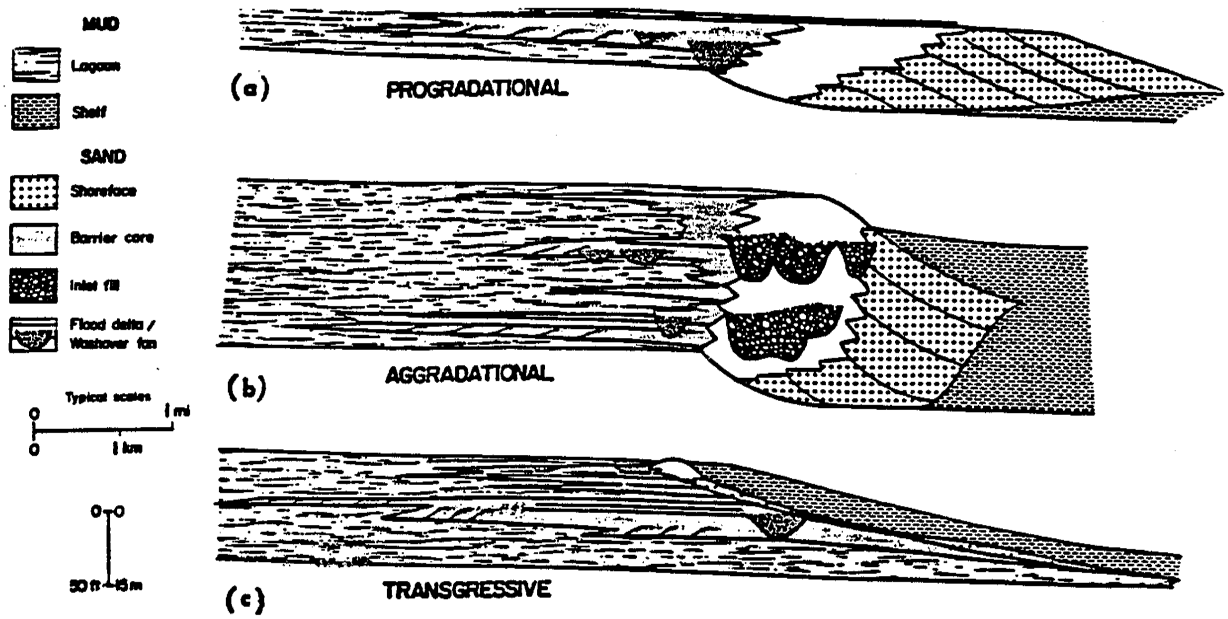

FIGURE 25. - Stratigraphy of (a) progradational, (b) aggradational, and (c) transgressive barrier island sand bodies (After Galloway, 1986).[11]

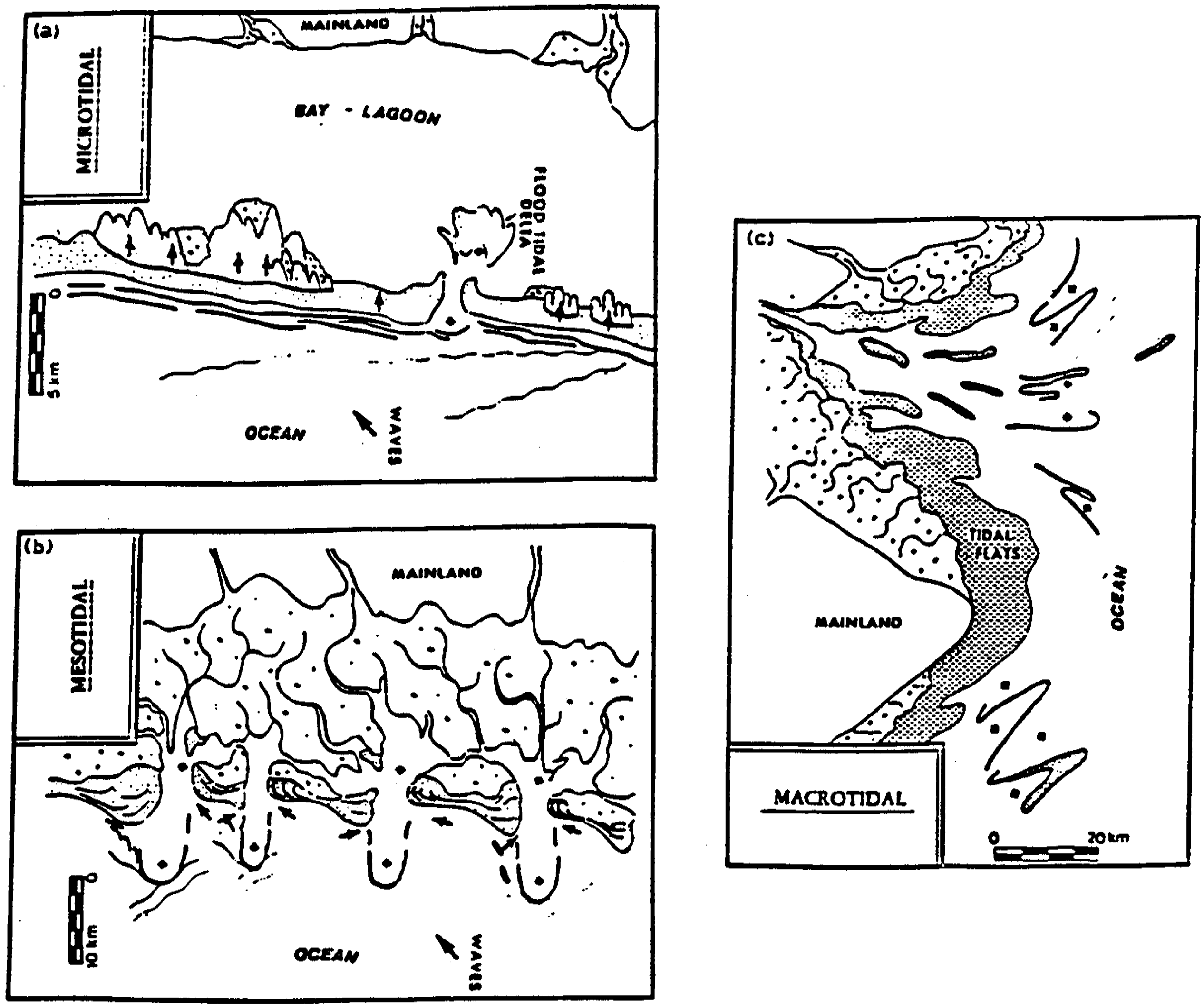

FIGURE 26. - Diagrams of Hayes' coastal morphology types. (a) Microtidal, showing long narrow barriers with numerous washovers and few inlets; (b) mesotidal, showing short, wide barriers with numerous inlets; and (c) macrotidal, on which barriers are absent.[7,11]

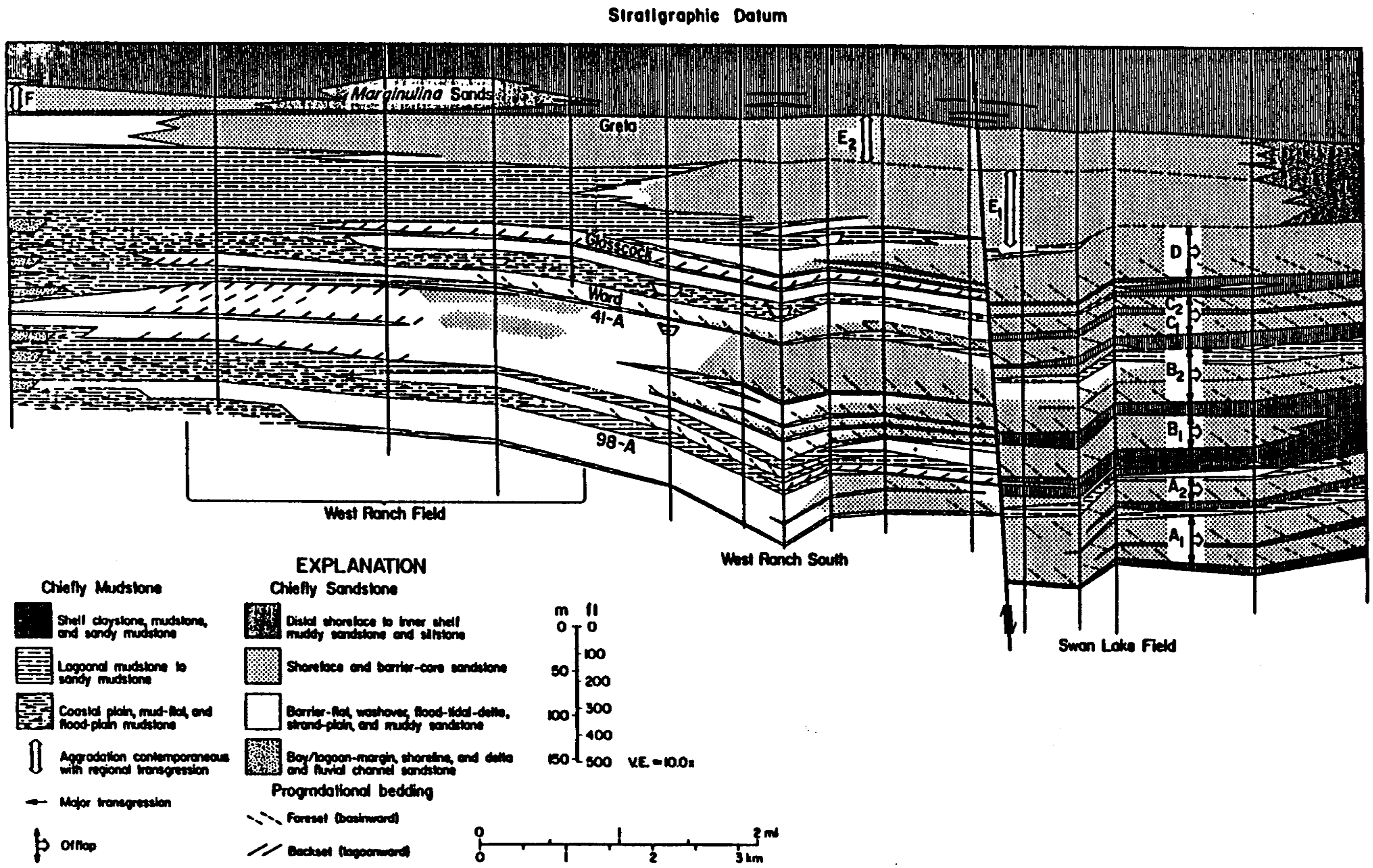

FIGURE 27. - Dip-oriented regional cross section through west Ranch field. West Ranch field lies updip of sand-rich axis of the Greta/Carancahua barrier/strandplain system. Stratigraphic relationships indicate six cycles of progradation or aggradation (labeled A through F) separated by transgressive marine shales. Main producing reservoirs in West Ranch field are labeled (After Galloway, 1986).[11] For genetic classification of Greta, Glasscock, Ward, 41-A, and 98-a reservoirs refer to text.

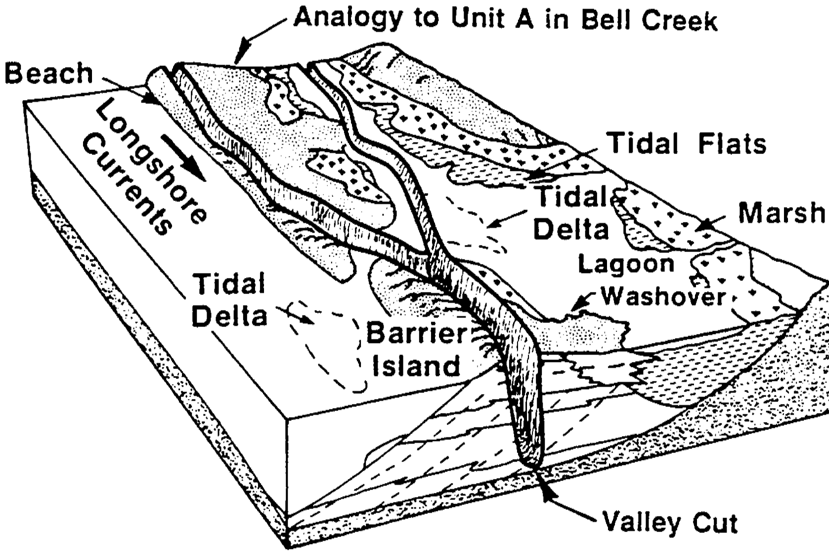

FIGURE 28. - Conceptual model for the barrier island deposystem of the Muddy formation and the location of Unit 'A', Bell Creek field within the deposystem. Note the deep erosional valley cuts which represent those found in Bell Creek field which separate the production units A, B, C, D, and E.

