FOSSIL ENERGY

DOE/PC/91008-0379
(OSTI ID: 3332)

FIELD DEMONSTRATIONS OF LOGGING TECHNOLOGIES FOR RESERVOIR CHARACTERIZATION

Final Report
October 1998

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February 1999

Performed Under Contract No. DE-AC22-94PC91008
(Original Report Number NIPER/BDM-0379)

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U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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DOE/PC/91008-0379
Distribution Category UC-122

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ABSTRACT

This compilation focuses on the practical aspects of the use of wireline logging in today's domestic petroleum industry. It explores the implementation methodologies and the technical and economic successes and failures encountered in use of advanced logging technologies and the use of innovative methods to extract reservoir petrophysical information from existing wireline logs. The majority of the logging applications reviewed are those performed in projects jointly funded by the domestic petroleum industry and the U. S. Department of Energy (DOE) in DOE's Field Demonstration Program, particularly under the Reservoir Class Program. Because less than one-half of the nearly 30 projects in the Reservoir Class Program have been completed, much of this work was reviewed in progress.

Projects in each of the three reservoir classes currently funded in the program (i.e., Fluvial-Dominated Deltas, Shallow Shelf Carbonates, and Slope and Basin Clastics) employed quantitative core-log models to predict foot-by-foot values of reservoir parameters such as porosity and permeability from historically collected wireline data. The approaches to model construction were varied, but led to remarkable success in several instances. The use of core-log models appears to be a readily available and probably underutilized approach that has particular application in describing the heterogeneous distribution of petrophysical properties associated with the often complex pore systems of Reservoir Classes I through III. The great potential of this technology for improving recovery on a large scale through better reservoir description is just beginning to be realized because of recent and widespread developments in data processing capabilities.

Borehole imaging is a facet of advanced technology whose utility is rapidly becoming recognized by industry. Acoustic, resistivity, and video imaging tools are being applied enthusiastically in numerous Class Program projects. Imaging tools provide information at resolution higher than most logging tools and generally provide information on the spatial orientation of discontinuities as well as detecting their presence. The continuing trend toward higher cost-effectiveness of imaging tools coupled with the wide spectrum of information they can provide on the pore-to-interwell scales suggests that these tools will soon become a part of the logging arsenal routinely applied by all operators.

Applications of emerging advanced logging tools in Class Program and related projects are demonstrating that many tools designed to measure reservoir properties not previously possible can make substantial contributions to reservoir understanding, but only if care is taken to select the right tools and implement them properly. Project results show that reservoir-specific calibration of tool response to the reservoir property or properties being measured is extremely important. Tools making substantial contributions in the projects reviewed include nuclear magnetic resonance, acoustic, dielectric, spectroscopy, pulsed neutron, and modular formation tester tools. New tools and technologies under development with DOE support include wireline microseismic tomography, interwell resistivity techniques, through-casing resistivity techniques, and array induction resistivity techniques.

Mainly because of increased capabilities for data processing, a new era of wireline logging has begun. New tools and capabilities will allow more accurate reservoir description than ever before possible at all scales using wireline log data, but new problems accompany these advances. As well as finding ways to extract critical reservoir property information from inconsistent suites of "old" wireline logs, methods for designing new optimal logging suites and logging procedures for newly discovered and existing reservoirs have to be developed.

ACKNOWLEDGMENTS

The authors, the editors, and indeed the entire petroleum industry owe a debt of gratitude to the U.S. Department of Energy (DOE) for its foresight in substantive support of oil-related technology research, field demonstrations of emerging and underutilized technologies, and technology transfer. Without the degree of commitment exhibited by DOE through the broad and ongoing field demonstration aspects of its National Oil Program many insights into technology strengths and weaknesses relayed by this volume would not have been possible. Funding for this compilation was provided by DOE through contract DE-AC22-94PC91008. The Contracting Officer was Rhonda Lindsey at the National Petroleum Technology Office in Tulsa, Oklahoma. The volume's content was greatly supplemented by two regional workshops on wireline logging technologies held in Midland, Texas, in 1997 and in Denver, Colorado, in 1998. The workshops were co-hosted by DOE and the respective Texas and Rocky Mountains regional lead organizations of the Petroleum Technology Transfer Council (PTTC).

Class Program and related program project personnel are the true authors of this volume. These professionals, representing independent and major producers and their project partners (e.g., service companies, universities, or other research organizations), have appropriately blended research and operations perspectives. Their approach has been multidisciplinary and mutually supportive. Their methods and results have been well documented through comprehensive reporting to DOE and through focused and continuing technology transfer efforts. They did the meticulous work of developing multifaceted and flexible reservoir management strategies that most often led to optimal evaluation of technologies in addition to improving recovery. Their diligent work and their attention to detail have made the task of editing simple and rewarding. The editors have merely focused on extracting information concerning the use and utility of wireline logging technologies and have tried to achieve a uniformity of format in presentation style. Any shortcomings in content or style, however, are solely the responsibility of the editors.

The authors and editors are indebted to numerous technical reviewers for their efforts to guide us toward simple, complete, and accurate delivery of information. Special thanks are due to John Doveton at the Kansas Geological Survey in Lawrence, Kansas, for technical review of core-log modeling discussions; Neil Hurley (AAPG Elected Editor) at the Colorado School of Mines, Golden, Colorado, and John Hensley at Phillips Petroleum in Bartlesville, Oklahoma, for their technical review of borehole imaging discussions; and to Dave Stief at Schlumberger Wireline and Testing in Midland, Texas, and Steve Morriss at Landmark Graphics in Austin, Texas, for their review of advanced logging technology discussions. Additional reviewers who contributed substantially to increasing technical quality of the document include Michael Madden, Viola Schatzinger, and Susan Jackson of BDM-Oklahoma in Bartlesville, Oklahoma. The quality of the document has also been greatly enhanced through the efforts of the BDM-Oklahoma Information Services Department.

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CHAPTER 1

OVERVIEW OF THE FIELD DEMONSTRATION PROGRAM: TECHNOLOGY APPLICATION IN PROBLEMATIC RESERVOIRS

The main purpose of this volume is to explore some of the contributions made by modern logging technologies and by innovative methods to extract reservoir information from existing logs in recently completed and ongoing field demonstration projects jointly funded by petroleum industry organizations and the U.S. Department of Energy (DOE). Because of DOE's emphasis on technology transfer, this extensive series of projects, executed by independent and major oil companies teamed with universities and other research organizations, serves as a readily accessible source of information to the oil industry. As such the projects are a valuable resource to determine the technological and economic stage of development of the technologies being employed in pursuit of improved recovery and profitability from domestic reservoirs. The content of this volume draws heavily on past project reports to DOE, publications by project participants, and presentations made by project personnel at professional society meetings, industry workshops, and symposia. For example, some material stems from presentations made by project operators and technical personnel at DOE-sponsored logging technology workshops presented to industry in 1997 and 1998 (PTTC/DOE, 1997; PTTC/DOE, 1998). The technical and economic discussions included in this report have been augmented by personal communication with project operators and technical investigators.

DOE's Field Demonstration Program Goals and Objectives

DOE has developed a coordinated strategic plan for all oil technology, natural gas supply, and related environmental research, development, and demonstration program activities. Individual program drivers stem from defined federal government roles to maintain reliable domestic energy supplies at reasonable costs; increase the value of federal lands and U.S. Treasury revenues by maximizing production; provide science and technology leadership; enhance global market opportunities for U.S. energy technologies; and serve as a catalyst for industry, state, and other federal agency partnerships. In this context, DOE's primary mission in the National Oil Program is to maximize the recovery of oil from known domestic reservoirs in an economically and environmentally sound manner, preserve access to this resource (i.e., to delay well and reservoir abandonments), and maintain U.S. competitiveness in the global marketplace.

Realizing that domestic production was declining rapidly and that huge volumes of oil were being abandoned in domestic reservoirs because of uneconomic production techniques, DOE initiated the Oil Recovery Field Demonstration Program in 1992. This program is one of the critical elements of the National Oil Program necessary to move improved oil recovery (IOR) technology from concept through research, pilot-scale experiments, and full-scale field demonstrations to industry acceptance and commercialization. Both successes and failures of the field demonstrations provide focus to concurrent research programs. Elements of the field demonstrations that are suitable for broad industry application are conveyed to the industry through the Oil Program's technology transfer effort.

Specific goals and objectives of the Field Demonstration Program include:

1. Extend the economic production of domestic fields by:
   - Slowing the rate of well abandonments
   - Preserving industry infrastructure (including facilities, wells, operating units, data, and expertise)
2. Increase ultimate recovery in known fields by demonstrating:
   - Improved methods of characterization of reservoir rocks and fluids
   - Advanced oil recovery and production technologies
   - Improved reservoir management techniques
   - Advanced environmental compliance technologies
3. Broaden and accelerate information exchange and technology application among stakeholders by:
   - Expanding participation in DOE projects to include both traditional and nontraditional participants
   - Increasing third-party participation and interaction throughout the life of DOE-sponsored projects
   - Making technology transfer products user friendly and readily available

To actively pursue DOE's goal of transferring the results of the Field Demonstration Program and other projects to the petroleum industry, DOE and BDM-Oklahoma, with the aid of the Petroleum Technology Transfer Council (PTTC), teamed to provide a fresh perspective on technology and a wide spectrum of practical applications of specific technologies. Because of their number, technical and economic scope, and diverse geographical representation, the technology transfer effort drew heavily from DOE's Reservoir Class Program field demonstration projects.

DOE's Reservoir Class Program

In its Reservoir Class Program, DOE is sharing the cost of field demonstration projects with industry. Reservoir Class Program objectives focus on employing field demonstrations and intense technology transfer to bring newly developing technologies and ideas as well as innovative applications of proven technologies to rapid, practical, and widespread use. The program emphasizes state-of-the-art applications of promising and genuinely new tools and techniques that require externally funded trials to discover and develop the best application techniques for both technical and economic success. Another major emphasis is on innovative applications of existing, cost-effective, but underutilized technologies.

Characteristics of the Reservoir Class Program

A powerful and unique feature of the Reservoir Class Program is that reservoirs with common geological origins have been grouped together for treatment under the program. The premise underlying the groupings is that geologically similar reservoirs will, to some extent, have similar reservoir characteristics and production problems. Therefore, this grouping system promotes the application of successfully demonstrated technologies and methodologies to other reservoirs in the same group. These geologically based reservoir groupings were determined through a study of reservoir information stored in DOE's Total Oil Recovery Information System (TORIS) database. The TORIS database contains data on more than 2,500 domestic oil reservoirs representing two-thirds of the known domestic oil resource, or about 360 billion bbl of original oil in place. Twenty-two distinct, depositionally defined reservoir groups (sixteen siliciclastic and six carbonate) are recognized in the TORIS database (Figure 1.1 and Figure 1.2).

As operators demonstrate existing and new reservoir characterization and improved recovery technologies in field projects, other operators can confidently take advantage of the successes and failures of the technologies in projects in reservoirs of analogous origin. It follows that the greater the geologic similarity the better; reservoirs in the same basin, or even within the same play (where deposits are most likely to be exposed to similar geologic processes throughout their history), have a greater chance of being predictably similar. Of course, DOE recognizes the fact that every reservoir is unique in certain respects, and that no analogy will be perfect.

Another important feature of the reservoir groupings in the Reservoir Class Program is that the reservoir groups have been prioritized by both the size of their remaining recoverable domestic resource and the likelihood of reservoir abandonment in the near future. The Reservoir Class Program consists of a series of industry cost-shared projects in the highest priority reservoir classes. Those reservoir classes are being addressed first under the Reservoir Class Program that will have the greatest impact on DOE's primary mission. This government-sponsored program makes a unique contribution by coordinating resource-directed priorities for technology development and demonstration projects.

Cost-shared projects of the Reservoir Class Program also serve as a source of risk abatement and accelerate the final stages of development of new technologies and novel applications of current technologies that might not attract funding from a risk-averse and highly cost-conscious industry. Outside the Reservoir Class Program, although risk sharing is common in exploration ventures, there are few good mechanisms or incentives in place to persuade coalitions of small or large operators to duplicate these kinds of research ventures in mature production environments.

The strong emphasis on technology transfer built into the Reservoir Class Program promotes widespread and rapid imitation of the successes achieved in Reservoir Class projects, another unique strength of the program and a reason for government involvement. Outside the Reservoir Class Program, successful technological developments achieved by individual oil companies or company coalitions generally are carefully guarded to maintain a competitive advantage. Industry, acting on its own, has no effective incentive to maximize technology transfer. By making information available to the entire industry, DOE's Reservoir Class Program has maximum impact on the goals and objectives of the Field Demonstration Program.

Current Reservoir Class Program Projects

DOE has awarded contracts for cost-shared projects in the three highest priority reservoir classes. Projects are cost-shared by DOE up to 50% of the total project cost. Thirty-two projects representing combined industry and government investments in excess of $250 million were initiated. These first three reservoir classes contain over half (over 120 billion bbl) of the 240 billion bbl of oil remaining in reservoirs listed in the TORIS database (Fowler et al., 1995). Projects address either near-term (results within five years) program goals of preserving access to reservoirs with high potential for increased productivity which are rapidly approaching their economic limit or mid-term (results within ten years) program goals of developing and testing the best advanced technologies through an integrated multidisciplinary approach. Each project is divided into two budget periods. Projects that prove technical and economic feasibility during the first budget period are subsequently funded for field demonstration during the second budget period.

CLASS I Projects – In 1992 and 1993 four mid-term and seven near-term projects were selected and awarded in fluvial-dominated deltaic (FDD) reservoirs (Figure 1.3). Three projects were cancelled. Among the most geologically complex and compartmented of all reservoirs, FDD reservoirs contain more than 30 billion bbls of oil recoverable at the end of current operations (Fowler et al., 1995). Reservoirs of this type are the most susceptible to abandonment and were thus selected as top priority to address with field demonstration projects. Six of the eleven projects had been completed as of the end of 1997.

CLASS II Projects – Three mid-term and six near-term field demonstrations in Shallow Shelf Carbonate (SSC) reservoirs were selected and awarded in 1993 (Figure 1.4). Class II is made up of shallow-shelf carbonates characterized by both open and restricted water circulation (Figure 1.2). Although each of these subtypes has distinctive biological, sedimentological, and chemical characteristics, the two types are often gradational and it is frequently difficult to assign a given reservoir to one or the other type with confidence. The TORIS database lists about 64% of Class II reservoirs as of open circulation origin, about 34% as restricted. The salient characteristic that both depositional environments share is rapid lateral changes in sediment character and associated depositional energy levels. Class II reservoirs are among the most highly heterogeneous of carbonate reservoirs. More than 50 billion bbls of recoverable oil are expected to be left in domestic SSC reservoirs at the end of current operations (Fowler et al., 1995).

CLASS III Projects – Four near-term and five mid-term projects in Slope and Basin Clastic (SBC) reservoirs were awarded in 1995. All of these projects remain active (Figure 1.5). Like the reservoirs of Class II, reservoirs of Class III are of more than one depositional type, being made up of both slope-basin and deep-basin clastic deposits (Figure 1.1). Close similarities in the nature of deposits in these two groups vs. other clastic depositional groups justify grouping the two together for treatment under the Reservoir Class Program. This Reservoir Class includes deposits created by sediment gravity flow processes (e.g., turbidites), deposits that are formed by sedimentary material settling out of the water column (e.g., diatomites), and slope or deep basin deposits reworked by deep ocean currents (e.g., contourites). SBC reservoirs in the U.S. contain more than 44 billion bbls of potentially recoverable oil that will remain in place after current operations (Fowler et al., 1995).

ADVANCED CLASS WORK Projects – This special series of projects deals with field-based reservoir characterization and recovery process projects aimed at refining advanced technologies that were demonstrated or identified in Reservoir Class Program field demonstration projects. In addition, technologies shown to be promising in laboratory research and development efforts (e.g., improved recovery methods and reservoir characterization technologies) are being considered for demonstration under Advanced Class Work activities. Three projects were conducted and are complete in the Advanced Class Work Program.

Selection of Logging Technologies as a Focus

In 1996 and 1997, technologies applied in DOE's Field Demonstration and related projects were reviewed. Objectives of this activity were to (1) identify technology advances and usable products demonstrated in Reservoir Class and other program projects, (2) organize a prioritized series of workshops focused on technologies of significant interest and utility to industry, and (3) produce a published volume on each technology addressed in the workshop series. The intent of these workshops and accompanying peer-reviewed volumes was not to provide a technically or academically oriented treatment of technologies, but "here's how we did it" and "here's how it worked" treatments in a case history format.

Two primary criteria were considered in selecting workshop topics and their order of presentation. First, technologies were considered that played important roles and produced results in Reservoir Class and related program projects. Second, technology areas were favored that have been recommended for research, development, and technology transfer by various recent surveys (both DOE-funded and non-DOE-funded) performed by both research-oriented and practical, industry-oriented organizations. Technologies identified jointly in both types of surveys include wireline-log-related, seismic-related, and directional-drilling-related technologies.

Another important consideration was whether the application of the technology has proceeded sufficiently in program projects to warrant a workshop including discussions of success or failure and overall project impact. Applying this criterion resulted in selection of wireline-log-related technologies as a first priority for treatment in this workshop and publication series.

Primary objectives of the logging workshops were to:

1. Bring out the decision-making process that led to selecting a particular logging technology for use
2. Convey the methodology for applying or implementing the technology
3. Discuss technological successes and problems encountered
4. Estimate the overall cost-effectiveness of the technology

The first workshop, "Advanced Applications of Wireline Logging for Improved Oil Recovery Workshop," was held in Midland/Odessa, Texas, on November 13, 1997, at the Center for Energy and Economic Diversification (CEED). This one-day workshop was a cooperative effort between BDM-Oklahoma and the Texas PTTC Regional Lead Organization (RLO), the Bureau of Economic Geology of the University of Texas at Austin, Texas. The workshop consisted of 7 presentations and an afternoon panel discussion. A similar workshop, held in conjunction with the Rockies PTTC RLO (the Colorado School of Mines at Golden, Colorado) on January 13, 1998, in Denver, Colorado, included 10 presentations with a greater emphasis on reservoirs in the Rocky Mountains.

Wireline Logs as Reservoir Characterization and Reservoir Management Tools

Success in reservoir management means maximizing the profitability of a reservoir to its operator(s) over its lifetime. One of the primary keys to achieving reservoir management success is an accurate knowledge of the reservoir itself (its rocks, its fluids, its wellbores, and any changes that have been induced by past operations) (Madden et al., 1998). Knowing the reservoir means having a conceptual model of the reservoir to use as a guide, a representation of the reservoir that can be used to predict qualitatively and quantitatively the parameters affecting fluid flow at every location in the three-dimensional (3-D) volume of the reservoir. In the past it was considered sufficient to create a single "most probable" representation of the reservoir to serve as a model for decision making, but successful operators now recognize the need to estimate the range of departure from the ideal that one might actually expect to encounter. The degree of uncertainty associated with the placement and magnitude of reservoir properties affecting fluid movement is now an important element of the reservoir model.

Because reservoirs are heterogeneous on several scales ranging from the microscopic scale of pores and individual sediment grains to the gigascopic scale of entire formations (Haldorsen, 1986), it is important to the success of implementing improved recovery techniques to have knowledge of reservoir property distribution at all scales. Identifying a cost-effective method to obtain needed reservoir information at the appropriate scale, whether it be microscopic-scale information on rock composition, pore structure, and rock-fluid interaction or larger-scale data on facies change, structural features, and formational architecture, is an important part of reservoir characterization. Adding supplementary and complementary information from a variety of sources can make more accurate (less uncertain) reservoir conceptual models. Information may come from either analog or deterministic sources. Analog information consists of 3-D conceptual ideas or models derived by studying the distribution of properties in depositionally or otherwise similar reservoirs, outcrops, or modern environments. Deterministic data are derived from direct sensing of reservoir properties either by direct physical contact with the reservoir, as in the case of properties measured by core analysis, by indirect methods (such as seismic waves), or by some combination of the two (such as wireline logging measurements and pressure-transient tests). A wide variety of geological and engineering tools is commonly available to gather deterministic information for incorporation into a reservoir model. Figure 1.6 depicts the scale of measurement and associated resolving power of several common deterministic tools.

Boreholes are traditionally used for direct observation or measurement of reservoir properties. Information at several critical scales may be obtained at the borehole by a number of methods. Drilling cuttings, cores, and a wide variety of wireline logs are primary tools for obtaining this information. Wireline logging data range from direct contact measurements to remotely inferred data depending on tool configuration and technologies employed. The majority of wireline applications probably fall in the near-borehole directly measured category. Wireline logging tools span several orders of magnitude in the volume of the reservoir they measure, from the pore scale into the interwell scale. Some provide information at scales other than the scale at which they measure directly. For instance, measurement of characteristic scale and orientation of sedimentary structures by borehole imaging tools can provide information by inference through association with analog models about sedimentary architecture and spatial characteristics of depositional facies on a much larger scale than that of direct measurement.

Three Divisions of Wireline Logging Technology

Projects being conducted under the Department of Energy's Reservoir Class Program and related field demonstration projects are making use both of data from conventional logging tools and data gathered using newly evolving, highly specialized logging technologies. A survey of reservoir characterization efforts in ongoing and completed projects identified three areas employing advanced logging technology. There is high interest in, and much attention given to the use of new tools capable of measuring reservoir rock and fluid characteristics not previously possible with conventional tools and providing measurements at a finer resolution than ever before. A subset of these advanced logging tools that has attracted great interest and seems to hold great promise creates visual images of the distribution of properties about the circumference of the borehole surface. A third area of advancement is in extracting additional information related to reservoir rock and fluid properties through integrating geological and petrophysical data from core or other primary sources and through applying advanced data processing techniques to conventional wireline log data. This area depends less on tool technological improvements and more on recent advances in computer processing capabilities. In Reservoir Class Program projects, all three categories of wireline log applications have contributed substantially to building accurate reservoir characterization models for implementing improved recovery techniques. The organization of this volume reflects these three major divisions.

Rock Typing Using Conventional Logs (Core-Log Modeling)

These approaches involve correlating rock properties and fluid transmissibility properties to single or multiple wireline log response. In many Reservoir Class Program projects, the approaches have enabled more accurate estimation of important reservoir performance-related properties on a fieldwide scale. This capability has resulted in a much more complete and less uncertain description of the reservoir on which to base recovery process implementation than would have been otherwise possible. Because these techniques are typically applied on a reservoir scale, the wireline curves upon which they are based are from logs that have been in widespread use by industry for an appreciable time. This aspect of wireline logging is addressed first because it focuses on information already contained in a large number of existing logs.

Use of Borehole Imaging Logs

Numerous Reservoir Class Program and other projects have used borehole imaging logs to describe such diverse properties as lithology, fluid saturations in thin beds, sedimentary structures and reservoir architecture, large-scale pore structure, and natural fracture orientation, aperture, and fluid content. This category also includes video-imaging tools frequently used for inspecting cased boreholes. Knowledge of the reservoir gained from these logs has contributed substantially to support reservoir modeling in several projects. These tools might be considered a subset of advanced logging tools in that they are just now coming into routine and widespread use, but the use of these "true imaging" logs is spreading rapidly and they will soon become standard tools used by most operators.

Use Of Advanced Wireline Tools:

Other modern and newly developed tools such as nuclear magnetic resonance, pulsed acoustic, and array induction tools have also contributed to a better understanding of petroleum reservoirs in DOE's Reservoir Class projects, particularly to a better knowledge of fluid distribution in the reservoir. Included in this class are those tools that have reached a stage of frequent application by industry, but whose utility in specific reservoir situations and whose optimum techniques for application are not yet widely understood.

This volume also offers a cursory review of newly developing advancements in wireline logging technologies that are still in the research stage, particularly a review of research and development activities being supported or cost-shared by DOE.

Chapters 2 through 4 contain case-history discussions of the use of logging technologies in the Reservoir Class Program and other DOE-supported and cost-shared projects. Names, addresses, phone and fax numbers, and E-mail addresses of project principal investigators and other relevant project personnel for those wishing additional information are included in Appendix A. Some projects have dedicated Web sites, and these are also listed in Appendix A.

For Further Information on Projects Reviewed and Related Projects...

This volume on the use of logging technologies in DOE's Field Demonstration Program and related projects provides only a small sampling of the vast amount of practical information on technology implementation, reservoir characterization, and reservoir management that is available from the projects. A good source of current overview information is the *Class Project Summary Sheets*, a volume published by DOE containing brief descriptions, recent accomplishments, and status information on all of the Reservoir Class Program projects. Another DOE publication, the *Reservoir Class Field Demonstration Publication and Presentation Bibliography*, lists all project technology transfer activities. Additional overview information can be downloaded from the National Petroleum Technology Office (NPTO) homepage (www.npto.doe.gov) in the form of the CLEVER (CLass EValuation Executive Report) database. The *Class Act*, a DOE-sponsored newsletter also available at the NPTO Web site, conveys current highlight information on important project accomplishments and upcoming technology transfer events such as workshops, publications, and presentations. Detailed current project information may also be obtained from interim project reports published by DOE. To obtain DOE publications relating to Reservoir Class Program or other projects, please contact:

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Because only a small number of the Reservoir Class Program projects discussed here have been completed, the authors hope to supplement this volume with project data and periodic updates on project progress in electronic form on the National Petroleum Technology Office Internet home page (www.npto.doe.gov). This will ensure that the utility to operators wishing to apply logging technologies demonstrated in these projects to their own reservoirs stays current after the publication of the volume.

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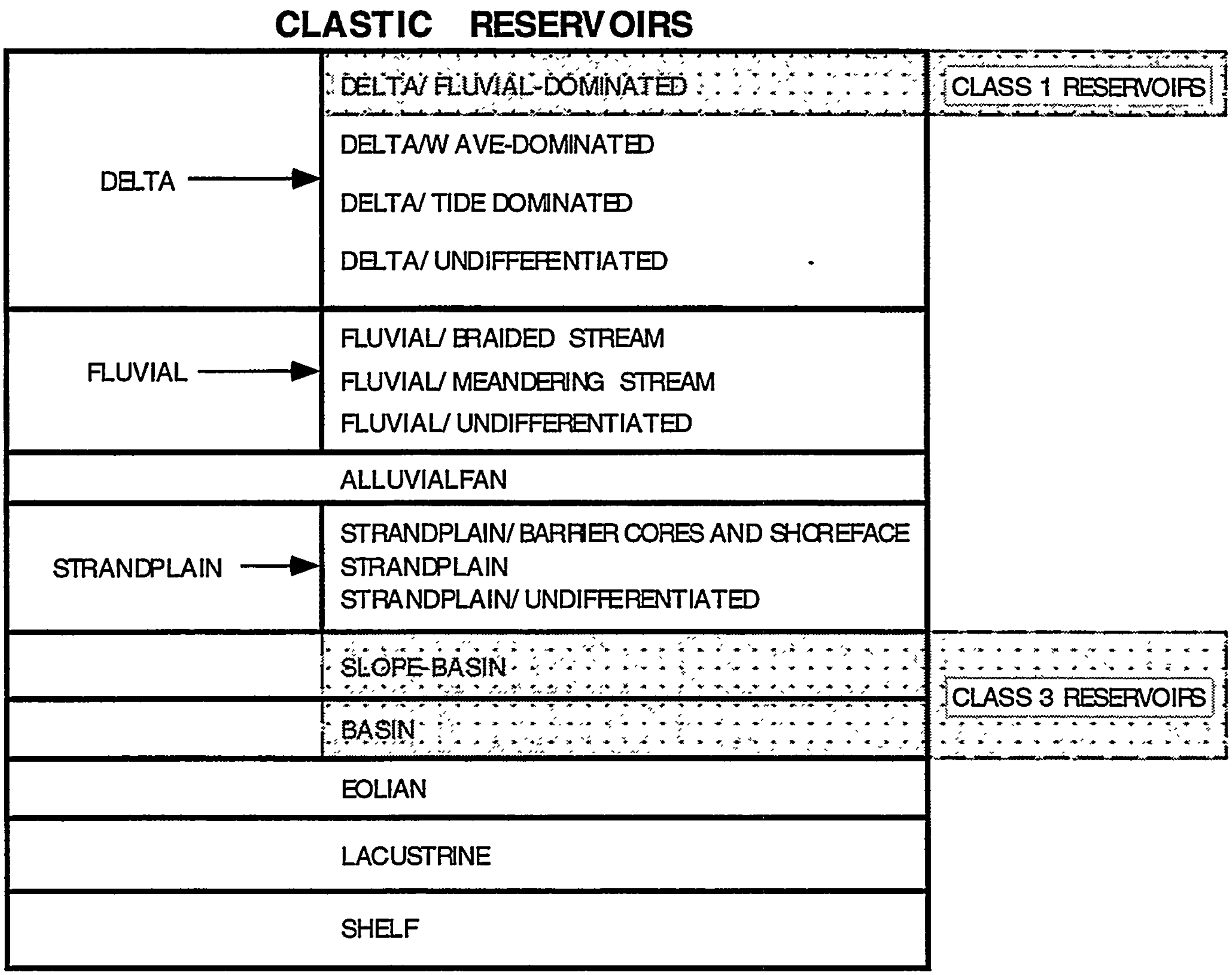

Figure 1.1 – Siliciclastic reservoir groups.

CARBONATE RESERVOIRS

PERITIDAL	DOLOMITIZATION MASSIVE DISSOLUTION OTHER	
SHALLOW SHELF (OPEN)	DOLOMITIZATION MASSIVE DISSOLUTION OTHER	CLASS 2 RESERVOIRS
SHALLOW SHELF (RESTRICTED)	DOLOMITIZATION MASSIVE DISSOLUTION OTHER	
SHELF MARGIN	DOLOMITIZATION MASSIVE DISSOLUTION OTHER	
REEFS	DOLOMITIZATION MASSIVE DISSOLUTION OTHER	
SLOPE-BASIN	OTHER	

Figure 1.2 – Carbonate reservoir groups.

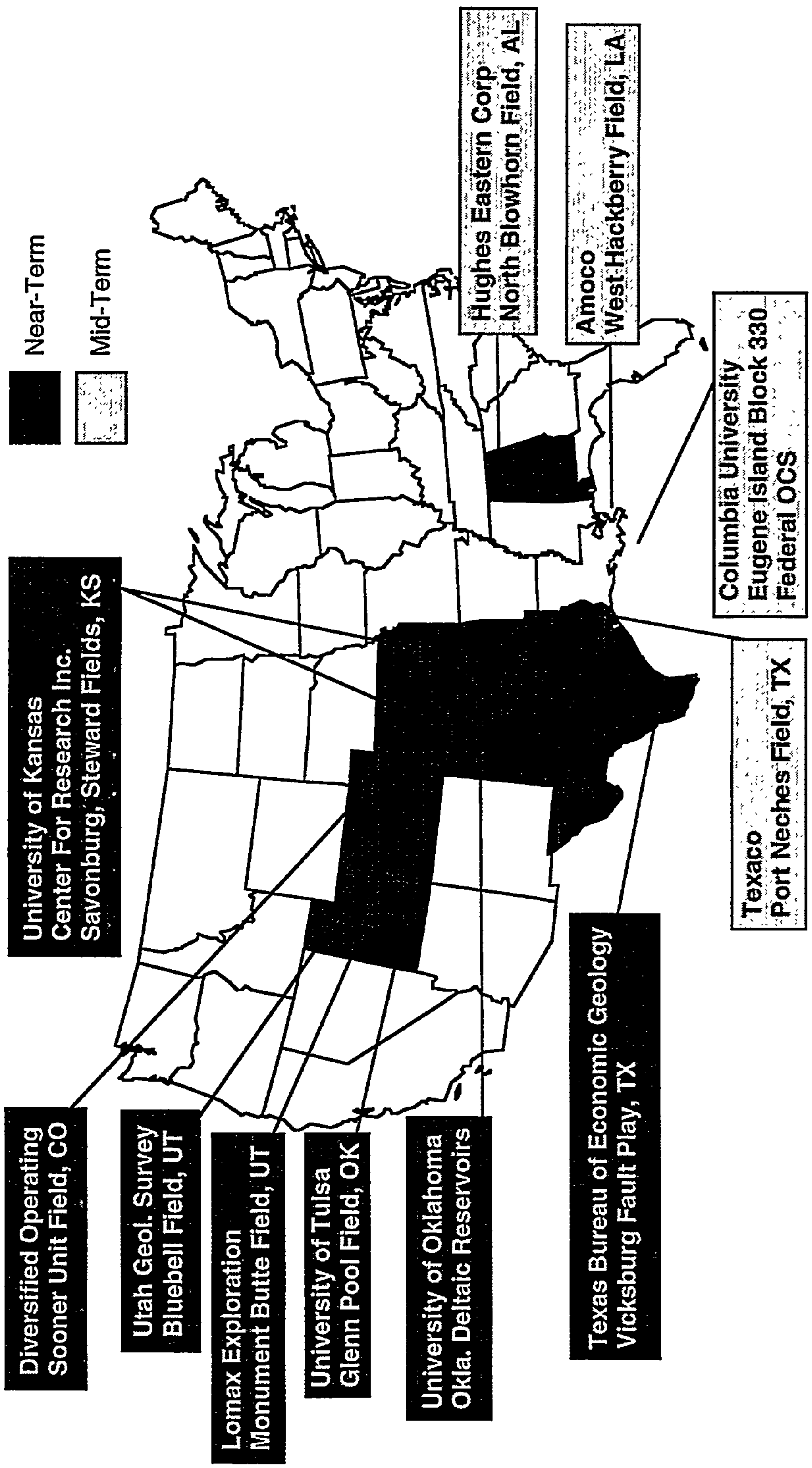

Figure 1.3 – Reservoir Class I oil recovery projects.

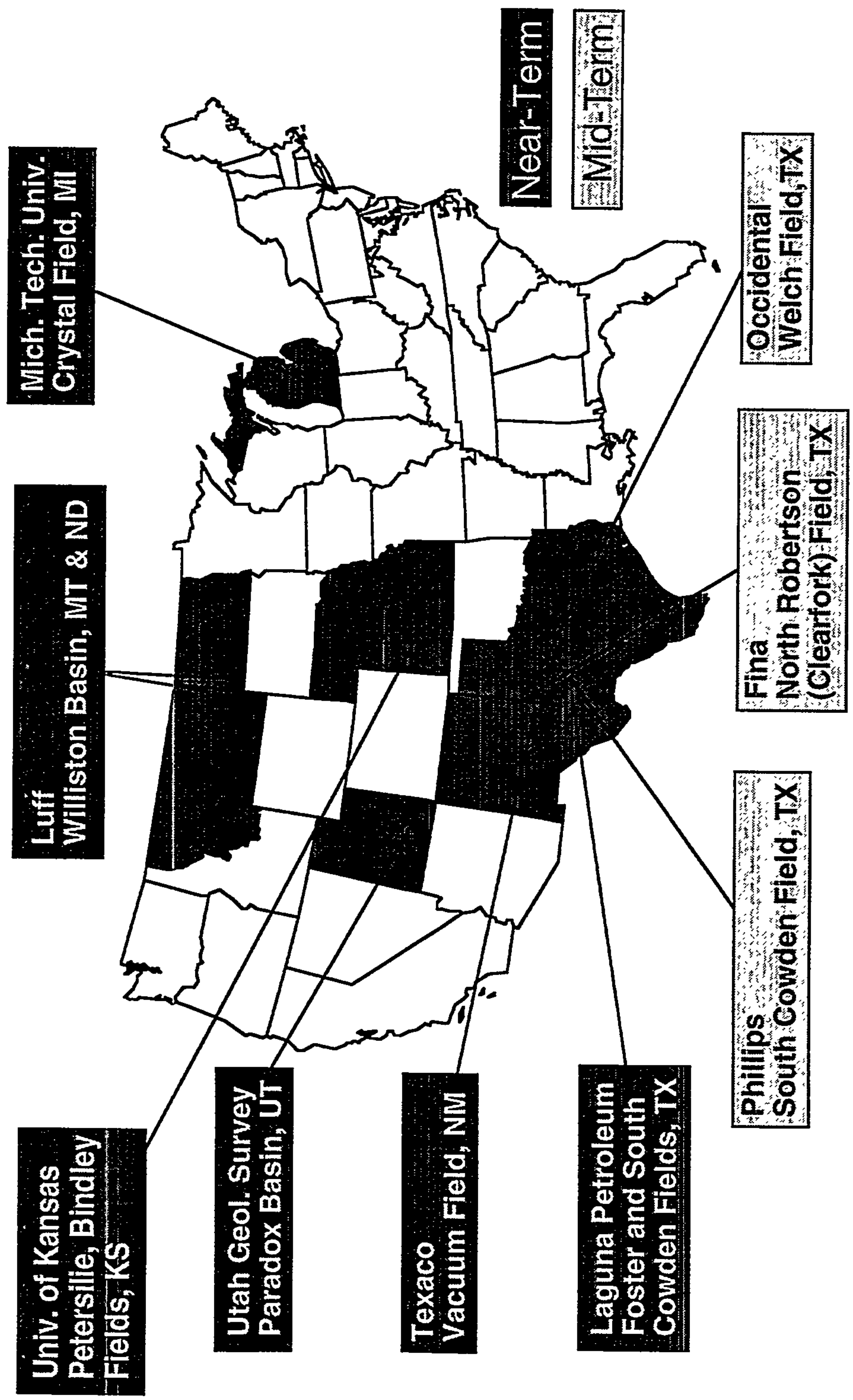

Figure 1.4 – Reservoir Class II oil recovery projects.

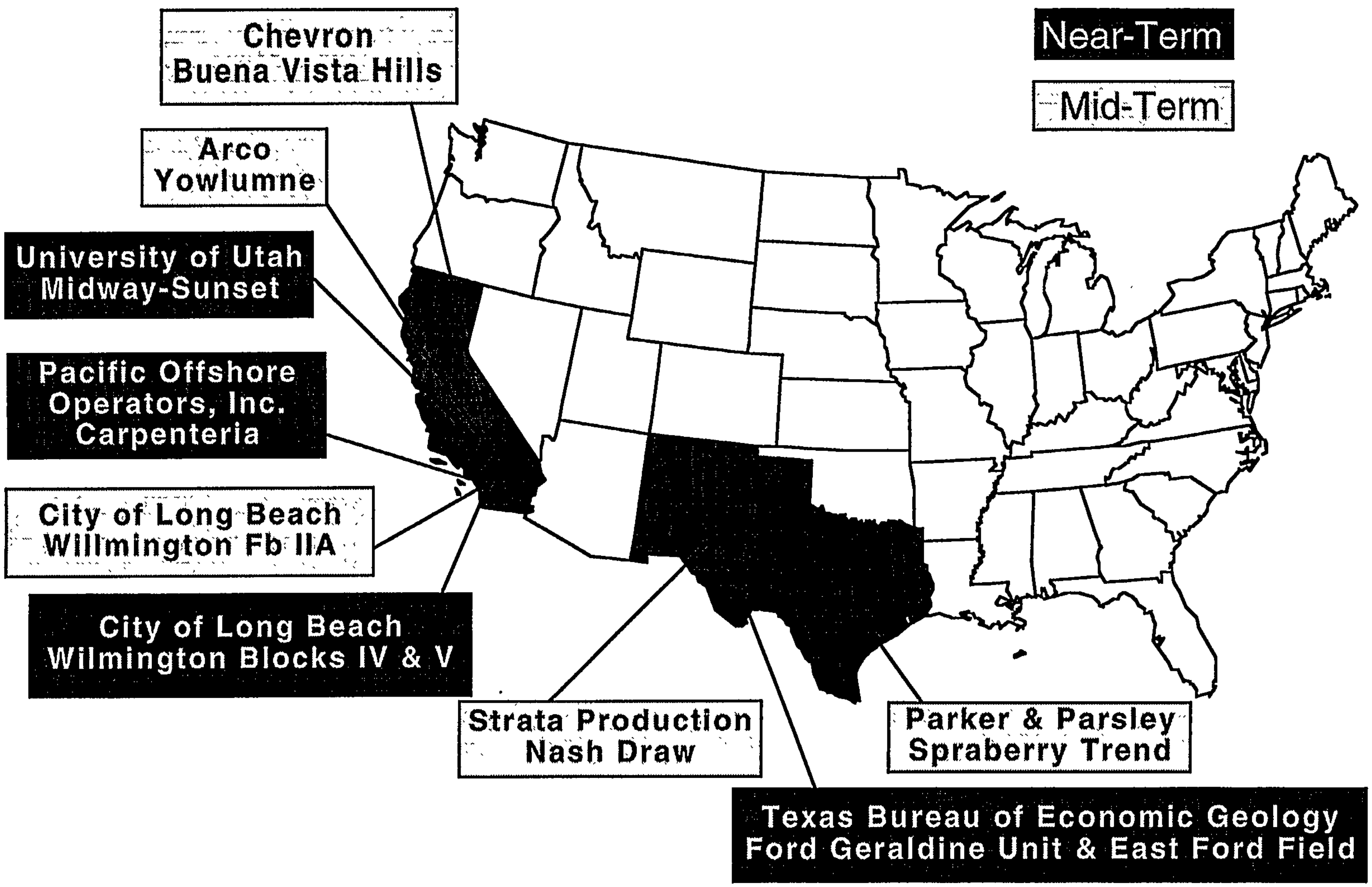

Figure 1.5 – Reservoir Class III oil recovery projects.

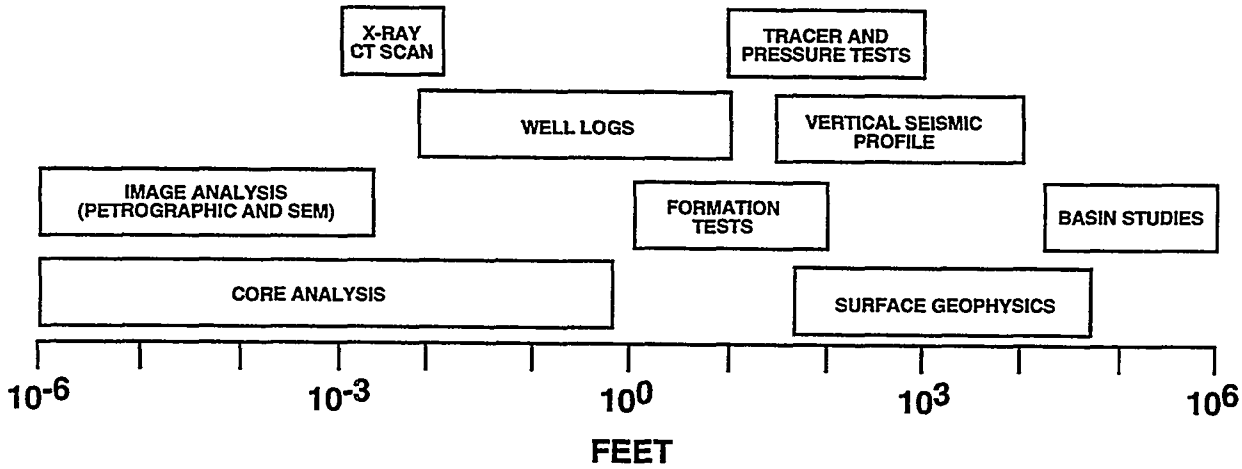

Figure 1.6–Scales of measurement and resolution of some common reservoir characterization tools. (Modified from Worthington, 1989)

CHAPTER 2

CORE-LOG MODELS: NEW INFORMATION FROM EXISTING LOGS

In a cursory review of DOE cost-shared project summaries and proposals submitted to DOE by project operators, core-log modeling was not identified as a critical technology. Only after project activities were detailed in quarterly and annual reports was it found that in certain projects, unique and highly integrated analysis of core and wireline log information made very significant contributions to technical and/or economic success.

What Is a Core-Log Model?

Core-log modeling is a subject that has no universally accepted or even widely recognized definition. For the purposes of the discussion that follows, core-log modeling is the attempt to develop correlations between wireline log response and reservoir properties observed in reservoir samples (i.e., rock properties, fluid properties or content, and/or fluid transmissibility properties). In the broadest sense, because materials retrieved from boreholes are the primary source of "ground truth" information about reservoir properties, all standard wireline log analysis might be said to deal with developing core-log models. However, in this chapter the focus is on reservoir-specific core-log models that have been developed and applied on a reservoir-wide scale rather than on the scale of individual wells. Specifically, these reservoir-tailored core-log modeling projects have been undertaken in previously developed reservoirs using, for the most part, existing wireline logs. Their goal is to enable predictions of petrophysical properties to be made over a wide expanse of the reservoir without the expense of collecting extensive new wireline log or core data.

Ease and direction of fluid movement are prime considerations in reservoir characterization. Yet these properties cannot be directly measured by standard wireline tools and they are prohibitively expensive to measure on a reservoir-wide basis through tracer tests or well tests. A standard approach for many years has involved the use of log-derived porosities to predict permeability in reservoir rocks of uncored intervals using the relationship between porosity and permeability derived from conventional core analysis. In many reservoirs, however, the relationship between porosity and permeability is not a simple one. The plot often shows only a very poor log-linear relationship when all core data from the reservoir are combined, resulting in substantially underestimated permeability heterogeneity prediction from log porosity.

In the DOE-sponsored Advanced Applications of Wireline Logging Workshop in Midland, Texas, in 1997, a majority of the 90-minute panel discussion that followed the workshop was spent in addressing the imperfect relationship between core and wireline log data. Specific topics discussed included problems associated with the typical bias toward better quality reservoir rock of core sampling for property measurements, the differences between the scale of measurement in core vs. log data, and the fact that both core measurements performed in the laboratory and wireline log measurements have associated errors that have not been properly accounted for. Alternative solutions, such as the use of minipermeameter measurements on cores rather than the use of core plugs (Georgi et al., 1993) may provide a better "training set" of permeability data for comparison with log porosity, but the root of the problem is probably more fundamental. Pore size, pore throat size, and other aspects of pore geometry such as pore surface area are the controlling factors.

The problem becomes more understandable when viewed from the perspective that pore systems are almost universally not uniform on a reservoir scale. Pore system geometry in siliciclastic rocks is strongly influenced by localized energy conditions under which the rocks are deposited. In carbonate rocks, pore geometry, although usually influenced to some extent by depositional conditions, is equally likely to be altered drastically after deposition by diagenetic factors in patterns that may or may not correspond to features of depositional origin.

Lack of a clear, straightforward relationship in many reservoir formations between log response and the reservoir characteristics that influence fluid movement and distribution has led many operators and researchers to seek more advanced solutions (e.g., Hearn et al., 1986; Wendt et al., 1986). As a first step, some operators of projects in DOE's Field Demonstration Program tried approaches only slightly more sophisticated than the traditional reservoir-wide scatter plotting of core porosity vs. core permeability, such as looking at porosity-permeability relationships within mappable reservoir zones or facies. This approach met with some success, but with notable exceptions, particularly in carbonate reservoirs. More sophisticated subsequent approaches were based on a more complete understanding of the basic pore systems that constitute the reservoir, the fluids that are present, and the physics of the wireline tools used in measurement.

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Applications of Core-Log Models in Field Demonstration and Other Projects

Core-log modeling has provided the basic framework for reservoir description and evaluation in several Reservoir Class Program projects. The projects reviewed here are those that have made extensive use of this approach to reservoir-wide description by innovative use of existing wireline data to describe the reservoir at essentially every well location and in some cases in the interwell areas as well.

A recurrent theme throughout this chapter is the use of "old" log data to describe as accurately as possible large, very mature domestic reservoirs discovered and developed many decades ago. Innovative gleaning of reservoir rock and fluid information from previously unsuspected sources characterizes many of these projects. A second significant focus of some projects reviewed in this chapter is on attempts to describe detailed characteristics of reservoirs that have defied accurate description by conventional wireline log analysis in the past. Innovative and new approaches are needed for more accurate understanding of these complex reservoirs to access their large remaining reserves. A third characteristic shared by several projects is the development of computerized approaches to reservoir-wide analysis of log data to enable internally consistent and accurate models for improved recovery evaluation of large reservoirs.

University of Tulsa—Glenn Pool Field, Oklahoma (Reservoir Class I): Balmohan G. Kelkar and Dennis R. Kerr

The Glenn Pool field is located in portions of Tulsa and Creek Counties in northeastern Oklahoma (Figure 2.1). The field was discovered in 1905 and is estimated to have produced 330 MMBO from the Bartlesville Sandstone. Bartlesville Sandstone is an informal subsurface or drillers' term applied to Pennsylvanian age (Desmoinesian) fluvial-dominated deltaic (Reservoir Class I) deposits that not only were responsible for the first commercial oil produced in the state, but also were responsible, through development of fields like Glenn Pool, for the early preeminence of Oklahoma as an oil-producing state (Northcutt et al., 1997). The main producing interval in the Glenn Pool field was called the "Glenn Sandstone" a unit with an average gross producing thickness of nearly 240 ft (net pay 140 ft) at a depth of 1,450 ft.

With decline in production, gas re-injection began in 1940, followed by waterflooding operations in 1944. Secondary recovery efforts had been responsible for production of an additional 100 MMBO by 1990. Results of modern waterflood studies and trial tests and implementations of tertiary recovery methods have shown the possibility for significant additional volumes of recoverable oil. The current estimate is that only 21% of the original oil in place has been produced. It is in this context that the University of Tulsa undertook this project in 1993 in the 160-acre Self unit of the Glenn Pool field (Figure 2.1). The project, scheduled for completion in early 1999, addressed producibility problems, injectivity problems, and lack of reservoir continuity in an attempt to improve secondary recovery performance through reservoir characterization studies and horizontal well injection technology. An additional objective of the project was to compare the cost-benefits of obtaining state-of-the-art data over conventional data for waterflood optimization and well placement. The reservoir management plan developed was based on integrating numerous technologies:

Conventional reservoir characterization data, such as that from

- Log and core analysis
- Production data

State-of-the-art data, such as that from

- Cross-borehole tomography
- Resistivity imaging logs
- Geostatistical realizations of interwell heterogeneity

A model of reservoir architecture was developed by defining and correlating discrete genetic intervals (DGIs) as contiguous facies deposited during a limited discrete increment of time. Each DGI likely corresponds to variations in baselevel position as the incised valley confining the Bartlesville Sandstone filled. In practice, each DGI is defined by the relative stratigraphic position of the occurrence of channel-fill and attendant crevasse splay facies. The superpositional relationship of the DGIs is established by the elevation of the top of channel-fill deposits with relationship to an overlying marker bed (Inola marker). In the project area, DGIs are the fundamental operational units for subsurface mapping. In the vicinity of the Self No. 82 well in the Self unit, seven DGIs are recognized (Figure 2.2).

Determination of DGIs relied on recognition of their facies makeup as observed through examination of facies distribution both in core and in outcrop. The practical recognition of facies on a large scale (100s of wells) was made possible by developing a relationship between the response of commonly available logs (i.e., spontaneous potential, gamma ray, and resistivity logs) and the occurrence of facies in cored intervals. Three facies contain the main reservoir-quality porosity and permeability:

- Channel-fill facies are recognized by a bell-shaped profile.
- Crevasse splay facies are recognized by a funnel-shaped or symmetrical log profile.
- Braided channel-fill facies have a blocky well log profile that can be highly serrated.

Two additional facies, floodplain mudstones and levees, constitute barriers or baffles in the reservoir. Additional efforts are being made to discriminate objectively and quantitatively between channel fills of meandering vs. braided stream origin using wireline log data (Kelkar and Kerr, 1998).

For each DGI, facies maps and facies-based net sandstone maps were created for the reservoir. These maps served as an initial model of vertical and areal heterogeneity. Geostatistics was then used to estimate geological features and properties at interwell locations. A conditional simulation approach was taken as opposed to a conventional kriging approach. Conditional simulations have several advantages over conventional kriging in that they honor the original sample data and the distribution of that data, honor the original spatial relationships established with that data, and can create equally probable realizations or images that help to quantify and understand uncertainty (Bahar and Kelkar, 1997). In this project a combination of three such conditional simulation techniques was used in constructing the reservoir description. This approach involved:

1. Indicator kriging and truncated Gaussian simulation to predict by simulation the interwell facies distribution
2. Sequential Gaussian simulation to arrive at interwell porosity distribution
3. Conditional distribution sampling of permeability values using porosity to arrive at interwell permeability distribution

Each of these techniques was applied sequentially. A computer program (COSIM) was developed incorporating all of these techniques into a single co-simulation package. This package is available as a public domain program.

The number of available density-neutron or sonic porosity logs available in the study area was not sufficient to develop a detailed description of the distribution of reservoir porosity as a basis for simulation. An empirical gamma ray to core porosity regression relationship was therefore established based on data from the Self 82 well drilled in the project. The relationship is moderately robust (Figure 2.3), and suggests that this is a reasonable way to overcome the paucity of porosity data in the area. The gamma ray log has the additional advantage that it may be run in cased holes where needed. Comparison of gamma ray response vs. porosity in two wells in the study area that had both open-hole gamma ray and porosity logs run gave comparable results with the exception that porosity calibration against cores yielded a slightly more optimistic porosity prediction for a given gamma ray intensity than porosity calibration against logs. The reason for this discrepancy is probably because 1-2 in. core plug samples represent an intermittent and small volume scale sampling of the reservoir usually selected visually with a bias toward better quality reservoir rocks.

One of the major drawbacks to estimation of porosity from gamma ray logs, especially in mature fields, is that logs have been run using tools of different vintages and tools provided by different service companies. Another factor leading to nonuniformity is that open hole logs always yield higher gamma ray readings than cased hole logs because of the attenuating effects of metal casing. If the raw values of gamma ray readings from different wells were translated to porosity without accounting for these facts, over- or under-estimation of porosity would result in nearly every instance. A multiwell normalization of the gamma ray curves was performed. This procedure brings the average value of the log response to shale (i.e., the shale base line) into alignment by addition or subtraction of a constant value to make the response over the shale interval equal to that of a "type" well or "average" well. All deviations from this shale base line, which are indicative of sand, can then be compared by reference to this common base datum.

After interwell simulation of facies distributions and correlation and assignment of interwell DGIs and thickness of DGIs, interwell porosity values were assigned. To obtain porosity values for flow simulation at interwell locations, average gamma ray values for each DGI at well locations were kriged to obtain an interwell array of gamma ray values which were then converted using the established regression equation to yield porosity. A random number generator was used to add the appropriate amount of "scatter" to the porosity predictions to reproduce a relationship similar to that of the original gamma ray vs. porosity relationship as shown in Figure 2.3.

Predictive capability for permeability on a fieldwide basis was achieved by first developing a relationship between core porosity and permeability for each DGI. For each DGI a porosity vs. permeability plot was constructed, and each plot was divided into several porosity intervals or classes. For each porosity interval a distribution function was created to express the distribution of permeabilities within that porosity class. These relationships were then used to create vertical permeability profiles from the porosity curves generated from the gamma ray logs. Permeability predictions at interwell locations were made by plugging the porosity predictions generated by the procedure discussed in the paragraph above into the appropriate relationship between porosity and permeability for each DGI. Sampling the permeability distribution corresponding to the appropriate porosity range supplies the appropriate "scatter" or expression of uncertainty to the generated permeability values.

Saturation values were based on porosity derived from gamma ray and induction/resistivity logs. Log-derived saturation values were compared with values derived from core analysis and with thermal decay time (TDT) logs as a check on the computational validity of the approach. Saturations were then averaged over each DGI before being propagated to the interwell area using kriging techniques.

As a screening test to identify areas with highest potential recovery before running flow simulations, the information derived previously was combined to quantitatively map a Potential Index (PI). This index is directly related to production capacity and reservoir storage capacity and inversely related to the accessibility of an area by other wells. As a first step, a Conductivity Index (CI) was calculated to reflect production capacity by multiplying permeability by thickness for each DGI. A Storativity Index (SI) was calculated as the product of porosity, saturation, and thickness for each DGI. Both these indices were assigned ranks (1 to 4) based on a quartile system. An Accessibility Index (AI) is assigned a value of 0 if the DGI is penetrated by an existing well, a 1 if it is not. A final calculation of the Potential Index or PI is performed by summing the ranked CIs and SIs and multiplying by AI. Summing the PI indices for each DGI effectively identified the interwell areas with highest potential (Kelkar et al., 1996).

Reservoir characterization using state-of-the-art technologies and reservoir flow simulation study results at the Self unit indicated that drilling of a horizontal injection well would be uneconomic, but supported a reservoir management plan based on well recompletions and stimulation. Thus far, recompletions of 7 wells out of 28 operating in the unit resulted in increased unit production from 10–20 BOPD to 35–40 BOPD for about eighteen months following implementation. Currently, production is from 30–35 BOPD. After complete implementation of the plan, unit production is expected to reach 80–100 BOPD. A conservative estimate made in early 1997 was that ultimate incremental production from the Self unit might be from 200,000 - 250,000 bbl. The cost in the first (advanced technology) stage of the project has been from $4.50 – $6.00 per incremental bbl of oil recovered, including the cost of cross-borehole tomography which was considered only marginally cost-effective. Discounting the cost of advanced technology usage that did not contribute substantially to project success (e.g., the tomography) brings the finding cost using the other methodologies developed down into the $2 – $3 per bbl range.

In the second stage of the project, reservoir characterization studies are being performed using only conventional data and the DGI and petrophysical property estimation approach described earlier in tracts in the Berryhill unit, a unit to the north of the Self unit in the Glenn Pool field (Figure 2.1). Costs per incremental bbl recovered during this phase of the project are currently also estimated to be in the $2 - $3 per bbl range.

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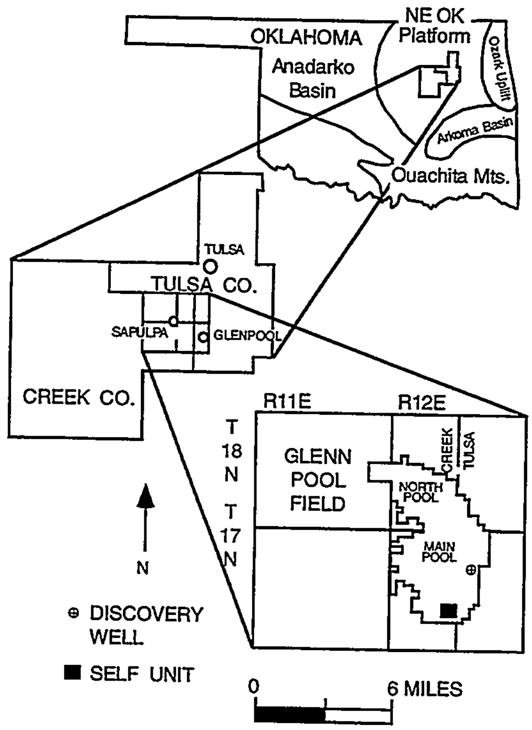

Figure 2.1 – Location of the Glenn Pool field. (From Kerr and Ye, 1997; modified from Kuykendall and Matson, 1992)

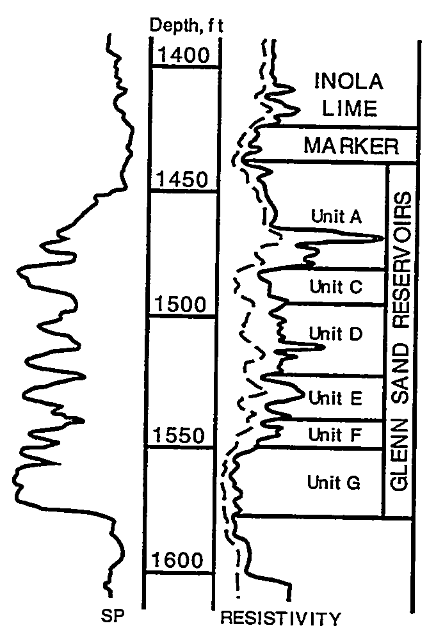

Figure 2.2 – Typical well log through the Glenn Sandstone interval in the Self unit. (From Kelkar et al., 1994)

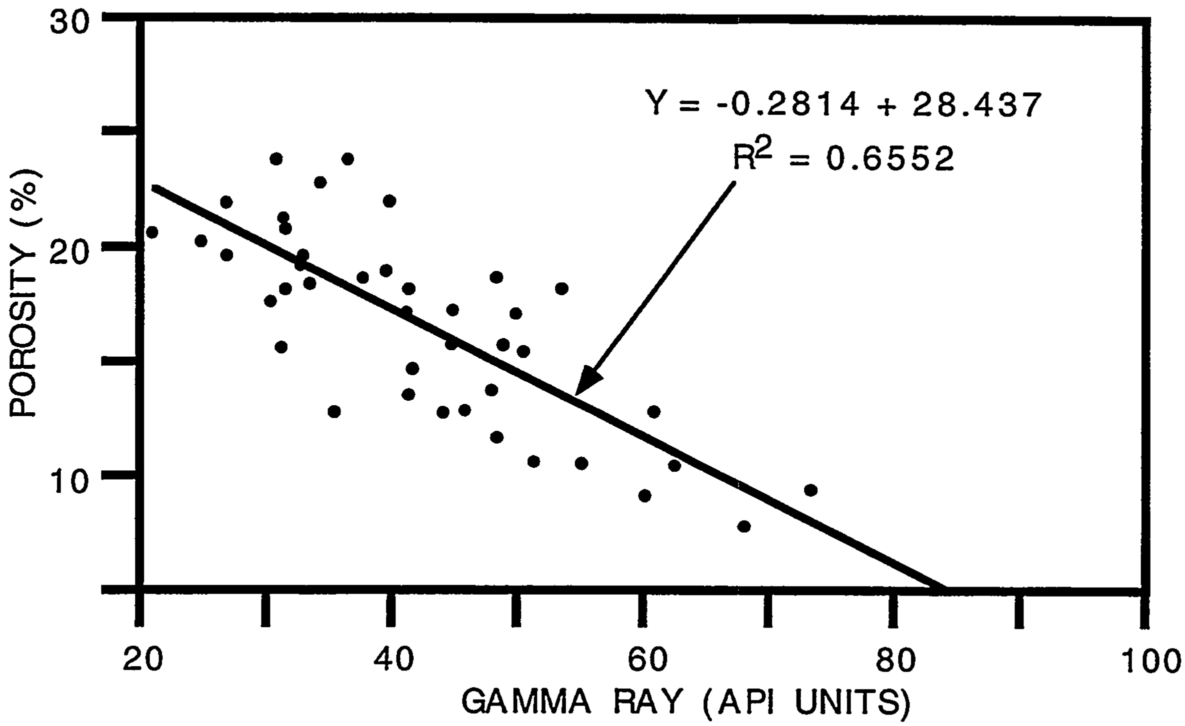

Figure 2.3 – Relationship between gamma ray intensity and porosity as observed in the Self No. 82 well. (From Kelkar and Kerr, 1998)

Fina USA Inc. – North Robertson Unit, Texas (Reservoir Class II): Jerry Nevans, David K. Davies, and Bill Dixon

The Permian Glorieta/Clearfork of West Texas shares many characteristics with other Shallow-Shelf Carbonate (Reservoir Class II) reservoirs. These historic reservoirs have a high degree of both areal and vertical heterogeneity, and both porosity and permeability are relatively low (Davies and Vessell, 1996). The reservoirs are compartmentalized with poor vertical and lateral continuity because of variations in porosity and permeability that under waterflood result in poor balance of injection and production, unexpected water breakthrough, and poor sweep efficiency. Typical Glorieta/Clearfork reservoirs have recovered only 15 to 22% of the oil they originally contained.

The North Robertson (Clearfork) unit (NRU) is located in Gaines County, Texas, on the northern edge of the Central Basin Platform of the Permian Basin (Figure 2.4). The producing horizons are Permian Age, Leonardian Series carbonates of the Glorieta and Clearfork formations (the latter referred to as the upper, middle, and lower Clearfork). The hydrocarbon-bearing interval extends from the top of the Glorieta to the base of the lower Clearfork, between the correlative depths of approximately 5,870 and 7,440 ft. The NRU project area of 5,633 acres contained a total of 252 wells as of March 1996, including 142 active producing wells, 109 active injection wells, and 1 water supply well.

Production from the North Robertson field area began in the early 1950s with 40-acre primary well development. This 40-acre primary development resulted in 141 producing wells by 1965. The NRU was formed effective March 1987 for the purpose of implementing waterflood and infill drilling operations to reduce nominal well spacing from 40 acres to 20 acres. At the time of unitization, oil production from the unit area was approximately 670 STBOPD, with a GOR of 1,550 scf/STB, and water production of 500 BWPD. The NRU was for a time during the 1980s the largest single waterflood installed in the onshore lower 48 states. Most of the 20-acre infill drilling was completed between unitization and the end of 1991. The high degree of vertical and lateral heterogeneity in the Glorieta/Clearfork suggests that infill drilling on a further reduced spacing coupled with a vigilant reservoir surveillance program will be required to optimally deplete this reservoir.

The current project, begun in 1994 and scheduled for completion in 1999, is identifying areas of the NRU with the best potential for reducing well spacing to 10 acres. The operators have undertaken to show that a targeted infill drilling program guided by integrated reservoir characterization can improve unit economics and recover significant amounts of oil remaining in the Glorieta/Clearfork reservoir.

Traditional Stratigraphic, Depositional Environment, and Diagenetic Studies

Early in the project, depositional and sequence stratigraphic models were constructed for the Glorieta and Clearfork formations on the basis of both macroscopic (visual) and microscopic (petrographic thin section and scanning electron microscope [SEM]) data obtained from observations and analyses of available whole core within the unit (Figure 2.5A and Figure 2.5B). Ten distinct lithofacies were defined, assigned an environment of deposition, and incorporated into 3-D sequence stratigraphic models. These models were later modified with further study and incorporation of additional core material from subsequently drilled wells.

The initial interpretations for depositional environments and sequence stratigraphy were derived primarily from qualitative descriptions and thin-section studies of the whole core samples, with the following results:

- Highstand Lithofacies Tracts
  - supratidal exposure
  - small isolated vegetation covered nearshore islands
  - intertidal and channelized tidal flats
  - lagoons
  - shoal water banks/sand belts
  - forebank
- Transgressive Lithofacies Tracts
  - forebank
  - reef
  - shallow basinal
- Lowstand Lithofacies Tracts
  - continental deposits

The lower Clearfork, which is defined as the portion of the Clearfork Formation directly overlain by the Tubb Formation (a silty dolostone interval known informally as the Tubb marker), was interpreted as primarily open marine-shelf conditions dominated by deposition of grainstones that developed in shallow water shoal environments (Figure 2.5A). The shoal areas may have coalesced and interfingered with one another thereby resulting in more or less continuous belts of current and wave-dominated grainstone deposits with allochems composed primarily of ooids, oncoids, fusulinids, and peloids. Intershoal regions exist laterally to grainstone shoals, and rocks from these intershoal areas contain greater amounts of muddy carbonate material and correspondingly lesser amounts of allochem material. Only minor amounts of shallow subtidal algal mat rocks were observed in the lower Clearfork. Contour maps of historical production performance suggest that many of the outer shelf grainstone reservoirs are in communication with one another and that the amount of compartmentalization and heterogeneity may not be as pronounced in the middle Clearfork, upper Clearfork, and Glorieta (which overlie the Tubb marker).

Initial analysis indicated that the upper/middle Clearfork and the Glorieta sequences were deposited under conditions different from the lower Clearfork. This section is typified by highstand lithofacies characterized by highly cyclic depositional environments consisting of inner shelf subtidal flats, small isolated vegetation-covered nearshore islands, restricted and open lagoons, and intertidal to supratidal channelized tidal flats. The lower portion of the middle Clearfork, which immediately overlies that Tubb marker, is an exception in that it is characterized by a transgressive lithofacies tract (approximately 150 to 250 feet thick). Within this interval, there is evidence of reef development represented in core as non-porous, mottled boundstones that contain sponge, algae, coral, and bryozoan fragments. Analysis of historical well performance data suggests that most of the dolostone rocks that characterize these reef depositional environments have generally poorer reservoir parameters. Porosity and permeability are reduced because the dolostones tend to be mud rich and anhydritic. However, debris aprons surrounding the reefs can have good reservoir quality, as in the southwestern region of the unit. Debris aprons are a significant portion of the reservoir in selected locations within the NRU. Although not as prevalent and well developed in the upper/middle Clearfork and Glorieta, grainstone shoals also comprise a significant portion of the reservoir quality rock. In general, the middle/upper Clearfork and Glorieta were deposited in more cyclical environments resulting in numerous variations in petrophysical properties both vertically and laterally. The degree of heterogeneity generally increases upward within the entire stratigraphic section and within each major carbonate cycle. This plus the appearance of less open marine sediments in the upper/middle Clearfork and Glorieta reflect the overall west to east progradational nature of sedimentation at NRU.

Continued study of available materials at NRU and elsewhere coupled with incorporation of new core information (more than 10,000 ft of core from NRU) as the project progressed, suggested that a wider diversity of facies is present within the Glorieta/Clearfork than was previously recognized. Distinctions among different varieties of grainstone shoal deposit, as well as identification of biohermal, beach, open lagoonal, and restricted lagoonal facies were made (Montgomery and Dixon, 1998). Abundant evidence of plant debris suggests that the interval was deposited under hot and predominantly humid (not arid as has been previously assumed) conditions in a complex array of specific environments (Figure 2.5C) with intermittently widespread vegetal covering of exposed islands and supratidal areas.

The diagenetic history of the Glorieta and Clearfork reservoirs was determined using thin sections and scanning electron microscope (SEM) data. This work indicated that pore geometry and, thus, reservoir quality variations within these rocks were largely the result of diagenetic overprinting (post-depositional alteration) of the original rock fabric. The most important diagenetic factors affecting these rocks include (1) the nature and extent of cementation (primarily by calcite in limestones and by secondary anhydrite in dolostones), (2) post-depositional leaching of chemically unstable grains, resulting in varying amounts of secondary dissolution porosity, and (3) the timing and duration of dolomitization (largely controlling crystal size in dolostones and, thus, intercrystalline pore size (an important characteristic controlling matrix permeability).

Moldic porosity has been attributed to skeletal and grain dissolution by post-depositional leaching during periods of subaerial exposure. Periods of leaching and dissolution are probably related to sea level fluctuations and predate diagenetic dolomitization; although some dolomite crystals have also been leached, resulting in the development of intercrystalline porosity. Most of the dolomitization observed may be explained by neomorphozation of syndepositional aragonite cement which lined fenestral pores. The fenestral fabric is representative of supratidal and intertidal facies. Calcite cement was subsequently dolomitized. Reflux dolomitization probably played a significant role in the dolomitizing process.

The best quality reservoir rocks are generally dolomitized ooid or skeletal grainstones deposited in shoaling depositional environments. These rocks contain abundant and uniformly distributed oomoldic, biomoldic, and intercrystalline porosity with good to excellent permeability. Open lagoonal dolostones also make up an important portion of the reservoir interval. They have moderate porosity and permeability values, are thick and widespread, and represent a significant portion of the total rock volume. In addition, zones of solution collapse breccia have recently been identified in the Clearfork in a number of fields (Montgomery and Dixon, 1998). These deposits, which may be indicative of fresh water invasion during periods of sea-level lowstand, include broken, leached, and partly rotated fragments of supratidal, island, and other facies. These zones correspond to structurally higher areas and often have conspicuous fracturing and good permeability. At NRU such breccias up to 40 ft thick have been noted in the upper Clearfork. Oil staining is often observed in these intervals, but more study will be required to determine their reservoir potential. Brecciated intervals may also act as thief zones to injected water.

Traditional analysis of porosity logs does not allow identification of pay quality rocks in the 1,400-ft-thick gross pay interval of the Glorieta/Clearfork. There is no simple, direct relationship between core porosity and core permeability (Figure 2.6). The fact that measured porosity in cores of the formation bears no consistent relationship with permeability is common knowledge in the Permian Basin. Highest porosities often are found in very low-permeability rocks. Although a degree of correspondence between reservoir quality and depositional facies was observed in cores, there has been little success in predicting depositional facies from openhole logs (Kamis et al., in preparation). Furthermore, porosity-permeability relationships in rocks within individual depositional facies (Figure 2.7) showed no measurable improvement over the general relationship displayed in Figure 2.6. The project partners relied on developing a basic understanding of pore systems present in the Glorieta/Clearfork to eventually lead to an ability to predict reservoir quality from wireline logs.

Core-Based Petrophysical Rock Typing

As a first step, the range of pore geometries in the Glorieta/Clearfork was studied in plugs taken from conventional cores using conventional petrographic methods, pore casts, SEM-image analysis, and information from capillary pressure analysis (Davies and Vessell, 1996).

Reservoir quality and continuity are dominated by variations in pore geometry. Reservoir rocks having equal values of total porosity may have significantly different permeability, relative permeability, and irreducible fluid saturation characteristics. These discrepancies are a result of changes in pore structure caused by variations in pore type, pore size, and pore throat size (Ehrlich and Davies, 1989). Extreme variation in pore geometry is characteristic of heterogeneous, low permeability carbonate formations such as the Clearfork/Glorieta sequence.

Quantitative analyses of pore structures were performed primarily by computer image processing of polished thin sections using an SEM specially equipped for image analysis, augmented with point count analysis of thin sections and examination of epoxy pore casts. The following parameters were considered:

- Pore body size and shape measurement
  - pore size
  - pore shape factor = [perimeter^2/(4 Π x area)]
  - length to width ratio
- Pore throat measurement
  - coordination number = [number of pore throats/pore]
  - aspect ratio = [pore size/pore throat size]
- Matrix/pore arrangement and interconnection in two and three dimensions

Pore geometries were classified by shape as triangular, irregular, polyhedral, and tetrahedral. Primary interparticle porosity has more triangular pores, which are generally well interconnected and are typical of the grainstone reservoir facies. Vuggy porosity is described as having irregular and sometimes elongated pores. Irregular pores are typical of dissolution porosity, and although porosity values may be high relative to triangular pores, interconnectivity is usually relatively poor resulting in lower reservoir rock quality.

This analysis led to the definition of seven different pore types. Their characteristics are summarized in Table 2.1. Rock types were then defined on the basis of characteristic pore type distributions.

A total of eight rock types have been identified from core examination and core-measured data, of which four have reservoir potential (one being limestone and water bearing), and four have barrier potential. Rock types were identified on the basis of volume proportions of pore types and unique lithological characteristics. The relative volume proportions of the seven pore types in each rock type are shown in Figure 2.8. Median core-measured values of porosity, permeability, and estimated recovery efficiency are presented for each of the eight rock types in Table 2.2. Recovery efficiency was estimated using methods outlined by Wardlaw and Cassan (1978) on the basis of the pore arrangement, coordination number, and aspect ratio. Low aspect ratios and high coordination numbers typically result in good reservoir sweep efficiency. Rock types 1 and 2 make up the primary reservoir *pay* intervals at the NRU. These rock types consist of coarsely crystalline dolostones that differ in terms of their pore size and geometries. They represent subtidal sandflat, grainstone shoal, and open shelf depositional environments. Rock types 3 and 4 are productive in certain areas, but have lower reservoir quality than rock types 1 and 2. These rocks are finely crystalline dolostones that have different pore geometries and usually correspond to supratidal, tidal flat, and restricted lagoon depositional environments. Rock type 5 is limestone and water-bearing in the NRU.

The highest quality reservoir rocks are typically associated with rock type 1, which consists primarily of grainstones. The coordination numbers and aspect ratios for rock type 1 are more favorable than for the other reservoir-quality rock types (2, 3, 4, and 5), and pore interconnectibility is much more favorable, resulting in good fluid flow potential. Rock types 3 and 4 generally have good coordination numbers and low aspect ratios, but pore interconnectivity is limited, indicating relatively poor fluid flow potential.

Non-reservoir rock types (rock types 6, 7, and 8) are essentially impermeable and can be considered to be flow barriers. The presence of these rock types is a significant factor influencing the degree of reservoir heterogeneity and compartmentalization. Knowledge of the distribution of these non-reservoir rock types is essential to the successful implementation and operation of secondary and tertiary recovery programs.

When the data were segregated by core-observed rock types, the relationship between porosity and permeability became fairly unique. Linear relationships could be utilized to define most of these core-measured permeability vs. core-measured porosity relationships for individual core-observed rock types, as shown in Figure 2.9.

Representative rock-fluid interaction data are required to accurately model reservoir flow conditions. Project plans are to augment available capillary pressure and relative permeability data sets with additional data from proposed infill wells as the 10-acre infill program progresses. Initial special core analyses have helped identify which rock types will be important with regard to reservoir producing mechanisms, as well as the rock types that will act as barriers to fluid flow. These data were used as initial input for reservoir simulation, as well as a guide for future data acquisition.

Oil-water relative permeability data were available on 12 core samples from a single well in the unit. These data confirm that rock types 1 and 2 are the primary pay rocks in the reservoir. From the limited data available, rock type 1 has a comparatively low irreducible water saturation, yet has a high residual oil saturation (a function of high pore aspect ratio). The planned acquisition and analysis of additional data during the 10-acre infill drilling program will provide the opportunity to further study the wettability and relative permeability characteristics of the various rock types, and to refine the flow simulation work.

A total of 24 core plugs from two wells were used to generate mercury-air capillary pressure curves. These data clearly show significant differences in the displacement characteristics of the reservoir rock types. Although these data are from wells in areas of the unit with the highest degree of reservoir continuity, some qualitative interpretations regarding reservoir quality and production/injection potential as a function of rock type could be made.

Using the methods presented by Thomeer (1960), the data have been interpreted as hyperbolic functions in order to estimate composite averages of pore throat radius, minimum entry pressure, and the relative amount of ineffective porosity (porosity occupied by mercury at injection pressure exceeding 500 psia) for each rock type. The results are summarized in Table 2.3. Rock type 1 is the primary reservoir rock with the largest pore throat radius, the lowest entry pressure, and the least amount of ineffective porosity. Rock types 2 and 5 are moderate quality reservoir rocks, and rock types 3 and 4 appear to have limited reservoir potential because of the small pore throat radii and large percentage of ineffective porosity. Rock types 6, 7, and 8 can be characterized as barriers to flow. Additional capillary pressure measurements will be made on core from the 10-acre infill program to validate currently available data.

Wireline-Log-Based Rock-Log Model

Because only a limited number of wells in the NRU have core-measured permeability for the Glorieta/Clearfork formations, use of wireline logs was required to identify critical rock types on a reservoir-wide scale. In a very general sense the wireline log based rock-log model developed for use at NRU is a series of crossplots that calculate permeability values from wireline log porosity values. These crossplots are calibrated to the eight core-observed rock types and their corresponding core-measured porosity vs. permeability relationships. The rock-log model was developed initially using five cored wells and was subsequently extended to the three remaining cored wells available.

The model was formulated to take advantage of the large amount of modern well log data (120 wells) that were available because of the completion of the 20-acre post-unitization infill drilling program between 1987 and 1991. These modern well log suites allow for a more comprehensive evaluation of formation properties than would be possible using older porosity and resistivity well log suites. The rock-log model requires the following modern wireline logs:

Gamma ray (GR)

Photoelectric capture cross-section (PE)

Compensated neutron (CNL Φ)

Compensated formation density (ρb)

Dual Laterolog – LLD and LLS (deep/shallow resistivities)

Borehole caliper

The wireline log data were corrected for wellbore environment, normalized to the core porosity and the mean porosity across the interval of interest (when required), and depth shifted. Sonic and Microlaterologs would have been extremely useful in isolating the highest quality reservoir rock types; however, these well logs were run with insufficient frequency to be used in the analysis. An attempt will be made to improve upon the existing rock-log model later in the project by recording these additional surveys in the 10-acre infill wells.

The wells drilled prior to unitization do not have the requisite well log suites required to use the rock-log model. However, because there is usually an abundance of older wireline log data for many older properties, such as the North Robertson unit, the project operators suggest that these well logs would be sufficient to formulate a competent rock-log model if the well log data are properly interpreted.

Crossplotting apparent matrix grain density, ρ_{maa}, vs. the apparent matrix volumetric cross section, U_{maa}, adequately segregated petrophysical rock types 5, 6, 7, and 8 (Figure 2.10). The lithology of petrophysical rock types 5–8 closely matches the lithology of core-observed rock types 5–8. To segregate the remaining four rock types, Plots of deep resistivity vs. crossplot dolomite porosity were used (as shown in Figure 2.11). Rock types 3 and 4 were segregated on the basis of their shallow resistivity response. There is a reasonable match between the lithology of petrophysical rock types 1–4 and the core-observed rock types 1–4. Accuracy of the predictive model was greater than 80% for all rock types with essentially no significant misidentification of the dominant rock types over the cored intervals.

Foot-by-foot permeability values were estimated from wireline log calculated porosity values utilizing the core-based porosity vs. permeability relationships for the applicable rock type. Accuracy of the model was tested by crossplotting calculated permeabilities vs. core-measured permeabilities. Results were mixed but acceptable with correlation coefficients between 0.6 and 0.8. The model reflects the general trend of permeability values from core (where core-measured permeabilities are high, the rock-log model predicts high values of permeability, etc.). The model worked best for rock type 1, which is the best quality reservoir rock type. Also in a very general sense, the model did a better job of predicting areas of high permeability than it did for areas of low permeability. An attempt will be made at improving the model's error rate by utilizing the additional core data obtained from infill wells drilled later in the project.

Flow Unit Delineation (Tying it All Together)

Applying the rock-log model to the other approximately 120 wells with appropriate log suites in the NRU provided a mechanism to identify individual flow units, which may consist of one or more rock types, and which may be related to some degree at least to their respective depositional environments. It is worth noting that rock types are usually not unique to a particular depositional environment, because pore structure is strongly controlled by diagenesis in dolomites of the NRU. Flow units are generally of limited extent and reflect a high degree of reservoir compartmentalization and heterogeneity both laterally and vertically.

The Glorieta/Clearfork formations (approximately 1,200 ft in gross thickness) have been layered into 21 potential reservoir layers using the established geological framework. Nearly all of these flow units are bounded by layers that are potential crossflow barriers, low reservoir quality rocks deposited in a supratidal depositional environment (the culmination of shoaling upward cycles ranging from approximately 50 feet to 200 feet in total thickness). Cycles have been identified within the whole cores. In some instances they have gamma ray log responses that are characteristic of the various rock types.

The origin of individual stratigraphic layers is related to rapid and frequent eustatic sea level changes on a carbonate shelf or platform that was essentially featureless or without any significant topography. Under such circumstances, small sea level changes produce highly cyclic sequences. These parasequences are carbonate-dominated with insignificant clastic influences. There is some correspondence between the sediment accommodation indicated by the respective stratigraphic unit isopachs and the distribution of the various reservoir rock types, because diagenesis operates within a framework established at the time of deposition. Based on the vertical and lateral distribution of rock types, the Glorieta and Clearfork formations were layered into 12 individual flow units consisting of potentially productive horizons bounded by cross-flow barriers. There are fewer flow units than stratigraphic layers, because diagenesis has "blurred" the stratigraphic boundaries in some instances. There is also correspondence between the occurrence of the reservoir rock types and the areas of the unit exhibiting good historical production and interconnectivity as per the reservoir performance maps (in particular, the distribution of reservoir rock type 1, the most favorable reservoir rock). Potential reservoir quality based on rock-type analysis was further compared with performance of individual wells using decline curve analysis (Doublet and Blasingame, 1995) employing type-curve methods (Fetkovich, 1980; Palacio and Blasingame, 1993).

The intrawell rock type, porosity, and permeability data were then extended on an interwell basis using geostatistical simulation. Also, based on the rock-log model, maps of kh, Φh, and the distribution of each rock type were constructed for each layer. Within the layer isopachs, there is correspondence between the distributions of reservoir rock types, porosity, and permeability and the reservoir performance maps. Information and insight gained from all geological studies were used to check the correctness of the rock-log model generated kh, Φh, and rock type values.

Reservoir performance in areas that were qualitatively evaluated as very favorable, favorable, and unfavorable for infill drilling was quantified with flow simulation. This process led to assessment of the merits of respective areas of the reservoir for infill drilling on the basis of the relative probability of success.

This project is signaling an end to the "blanket" approach to infill drilling for the Glorieta/Clearfork by drilling geologically targeted infill wells with initial production rates approximately 18% higher than past infill wells. Production from 14 targeted infill wells resulted in an increased production of 900 BOPD initially that continued at a 600 BOPD in late 1997. Only about 10% of the increased production obtained from targeted infill wells is estimated to be due to acceleration of production, and new reserves are being captured at about half the cost of a "blanket" infill program ($4 – $6 per bbl vs. $6 – $10 per bbl).

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TABLE 2.1 – Pore Types Identified from Core Thin-sections, XRD, and SEM Analysis

Pore Type	Size(microns)	Shape	Coordination Number	Aspect Ratio	Arrangement	Geologic Description
A	30 to 100	Triangular (interparticle)	3–6 (moderate)	> 50–100:1 (moderate)	Interconnected	Primary interparticle
B	60 to 120	Irregular (generally elongate)	< 3 (low)	up to 200:1 (high)	Isolated	Shell molds –dissolution vugs
C	30 to 60	Irregular (generally elongate)	< 3 (low)	up to 100:1 (high)	Isolated	Shell molds –dissolution vugs
D	15 to 30	Polyhedral	~ 6 (high)	< 50:1 (low)	Interconnected	Intercrystalline
E	5 to 15	Polyhedral	~ 6 (high)	< 30:1 (low)	Interconnected	Intercrystalline
F	3 to 5	Tetrahedral	~ 6 (high)	< 20:1 (low)	Interconnected	Intercrystalline
G	< 3	Sheet/slot	1 (Intercrystal line pore throats)	1:1 (Intercrystalline pore throats)	Interconnected	Interboundary sheet pores –interconnected intercrystalline pores

TABLE 2.2 – Rock Types Defined for the Clearfork and Glorieta Formations

Rock Type	Lithology	Dominant Pore Type	Secondary Pore Types	Median Core Porosity (%)	Median Core Permeability (md)	Recovery Efficiency (%)	Reservoir Quality	Crossflow Barrier Quality
1	Dolostone	A	B, C, D	4	0.7	35 - 45	Excellent	Poor
2	Dolostone	B, C	D, E	5.6	0.15	30 – 35	Good	Poor
3	Dolostone	C	D, E	3.5	0.39	20 – 30	Poor	Moderate
4	Dolostone	B	F	7.5	0.01	35	Poor	Moderate
5	Limestone	C	A, D, E, F	5.8	0.4	30 – 35 (water bearing)	Good (water bearing)	Poor
6	Anhydritic Dolostone	C, D	F	1	0.01	0	None	Good
7	Silty Dolostone	E, F	---	2.3	0.01	0	None	Good
8	Shale	G	---	---	0.01	0	None	Good

TABLE 2.3 – Quantitative Analysis of Mercury-Air Capillary Pressure Data

Rock Type	Throat Radius (microns)	Displacement Pressure (psia)	Ineffective Porosity, at 500 psia injection pressure (%)
1	7.61 – 53.30	2 – 10	8.2 – 29.6
2	2.67 – 3.55	30 – 40	23.1 – 49.5
3	0.36 – 1.33	80 – 300	61.6 – 72.3
4	1.77	60	88
5	1.07 – 1.78	60 – 150	21.7 – 57.2
6	0.133	800	100
7	—	—	—
8	—	—	—

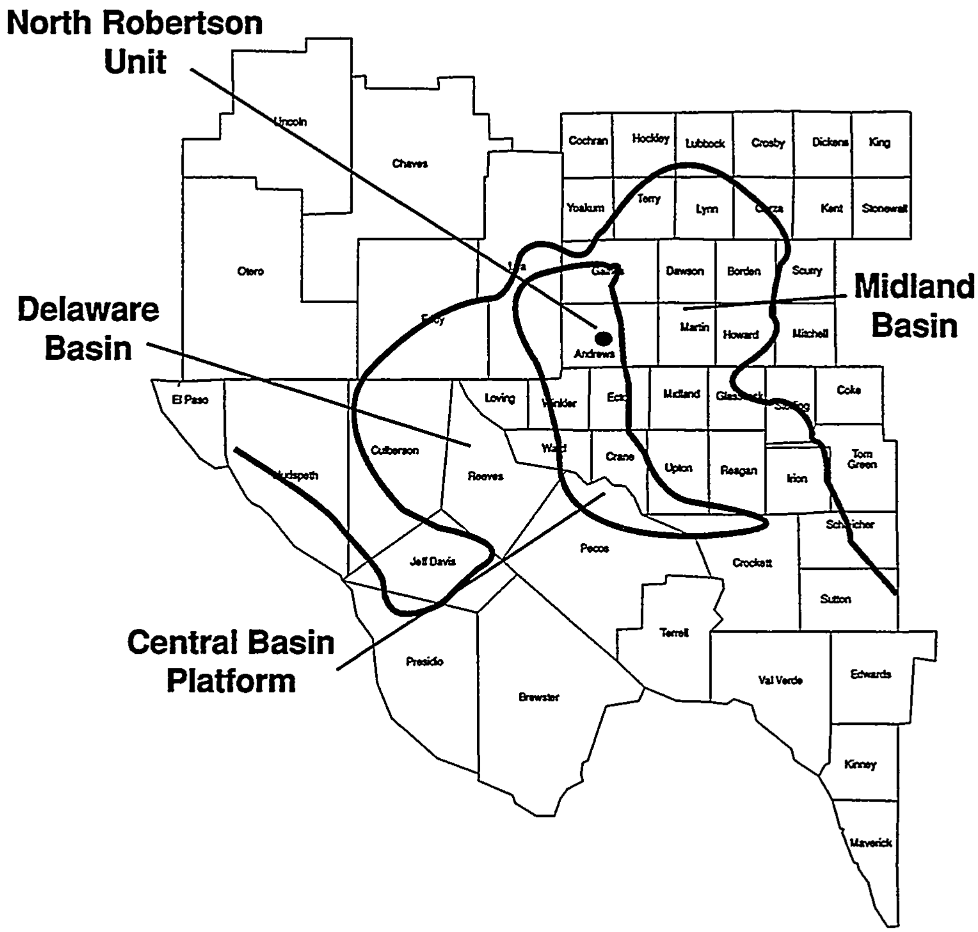

Figure 2.4 – Location of the North Robertson unit on the northern edge of the Central Basin Platform

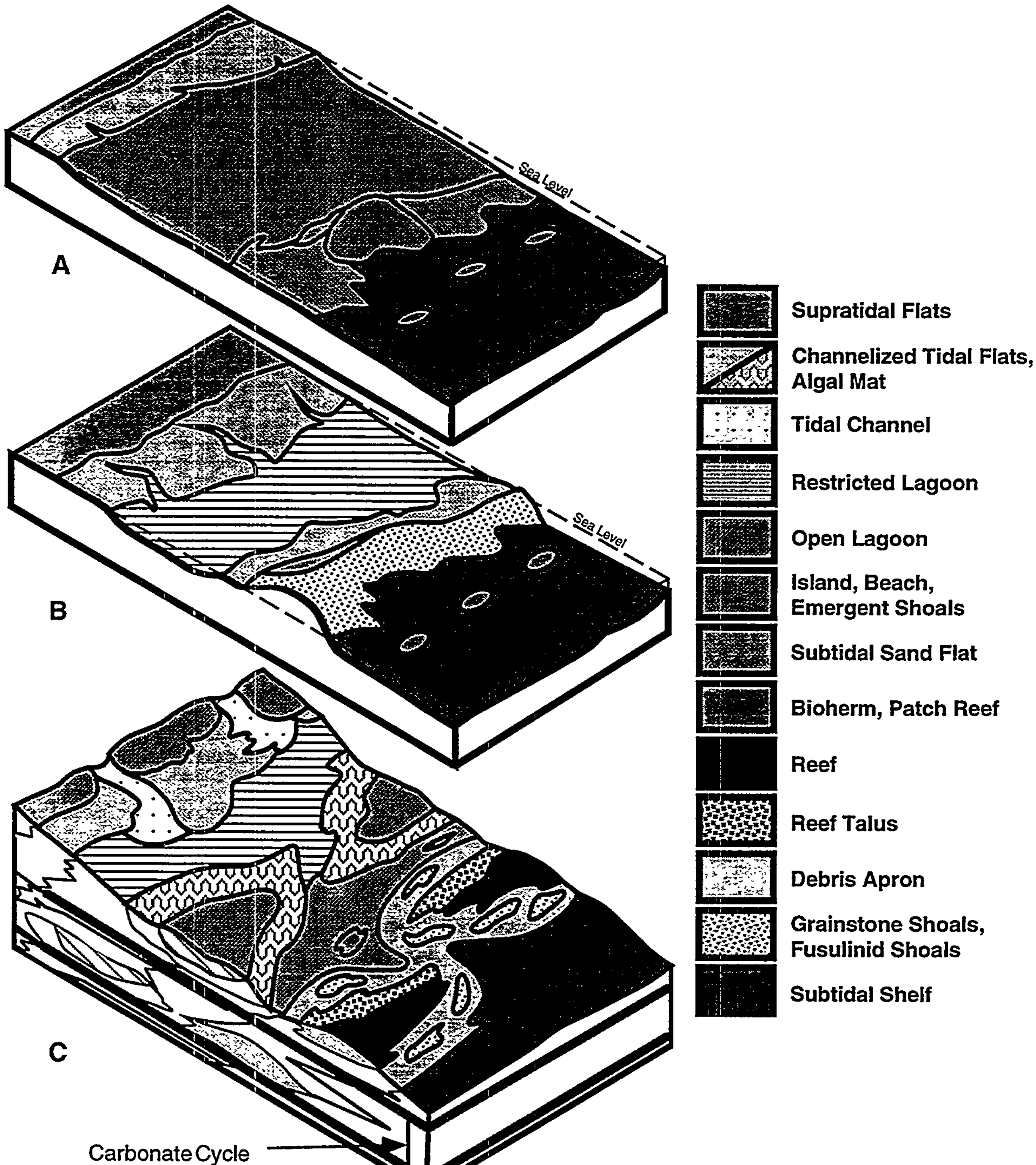

Figure 2.5 – Depositional facies in the Clearfork: (A) depositional environments of the lower middle Clearfork and the lower Clearfork (From Pande, 1996); (B) depositional environments of the upper middle Clearfork, upper Clearfork, and Glorieta (From Pande, 1996); (C) comprehensive depositional model (From Kamis et al., in preparation).

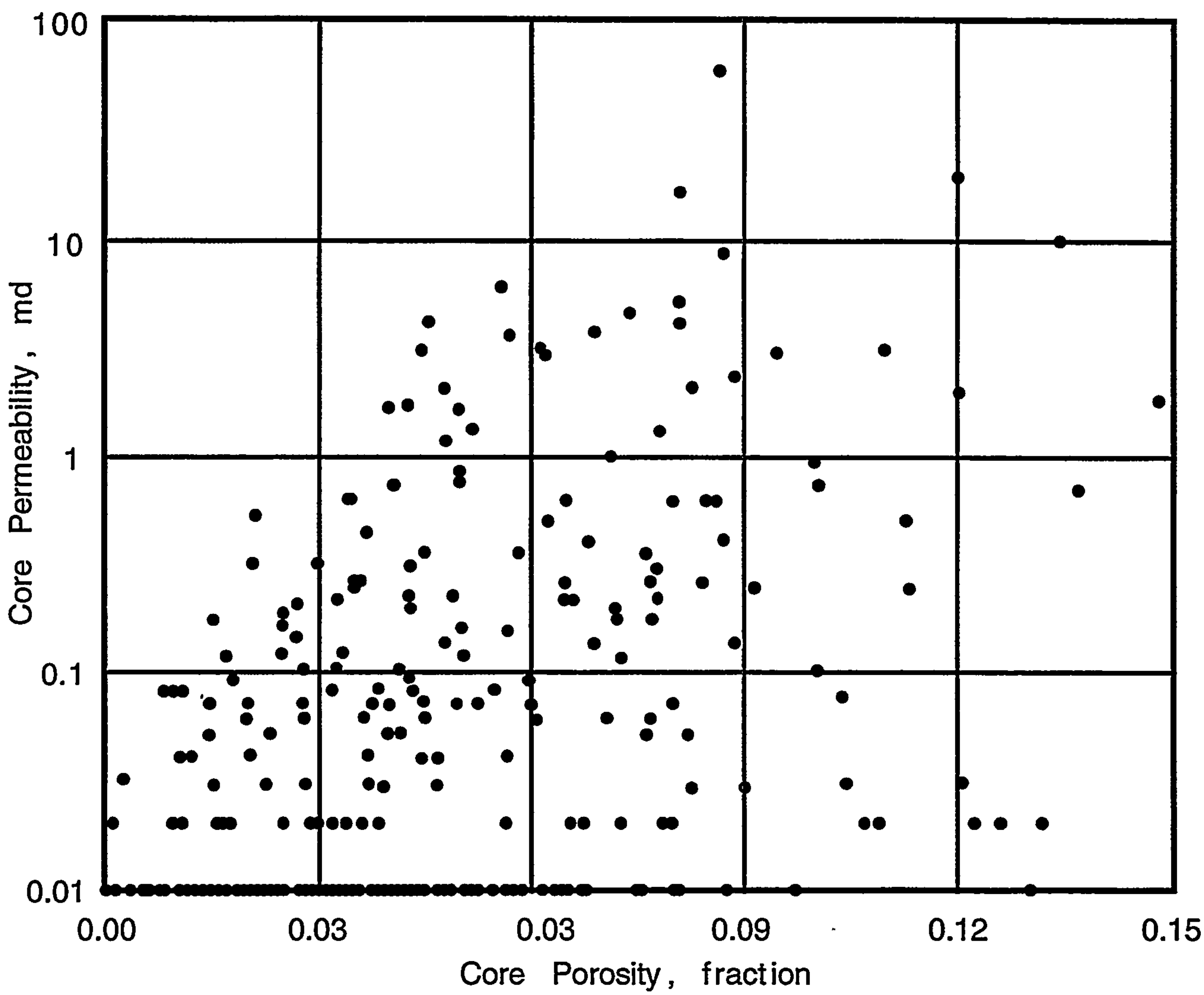

Figure 2.6 – Porosity vs. permeability crossplot for all rock types present at the North Robertson unit. (From Pande, 1996)

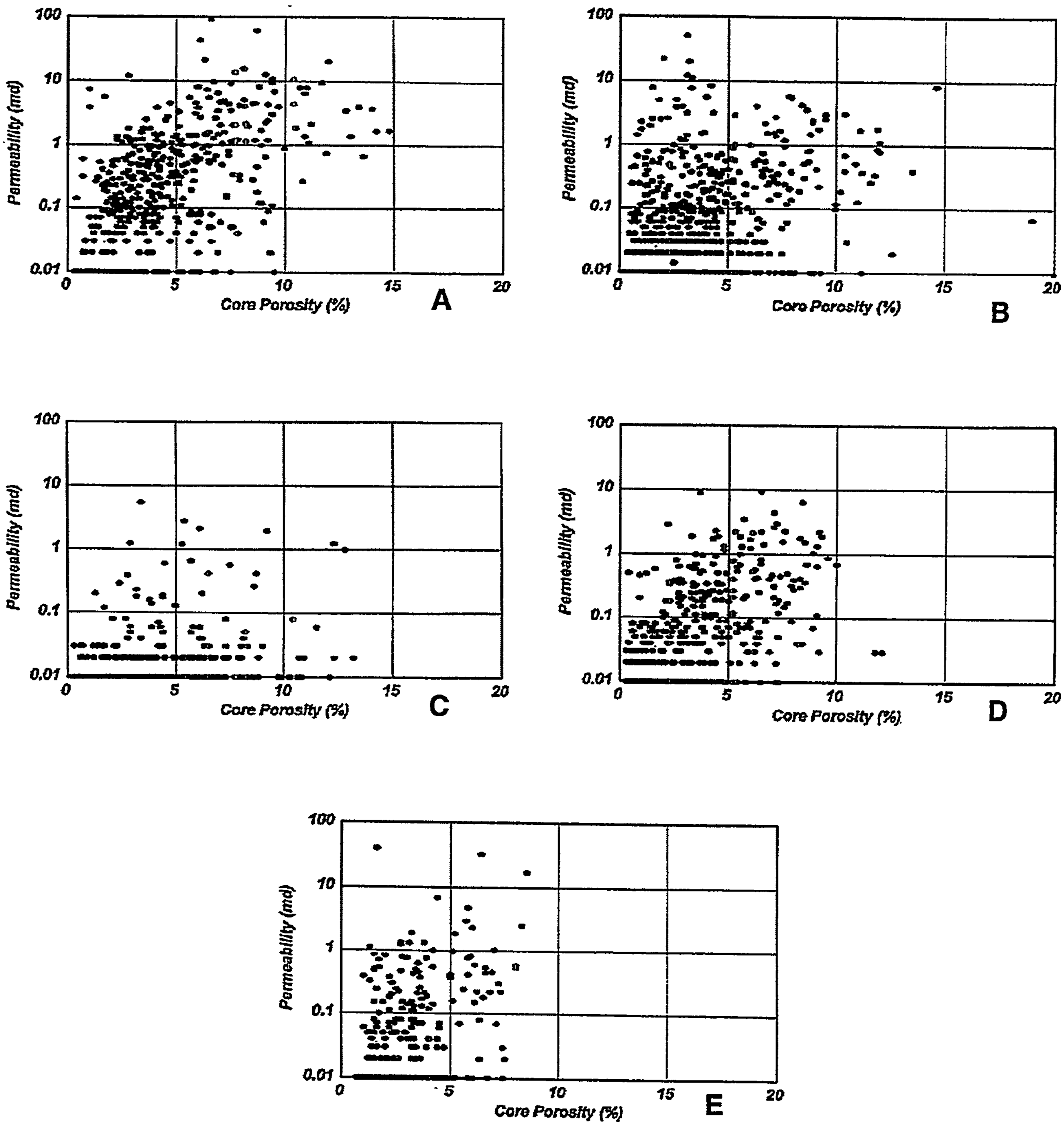

Figure 2.7 – Porosity vs. permeability relationships for major Clearfork depositional facies: (A) shoal water bank/carbonate sand belt; (B) channeled tidal flat; (C) supratidal/high intertidal; (D) lagoonal; (E) forebank/shelf. (From Nevans, 1997)

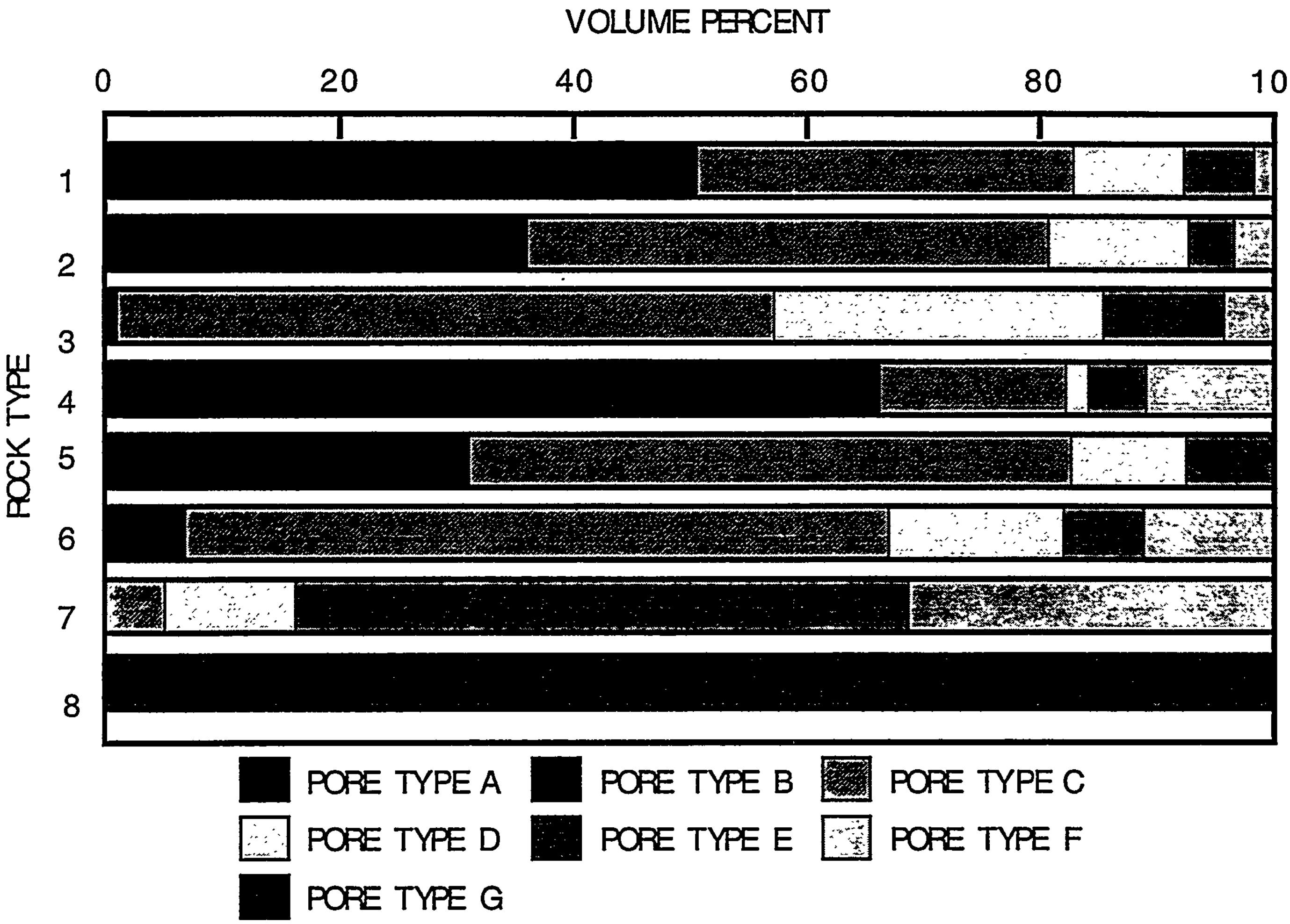

Figure 2.8 – Relative volume proportions (%) of pore types A–G in each rock type. (From Nevans et al., 1996)

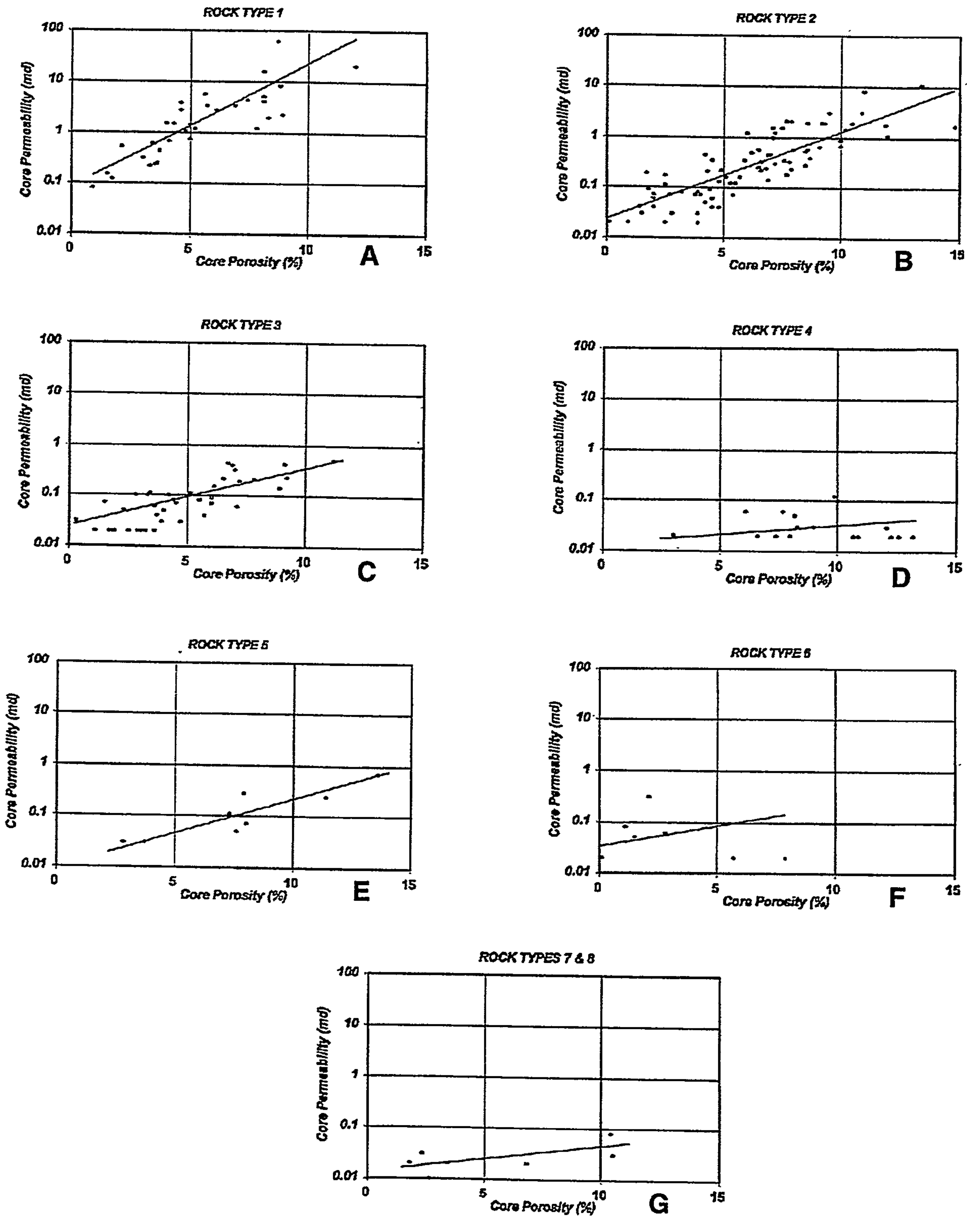

Figure 2.9 – Porosity vs. Permeability relationships for rock types 1(8: (A) rock type 1; (B) rock type 2; (C) rock type 3; (D) rock type 4; (E) rock type 5; (F) rock type 6; (G) rock types 7 and 8. (From Nevans, 1997)

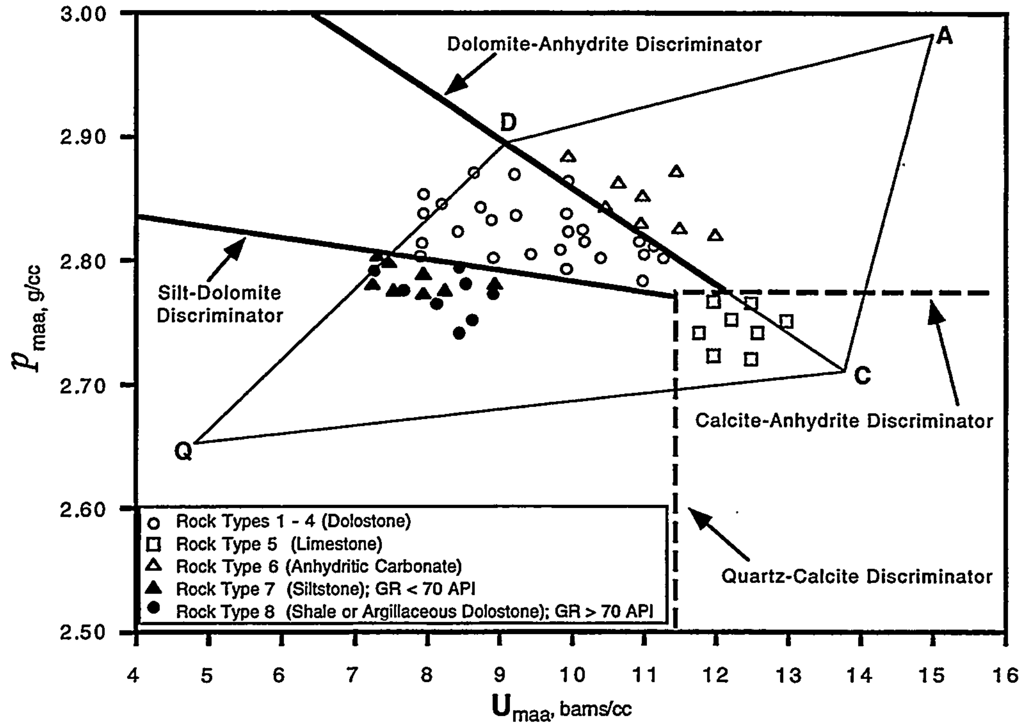

Figure 2.10 – Cross plot of matrix grain density vs. matrix volumetric cross section used to segregate and identify rock types 5, 6, 7, and 8. (From Nevans et al., 1996)

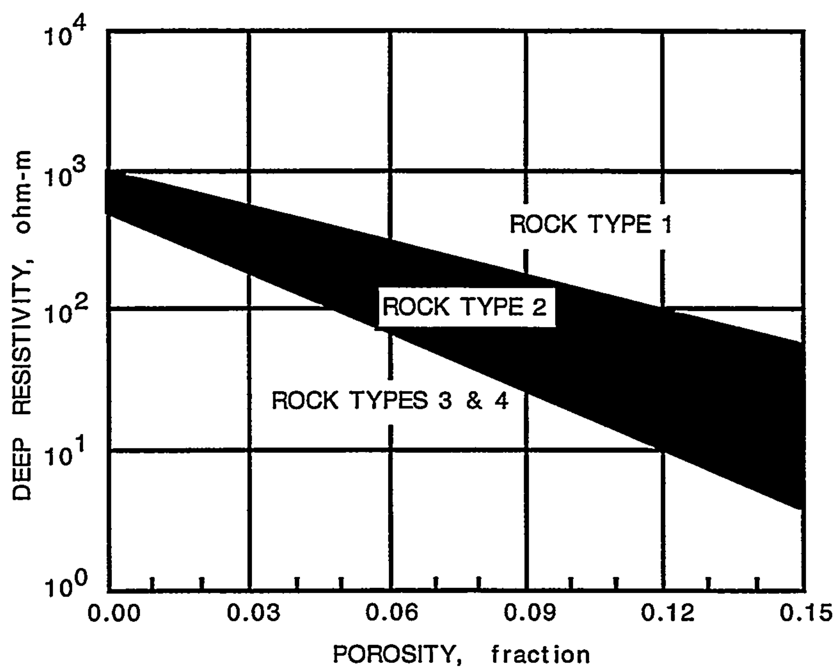

Figure 2.11 – Resistivity vs. porosity plot used to identify "pay" rock types. (From Nevans et al., 1996)

Oxy USA Inc.—West Welch Unit, Texas (Reservoir Class II): Rebecca Egg, Archie Taylor and Greg Hinterlong

The West Welch unit of the Welch field is located on the northern shelf of the Midland Basin in the northwestern portion of Dawson County, Texas (Figure 2.12). The Welch field was discovered in 1936, and the field has been producing oil since the early 1940s from the Permian (Guadalupian) low permeability shallow shelf carbonate San Andres Formation at depths of approximately 4,800 ft. The productive section is overlain by impermeable anhydrites and dolomites. The reservoir section thins to the north toward the paleoshoreline. Permeability in general decreases to the east and west, and the southern limits of the field are determined by a downdip high-water-saturation (aquifer) zone. Waterflooding was initiated in 1958 and reached full-field implementation in 1972.