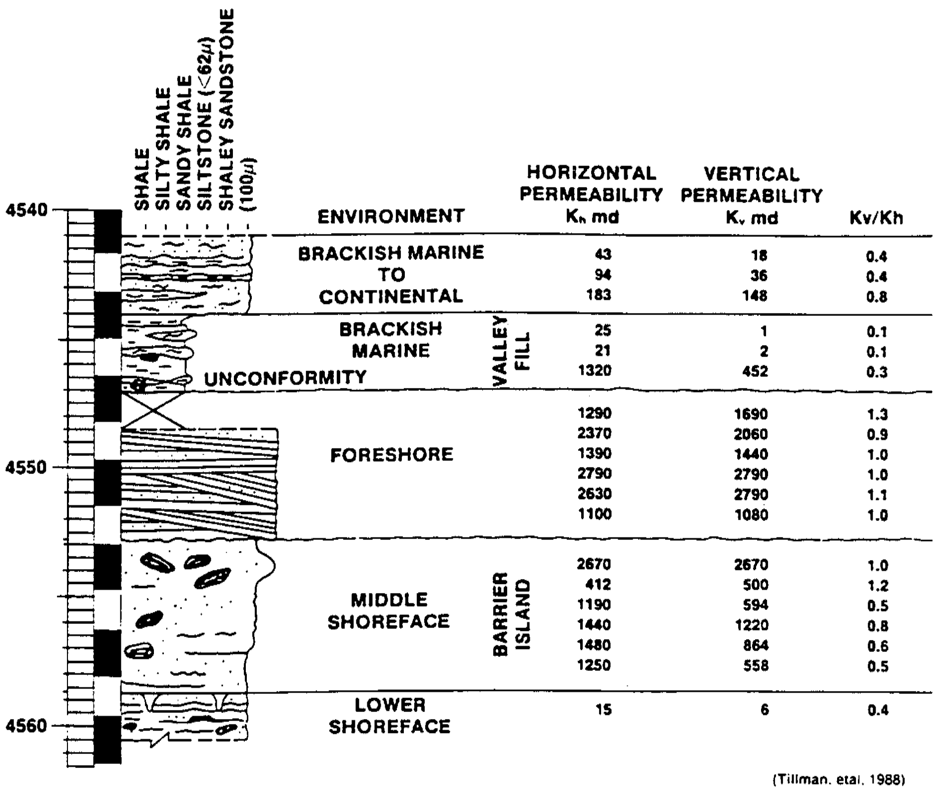

FIGURE 29. - Vertical sequence of facies in well 27-7, which include regressive barrier island deposits and overlying valley fill deposits. Note petrophysical properties associated with each facies.

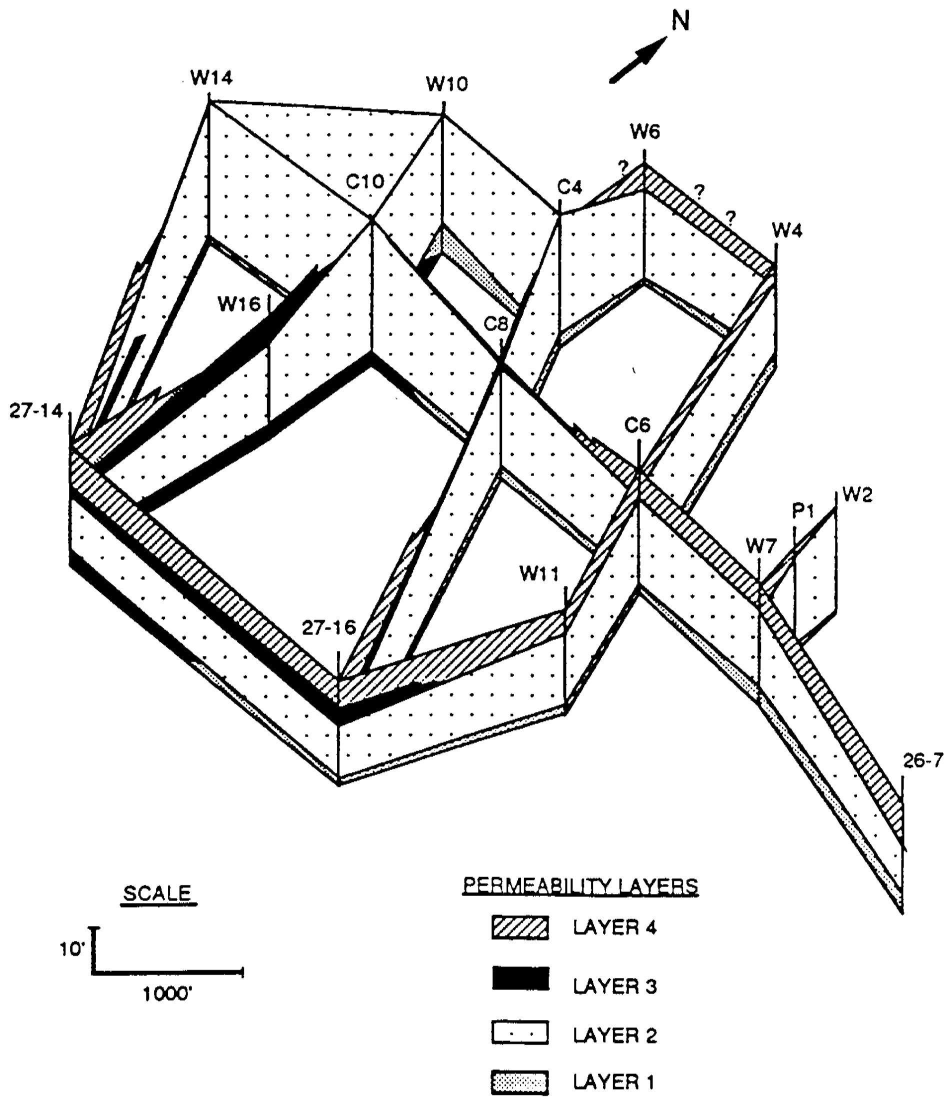

FIGURE 30. - A 3-D diagram showing the spatial distribution and thickness of facies in the TIP area (See fig. 49 for well locations). Datum is base of the lower Muddy sand, and top is top of the Muddy sand. Note that the paralic (back-barrier) facies occur in two horizons, with the bottom horizon representing remnants of the first barrier.

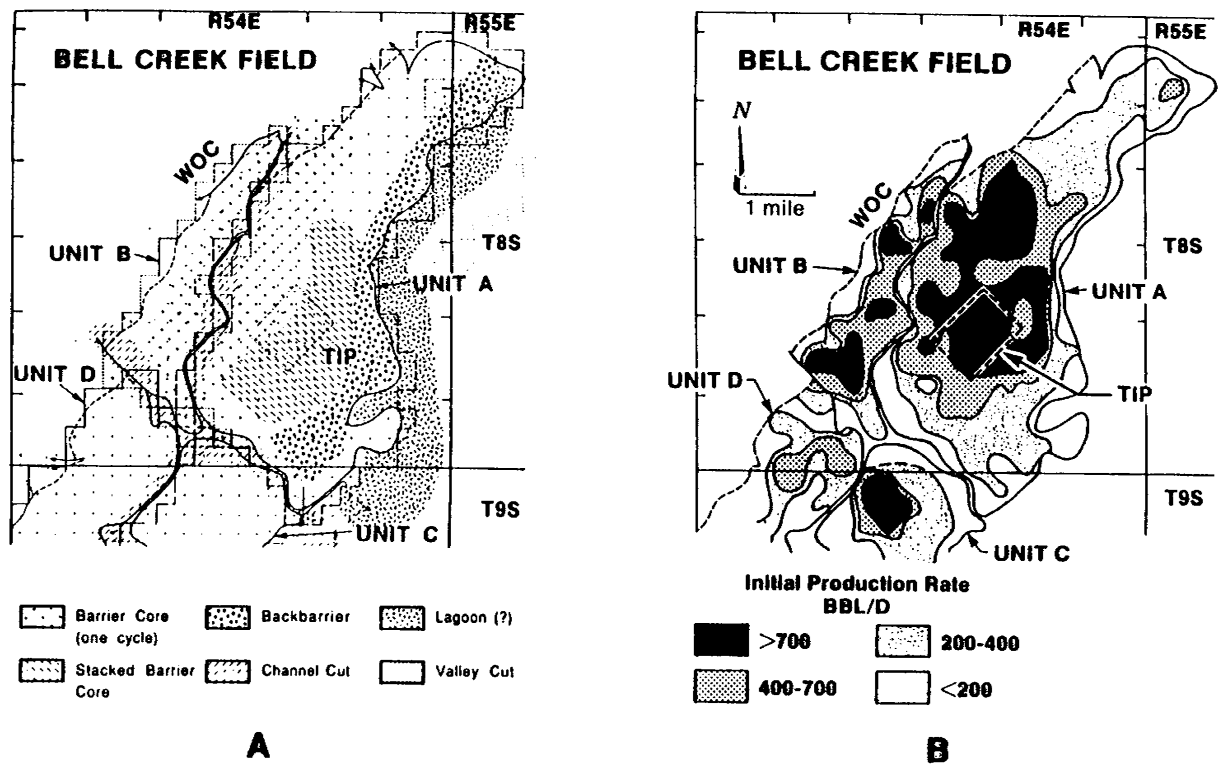

FIGURE 31. - Comparison of distribution of facies (a) and initial production rate potential (b).

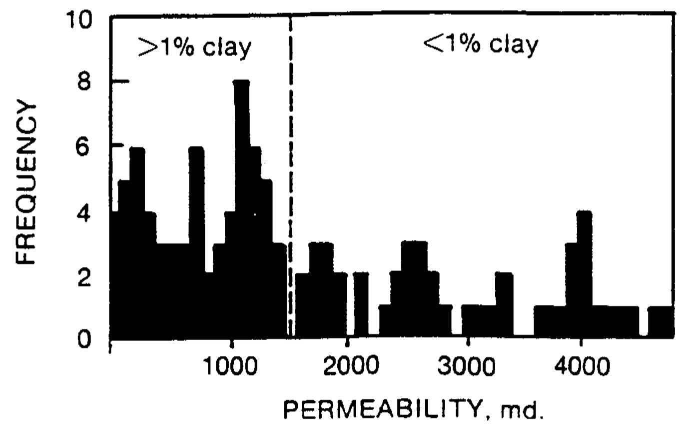

FIGURE 32. - Frequency histogram of permeability from the foreshore facies indicate two populations which can be related to the diagenetic clay content of the sandstone.

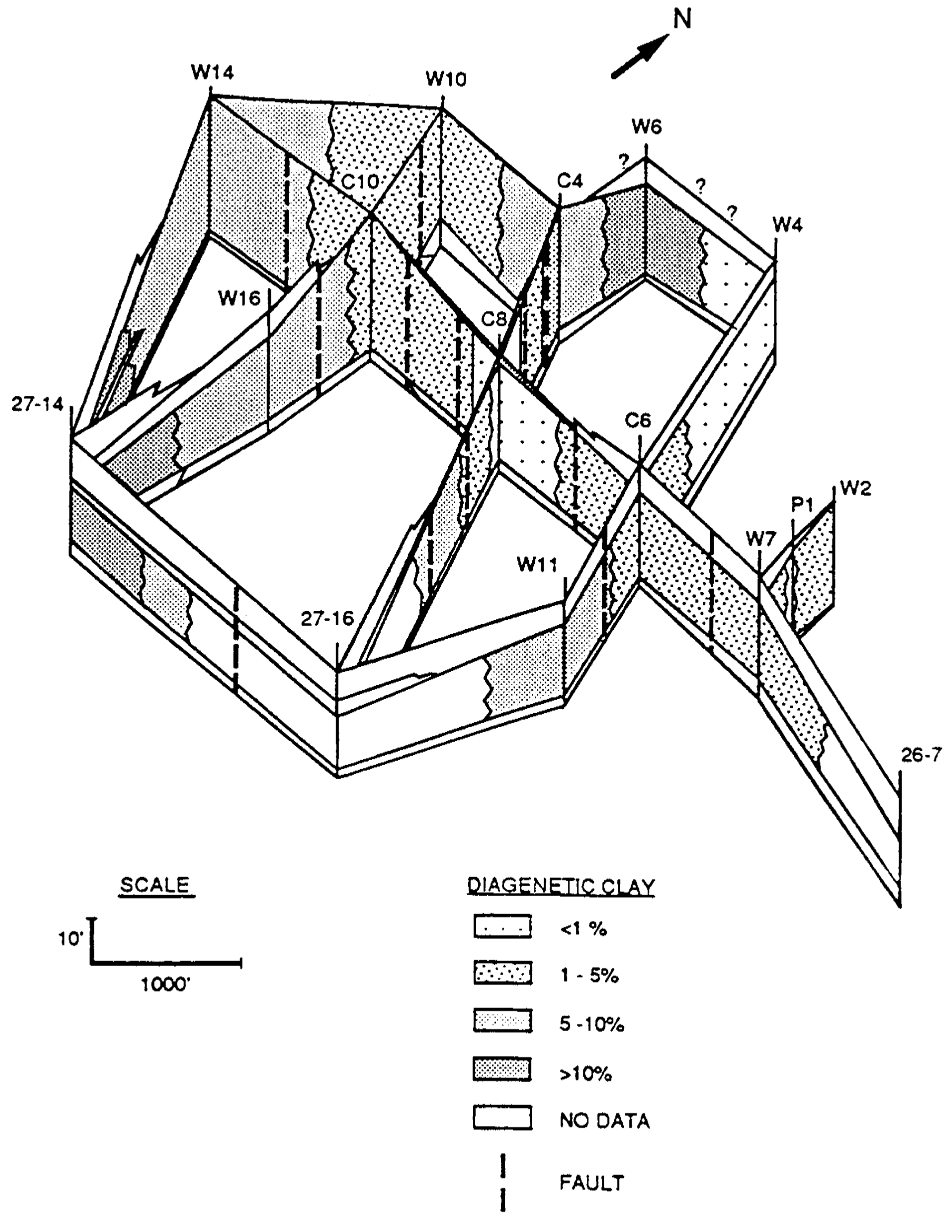

FIGURE 33. - Spatial distribution of diagenetic clay in the TIP area. Note that changes in clay content tend to correspond with the presence of faults. (see fig. 49 for well locations).

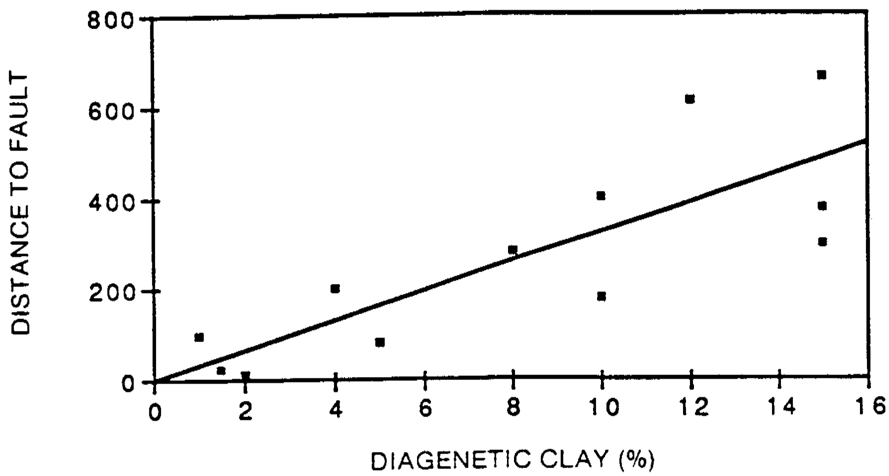

FIGURE 34. - Crossplot of distance to nearest fault and quantity of diagenetic clay.