After proceeding with pilot CO_2 flooding at South Welch unit, one of four large units of the Welch field, Oxy USA began evaluation of cyclic CO_2 treatments in the offsetting West Welch unit to accelerate production and recover additional oil that would not be recovered by conventional CO_2 flooding. At project outset the unit had produced 67 MMBO, 11 BCFG, and 129 MMBW. Since 1960, when waterflooding began at the unit, 254 MMBW had been injected. The unit contained 340 active producers and 207 injection wells and covered approximately 12,000 surface acres. Unit production was 2,837 BO, 518 MCFG, and 22,896 BW per day. The unit-wide average water cut was 89%. The West Welch unit has been developed by infill drilling and pattern modification and is currently producing from 20-acre line drive patterns for the most part. Reservoir quality is poorer at West Welch unit than at South Welch unit. Average porosity is 9.5%, with a geometric average permeability of 1 md.

The cooperative project with DOE started in August 1994 and is scheduled for completion in 2000. Primary goals of the project were to economically ascertain, through detailed reservoir characterization and simulation of additional recovery, the effectiveness and economics of stimulation processes such as hydraulic fracturing, and to select and plan additional improved oil recovery procedures before committing to development at the West Welch unit. The joint project was designed to demonstrate the effectiveness of applying conventional methods of reservoir characterization using cores and logs integrated with advanced technologies to upgrade quality of reservoir data. Detailed and accurate reservoir characterization would be employed in simulating production performance and predicting the economics of CO_2 flooding this tight reservoir. The first phase of the project was primarily devoted to the advancement of reservoir characterization, simulation of reservoir performance under stimulation conditions (hydraulic fracturing and CO_2 treatment), and acceleration of production response (Taylor et al., 1997). The project area covers 564 acres in the south central portion of West Welch unit. This area alone has produced 7.7 MMBO. In 1997, within the project area, 38 producing wells, 23 injection wells, two observation wells, and one water supply well were active. Eleven of the wells have been cored. The average porosity is 12%, and the average permeability is 2.2 md.

The project plan consisted of the following consecutive stages:

- Starting with the preproject/base geological model of the reservoir, perform reservoir simulation to obtain a primary and waterflood production history match and, if the match is acceptable, use the model to predict the effectiveness and economics of a CO_2 injection project in West Welch unit.
- Initially apply a cyclic CO_2 injection process in 5 wells to test enhancing the CO_2 flood in a low-permeability part of the reservoir.
- Perform advanced sedimentologic analysis of cores, petrographic and petrophysical laboratory testing and imaging of the cores, and advanced log interpretations and core-log calibration for developing a detailed and revised reservoir model that includes capability to predict continuous vertical permeability profiles from well log data.
- Further revise the reservoir model by integrating, calibrating, and upgrading it with 3-D seismic and interwell tomography data.
- Design an optimum hydraulic fracturing process based on reservoir characterization and passive seismic (the latter for mapping fracture wing orientation).
- Repeat the history match of primary and waterflood performance using the revised reservoir model to determine what degree of improvement has occurred in the accuracy of the simulation.
- Through simulator prediction, justify process economics and design an optimum CO_2 flood implementation for installation during the field demonstration phase of the project using the refined geologic model.
- Implement (if warranted in the step above) the designed CO_2 flood to recover additional oil.

Use of the Preproject/Base Geological Model

The base geologic model enabled the simulator to obtain reasonable waterflood performance history matches, but required severe changes such as addition of pinchouts and use of permeability multipliers. The model was then used to predict the stimulation resulting from cyclic CO_2 treatments in producers. Wells for these treatments were selected to represent a cross section of differing production characteristics (e.g., water/oil ratio, rates). The incremental production resulting from cyclic CO_2 stimulation of the initial 5 wells selected using this base-model simulation was marginal (Taylor et al., 1996b; Lyle, 1996). Post-stimulation oil production from only two wells was above base production rate prior to stimulation. Under the initial injection and producing conditions, wells exhibited a decline in production or injection based on the total pore volume connected to the wellbore. Once steady state conditions were reached, the decline stabilized and the connected pore volumes between injector and producer controlled the flow. The numerical model's inability to incorporate molecular diffusion effects may have contributed to its poor prediction under these circumstances.

Refining the Base Geologic Model Through Core-Log Modeling

The base model was progressively "fortified," beginning with detailed sedimentological analysis of depositional environments (supratidal, intertidal, and subtidal), determination of the lateral and vertical distribution of depositional facies through a sequence stratigraphic approach, and advanced petrophysical analysis (Hinterlong and Taylor, 1996a, 1997). This initial reservoir description began with classification of rock types using core and thin section examinations and resulted in identification of eight different depositional facies. The poor relationship between raw core porosity and permeability data in the project area is shown in Figure 2.13. This relationship was not noticeably improved by segregating the data by facies. Certain of the eight facies-specific porosity-permeability transforms were similar enough to combine, resulting in a total of four transforms. An approach was then undertaken employing yet more detailed petrophysical analysis. Thin sections, scanning electron microscope (SEM) images, pore casts, and pore geometry analyses were used to generate a synthetic capillary pressure data set and to distinguish four separate rock types (three reservoir rock types and one non-reservoir type), each with distinct production characteristics. However, both these approaches failed to tie permeability to log response on a consistent basis.

Concurrent with the rock type classification resulting from petrographic image analysis, relative permeability experiments were being conducted on core samples from wells drilled in the project area. The results of the experiments indicated that the formation was of mixed wettability ranging from water-wet to intermediate oil-wet. The variations in wettability hampered the accurate prediction of rock type from well logs. Further study showed that the oil wet pores affected the well logs far more than the actual percentage of oil wet pores present.

In simulation, the mix of relative permeability rock types is a critical factor in obtaining a good oil recovery forecast. Initially, the rock wettabilities were designated by layer, based on dominance of computed wettability from well logs. As a consequence of laboratory and other studies performed in the project, the relative permeability used in simulation was changed to predominantly water wet. The resulting simulation oil/water ratio match was improved by this changing of the mix of wettabilities, requiring only slight changes in the actual relative permeability curves.

A third attempt to determine petrophysical properties from log data resorted to a more fundamental theoretical approach. None of the standard logging techniques measures permeability directly. The prediction of permeability by porosity alone has been used extensively in reservoir descriptions but has no basis in theory. This empirical correlation assumes that as pore volume increases, interconnected pore volume increases proportionately, which is not true. Use of this relationship has had successes in sandstone reservoirs, but the more complex nature of the carbonate pore structure rarely fits this relationship. As a result, a single porosity value may have a permeability range covering several orders of magnitude, because the real control of permeability lies in characteristics of pore throats connecting the pores (Herrick and Kennedy, 1993).

Traditionally, permeability values are derived from laboratory measurements through the Darcy equation. Earlier attempts of determining permeability from logs utilized standard log computations such as water saturation and clay volume using the Archie equation. The procedure, however, involves certain difficult-to-obtain parameters such as the values of m and n factors and the resistivity of pore water.

In hydrogeology, the best known of the predictive equations for hydraulic conductivity is the Carman-Kozeny equation developed in 1930s and best described in English literature by Bear (1972).

$$K = \frac{\Phi^3}{K_o \tau (1-\Phi)^2} \tag{2.1}$$

Where:

K = total permeability (Darcys)
Φ = porosity
K_o = Kozeny factor
τ = tortuosity

Because of the expense and difficulty in measuring the Kozeny and tortuosity factors, average values are normally assumed.

In the West Welch field, detailed work with the Carman-Kozeny equation resulted in derivation of a permeability relationship utilizing the information from standard porosity/resistivity log suites and special core analysis data. Capillary pressure data, the basic Carman-Kozeny equation, and the work of Herrick and Kennedy led the operators to explore the resistivity log response as a major contributor to permeability prediction. Because wettability was expected to have a major impact on resistivity, the operators also tried to obtain a log response that identified wettability. Extensive petrophysical analysis was conducted on a large number of cores and thin sections to acquire data necessary for developing a method to calculate continuous reservoir permeability profiles. Capillary pressure data were used to develop a relationship between porosity, pore entry radius, the Kozeny constant, tortuosity, and permeability. This approach established a methodology for determining permeability values from conventional log response, but again the actual log responses to be used for each variable still needed to be identified.

The operator adapted a modified form of the Carman-Kozeny equation to characterize permeability of the West Welch oil reservoir as a function of the pore volume, the length of the flow path, and the internal surface area of the pore system. Monicard (1980) related permeability to pore surface area in a modified Carman-Kozeny equation:

2.2

$$K = \frac{\Phi^3}{5S_s^2(1-\Phi)^2}$$

Where:

K = total permeability (Darcys)
Φ = porosity
S_s^2 = surface area

Neural network analysis helped the project operator identify which log responses had meaningful relationships to the functions in the Carman-Kozeny equation. Total gamma ray response was found to correlate to the Kozeny Factor (K_o) or surface area which is an indicator of pore size and rugosity. Pore surface area generated from core data using equation 2.2 shows a good overall correspondence to gamma ray response (Figure 2.14). The correlation was improved by normalizing the gamma ray response to the maximum and minimum deflections within the reservoir interval via the following:

2.3

$$GR_{norm} = \frac{GR - GR_{min}}{GR_{max} - GR_{min}}$$

Where:

GR_{norm} = normalized gamma ray value
GR = gamma ray response
GR_{min} = minimum gamma ray response in interval
GR_{max} = maximum gamma ray response in interval

Tortuosity (τ in equation 2.1) was determined to be best related to the cementation exponent, which could be obtained from the response of the pad resistivity tool (i.e., R_{xo}). On a reservoir scale, tortuosity is the ratio of the total length of the flow path compared to the shortest distance to reach the pressure sink (producing well). In electrically nonconductive rocks, the flow path of the current coincides with the flow path of the conductive fluid. Because resistance to flow is related to length of the flow path, logging tools measuring the electrical properties of the formation should provide information on fluid flow characteristics with proper interpretation. Although the information is contained within the resistivity measurements, developing an accurate interpretation of the values has been elusive. Nugent (1984) developed a relationship to generate the cementation exponent of a formation from a comparison of acoustic porosity to total porosity:

2.4

$$m_{NR} = \frac{2Log(\Phi_{acoustic})}{Log(\Phi_{total})}$$

Where:

m_{NR} = cementation exponent
$\Phi_{acoustic}$ = acoustic porosity
Φ_{total} = total porosity

The Nugent cementation exponent (m_{NR}) can be used as an estimate of the tortuosity term. The assumption here is that acoustic porosity is a measure of actual interconnected porosity. This relationship, however, may be misleading if fractures or oversized pores are present.

If mud filtrate resistivity and formation cementation exponent are known, the Archie equation can be used to calculate a porosity value related to the volume of interconnected conductive fluid within the measurement area:

2.5

$$\Phi_R = (R_{mf} / R_{xo})^{1/m}$$

Where:

Φ_R = interconnected conductive-fluid-containing porosity
m = Archie cementation exponent
R_{mf} = resistivity of mud filtrate
R_{xo} = observed flushed zone resistivity value

A value of 2.0 was assumed for m in the present study. This porosity was then substituted for acoustic porosity in the Nugent equation (2.4 earlier). Lithology-corrected density porosity (corrected using a photoelectric or acoustic curve for correction) was used to obtain total porosity.

A modified form of the Carman-Kozeny equation incorporating estimates of tortuosity and surface area from resistivity and gamma ray, respectively, was then used to estimate permeability:

2.6

$$k = \frac{100\Phi^3}{m_{NR} GR_{norm}^2 (1-\Phi)^2}$$

Where:

k = permeability (Darcys)
Φ = porosity (total, corrected)
m_{NR} = Nugent cementation exponent, resistivity-based (Nugent R)
GR_{norm} = normalized gamma ray response

A detailed description of how log responses were used to determine individual factors for the Carman-Kozeny equation can be found in Taylor et al. (1997). The selection and use of most of the previously discussed input curves for estimating formation permeability have been documented in several instances in the literature; the novel and critical aspect added by the operator in this project is the inclusion of resistivity measurements into the calculation.

When the technique was applied to cored wells, permeability was predicted very well in many instances. In some cases, however, the prediction was not as satisfactory. This was found to be true in rocks having one of two distinct characteristics. One situation involved rocks found by laboratory analysis to contain more smooth and more water-wet pores than the more normal mixed oil-wet case. When the rock is water-wet, changes in resistivity to residual oil because of flushing by drilling fluids will be greater than when the rock is oil-wet. Oil-wet rocks have smaller effective pore throats to the flow of current caused by the resistive oil lining the pore and pore throats, thereby reducing the diameter of the conducting-fluid-phase conduits in the pore system. As a result, in rocks with LLD resistivities less than 50 ohm, a satisfactory permeability approximation was derived simply by scaling the Nugent R values directly against the logarithm of core permeabilities. These conditions were generally found to occur in rocks with greater than 4% porosity; rocks with less than 4% porosity were water wet, but did not have sufficient conductivity. The second rock type which gave unsatisfactory results using the modified Carman-Kozeny equation was sucrosic dolomite composed of uniformly large, smooth crystals of dolomite with intercrystalline porosity. These intervals, identified by having a normalized gamma ray response of less than 0.25 (on a scale of 0 to 1), responded well to a single traditional porosity-permeability transform. Fluid-flow performance in this rock type was found to be very similar to that in pore systems found in siliciclastic rocks. A logic flow chart was created incorporating each of the considerations discussed previously to select and apply the best permeability prediction technique for each of the three rock types. The resulting core-log model allowed a foot-by-foot determination of permeability from log response on a reservoir-wide scale.

The core-log modeling approach employed in this project greatly increased the amount of permeability data available to be entered in the geologic model, the only restriction being that the multiple-log-curve analysis procedure was limited to wells with sufficient log data, i.e., total gamma ray, deep resistivity, flushed zone resistivity, and bulk density (with a photoelectric and/or acoustic curve for lithology correction). The results were found to give as good agreement with the whole core-derived permeabilities as plug core analysis, with discrepancies of a magnitude that could be fully accounted for by differences in the inherent volume of rock measured. The greatest discrepancies were noted in an oolitic section, a rock type not encountered by and not originally incorporated into the core-log model.

Extending the Model to the Interwell Scale Using 3-D Seismic and Cross Well Tomography

Seismic methods are often employed to provide information on porosity and reservoir architecture between existing wells. Although the sequence stratigraphic framework established at West Welch unit using geology ascertained from cores and logs at the wellbores can suggest the pinch-out of zones between wells, it does not indicate where those pinch-outs might occur. It was anticipated that 3-D seismic interpretations would help approximate the pinch-outs and that tomography data would further refine the inter-well characteristics of the reservoir. Therefore, the base geologic model was additionally enhanced by incorporating seismic and tomography data to define the interwell properties (Watts and Hinterlong, 1995; Hinterlong et al., 1996; Taylor et al., 1996b).

Shear wave and vertical seismic profile (VSP) processing have been completed on 15 tomogrophic lines. The results show that shear wave data provide more details than the compression wave data. The images correspond well to the depositional model. The sections on the seven best quality lines showed realistic seismic anomalies with 8 to 10 ft vertical resolution. Synthetic seismograms generated from sonic and density logs on three wells were used to check the correlation of cross well reflections. Cross well seismic velocities computed at 5-ft resolution and wellbore acoustic log velocities match for the source wells. Results of the cross well tomographic survey are still being interpreted and have yet to be incorporated into the refined reservoir model.

An investigation into using 3-D seismic attributes to estimate petrophysical properties between wells revealed several correlations between seismic attributes and pore volume that might be useful. Correlations between seismic structure and pore volume and the seismic-derived isopachs and pore volume were excellent. The relative amplitude of at least one horizon had excellent correlation with pore volumes across the total main pay interval. The inverted seismic velocity correlation with pore volume varied from fair to good. Instantaneous amplitude, instantaneous frequency, and instantaneous phase did not correlate with pore volume distribution for any of the reservoir intervals.

The reservoir thickness (isopach) and the interval velocity were selected for the initial transformation to pore volume values. The transformation of thickness and velocity attributes to pore volume were successfully applied to all reservoir intervals. The log data were reviewed to produce a final seismic attribute-to-porosity transformation. A very good overall correspondence was observed between seismic-guided and well-derived average porosity. The seismic-guided method has estimated average porosity values for each seismic bin location which tie to the well data to within 0.4% porosity (Figure 2.15).

Fracture treatment results were monitored by passive seismic techniques. An observation well was used to monitor the seismic events created by the fracturing process. The passive seismic events were recorded before, during, and after the fracture was pumped, with over 200 events identified.

Reservoir Simulation

The simulation project involved the entire production history starting in 1948, followed by several forecast simulations. An equation-of-state-based commercially available compositional simulator was used to compare the quality of matching of primary and waterflood reservoir performance using a conventionally obtained geologic description of the reservoir (base geologic model) vs. the match obtained using a model refined by advanced technologies (i.e., core-log modeling and seismic). Simulation was also used to design an optimum CO_2 flood installation for the field demonstration phase of the West Welch unit project.

The reservoir simulator with the basic geologic model, after being calibrated by the history match, was judged to be capable of making reasonably accurate projections of future performance of the demonstration area under secondary and tertiary recovery scenarios. Several forecast simulations were conducted to determine CO_2 flood performance under various scenarios for design of an optimum CO_2 flood. The base geologic model predicted lower injection rates and earlier breakthrough than the advanced-technology-enhanced or refined model applied later.

Simulation using the refined model very closely matched the oil and water production during the entire production history, which gave confidence to the accuracy of the improved geologic model and the simulator's potential to predict future reservoir performance. The integrated and revised model, when used to forecast CO_2 performance, projected an increased recovery compared to the base model. Analysis of simulation runs indicated that installation of a miscible CO_2 flood in the demonstration area would result in the economic recovery of an additional 2 million bbls of oil over the next 14 years compared to continuation of current waterflood operations. A larger volume of CO_2 will be required to realize the higher recovery. The performance forecast also showed a significant drop in production rate in the early life of the CO_2 flood. This effect would result from reduction of injection pressure in order to stay below the formation fracture gradient.

Fracture stimulation study results were also incorporated into the simulation process (Taylor et al., 1996a, b; Taylor et al., 1997). High permeability representing each fracture was modeled using 3 east-west gridblocks, including the well block, to represent a 100-ft fracture half length. The effects on recovery were less than the previous 400-ft fracture half lengths tested, but still showed reserve increases of about 20,000 bbls of oil for each fracture-treated injector. The larger 400 foot fractures increased reserves by about 100,000 bbls per injected well treated. However, based on the fracture growth model that has been built and successfully used in new wells, the 400-ft fracture would grow out of zone and result in CO_2 losses. The smaller treatments should keep CO_2 from being lost out of zone, yet still improve the sweep efficiency.

Technology Impact on the Project

Originally, Oxy had determined that tertiary operations would not be economical in the lower quality reservoir of West Welch unit, but analysis of simulation runs based on the refined geologic model of West Welch unit indicates that the installation of a miscible CO_2 flood in the demonstration area will result in the economic recovery of an additional 2 million bbls of oil over the next 14 years compared to the yield from a continuation of current waterflood operations.

Water injection rates were cut back in June 1997 to reduce the reservoir pressure prior to CO_2 injection to ensure that all CO_2 injection occurs below the formation parting pressure. As a result of the curtailed injection, the total liquids production at the production satellite dropped by 370 bbls per day in just 48 hrs with no measurable change in oil cut. This rapid drop indicates that some amount of direct flow down induced fractures was occurring between injectors and producers. In the 4 months of curtailed injection, total liquid production dropped by nearly 1,000 bbls per day to 3,000 bbls per day while the oil production dropped by nearly 70 bbls per day to 230 bbls per day. Although the higher injection pressures apparently caused some inefficient cycling of injectant, this response suggests that the higher pressures allowed some amount of sweep in the less permeable intervals.

CO_2 injection was initiated at West Welch unit in October 1997. The current CO_2 injection rate averages 547 MMCFD per well; this rate compares well to the seismic-enhanced model prediction of 415 MMCFD per well. Breakthrough also appears to be following the enhanced model. While the base model predicted CO_2 production rates over 1 MMCFD at the end of six months, the enhanced model predicted breakthrough in 1999. Delayed breakthrough of CO_2 should mean a more effective flood because of extended continuous injection. The installation of the produced CO_2 gathering system was also delayed, improving project economics. Beginning in September 1998, field personnel began to notice changes in the pumping characteristics of several wells. Analysis of the gas streams from these wells revealed elevated concentrations of CO_2, though the gas rates for individual wells do not yet exceed 10 MCFD. Considering the low volumes involved, this initial appearance of CO_2 in producers indicates that the prediction of time to full breakthrough may be quite good.

A few surprises have been seen in the wells showing CO_2 in the gas streams. Three of the wells offset injectors in tract 48, but two of the producers are in tract 49, east of the project area. These two wells are located more than 0.25 miles northeast of WWU 4807, the injector that received a fracture stimulation treatment of 63,500 lbs sand in 1995. The operator believes it is this fracture that is influencing the remote breakthrough. The passive seismic data collected and reported on that sand frac showed one wing of the fracture extending 1,000 ft east and slightly north of the injector. While one would not expect the fracture to be propped with sand to its tip and it does seem probable that most of the CO_2 would sweep out through the walls of the fracture, the orientation determined by the passive seismic data is in loose agreement with field response. Well tests indicate slight oil rate improvement in several of the five wells producing CO_2.

Although the geologic model is still being integrated, the simulator-forecasted results for an optimally designed miscible CO_2 flood in the demonstration area gave sufficient economic incentive to justify continuation of the project into the field demonstration phase. It is expected that the use of core and log interpretation together with cross well seismic tomography and 3-D seismic will refine the geologic model down to 5 ft vertical resolution between wells. Seismic-guided geologic modeling for the final simulation runs is pending in the West Welch unit

The methodology developed to obtain continuous permeability profiles from conventional log response was an important advancement, because permeability determination in shallow shelf carbonates is usually limited to cored intervals. The core-log model established served as the primary foundation for creating confidence in the performance predictions for various secondary and tertiary operating scenarios, which in turn led to design of a CO_2 flood for installation in the field demonstration phase of the project. In 1997, after progressing with the reservoir model and simulation, the project area was expanded to include 14 wells on the south side of the original project area. The south expansion area added approximately 275 acres to the project area and an estimated 700,000 bbls of additional oil reserves. Continuation of the project is justified not only economically, but also to complete the demonstration of the important technologies demonstrated in the reservoir characterization phase. The ability being developed in this project to accurately characterize the interwell space in shallow shelf carbonates should add tens of millions of bbls to the U.S. oil reserve base.

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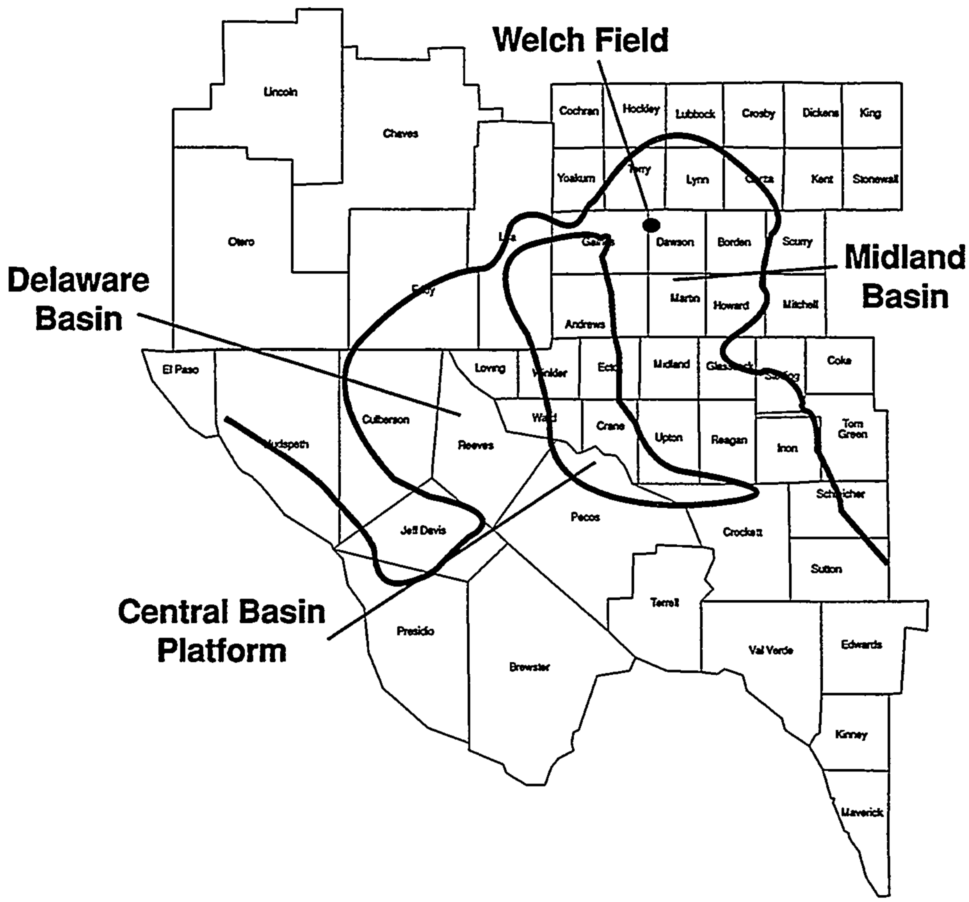

Figure 2.12 – Location of the Welch field in Dawson County, TX.

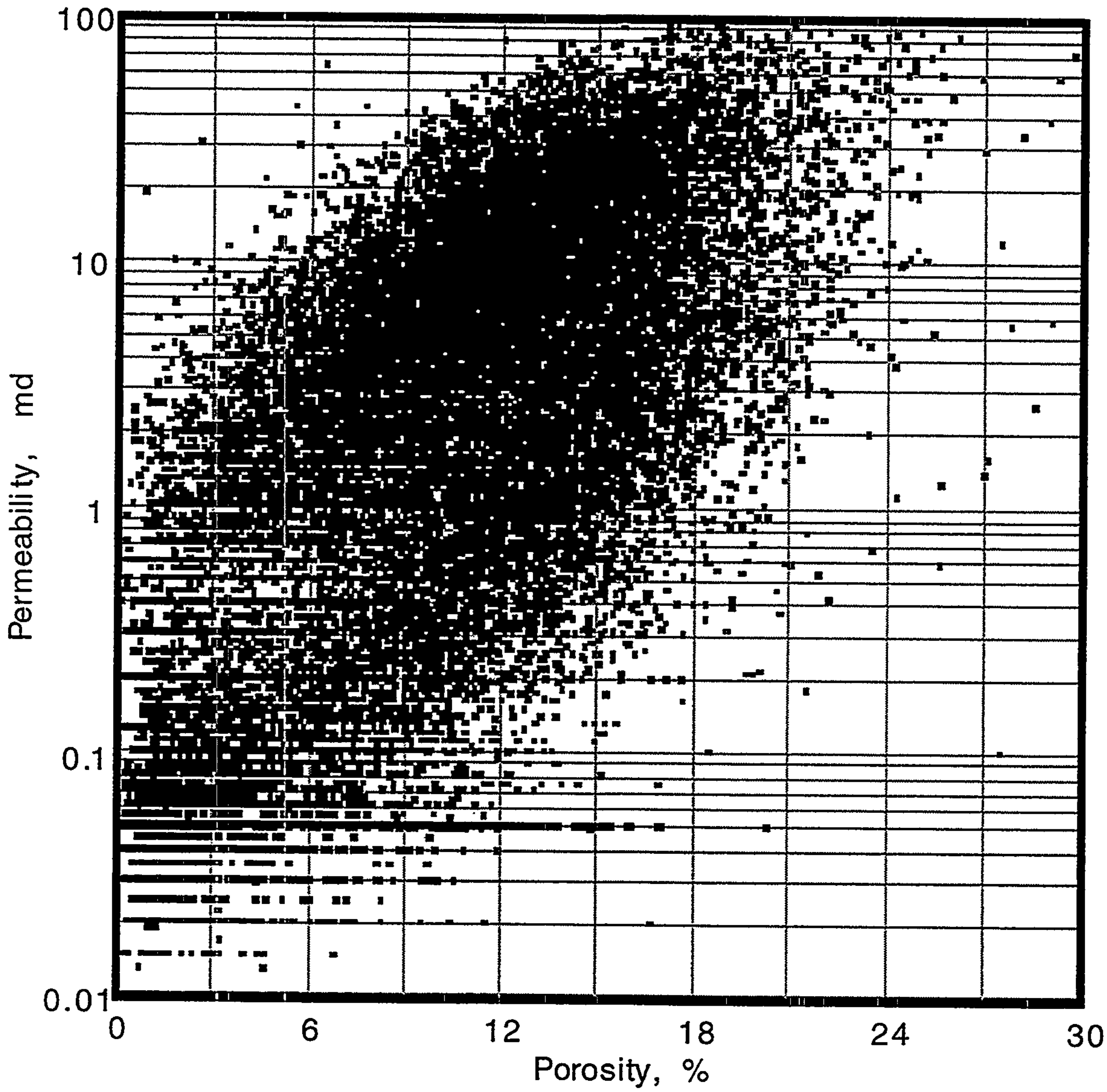

Figure 2.13 – Core porosity vs. core permeability relationship at the West Welch unit. (From Taylor et al., 1997)

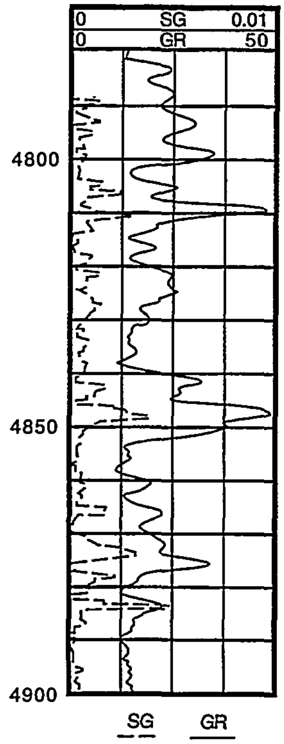

Figure 2.14 – Plot of computed pore surface area from core data (left curve) vs. total gamma ray response (right curve) for a typical West Welch unit well. (From Hinterlong and Taylor, 1997)

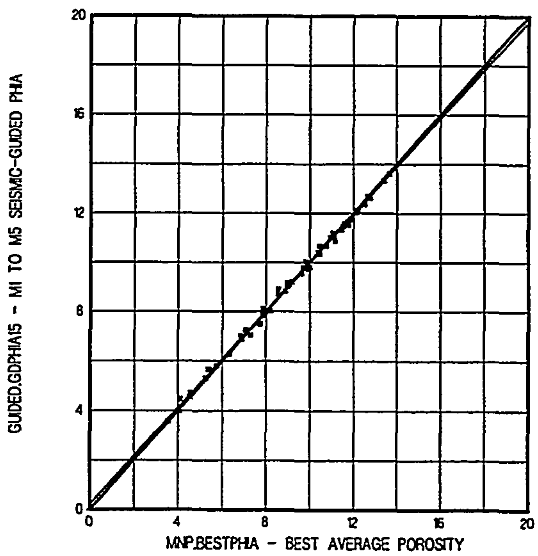

Figure 2.15 – Comparison of log-derived average porosity (horizontal axis) with seismic-guided average porosities (vertical axis) at well locations in the West Welch unit project area. (From Taylor et al., 1997)

Pioneer Natural Resources Inc./Parker and Parsley Development Co.—Spraberry Trend, Texas (Reservoir Class III): Chris Whigham

The submarine fan and basin plain sandstones of the Permian Spraberry Formation were deposited from turbidity and density currents flowing into the Midland Basin in west Texas from the basin's northwestern shelf (McDonald et al., 1997). Dominant sediments are very fine-grained sandstones, siltstones, and mudstones. Natural fractures dominate the performance of all Spraberry reservoirs, but after many decades of production, their distribution and orientation are still poorly understood. Waterflooding was initiated in the Spraberry in the 1950s, but recovery of oil from this process has been relatively poor and is now only marginally economic. Under current operations, ultimate recovery from Spraberry reservoirs is expected to be no greater than 12% of the original oil in place.

The primary objective of this Class III project, begun in 1995 and scheduled to be completed in 2000, is to investigate the use of CO_2 injection to improve recovery from the Spraberry. "Conventional wisdom" implies that recoveries would not be substantially improved. The current project being conducted on the E.T. O'Daniel lease in Midland County (Figure 2.16), however, is testing the hypothesis that when CO_2 is continuously injected under near-miscible conditions, significant amounts of oil previously unaffected by waterflooding will be moved by a natural gravity-drainage mechanism from the rock pores into the fracture system and to the producing wells.

Project participants estimate that no less than 6 billion bbls of oil remain in Spraberry reservoirs to be addressed by techniques such as the one being investigated. The project is investigating the proposed recovery mechanism through laboratory experiments and is characterizing the Spraberry reservoir for input to reservoir simulation models. Simulation results will be used to estimate the technical and economic potential of the approach and to determine the optimum design and implementation of a pilot CO_2 injection demonstration.

Spraberry reservoirs are typically low porosity, low permeability fine-grained sandstones and siltstones interbedded with shaly non-reservoir rocks. The Spraberry is yet another example of a formation in which porosity vs. permeability plots display a lot of scatter. Some high permeability values encountered in essentially nonporous rocks are associated with fracturing. Traditional characterization of Spraberry reservoirs has been based primarily, and with only moderate success, on the magnitude and variation in gamma ray log response. There are several potential problems with this practice:

- Different levels of radioactivity characterize different amounts and types of clays.
- Variations in abundance of other radioactive minerals can also influence gamma ray readings. Among the rock-forming minerals, potassium-rich feldspars and micas may contribute substantially, and accessory minerals such as rutile and zircon also may have influence.
- Gamma ray response provides little to no information on the presence of authigenic cements such as calcite or quartz that may substantially occlude porosity.

Therefore, all units with high gamma ray responses are not necessarily of poor reservoir quality. Conversely, low gamma ray response does not assure the presence of clean, porous reservoir quality sandstone. The fact remains, however, that for many wells a vintage cased-hole gamma ray may be the only log available. A method was needed that could make use of the information contained in these old logs to help distinguish pay zones in areas where no cores or porosity logs were available.

Petrographic examination of core materials showed that porosity correlates well inversely with the total amount of clay and carbonate cement observed (Figure 2.17). To achieve reservoir-wide evaluation and identification of thin, oil-bearing intervals suitable for hydraulic fracture treatment and completion as pay intervals in the Spraberry, a wireline-log-based technique was developed. The technique is based on shaly-sand log interpretation and core-log analysis and involves integration of the following data types: ultraviolet photographs of whole core, thin-section analysis, minipermeameter measurements, whole core analysis, and open- and cased-hole logs.

Log interpretation models are sensitive to uncertainties in both Archie parameters m and n. Conventional values of $m = 2$ and $n = 2$ have commonly been applied in the Spraberry. According to Aguilera (1974), however, m at least should be considerably smaller in naturally fractured reservoirs like the Spraberry, possibly ranging from 1.1 to 1.3. In this study, deriving m and n values from Spraberry core data showed great improvement over using conventional m and n values that greatly overestimate water saturation (Banik and Schechter, 1996a, b). Best overall m and n values for the Spraberry Trend area examined are $m = 1.66$ and $n = 1.46$ (Figure 2.18). The cementation factor a was found by Maute et al. (1992) to be a weak-fitting parameter with no physical significance and can generally be set to unity.

Volume of shale was calculated from gamma ray logs using the Larionov nonlinear relationship, normalizing the logs using minimum and maximum values within the zone (Asquith, 1990).

$$V_{SH} = .33\left[2^{(2*IGR)} - 1.0\right] \tag{2.7}$$

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \tag{2.8}$$

Results were compared with core fluorescence under ultraviolet light showing a sharp distinction between fluorescent oil-bearing sand and muddy zones containing no oil. As expected, some intervals with low shale/clay content were not fluorescent or productive. Thin section examination of these intervals revealed abundant dolomite cement occluding pores. Porosity was calculated from sonic, bulk density, and neutron-density cross plots. Mainly density and neutron logs were used. Comparison of excess porosity observed using the neutron-density tool vs. core-observed porosity gave an estimate of fluid-filled fracture porosity over cored intervals. Nuclear Magnetic Resonance logs were also run for evaluation to improve both porosity and saturation values for thin shaly sand intervals. Porosity and volume of shale were used jointly to successfully discriminate pay from nonpay intervals. On this basis, three major rock types (think of these as rock types incorporating flow properties) were distinguished:

- Rock Type A – massive, clean siltstone, low clay and dolomite content, mostly intergranular porosity, strongly fluorescent, low water saturation
- Rock Type B – moderately low clay, moderately high dolomite content with weak or no fluorescence, high water saturation
- Rock Type C – muddy, clay-rich zones (mostly illite) that do not fluoresce

Rock type A is the main pay rock type. It is almost always hydrocarbon-bearing and is characterized by having porosity in excess of 7% and volume of shale less than 15% (average 7%). Permeability of the matrix is generally in excess of 1 md. Drainage capillary pressures are generally in the range of 75 – 200 psi. Water saturations are usually 35 – 50%.

Rock type B is generally more nonpay than pay with porosity at or less than 7% and a volume of shale less than 15% (average 14%). Permeabilities are typically less than 0.1 md with drainage capillary pressures in the 300 – 1,000 psi range. Water saturations are in the 50 – 80% range.

Rock Type C is always nonpay with porosity less than 7% and volume of shale greater than 15% (average 18%). Permeability is less than 0.1 md and drainage capillary pressures are in the 1,000 – 15,000 psi range. Water saturations are greater than 80%.

The previous rock types are readily distinguishable using gamma ray. No open hole logs are being run on a routine basis in Spraberry development wells. An uncompensated, counts-per-second gamma ray – neutron log provides, after normalization, the perfect tool for recognition of reservoir zones using the above cutoff criteria. For use in wells for which only old cased-hole gamma ray logs are available, a transform was developed to create a synthetic sonic log from the gamma ray curve. The curves are compared in Figure 2.19. The synthetic sonic log can then be used as a porosity tool to distinguish pay from nonpay rock types using the criteria developed.

Currently, work in the project is aimed at finalizing reservoir maps to provide geographic distribution of original oil in place and other critical input information for reservoir simulation.

Laboratory studies have revealed the reservoir to be weakly water-wet, thus explaining the poor historical response of the reservoir to waterflooding. Oil recovery by gravity drainage during CO_2 injection in laboratory coreflood experiments indicates good potential for success of the proposed CO_2 flood.

If successful in the field implementation phase, the injection of CO_2 into fractured reservoirs like the Spraberry could have profound effects on recovery. The operators believe that as much as 125 MMBO might be recovered from the Spraberry Trend alone. Extrapolation to other similarly fractured reservoirs could mean 2 – 3 billion bbls of additional recovery from domestic reservoirs and a guarantee that access to the reservoirs will be maintained while further improvements in recovery technologies are developed.

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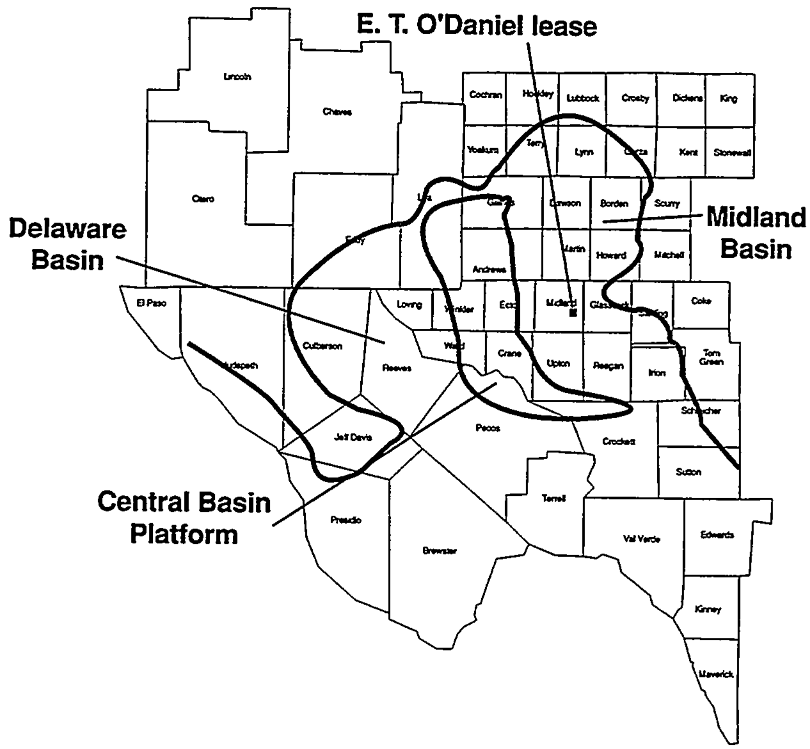

Figure 2.16 – Location of the E. T. O'Daniel lease within the Spraberry Trend, West Texas. (From Schechter, 1997)

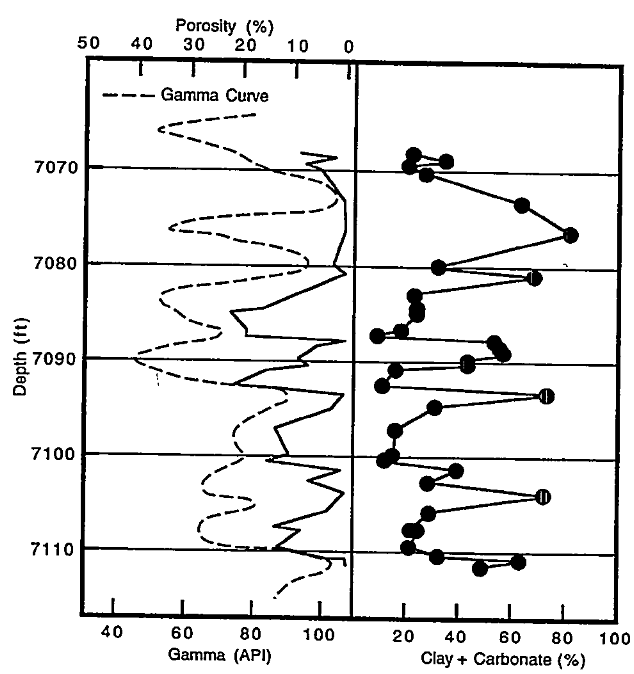

Figure 2.17 – Correspondence between core porosity, gamma ray response, and the summation of carbonate (cement) and clay (matrix). (From Schechter, 1997)

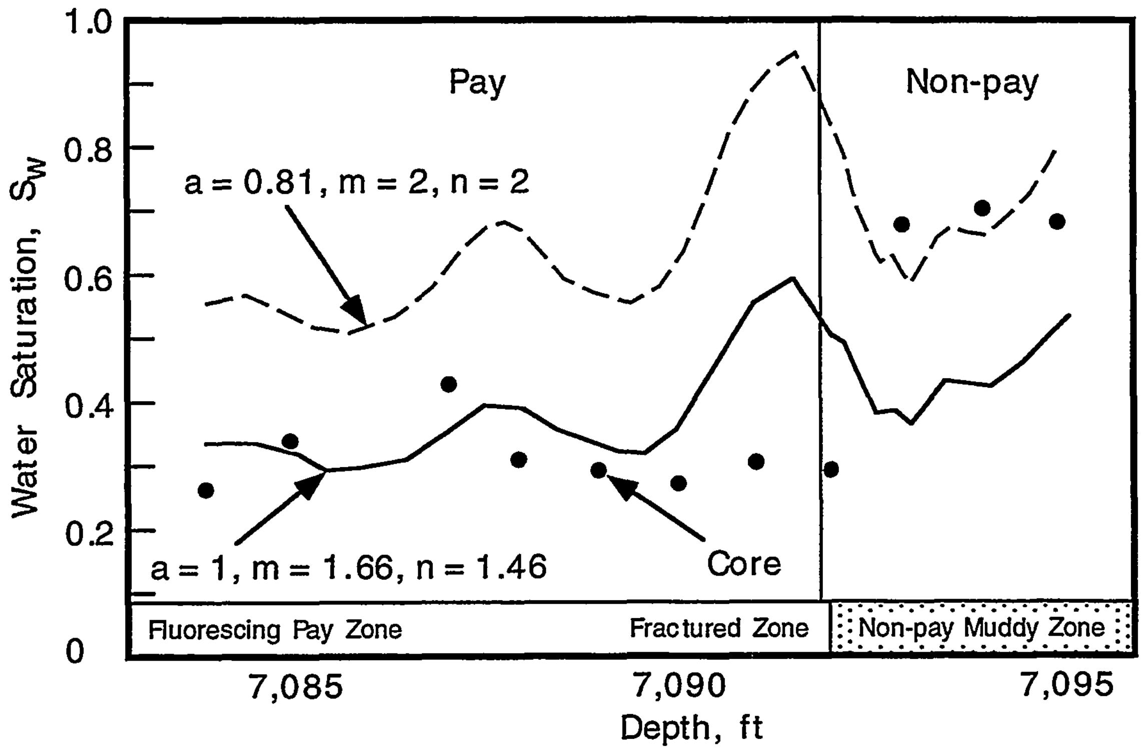

Figure 2.18 – Log-derived water saturation calculated using conventional vs. derived *m* and *n* values and compared with core-measured water saturation. The sharp contrast between pay vs. nonpay is observed by absence of fluorescence below 7,092 ft (From Schechter, 1997)

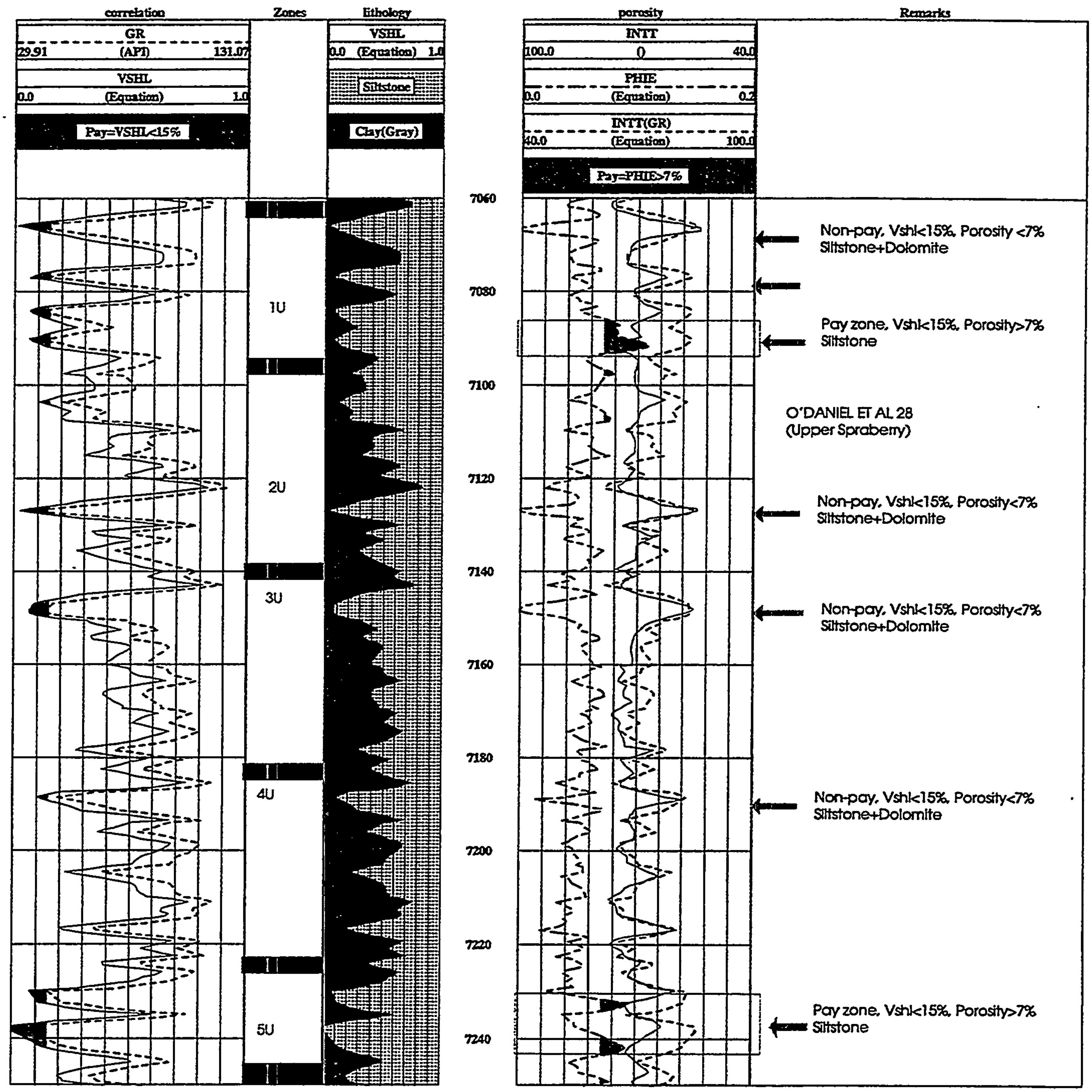

Figure 2.19 – Comparison of sonic log (INTT) and synthetic sonic log generated from gamma ray curve (INTT[GR]) for a well on the E.T. O'Daniel lease. (From Schechter, 1997)

Strata Production Company—Nash Draw Pool, Texas (Reservoir Class III): Bruce A. Stubbs

Production at Nash Draw Pool in Eddy County, New Mexico (Figure 2.20), is mainly from basal Brushy Canyon (Permian, Guadalupian) zones of the Delaware Mountain Group (Stubbs, 1998). The Nash Draw Pool, discovered in 1992 and located on the north flank of the Delaware Basin, is classified as a stratigraphic trap producing from a stacked series of thin submarine channel/fan (Reservoir Class III) sands at depths of 6,600 to 7,000 ft. A total of 14 sandstone intervals within the Brushy Canyon and Cherry Canyon members contribute to production with an average net pay thickness of 90 ft, mean porosity of 12 to 20%, and mean permeability from 0.5 to 18 md. Estimated recovery on primary production from this small reservoir containing 25 to 50 MM bbls of OOIP is very low, in the 10% to 16% range. Low recoveries are typical of similar small Delaware Mountain Group reservoirs in the area which, like the Nash Draw Pool, have a solution-gas drive mechanism. Production at Nash Draw Pool at project outset was on steep decline and gas-oil ratios were increasing rapidly.

The reservoir consists of complex sands typified by sequences of oil-water contacts with very low vertical permeability overall and horizontal permeability that varies from poor to good in patterns that have traditionally been difficult to predict. By comparing a control area using standard infill drilling techniques to a similar area developed using advanced reservoir characterization methods, the goal of this project, begun in 1995 and scheduled to be completed in 2000, is to demonstrate that a development program based on advanced reservoir characterization methodologies and reservoir management techniques can significantly improve oil recovery over that obtained by more traditional methods. Enhanced recovery options including horizontal drilling, waterflooding, and injection of lean gas or CO_2 will be evaluated and tested in a pilot area before moving to full-field implementation.