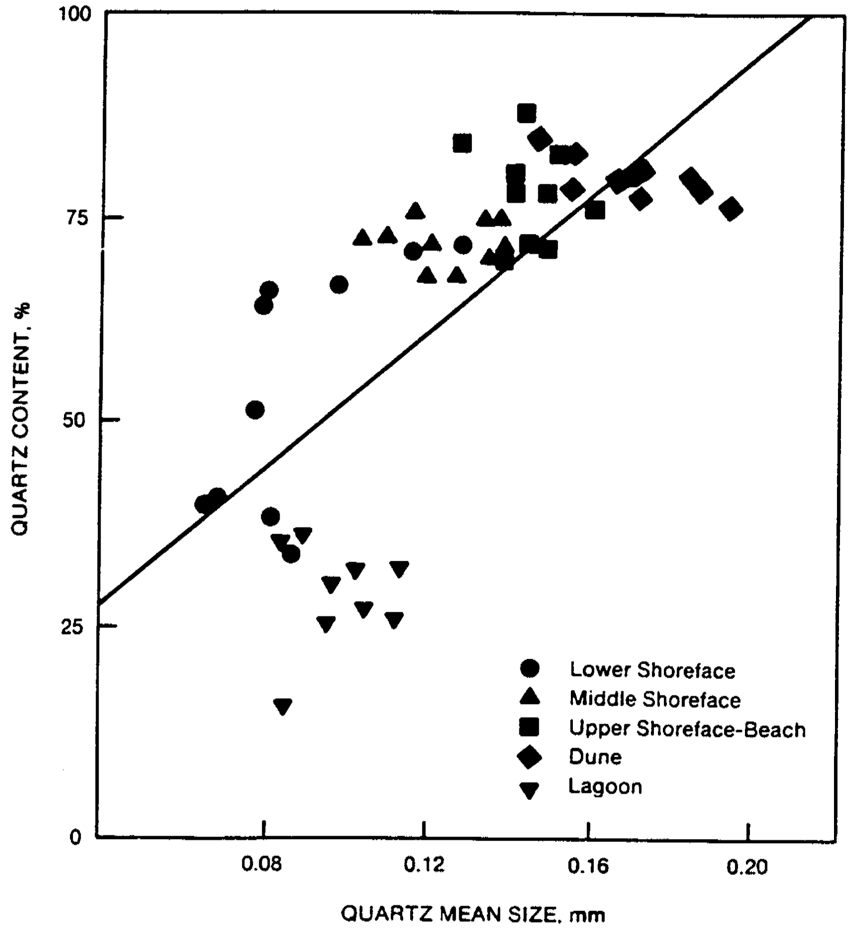

FIGURE 35. - Cross plot of quartz content and mean quartz size, Galveston barrier complex, TX. Correlation coefficient (R) for the regression line is 0.71. After Davies and Ehteridge (1975).[21]

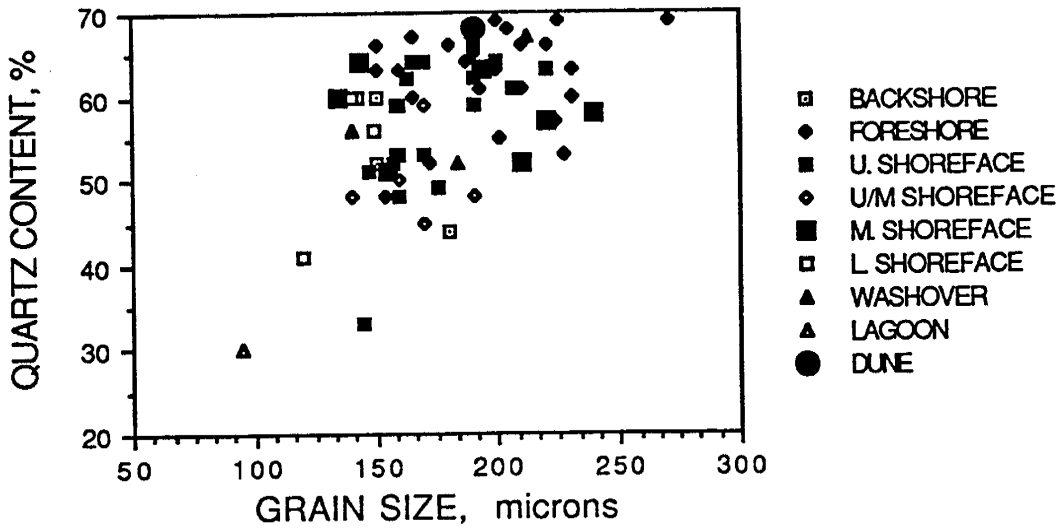

FIGURE 36. - Cross plot of quartz content and grain size, Unit 'A', Bell Creek (MT) field.

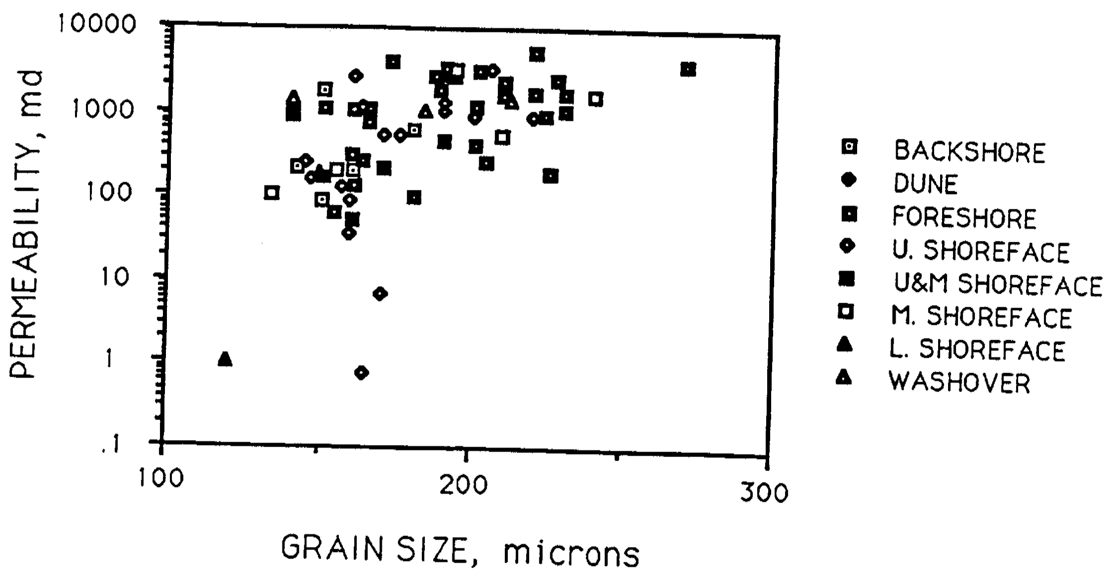

FIGURE 37. - Cross plot of permeability and grain size, Unit 'A', Bell Creek (MT) field.

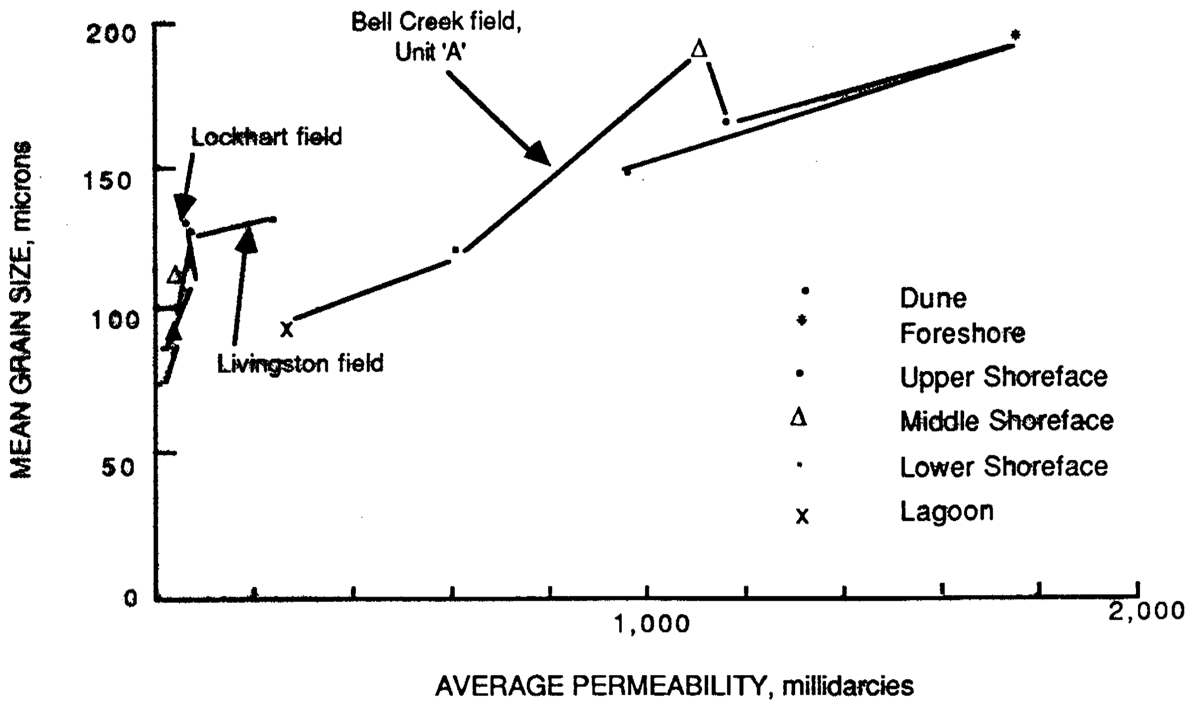

FIGURE 38. - Plot of mean grain size and average permeability for corresponding facies from Unit 'A', Bell Creek (MT) field, Lockhart (TX) field and Livingston (TX) field. Data for the two Texas fields interpreted from Self et al.1986[39]

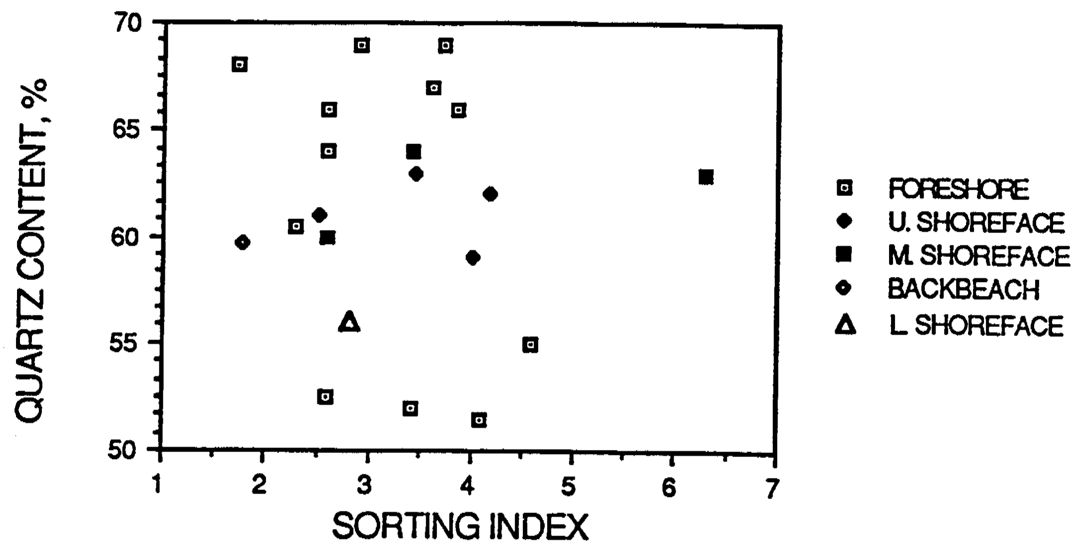

FIGURE 39. - Cross plot of quartz content and sorting index, Unit 'A' Bell Creek (MT) field.

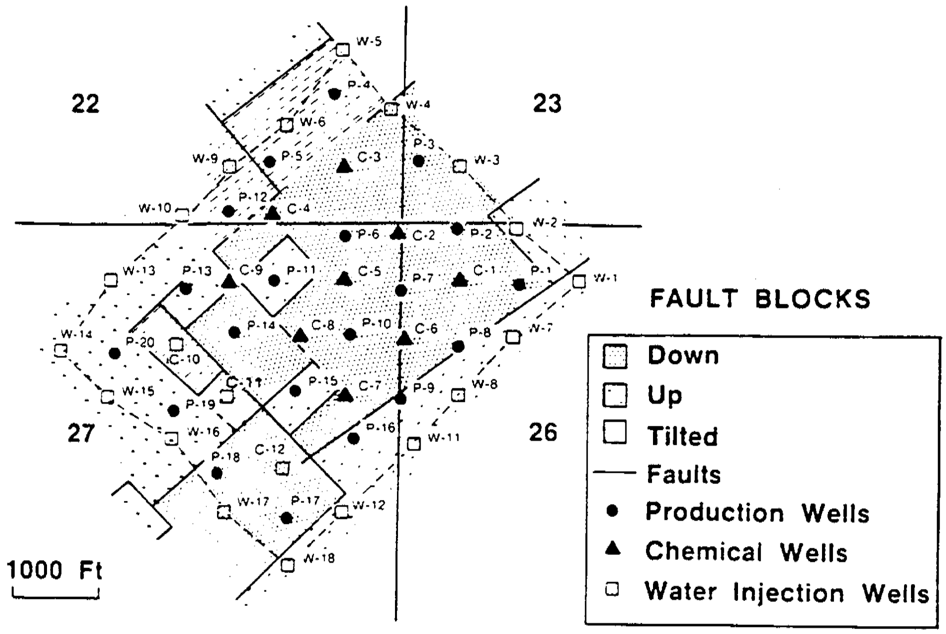

FIGURE 40. - Separation of the reservoir in the TIP area into small, tectonic blocks as a result of faulting. Note the locations of wells P-11 and P-14 in section 27, which although adjacent to each other, produced different amounts of oil due to the vertical displacement of reservoir blocks.

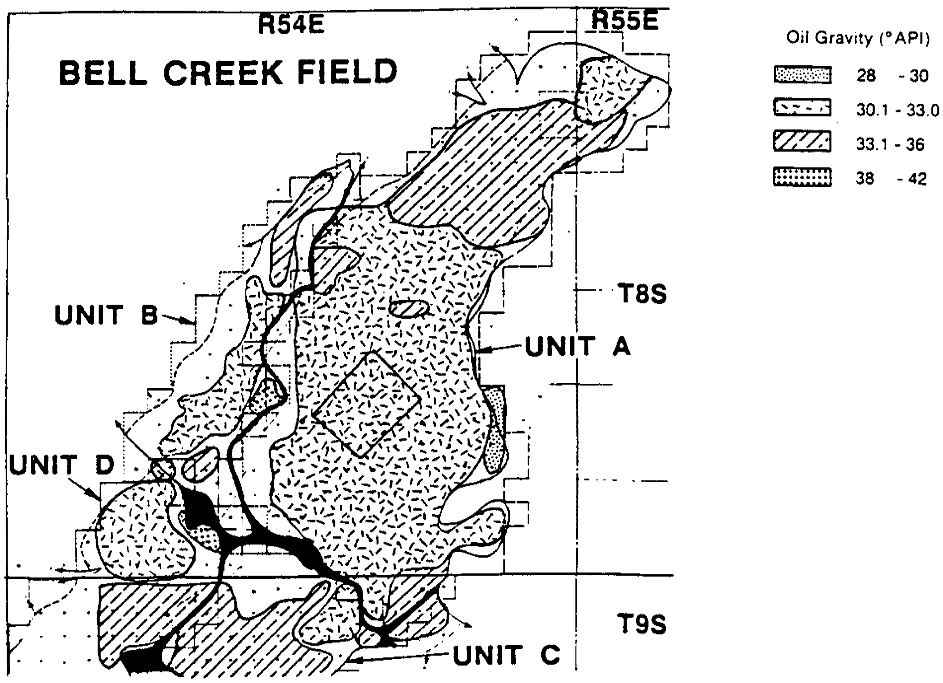

FIGURE 41. - Areal variations in oil gravity values (° API).

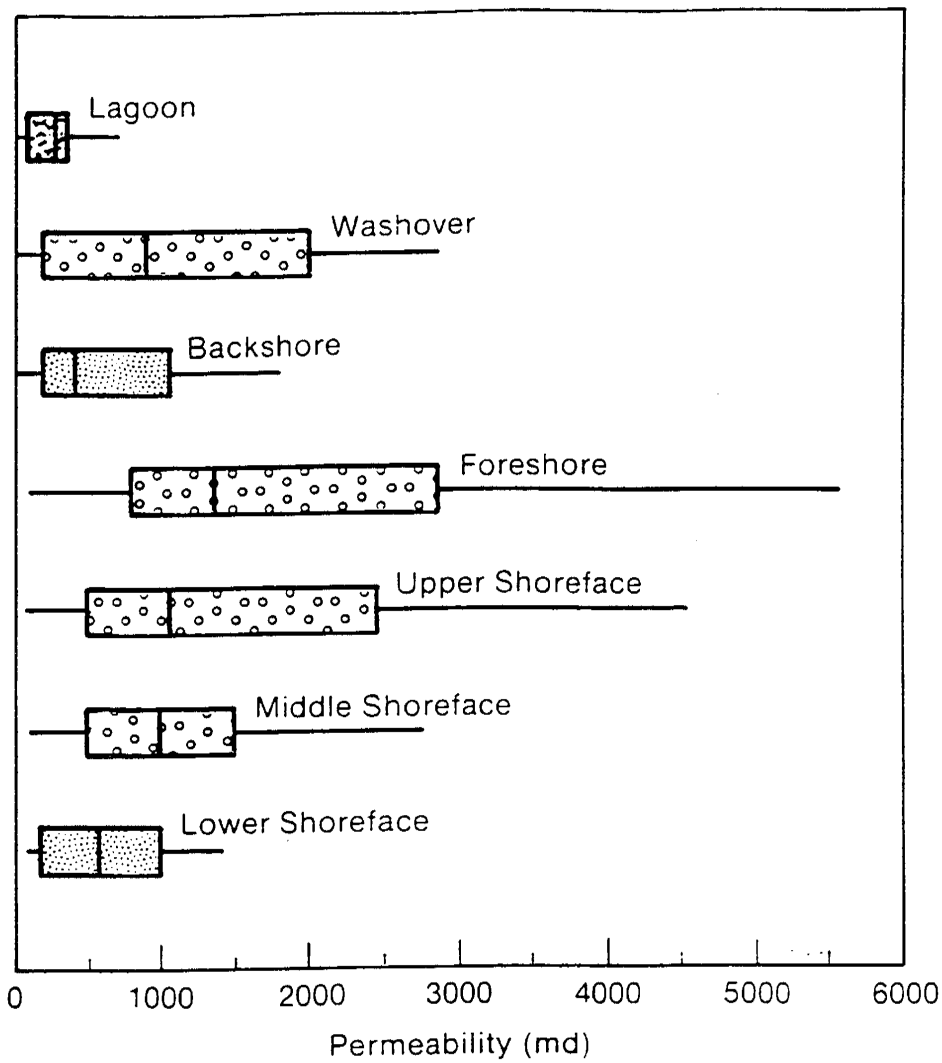

FIGURE 42. - Box-and-whiskers plot of facies permeability values in the TIP area, Unit 'A', Bell Creek field. The box includes the middle 50% of the permeability values, while the 'whiskers' extend to 1.5 times the box (or interquartile range). The few values which are greater than this are considered outliers and are excluded from the diagram.

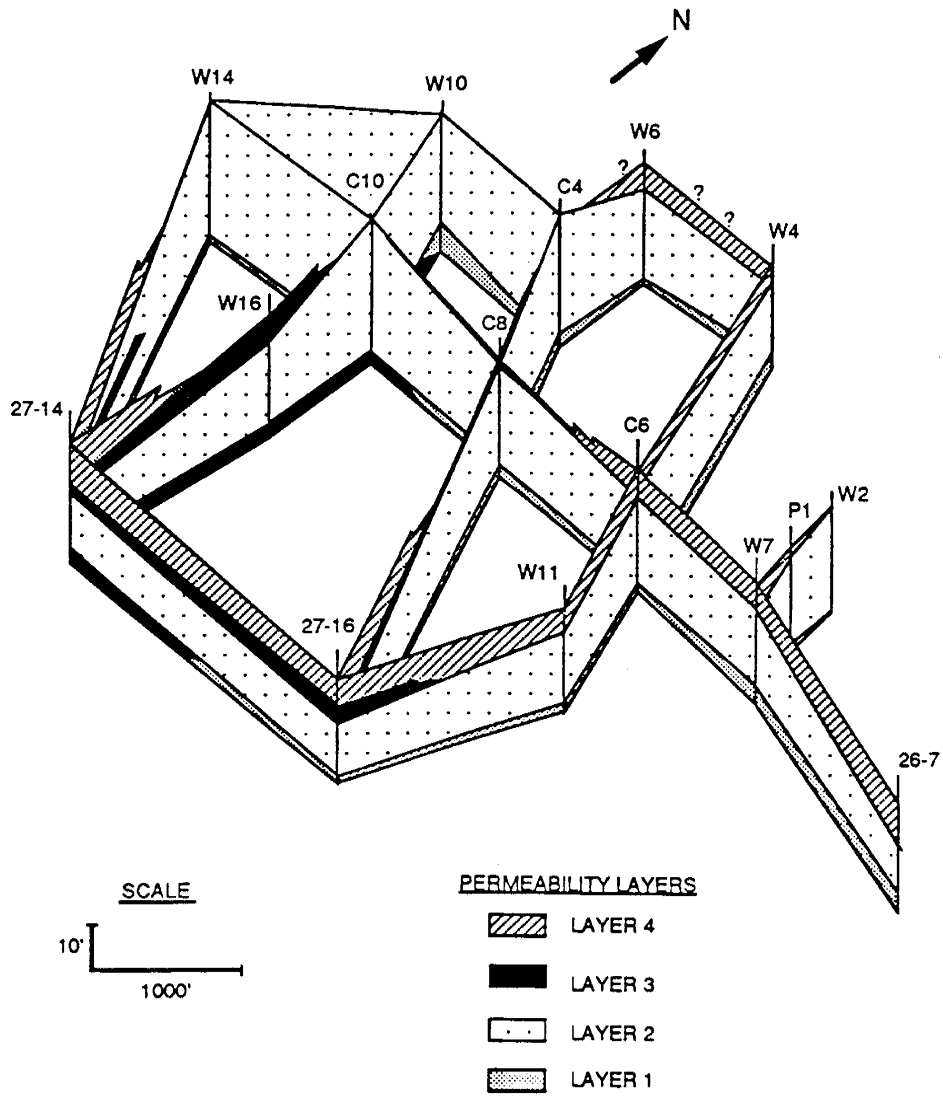

FIGURE 43. - A 3-D permeability layer model of the TIP area in Unit 'A'. See figure 49 for well locations and table 10 for layer characteristics.

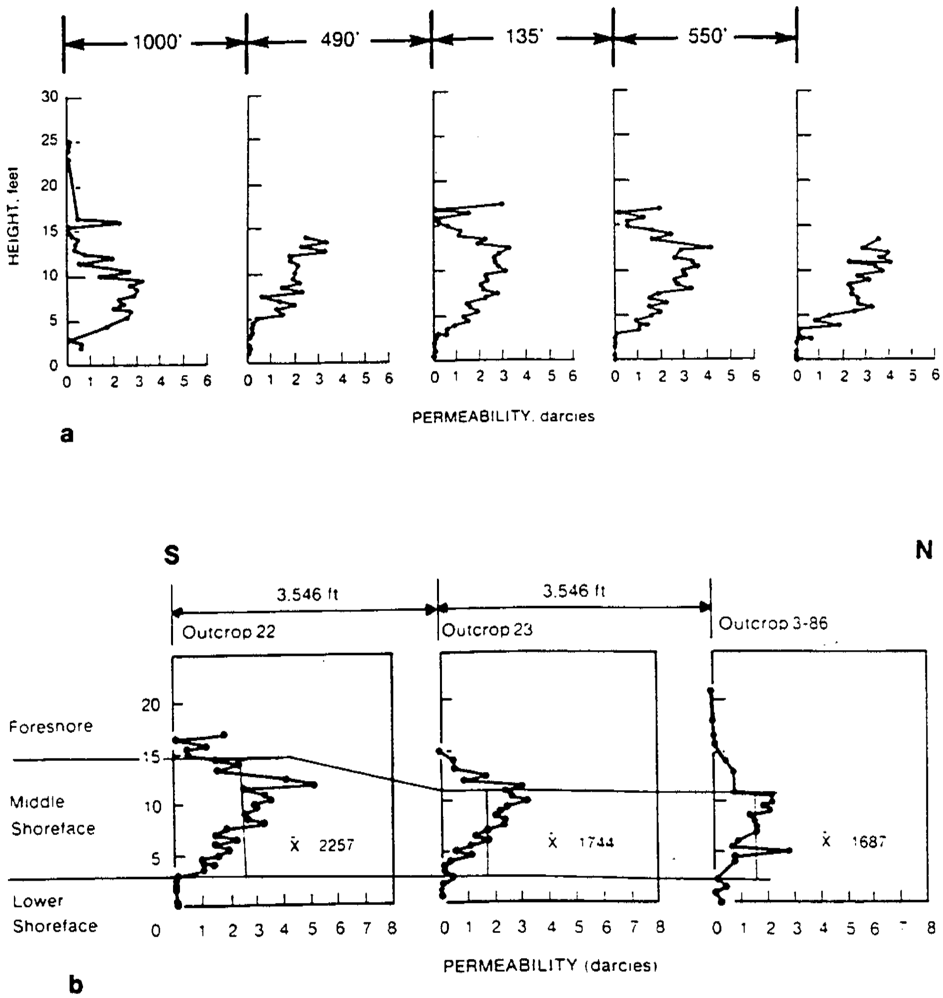

FIGURE 44. - Vertical profiles of permeability across a 2,000 ft. face of an outcrop exposure of the Muddy formation, WY (a) and from 3 outcrops over a distance of 1.3 miles (b). Note the similar profiles and average values over distances of 2,000 ft and those greater than a mile.