The advanced reservoir characterization effort integrates geological, geophysical, petrophysical, production, and reservoir engineering data. Six data wells were drilled, cored, and logged. Study of 500 sidewall cores led to identification of three major rock types, each with its own characteristic porosity vs. permeability plot. Core analysis included wettability and relative permeability determinations, as well as analyses of mineralogy, pore structure, and clay content. The stratigraphic framework was quantified in petrophysical terms using innovative rock-fabric/petrophysical relationships calibrated to wireline log responses. Vertical seismic profiles and a 3-D seismic survey were acquired to assist in interwell correlations and facies prediction. Geostatistical techniques are being applied to 3-D seismic attributes to extrapolate petrophysical properties into the interwell area.

It became evident early in the project that a new and accurate method for predicting oil zones (i.e., identifying producing intervals, estimating OOIP, estimating productivity, and optimizing completions) was necessary. Furthermore, to have fieldwide applicability, the method would have to be usable with gamma ray, neutron, density, and resistivity logs available from existing wells. Among the problems that needed to be solved was that of identifying very thin productive intervals. A typical example would be a 5-ft-thick sand that is essentially water-wet with the exception of a 1-ft-thick pay interval (Figure 2.21 and Figure 2.22). Analysis of whole core supplemented by sidewall cores was used to develop a technique for wireline log identification of oil-productive intervals. The technique is based on the premise that zones with residual oil saturation have a high probability of being productive and zones with no residual oil saturation have a low probability of being productive.

In general, a calibration of the Microlaterolog is performed. The steps involved in the procedure include careful consideration of mud resistivity, correction of porosity using core-log porosity transforms, identification of high residual oil saturation zones, thin-bed corrections, and elimination of shaly zones. The analysis requires the following detailed steps (Stubbs, 1997):

1. Obtain an accurate history of the resistivity of the mud filtrate (R_{mf}) while drilling the pay zones. Similarly, obtain accurate R_{mf} values for the mud used while logging. Correct the R_{mf} values to bottomhole temperature using Arp's equation:

   2.9

   $$R_{mf}(corr) = R_{mf\,@\,75^\circ F} x (75^\circ + 7) / \left(T_{ambient} + 7 + \left((depth / 100 ft) x T_{gradient\ \ per 100 ft}\right)\right)$$

2. Correct the porosity values using a cross-plot of log vs. whole-core porosity data (Figure 2.23). The transform is obtained from a regression analysis of core porosity data vs. the average of the neutron-density porosity values. Both logs are used, because due to variations in cementation or shaliness, a 10 – 15% discrepancy in porosity values may occur. A correction factor (C) can be applied to further refine the porosity values to better match cores and individual rock types. For example:

   2.10

   $$Phi(corr) = \left(\left(Phi_{x-plot} x 0.7867\right) + 3.2012\right) x C$$

3. Calculate a residual oil saturation (S_{xo}) from the Microlaterolog (MSFL) using the R_{mf} (corr) and Phi(corr) values calculated in the previous steps:

   2.11

   $$S_{xo} = 1 - \left(F_r x R_{mf}(corr)\right) / R_{xoMSFL})^{0.5} \quad Where: F_r = 0.81 / Phi(corr)^2$$

4. Calculate an S_{xo} value for each interval of digitized log data and sort to identify intervals with S_{xo} values greater than the residual oil values found in the cores. At the Nash Draw field, zones with greater than 20% residual saturation have proven to have sufficient mobile oil to be productive. This is the first sorting step in the process of productive oil zone determination. These intervals are identified as potentially

productive at this point and can next be processed against other criteria to arrive at a more accurate determination of productive zones.

5. Because of the thin-bedded nature of the Delaware Formation, the deep resistivity log is influenced by zones above and below thin productive zones. The averaging of approximately 3 ft of native reservoir zone and invasion zone leads to low estimates of true resistivity (R_t). Low R_t values yield high S_w calculations and pessimistic interpretations of potential productive zones. To compensate for the averaging effects, an adjustment factor is used to obtain a corrected R_t value. This correction factor can be obtained by (1) using published Tornado Charts, or (2) calibrating the factor against a productive zone whose S_w is known from production and test data. Given the bedding geometries and reservoir rock characteristics that prevail at the Nash Draw Pool, a common correction factor used is 1.1. Measured R_t values are corrected upward by 10% by multiplying by this factor. In laboratory measurements permeability to oil dropped quickly to nearly 0 in rocks with greater than 55% S_w. Therefore, by applying an S_w cutoff of 60% or less, only intervals that have favorable relative permeability values will be included as potentially productive.

6. A further elimination of nonproductive shaly sands is next applied by removing from consideration all intervals with gamma ray values greater than 70 API units.

7. Zones with a corrected porosity value of less than 11% have been found to have permeabilities too low to be productive. Removing all such zones from further consideration at this stage gives a final identification of productive intervals. Resolution of zones down to 0.5 ft in thickness is possible with this technique.

   The core-calibrated log analysis technique yields comparable results to those obtained from magnetic resonance logs (CMR tool). In some instances, the resolution obtained is actually higher than that obtained from the magnetic resonance log. The operator ran this tool as a step in confirming the core-log model being developed, and would use it as a basis for forming a log model in reservoirs with limited or no core data. (In some cases, the CMR log showed more water than is actually present, probably because its depth of investigation was shallow [1-2 in] and it saw mainly the flushed zone.)

8. Using S_w, Phi(corr), and other basic reservoir parameters an OOIP value can be calculated for each recognized productive reservoir interval. A calculated value of 300 bbl/ac-ft is used by the operator as a cutoff for pursuit of further development.

9. Permeability-porosity transforms are then used to estimate permeability for calculated porosities in each interval. By applying relative permeability data to each interval its productivity to oil and water can be estimated. This information, when

coupled with fracture geometry data, leads to better completions and reduced expenditures on nonproductive zones.

The above procedure has been captured in a computer software tool (Advanced Log Analysis [ALA] tool) developed by the operator for application in the Nash Draw Pool and similar Delaware Mountain Group reservoirs. Application of the ALA tool in four other Delaware wells in southeast New Mexico achieved good results. Three wells were essentially similar to those at Nash Draw Pool. In the fourth well, a new rock type was encountered that required some modifications to enable prediction of pay intervals.

The operator identifies 3-D seismic as the number one and perhaps the most cost-effective tool for locating prospective drilling sites in this project, but also emphasizes that the core-log model is the critical tool for defining net pay. Two intervals in the Brushy Canyon section were considered as potential pay at the outset of the project. As a result of information obtained from the core-log model (ALA tool), only one zone was identified as potential pay. The second zone is more appropriately viewed as a transition zone with low oil saturations and high capillary pressure. The geological model based on the core-log modeling technique in combination with the 3-D seismic acquired has been used to locate and drill two wells that encountered good reservoir quality sands, and a directional/horizontal well is being designed to target reserves associated with a seismic anomaly under a playa lake and potash mining operations. Current efforts are concentrating on defining the reservoir volume which supports the pilot area wells.

Reservoir simulation using the model developed indicates that early pressure maintenance could significantly increase, perhaps as much as double, recoveries in some areas, but that the reservoir is compartmentalized laterally in other areas. Pressure maintenance projects will have to be designed for individual compartments. Targeted drilling, probably employing combinations of vertical and horizontal wells with selective completions, will be used to develop compartments to optimize recoveries. Simulation also indicates that CO_2 injection could result in significant recoveries.

Incremental reserves of about 275 MBO and 1,800 MMCFG have been realized from the project wells already drilled. Project goals are to achieve an increase in recovery from the current 10% of OOIP at Nash Draw Pool to as much as 35%. This would entail increases in production by as much as 2,500 BOPD and recovery of about 18.5 MMBO.

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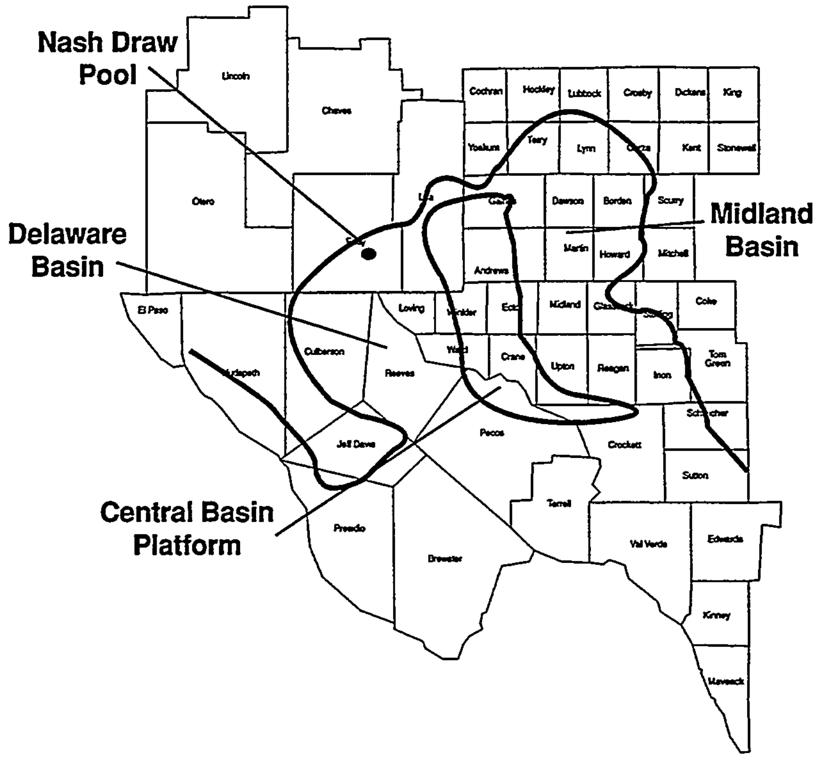

Figure 2.20 – Location of the Nash Draw Pool on the northern rim of the Delaware Basin.

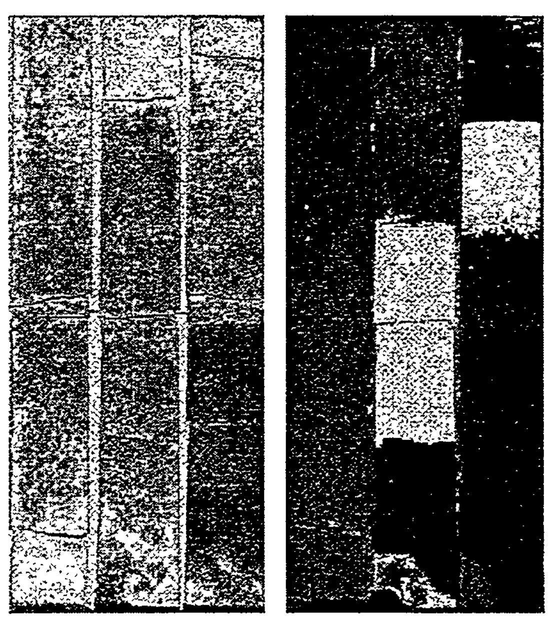

Figure 2.21 – Core photographs in plain light (left) and fluorescent light (right) showing typically thin pay zones being pursued in Delaware Sandstones. (From Stubbs, 1998)

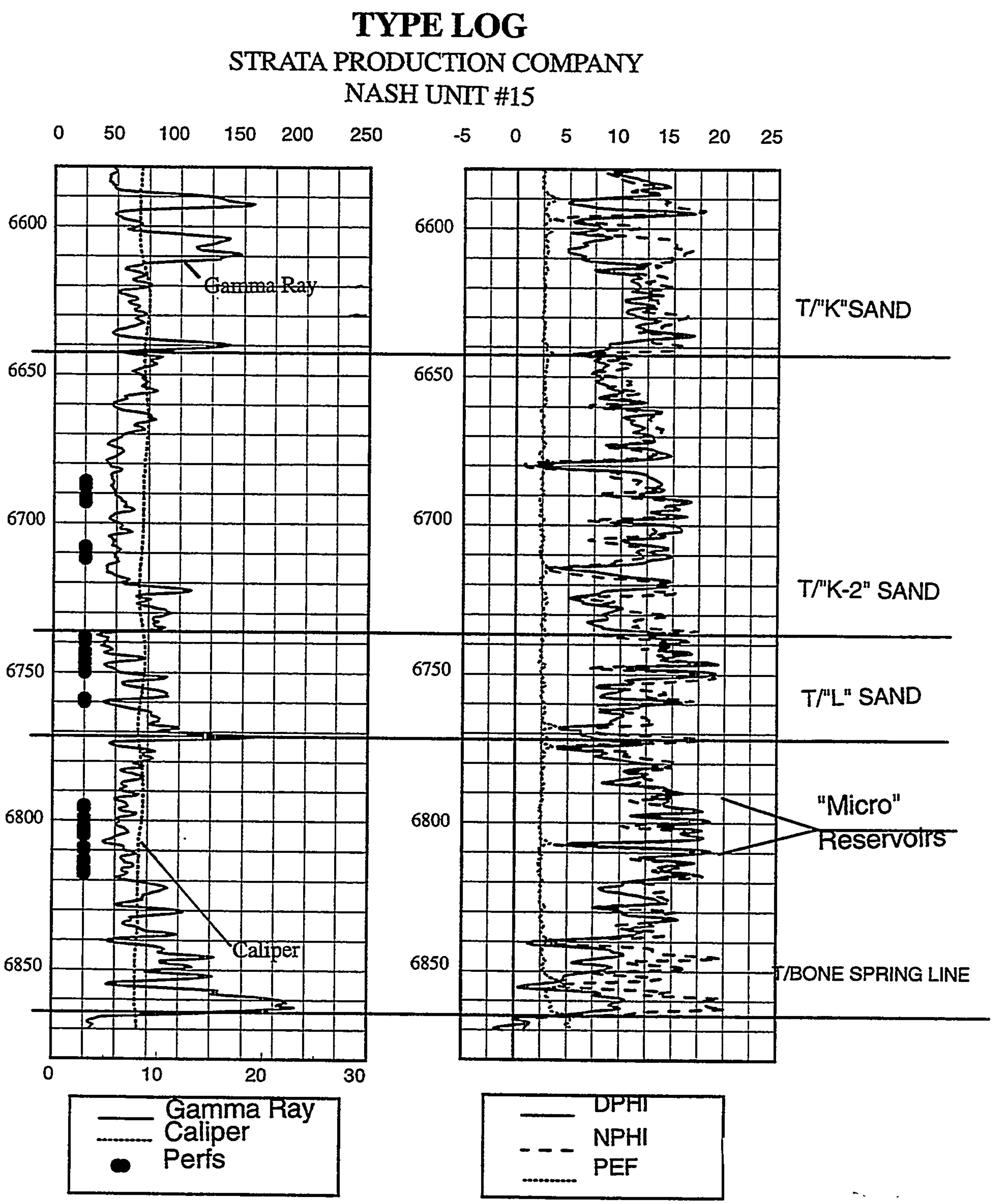

Figure 2.22 – Basal Brushy Canyon Sandstones showing the stacking of thin, multiple reservoir packages; each sandstone is composed of stacked "micro" reservoirs separated by vertical permeability barriers. (From Murphy, 1997)

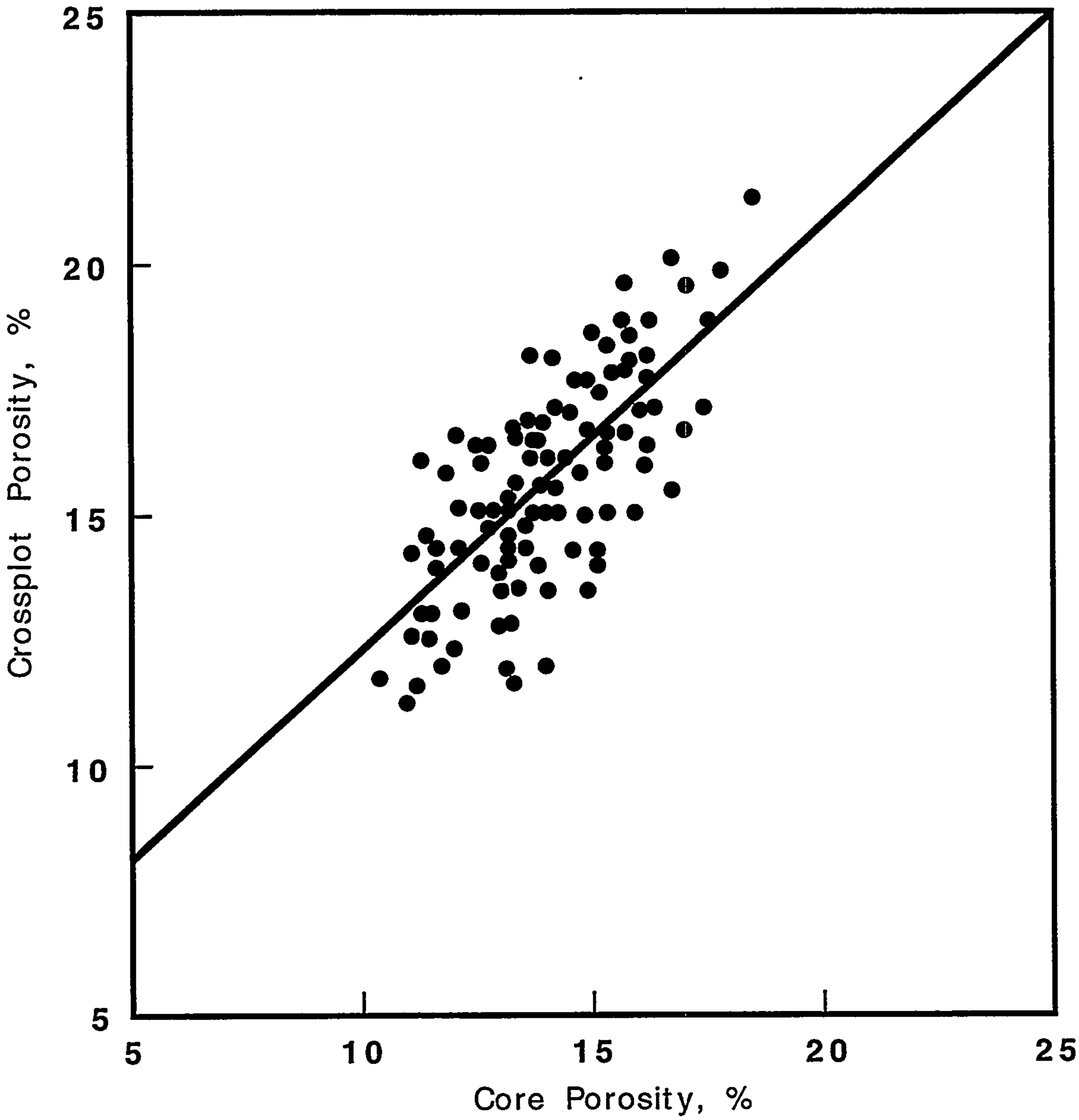

Figure 2.23 – Calibration of density-neutron crossplot porosity vs. whole core porosity. (From Murphy, 1997)

Bureau of Economic Geology—Geraldine Ford Field, Texas (Reservoir Class III): Shirley Dutton and George Asquith

Recovery efficiencies in the slope basin and deep basin clastic reservoirs in the turbidite sandstones of the Permian Delaware Mountain Group in the Delaware basin in west Texas and New Mexico are very low. Of the nearly 1.8 billion bbls of oil originally contained in more than 100 reservoirs of this type, more than 1.5 billion bbls remain in the ground.

The reservoir at the Ford Geraldine unit (Figure 2.24) was discovered in 1956 at a depth of about 2,600 ft and has been on waterflood since 1969. The central part of the field has been CO_2 flooded since 1981.Tertiary recovery has been about 5.7 MMBO or about 5.8% of OOIP with an estimated ultimate recovery of 9% of OOIP. Recovery through primary, secondary, and tertiary operations has been about 28% of the original 99 MM bbls of OOIP. Currently the field contains 122 producer and 88 injector wells.

In this project begun in 1995 and scheduled to be completed in 2000, the operators selected the Ford Geraldine unit and the smaller East Ford field (Figure 2.24) to demonstrate that detailed reservoir characterization is a cost-effective way to recover a higher percentage of the OOIP through strategic placement of infill wells and geologically based field development. The remaining oil in place target for the project in these two fields is 89 MMBO. The reservoir characterization phase of the project included the following:

- A 3-D seismic survey designed for imaging Delaware Sandstones
- Outcrop characterization of the producing sandstone formation to determine sandstone depositional processes and sandstone dimensions
- Subsurface logs and cores
- Petrophysical analysis
- Reservoir simulation of a demonstration area

Petrophysical analysis at the Ford Geraldine unit is complicated by the incomplete nature and the vintage of the logging suites. Of 340 wells in the field, 305 have logs; however 118 wells have no porosity logs, 84 of the 187 wells with porosity logs had only "old" (1950s vintage) neutron logs, and only 38 wells had both porosity and resistivity logs (Asquith et al., 1997; Dutton et al., 1998b). Because most of the wells in the Ford Geraldine unit were drilled and logged in the 1950s and early 1960s, special techniques had to be used to maximize the information that could be derived from these old-style logs (Figure 2.25).

The first step taken was to normalize the old gamma ray and neutron logs to modern logs. Neutron logs were first normalized against shale and evaporite sections on an individual well basis. Because the reservoir sandstone contains abundant authigenic clays, it was also necessary to make a correction for volume of clay in calculation of neutron porosity (Dutton et al., 1998a). The correction for clays was obtained from gamma ray responses in clean sandstone vs. response in organic-rich siltstones, the nearest lithology to shale available in the section. Gamma ray cutoffs for "shale" and clean sandstone were determined at 90 and 40 API units respectively, by plotting gamma ray response vs. sonic interval transit times. Volume of clay (V_{cl}) then becomes:

2.12

$$V_{cl} = 0.33\left[2^{(2*IGR)} - 1.0\right]$$ where: IGR = (GR-40)/(90-40) = gamma ray index

(Atlas Wireline, 1985) and: GR = gamma ray value from log

Normalized neutron porosity was corrected by multiplying by (1.0 - V_{cl}). Sonic logs and normalized and clay-corrected neutron logs were then correlated to core porosity by reduced major axis regression.

Resistivity logs can be used to calculate a formation's water saturation (i.e., whether it is potentially hydrocarbon-productive or water-bearing) if several parameters are known, including:

- Formation water resistivity (Rw)
- True formation resistivity (Rt)
- Archie's cementation exponent (*m*)
- Archie's saturation exponent (*n*)

Rw was estimated across the study area from a map of prewaterflood salinity (Ruggiero, 1985).

In the Ford Geraldine unit, a Deep Laterolog (LLD) was commonly run, but was often unaccompanied by other logs to measure either the flushed zone or the invaded zone resistivities. These additional logs make it possible to correct the resistivities of the partially invaded zone measured by the LLD to the true resistivity (Rt) needed for calculation of accurate saturations. To circumvent this deficiency in wells with only an LLD resistivity log, a linear regression transform was developed between Rt (as calculated in 12 Ford Geraldine wells with shallow resistivity measurement tools run as well as the LLD) and the LLD curve response:

2.13

$$Rt = 1.3002 * LLD + 0.3397$$

Without applying this transform, water saturations in wells with only LLD logs would be substantially overestimated. A typical calculation ignoring the transform suggests an underestimation of OOIP by 155 MMBO in a 40-acre tract (Dutton et al., 1998a).

Using a combination of core and log data, cementation (m=1.83) and saturation (n=1.90) exponents were calculated for use at Ford Geraldine unit. Cementation exponent (m) was obtained by measurement in cores and confirmed by back-calculation from sonic porosity and flushed zone resistivity log values. A new technique was developed to calculate the value of the saturation exponent (n). The approach developed used core porosity and water saturation values from relative permeability data to back-calculate n.

The Archie equation for water saturation for reservoir sandstones at Ford Geraldine unit then becomes:

2.14

$$Sw = \left[\left(1/Phi^{1.83}\right) * (Rw/Rt)\right]^{1/1.90} \quad \text{where: Phi = fractional porosity}$$

Cutoffs to define net pay were established based on core and log data and on published information. Because of the lack of adjacent shales, accurate values of V_{cl} are difficult to determine for the Delaware Sandstones. Selection of a V_{cl} cutoff was therefore based on the work of Dewan (1984), which suggests a 15% cutoff for reservoirs with dispersed clay. A plot of core porosity vs. permeability (Figure 2.26) suggests using a porosity cutoff of 15% or greater for rocks with 1 md of permeability and a cutoff of 20% or greater for rocks with permeability of 5 md or more. Normalization of five relative permeability curves led to picking a water saturation cutoff for net pay at 60%, a value at which the relative permeability to oil is roughly 8 times that of permeability to water. This technique was based on the work of Schneider (1987).

The above petrophysical analysis of the reservoir interval of the Ford Geraldine unit was used to calculate porosity, hydrocarbon saturation, and net pay. The amplitude family of seismic attributes had the highest correlations with reservoir properties of average porosity, and porosity-thickness (Dutton et al., 1998a). On the basis of reservoir characterization of the Ford Geraldine unit and the East Ford field, the northern end of the Ford Geraldine unit was chosen as a potential pilot demonstration area. A detailed geostatistical model for the distribution of reservoir properties in the Ford Geraldine demonstration area was developed and used as input to simulation models to evaluate the fluid flow performance of a CO_2 flood of the reservoir. Simulations of the pilot area indicate that a minimum of 10% of the remaining oil (1.0 MMSTB) is recoverable through CO_2 flood.

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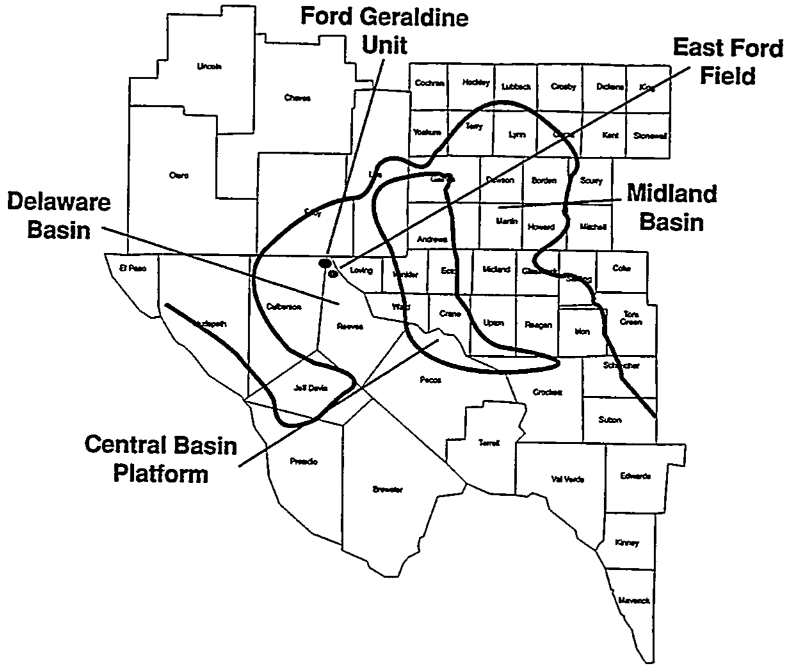

Figure 2.24 – Location of Ford Geraldine unit and East Ford fields in Reeves and Culberson Counties, Texas. (From Dutton et al., 1998a)

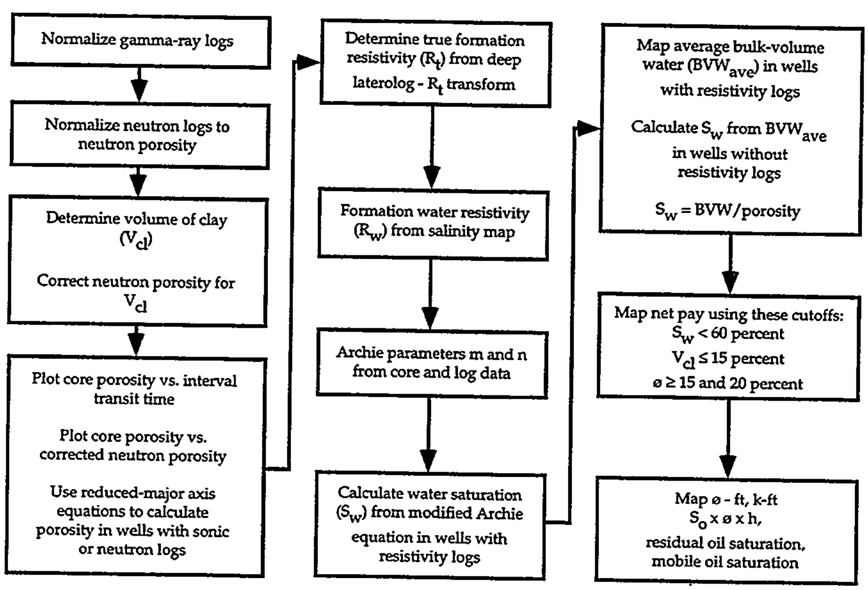

Figure 2.25 – Flow chart of petrophysical analysis performed at the Ford Geraldine unit. (From Dutton et al., 1998a)

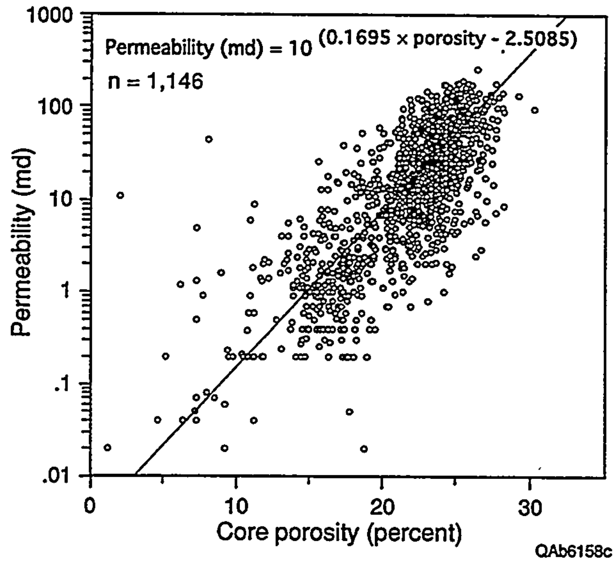

Figure 2.26 – Cross-plot of core porosity vs. permeability for the Ford Geraldine reservoir. (From Dutton et al., 1998a)

Additional Examples of Working with "Old Logs"—Bureau of Economic Geology

In a Reservoir Class I project completed in 1996 – Revitalizing Mature Oil Play Strategies for Finding and Producing Unrecovered Oil in Frio Fluvial-Deltaic Reservoirs of South Texas (Project ID: DE-FC22-93BC-14959) – objectives were to develop interwell-scale facies models and to assess engineering attributes in order to characterize reservoir architecture and flow unit controls on location and volume of unrecovered mobile and residual oil. The project looked specifically at Frio reservoirs in the T-C-B and Rincon fields in the Vicksburg Fault Zone play. Notable among the technologies employed in the study were the use of 3-D seismic and the analysis of "old" electric logs.

Core porosity vs. permeability relationships were established using a nonlinear regression technique for each major depositional facies. The development of petrophysical models to predict porosity, permeability, and water saturation from log data was based on evaluation of both routine and special core analysis data and petrographic identification of the type and distribution of clay minerals.

Major hurdles in the log analysis at Rincon field involved determining a bulk shale volume indicator and developing a porosity algorithm (only 6 of nearly 200 wells in the project study area had porosity logs) (Knox et al., 1996). Relationships between log resistivity and porosity were studied in order to develop a model to determine porosity from electric log data. In calculating porosity from resistivity logs, a correction for shale content was developed to compensate for the effects of shale on conductivity as measured by logs. A shale volume correction developed from the spontaneous potential (SP) curve was used to correct resisitivity-derived porosities. Relationships determined for porosity and resistivity were subsequently used to calculate permeability using the appropriate porosity-permeability relationship identified for each reservoir facies type.

A PC-based software package – Reservoir Characterization Advisor - Fluvial Deltaic – was developed in this project to help identify and prioritize reservoirs with reserve growth potential. The software provides an interactive guide for advanced, integrated multidisciplinary reservoir characterization studies in fluvial deltaic reservoirs. It is designed, through the use of menus, text, graphics, and data-entry and prioritization screens, to be simple to use and informative for operators of fluvial deltaic reservoirs.

In a non-Reservoir-Class DOE-supported project completed in 1997, the Bureau of Economic Geology constructed a reservoir model to predict the location of remaining mobile oil in the South Cowden (Grayburg) field in west Texas (see also discussion of this field under the Phillips Petroleum Company Class II project in Chapter 3 of this report). This project – Geoscience Engineering Characterization of the Interwell Environment in Carbonate Reservoirs

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Table 2.4 - Porosity Logs Available in the South Cowden Study Area

No. Of Wells	Log Type
47	Neutron logs calibrated in counts per second
10	Open-hole neutron logs calibrated in porosity
33	Cased-hole neutron logs calibrated in porosity
16	Sidewall neutron logs
58	Acoustic logs
40	Neutron/density logs (with occasional acoustic logs also)
204	Total

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Table 2.4 - Porosity Logs Available in the South Cowden Study Area

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40	Neutron/density logs (with occasional acoustic logs also)
204	Total

University of Kansas—Schaben Field, Kansas (Reservoir Class II): Timothy Carr and Willard Guy

The majority of Mississippian production in Kansas occurs at or near the top of the Mississippian section just below the regional sub-Pennsylvanian unconformity. These reservoirs in the mature stage of their productive life account for over 40% of total annual production in the state and cumulative production exceeds 1 billion bbls (Carr et al., 1995a). High water cuts and overall low recovery factors place continued operations at or near their economic limits. A large number of these reservoirs are operated by small independent producers who do not have resources to develop and test advanced technologies, yet access to new technologies is important for sustaining production and increasing economic viability of their reservoirs.

The Schaben Field Project

This project, begun in 1994 and scheduled for completion in 1999, addresses producibility problems in Kansas fields like the Schaben field in Ness County (Figure 2.27) that produce from Mississippian (Meramecian and Osagian) shallow shelf dolomites (Reservoir Class II) beneath the sub-Pennsylvanian unconformity. Major problems in these reservoirs include inadequate reservoir characterization, drilling and completion design problems, and non-optimal primary recovery. The Schaben field is located on the western flank of the Central Kansas uplift at the western edge of the Mississippian Osagian subcrop beneath the sub-Pennsylvanian unconformity. Discovered in 1963, the field contains 78 wells on 40-acre spacing. As of late 1996, cumulative production had reached 9.1 MMBO and daily production from 51 wells was 326 BOPD. The project demonstration site contains 1,720 acres with 29 wells. The project aims at demonstrating the tools and techniques that will facilitate integrated, multidisciplinary reservoir characterization in a cost-effective manner that can be duplicated by other small independent operators.

The project developed, modified, and/or demonstrated a number of cost-effective tools and techniques for reservoir description. Most important among these include:

- A low-cost, easy-to-use, spreadsheet-based software package for analysis of wireline log data
- A new "pseudoseismic" approach to subsurface visualization using wireline logs
- An extension of the BOAST-3 reservoir simulation program developed by the Department of Energy that improves capabilities for full-field reservoir simulation

The geologic reservoir characterization for Schaben field was completed and used as input to a full-field, PC-based reservoir simulation with a slightly modified version of BOAST-3. Both the pseudoseismic and spreadsheet-based log software were used along with core and well data to develop an enhanced reservoir model for the field. Pseudoseismic visualization provided a detailed macro-scale view of reservoir patterns, while petrophysical analyses were used to recognize subtle trends and patterns for each of multiple reservoir intervals. Petrophysical results were tied to newly acquired core data to provide detailed documentation of reservoir heterogeneity. Core analysis using nuclear magnetic resonance also was employed in the project to identify and quantify porosity containing bound vs. free water. The reservoir model developed emphasizes the incremental recovery opportunities provided by both vertical and lateral reservoir compartments. Much of the geologic, engineering, and production data, including maps, cross sections and core analyses is available on-line electronically at reservoir, lease, and well scales. (See the project Web site.)

Reservoir simulation was used to develop a reservoir management strategy. Ten infield well locations and 3 candidates for recompletion were identified. The major operators at Schaben field have adopted the reservoir management strategy suggested by this project and have drilled 7 infield locations. Four wells were drilled by the project operator and 3 existing wells were drilled deeper and recompleted. Infield locations drilled and recompletions performed by the operator at the demonstration site resulted in an initial production increase of 350 BOPD, more than double the preproject production. Project results and products are being used by operators elsewhere in Kansas and in other parts of the United States. At least 2 additional infield wells are planned by other operators at Schaben field.

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PfEFFER – Integrated Analysis of Wireline Log and Reservoir Data in a Spreadsheet Environment:

This and the following section describe the log-analysis software products that originated in or have been modified and/or employed in the Schaben field project. PfEFFER (Petrofacies Evaluation of Formations For Engineering Reservoirs) is a Visual Basic "add-in" computer program developed by the University of Kansas. It is designed to operate from the Microsoft spreadsheet program EXCEL for petrofacies analysis and mapping of hydrocarbon reservoirs. The equations and models employed in the package are firmly grounded in classical log analysis. The Pickett plot (Figure 2.28) plays a central role in the methodology as a graphical device to map numerous relationships including techniques that incorporate estimations of pore size, permeability, and mineralogy. Archie system relationships will plot as straight lines, and the plots can display data such as water saturations, bulk volume water (BVW), capillary pressure data, and nuclear magnetic resonance (NMR) measurement (free fluid vs. bound water porosity) results. Data can be entered into the system either from digital LAS files or by manual input.

The software is aimed at utility in both the exploration and exploitation environment. It is designed to give serviceable performance for the professional log analyst, but the product was specifically developed for generalists who need to perform log analysis in a quick and simple software medium, and integrate the results with reservoir information from other data sources. The more important objectives of the software include the following:

- Resolve the reservoir parameters that most affect performance.
- Characterize subtle properties important to understand and model hydrocarbon pore volume and fluid flow.
- Recognize and resolve bypassed, subtle, and complex oil and gas reservoirs.
- Differentiate commingled reservoirs.
- Assist in managing and integrating large amounts of geological and engineering information to improve modeling of the reservoir and selection of appropriate improved recovery options.
- Provide a practical tool to assist the geoscientist, engineer, and petroleum operator in efficiency and effectiveness.

In straightforward analyses, the user may be satisfied with a single solution, but the spreadsheet-based database and graphics approach allows rapid and repetitive interaction and comparative evaluation of multiple interpretations or best-case/worst-case extremes. Errors on logging tool measurements can be accommodated by incorporating simulated error from a random number generator in a series of multiple runs. Sensitivity analysis can be applied to equation parameters to evaluate their effects. Multiple wells may be handled collectively, and the program may be used to prepare maps and cross sections displaying values of calculated parameters.

A typical approach is to assign a "workbook" in the spreadsheet program to each well, with individual "worksheets" allocated to stratigraphic or other subdivisions of the reservoir. An additional workbook can be used to represent the entire field, with individual well and reservoir subdivision properties assigned to worksheets within that workbook. By linking cells in the field workbook with cells in individual sheets of the well workbooks, automatic revision at all levels can be made if any revisions are made on individual wells or portions of wells. This feature has real advantages in performing consistent log analysis on a fieldwide basis and in presenting fieldwide results. Graphic mapping of data highlights problem wells that can be checked immediately by entering the well workbooks. Corrections made in well workbooks will then be carried forward automatically for incorporation into revised maps. In this mode of use, with mapping becoming a part of the log analysis, interactive comparison of results from neighboring wells aids in making decisions about individual wells. A "mosaic" style of log analysis emerges, and wells are seen in their field context rather than as isolated entities.

A cross section capability allows panels to be constructed of well variability across a field with log variables or reservoir attributes color-coded as spreadsheet columns and hung on a user-selected datum (Figure 2.29). Such displays provide an immediate perspective on reservoir connectivity and conformance and contribute to determination of reservoir flow units. They also provide a link to integrate log analysis results with conceptual geological models such as sequence stratigraphic interpretations of a reservoir.

PfEFFER also aids in the design and assignment of parameters to grid blocks as input to reservoir simulation through conversion from well coordinates to those used by the simulator. It can also be used to:

- Establish the plot file for each reservoir layer and each parameter.
- Design grid spacing.
- Generate the grids.
- Locate wells in the grid domain for ease of editing and preparing the simulation input file.

The ability to move quickly and interactively between well coordinates and grid system coordinates further contributes to the mosaic style of analysis achieved by the program. PfEFFER also can be used for viewing simulation output (Figure 2.30).

This software package provides a design base for linkage to BOAST-3, to simple graphic information systems (GIS) capabilities, and to the generation of displays of massive amounts of wireline log data through a "pseudoseismic" approach (see next section). The software was developed with the financial, data, and beta testing support of DOE, the Kansas Technology Enterprise Corporation (KTEC), 5 major oil companies, and 17 large independent oil and gas companies operating in Kansas. The software is available in both PC and MacIntosh formats.

Under the DOE's Advanced Class Work Program (see Chapter 1 for a description of this program) further improvements of PfEFFER's capabilities were pursued. Enhanced capabilities of the software now include:

- Definition and flagging of pay via cutoffs
- Definition and flagging of flow units
- Addition of movable oil plots and analysis
- Inclusion of shaly sand analysis for fluid saturation calculation
- Addition of the Hough transform method for definition of Archie m and R_w
- Incorporation of techniques for analysis of secondary porosity
- Development of forward-modeling techniques to assist in integrating core and log data

Software modules were also developed under the DOE's Advanced Class Work Program to link PfEFFER's capabilities with other software; i.e., bridges to GIS WHEAT and BOAST-3.

The software can be purchased at the:

Publication Sales Office
Kansas Geological Survey
University of Kansas
1930 Constant Ave
Lawrence, KS 66047-3726

Ph: (785) 864-3965, Fax: (785) 864-5317

Survey Web site: http://www.kgs.ukans.edu/
PfEFFER Web site: http://crude2.kgs.ukans.edu/PRS/software/pfeffer1.html
Order form located at: http://crude2.kgs.ukans.edu/PRS/software/orderForm.gif

Direct inquiries about PfEFFER can be directed via email to:
PfEFFER@kgs.ukans.edu

A demonstration version of PfEFFER is available from the North MidContinent office of the Petroleum Technology Transfer Council (PTTC) at:

North MidContinent PTTC
C/O Energy Research Center
University of Kansas
1930 Constant Ave.
Lawrence, KS 66047-3724
Ph: (785) 864-7398, Fax: (785) 864-7399
Website: http://crude2.kgs.ukans.edu/ERC/pttcHome.html

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Bohling, G., J. Doveton, W. Guy, L. Watney, and S. Bhattacharya, 1998, PfEFFER 2.0 Manual, Kansas Geological Survey, 161 p.

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Pseudoseismic Transforms of Wireline Logs—a Seismic Approach to Petrophysical Sequence Stratigraphy:

Stratigraphic interpretation from wireline logs is typically drawn from multiple log traces or from crossplots of log data. Both techniques can readily depict vertical changes in lithology or reservoir quality, but lateral relationships are not as readily visualized, especially when very large numbers of wells such as are typically found in mature oil and gas provinces are involved. Since 1889, more than 300,000 wells have been drilled in Kansas alone. Yet, areally extensive subtle traps are still being found; new fields, new pools, extensions, bypassed pay, and infield opportunities are realized regularly. Extreme frustration, however, is encountered in applying computer-aided exploration and development techniques to the large amount of data available. The problem is typical of any large field or producing region. The problem of reviewing and interpreting wireline log data from wells that may number in the thousands seems intractable. Studies in such areas are usually severely limited in either area or scope as a result.

Treating wireline data in a manner similar to seismic data can ease the data-handling burden. In a sense, both are simple x-y series data, one in the domain of amplitude vs. depth, the other in the domain of amplitude vs. time. A single log curve or a combination of curves from multiple tools (e.g., gamma ray, density, and neutron logs) can be transformed to a color coded "cross-plot" log that is similar in appearance to a single seismic trace. These transformed logs can then be processed and displayed by computer workstation programs designed to handle large volumes of seismic data. Transformation of well spacing to seismic trace spacing is accomplished by selecting an appropriate bin size and rounding well locations to the nearest whole bin location. Areas without representative wells can be represented by empty bin locations.

Using only simple zoom, datum, and manual and autopicking tools that accompany the seismic software package, lines containing hundreds of wells can be interpreted for such details as truncation of individual beds; lateral facies changes; extent and geometry of sedimentary beds/units; truncation, onlap, and downlap of specific stratigraphic units and subunits; presence of faults; and so forth in just a few hours (Figure 2.31). Vertical resolution is a function only of the resolving power of the logging tools and the increment of digitization, and data may be manipulated and displayed in either 2-D or 3-D modes.

Software with these capabilities is being developed jointly by the University of Kansas, the Kansas Geological Survey, and Landmark Graphics. New dimensions in petrophysical analysis are being investigated through evaluating the utility of additional seismic processing operations such as automatic gain control, filtering, wavelet convolution, spectral analysis, and attribute analysis in interpreting wireline log data. These operations may help operators identify trends in the data set and emphasize different aspects of the subsurface geology never before possible. Other applications of the pseudoseismic approach that are pending investigation include using sonic logs to create synthetic seismic sections and to map regional velocity functions, and using the interpolation tools of the workstation software to model missing pseudotraces/wells.

More information on this technique may be found at the following Web site:
http://www.kgs.ukans.edu/PRS/publication/carr.html
Software is available at the following Web site:
http://www.kgs.ukans.edu/PRS/publication/OFR97-22/ofr9722.html

Pseudoseismic References

Carr, T. R., J. H. Hopkins, H. R. Feldman, A. Feltz, J. H. Doveton, and D. R. Collins, 1995, Color 2-D and 3-D pseudo-seismic transforms of wireline logs; a seismic approach to petrophysical sequence stratigraphy: Landmark Computer Graphics User Net, 6 p.

Hopkins, J. F., T. R. Carr, and H. R. Feldman, 1996, Pseudoseismic transforms of wireline logs; a seismic approach to petrophysical sequence stratigraphy: Symposium on Advanced Wireline and Geophysical Technology, 17th Annual Gulf Coast Section SEPM Research Conference, Houston, December 8-11, p. 133-144.

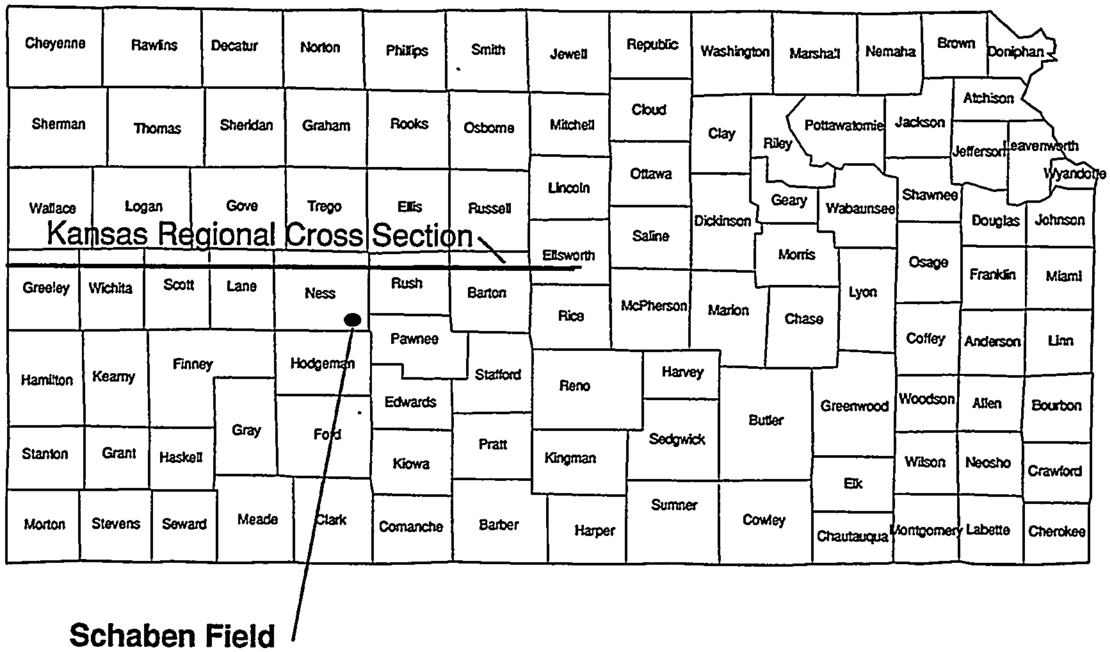

Figure 2.27 – Location of Schaben field in Ness County, Kansas.

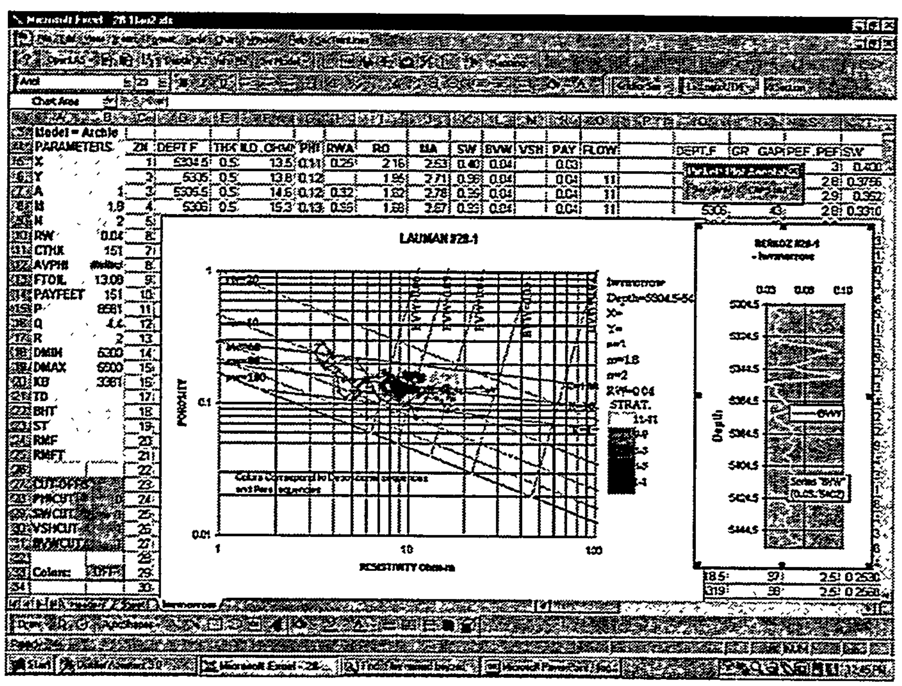

Figure 2.28 – The Pickett plot is a very versatile feature and one of the cornerstones of the PfEFFER log analysis software package.

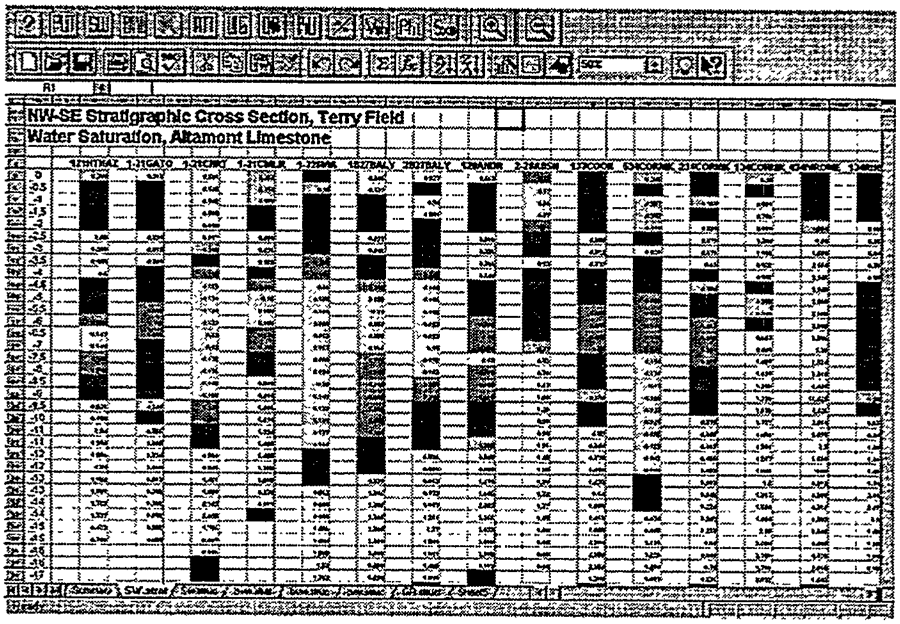

Figure 2.29 – Color-coded cross sections from PfEFFER can quickly display vertical and lateral changes in calculated reservoir parameters such as water saturation. (green = 0.11-0.13, yellow = 0.13-0.17, magenta = 0.17-0.22, red = 0.22-0.26, purple = 0.26-0.32, dark purple 0.32-0.42, black 0.42-0.52, white > 0.52)

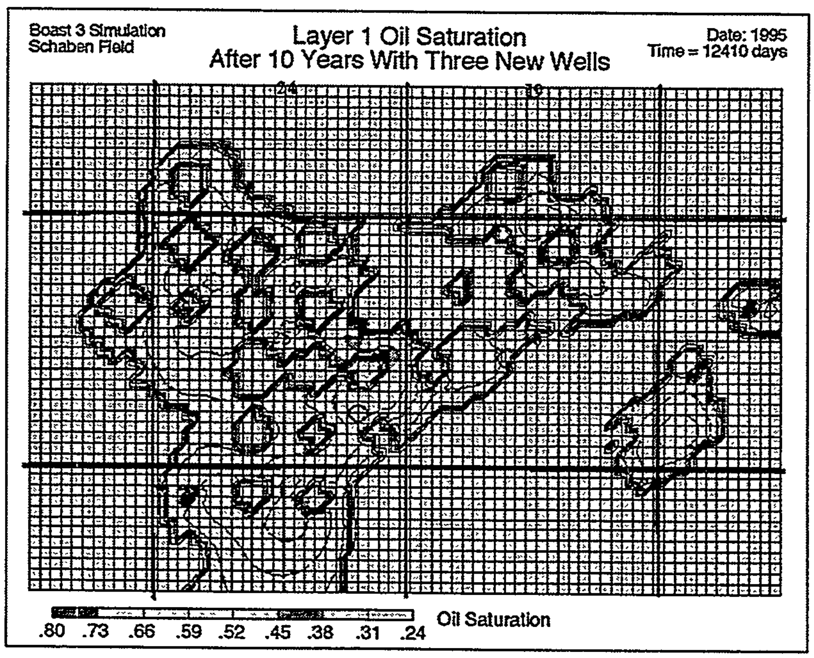

Figure 2.30 – Contoured output from Boast 3 simulation, oil saturation.