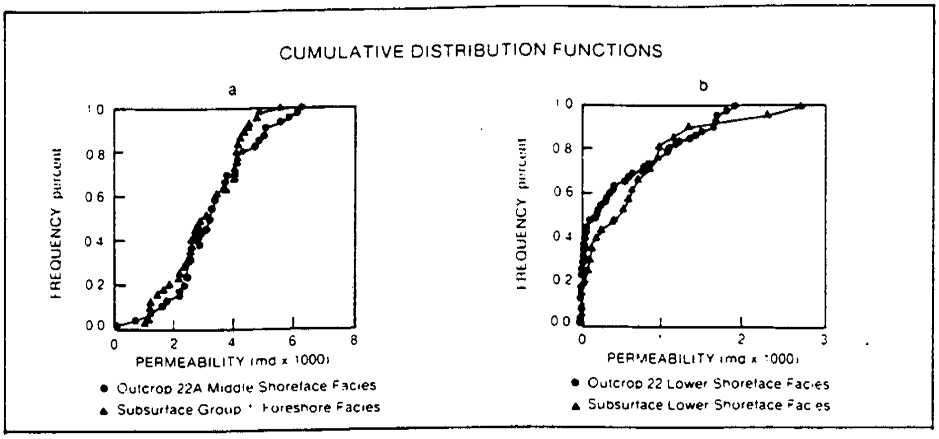

FIGURE 45. - Comparison of subsurface and outcrop permeability cumulative distribution functions. Similar frequency functions exist for outcrop middle shoreface facies and subsurface, low-diagenetic cement content foreshore facies (a), as well as outcrop and subsurface lower shoreface facies (b).

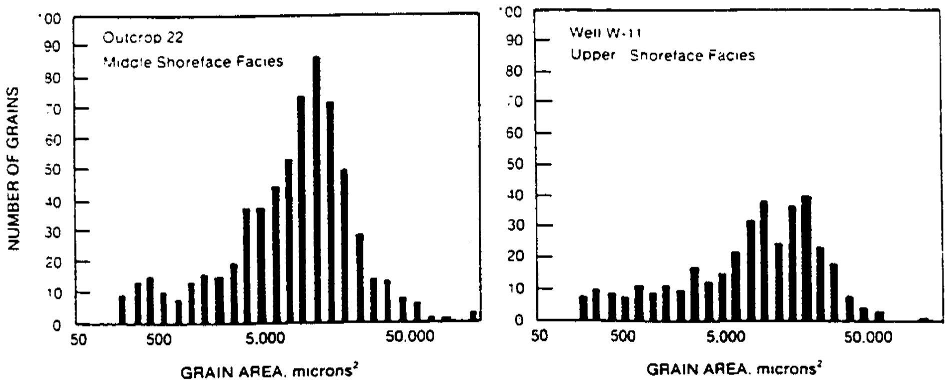

FIGURE 46. - Frequency distributions of grain sizes calculated by image analysis of thin sections. Note that the outcrop middle shoreface facies and the subsurface upper shoreface facies have similar distributions.

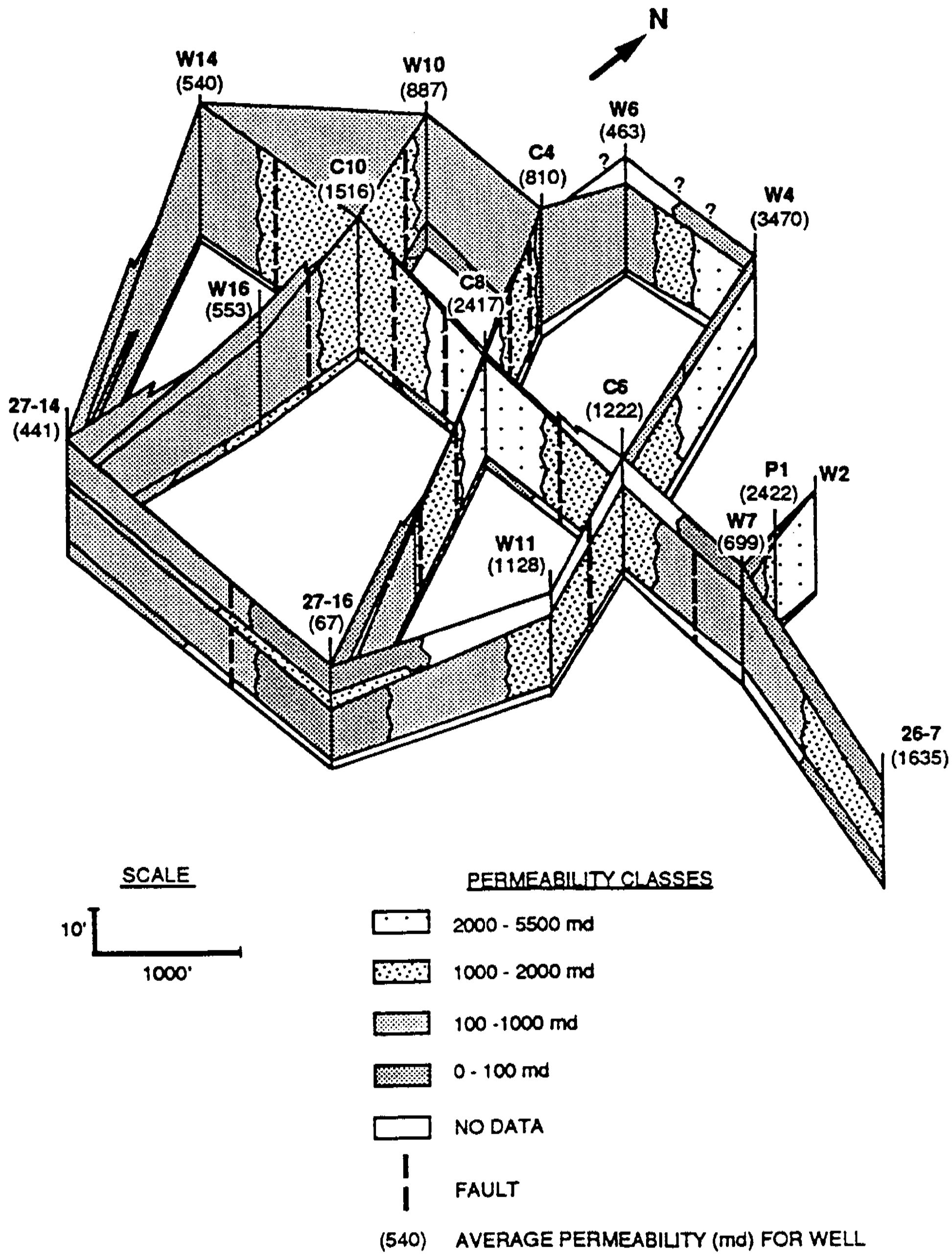

FIGURE 47. - Flow unit model for the TIP area in Unit 'A'. Note that the lateral changes in permeability correspond with the presence of faults and diagenetic clay content shown in figure 33.

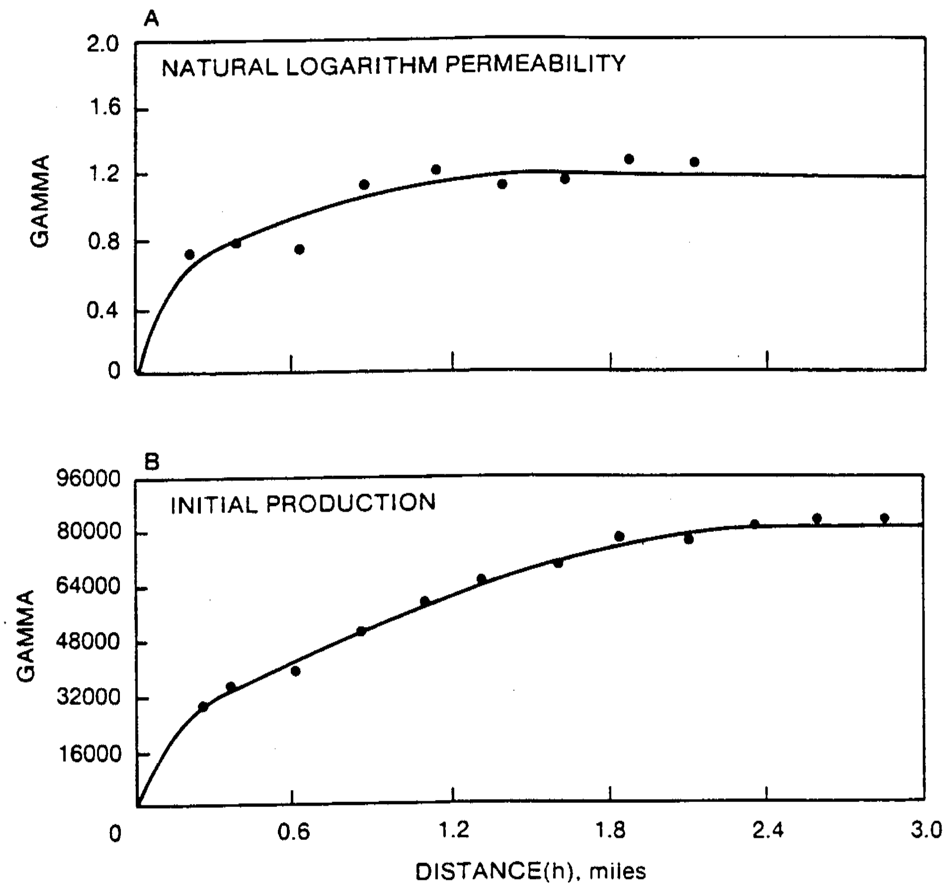

FIGURE 48. - Variogram for average permeability (a) and initial production (b) per well. Both variograms indicate two ranges of correlation: 0.25 miles and 1.5 to 2.5 miles respectively.

R 54 E

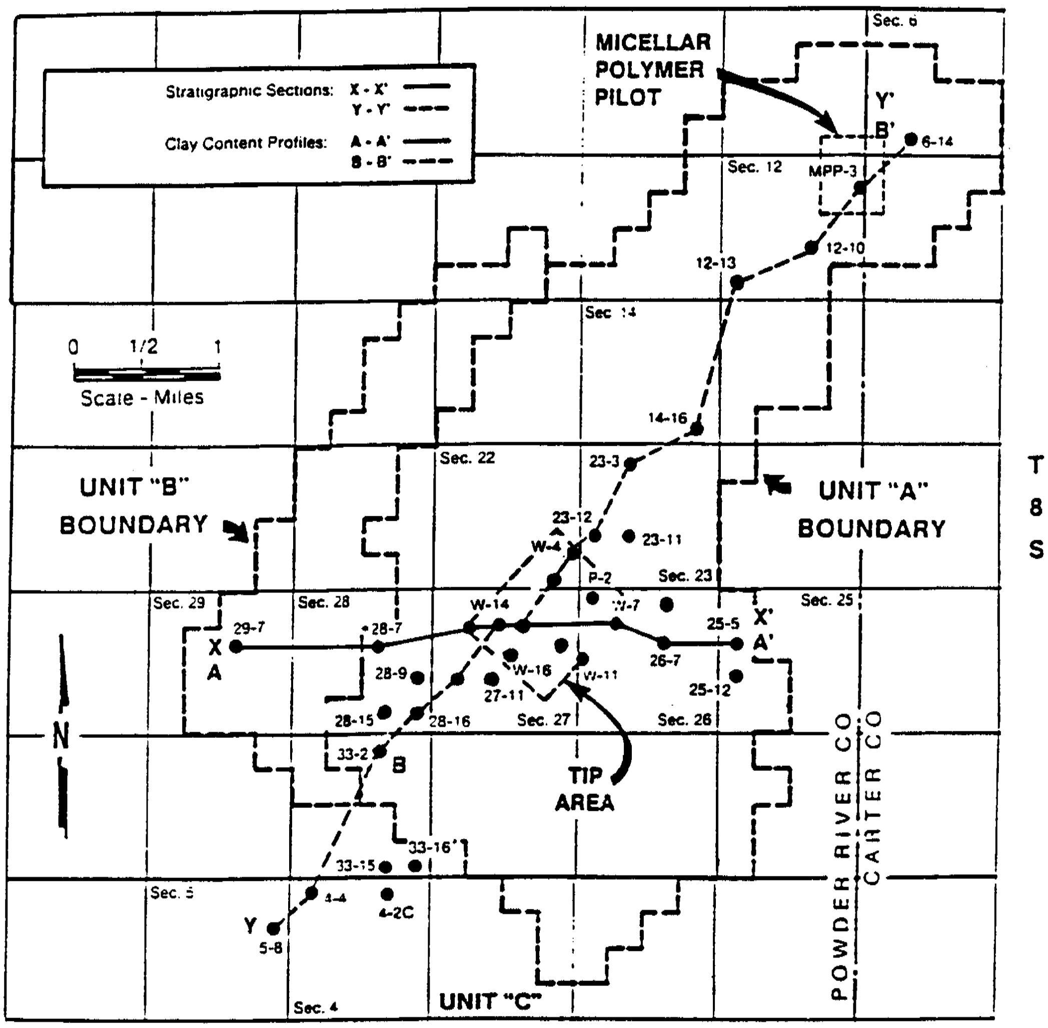

FIGURE 49. - The study area in Units 'A', 'B', and 'C' of Bell Creek field with locations of log-based stratigraphic and clay content profiles.