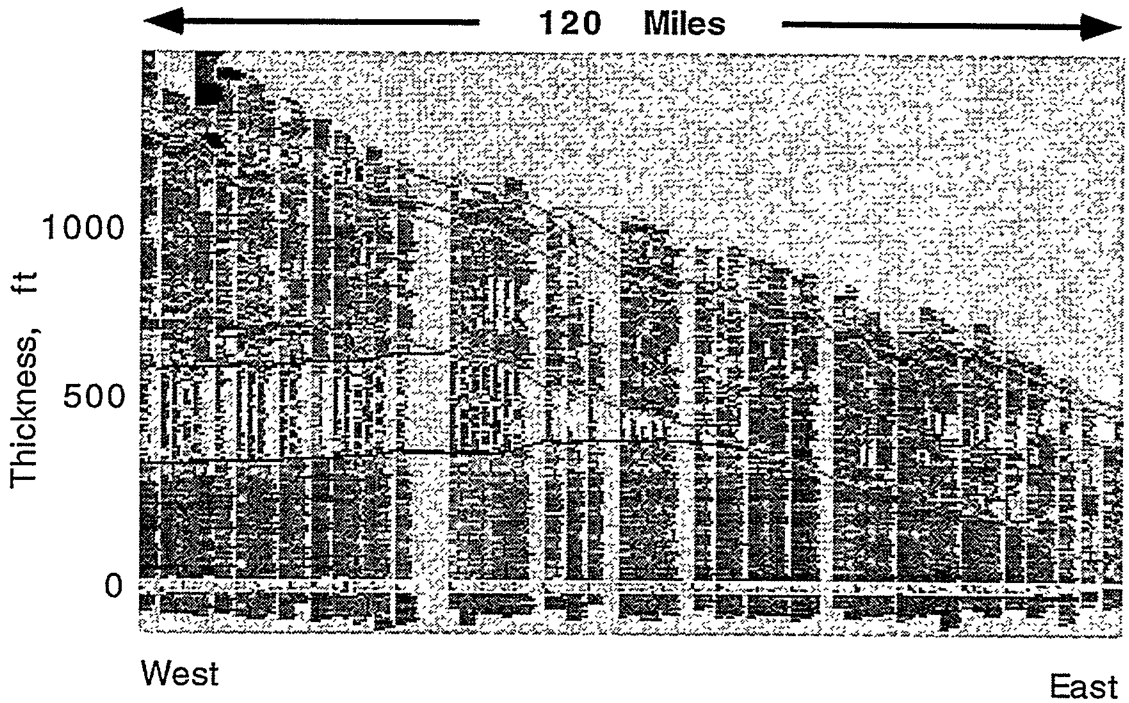

Figure 2.31 – Handling log data in a "pseudoseismic" fashion allows rapid display and interpretation of large-scale stratigraphic relationships incorporating large numbers of wells using seismic workstation software.

Summary of the Use of Core-Log Modeling

Modern reservoir characterization almost always involves establishing some kind of a correspondence between core data (or core analysis data) and log response in an attempt to get information about the ease of fluid movement in the subsurface reservoir. Usually this is accomplished by establishing a predictable relationship between porosity and permeability as measured in core; then using log porosity to predict permeability profiles. In a number of reservoirs, the core-porosity to core-permeability relationship is reasonably good and acceptable for use in reservoir modeling. This is generally the case for reservoirs with simple pore systems and/or reservoirs in their primary stage of production.

In very mature reservoirs with low production and marginal profitability, however, reservoir models with even a moderate degree of uncertainty may not be acceptable for reservoir management decision making. Also, in reservoirs with complex pore systems, an extremely high degree of model uncertainty in fluid flow properties may result from very poor relationships between observed core porosity and permeability. Both reservoir situations are represented in the Reservoir Class Program projects reviewed in this section. Several of the projects (the University of Tulsa Reservoir Class I project, the Pioneer Natural Resources Class III project, and the Bureau of Economic Geology's work in reservoirs belonging to Reservoir Classes I, II, and III) are dealing with situations where porosity logs are not available at enough of the wellbores to build the detailed reservoir model needed to guide improved recovery efforts. These projects all employed innovative approaches to derive basic reservoir petrophysical data from the "old" logs available. In the Fina USA and Oxy USA (Reservoir Class II) projects, conventional porosity logs are available, but the pore-system complexity of the West Texas Permian carbonate reservoirs they are exploiting precludes using the simple universal approach to predicting permeability directly from porosity. The Strata project is evaluating a relatively modern reservoir with the special problems associated with very thin pay zones in turbidite sands (Reservoir Class III) that cannot be accurately identified using conventional log analysis procedures.

The success of the case studies reviewed has been in their ability to empirically (sometimes intuitively) subdivide the reservoir into flow units each implicitly dictated by its unique pore/pore-throat characteristics and to apply separate permeability predictions based on porosity for each. In terms of the Carman-Kozeny equation, permeability is a function of both porosity AND specific pore/pore-throat characteristics. When total field datasets are divided into groups that display consistent pore/pore-throat characteristics, permeability becomes controlled primarily by the porosity term. To the extent that rocks can be grouped with similar pore/pore-throat characteristics, permeability can be predicted by porosity.

In these projects, the special problems of each reservoir were approached with a variety of core-log modeling techniques; each designed specifically to address the problem at hand. Some models involved an intermediate identification of lithologic types or genetic rock units; others aimed more directly at identifying rock porosity types. The various approaches all made maximum use of existing wireline log data, with emphasis placed on data that were available on the most widespread basis. Although other techniques such as nuclear magnetic resonance (NMR) logging (see discussion in Chapter 4) may provide alternative estimates of permeability, the cost of this newly emerging technology has prevented it from being routinely applied on a fieldwide basis in older fields. In terms of information received that had strong influence on project decision making, core-log modeling was among the most cost-effective of all technologies applied in Reservoir Class Program projects.

The careful matching of log response to core observation (whether in whole core, thin section, SEM analysis, or results from routine and special core analysis) played a critical role in development of core-log models in each project. Core-log model development was demonstrated to be an iterative process. Initial core-log models were tested and calibrated by comparing their predictions against core material not already incorporated into the models. As characterization of the reservoirs progressed, modification of models to include newly encountered rock types not explained by previous versions made the models more robust and more widely applicable.

In every project reviewed, it is difficult to see how core-log modeling studies could have been performed successfully without the ability to process large volumes of digital wireline log data. Aside from allowing large numbers of wells to be addressed, data processing capabilities allowed the effects of differences in borehole environments to be corrected and differences in logging tool responses to be accommodated through normalization procedures on a fieldwide scale and, in some cases, on multiple curves per well. In several instances (e.g., in the Strata, University of Tulsa, and University of Kansas projects), the operators and their project partners have developed publicly available software to allow others to imitate their model-building procedures. Important to note is the fact that much of this work was accomplished without the requirement for access to mainframe computer facilities. Much was accomplished and can be accomplished by others using only PC hardware.

Most operators in the reviewed projects had previous experience in using core-log models for reservoir description, and most also agreed that core-log modeling is, at the present time, an underutilized technology. At the DOE/PTTC-sponsored workshop on Advanced Concepts in Wireline Logging for Improved Oil Recovery in Midland, Texas, the general concept of core-log modeling was lauded in the panel discussion as potentially effective in making maximum use of the latent information that resides in millions of existing wireline logs, both of old and modern vintage. All of the projects discussed here achieved the goal of obtaining new and useful information for reservoir description from previously existing logs, but each approach was unique, based on long familiarity with the problems and characteristics of the individual reservoirs being studied. Not one of these approaches could be applied in detail without modification to reservoirs of different types. There is a need for additional research, development, and demonstration of the techniques for core-log modeling that are appropriate for major reservoir classes.

CHAPTER 3

BOREHOLE IMAGERS: OPENING A NEW PERSPECTIVE ON THE RESERVOIR

Borehole images are displays that can be viewed and interpreted visually to (1) examine the condition of the borehole surface, or (2) clarify or identify reservoir rock and/or fluid properties and observe their distribution in 3-D space about the circumference of a cased or uncased borehole. Numerous types of wireline tools for capturing images have evolved from the conceptual stage to common application by industry over the past two decades. Their potential contribution for cost-effectively supplying a wide variety of subsurface information is widely recognized. An excellent example of this recognition is the critical information contributed by borehole imagers for reservoir characterization in a large number of Reservoir Class Program and other DOE-supported projects in the past few years.

Some Types of Borehole Imaging Tools in Common Use

Some borehole imaging tools capture property information essentially at the surface of the borehole, while others describe formation and/or fluid characteristics at some finite depth beyond the borehole surface. Resolution, both vertical and horizontal, and scale of information provided vary with tool type and configuration, but the resolution attainable with certain types of borehole imagers is greater than that of any other wireline log type.

Display types vary from tool to tool. Video imagers present continuous and simultaneous visual views of borehole interiors. Other imagers capture azimuthal variations in properties, and their output is generally viewed in two dimensions as unwrapped presentations. These images, often referred to as borehole maps, are amenable to distribution in hardcopy with reports and publications or as computer animations in cylindrical form. Two-dimensional (2-D) displays generally feature azimuth on the horizontal axis and depth on the vertical axis with variations in measured properties represented in gray-scale or false-color images. Image displays generally include information on directional orientation of the features imaged with respect to true north. By convention, borehole maps usually display north [0°] at the left, followed by east [90°], south [180°] at the center, west [270°], and return to north again [360°] at the right. Nonhorizontal planar features such as fractures intersecting the borehole at some angle to the vertical appear as sinusoidal curves on these plots, and calculation of their spatial orientation is a simple exercise.

Yet other tools form images in depth beneath the borehole surface and do not address azimuthal variations. Some of these tools, because they do not create directionally "true" images of the borehole, will not be treated here. Other imaging tools that did not play substantial roles in the DOE-supported projects reviewed also will not be addressed. Some however, such as nuclear magnetic resonance imagers, are treated later in the Advanced Tools section.

Images are obtained by lowering the borehole logging tool into a wellbore and recording information at a depth determined by the wireline length, as with most logging tools. Most imaging tools transmit a stream of information to the surface, where the information may be either converted immediately into a visual image, as with video imaging tools, or stored electronically or transmitted for offsite processing as is the case with tools taking more complex measurements. Computer processing guided by expert analysts is required to convert some raw tool data into a reliable and meaningful image. In some cases, this processing can be done at the well site.

Borehole images are currently obtained in several ways: by reflecting signals (light or sound) off the surface of the borehole (or casing) through fluids present in the borehole, or by reading rock and fluid properties beyond the surface of the borehole through direct contact or remote sensing techniques. Based on the technologies commonly employed, there are currently three basic types of true imaging tools to consider: those based on visible light, those based on sound waves, and those based on small-scale resistivity measurement.

Video/Optical Imagers

This is commonly the simplest of the borehole imaging technologies. It employs television technology coupled with a downhole light source to transmit visual images to the surface in real time. This technology is a logical outgrowth of the earliest borehole imaging, which involved lowering a still camera down the borehole (Paillet et al., 1990). Video/optical imagers have become genuinely useful with the advent of cameras and lighting systems capable of coping with a variety of borehole conditions adverse to standard video technology.

The lack of need for processing or extensive interpretation of the data received at the surface is probably the main strength of this technology. Fisheye lenses directed downward can provide a 360° view of the borehole surface. The tools instantly provide high resolution data on the borehole surface (either rock or casing), allowing nearly interactive wellsite decision making under the right conditions. In wellbores filled with opaque fluids, however, the borehole fluid must be changed, or arrangements made to introduce clear fluids between the tool and the borehole wall.

These tools are ideal for surveying boreholes filled with clear fluids such as water, gas, or air. For air- or gas-filled boreholes the video survey may be the only reasonable choice. The tools also are used to some extent in oil- or mud-filled boreholes by locally providing a photographic "window" by injecting clear fluid between the camera lens, light source, and the borehole wall.

High resolution makes the tools valuable for evaluating sedimentary structures, bedding features, and fractures in uncased holes. The tools are especially useful for determinating fracture apertures (Lau et al., 1987). In cased holes, typical applications are for locating perforations, inspecting casing condition (splits, corrosion, etc.), and identifying producing intervals by observating hydrocarbons entering the wellbore.

The Reservoir Class III project conducted in the California Buena Vista Hills Field by Chevron USA, Inc. made excellent use of video imaging technology for determinating sites of fluid entry into the wellbore.

Acoustic Imagers

Acoustic imaging began development as an outgrowth of sonic logging technologies more than three decades ago. The technology is based on emitting sound pulses from a source centralized in the borehole and recording the characteristics of those pulses received at the tool after reflection off the surface of the borehole (Figure 3.1). Key pieces of information received by the tool are travel time and amplitude. Variation in acoustic impedance is the physical basis of the technology. The acoustic source, actually a transducer, rotates at a known rate as the tool is continuously raised in the borehole, allowing reflected signals to be recorded with directional information as the entire circumference of the borehole is surveyed.

In the early years of acoustic tool development, poor image resolution and attenuation by drilling mud were problems that limited use of the technology (Paillet et al., 1990). Modern tools, however, generate the high acoustic frequencies (in the hundreds of kilohertz to megahertz range) required for high resolution and adequate penetration of energy through most drilling muds (Hayman et al., 1994). Modern tools also have flexibility to vary sampling rate and frequency to optimize tool response for each borehole's geometry, rugosity, and fluid conditions.

In practice, variations in acoustic velocity of the borehole fluids are measured and recorded as the tool is lowered into the borehole. Image data are then collected as the tool is withdrawn and vertical variations in fluid acoustic properties are re-introduced during computer processing to produce the most accurate borehole images possible (Hayman et al., 1994).

Two-way travel time of the emitted pulses serve in calculations of borehole shape and size, but the amplitude of the pulses reflected off the borehole wall also contains valuable information. Features that scatter the energy of the pulse, such as vugs or the intersections of fractures with the rock face or irregularities on the surface of casing, produce characteristic anomalies in the received signal (Paillet et al., 1990). As the tool moves vertically, changes in lithology are reflected in changes in amplitude of the reflected signal because of accompanying changes in acoustic contrast between the borehole surface and its contained fluids. Of course, interpreting the amplitudes of reflected signals may be complicated by attenuation because of factors such as tool tilting, tool eccentering, and scattering of energy by particles suspended or moving in the borehole fluid.

Generally, acoustic imaging results are better in hard formations which have higher acoustic contrasts with borehole fluids and reflect more energy. The same argument indicates that lower density muds also will give better images. Smooth borehole surfaces, because they cause less dispersion of energy, also generally yield better results. The presence of thick mud cake tends to lower resolution by masking underlying differences in acoustic contrast. A very important and sometimes overlooked consideration in acoustic imaging is that, no matter how significant variations in composition of the borehole wall may be, those variations will not show up on acoustic images unless the variations are also accompanied by significant differences in acoustic properties.

Advantages of acoustic imagers are their compatibility with either clear or opaque muds,and both electrically conductive (water-based) and nonconductive (oil-based) muds. Even high mud weights are no longer a problem in most cases. The major strengths of the technology are in its use for analysis of fractures and for borehole shape analysis. Fracture detection, of course, depends on fractures being sufficiently open and filled by borehole or other fluids to offer the requisite acoustic contrast.

Borehole cross-sectional shapes are often represented simply as plots of variation in radius at constant depth. More sophisticated spiral plots such as that shown in Figure 3.2 show variation in cross-sectional shape over a range of depth. Wellbore breakouts are shape features consisting of diametrically opposed enlargements on the surface of the borehole that are vertically continuous over some interval (Figure 3.3). These features result from failure of rock adjacent to the borehole because of compressive stress in a direction generally perpendicular to the plane in which the breakout lies. This information can be used to predict the potential orientation of both natural and induced fractures. Other significant borehole shape alterations because of drilling activities such as simple washouts or keyseating (where drill pipe wears on the side of the borehole) are also readily detected using acoustic methods.

In cased holes, acoustic imagers can inspect casing for location of splits, corrosion, scale, or perforations. If properly attuned, they also can investigate variations in casing thickness and the condition of cement behind casing.

In DOE's Field Demonstration Program, acoustic imaging tools played a part in reservoir characterization in the following projects (discussed in detail later in this chapter):

- Utah Geological Survey – Bluebell Field, UT (Reservoir Class I)
- Phillips Petroleum Co. – South Cowden Unit, TX (Reservoir Class II)
- Fina USA Inc. – North Robertson Unit, TX (Reservoir Class II)
- Oxy USA Inc. – West Welch Unit, TX (Reservoir Class II)

Resistivity Imagers

Resistivity imaging evolved from already existing multiple-armed small-scale resistivity technology employed in dipmeters in the 1980s. Today's technology consists of placing a much larger number of similar, small-scale, focused resistivity devices side by side in contact with the formation. Focused devices prevent currents from flowing axially up the borehole directly to the return electrode, which may be as much as 10 m or more away (Lovell et al., 1997). The devices are placed on metallic pads mounted on multiple arms which are pressed against the circumference of the borehole (Figure 3.4). Some modern tools cover about 80% of the surface of the borehole with 4-armed configurations carrying as many as 48 measuring devices per arm (Foulk, 1997). The images produced are, in effect, a kind of electrical current density map of the borehole surface beneath the pads (Williams et al., 1997).

Resistivity measurements are influenced by gross lithology, pore structure, and fluid content. Like conventional-scale focused resistivity tools, each of the individual pad-mounted resistivity devices measures bulk electrical conductive properties of the formation. Tools usually respond to the properties of only a small volume of formation immediately below the borehole surface. The depth of investigation under typical circumstances is less than 20 mm (Williams et al., 1997). Anomalies at greater depths beneath the borehole surface must be of very large size to appreciably affect tool response. Resolution of resistivity-associated anomalies in the 0.5 cm to 1 mm range can be obtained with modern tools. Figure 3.5 shows a comparison of resolving power of acoustic vs. resistivity imaging logs run over the same interval in a siliciclastic section.

A primary requirement for borehole resistivity imaging is the presence of a conductive borehole fluid. Mud cake also becomes an influential factor in resistivity imaging. Resistivity tools are able to image through mud cake, but the degree of resolution, especially of shallow-reading, small-scale tools will be affected adversely by thicker mud cake. Other borehole conditions that may affect the quality of the resulting image include encountering borehole shape irregularities (e.g., washouts, keyseats, breakouts, etc.) and sticking or excessive rotation of the tool (Maute, 1992). Also, the need for extensive interactive processing and interpretation of the raw data make the tools of limited value as a source of on-site decision support. Some commercial service companies, however, are now successfully providing on-site processing.

Resistivity imaging tools are particularly sensitive to many information types on several scales that are important to geologists and petroleum engineers. Thin beds are usually easily recognized, especially when interbeds are of rocks with slightly greater or lesser shale content, and vertical changes or trends in bed thickness that help in identification of many depositional environments are readily determined. Well-to-well correlation of highly resolved vertical sequences allows insight into reservoir architecture on interwell and larger scales that is not obtainable by conventional logging methods (Carr et al., 1997). In siliciclastic rocks, characteristic crossbedding types, crossbed sets, and other sedimentary structures such as slumps and soft sediment deformation features also provide evidence of depositional conditions. Mudstones, clays, and shales are highly conductive and are usually represented by darker colors on borehole map displays. Sandstones are more resistive in general, but displays are generally attuned to show more highly resistive tight sandstones as light in color, while showing more permeable sandstones containing borehole fluids as darker in color. Resolution of fine-scale features is generally best in interbedded lithologies with significant resistivity contrasts. Small-scale resistive anomalies in conductive or moderately conductive lithologies like shales or sandstones might include things like fossils, pebbles, concretions or nodules, or hydrocarbon-bearing voids (Williams et al., 1997). In more resistive lithologies such as carbonates, conductive anomalies at a similar scale might include items such as clay chips or fluid-filled vugs.

Detailed consideration of the vertical sequence of the sedimentary features observed in a number of wells can lead to an effective model of reservoir architecture that makes defining major reservoir zones for simulation possible. Features, made visible in images by subtle differences in pore structure, fluid content, and composition, may be used in many cases to directly predict general fluid flow anisotropies and other interwell-scale heterogeneities that affect reservoir fluid flow. In carbonate rocks, which are highly resistive and are usually shown as lighter in color than either sandstones or clay-bearing rocks, images of such features as fossils, burrows, nodules, cemented zones, vugs, or other variations in pore morphology may also provide information about depositional and/or diagenetic patterns that are ultimately related to variations in reservoir fluid storage and flow properties. Ability to image these features in carbonate rocks, however, depends on the presence of sufficient resistivity contrast between the features and the matrix in which they are enclosed.

Resistivity imaging tools, like the dipmeter tools from which they evolved, are highly useful for identifying and quantifying structural and tectonic features. In addition, fracture characteristics often are readily discernible, especially fractures containing borehole or formation fluids. Furthermore, information on fluid content and even fracture aperture may also be obtained. Such information provides useful insights into expected large-scale reservoir fluid flow patterns. Drilling-induced fractures are often detectable and can be used to predict the direction of maximum compressive stress in the subsurface. The stress direction is usually at 90° to the plane defined by these diametrically opposed sets of vertical fractures filled with borehole fluid.

Fracture apertures or widths have traditionally been studied only in cores. Even cores, however, are not ideal for collecting information on fracture widths. Open fracture surfaces are commonly disturbed by the coring process itself, and widths are often affected as cores are brought to the surface and pressure is released. The still-controversial measurement of fracture aperture widths by electrical borehole imaging tools was the subject of a well-attended invited talk given by Neil Hurley of the Colorado School of Mines at DOE's Advanced Concepts in Wireline Logging workshop in Denver in 1998 (PTTC/DOE, 1998). Early in the development days of resistivity imaging, Luthi and Souhaite (1990) modeled fracture aperture width measurement. Because open fractures are invaded by mud, mud resistivity is the main input parameter in the calculation method Luthi and Souhaite derived. This method has since been incorporated into commercial software used by Schlumberger for estimating aperture widths from microresistivity imaging tool response. Complete acceptability of this technique has not yet been achieved, but the combination of borehole image data with additional information in the form of mudlogs and other openhole logs, especially gamma ray logs, has led to successful identification of flowing fractures in a number of case studies involving both vertical and horizontal wells (Hornby et al., 1992; Hurley et al., 1994).

In a large number of DOE's Field Demonstration Program and other DOE-supported and cost-shared projects, microresistivity imaging tools played a vital part in reservoir characterization. Use of these tools in the following projects will be discussed in more detail later in this chapter:

- Columbia/Lamont-Doherty–Eugene Island Field, Louisiana offshore (Reservoir Class I)
- Inland Resources Inc./Lomax Exploration Co.–Monument Butte Unit, Utah (Reservoir Class I)
- University of Tulsa – Self Unit, Oklahoma (Reservoir Class I)
- Utah Geological Survey – Bluebell Field, Utah (Reservoir Class I)
- University of Alabama – East Frisco City Field, Alabama (Research and Development by Small Independent Operators Project)
- Fina USA Inc. – North Robertson Unit, Texas (Reservoir Class II)
- ARCO Western Energy Inc. – Yowlumne Field, California (Reservoir Class III)
- Chevron USA Inc. – Buena Vista Hills Field, California (reservoir Class III)
- Pioneer Natural Resources Inc./Parker and Parsley Development Co.–Spraberry Trend, Texas (Reservoir Class III)
- University of Wyoming – Oregon Basin Field, Wyoming (Eolian Deposits treated in a DOE Geoscience Program Research and Development Announcement [PRDA] project)

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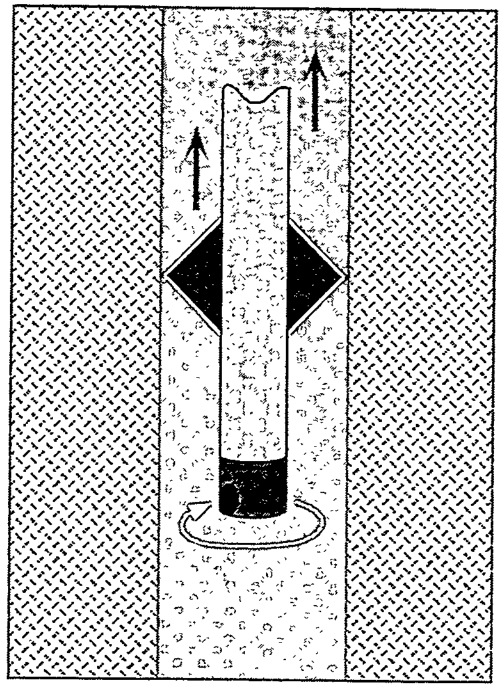

Figure 3.1 – Schematic diagram of rotating acoustic transducer on borehole-centered acoustic imaging tool.

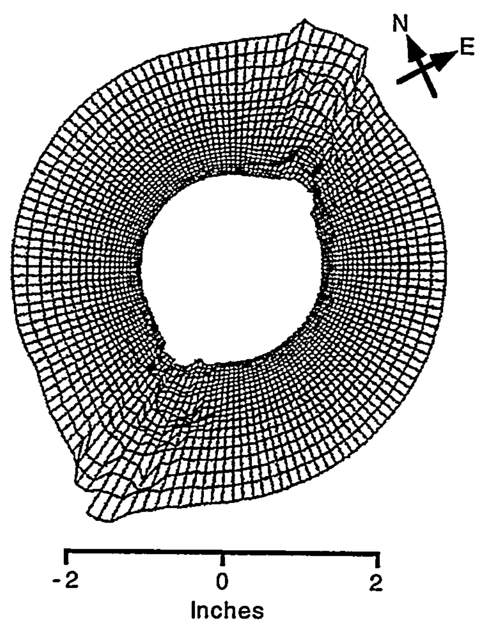

Figure 3.2 – A borehole spiral-shaped plot of acoustic imaging tool data showing a northeast-southwest-oriented borehole breakout. (From Fowler, 1996, supplied by Schlumberger Well Services).

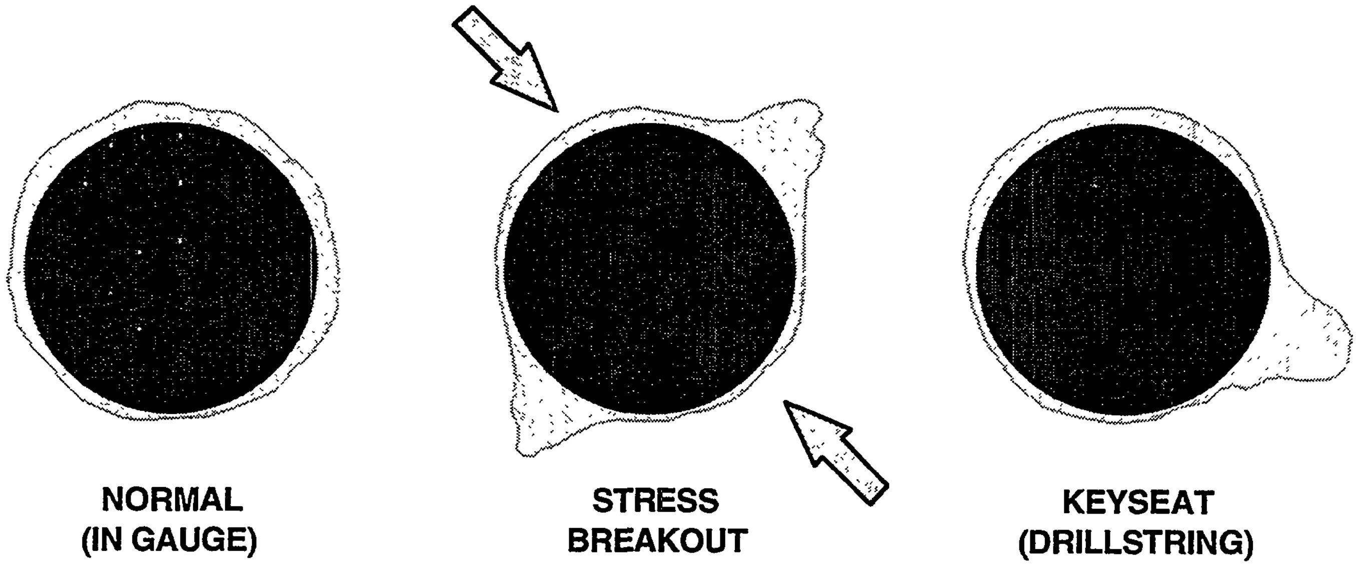

Figure 3.3 – Aspects of borehole shape analysis: left, normal in-gauge borehole; center, stress breakout with maximum principal stress direction indicated by arrows; right, drillstring keyseat.

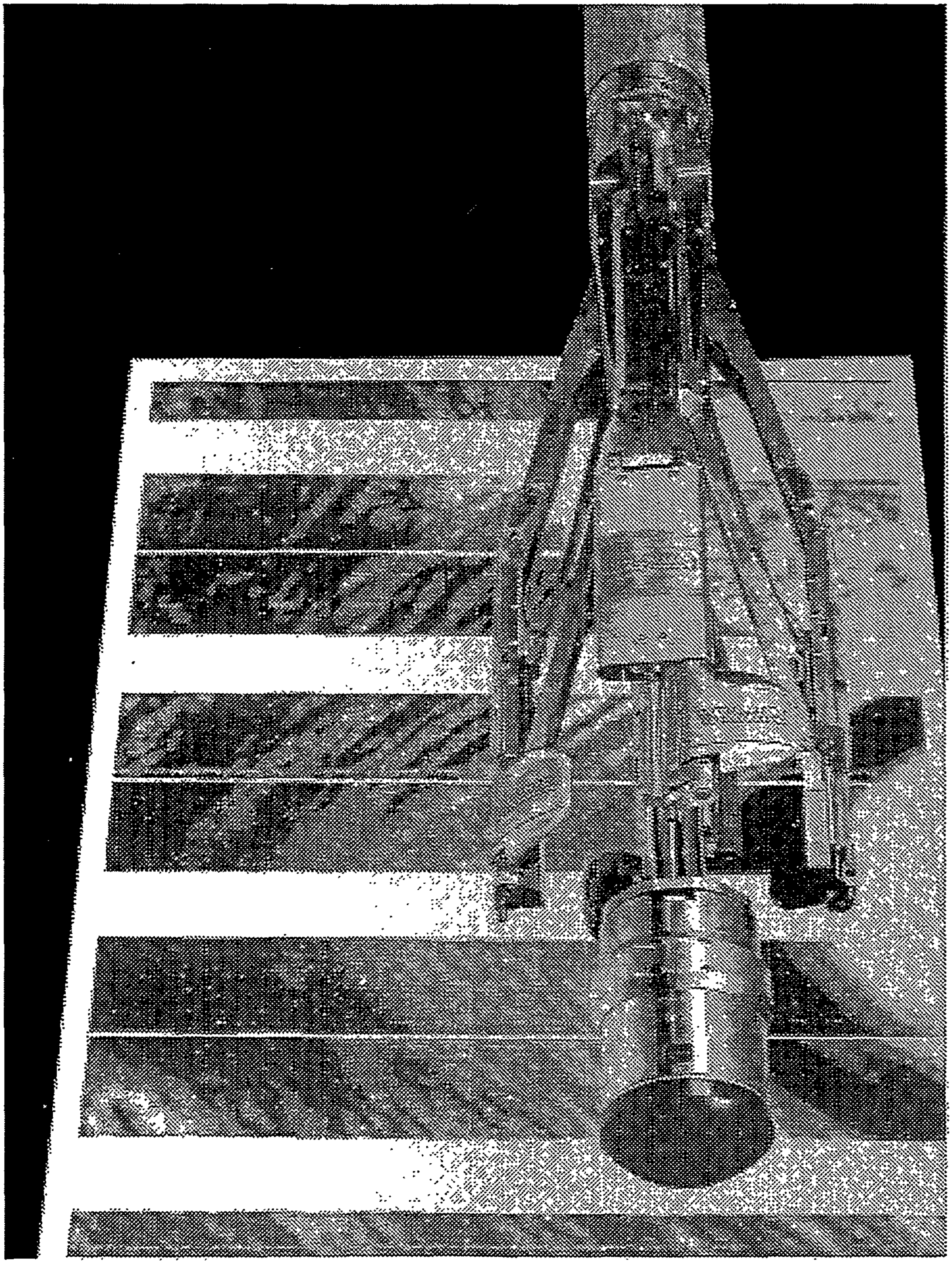

Figure 3.4 – Photograph of a modern multiple-armed microresistivity imaging tool that yields high coverage of the borehole circumference through folding pads and high numbers of resistivity measurement devices. The panel in the back shows a typical log presentation. Conductive intervals are shown in dark shades, wheras resistive intervals are light. (Supplied by Schlumberger Well Services)

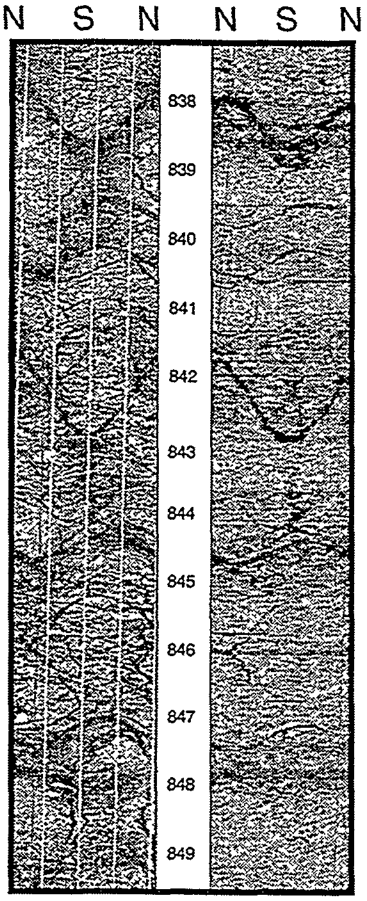

Figure 3.5 – Comparison of resolution capabilities of borehole imaging tools: right, acoustic image; left, microresistivity. (From Fowler, 1996, from materials supplied by Schlumberger Well Services)

Applications of Borehole Imaging Technologies in Field Demonstration Projects

Borehole imaging technologies have contributed to reservoir description in Reservoir Class Program Field Demonstration Projects in all three depositional-system-based reservoir classes and in other projects in related depositional systems and unrelated reservoir types. In this section, projects employing these technologies will be described, and the contribution of the specific imaging technologies will be addressed. For those projects that also made use of core-log modeling techniques, only a cursory overview of the project will be provided, and the reader is referred to appropriate discussions in Chapter 2 for project details.

Columbia/Lamont-Doherty—Eugene Island Field, Louisiana Offshore (Reservoir Class I): Roger N. Anderson

The Eugene Island field in the U.S. Louisiana offshore (Figure 3.6), is the world's most prolific reservoir of Pleistocene age, having produced more than one billion bbls of oil and oil-equivalent gas and condensate since its discovery in 1972. The field, which consists of two rollover anticlines bounded on the north and east by a large down-to-the-basin growth fault system, produces from more than 25 Pleistocene Sandstones of fluvial-dominated deltaic (Class I) origin at depths ranging from 4,300 to 12,000 ft. Faulting and permeability barriers separate these sandstones into more than 100 oil and gas reservoirs.

Conventional wisdom suggests that hydrocarbons migrate upward from their deep sources of generation over long geologic expanses of time, but several characteristics of the Eugene Island field suggest otherwise:

- Oil and gas are being produced from reservoirs as young as 400,000 yrs. (Oils are Cretaceous in age).
- The field has depleted at an unexpectedly slow rate; reserve estimates have been revised upwards at least 8 times.
- The behavior of the oil-water boundary is erratic.
- In some reservoirs, pressures have been increasing with time.
- Monitoring the chemistry of the produced oil in shallower reservoirs since discovery reveals that biodegraded oils produced early in the field's history have been gradually replaced with less biodegraded oils.
- Outcrops of some of the growth fault zones at the sea floor are the sites of active oil seeps.

These observations led the Lamont-Doherty Earth Observatory of Columbia University to team with other universities of the Global Basins Research Network and with industry to test the concept that growth faults in the Block 330 portion of the Eugene Island field (operated by Pennzoil) are conduits through which the producing reservoirs are actively recharged. Secondly project researchers proposed to test the concept that enhanced production might be developed by producing directly from a fault zone.

Analyses of 3-D seismic surveys acquired at different times (this is now commonly referred to as 4-D seismic surveying) revealed shifting trails of amplitude anomalies thought to be caused by natural gas and oil migrating upward sporadically along growth fault zones. A growth fault pathway identified using this seismic technique was targeted for drilling and fault zone testing. The "Pathfinder" well was deviated into the anomaly, and more than 350 ft of core were obtained from the fault zone. Microresistivity images obtained over the growth-fault interval contain highly resistive fractures further suggesting that they are hydrocarbon-bearing (Figure 3.7). Hydrocarbon fluid samples were obtained from the interval, but production could not be established, because fracture permeability closed when attempts were made to produce from the zone.

This Reservoir Class I project, begun in 1992 and completed early in 1996, has reshaped the oil producers' view of where productive reservoirs might lie in the Gulf of Mexico and also in similar sedimentary basins dominated by growth faulting around the world (e.g., those in Nigeria, the North Sea, Indonesia, and the Caspian Sea).

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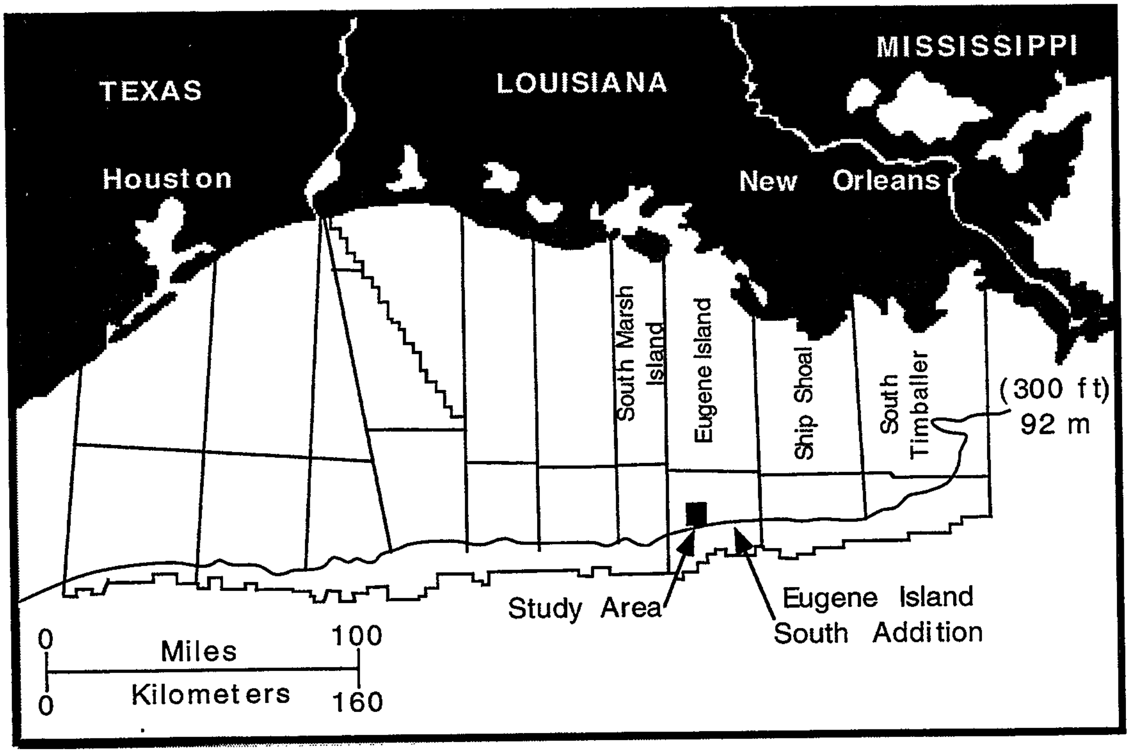

Figure 3.6 – Eugene Island Block 330 location. (From Fowler, 1996, modified from Anderson et al., 1994)

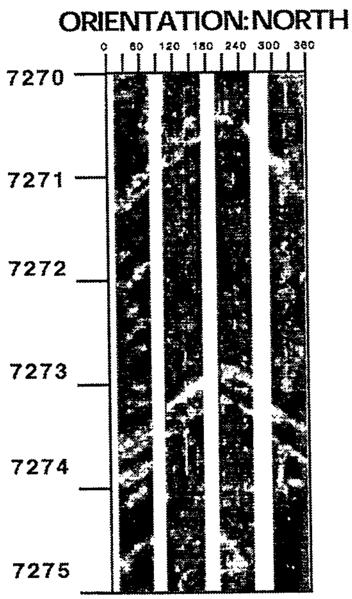

Figure 3.7 – Image from the growth fault interval revealing resistive fractures (light-colored sinusoidal traces) that may contain hydrocarbons. (From Fowler, 1996, modified from Anderson et al., 1994)

Inland Resources Inc./Lomax Exploration Company—Monument Butte Unit, Utah (Reservoir Class I): Bill Pennington and Dennis Nielson

Waterflooding technology has not been commonly used in Uinta Basin reservoirs because of their low permeability, high heterogeneity (especially characteristic of these lacustrine, fluvial-deltaic, Class I reservoirs), and the presence of paraffinic oils. In addition, reservoirs in the region tend to be gas-undersaturated with initial reservoir pressures close to the bubble point pressure resulting in a primary recovery of only about 5% (Pennington et al., 1995). Low primary recovery makes consideration of secondary recovery a necessity. Contrary to the prevailing "conventional wisdom" at the time, John Lomax implemented a successful waterflood on the Monument Butte unit in Duchesne County, Utah in 1987 (Figure 3.8).

The discovery well was drilled in the Monument Butte unit in 1981, and production was established from the Douglas Creek Member of the Eocene Green River Formation. Development proceeded, concentrating mainly on the "D" sandstone. Primary production was anticipated to recover 309,000 STB of oil or about 5.5% of the 5.67 MMSTB of oil originally in place (OOIP). By 1987, prior to initiation of the waterflood, field production had declined to 30 bbl/day. The waterflood proved successful, and by 1991 production at Monument Butte had increased to 330 bbl/day. Estimated ultimate recoverable reserves of the "D" sandstone alone have increased to over 1.2 MMSTB, 20% of OOIP.

The objectives of this Class I project, begun in 1992 and completed early in 1996, were to use reservoir characterization and reservoir simulation to understand the oil production mechanisms responsible for the success of the waterflood at the Monument Butte unit and to transfer the findings to implement waterflooding at nearby units, particularly the Travis and the Boundary units. Reservoir characterization activity in the project consisted primarily of

- Drilling five wells in the Monument Butte unit, 2 in the Travis unit, and 3 in the Boundary unit
- Extracting and analyzing a full diameter core and several sidewall cores
- Obtaining microresistivity imaging logs from several wells
- Obtaining magnetic resonance imaging (MRIL) logs from two wells
- Characterizing oil samples from several wells (chemically and physically)
- Determining oil-water relative permeabilities
- Performing geostatistical analyses

Microresistivity imaging tools were run in six wells (Figure 3.9), mainly to determine the internal and external geometry of the reservoir and distribution of reservoir quality. This entailed interpretation of lithology, sedimentary bed thickness (with resolution down to 1 in.), sedimentary structures (including zones of sediment slumping), paleocurrent directions, depositional facies, sand body geometries, and general depositional environments. Tool response in each of these categories was calibrated against observations made in cores.

Resistivity imaging logs also provided information on regional dips and on fractures. The fractures ares low resistivity features on the logs because of invasion by borehole fluids. In contrast to the simple structural setting of the Monument Butte area, which shows a simple homoclinal dip to the northeast, the reservoir sandstones within the project area are pervasively fractured. Observed fracturing, however, dies out higher in the section. Fractures generally trend east-west to northwest-southeast, parallel to the trends of major systems of faulting in the vicinity. Most fractures measured by the imaging logs are steeply dipping or near vertical. From a statistical standpoint there is a low probability of intersecting steeply dipping fractures with a vertical well. The conclusion follows that the sandstone reservoirs in which these fractures commonly occur are pervasively fractured.

Another important fact revealed by the imaging logs is that fracturing is stratigraphically bound. Sandstone intervals are highly fractured, whereas adjacent mudstones and shales are not (Figure 3.10). Natural fractures in the reservoir will therefore produce anisotropic horizontal permeability in the reservoirs that may significantly affect interwell fluid flow patterns. The same fractures, however, will not contribute to vertical permeability between shale-separated layers. Imaging logs detected faults in several wells, but no consistency in their orientation was observed (Figure 3.11).

Although the microresistivity imaging log was found to be useful for evaluating fracturing, thin-bed stratigraphy, and picking appropriate core points, the operator felt that it would not be practical in an economic sense to use this tool on every well drilled. Calibrating this tool's response against other, more common log suites was recommended, as was reserving use of this tool to perhaps one well in every one or two square miles. These guidelines are recommended for areas like the study area, but the operator suggests their re-evaluation for areas of different geological complexity or under different project economic conditions.

Reservoir modeling activities included reservoir simulation of all three units at different scales and near-wellbore modeling of paraffin precipitation effects. The Lower Douglas Creek, which contributes most to production in the Travis unit, was found to mainly consist of thick, isolated lenses of sand of fluvial origin. This architecturally complex and heterogeneous reservoir was identified as difficult for implementating a successful waterflood. Other fluvial reservoir sandstones in the Green River were also classified as not being immediate candidates for waterflood. The "D" reservoir (probably of subaqueous lacustrine bar origin), is more homogeneous and continuous, and is a better candidate for waterflooding than other reservoir intervals. Simulation identified new reservoirs in the Boundary unit. Simulation also established the extent of pressurization in reservoirs in the immediate vicinity of the Monument Butte unit. This information resulted in a major expansion of the unit and further increased production from about 300 BOPD to about 2,000 BOPD. Industry interest in this project and the success of the Monument Butte Waterflood has led to the implementation of at least 17 new and similar waterfloods in the Monument Butte region.

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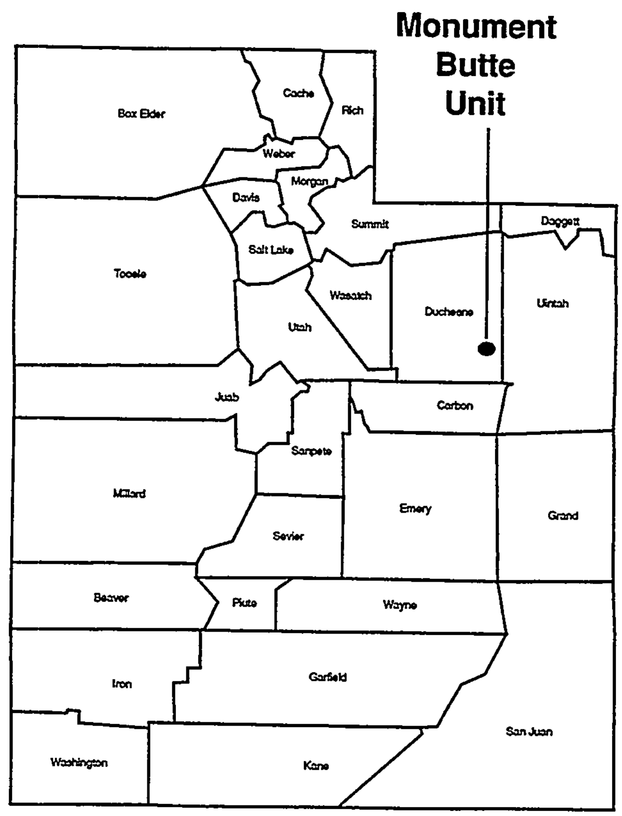

Figure 3.8 – Location of the Greater Monument Butte study area in Duchesne County, Utah.

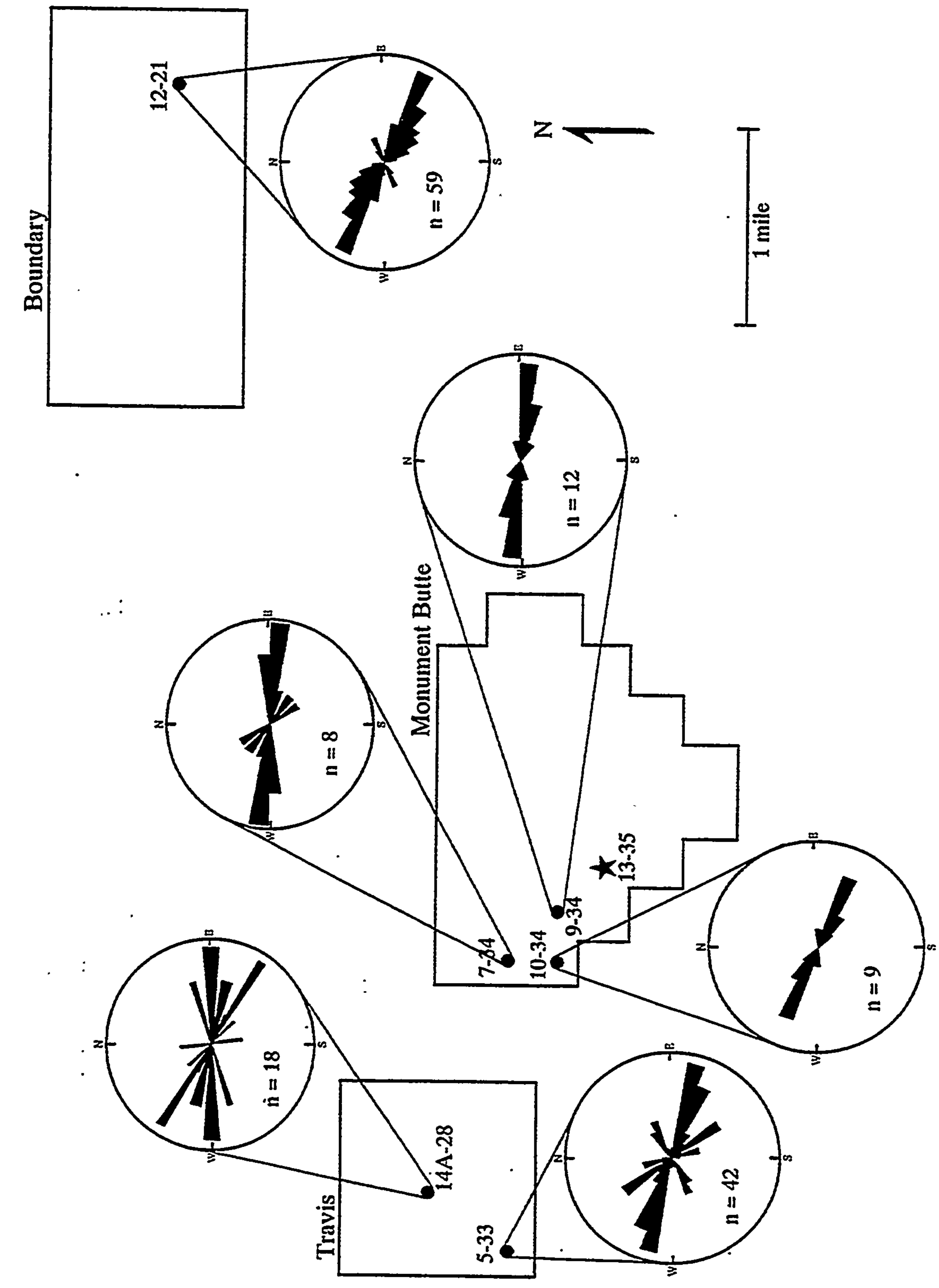

Figure 3.9 – Rose diagrams showing the orientation of 140 fractures imaged by microresistivity logs in the Monument Butte study area. (From Pennington et al., 1996)

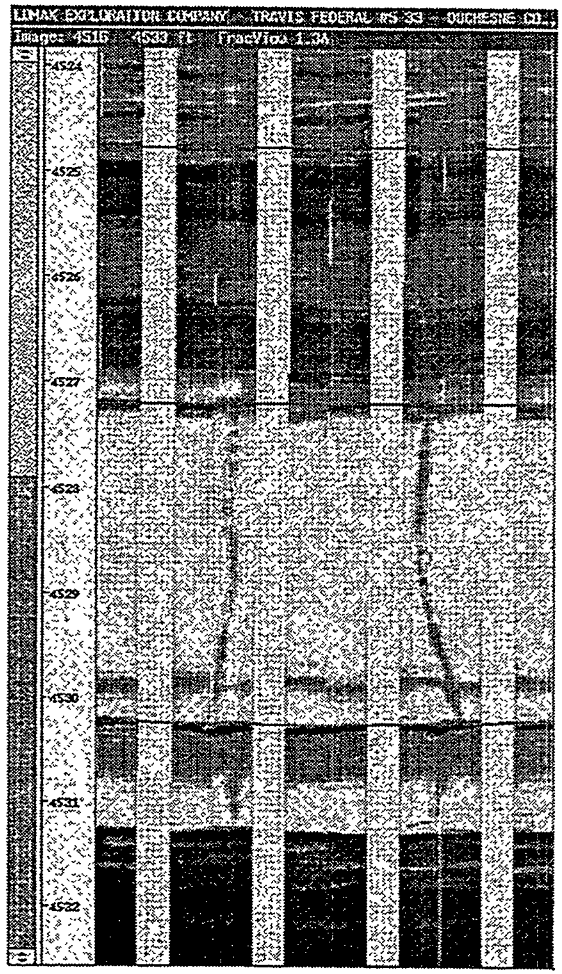

Figure 3.10 – Microresistivity image showing stratigraphically bound vertical fracture in the No. 5-33 well in the Travis unit. (From Pennington et al., 1996)

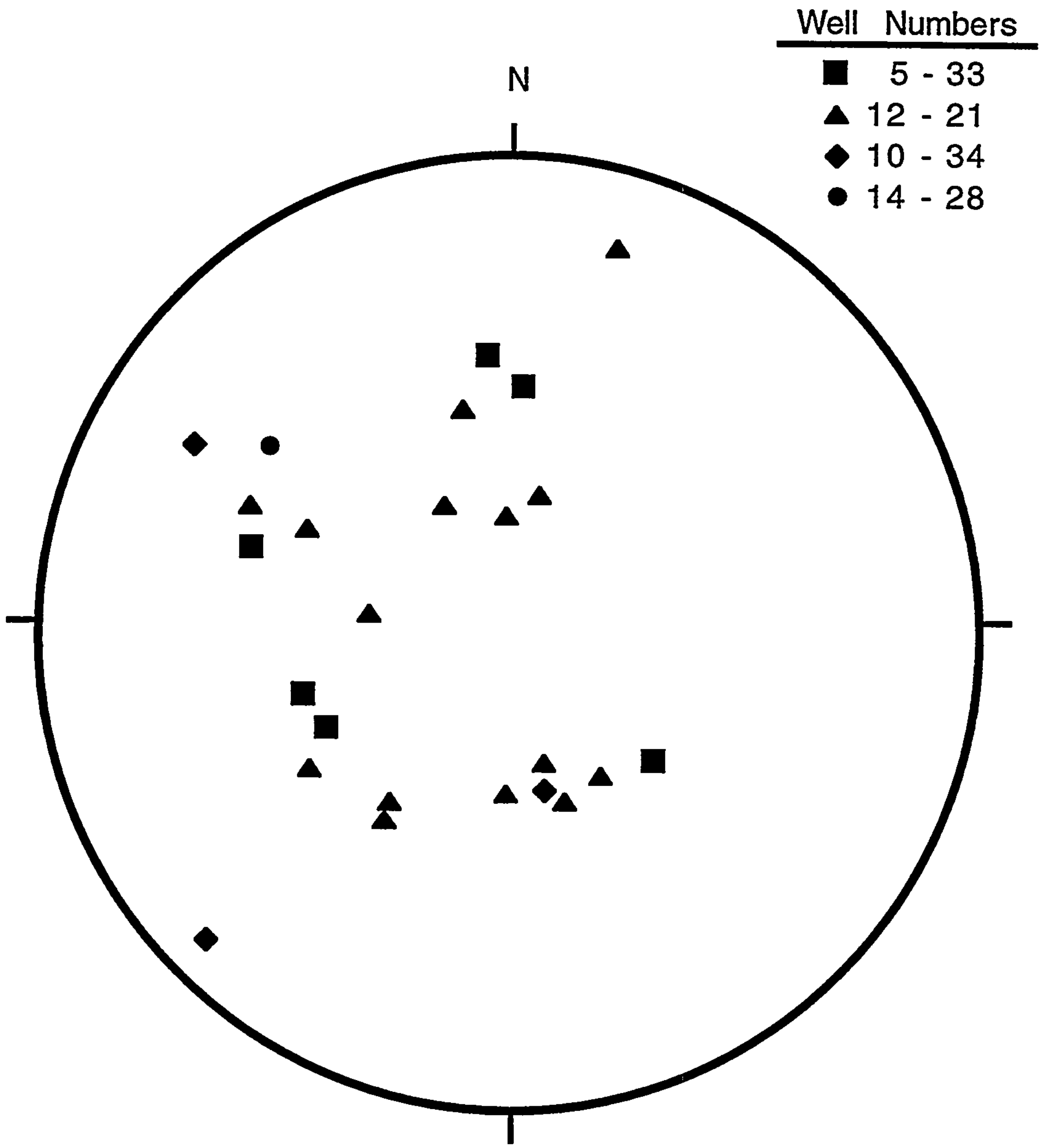

Figure 3.11 – Equal area projection (upper hemisphere Schmidt plot) of poles to minor faults measured by microresistivity imaging logs in the Greater Monument Butte area. On this plot vertical planes would have poles that plot near the circumference. The data plotted indicate a concentration of east-west oriented faults dipping at approximately 45°. Symbols code data from wells shown on Figure 3.9. (From Pennington et al., 1996)

University of Tulsa—Self Unit, Glenn Pool Field, Oklahoma (Reservoir Class I): Dennis R. Kerr and Balmohan G. Kelkar

A significant part of the project being carried out by the University of Tulsa at the Glenn Pool field in northeast Oklahoma (see discussion in Chapter 2 for project details) was conducted in the Self unit in the southern part of the field (Figure 2.1). In this facet of the project, a microresistivity borehole imaging tool was run in a newly drilled well (the Self No. 82) to evaluate the tool's potential contribution to waterflood performance improvement in the fluvial-deltaic (Reservoir Class I) sandstones of the Bartlesville Sandstone.