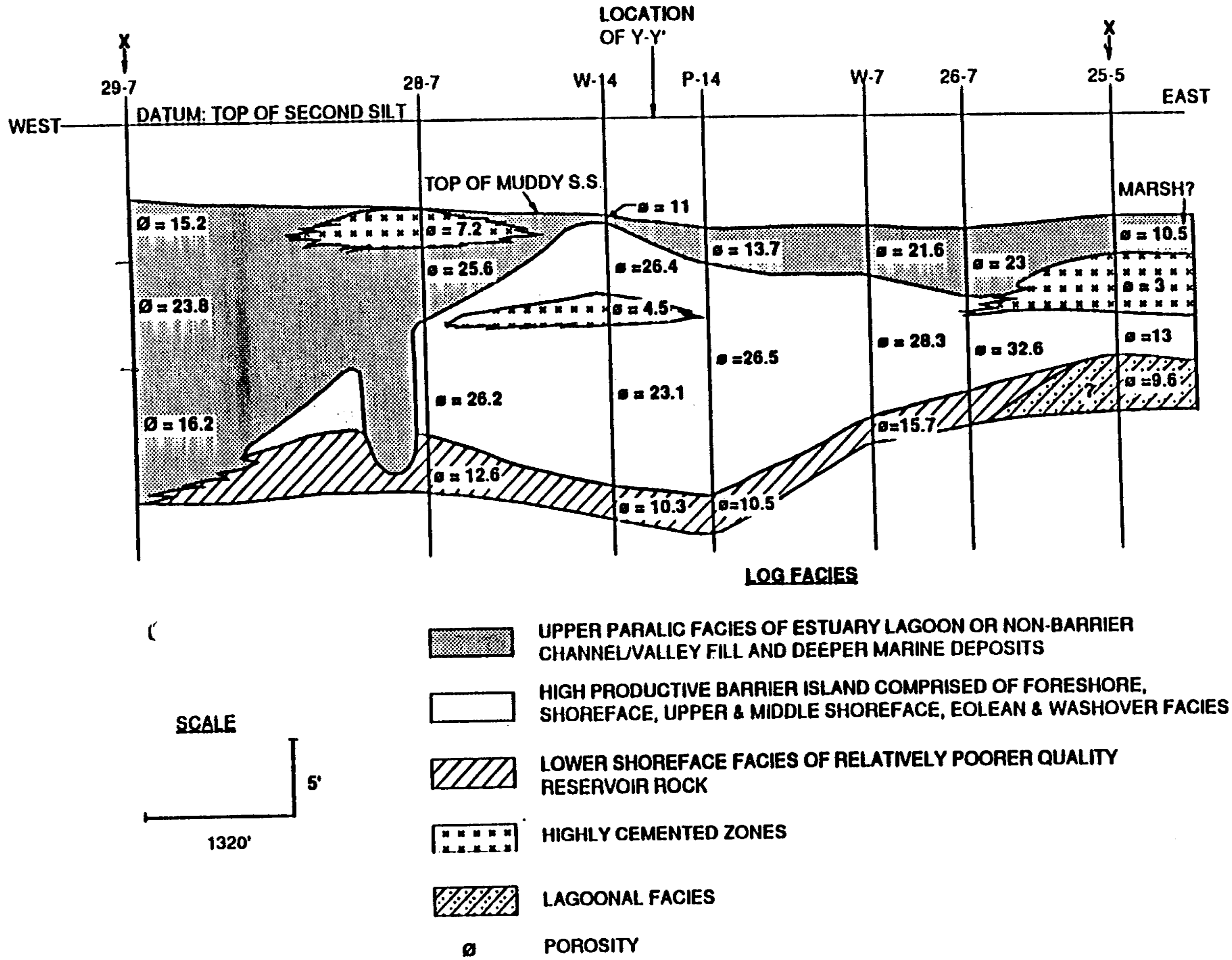

FIGURE 50. - Dip-oriented stratigraphic cross section XX' of the barrier island deposit at Bell Creek field obtained from log-based facies analysis. See figure 49 for location.

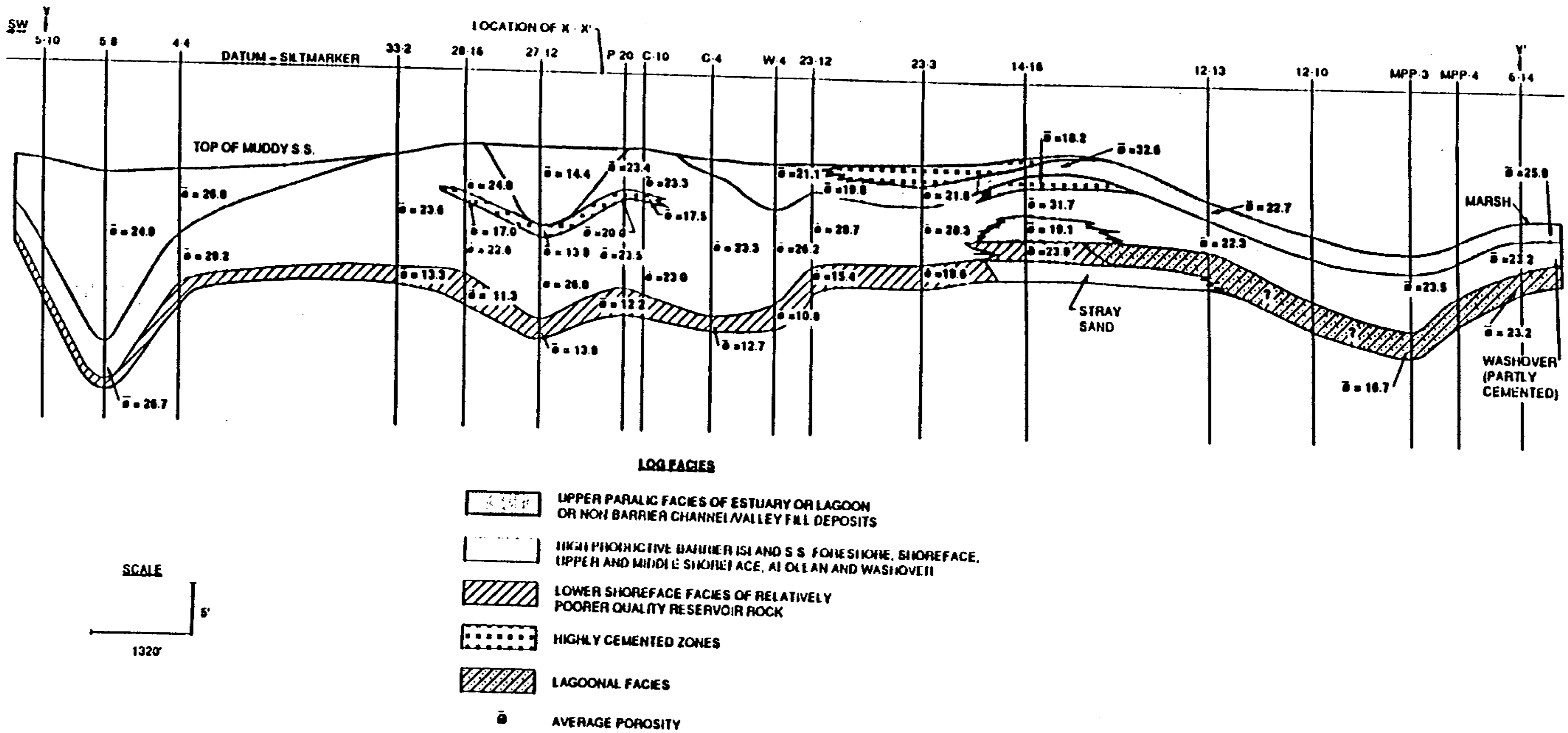

FIGURE 51. - Strike-oriented stratigraphic cross section YY' of the barrier island deposit at Bell Creek field obtained from log-based facies analysis. See figure 49 for location.

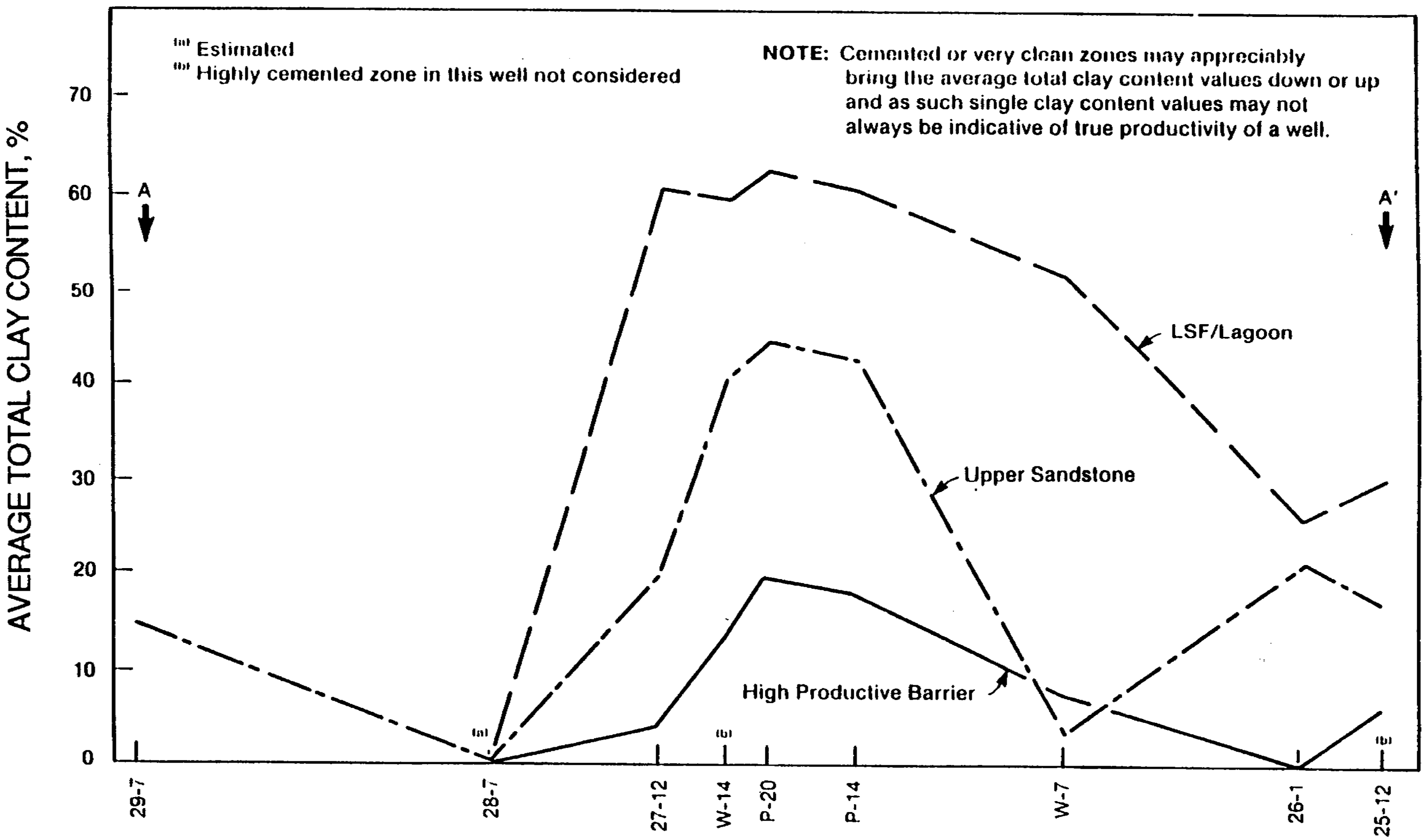

FIGURE 52. - Distribution of average total clay content in the three-log-derived facies along dip section AA'. See figure 49 for location.

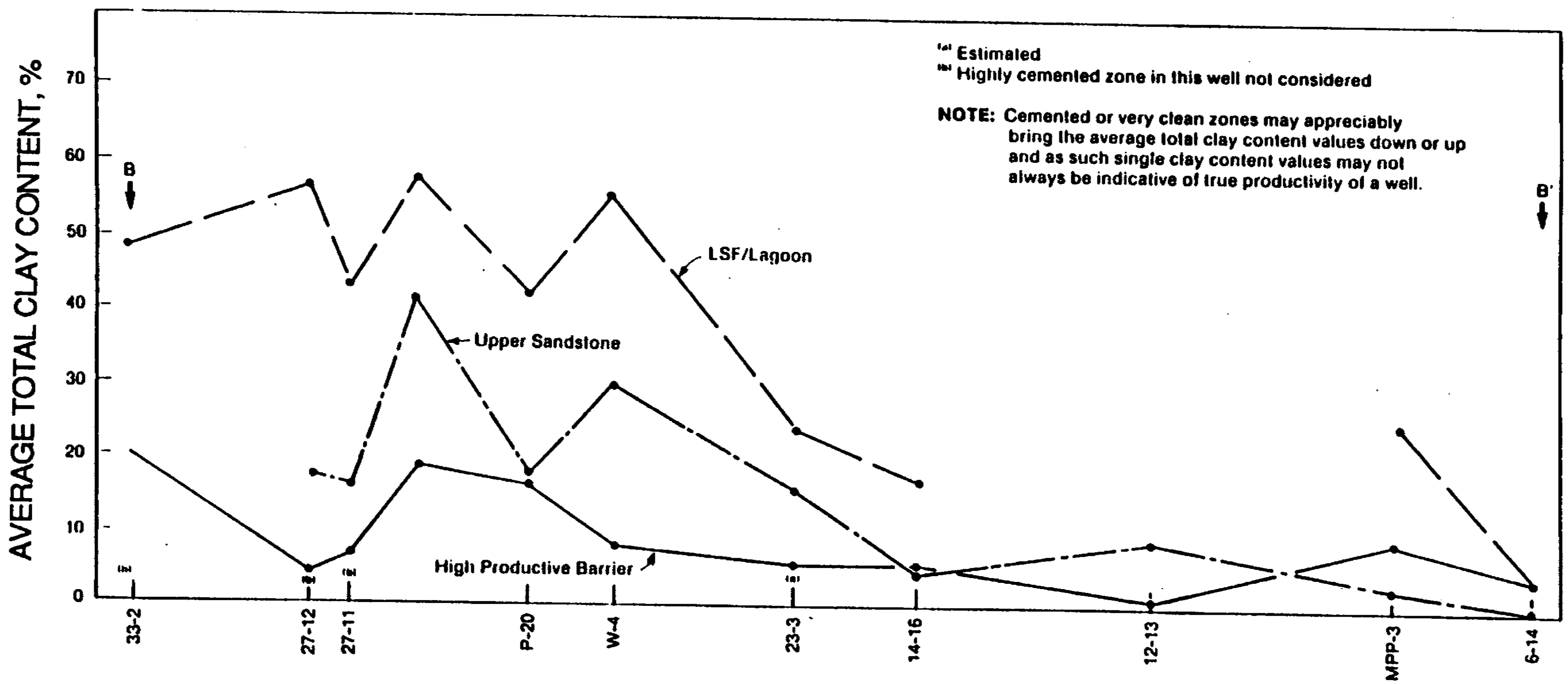

FIGURE 53. - Distribution of average total clay content in three log-derived facies along strike section BB'. See figure 49 for location.