Core and outcrop interpretation indicate that in the Self unit, facies change upward through the Bartlesville Sandstone from braided fluvial deposits (lowstand systems tract) to meandering to tidally-influenced meandering fluvial (transgressive systems tract) (Ye, 1997). In the Self unit, DGI F (discrete genetic interval F - see the University of Tulsa project discussion in Chapter 2 for definition of discrete genetic intervals) is a braided fluvial interval, whereas DGIs A through E are meandering fluvial channel fill and crevasse splay sandstones and floodplain mudstones (Figure 3.12).

In the Self No. 82 well, DGIs A through C are composed of channel-fill facies related to point bar deposition and migration in a meandering fluvial system. In such systems, deposits are characterized by large-scale sediment packages representing periods of higher energy during which coarser sediments are transported. These relatively porous and permeable packages are separated by distinct and extensive lateral accretion surfaces representing low energy periods during which fines (silt, mud, and clay) are deposited over the surface of the bar.

Each channel-fill sequence consists of a vertical succession of subfacies that characteristically fines upward in texture with a corresponding decrease in scale of physical sedimentary structures and an increase in the proportion of mudstone interbeds. The lowermost subfacies in the sequence, the lower channel-fill subfacies, is well to moderately sorted medium grained sandstone containing medium-scale cross stratification and common mudstone drapes. The overlying middle channel-fill subfacies contains moderately sorted, lower medium-grained sandstones ranging to poorly sorted, silty fine-grained sandstones with horizontal to low-angle parallel stratification and ripple lamination. The middle channel-fill subfacies comprises lateral accretion bars laid down by laterally migrating channels of the meandering stream. Medium- to very-thin-bedded mudstones to silty mudstones drape the lateral-accretion surfaces. The upper channel-fill subfacies consists of mudstone to silty claystone.

This project explored the potential use of microresistivity imaging logs for waterflood development through location of individual injector and producer pairs with respect to lateral accretion bar deposits of meandering channels such as those found in DGIs A to C at the Self unit. Wells located along depositional strike on the same bar are more likely to be in communication. Fluvial channel fill facies architecture can be reconstructed from dip directions and dip angles of contained sediment packages. The comparison of azimuth directions between cross stratification in the lower channel-fill subfacies and dip direction of lateral accretion surfaces in the middle channel fill subfacies can be used to locate a well relative to the upstream, midstream, or downstream side of a lateral accretion bar (Grace and Newberry, 1990; Ye, 1997). The dip azimuth of cross stratification in the lower channel fill parallels the main flow direction of the deepest part of the channel (i.e., the thalweg of the channel) and points downstream. The dip azimuth of lateral accretion surfaces points more or less toward the channel thalweg (i.e., at approximately a right angle to the dip azimuth of the cross strata in the lower channel fill subfacies). However, on the upstream end of the bar, the lateral accretion surfaces dip not exactly toward the thalweg, but slightly in an upstream direction resulting in a slightly acute angle between their azimuth and that of the channel thalweg. Conversely, on the downstream end of the bar, lateral accretion surfaces dip slightly in a more downstream direction forming a slightly obtuse angle with the azimuth of the channel thalweg. In a well, if the measured angle between the azimuths is significantly greater than 90°, the well is located on the upstream side of the bar. If the angle is substantially less than 90°, the well is located on the downstream side of the bar. Angles near 90° indicate a midstream or central position on the bar. This technique can be used to determine the location of wells within lateral accretion bars by analysis of microresistivity image logs.

The Self No. 82 well, drilled for reservoir characterization using advanced technologies, was located on the basis of isopach and facies mapping. Core and wireline log facies interpretation indicate that DGI C in this well is made up of lateral accretion deposits. Analysis of the microresistivity imaging log (Figure 3.13) run over this interval suggests that the Self No. 82 is located in a downstream lateral accretion bar position. Analysis of the geometry of lateral accretion surfaces in the Self No. 82 indicates that an estimated 19 lateral accretion mudstone drapes might be expected to serve as baffles/barriers in the interwell rock volume of DGI C between the Self No. 82 and the Self No. 81 injection well which is adjacent but in a position perpendicular to depositional strike. Also, vertical changes in the dip direction of lateral accretion surfaces observed within the middle channel-fill subfacies predict the history of thalweg migration, reflecting changes in the sinuosity of the stream with growth of the bar and accompanying changes in the interwell path of maximum porosity and permeability.

In the Self No. 82 core of the DGI C interval, bleeding oil was observed in middle channel-fill lateral accretion subfacies, while lower channel-fill sandstones appeared to be water-flushed. This observation is consistent with the presence of effective baffles to fluid flow in the middle channel-fill facies between the Self No. 82 well and adjacent injectors positioned perpendicular to depositional strike. More efficient flushing of such intervals might be obtained by placing injector-producer pairs along depositional strike from each other.

In the same well in a slightly lower interval (DGI D), the microresistivity imaging log indicates that the interval is made up of four separate crevasse splay units, each with a different paleocurrent direction. Notably, however, only unit D2 has been effectively waterflooded (dark color corresponding to low resistivity water on Figure 3.14). Other sand units in the interval remain oil-saturated (highly resistive) and show up as lighter in color. The thin mudstones in the sequence serve as effective vertical permeability barriers.

Borehole imaging was not widely used in the Glenn Pool project, but the potential for using this type of tool for making future reservoir decisions to recover the remaining 80% of OOIP is high. Fluvial-related Sandstones contain a tremendous amount of directional information that can be used to predict sand body architecture and interwell fluid flow patterns. The images obtained in this project were, because of their ability to resolve and measure the properties of thin reservoir beds, influential in determining where remaining oil is located within the Self unit and the Glenn Pool field in general. Recompletions that led to more than doubling preproject production from the unit were supported by observations made on borehole images (Kerr et al., 1998).

Because of the shallow depth of the reservoir (1,450 ft) and the relatively thin reservoir intervals involved, microresistivity imaging logs were considered by the operator to be only moderately cost-effective. Micrologs, miniperm tests, and oriented core analysis might be used in future studies in the Glenn Pool reservoir to obtain nearly the same information at less cost.

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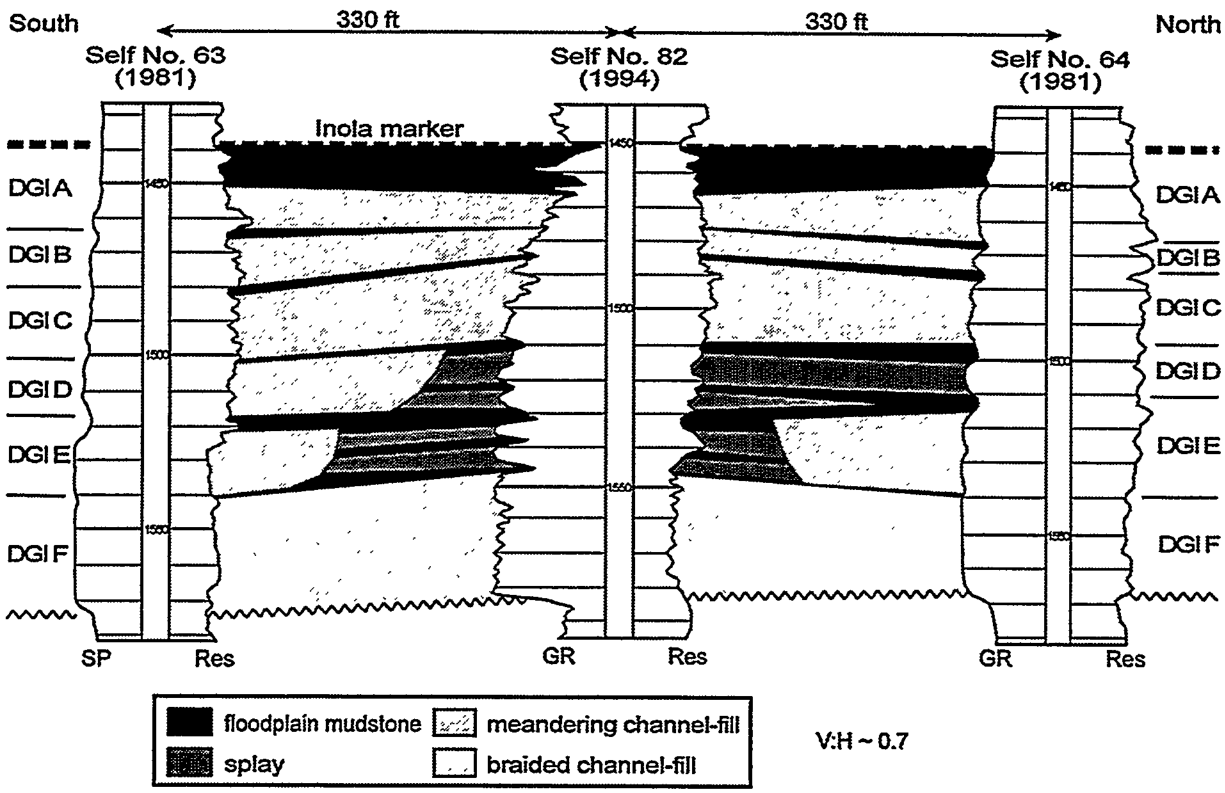

Figure 3.12 – North-South cross section of the Bartlesville (Glenn) Sandstone showing facies architecture and discrete genetic intervals within the Self unit. (From Kerr and Ye, 1997)

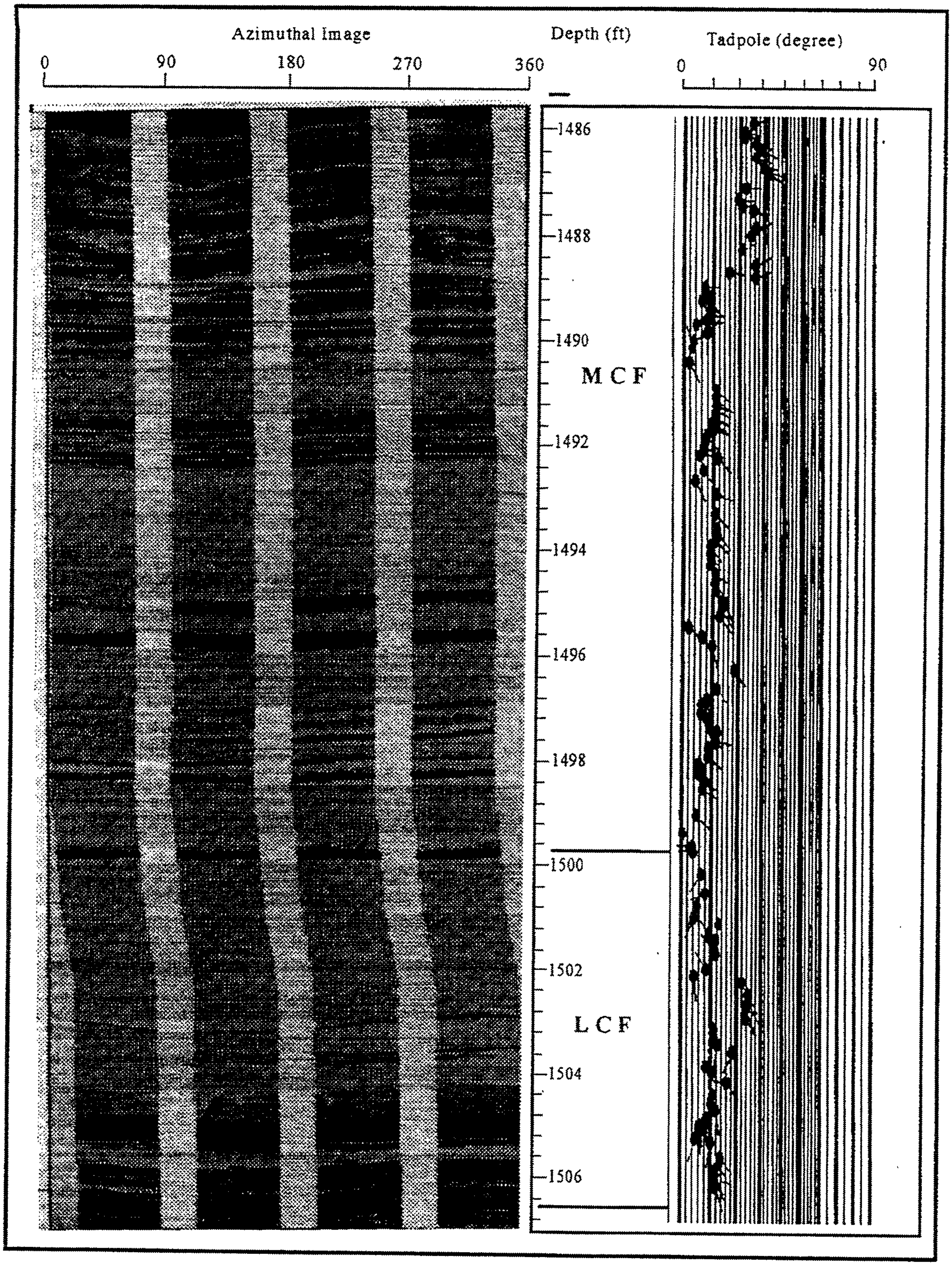

Figure 3.13 – Microresistivity image and tadpole plot for DGI C in the Self unit No. 82 well showing difference in azimuthal angle between cross stratification in the lower channel-fill subfacies (LCF) and lateral accretion surfaces (black bands) in the middle channel-fill subfacies (MCF) (From Kerr and Ye, 1997).

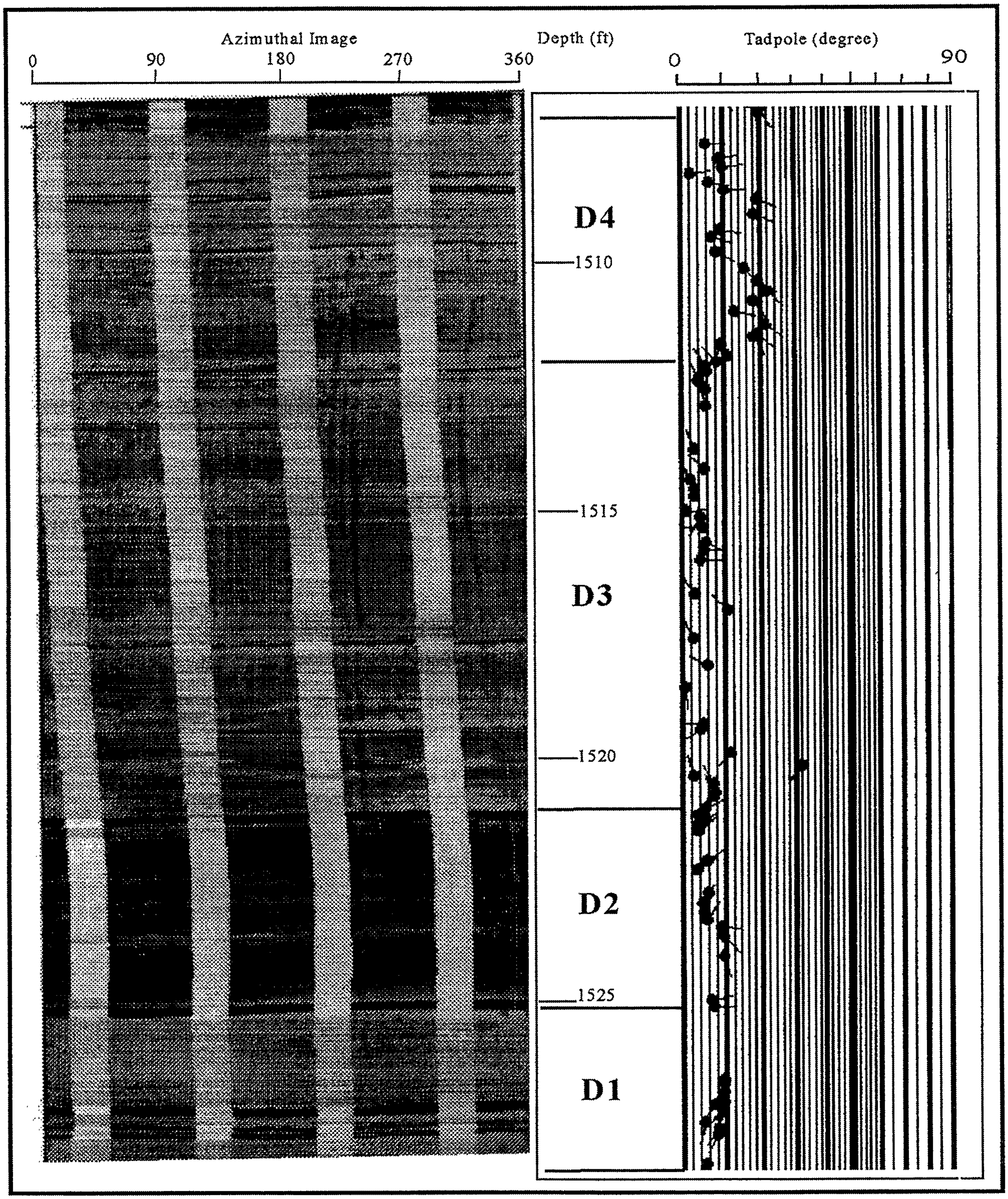

Figure 3.14 – Microresistivity image revealing a 4–ft-thick flushed zone (dark band) in an interval containing numerous crevasse splay sands that are for the most part poorly swept. (Modified from Kerr and Ye, 1997)

Utah Geological Survey—Bluebell Field, Utah (Reservoir Class I): Craig D. Morgan

The Bluebell field in Duchesne and Uintah Counties, Utah (Figure 3.15) is the largest oil-producing field in the Uinta Basin, covering 251 square miles (650 km^2). As of July 1996 the field had produced more than 136 MMBO and 174 BCF of associated gas. Typical well spacing is 2 wells per section, but much of the field is still developed at 1 well per section. Production has been from the Eocene - Paleocene Green River and Wasatch formations from depths of approximately 9,000 to 14,000 ft. The productive interval consists of interbedded, fractured siliciclastic and carbonate beds deposited in a fluvial-dominated deltaic lacustrine environment. Accurate correlation of producing horizons from well to well has generally not been possible. Wells have typically been completed by perforating 40 or more beds over a 1,000 to 3,000 ft interval, then acidizing the entire interval (Morgan and Allison, 1996). This completion technique is believed to leave many potentially productive beds damaged and/or untreated, while allowing water-bearing zones and thief zones to communicate with the wellbore. Operators of the Bluebell and neighboring fields have observed interference in wells as far as a mile apart.

The primary objective of this project, begun in 1993 and scheduled for completion in late 1999, is to use multidisciplinary reservoir characterization to develop more appropriate completion practices for this and similar reservoirs suffering from poor recovery because of inadequate identification, completion, and treatment of pay zones. Reservoir characterization technologies employed in the project include analysis of analog outcrops, analysis of surface fracture patterns, digital log analysis (80 out of 300 wells), and analysis of borehole imaging logs in addition to examination and analysis of available core materials. Results of the reservoir characterization were to be used to:

- Recomplete a well using multi-stage, high diversion, low friction acid treatments over a 1,500 ft interval
- Isolate and recomplete several bed-scale intervals in a second well (stimulate each bed separately)
- Drill and complete a new well using techniques learned from the previous demonstrations

Fractures are believed to be the dominant permeability mode for hydrocarbon production in the Uinta Basin. Fracture permeability may be several orders of magnitude higher than matrix permeability, and is believed to be the reason why the second well in a section almost always produces less oil than the first well. Several log types can give at least a qualitative indication of the presence and intensity of fracturing, but operators in the region have traditionally used mud-gas kicks to indicate the presence of both fracture permeability and hydrocarbons. However, fractures in clay-rich beds with little matrix porosity and permeability generally are short-lived in terms of production. Perforations need to be confined to clean beds with porosities greater than 6% and with less than approximately 2% of clay.

To further understand the role of natural fractures in controlling fluid flow in the reservoir, subsurface information from a combination of oriented-core data (two cores), an acoustic imaging log, and two microresistivity imaging logs was analyzed (Figure 3.16). Orthogonal fractures present at the surface (northwest-southeast, east-west) were not observed together at reservoir depths. Two sets of subsurface fractures are present across the Bluebell field. The two sets appear to be vertically segregated from each other. Fractures oriented east-west are associated with the producing intervals of the most productive wells. Stratigraphically above the east-west set, a set of northwest-southeast fractures is present (Figure 3.17). In the five wells examined, the transition from one set of fracture orientations to the other does not occur at the same depth in each well, either in stratigraphic or absolute subsea depth terms. Based on the information available, east-west fractures should be the primary targets for completion, and any deviated wells should be oriented in north-south or northeast-southwest directions to enhance fracture production.

Results of this study show that fracture density, orientation, and filling vary with differing rock types. Sandstone beds have lower fracture densities, but generally longer fractures and wider fracture apertures as observed in cores. Fractures in sandstone beds also tend to be nearly vertical. Intersections of fractures with each other are rarely observed in the sandstones. A very high percentage of sandstones are fractured, however, and the most productive fractures tend to occur in well-indurated sandstones. Carbonates and mudstones have higher fracture densities, with numerous fracture intersections observed in core because of their multiple orientations. The fractures are short and primarily calcite-filled with very narrow apertures, usually no greater than 0.5 mm. Quartz-rich sandstones with little clay, high matrix porosity and permeability, and large open fractures are the most productive reservoirs at Bluebell, especially if they immediately overlie fractured mudstone, which may serve as a source of hydrocarbons.

A novel approach based on geostatistical principles was then employed to generate fracture density distributions reservoir-wide. The dependency of fracture frequency on rock types was used as soft conditioning or guiding data when generating frequency distributions over the entire study area. This was accomplished using an indicator-based conditional simulation method called the Markov-Bayes method. Sequential indicator simulations and sequential Gaussian simulations are also being performed for comparison.

Because the Bluebell field encompasses several hundred square miles, a 20-square-mile portion of the field was selected for detailed reservoir characterization and analysis. About 60 beds were correlated over the area, and data on thicknesses, porosities, and saturations were generated from geostatistical modeling and input to simulation models. Using these three parameters, five beds were selected as most promising for recompletion on the basis of original oil in place (OOIP) in the study area. Simulations were performed on 10 realizations to determine which of the five beds were potentially the most productive. Single well simulations were carried out on the wells selected for multistage recompletion and bed-scale recompletion to select appropriate intervals for recompletion.

Because of mechanical problems, the well recompleted using a multistage approach did not yield a valid test of the success of the approach. However, cased hole logs run in the well provided good information on reservoir conditions. Four bed-scale acid treatments were pumped in a second well. The first two of the treatments resulted in recovery of water, through communication above and below the test interval. The third and fourth treatments were mechanically sound and resulted in an increase in daily oil production. Production, although increased, remains erratic and will require monitoring over an extended period to determine ultimate effectiveness. Logs have determined that acid went for the most part into beds that already had fractures and that few new fractures were created.

Because of reduced drilling activity in the field, fewer than the anticipated number of imaging logs were obtained. Borehole breakout data from imaging logs were found to be unsatisfactory for determinating in-situ stress orientations. A new well being drilled in the field will be evaluated by borehole imaging logs and will be completed using experience gained from successes and failures in recompletions discussed earlier.

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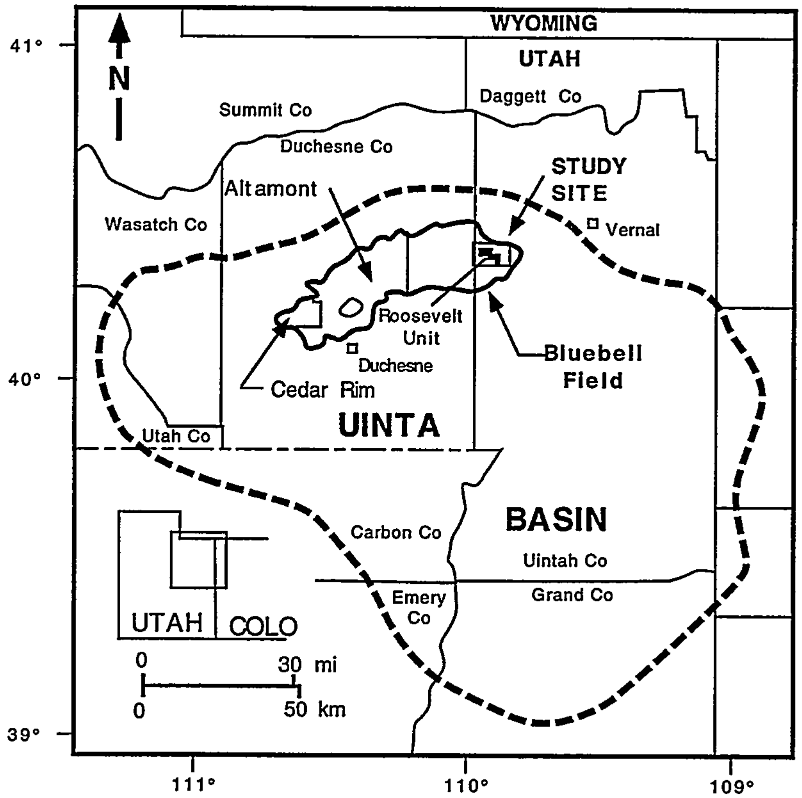

Figure 3.15 – Location of the Bluebell field study area in the Uinta Basin. (From Allison and Morgan, 1996)

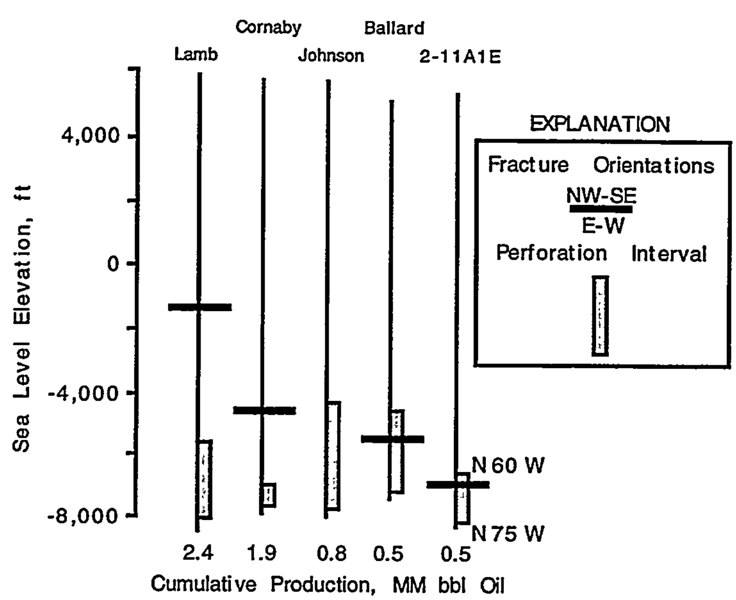

Figure 3.16 – Distribution of fracture orientation with depth in the Bluebell field. See Figure 3.18 for data sources. (From Allison and Morgan, 1996)

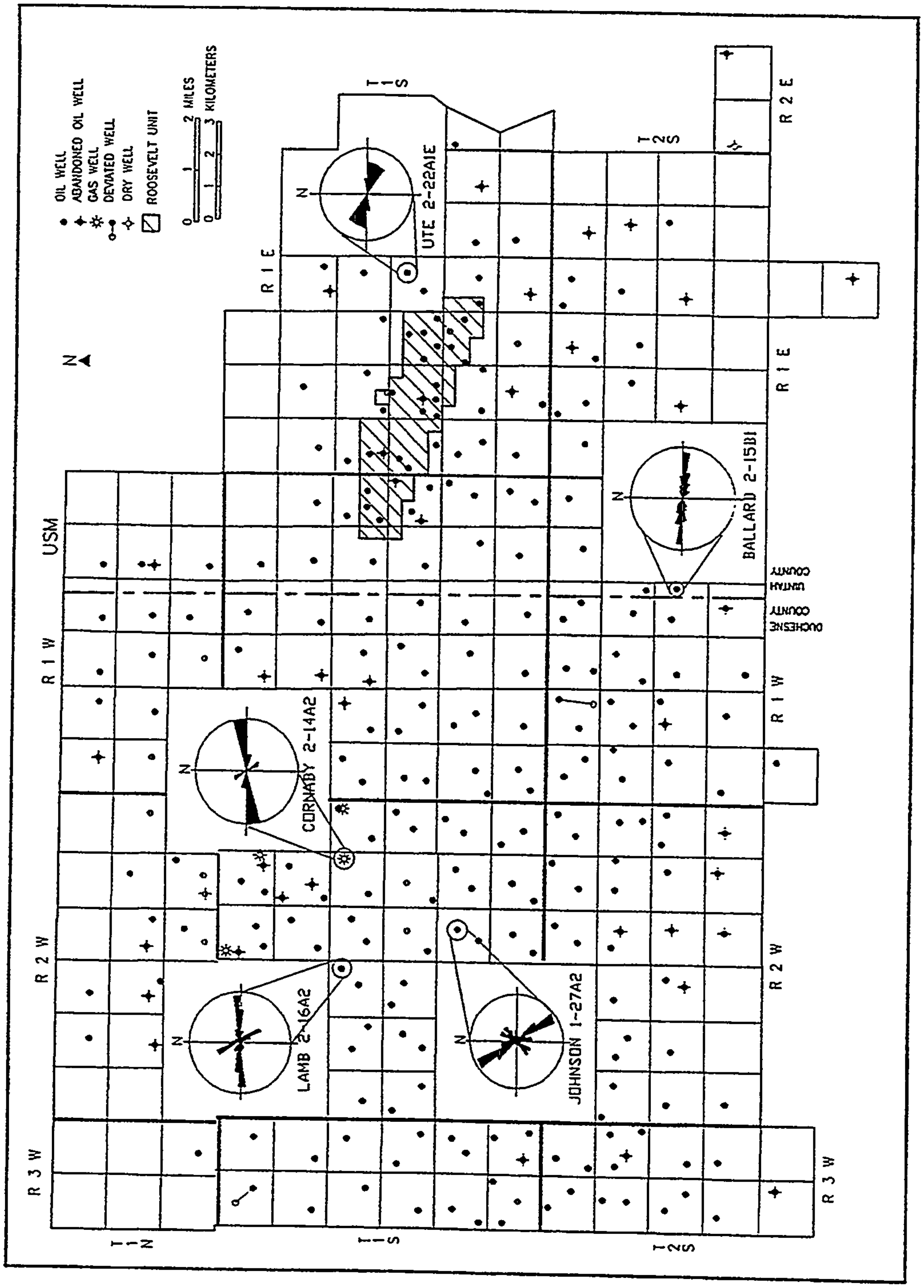

Figure 3.17 – Fracture orientations from well logs and oriented cores in the Bluebell field: Lamb 2-16A2 (Schlumberger Fomation Micro-Imager [FMI] log), Cornaby 2-14A2 (Western Atlas Circumferential Borehole Imaging Log [CBIL], Ute 2-22A1E (oriented core), Johnson 1-27A2 (oriented core), Ballard 2-15B1 (FMI log). (From Allison and Morgan, 1996)

University of Alabama—East Frisco City Field, Alabama (Research and Development by Small Independent Operators Project): Ernest A. Mancini

Many small independents lack resources to test unfamiliar technologies or novel, unproven approaches. To reduce financial risk to these operators and to encourage the use and spread of advanced technologies and techniques, DOE is providing up to 50% cost-sharing through a program of "Research and Development by Small Independent Operators" to provide solutions for local production problems. By providing cost-sharing ($50,000 or less per project), DOE is encouraging producers to experiment with higher risk approaches that could mean the difference between maintaining production or shutting down an oil field.

In 1996, the University of Alabama Department of Geology conducted work under this cost-sharing program with its partners, Cobra Oil and Gas and Schlumberger Well Services to investigate whether microresistivity imaging tools could be used to determine facies and reservoir characteristics in Upper Jurassic Frisco City Sandstone reservoirs in southwestern Alabama (Figure 3.18).

The first commercial production of hydrocarbons from the Haynesville Formation Frisco City Sandstone was from the Frisco City field in 1986 (Mann et al., 1989). This discovery was part of an updip basement structure play (the Conecuh Ridge complex on Figure 3.19) that has since that time led to establishment of 15 new Haynesville fields. Ten of these fields are productive from the Frisco City Sandstone.

The goal of this project was to develop scientifically valid methodologies for comparing and integrating detailed whole core information and fullbore Formation MicroImager (FMI) resistivity imaging well log data to investigate a more economical solution for reservoir characterization and production applications in Frisco City reservoirs. Most operators do not use FMI log data. Presently, whole core analyses are considered critical for determining reservoir-grade sandstone and for developing fluid flow models used for drilling and production and for reservoir management. If FMI log data can be used for the qualitative and quantitative analysis of detailed formation features associated with local changes in porosity and permeability and for the definition of reservoir-grade sandstone, the result would expose the integrity of the wellbore to less risk than the acquisition of whole cores. Plus, in many instances, FMI log acquisition may represent a cost savings over taking whole core and performing core analyses.

The objectives of the project team were as follows:

- Establish a regional reservoir stratigraphic model for the Frisco City Sandstone using existing geophysical logs, FMI logs, and whole cores.

- Test the correlations established from the study previously discussed by drilling, coring, and image-logging a selected test well.
- Determine the reservoir quality of the Frisco City Sandstone by using the FMI and associated logs.
- Draw conclusions and make recommendations regarding the use of FMI logs for reservoir characterization and reservoir quality determination.

To accomplish the first objective, available geophysical logs (including imaging logs) and whole cores for the Frisco City Sandstone were studied. Also, extensive discussions occurred among the research team members, between team members and industry geologists actively exploring for Frisco City Sandstone reservoirs, and between team members and geologists at the Geological Survey of Alabama. At this time, there is no consensus on the regional reservoir stratigraphic model for the Frisco City Sandstone. Updip, braided streams associated with alluvial fans were pervasive, while the area of study was dominated by transitional environments ranging from braid-deltas to ebb deltas and strandplains to tidal channels. Downdip, subtidal marine deposition occurred. Using this regional reservoir stratigraphic model, the key elements for identification for reservoir delineation would include the braid-delta, the ebb-delta, the tidal channel, and the strandplain environments. The potential strand plain reservoirs would have an orientation parallel to the ancient shoreline, while the braid-delta, ebb-delta, and channel reservoirs would be oriented at some angle to the ancient shoreline. Characteristic sedimentary structures define these last three environments.

The second objective of the study was to test the correlations that might be established from independent study of existing geophysical logs, FMI logs, and whole core in a selected test well. The well used was the Cobra Oil and Gas Walker 6-8 No.1 well in the East Frisco City field in Monroe County, Alabama (Figure 3.19). The FMI log data from the test well was evaluated by a senior logging company geologist with extensive experience in interpreting borehole image data in southwestern Alabama. Specifically, this task was designed to evaluate the effectiveness of using the FMI log to characterize the sedimentary and textural parameters of the Frisco City Sandstone. The reservoir characterization as determined from the FMI log was then compared to the sedimentary characteristics as observed in the whole core by oil company and university geologists. The interpretation derived from the FMI log was evaluated in terms of their observations from the whole core and the established regional reservoir stratigraphic model.

The interpretation of the environments of deposition for the Frisco City Sandstone from the FMI log was consistent with the independent interpretations made by studying the whole core. Study of the whole core permited the recognition of higher order sequences in the Frisco City Sandstone; however, the FMI log provided paleocurrent and sandstone orientation information critical to determining whether the sandstones were deposited parallel or at some angle to the ancient Jurassic shoreline. The data from the FMI log also showed that the tidally influenced paleoenvironment in the upper Frisco City strata is distinct from the marine-influenced deltaic paleoenvironment in the lower Frisco City deposits.

The third objective of the study was to interpret the reservoir quality of the Frisco City Sandstone by using the FMI and associated logs and compare those results to the whole core observations and analyses. The information regarding the reservoir quality of the Frisco City Sandstone as determined from the FMI log (i.e., delineation of intervals containing porous and permeable reservoir rock) was consistent with the results from the core analyses. The productive interval in the well was also accurately defined by the FMI log.

The fourth objective of the study was to draw conclusions and to make recommendations regarding the use of FMI logs for reservoir characterization and reservoir quality determination in lieu of whole core studies and whole core analyses or in combination with whole core studies and whole core analyses.

The FMI log was found to be a valuable advanced technology for sandstone reservoir characterization and reservoir quantification in the Frisco City Sandstone. Interpretation of the environment of deposition at East Frisco City field by using the FMI log was enhanced and did not differ significantly from the interpretation made by studying the whole core. The information gained from the FMI log regarding paleocurrent direction and sandstone orientation is not attainable from studying whole cores. However, this information is critical in establishing a regional reservoir stratigraphic model for the Frisco City Sandstone. To date, no consensus exists among geologists regarding such a model, but data from the FMI log may help build an integrated interpretation.

The FMI log proved to be a reliable tool for deciphering reservoir quality. The porous and permeable intervals in the Frisco City Sandstone as determined by using the FMI log were consistent with the pay zones defined by using whole core analyses. The FMI also proved to be beneficial in identifying anisotropic features that could be barriers to flow. Core analyses did indicate which porous and permeable intervals had potential for oil production, but using the FMI log rather than core could result in cost savings of as much as $25,000 per well in this area. However, pending further calibration, the use of the FMI log in conjunction with standard core analyses is the preferred method of evaluation at the present time.

In Frisco City reservoirs, the project participants feel that microresistivity image logging has the potential to replace the need for riskier and more expensive core operations. Companies using imaging log data should be able not only to characterize reservoir sandstone but also to quantify the reservoir quality of the sandstone, thereby providing a more cost-effective methodology for reservoir characterization and production for Upper Jurassic Frisco City Sandstones.

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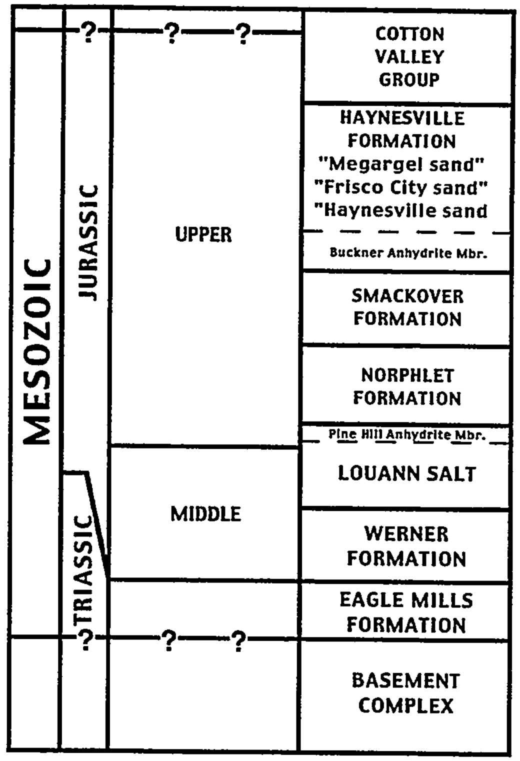

Figure 3.18 – Stratigraphic column for the Jurassic section in the southwestern Alabama study area. (From Mancini et al., 1997)

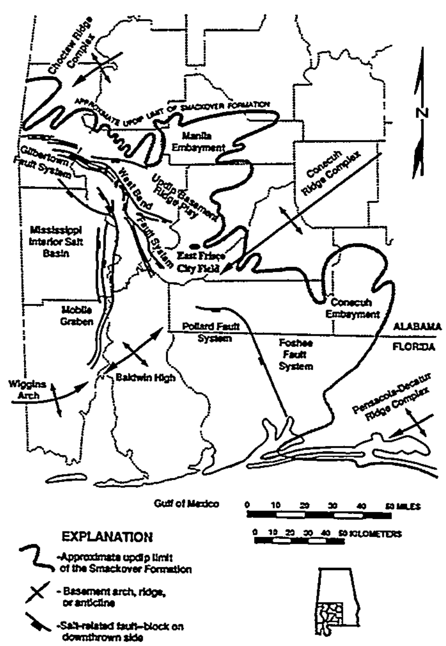

Figure 3.19 – Geological features of southwestern Alabama and their location with respect to the East Frisco City field project area. (From Mancini et al., 1997)

Phillips Petroleum Company—South Cowden Unit, Texas (Reservoir Class II): Rex Owen, Matt G.Gerard, and Ken Harpole

The South Cowden unit is located in Ector County, Texas, and produces from the Permian Grayburg and San Andres formations along the Eastern Margin of the Central Basin Platform (Figure 3.20). These formations were deposited in shallow carbonate shelf (Reservoir Class II) environments. The field, producing from a 150 – 200 ft gross interval at a depth of approximately 4,550 ft was discovered in 1940 and unitized for secondary recovery operations beginning in 1965. The waterflood is now in its mature stage with watercut exceeding 95%. Additional recovery by CO_2 injection at miscible or near-miscible conditions is a technical option that has been known to mobilize additional oil in such reservoirs. However, because the South Cowden unit is relatively small in size (original oil in place is estimated to be only about 100 MMBO) the economies of scale inherent in CO_2 injection projects that have produced much additional oil from such reservoirs in the area are not applicable. New and innovative methods are required to reduce the investment and operating costs to apply this technology economically at South Cowden.

In the DOE cost-shared part of this project, begun in 1994 and scheduled for completion in 2001, reservoir characterization is being employed to restrict the CO_2 flood to the high quality rock in the unit, and horizontal injection wells are being used to cut investment and operating costs. Several horizontal wells drilled from a central location are being employed to:

- Reduce the number and cost of new injection wells, wellheads, and equipment
- Allow concentration of surface reinjection facilities
- Minimize cost of the CO_2 distribution system
- Improve sweep efficiency over vertical injection wells

Horizontal CO_2 injectors are also favored because of the poor mechanical condition of most existing vertical wellbores in the field, which makes them unsuitable for simple conversion to CO_2 injectors.

Detailed reservoir characterization was performed prior to selecting the drilling site and orienting the horizontal CO_2 injection wells. A preproject single-zone production test of a highly permeable water-bearing grainstone zone below the reservoir zone flowed 100% water to the surface (Harpole et al., 1996). In the project, two vertical wells were drilled and cored through the reservoir to gather pertinent reservoir information. Openhole microfracture tests were performed on both wells to determine formation parting pressure and the orientation and other characteristics of induced fractures. Acoustic borehole imaging tools were run in both wells to analyze the resulting fractures. The first well was drilled to TD below the reservoir and through the water-bearing grainstone before fracturing and logging; the second well was drilled only to a point above the water-bearing grainstone before fracturing and logging. Formation parting pressures were determined to be 2,608 psi and 2,717 psi, respectively, in the two wells.

Borehole images were of good quality and suggested that the reservoir interval itself, probably because of its higher permeability, was more resistant to fracturing than nonpay intervals immediately above and below. In the first project well, fracturing initiated in the water-wet fusulinid dolowackestone - peloid dolograinstone (Caldwell et al., 1998) zone just below the reservoir and extended upward only 10 – 20 ft into the overlying reservoir facies (mainly burrow-mottled peloid dolopackstones) before splintering and dying out. In the second well, fractures were observed to extend below the base of the logging run which ended some 40 ft above the well depth at the time of fracturing. The interpretation of these tests through borehole image logs says much about the potential consequences of past stimulation and injection practices in the Grayburg - San Andres. Either stimulations or injection above the parting pressures of the intervals adjacent to the reservoir pay zone could result in the creation of out-of-zone fluid pathways and unwanted communication with the pressured water-bearing zone below the reservoir. This knowledge of the reservoir led to careful monitoring of bottomhole pressure during injection of CO_2 in the field demonstration phase of the project.

Borehole imaging has led to a better understanding and increased respect for fractures at the South Cowden unit, but the understanding of fractures is still incomplete. Two horizontal wells were drilled. Water-alternating-gas (WAG) CO_2 injection in these wells and in the two new vertical wells began in late summer to early fall of 1996 at a rate of 8 MMSCFD. Recycling of CO_2 began later that year. By mid-1997, injection rate had increased to 8.8 MMSCFD. Three leaseline vertical injection wells were also drilled in 1996, and profile surveys run in the initial water injection phase in these wells indicated out-of-zone injection which was later corrected in two of the wells by foamed cement workovers. The third is shut in pending further remediation. One of the horizontal injectors is experiencing loss of CO_2 through what is believed to be a fracture system in the toe of the well. Some CO_2 is moving into the lower water-bearing zone and being produced in adjacent wells. Remediation of the injection profile for this well is planned for 1998. The second horizontal well is performing as expected with injectants leaving the wellbore through 250 ft of interval scattered throughout the length of the horizontal section.

By early in 1997, project area production increased about 40 BOPD as a result of new wells drilled in 1996 and another 40 BOPD as a result of WAG injection. By late in 1998 the project area was producing 250 BOPD above what would have been achieved through continued waterflood operations. A mutual cost savings has been realized through joint development of a new CO_2 flood facility with the operator of an adjacent South Cowden unit. From the two projects, an additional 9.9 MMBO is expected to be recovered, extending field life by approximately 20 years.

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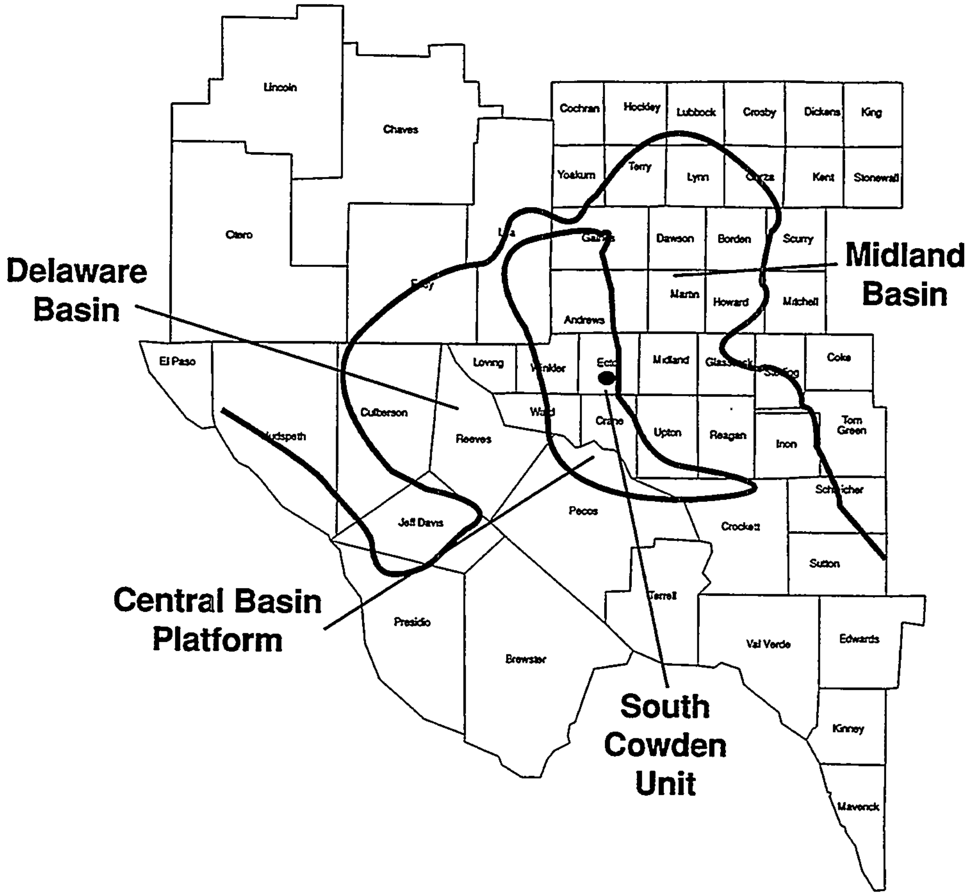

Figure 3.20 - Location of the South Cowden unit.

Fina USA Inc.—North Robertson Unit, Texas (Reservoir Class II) and Oxy USA Inc.—West Welch Unit, Texas (Reservoir Class II)

Both of these projects are discussed in detail and complete project references are listed under the appropriate core-log modeling project headings in Chapter 2. Borehole imaging contributed in only minor ways to results in both projects and is therefore discussed here very briefly.

In the Fina USA project at the North Robertson (Clearfork) unit in Gaines County, Texas, log-based images of the borehole wall were obtained in two cored wells using both a microresistivity imaging tool and an acoustic-based tool. The microresistivity imager failed to identify most of the small-scale features and many of the larger-scale features observed in core. Insufficient resistivity contrasts within the rock are the most probable explanation for the tool's failure to pick up these features. The acoustic imager, on the other hand, was much more successful in identifying fractures, vugs, and bedding planes, but it still missed many small features present in the core. The operator plans to continue to pursue research on the usefulness of the acoustic imaging tool as a means of imaging rock fabrics, and is considering additional employment of the tool in an existing 20-acre-infill injection well to determine the degree of fracture propagation caused by long-term injection in east-west oriented line drive patterns.

In the Oxy USA project at West Welch unit in the Welch (San Andres) field in Dawson County, Texas, an acoustic imaging tool was used to investigate directional permeabilities because of suspected naturally occurring fractures. No fractures were found, however. The utility of the tool for descriptive purposes in the San Andres reservoir was limited by the generally low acoustic contrasts associated with reservoir components.

ARCO Western Energy Inc.—Yowlumne Field, California (Reservoir Class III): Michael S. Clark and Mike L. Laue

The Yowlumne field is a domestic "giant" oil field (Figure 3.21) that has produced more than 100 MMBO at depths greater than 13,000 ft from the Miocene Stevens Sandstone in Kern County, California. Over a period of more than 20 years since its discovery in 1974, the field has experienced primary depletion, a secondary recovery program, and significant decline (35% per year) as the waterflood matured. Like many other reservoirs in the San Joaquin Basin, the Yowlumne reservoir is interpreted on the basis of well, 3-D seismic, and pressure data as a layered, fan-shaped, prograding turbidite (Reservoir Class III) complex containing several lobe-shaped sand bodies that represent distinct flow units (Clark et al., 1997). In cross section, the fan deposits are lenticular in shape and do not significantly incise underlying strata. Large-scale channeling is absent, and deposition was primarily as sheet sands transported by sediment gravity flows. Sediments at Yowlumne field were deposited by currents flowing from south to north (Figure 3.22). Although a high ultimate recovery factor is expected from the field, reservoir simulation predicts that significant undrained oil (3 MMBO) still exists at the margins of the fans or lobes. Numerous interbedded shales and the deteriorating reservoir quality within the sand layers limit the producibility of these fan-margin deposits by vertical wells (Table 3.1).

This project, begun in 1995 and scheduled for completion in 2001, is attempting to demonstrate the effectiveness of exploiting a fan margin through use of a high-angle well completed with multiple hydraulic fractures through a stacked sequence of reservoir sand lobes (Figure 3.23 and Figure 3.24). A high-angle well offers better pay exposure to the well bore than conventional vertical wells by establishing vertical communication via the fracture planes connecting thin interbedded layers within the wellbore. The equivalent production rate and reserves of three vertical wells are anticipated at one-half to two-thirds the cost of drilling vertical wells.

Borehole breakouts identified from 4-arm, dual-caliper dipmeter logs were used as a first estimate of regional stress orientation. Borehole deformations were assumed to be the result of differential horizontal stress, with the azimuth of the shorter axis as measured by the dual caliper assumed to coincide with the direction of maximum horizontal stress (S_{Hmax}). Borehole shape irregularities because of washouts, keyseats, sloughing shales, and the like were omitted. Within the reservoir interval, breakouts indicate S_{Hmax} most commonly in a north-south orientation. Of 12 wells identified with breakouts in the reservoir interval (Figure 3.25), eight show S_{Hmax} oriented approximately N 20° E (NNE-SSW) and four show S_{Hmax} oriented approximately east-west (WNW-ESE).[1]

[1] Discrepant breakout orientations that occur at right angles have been observed in other reservoirs to occur along pre-existing fractures intersecting the wellbore. (Neil Hurley, personal communication to editors)

From surrounding fields, breakout data suggested that S_{Hmax} is oriented north-south on a more regional scale (Castillo and Zoback, 1994). From two nearby wells with breakout data, the same north-south orientation of stress was predicted for the frac test run in well 84-32 (the northernmost well in section 32 seen in Figure 3.25). This fracture direction would also be perpendicular to the trend of a reverse fault in the immediate vicinity of the well. However, the fracture orientation interpreted from micro-seismic logging in a well offset from the one in which the frac test was conducted, was NW-SE, nearly parallel with a set of known fault planes in that part of the field. Induced fracturing is likely to be most effective in deviated wellbores oriented NW-SE and least effective in those oriented NE-SW.

Geologic and reservoir descriptive work was completed in the area in which the deviated well was to be drilled. Fracture azimuth and symmetry were predicted using borehole breakout geometries from field wells supplemented by frac-test orientation results. Estimates of formation mechanical properties and stress profile were made using full-wave sonic log data and treating-pressure data from a hydraulically fractured well in the field. Reservoir simulation was used to select the final location and orientation of the slant well.

The slant well was drilled successfully into the eastern fan margin. The well deviates up to 85° to the west, roughly parallel to strike, and extends to a measured depth of 14,300 ft with a 1,100 ft lateral leg across the intended thin bedded fan margin section. True gross vertical thickness of the reservoir penetrated was about 180 ft. A dipole shear sonic imaging tool was run to obtain mechanical properties for designing hydraulic fracture treatments. A microresistivity imaging log was also run to obtain information on naturally occurring faults and fractures also. Unfortunately, the tool failed and the wait time to obtain a backup tool was prohibitive because of hole conditions. Therefore, no images were obtained. Hydraulic fracture treatments to induce NW-SE fractures were reduced to 2 from the original 3, 250-ft-spaced treatments planned because a portion of the reservoir encountered appeared to have been adequately swept by the existing waterflood. Hydraulic fracturing characteristics are still being evaluated. The well is currently producing at a rate of 160 BOPD, 190 MCFGPD, and 120 BWPD.