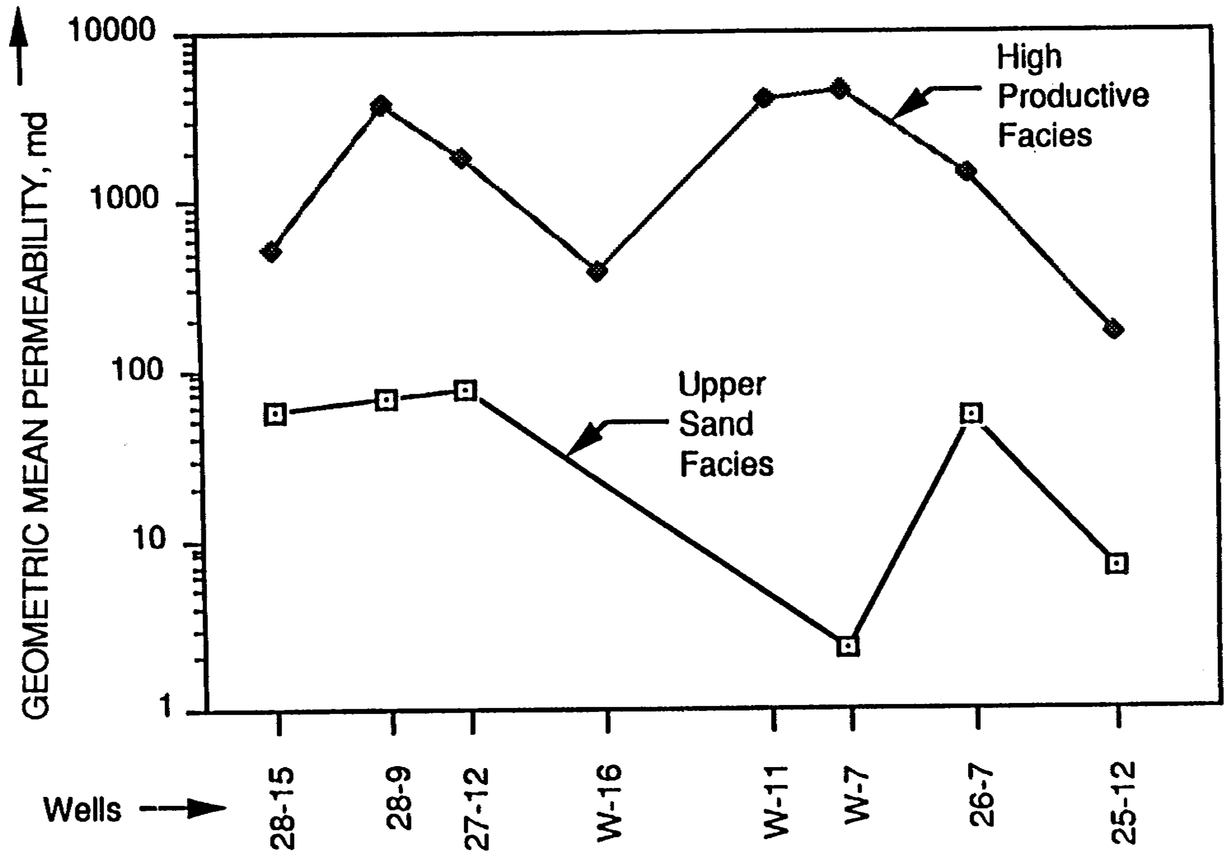

FIGURE 54. - Distribution of geometric means of air permeability in the dip direction, Unit 'A' Bell Creek (MT) field. See figure 49 for location of wells.

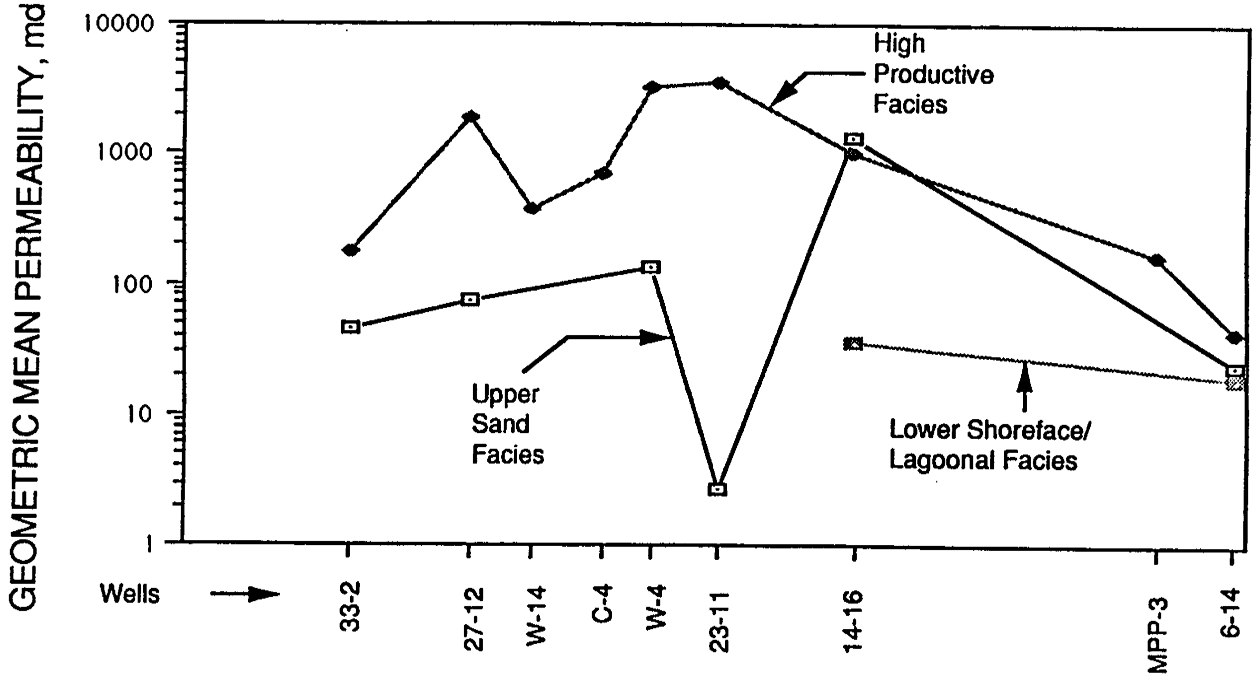

FIGURE 55. - Distribution of geometric means of air permeability in the strike direction, Unit 'A' Bell Creek (MT) field. See figure 49 for location of wells.

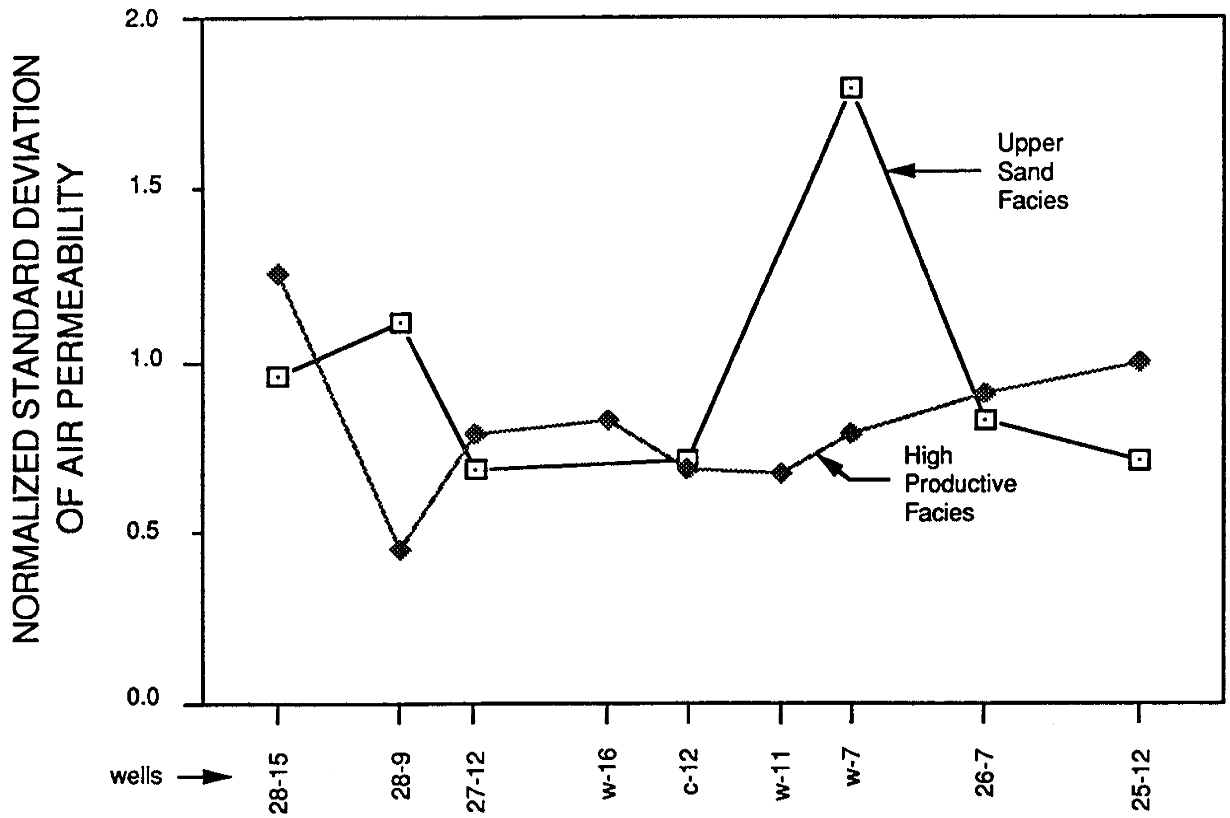

FIGURE 56. - Degree of permeability stratification in Unit 'A', Bell Creek (MT) field. Facies are from the distribution of normalized standard deviation of air permeability along the dip profile AA' indicated in figure 49.

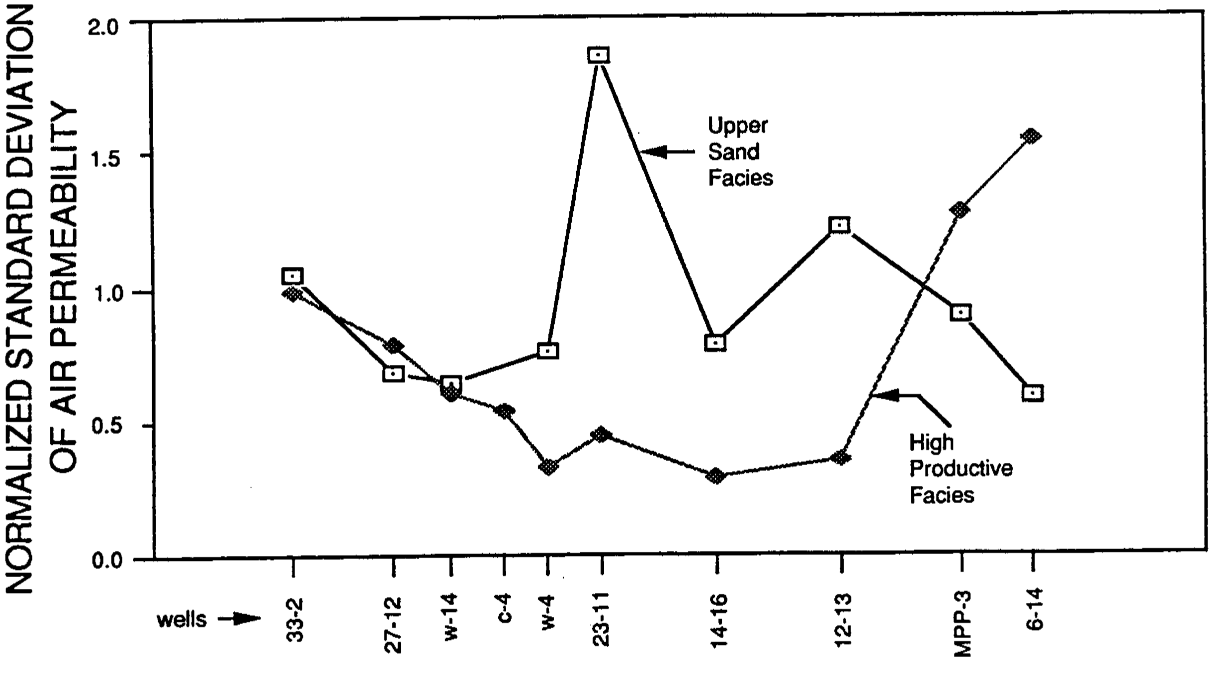

FIGURE 57. - Degree of permeability stratigication in Unit 'A', Bell Creek (MT) field. Facies are from the distribution of normalized stand deviations of air permeability, along strike profile BB' indicated in figure 49.

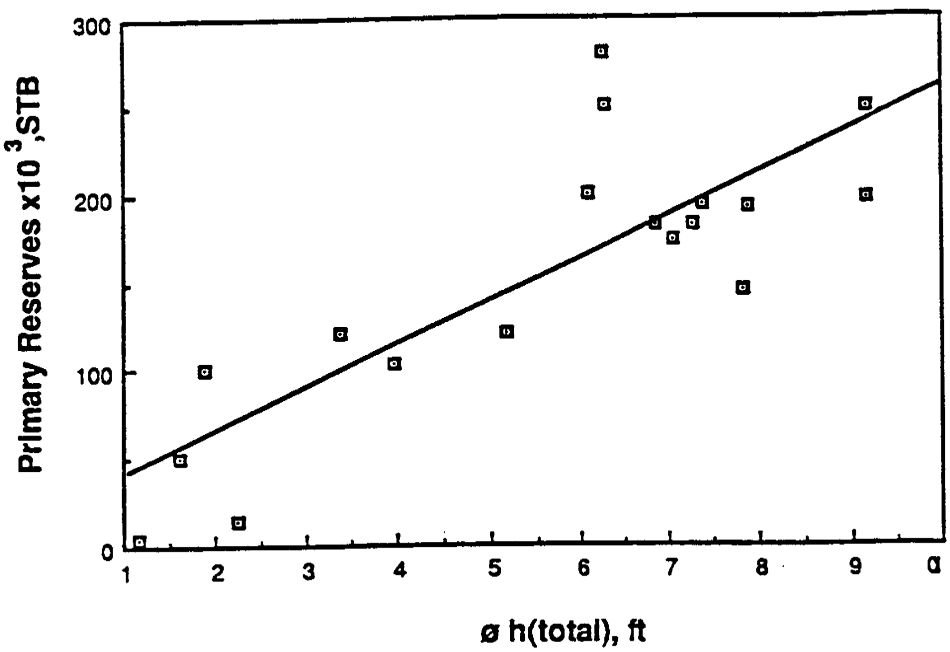

FIGURE 58. - Plot of primary reserves against storage capacity.

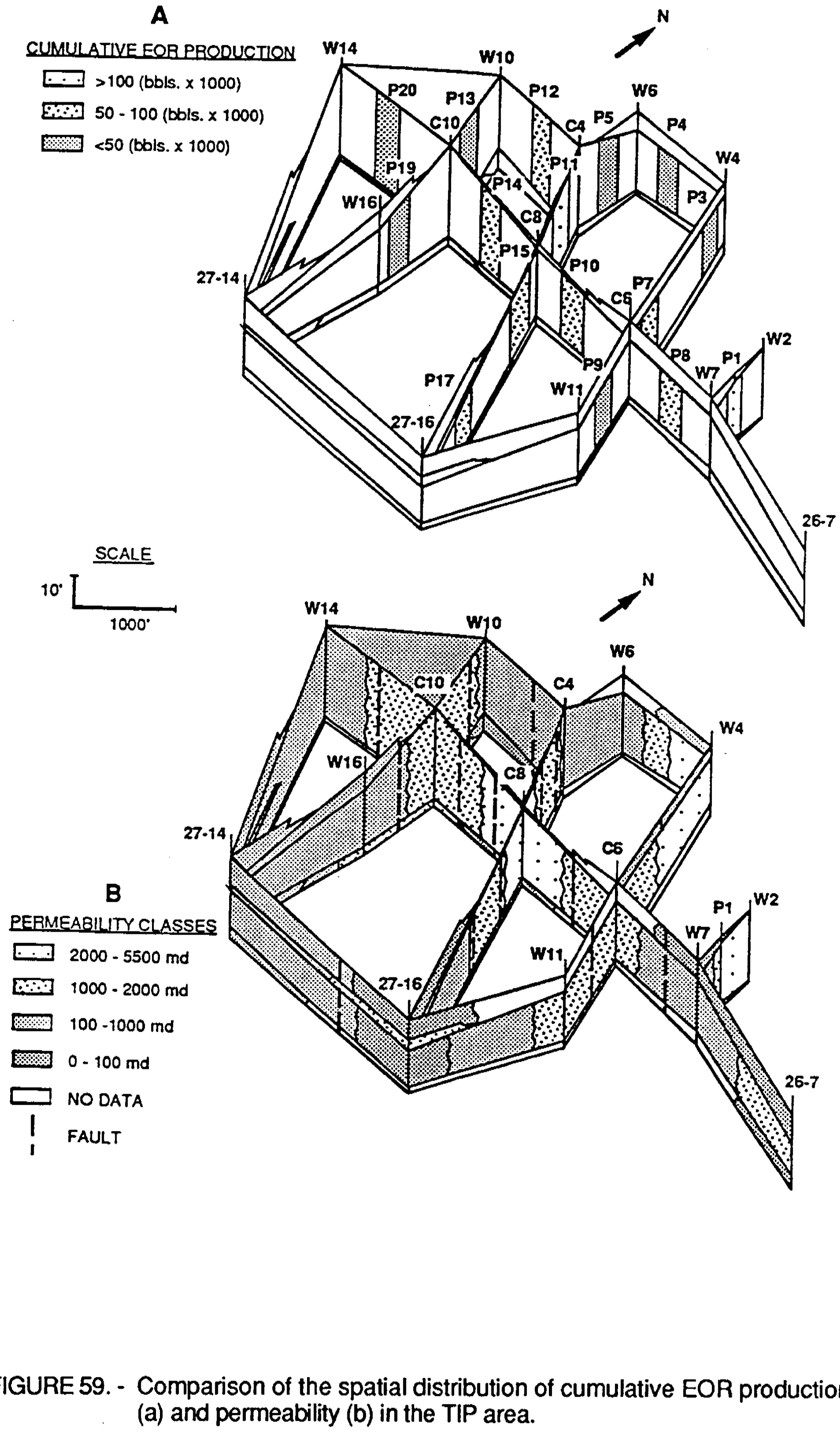

FIGURE 59. - Comparison of the spatial distribution of cumulative EOR production (a) and permeability (b) in the TIP area.

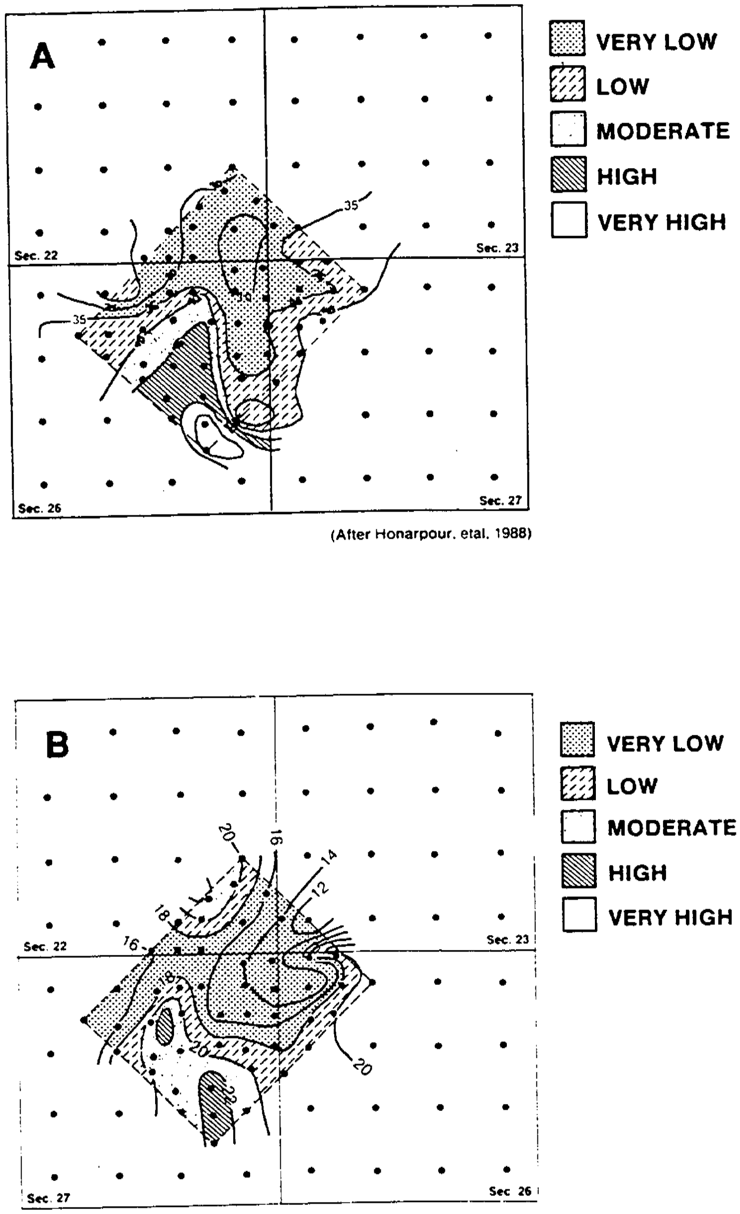

FIGURE 60. - Comarison of residual oil saturation distribution obtained by full-scale areal simulation, in percent (a) and that from measurement of cores drilled after 1980 (b).

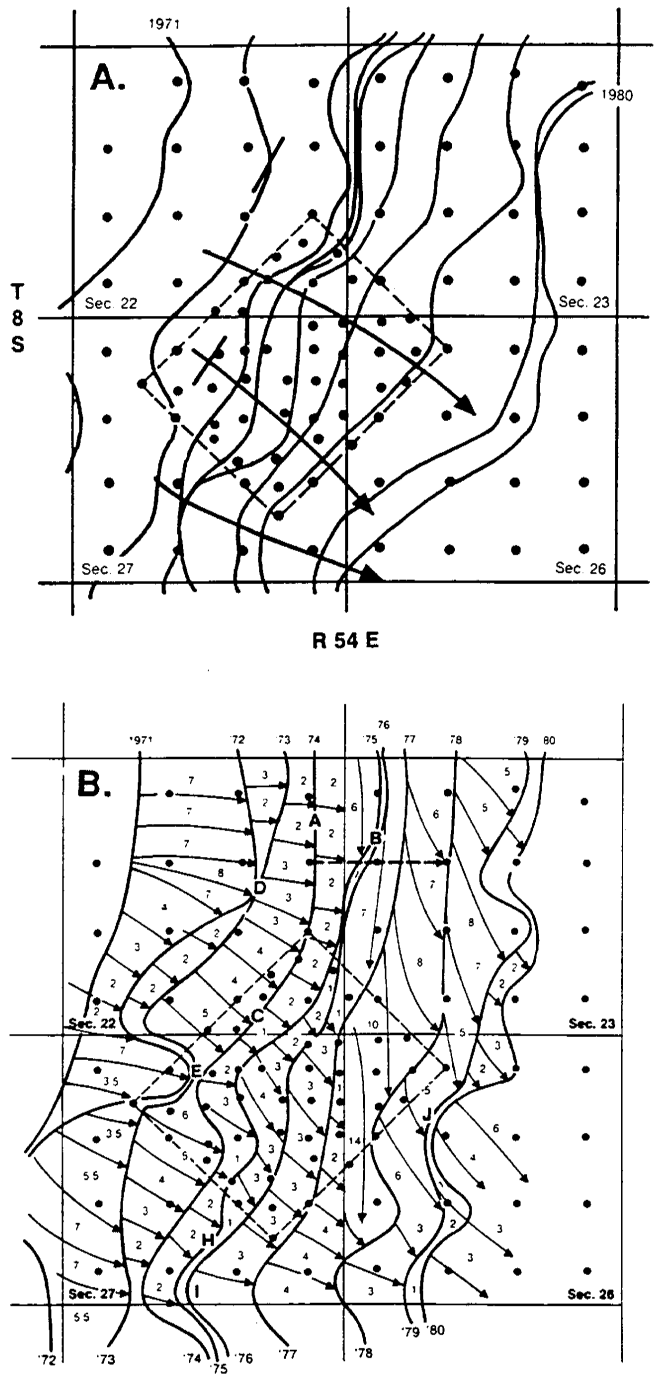

FIGURE 61. - Comparison of waterfront advancements obtained by full-scale areal simulation (a) and that from the 70% water cut production data (b).

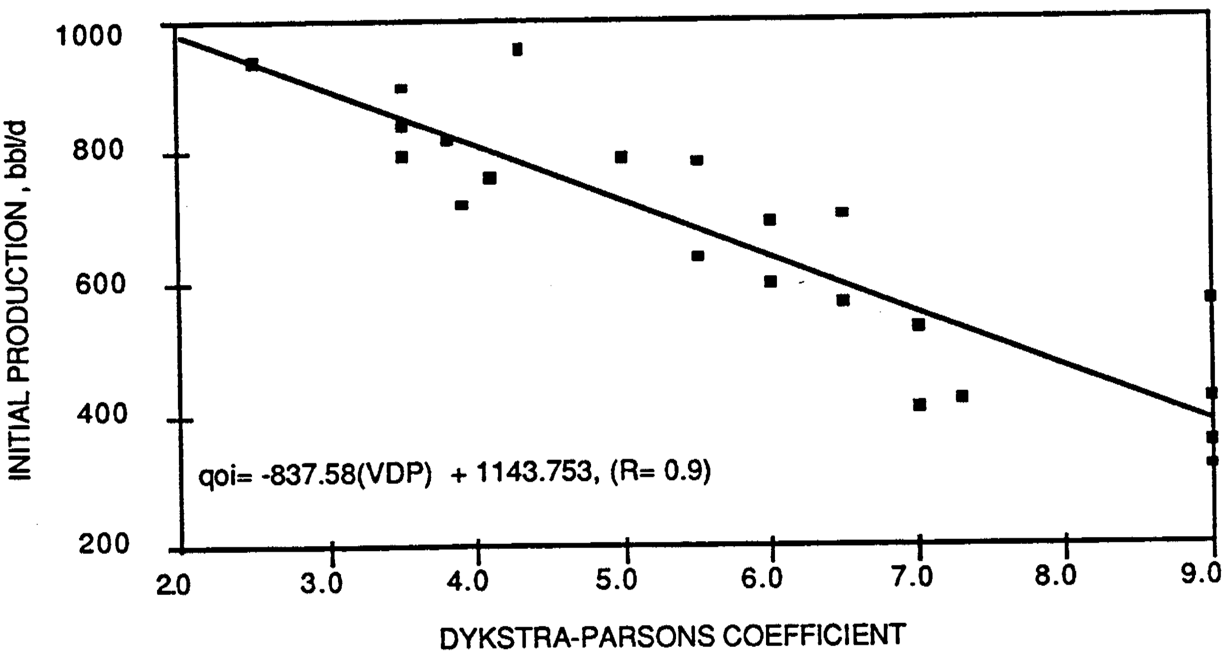

FIGURE 62. - Correlation of initial primary production rate data with Dykstra-Parsons coefficient for cored wells in the central portion of Unit 'A'.

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