Deterioration of reservoir quality and thickness along fan margins is characteristic of many Class III turbidite reservoirs. In addition, many waterflood patterns tend to sweep oil toward fan margins where it becomes trapped. The high-angle well placement and fracturing technologies addressed in this project should apply to a large number of reservoirs of this type. Successful demonstration of this approach could increase Yowlumne field reserves by as much as 8.3 MMBO and increase reserves in analogous California reservoirs by 330 MMBO.

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TABLE 3.1 - Fan Margin vs. Fan Axis Reservoir Properties

PROPERTY	FAN AXIS	EAST MARGIN
Effective Porosity	16%	12%
Air Permeability	50-100 md	5-10 md
Liquid Permeability	10-20 md	2 md
Net/Gross Sandstone	0.8	0.65
Clay Volume	< 6%	> 12%

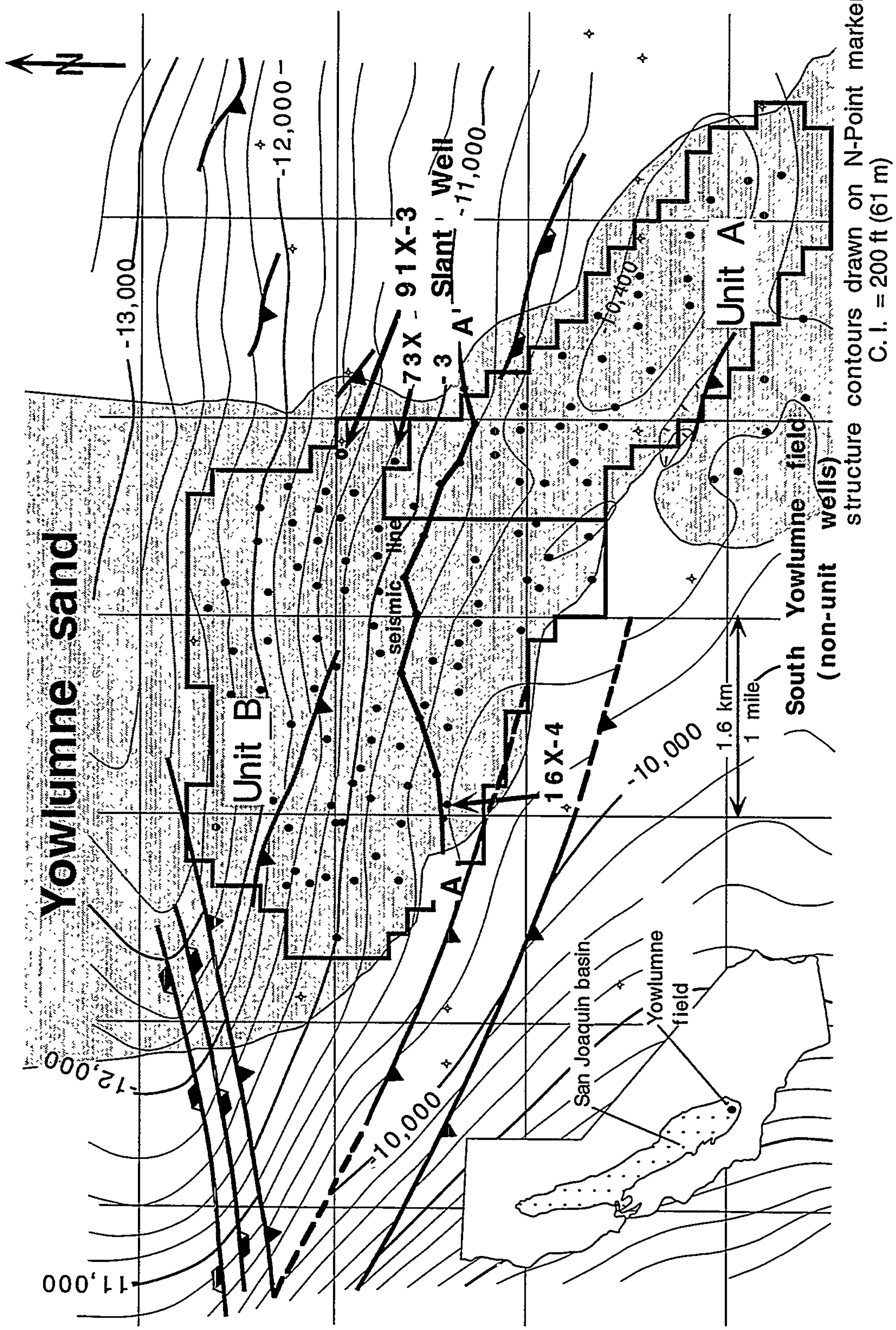

Figure 3.21 – Inset map of California showing location of Yowlumne field within the San Joaquin Basin and detailed structure map of study area. (From Niemeyer, 1997)

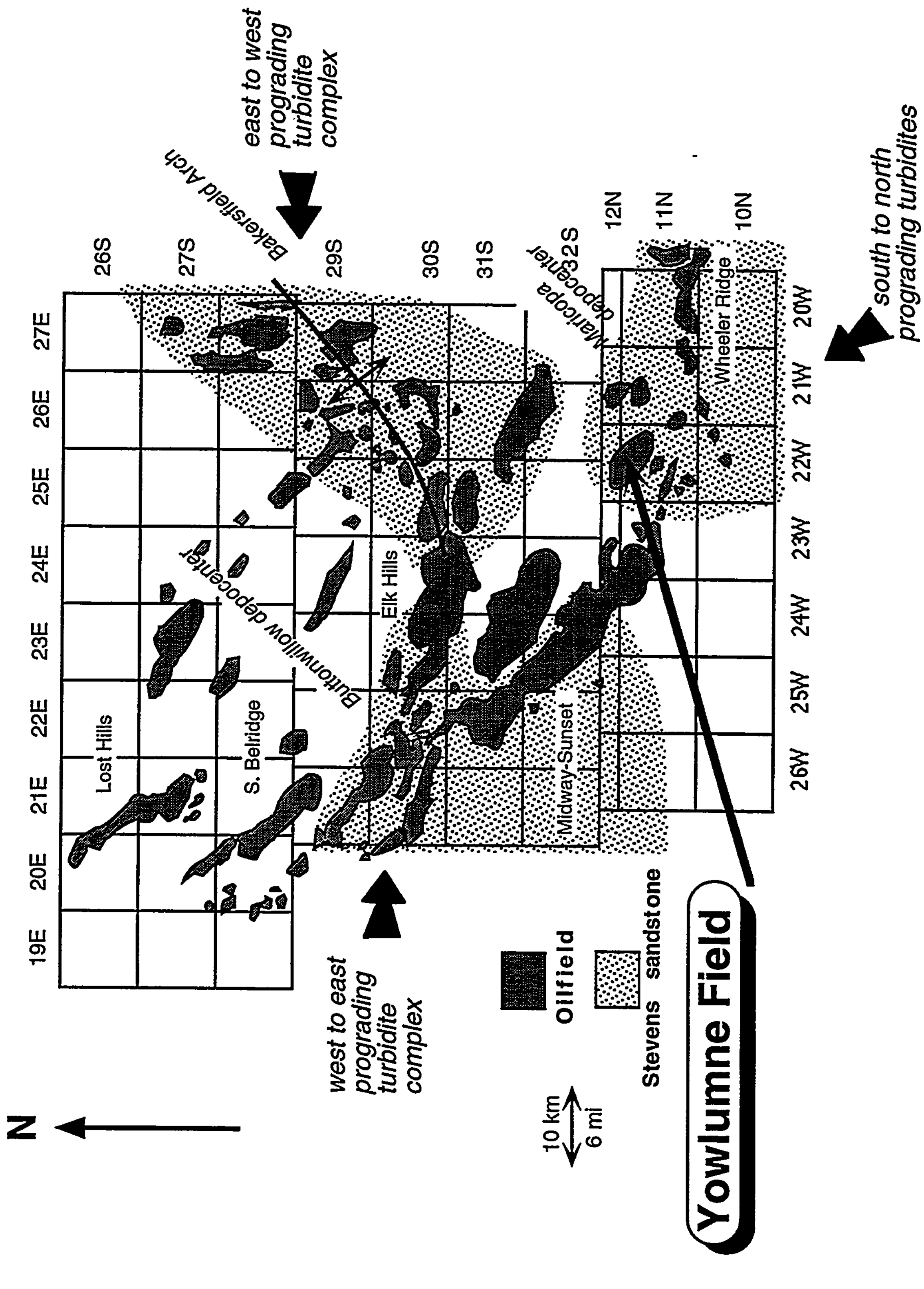

Figure 3.22 – Map of the southern San Joaquin basin showing the three main turbidite depositional systems in the area and their relative directions of transport into the basin. (From Niemeyer, 1997)

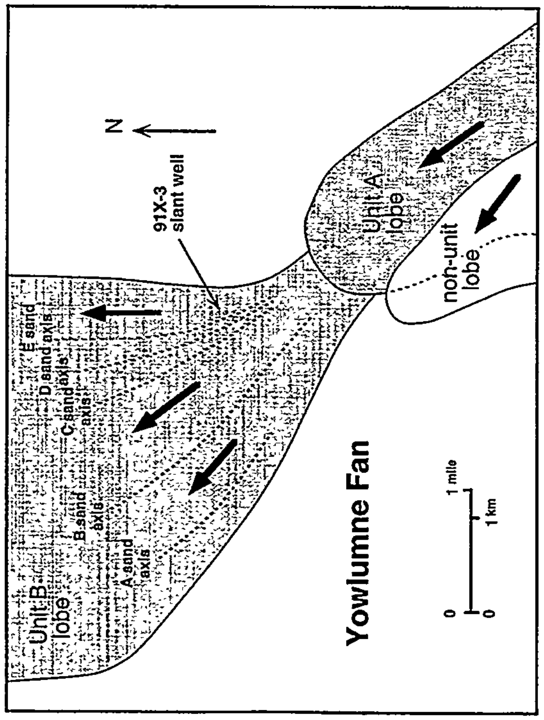

Figure 3.23 – Schematic diagram showing geometries exhibited by depositional lobes that compose the Yowlumne fan. Solid arrows indicate sediment transport direction. Note the location of the slant well. (From Niemeyer, 1997)

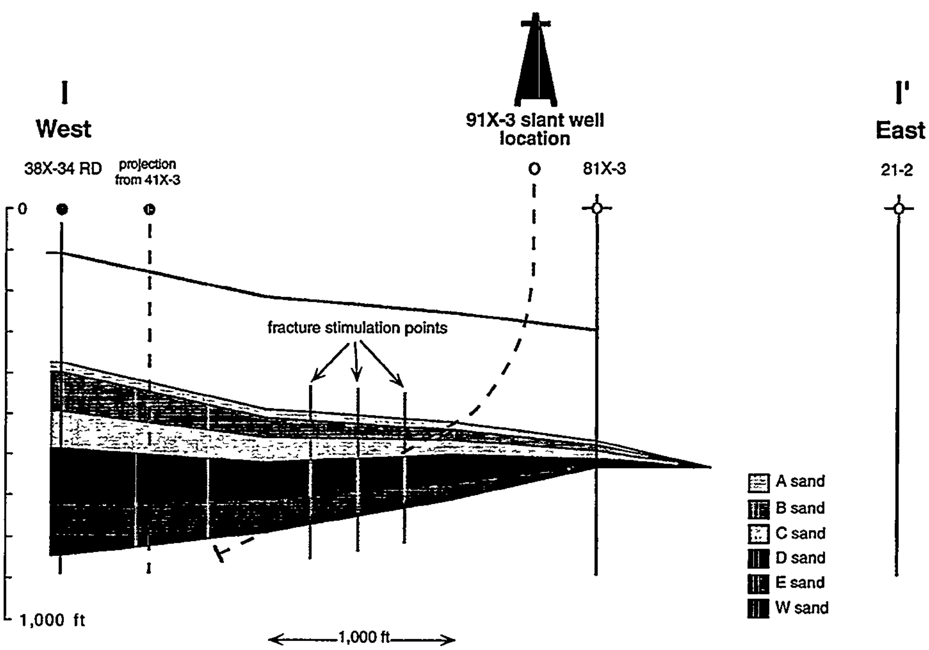

Figure 3.24 – East-west cross section showing the five main reservoirs and their penetration by the slant well. (From Niemeyer, 1997)

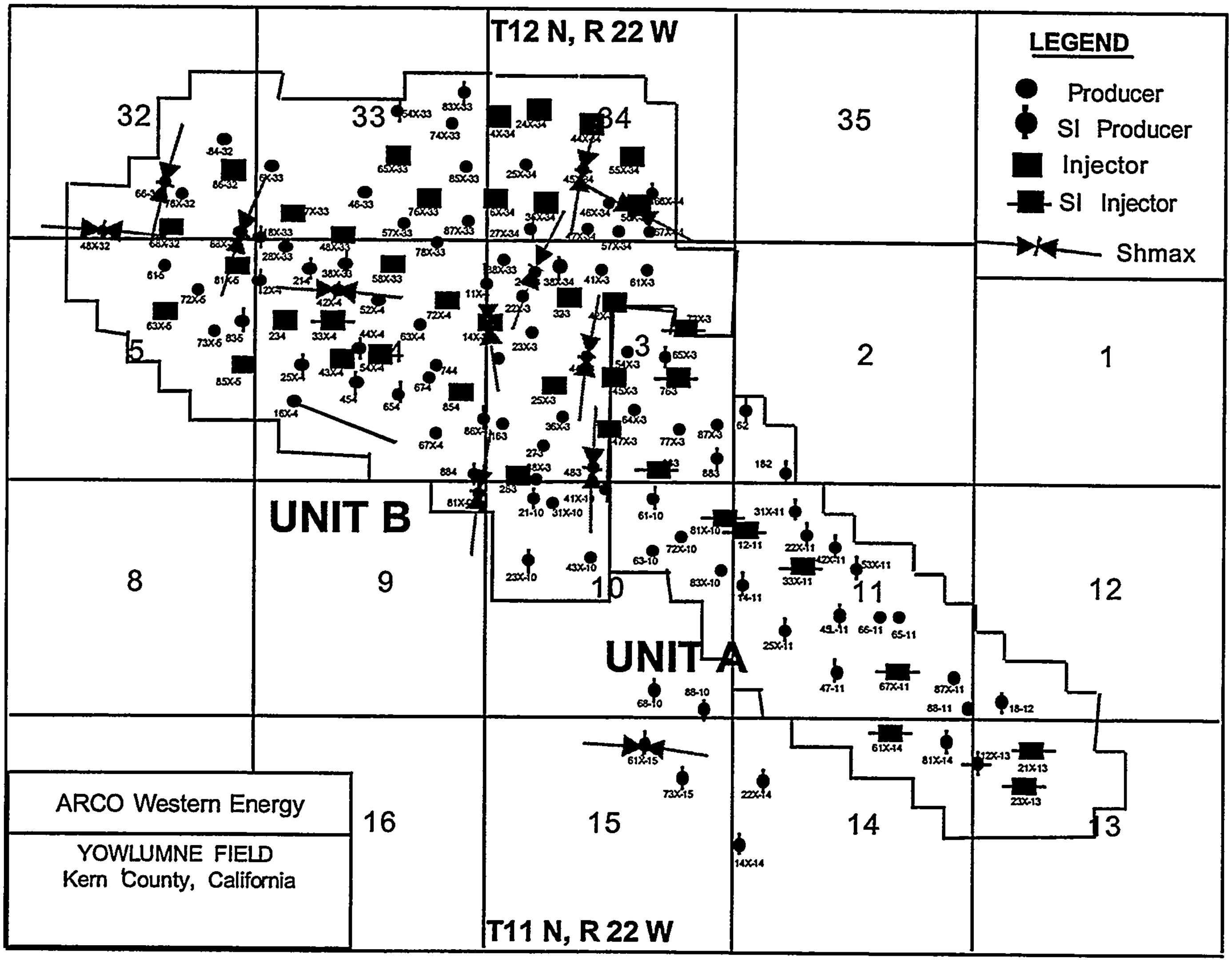

Figure 3.25 – Direction of maximum horizontal stress (S_{hmax}) indicated by arrows from borehole breakout data in the study area. (From Niemeyer, 1997)

Chevron USA Inc.—Buena Vista Hills Field, California (Reservoir Class III): Mike Morea and Tom Zalan

The Antelope Shale zone was discovered at the Buena Vista Hills field (Figure 3.26) in Kern County, California, in 1952 and has been under primary production for over 45 years. More than 160 wells have been drilled through the Antelope Shale section. In the West Dome area, the area studied in this project, 20 of 52 wells are producing, 31 are shut in, and 1 is abandoned. Recovery to date from the West Dome has been about 9 MMBO of an estimated original oil in place of 130 MMBO from a gross pay interval about 800 ft thick. About 93% of the oil in the West Dome is still trapped in the reservoir.

The reservoir rock is a siliceous shale, a rock type with very unique production characteristics. It is composed of diagenetically altered silica shells of microscopic diatoms, planktonic plants that thrived in the coastal waters of western North America during the Miocene Epoch. The Antelope Shale reservoir consists primarily of a stack of 1–5-cm-thick graded beds of siliceous shale with intercalated discrete sand beds from 1 mm to 25 cm in thickness (Figure 3.27). Sand represents only a few percent of the total reservoir thickness. Sand and diatomite deposition in these graded beds was from turbidity currents (Reservoir Class III). Siliceous shale deposits resulted as fine detritus, thrown into suspension by turbidity flow, settled out in the basin area distal to submarine channels carrying coarser sediments. As reservoir rocks, siliceous shales have very high porosity (27–30%) but low permeabilies (0.08 md is typical in the West Dome area) because of the small size of pores and the fact that much of the porosity is internal to the skeletons of the diatoms. Presence of either natural or artificial fractures is necessary to produce oil or gas at commercial rates. In the San Joaquin Valley region, the Antelope Shale and similar shales (like the Belridge Diatomite) in the Monterey Formation contain about 10 billion bbls of OOIP in fractured siliceous shales.

This project, begun in 1996 and scheduled for completion in 2001, uses advanced reservoir characterization techniques including innovative core and wireline log analyses, laboratory core floods, and well tests to determine the reservoir and production characteristics of the Monterey Formation. Other technologies being employed in the project for reservoir characterization include multicomponent vertical seismic profiling, cross-well seismic tomography, outcrop fracture studies, and regional tectonic studies. The resulting reservoir model will be used to simulate how the reservoir will respond to advanced secondary recovery and enhanced oil recovery processes such as an anticipated CO_2 flood.

Downhole Video Logging in Existing Producers

The operator routinely uses downhole video cameras to evaluate producing wells under both static (shut-in) and dynamic (flowing) conditions. In the operator's experience, most effective use has been made of this technology under these conditions:

- Wellbore fluids are clear.
- Flow rates are not turbulent.
- Water is the continuous phase.
- Gas flow rates are low.
- Segregated flow exists.
- Mechanical problems are expected (i.e., the log is run primarily for casing inspection).
- Scale is present .

The tool must be deployed in such a way as to be compatible with typical producing conditions. Shut-in or static conditions usually give the best results. Shut-in video surveys were found to be very effective for detecting fluid entry in the Buena Vista Hills field. The operator found that the application of video logging can be improved by determining fluid levels and shut-in surface pressures prior to running the log. Wells should be shut in for a day or more before running the log so the pressure buildup will push the fluid level in the well down to mid-perf level. Gas and water may continue to flow from high pressure zones and enter low pressure zones. During logging, a first pass should be made down the wellbore and then up during shut-in conditions. The camera should then be moved to the top of the perforations and the flow line opened enough to begin bleeding off pressure (until hissing is heard). Very gradual opening of the flow should minimize movement of fines that may obscure visibility and should keep the fluid level from rising too rapidly. The well should then be logged downward until the fluid level is reached. Logging should not continue into the fluid-filled portion of the well unless the fluid is clear during shut-in. Once the fluid level is reached, the flow rate can be increased and the well logged upward ahead of the rising fluid level.

Two wells were logged mainly under shut-in conditions to successfully identify gas and oil entry into the wellbore and to accurately locate holes and leaks in casing requiring remediation. Oil and water entry were observed in the air-filled part of the borehole during both shut-in and flowing periods. Gas entry was observed in the air-filled part of the borehole under flowing conditions only and in the fluid-filled part of the borehole under both shut-in and flowing conditions. The technology was particularly appropriate for these wells being produced on pump, where there was too little room to run conventional production logs in the annulus between the tubing and the slotted liner. Also, video logging can provide more definitive data in low-volume producing wells where production log interpretation is often subjective. Evidence from the surveys suggests that significant cross flow occurs during shut-in periods. Gas flows out of the deeper parts of the reservoir into the lower pressure zones, and water flows out of both deeper (possibly) and shallower zones into lower pressure zones. These findings were used to plan further production logging and cross-well seismic surveying.

Openhole Electrical Imaging in a Potential Injector

A microresistivity imaging log was run in a newly drilled well to define parameters related to structural deposition, textural characteristics for comparison to core, core orientation, and fracture analysis. At a certain common depth in the reservoir, the microresistivity tool's calipers indicate a rotation in stress direction (i.e., a change in borehole breakout orientation) that corresponds to a similar change in stress direction as determined by the Dipole Shear Imager (DSI). The DSI, a sonic tool (see discussion under this project in the Advanced Tools section - Chapter 4), run in the same well also indicated a change in the magnitude of stress at that depth. No corresponding change in fracture frequency on the resistivity imaging record was noted, however.

Figure 3.28 shows a typical microresistivity image from the lower part of the Upper Antelope Shale section. Resolution is good, resolving bedding down to about 0.1 ft. The images enabled core-log correlations to be established within ± 1 in., and were useful for identifying missing sand intervals in cores. Shown on the figure at 4,279 ft is an example of a normal fault. Figure 3.29 is an equal area net projection of all planar features interpreted from the imaging log over a 50-ft interval. Bedding planes (green) show a tight clustering of dips averaging about 10.9° with an azimuth of N34°E. The red, dark blue, and light blue squares show small open fractures of varying quality ("A" being of highest quality and "C" being of lowest quality). Figure 3.30 plots the azimuth histogram of these fractures. The most abundant are in the S40°E to S45°E direction. Dips range from 10° to 90°, but most are in the 80° to 90° range. The orange squares, pink squares, and pink X's on Figure 3.29 are faults, microfaults, and healed fractures. Their orientation is similar to the fracture orientations shown in Figure 3.30. No major open fracture zones were discernible on the images.

The fracture system at the West Dome area is not believed to be pervasive, although there is evidence of significant fracture permeability in the Buena Vista Hills field. Pressure build-up analyses indicate low average permeabilities of 0.64 md and small well-drainage radii of 76 to 554 ft. On observation, the bulk core obtained from the proposed injection well drilled in this project contains relatively few larger scale fractures and no major open fracture zones. Sandy intervals did appear to be more fractured. Core recoveries in the Buena Vista Hills field are typically more than 95% (the core in this study recovered over 99.5%). However, in other fields in the Monterey Formation, core recoveries may be as low as 5% or less in the highly fractured part of the reservoir. Outcrop work performed in this study along with reinterpretation of borehole images and logs from several wells in Buena Vista Hills and other Antelope Shale fields nearby indicates that brecciated faults and connected open fractures are major hydrocarbon pathways in the Monterey Formation.

Video and microresistivity imaging tools have already made significant contributions to understanding the movement and potential movement of fluids within and between reservoir layers or zones at Buena Vist Hills. The project is still in the reservoir characterization phase, but its ultimate goal is to recover as much as 5% – 15% of additional OOIP through continued advanced reservoir characterization, reservoir modeling, simulation, and application of appropriate enhanced oil recovery technologies.

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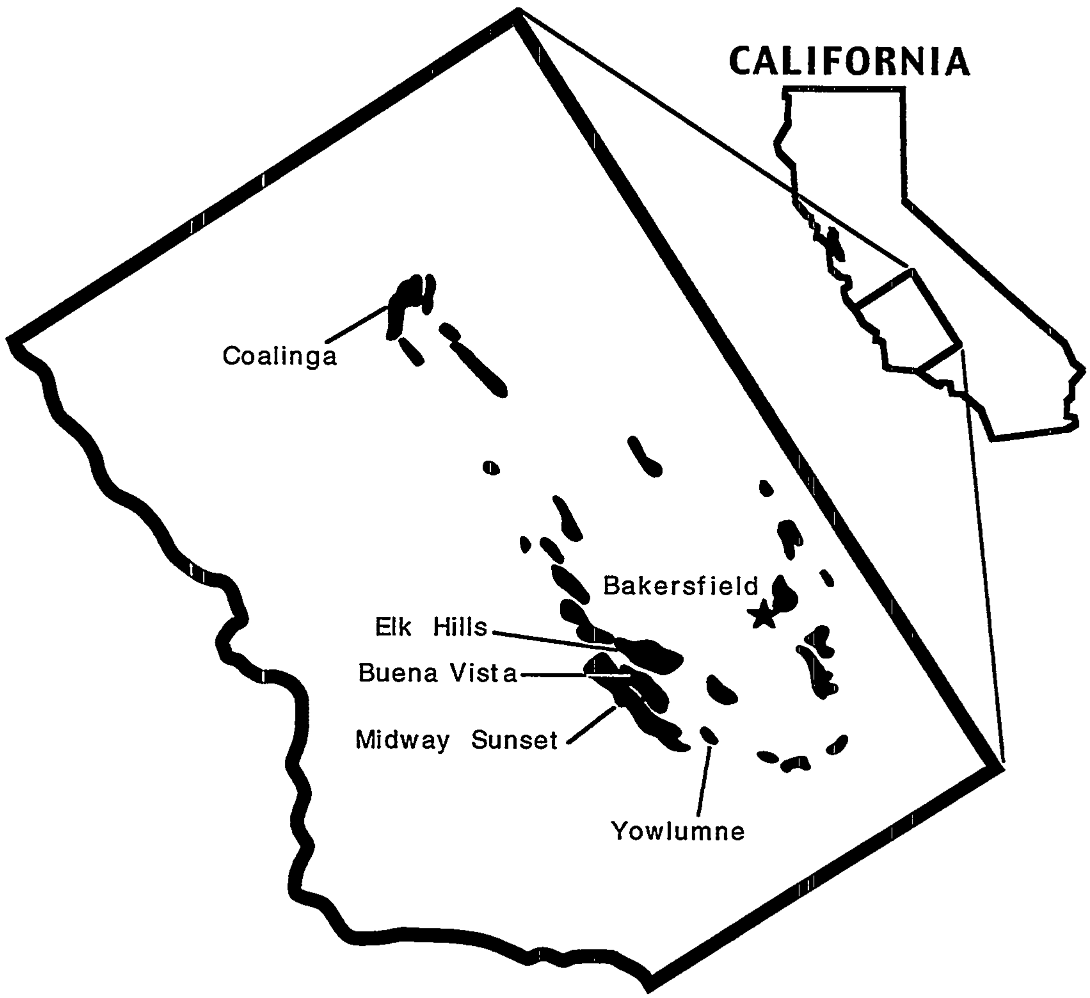

Figure 3.26 – Location of the Buena Vista Hills and other selected oil fields in the southern San Joaquin Valley. (From Toronyi, 1997)

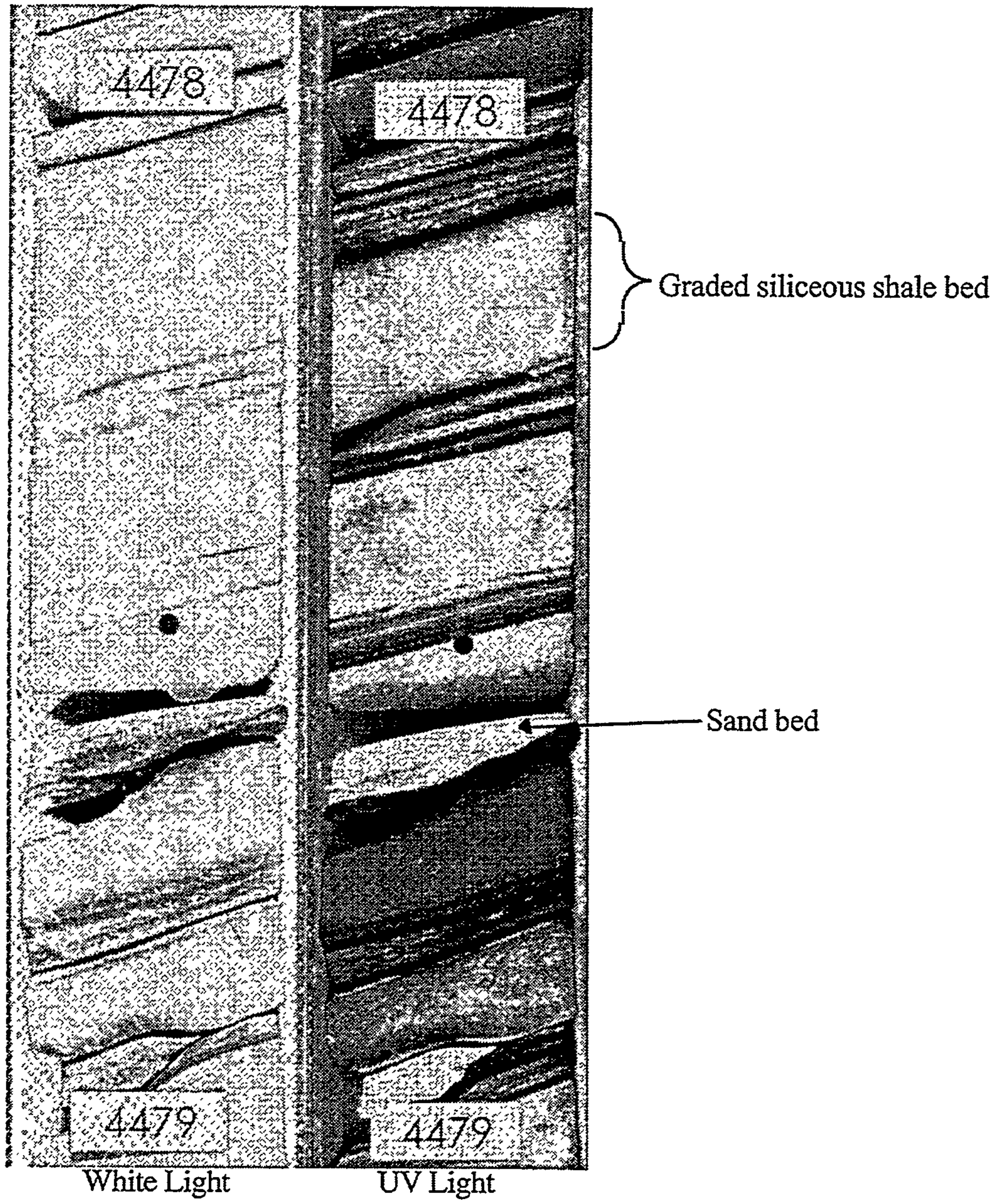

Figure 3.27 – Core photographs showing the interbedded nature of sandstones and siliceous shales in the Antelope Shale. (From Toronyi, 1997)

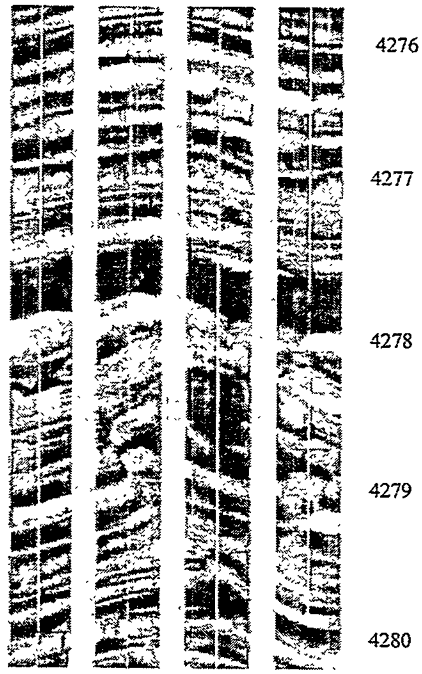

Figure 3.28 – Microresistivity image in the upper Antelope Shale showing the thinly interbedded nature of the formation; note the small normal fault at 4,279 ft. (From Toronyi, 1997)

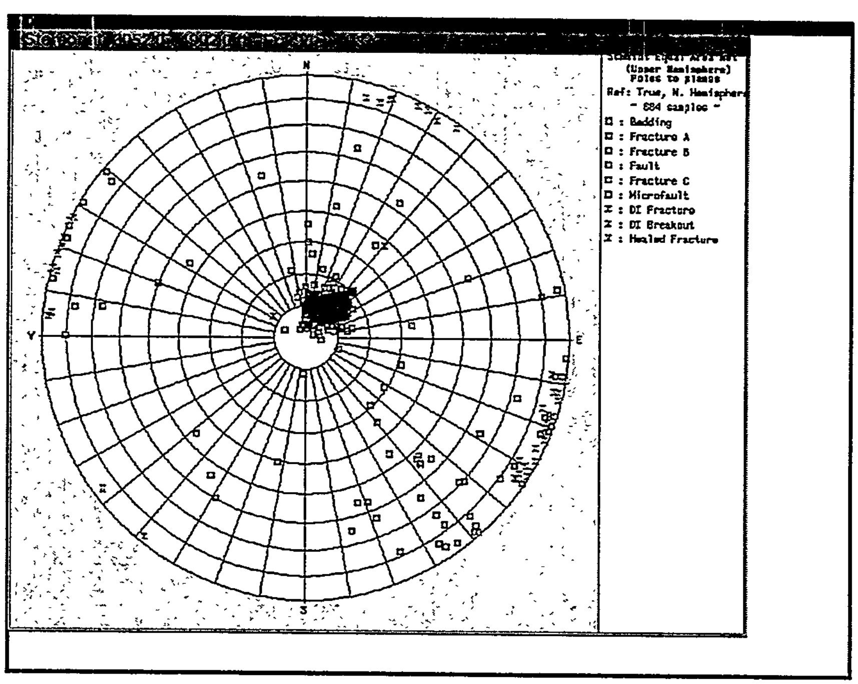

Figure 3.29 – Upper hemisphere polar equal area net of poles to planes of bedding, faults, and fractures. (From Toronyi, 1997)

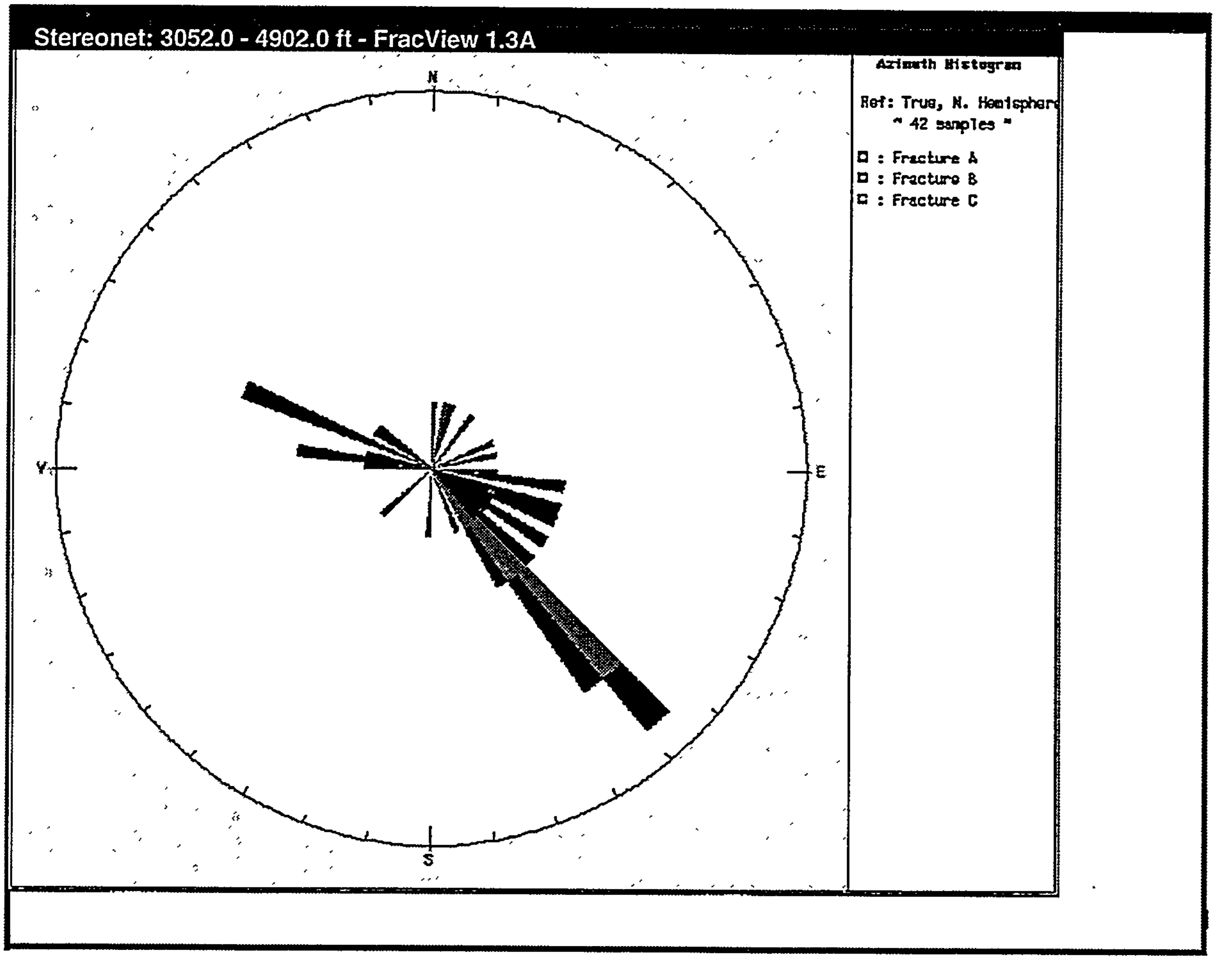

Figure 3.30 – Rose diagram of fracture dip azimuths from microresistivity images. (From Toronyi, 1997)

Pioneer Natural Resources Inc./Parker and Parsley Development Co.—Spraberry Trend, Texas (Reservoir Class III): Chris Whigham

This project being performed in the Spraberry Trend in the west Texas Permian Basin is seeking to show that CO_2 injected into fine grained, naturally fractured slope basin and deep basin clastic (Reservoir Class III) reservoirs can recover significant amounts of oil not mobilized by past waterflood operations. Characterization of the Spraberry reservoir is making use of core-log modeling, borehole imaging, and advanced logging tool technologies. (Please refer to the core-log modeling discussion on this project in Chapter 2 for a more complete project overview.)

A centrally located vertical production well was drilled in the pilot project area. The well was sponge-cored through the main pay interval to characterize natural fractures and to determine current oil saturations. A microresistivity imaging log was run over the same interval. Good agreement in orientation of natural and drilling induced fractures was observed between the log image and the paleomagnetically oriented core. Both suggested a N85°E alignment. However, the classic reported value in the past for Spraberry fracture orientation is near N50°E. Most of the field-response data support the latter value, whereas more recent near-borehole survey data suggest more of an east-west orientation (Figure 3.31). The operator will continue with coring and field testing to resolve the significance of this difference in measured fracture trends.

A critical part of the reservoir characterization performed in the project has been the drilling, coring, and borehole image logging of horizontal legs in a well in the Spraberry reservoir in Midland County, Texas. The cores obtained are the first known horizontal cores from the Spraberry. They have provided critical information on fracturing that will be necessary for implementing CO_2 injection. A total of 226 ft of oriented horizontal core were recovered from a 397 ft total horizontal interval within the upper Spraberry (McDonald et al., 1997). Logs run after the coring operation confirmed that the core represented a 2–3-ft-thick section of pay located some 6 to 8 ft above the main pay in the uppermost pay unit in the Spraberry. A second horizontal leg, kicked off about 200 ft deeper into another main pay unit, also was cored. This second operation recovered about 169 ft of core over a horizontal distance of 443 ft. The mechanics of obtaining core in these horizontal legs were similar to those of coring vertical wells. In fact, the problems which hampered horizontal coring operations were also typical of problems commonly encountered in coring vertical wells (i.e., jamming of core barrels with shale or rubble, failure of core catchers, etc.).

Study of the oriented core revealed the following:

- Three distinct fracture sets trending NNE, NE, and ENE are present in the cores. Fractures oriented NE are found only in the upper pay unit and are commonly mineralized, at least partially, with barite. Unmineralized NNE and ENE fractures occur in the lower pay unit.
- Each fracture set has its distinct pattern of spacing, mineralization, distribution with respect to lithology, surface characteristics, and distribution of strikes. Each fracture set was therefore interpreted to have resulted from a separate stress event.

A microresistivity imaging log was run over the cored intervals of the horizontal leg in the upper pay unit. Good quality images were obtained over the interval, but there was some ambiguity in correlating fractures observed in core vs. those observed in the log images in sections where data of both types were available (Figure 3.32). A tolerance of ±6 in. was allowed for matching fractures observed in both core and imaging log data. Over the interval 24 fractures were observed in the core that had no correlatable counterpart on the imaging log. Conversely, 36 fractures on the image log had no observable equivalents in the core. Only 15 fractures could be correlated in both core and log, no matter what depth shift was employed. Surprisingly, obvious features like fracture swarms and isolated fractures observed in core did not leave such apparent impressions on the imaging log. However, the overall trend of fracture strikes was nearly the same as observed both in core and on the log.

The reasons for the discrepancies between core and image log observations are not completely clear. Cable stretch during tool conveyance and the usual uncertainties associated with assigning exact depths to retrieved core materials may be a partial explanation for correlation problems. The significance of more fractures (133%) observed on the imaging log, however, is more difficult to explain. It seems unlikely that the log is seeing fractures that were not detectable by direct observation in cores. Coring induced fractures in the wellbore might be offered as a partial explanation. There is difficulty also in explaining the imaging tool's inability to identify mineralized fractures observed in core. The results of this test certainly show the need for calibrating imaging tools against core for a particular reservoir or formation.

Fracture information, obtained in substantial part by imaging logs and used in conjunction with other reservoir characterization data, is being used to determine a number of design parameters in the proposed pilot CO_2 flood area, including:

- Well spacing
- Pattern orientation
- Water and CO_2 injection rates
- Predictions of observation well response and gas, oil, and water production rates.

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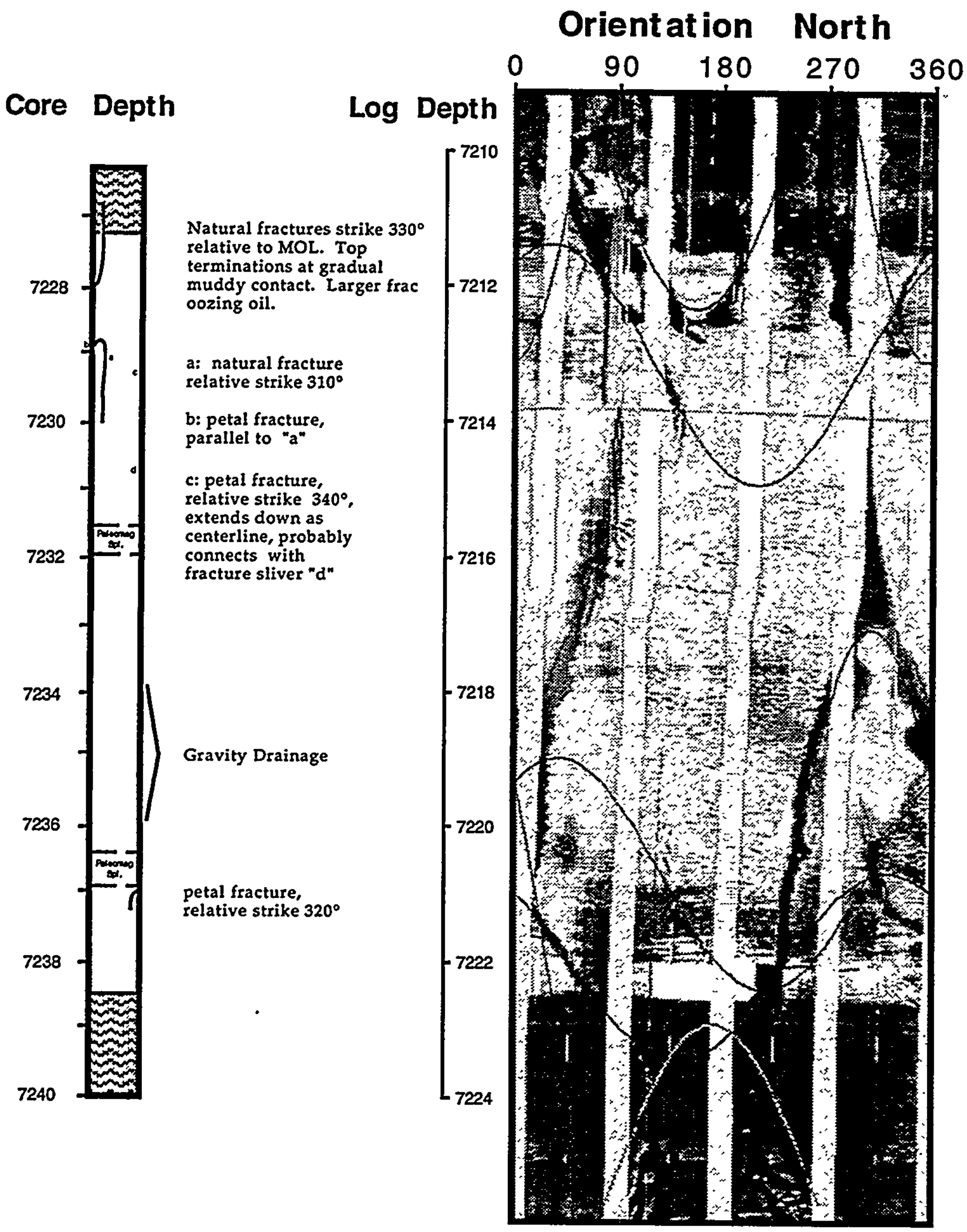

Figure 3.31 – Comparison of fractures and interface between pay and nonpay in the upper Spraberry as observed in core vs. the microresistivity imaging log. Fracture orientation is roughly east-west. Base of pay is at 7,237.5 ft (core), 7,220.5 ft (log). (Modified from Schechter, 1997)

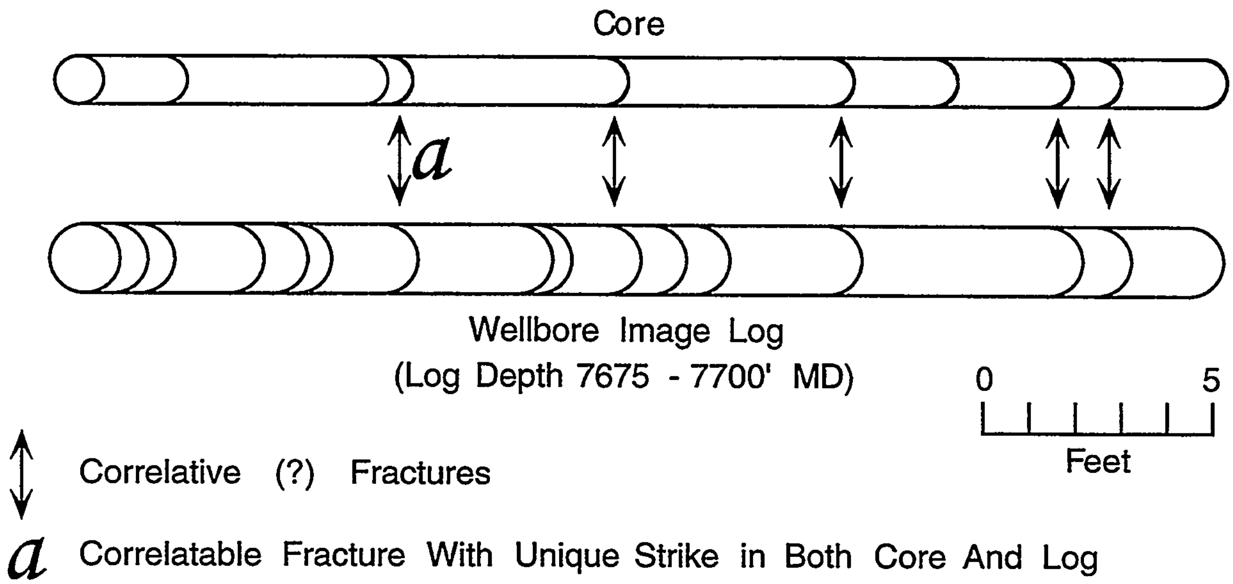

Figure 3.32 – Comparison of fractures observed in core vs. microresistivity imaging log in a horizontal well in the upper Spraberry. (From McDonald, 1997)

University of Wyoming—Oregon Basin Field, Wyoming (Tensleep Sandstone Eolian Deposits): Mary Carr-Crabaugh and Thomas L. Dunn

In Wyoming reservoirs, the Middle Pennsylvanian (Desmoinesian) to Lower Permian (Wolfcampian) Tensleep Sandstone (Figure 3.33) contains the largest potential reserves recoverable by enhanced oil recovery (EOR) processes. The formation has produced billions of bbls of oil, but in some reservoirs as few as one in seven bbls of discovered oil is recoverable by current primary and secondary techniques. This study, focused on the Tensleep in the Bighorn Basin area in Wyoming, sought to identify the fluid-flow anisotropies within the formation that would affect implementation of EOR.

A fundamental aspect of this project performed in 1993 through 1996 was the study of heterogeneities influencing fluid flow (1) in outcrop through measurement of vertical sections and construction of photomosaics, (2) in thousands of feet of core, and (3) by analysis of tens of thousands of feet of wireline log data in the Bighorn and Wind River basins. Both the depositional and diagenetic aspects of heterogeneity were investigated.

The data indicate the Tensleep can be divided into a series of cycles (Figure 3.34) composed of eolian sandstone and marine dolomite related to repeated regression and transgression of the sea (Andrews and Higgins, 1984; Wheeler, 1986; Kerr, 1989; Carr-Crabaugh and Dunn, 1996). In the idealized cycle (Figure 3.34), sharp-based eolian sandstones deposited during the regressive phase of the cycle may show a thin, discontinuous interdune accumulation near the top. Uppermost eolian sandstones are commonly contorted (possibly as a result of fluid escape associated with initial flooding) and are gradationally overlain by sandy marine dolomites of the transgressive phase. Marine dolomites are truncated during the subsequent regression. A single eolian unit may be composed of a single set of cross strata or a series of sets and may vary in thickness from 3 to 55 ft (1 – 17 m). Sandy dolomitic units range from a few inches to as much as 25 ft in thickness (10s of cm to 8 m).

Bounding surfaces are the primary features contributing to or associated with fluid flow heterogeneity and compartmentalization in Tensleep reservoirs. Kocurek (1988) described a hierarchy of surfaces based on their mode of origin. The largest scale surfaces, and the most areally extensive, are those that mark transgressions that end eolian deposition in each of the recognized cycles (Figure 3.35). Less extensive first-order surfaces mark the boundary created by the migration of climbing bedforms within eolian sequences. With the passing of simple dunes, a single set of cross strata is produced. The bounding surface itself originates as a result of erosional processes in the inter-dune area. On outcrop these surfaces are commonly undulatory and may show up to 20 ft (6 m) of relief over a distance of 300 ft (92 m) (Carr-Crabaugh and Dunn, 1996). In a slightly more complex case, the lee face of the primary dune bedform may have superimposed bedforms which create second-order surfaces as they migrate.

The most common surface types occurring in the Tensleep are third-order or reactivation surfaces. These occur within a set of cross strata as a result of re-orientation of the lee face under the influence of fluctuating airflow conditions. Each of these surfaces contributes to the heterogeneity of the unit, primarily because more tightly packed wind ripple laminae overlie the erosional surfaces, resulting in low permeability and inhibition of fluid flow across the bounding surfaces (Carr-Crabaugh and Dunn, 1996).

Erosional-bounded sediment packages such as those described earlier, control the geometry of flow units in eolian reservoirs. Better prediction of flow units then, can thus be made by reconstructing the types of bedforms that formed the accumulation. Subsurface study of the occurrence and frequency of erosional bounding surfaces is limited, however, by the availability and quality of core data. As a consequence, an added facet of the comprehensive regional study of the Tensleep involved an attempt to reconstruct critical aspects of reservoir architecture from borehole image data. An integrated study of three cores and three microresistivity imaging logs (i.e., two FMS logs and one FMI log) from the Tensleep Sandstone in the Oregon Basin field (Figure 3.36) in the western Bighorn Basin, found that all types of erosional bounding surfaces identified in surface outcrops were also present in the subsurface and could be identified and classified from borehole images (Carr-Crabaugh et al., 1996). Comparison of the stratification orientation above and below an erosional bounding surface makes it possible to classify the erosional bounding surface within the process-oriented hierarchy described earlier. Appearance of key first- through third-order surfaces as observed in both core and on imaging log tadpole plots is shown in Figure 3.37. First-order surfaces, which have a very strong influence on interwell-scale fluid flow but generally extend from well to well, have very low dips, typically less than 5°. Second-order surfaces, which form reservoir compartments of substantial size that often do not extend between vertical wells, have dips generally in excess of 10°, but have less lateral extent. Third-order surfaces, like those of the first-order, are also relatively flat with dips usually in the 7° to 10° range. An interpreted image with first-, second-, and third-order surfaces identified appears in Figure 3.38.

Using foreset and bounding surface orientations interpreted from the imaging logs and a computer program developed by Rubin (1987), a 3-D model of the dune that formed these accumulations was created. The dunes which formed Tensleep accumulations in the Oregon Basin field were determined to be large, crescent-shaped bedforms migrating to the south-southwest with superimposed bedforms migrating to the southeast. Such reconstruction of bedforms can be used to model the 3-D geometry of flow units enclosed by erosional bounding surfaces (Carr-Crabaugh et al., 1996). These models can then be used to distribute heterogeneities in porosity and permeability for input to reservoir flow models. Analysis of reservoir architecture using these techniques suggests targeting horizontal wells to intersect as many reservoir compartments bounded by second-order surfaces as possible as a key to improved recovery.

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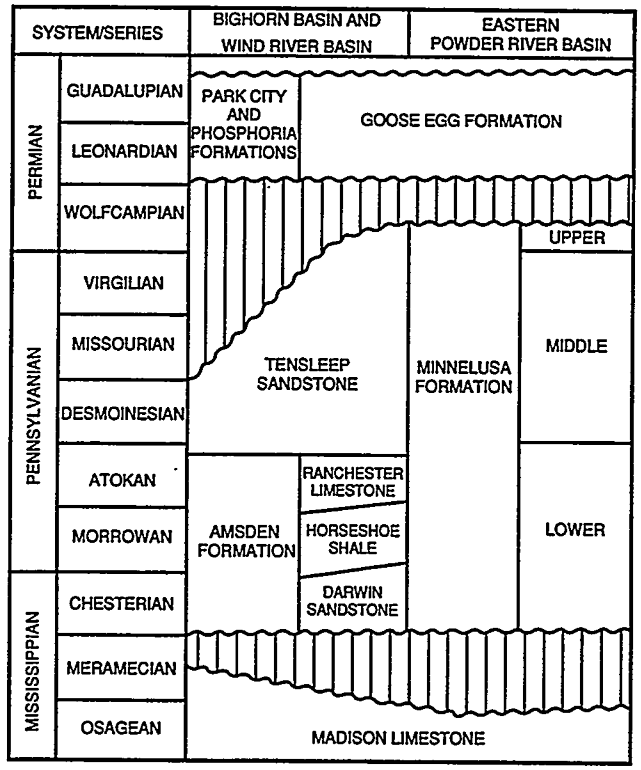

Figure 3.33 – Correlation chart showing Mississippian through Permian units in the Bighorn and Wind River basins. (After Wheeler, 1986, from Carr-Crabaugh, 1998)

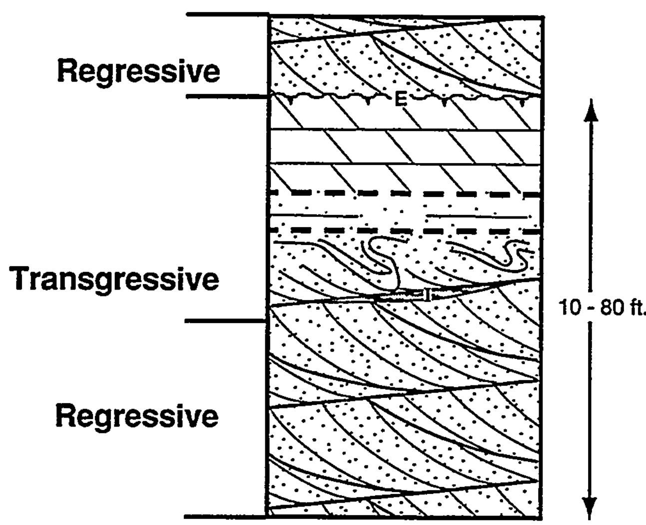

Figure 3.34 – Idealized Upper Tensleep eolian-marine cycle. Layer I is a thin interdune accumulation common toward the top of the eolian part of the cycle. Surface E is an erosion surface or sequence boundary marking the end of marine deposition and the start of a new cycle. (Modified after Carr-Crabaugh, 1998; Carr-Crabaugh and Dunn, 1996)

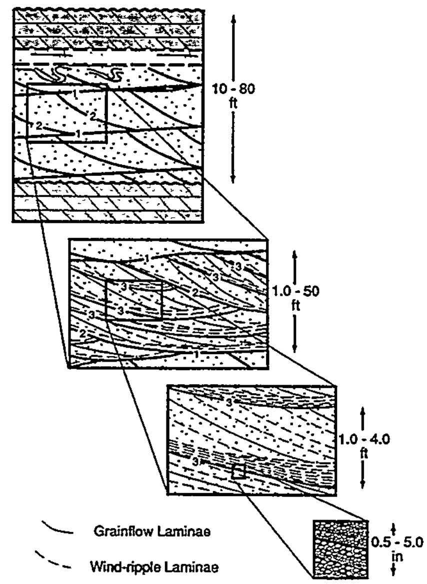

Figure 3.35 – Illustration of different scales of reservoir heterogeneity in the Tensleep Sandstone. The largest scale of heterogeneity is defined by the cyclic appearance of marine dolomitic units dividing the cross-stratified eolian sandstones. Smaller scale heterogeneities are defined by first-, second-, and third-order erosional bounding surfaces indicated by 1, 2, and 3 on the diagram. (From Carr-Crabaugh and Dunn, 1996)

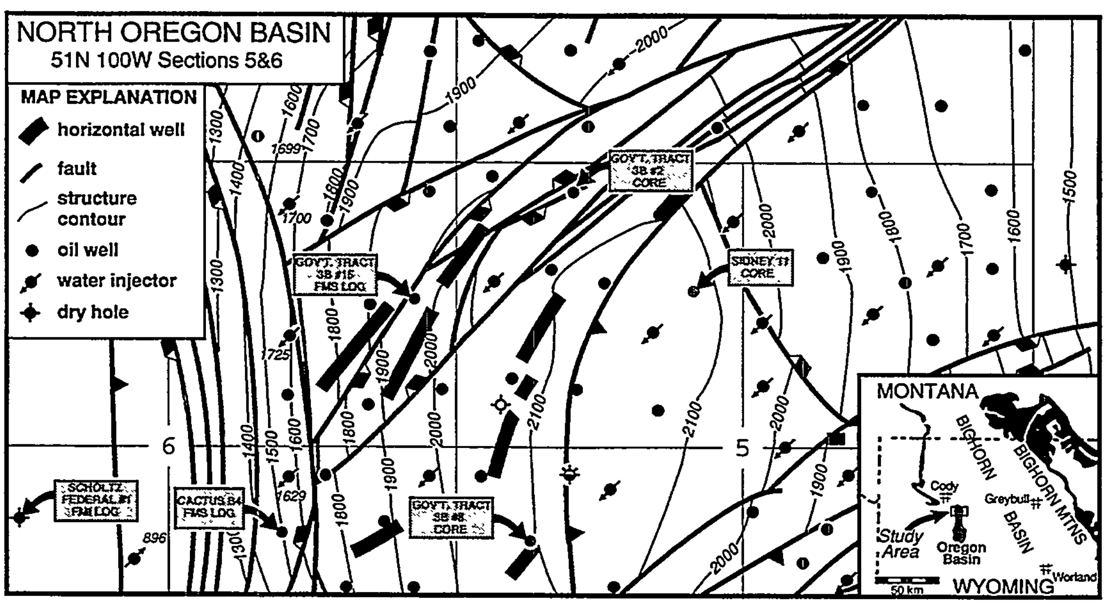

Figure 3.36 – Sources of azimuthal data on Tensleep eolian deposits in the North Oregon Basin field study area. (Quarter sections are delineated.) (From Carr-Crabaugh, 1998)

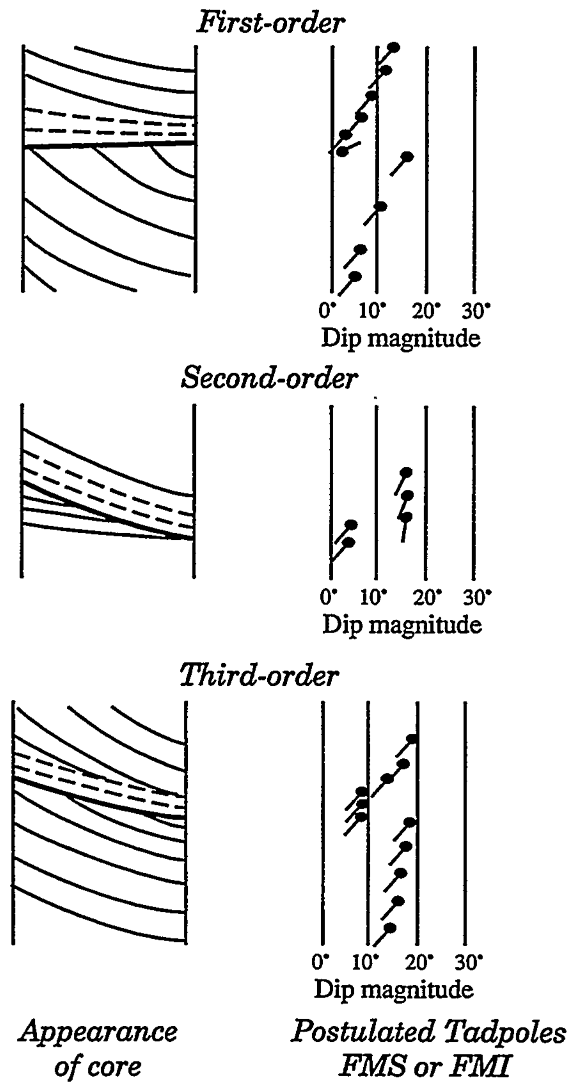

Figure 3.37 – Comparison of erosional bounding surface types observed in core and outcrop with the corresponding expected microresistivity tadpole plots. Structural dip has been removed. In the core plots, dashed lines are wind-ripple laminae and solid lines are grainflow laminations. (From Carr-Crabaugh, 1998)

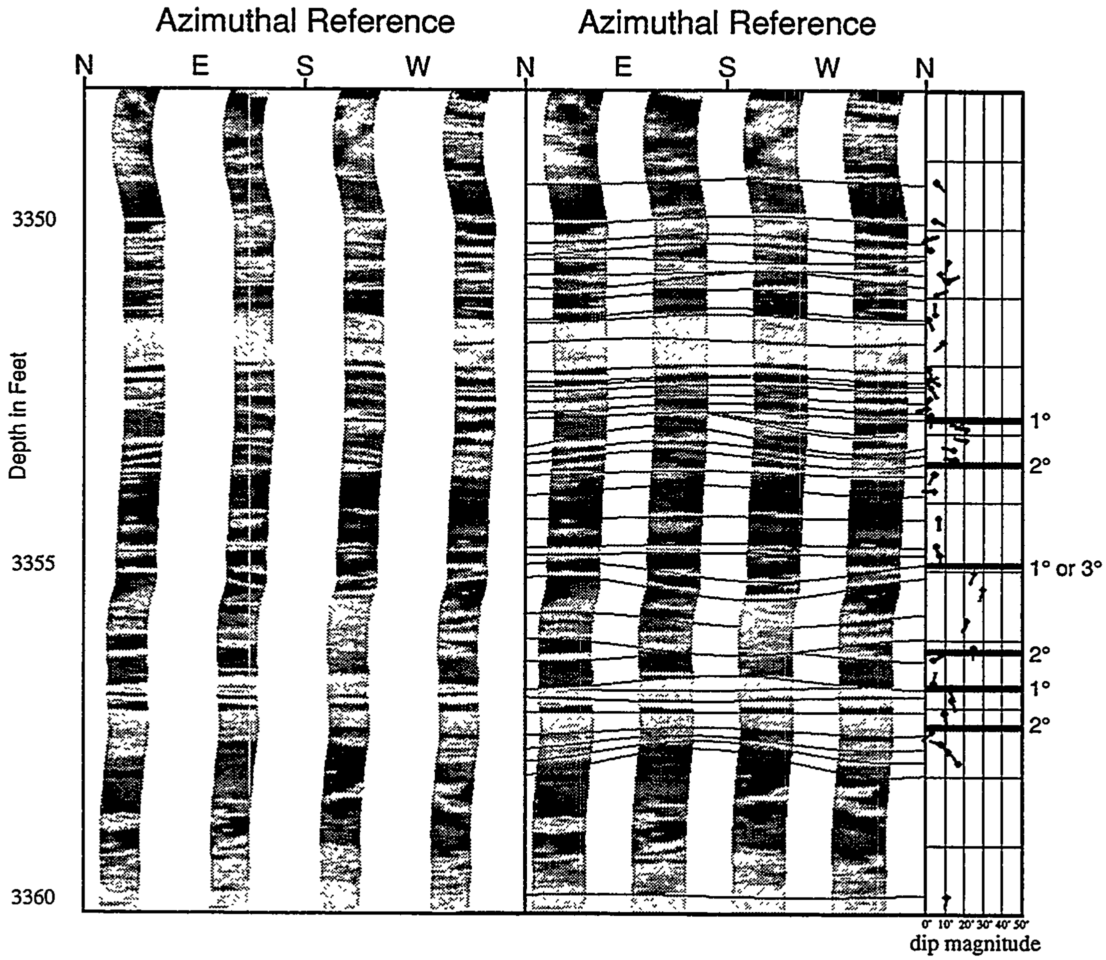

Figure 3.38 – A typical Tensleep microresistivity image and the resulting interpretation of first-, second-, and third-order bounding surfaces. Image at left is uninterpreted. Structural dip has been removed from both images. (From Carr-Crabaugh, 1998)

Summary of the Use of Borehole Imaging

Through its programs of cost-shared and other supported projects, DOE gives access to a wide perspective on the use of borehole imaging technologies in a number of basin settings, in a variety of reservoir rock types, and at various depths. Even horizontal wellbores have been explored with these tools. Project results have shown that borehole imagers can provide, either directly or indirectly, information concerning parameters affecting subsurface fluid flow patterns at almost any scale from that of microscopic pores through the interwell scale, to the scale of gross reservoir architecture. In addition, the high resolution of tools such as microresistivity imagers can help identify thin productive zones in mature, marginally economic reservoirs, potential pays that might otherwise be lost in the poorer resolution of more conventional resistivity logs. The alternative for obtaining this type of information has traditionally been to take full diameter core of all suspect intervals. Even at shallow depths, the amount of core material required to evaluate an entire reservoir interval might not make coring a cost-effective alternative for identifying thin bypassed pay zones.

At a slightly larger reservoir-descriptive scale, conventional cores usually contain some, but not necessarily all, of the information one would like. They contain a detailed and usually, but not always, uninterrupted vertical sequence of all the beds in the cored interval. Sedimentary features and geologic structures, such as fractures, are discernible in cores of both siliciclastic and carbonate rocks. Features observed can help define sedimentary facies and depositional environments and can lead to stratigraphic architectural models and structural models for the reservoir. Presence and even density of fractures can sometimes be determined if their presence does not lead to problems with the performance of the coring tool and failed recovery. In spite of their expense, however, conventional cores do not give information on the spatial orientation of sedimentary features and structures. This is information that is needed to predict fluid-flow patterns in the subsurface, patterns that greatly influence the economic success of improved recovery operations. In addition, we would like to know whether fractures are open or closed in the subsurface and, if open, what fluids they contain. Oriented and native state or pressure cores may address some of these issues, though sometimes at considerable incremental expense, but many questions will remain unanswered. Borehole imaging tools can often provide all of this information more reliably and, under most circumstances, more cost-effectively.

The number of imaging applications reviewed in these projects is too small to draw conclusions about the relative utility of one borehole imaging technology vs. another. All of the borehole imaging technologies employed in the projects have been used with great success by industry in a wide variety of reservoir types and circumstances. The key to success in using borehole imaging tools is perhaps to realize that, as in the case of most wireline tools, what a particular tool measures may not necessarily directly correspond to the information one would like to obtain. In some instances, the tool may measure a property that correlates with the property or feature of interest in some predictable way. Interpretation is then relatively straightforward depending on the degree of correlation and one's ability to anticipate borehole or formation conditions that may change the nature of the correlation. At times the link between what the tool "sees" and what one wants to know will be very tenuous, and very special conditions may have to occur and be maintained to get the information wanted from the recorded signals. Acoustic tools "see" acoustic contrasts, resistivity tools "see" resistivity contrasts. The further removed the desired information is in relationship to the properties observed by the tools, the more difficult it will be to get the information we want with accuracy. The panel discussion held in conjunction with the Advanced Applications of Wireline Logging for Improved Oil Recovery Workshop in Midland, Texas, in November 1997, concluded that borehole imaging tools should not be run just to see what we can see; rather, the tool should be chosen and the survey should be designed around the information that is needed. Different tools have significantly different strengths and weaknesses depending on factors such as formation, contained fluids, depth, borehole environment, etc. Comparison of core vs. image data in projects like these gives the information and experience needed to match imaging tools with formation properties, borehole conditions, and the type of information desired.

In practically every instance in which uncased borehole surface imaging was used in the projects reviewed, imaging tools were run in tandem with coring. This practice might be interpreted as an attempt to evaluate the performance of tools in which full confidence has not yet been fully developed, but perhaps more accurately this should be looked at as a necessary calibration step. The objective becomes simply to observe how the logging tool responds to features of importance observed in the core, whether those features are structural, sedimentological, compositional, or related to fluid content. The amount of core calibration needed will be a function of the reservoir-wide variability of the properties to be measured (i.e., a function of the variability in formation properties and properties of contained fluids), but it will also be a function of variability in borehole environments. After calibration, borehole imagers provide tremendous economies of scale for cost-effectively collecting information over large vertical intervals within, above, and below the reservoir.

Calibrating against cored intervals coupled with running imaging logs under carefully controlled borehole conditions designed for optimizing retrieval of the needed information is the first step. Next, and just as important, comes processing the raw data collected by the tool to emphasize and optimally display the information wanted. A popular rule-of-thumb in the industry today is that for every dollar spent in obtaining raw data, plan to spend an equivalent amount to optimally process that data. Of greater concern than processing expense, perhaps, to attendees at the Advanced Logging workshops, was a desire to perform interpretations on the wellsite in real time to enable the information these logs provide to be incorporated into making critical reservoir decisions. Satellite links transmitting data to a centralized processing facility have proven much too slow to provide interactive decision-making on the wellsite. Progress is being made rapidly, however, and some service companies already are offering on-site processing. It seems likely that the trend towards higher capabilities in digital data processing that made borehole imaging possible will continue and will resolve this problem completely in the near future.

The potential value of borehole imaging tools is just beginning to be fully realized. They are tools that not only provide a detailed basis for core-log adjustments and orienting conventional cores, but also serve as reservoir descriptive tools in their own right. They provide high resolution, continuous, and azimuthally oriented information on a wide variety of reservoir parameters that are difficult or impossible to measure with other wireline tools. As has been demonstrated in the DOE-sponsored Field Demonstration Program projects, borehole imagers, like other reservoir descriptive technologies, are most effectively used in conjunction with other sources of reservoir characterization data, such as cores, outcrop analogs, other wireline logs, seismic data, well tests, and production/injection data. Data from each source are used in complementary and supplementary fashion by interpolation, extrapolation, or correlation to create a coherent and mutually supportive model of the subsurface reservoir. The model will incorporate a wide range of formation, fluid, and structural aspects, as well as an understanding of the variability that might be expected in association with each over the 3-D volume of the reservoir.

CHAPTER 4

ADVANCED TOOLS: BRINGING NEW TECHNIQUES TO PRACTICAL APPLICATION

Often, in reservoirs presumed depleted after primary, secondary, or even tertiary recovery operations, there are bypassed oil zones with significant movable oil remaining. For economic recovery of such bypassed oil, appropriate logging technology is needed, first to identify the bypassed zones and then to obtain information for selecting suitable production technology. Thus, wireline logging is one of the most important parts of the drilling and completion process. Logging costs generally account for less than 10% of completed well costs, but logs are critical in identifying which zones to complete and how to complete them.

New tool combinations and advanced logging tools are being developed and used to cost-effectively measure critical reservoir properties. Advanced logging tools are those established tools that have undergone significant improvements or newly developed tools that have recently become commercially available. Many advanced tools can measure specific reservoir properties more accurately and at higher resolution than conventional tools. Others may measure reservoir properties not previously measurable. Significant advances have been made in logging instrumentation over the last 20 years, resulting in many improvements in open-hole and cased-hole tool designs and measurement capabilities.

This chapter focuses on the advanced tools and techniques used by DOE Reservoir Class Program project operators. The particular tool applications and lessons learned should be helpful to other operators who are considering using many of these advanced logging tools and techniques in similar types of reservoirs. The first section briefly discusses the types of advanced logging tools, how they work, and their capabilities and limitations. This is followed by discussion of how the individual project operators used the advanced tools and the tools' contributions toward the overall success or failure of the projects. The chapter ends with a summary of the status of advanced logging technologies.

Types and Uses of Advanced Logging Tools

There are numerous situations and reservoir conditions in which advanced logging tools are appropriate. Commercially available advanced open-hole and cased-hole logging tools can improve understanding of current reservoir conditions and pore fluid distribution in zones with high irreducible water saturation caused by very fine-grained rock texture. The need for cost-effective technology to evaluate thin beds and highly heterogeneous reservoirs coupled with a desire for real-time measurement while drilling, has driven formation evaluation tool development toward more accurate, higher resolution measurements. Magnetic, resistivity, acoustic, and nuclear tool development efforts are currently focused on redesigning sensors to measure deeper into the formation, reducing the time between tool measurements and data interpretation for decision making, and developing new cost-effective logging techniques.

The most popular of the advanced logging tools used in DOE's Reservoir Class Program projects are the borehole imaging tools (described in Chapter 3). While imaging tools have been available for many years, they have undergone numerous recent advancements in tool design and instrumentation that have further increased their utility and popularity. With the advent of pulsed Nuclear Magnetic Resonance (NMR) logging tools, NMR logging is fast becoming another of the mainstream logging applications. All the major logging companies now offer NMR logging and more than 3,000 such logs have been run to date. Other advanced logging tools used in the projects reviewed include the Carbon/Oxygen and Elemental Capture Sonde tools, the Modular Formation Testing tool, and the Electromagnetic Propagation Tool. Advanced tool designs involving sonic waves include the Pulsed Acoustic, the Dipole Shear Sonic, and the Digital Array Sonic tools.

Schlumberger and Halliburton have each developed integrated logging strings combining several tools that provide quicker and more accurate measurements, in real time. These innovative tools can lower operating costs by letting operators log twice as fast and significantly reduce the rig time required from set-up to delivery of the results. Enhanced technologies and configurations improve pad contact over that of individual tools screwed together into a long string. Integrated sensors provide answers for lithology, porosity, water saturation, gas identification, movable hydrocarbon analysis, and shale volume. The tools are able to deliver higher resolution imaging measurements that are both depth-matched and speed-corrected in real time. Additional tools, such as NMR tools, can be run to measure difficult-to-interpret zones. Whether profiles from production logs, fluid samples from a formation tester, porosity from a sonic log, or saturation from a pulsed neutron device, the tools provide data for monitoring of fluid movement and optimization of production. Several operators used these enhanced tool combinations to improve the core-log modeling portions of their projects.

Nuclear Magnetic Resonance (NMR) Tools

NMR logs run in open-hole situations provide porosity, pore size distribution, and permeability as well as information about fluid types, saturations, and moveability. Radio-frequency signals emitted by protons re-aligning following introduction of a pulsed magnetic field give information through the timing of their emission (i.e., spin- lattice [T_1] and spin-spin [T_2] relaxation times) on pore system surface-to-volume ratios. The response is sensitive to fluid types, both hydrocarbons and waters, and rock characteristics such as pore size, wettability, and to some extent mineralogy (if paramagnetic minerals are present).

Two of the most popular NMR tools used in the Reservoir Class Program projects are NUMAR's MRIL (Magnetic Resonance Imaging Logging) tool and the Schlumberger CMR (Combinable Magnetic Resonance) tool. The MRIL differs from the CMR tool in that it utilizes the earth's magnetic field, whereas the CMR uses the field from permanent magnets. NMR logs have been used mostly for determining irreducible water saturation and estimating permeability.

NMR tools are shallow-reading devices. Using an early MRIL tool as an example, they typically sense a cylindrical shell approximately 4 ft long, 14 inches in diameter, and about 0.1 inches thick (Maute, 1992). The tools usually read at a depth from 1 to 4 inches into the formation. Resolution depends on the operating frequency, which directly affects the signal to noise ratio and dictates appropriate logging speed. Because flushing by mud filtrate is rarely complete, substantial hydrocarbon saturations are frequently observed surrounding the wellbore. In the extreme invasion case, the NMR tool may not detect the presence of gas, but if gas is present, it usually diffuses back through the mud prior to the logging run.

CMR tools are pad-mounted with the minimum recommended borehole size being 6.25 inches (Morris et al., 1996). When borehole conditions are very good, the tool can be run in borehole sizes of 5.785 inches. The MRIL tool is a mandrel-type design that is run centered in the borehole. Current technology does not allow for NMR logs in recent slim-hole drilling applications. Advancements in tool design are focusing on reducing the size of the tools to enable measurements in wellbores down to 4 inches.

The CMR tool works in both conductive and resistive muds, whereas the MRIL tool requires resistive mud. Ability to distinguish the nature of the hydrocarbon fluid when drilling with oil-based muds is a powerful feature of NMR logging. Current resistivity tools are unable to distinguish between highly resistive drilling mud and oil-saturated reservoir rock. NMR tools are capable of simultaneous measurements with all density, neutron, and gamma ray tools, selected induction tools, and selected formation-testing tools.

Borehole NMR measurements are cyclic rather than continuous with a wait time and an acquisition period. The measurement cycle is completed at every sample rate interval (usually 6 inches). Long cycle times improve the accuracy of NMR logs, but result in slow logging speeds. Most NMR logs are run at logging speeds of 150-600 ft/hr. Recent improvements of these tools include reducing the minimum acquisition period, which is currently 0.28 ms, to increase the measurement sensitivity to fast decaying signal components (i.e., those from small pore sizes and high viscosity oils).

To properly plan and interpret NMR well logs, it is essential to understand the physical properties of the formation fluids (Kleinberg and Vinegar, 1996). In the cases of both conventional neutron and NMR measurements, the formation response is proportional to the density of protons, which can be converted to a hydrogen index. Each fluid has a characteristic hydrogen index. NMR tools are sensitive only to hydrogen in fluid phases, whereas neutron tools are sensitive to all hydrogen nuclei, whether they are in the pore space, in the clay matrix, or associated with hydrated crystalline phases such as gypsum. Thus the NMR measurement is a more accurate indicator of effective porosity in shaly sands than the neutron measurement. The CMR tool suffers no borehole effects under normal conditions and thus does not require complicated environmental corrections. From the NMR tool's perspective, the effects of temperature and pressure on fluids tend to compensate in downhole conditions.

The crude's API gravity is usually sufficient to give a good indication of hydrogen index, and the gravity of the oil coupled with temperature allow estimation of the oil viscosity under downhole conditions. From this information, a distribution of expected spin-spin relaxation times (T_2) can be determined. The distribution is proportional to the density of the hydrogen in the pore fluids and depends upon the mixture of hydrocarbons in the crude. The T_2 distribution represents the primary log output from which porosity, bound-fluid porosity, free-fluid porosity, and continuous permeability profiles are all derived (Freedman and Morris, 1995).

The NMR properties of gas are quite different than those of water and oil under typical reservoir conditions and can be used to quantify the gas phase in the reservoir (Akkurt et al., 1995). Gas has a significantly lower hydrogen index and causes a large reduction in NMR-predicted porosity compared to total porosity present. Failure to recognize the presence of gas may result in gas being interpreted as bound fluid, which, in turn, may result in excessively high estimates of irreducible water saturations and very low porosity and permeability estimates. Used in conjunction with the density log, the crossover effect between NMR and density porosity can be used to identify gas zones more accurately than neutron-density crossover.

To divide effective porosity into that occupied by movable and immovable fluid, a T_2 cutoff must be selected. A cutoff determined on a foot-by-foot basis from log-derived lithology is preferable over application of one constant value throughout the formation. For sandstones in general, experimental data support a value of 33 ms (Morris et al., 1996). For typical carbonates, a T_2 cutoff of 92 ms has been found optimal for detection of oil-water contacts (Chang et al., 1994).

Experience has shown that for accurate estimates of a formation's petrophysical parameters and to have confidence in the assumptions made in interpretation, NMR logging must be done in conjunction with conventional logging (Kenyon, 1997). Further calibration of the NMR log response using core measurements (whole or sidewall cores) is required for the accurate prediction of permeability and estimates of producible gas and irreducible water saturation. Once the correlation is made, the NMR log can be run in analogous parts of the field at less cost than coring additional wells.

Recently introduced NMR logging techniques, such as the differential and shifted spectrum methods (Akkurt et al., 1995) and the time domain matched filter analysis method (Prammer et al., 1995), enable hydrocarbon typing and near-borehole water saturation determination. By using properly chosen pulse sequences, the different relaxation and diffusion properties of light oil and natural gas can be discerned to determine saturations of various phases. Providing the formation is water wet and the hydrocarbon is relatively light, these methods can use the T_1 (spin-lattice) contrast between the brine and hydrocarbons to identify pay and the diffusion contrast between the liquid and gas phases to type the hydrocarbon.

In DOE's Reservoir Class Program, NMR tools played a part in reservoir characterization in the following projects:

- Inland Resources/Lomax Exploration Company – Monument Butte unit, UT (Reservoir Class I)
- Fina USA Inc. – North Robertson unit, TX (Reservoir Class II)
- Chevron USA Inc. – Buena Vista Hills Field, CA (Reservoir Class III)
- ARCO Western Energy Inc. – Yowlumne Field, CA (Reservoir Class III)

Acoustic Tools:

Recent developments in full wave acoustic logging are largely driven by the need to evaluate fractured reservoirs (i.e., low permeability chalks, shales, and carbonates), and for the design of hydraulic fracture treatments. Full-wave acoustic data include compressional, shear, and Stonely waves. The compressional wave is used to determine porosity. The ratio of shear to compressional velocities is used to identify lithologic properties and detect gas. Shear-wave amplitude is used for fracture identification. Amplitude and velocity data of both compressional and shear waves are used for evaluating cement bonds, calibrating seismic, and determining rock mechanical properties. Stonely waves, derived from multipole array acoustic data, are related to fluid movement and are sensitive to formation fractures. Formation fluid viscosity and compressibility also affect the wave attributes. By comparing Stonely wave permeability with permeability derived from NMR, it is possible to separate permeability contributions arising from fractures from that of the rock matrix. This has important implications for the hydraulic fracturing and producibility of the reservoir. New methodologies have been developed to separate wave attributes and suppress noise and scattering effects in the data.

The parameters that need to be calculated in acoustic logging for discriminating oil from brine are the compressional and shear wave velocities of rocks saturated by these fluids. The fluid density and the bulk modulus are markedly different for liquid hydrocarbons and brine. In a reservoir these two properties decrease with temperature and increase slightly with pressure. In general practice, if API gravity is known, the density and bulk modulus can be calculated using formulae given by Batzle and Wang (1992). Alternatively, using a formula given by Biot (1956), the bulk modulus of fluid-saturated rocks can be calculated from the moduli of the constituent parts (i.e., the modulus of the dry rock [the moduli of the minerals making up the rock] and the modulus of the fluid saturating the rock). Once the moduli are calculated, a computation of velocity can be made.

Acoustic logs respond well to variations in oil saturations because hydrocarbons usually have lower acoustic properties, such as bulk modulus and density, compared to brine (Clark, 1990). Lower compressional wave velocities (V_P) occur in hydrocarbon-saturated rocks compared to brine-saturated rocks. While the compressional wave velocities in hydrocarbons and in brines are quite different, there is no appreciable change in shear wave velocities (V_S), because the modulus of rigidity, which influences the shear-wave velocity, hardly changes with changes in fluid saturation. Therefore, the V_P/V_S ratio is recognized to be a sensitive indicator of hydrocarbons. An acoustic log hydrocarbon indicator (ALHI) usable for estimating hydrocarbon saturations has been developed by Williams (1990) based on the difference between the measured V_P/V_S and that predicted for a 100% water-saturated rock.

Digital array sonic logs are being used by engineers to help design of hydraulic fracture stimulation in marginal wells with low permeability. Digital array tools measure compressional and shear wave travel times. With these data, the mechanical rock properties (Young's modulus and Poisson's ratio) can be calculated. From these elastic constants, a frac pressure gradient as a function of depth may be computed. Because about 20% or more of the total cost of drilling a well may be involved in fracturing, proper fracture treatment design is critical to maximize production. Too small a fracture treatment may result in inadequate drainage of the reservoir, causing the well to be unprofitable. Conversely, too large a treatment can be an unnecessary waste of completion funds, or such a fracture may intersect a neighboring water zone and increase lifting costs.

When pressure is increased in the borehole, rupture occurs in the plane at right angles to the direction of least compressive stress. Hydraulic fracture design depends on the magnitude and distribution of in-situ horizontal stresses in the producing well and the surrounding formation, and also on the flow behavior of the fracturing fluid. These variables enable a determination of:

- Direction and orientation of deviated wellbores
- Direction and geometry (height, length, and width) of the created fractures
- Whether multiple zones should be fractured simultaneously or one at a time
- Design parameters for hydraulic fracturing (e.g., horsepower, pumping pressure, etc.)
- Fracturing fluid flow behavior and efficiency

In DOE's Reservoir Class Program, acoustic tools played a part in reservoir characterization in the following projects:

- City of Long Beach – Wilmington Field, CA (Reservoir Class III)
- Strata Production Company – Nash Draw Pool, TX (Reservoir Class III)

Dielectric Tools

Dielectric tools such as Schlumberger's Electromagnetic Propagation Tool (EPT) are similar to acoustic tools, but use electromagnetic waves and operate at microwave frequencies (e.g., 200 MHz to 1.1 GHz). Just as sound passes through different materials at different characteristic speeds, so do electromagnetic waves. The tool measures the formation's dielectric properties, which are a function of the water saturation and relatively independent of water salinity. The dielectric constant of water (78) is much higher than that of oil (2) and rock (4 to 10) (Dewan, 1983). Use of a dielectric tool does not necessarily require knowledge of mud filtrate resistivity, nor does it require complete replacement of connate water by mud filtrate in the flushed zone. The primary advantages of the tool occur where formation water is fairly fresh or in fields that have been under waterflood and the formation water has a high resistivity similar to that of oil and gas. In instances where the salinity of the water varies greatly over relatively thin intervals, the EPT log is less affected than resistivity measurements.

The EPT measurement responds mainly to the water content in the formation, rather than to the matrix or any other fluid. Because of the tool's shallow depth of investigation (1 to 6 inches), it can be assumed that only the flushed zone is influencing the measurement and that the water is primarily mud filtrate. The close spacing between transmitter and receiver provides a very fine vertical resolution (about 2 inches) making the oil/water contact easy to locate. For the tool to operate successfully, the hole must be as smooth as possible, and the drilling mud must be properly balanced to avoid creating excessive mud cake. The tool is often run in combination with gamma ray, neutron, and density tools. Since its development, the tool has had limited application. In most cases, the expense involved in maintaining the mud conditions must be carefully evaluated to justify the data obtained.

EPT tools played a part in reservoir characterization in the Fina USA project in the North Robertson unit, TX (Reservoir Class II).

Spectroscopy Tools

New spectroscopy tools have improved the ability to accurately determine mixed lithologies and reservoir fluids in both open and cased holes. The tools measure the abundance of different types of gamma rays produced by the interaction of high-energy neutrons emitted by the tool with the nuclei of atoms, which comprise the rock and fluid.

This measurement of the ratio of various elements enables determination of lithology and identification of potential hydrocarbon-bearing formations. Oil/water or gas/water interfaces can be monitored in reservoirs under active flooding (water, miscible, or thermal). The hydrogen curve can be used as a porosity indicator and high-porosity gas reservoirs can be differentiated from tight formations. While these tools can be widely applied, there are some limitations on the reservoir conditions under which they are most effective.

In the Dresser-Atlas Carbon/Oxygen log, the ratio of the inelastic gamma radiation due to carbon to that due to oxygen is measured. In cased wells, this log can determine the hydrocarbon saturation independent of water salinity. The C/O ratio depends on the hydrocarbon and water saturation, the nature of the rock and its porosity. For sandstone with 30% porosity, the C/O ratio varies from 1.56 at 100% water saturation to 1.72 at 25%. The tool is most effective in water wet reservoirs with porosity above 10%. In lower porosity reservoirs, tool speeds must be reduced (to < 100 ft/hr) to allow for capture of enough radiation to form an accurate ratio.

Schlumberger's Elemental Capture Sonde estimates concentrations of numerous elements, including potassium, thorium, and uranium (generated from a gamma ray spectroscopy tool), plus aluminum, silicon, calcium, iron, sulfur, titanium, and gadolinium. These values are transformed into mineralogical concentrations, which are related to grain size, porosity, permeability, and cation exchange capacity. Local core calibration is critical, however, rather than relying on a generic normative solution. Because sedimentary minerals have particular chemical and infrared properties, the measurements can be used for detecting and correlating lithofacies with high mineral concentrations (e.g., high sulfur could indicate evaporites). The ratio of the intensity of capture radiation of silicon and iron to that of calcium (Si/Ca and Fe/Ca ratios) can be used to determine lithology and amount of clay. For example, the Si/Ca ratio typically is 1.20 in limestones, 1.38 in shale, and 1.50 to 1.80 in sandstones. The sonde can be either kept stationary or raised slowly during measurements.

In DOE's Reservoir Class Program, spectroscopy tools played a part in reservoir characterization in the Chevron USA Inc. project in Buena Vista Hills Field, CA (Reservoir Class III).

Pulsed Neutron Tools

Until recently, waterflood surveillance in lower reservoir quality reservoirs has not included the use of pulsed neutron logs, because operators felt that they did not perform well in low porosity, low salinity conditions. Recent advances in tool design, however, have produced logging tools that work well for both fairly fresh formation water and low porosity formations.

These cased-hole tools (such as Schlumberger's Thermal Decay Time [TDT] tool) measure the decay of slow neutrons captured by chlorine (sodium chloride) in the interstitial water. Total gamma ray count at the detector depends on the porosity, salinity, and shaliness of the formation. The presence or absence of chlorine dominates the upper part of the gamma ray spectrum. The lower part of the spectrum remains relatively insensitive to chlorine, but is dominated by the presence or absence of hydrogen. Therefore, the total spectrum is divided in two energy windows: the low energy window, called the "Hydrogen window," responds to porosity and the high-energy window, called the "Chlorine window," responds to porosity and salinity. While the two window counts are matched in a 100% water-saturated sandstone, they separate in formations containing hydrocarbons.

Knowing the salinity of the interstitial water and the porosity of the reservoir, the logging engineer can determine lithology and identify potential hydrocarbon-bearing formations by measuring the ratio of the two elements. These same parameters determine the resistivity of the formation. Oil/water or gas/water interfaces can be monitored in reservoirs under active flooding (water, miscible, or thermal). The hydrogen curve can be used as a porosity indicator, and high-porosity gas reservoirs can be differentiated from tight formations. The tool's accuracy in calculating saturation is not as good in cased-holes as in an open-holes, but it provides acceptable measurements if the porosity is greater than 15% and the salinity higher than 100,000 ppm. The presence of boron, lithium, gadolinium, or iron can affect the tool's measurement and may lead to erroneous interpretations.

While the cost associated with recording a large number of pulsed neutron logs may be prohibitive for many small operators, in some instances monitoring the preferential fluid movement in near-wellbore regions of producing wells is extremely important. To be effective the logs must be run on the same wells over a period of time to measure the change in formation water saturations. By equally spacing the tests across an area, it is possible to determine the effectiveness of current waterflood operations for reservoir surveillance purposes. The data can be also used as an additional history match parameter for reservoir simulation.

In the Reservoir Class Program, pulsed neutron tools played a part in reservoir characterization in the Fina USA project in North Robertson unit, TX (Reservoir Class I).

Modular Formation Testing Tools

These highly versatile wireline tools, such as Schlumberger's Modular Dynamic Tester or MDT tool, can provide multiple fluid and pressure measurements at minimal cost. Several tool modules can be combined to provide a wide range of formation testing options (Preeg, 1994). The tool can take multiple samples of produced fluids for surface identification and analysis, and an unlimited number of pressure measurements to determine fluids in place and to estimate permeability. Packer modules can isolate intervals less than one-meter thick for accurate measurements from highly laminated, fractured, and vuggy formations.

Determination of permeability distribution is critical for designing pressure maintenance and improved oil recovery techniques. Pressure buildup transients from vertical and horizontal monitor probes are recorded and analyzed to estimate radial and vertical reservoir permeability. Accurate measurements can be recorded in zones with permeability as low as 0.1 md (Preeg, 1994). The optical fluid analyzer can provide real-time information to differentiate gas, oil, and water in the flowline. This technique can significantly reduce the expensive rig time associated with traditional drillstem tests.

In DOE's Reservoir Class Program, a modular formation testing tool played a part in reservoir characterization in the Chevron USA Inc. project in Buena Vista Hills Field, CA (Reservoir Class III).

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Applications of Advanced Logging Technologies in Field Demonstration Projects

A variety of advanced logging tools have contributed to reservoir characterization in the DOE Reservoir Class Program Field Demonstration Projects. Projects are ongoing, or recently completed, in all three depositional-system-based reservoir classes. In this section, those projects that used advanced logging technologies will be addressed and the contribution of the advanced logging tools to the success or failure of the project will be discussed. For those projects that that have used borehole imaging or core-log modeling techniques, only a cursory overview of the context and scope of the project will be provided. The reader is referred to previous chapters and to the published reports and journal articles referenced there.

Inland Resources Inc./Lomax Exploration Company—Monument Butte Unit, Utah (Reservoir Class I): Bill Pennington

(See Chapter 3 for a complete project overview.) Inland Resources Inc. studied the effectiveness of secondary recovery methods in the Monument Butte unit, located in the Uinta Basin, Utah (Figure 3.8). The reservoirs are fluvial deltaic sandstones deposited in the lacustrine environments of the Green River Formation (Lutz et al., 1994). Prior to waterflooding, primary recovery was only 5% of oil in place, typical of an undersaturated reservoir whose initial reservoir pressure was close to the bubble point (Pennington et al., 1996). The varied environments of deposition, the heterogeneous nature of the reservoir, and presence of high-paraffin crude did not initially make the reservoir appealing for waterflood. Yet, waterflooding since 1987 has been extremely successful with secondary recovery nearly double that of primary recovery. The success of this waterflood and others that are being developed in the area led to better understanding of the reservoir characteristics that control fluid movement.

An average well at Monument Butte has approximately 20 sandstone units within the Douglas Creek member of the Green River Formation to be evaluated. Half of the sandstones can usually be eliminated as potential pay based on their discontinuity or thickness. Determining the relative permeability of the remaining sands is critical to making a commercial completion. The degree of natural and induced fracturing plays a key role in providing the required permeability. Cost-effective use of advanced logging tools has improved the operator's ability to measure the permeability of the reservoir, identify productive intervals, and reduce the cost of well completions by more than 10%.

In addition to the microresistivity imaging tools used to determine fracture orientations (discussed in Chapter 3), the operator ran a nuclear magnetic resonance (NMR) tool in five wells in the Monument Butte, Boundary, and Travis units. (The lack of pay identified using conventional logs coupled with poor wellbore conditions prevented NMR logs from being run in two additional wells!) The NMR tool was run to determine porosity, evaluate permeability, and indicate movable oil and water. Reservoir, fluid, and borehole properties determined the optimum mode of operation for the NMR. Temperature, pressure, oil viscosity, mud type, and invasion characteristics can impact the information available from the log. This complexity requires careful selection of optimum acquisition parameters based on the expected logging conditions.

The Federal 10-35 well is an example of the decision-making power of the NMR tool. A full suite of logs (gamma ray, compensated neutron - density, and dual laterolog) and sidewall cores were available from the Federal 10-35 for correlation with the NMR log. There was reasonable correlation of the NMR log with conventional logs, but certain characteristics of the NMR log were not reflected in the resistivity and porosity logs. The density curve exhibited a porosity of 13 to 16 percent vs. 11 to 15 percent porosity obtained from sidewall cores. In comparison, the NMR log indicated a lower porosity of 8 to 13 percent. The NMR tool, however, suggested significantly higher permeabilities of 6 to 35 md compared with the 0.15 to 0.43 md obtained from the sidewall cores. Both the conventional log interpretations and core data were similar to those from other sandstones in which completion attempts had been unsuccessful.

Reservoir simulation was used to evaluate the fluid-flow conditions in the reservoir. Simulation indicated that the reservoir behaves as if it has a higher overall permeability (of the order of 25 md). Thus, the NMR permeability distribution may be more indicative of the actual reservoir permeability than that measured on sidewall cores. The movable hydrocarbon curve on the NMR log indicated a zone containing commercial volumes of oil and no movable water. Subsequent completion of the zone established commercial production, whereas if only conventional logs were relied upon the zone would not have been completed.

The more representative permeability on the NMR log could be explained by the thermodynamic properties of the paraffinic crude in the pore spaces. Unless rigorous cleaning of the core plugs is performed, paraffin at room temperature could remain in the pore throats, reducing effective permeabilities in the laboratory below those in the reservoir (Safley et al., 1997). The importance of vertical fracturing in the Lower Douglas Creek sandstones, observed on the formation microresistivity imaging logs, would be unlikely to be observed in sidewall cores. Vertical fractures might also contribute to higher reservoir permeabilities determined by reservoir simulation than those measured in the laboratory.

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Fina USA Inc.—North Robertson Unit, Texas (Reservoir Class II): Jerry Nevans and Bill Dixon

(See Chapter 2 for a complete project overview.) Fina's North Robertson unit (NRU) located in West Texas produces from the Permian Glorieta and Clearfork formations (Figure 2.4). These shallow shelf carbonates and interbedded anhydrites, deposited as shoaling upward grainstone shoals (Figure 2.5), have a high degree of heterogeneity. Porosity varies from 0 to 25 percent. Air permeability varies from 0.01 md to more than 1 darcy (Chang et al., 1997). Reservoirs are discontinuous and compartmentalized, creating problems with poor sweep efficiency and premature water breakthrough during waterflooding. Improved reservoir characterization is required to target 10-acre infill drilling and maintain efficient waterflood surveillance. The goal is to produce more than the 20% of original oil-in-place typically recovered from Glorieta/Clearfork reservoirs.

In order to determine the best reservoir quality rock and the current fluid saturation, Fina performed an integrated geologic and engineering reservoir characterization study using available logs and cores (Nevans et al., 1998). For the 10-acre infill wells, Fina used a logging suite consisting of: Dual Laterolog, Micro Laterolog, Compensated Neutron Log, Compensated Spectral or Litho-Density Log, Spectral Gamma Ray log, and a Sonic log. To gain a better understanding of the reservoir, several advanced logging tools were also run and integrated with core analysis in order to characterize more accurately the permeability, fluid content, and rock fabric.

Quantitative rock type porosity-permeability relationships were established in order to identify the most attractive pay intervals. By using multiple geologic "filters", it was possible to better segregate data points on porosity versus permeability crossplots. "Filters" included depositional environment data, shallowing-upward sequence tops, rock type data, mud log data, and numerous open-hole log responses (including PE, Spectral Gamma-Ray, and Invasion Profile). Neural network technology allowed combination of curve data to identify unique porosity-permeability relationships.

NMR Tool

Fina ran an NMR tool over selected sections of two cored wells seeking information on lithology-independent porosity, pore size distributions, permeability, and fluid saturation. The distribution of free and bound fluids in the rock pores indicated by NMR suggests that the reservoir is oil-wet. The determination of the fluid distribution was used in the processing of the raw log data to yield a visual representation of the pore distribution in the reservoir. Permeability was estimated using an empirical relationship involving the tool's porosity measurement and the T_2 time (Nevans, 1996).

Reservoir quality of the Clearfork is dominated by variations in pore structure caused by variations in the pore type, pore size (i.e., microcrystalline to large vugs), and pore throat size. Because the NMR tool is less sensitive to microporosity in the low-permeability silty zones, NMR porosity can be interpreted as an effective porosity. The wetting phase, pore geometry, saturation, and fluid type determine the effective pore throat size. Oil-wet rocks have smaller effective pore throats to fluid flow than similar water-wet rocks. Because the Archie equation does not apply in oil wet systems, previous log interpretations of Clearfork reservoirs may be in error, causing estimates of oil saturations based on water-wet reservoirs to be overly pessimistic.

A drawback of running the NMR tool was that the data turnaround was slow and costly. In addition, log measurements had to be closely calibrated with core analysis to properly interpret the data. Clerke (1993) developed a core-calibrated evaluation technique that could be used for the Clearfork reservoir. Rapid lateral changies in permeability and pore geometry of shallow shelf carbonates, like those in the NRU Clearfork reservoir, may be difficult to measure accurately given the tool's shallow depth of investigation, typically from 1 to 4 inches depending on pulse sequence (Morriss et al., 1993).

Most of the previous applications of the NMR tool in the Permian Basin had been to differentiate between oil and water in low resistivity clastic reservoirs. Most of the literature on NMR logging techniques assumes that the rock is water-wet. Many of the relationships developed between NMR porosity and permeability need to be re-evaluated for oil-wet reservoirs. The NMR tool may have application in other shallow water carbonates; however, work needs to be done by the service companies on the relationships between the time shifts in the oil response curves and petrophysical parameters.

Dielectric Tool

Fina also used a high frequency (200 MHz) dielectric log to provide a measure of fluid distribution in the flushed zone. This device works well in formations with mixed lithologies, such as encountered in shallow shelf carbonates, and is at least moderately salinity independent. The measurement is particularly appropriate in fields that are currently under active waterfloods. The tool produces a more reliable measure to differentiate between residual and movable hydrocarbons than can be obtained from the usual low frequency flushed zone resistivity devices, such as the Micro Laterolog or the Micro Spherically Focused Log.

Traditional water saturation calculation techniques do not always produce accurate answers in fractured and vuggy carbonates. This is further complicated at NRU by the fact that the reservoir is oil-wet. Because the flushed zone saturation can be calculated independent of the Archie saturation exponent or cementation factor, the dielectric tool produces more accurate flushed zone saturation calculations. If a low frequency flushed zone device is run, it yields a rock fabric parameter that can be used to determine the type of porosity present (i.e., intergranular, vuggy, or fracture).

Pulsed Neutron (TDT) Tool

To measure changes in water saturation profile for selected wells, Thermal Decay Time (TDT) logs were run in 1995. Fina performed 10 surveys on 20-acre infill producing wells drilled between 1987 and 1991. Original open-hole water saturation data provided a baseline data set for correlation with later TDT logging surveys. These surveys helped to determine the effectiveness of current waterflood operations and identify intervals that may require recompletion. In the NRU 3527 drilled in 1987 (Figure 4.1), the Clearfork carbonate reservoir is very heterogeneous, but additional waterflood potential as determined by the TDT log remains in thin zones between 7,125 ft to 7,170 ft. Whereas TDT logs generally require higher porosity than is present in much of the Clearfork, TDT logging will continue to be an important part of the NRU reservoir surveillance and monitoring program. TDT logs were run in conjunction with spectral gamma ray logs. In depleted intervals and swept zones, the pores are likely to be lined with uranium salts, which can be detected by spectral gamma ray measurements. This occurrence also proved useful for delineating reservoir flow units.

Summary

Based on results of the core-log modeling (see Chapter 2 discussion) and advanced logging, a visual representation of the vertical pore and fluid distribution in the reservoir was developed. The interwell distribution of primary pay and nonpay were generated using conditional simulation techniques. Rock type distributions were reviewed to determine if they honored the geologic model developed for NRU. Discrete zones within the Glorieta/Clearfork section that contribute most to production were identified. Intervals of relatively high porosity and permeability reservoir are separated by larger intervals of lower permeability rock that act as source beds. Petrophysical parameters (porosity and permeability) were assigned for each pay rock interval by honoring the log and core data, reservoir performance, and pressure transient analysis.

A total of 18 wells, 14 producers and 4 injectors, were drilled and completed to develop waterflood patterns. The integrative approach improved the prediction of reservoir quality and definition of hydraulic flow units in noncored intervals by better accounting for the complex nature and high degree of heterogeneity present. Initial stabilized oil production (average 90 bbl/day/well) from the 14 new producing wells, whose location was based on the revised model interpretation, is significantly better than that from previous infill wells (average 26 bbl/day/well). Refinements to the ten-layer, black-oil model incorporating the dual porosity reservoir description, are currently underway. Additional 10-acre infill wells are planned.

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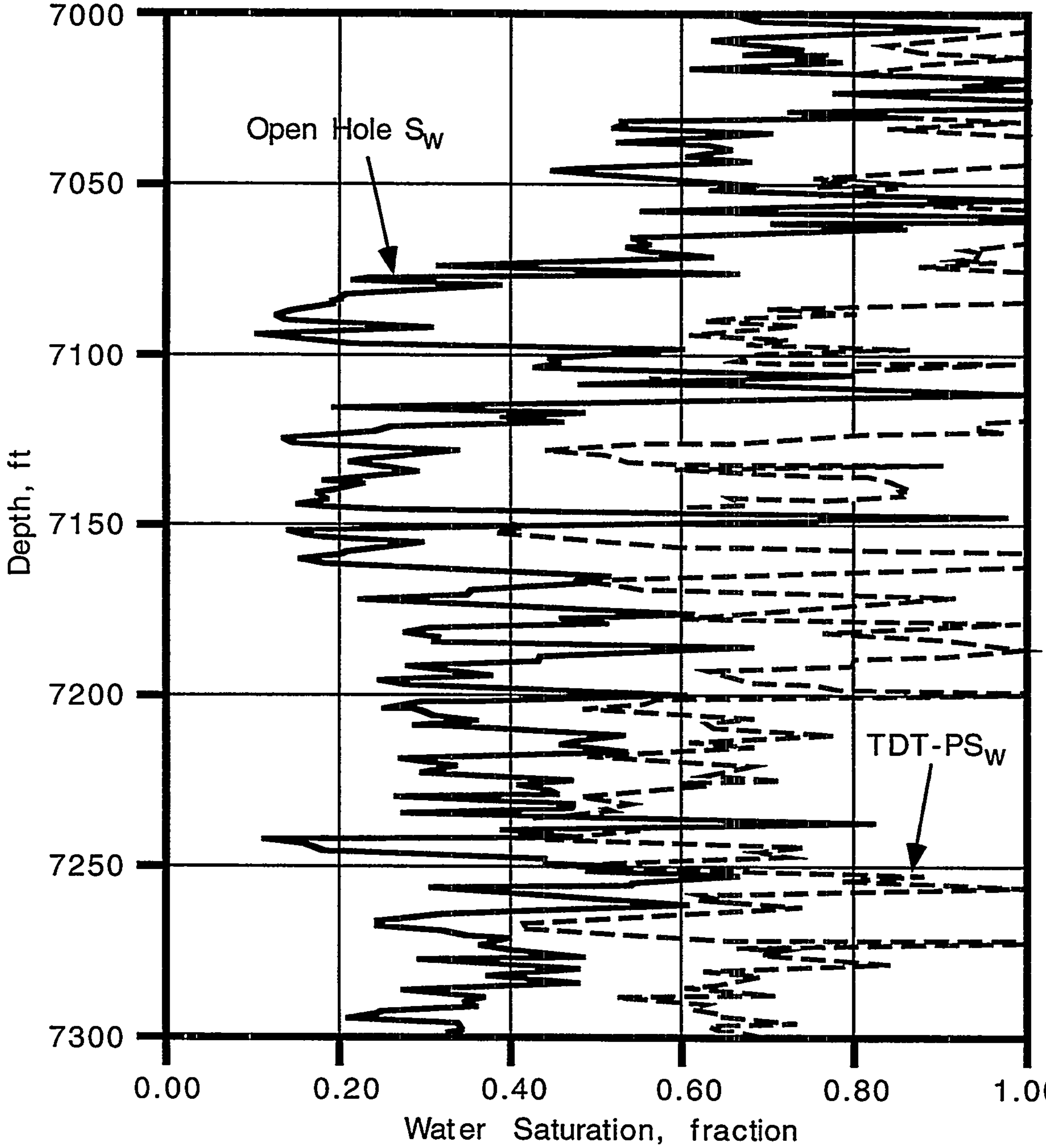

Figure 4.1 – Change in water saturation in the waterflooded Clearfork reservoir in well NRU 3527 as monitored by the TDT log. (From Pande, 1996)

ARCO Western Energy Inc.—Yowlumne Field, California (Reservoir Class III): Michael S. Clark and Mike L. Laue

(See Chapter 3 for a complete project overview.) The Yowlumne field is located in the southern San Joaquin basin, Kern County, California (Figure 3.21). The reservoir is the Miocene Stevens Sandstone, a layered, fan-shaped prograding turbidite complex containing several lobe-shaped sandstone bodies that act as distinct flow units (Figure 3.23) (Clark et al., 1997). Sand bodies were deposited as "sheet sands" transported by sediment gravity flows. Interbedded shale intervals and deteriorating sandstone rock properties toward the fan margins limit producibility from vertical wells. The 13,000-ft depth presents a challenge for hydraulic fracturing and artificial lift techniques.

To capture a portion of the estimated 3 MMBO trapped at the fan margins that would be bypassed by vertical infill wells, ARCO drilled and completed a long radius, near-horizontal well (Figure 3.24). The location and orientation are discussed in detail in Chapter 3. Originally, three hydraulic fracture treatments were planned to maintain communication between large pay intervals of the reservoir. Greater pay exposure with the equivalent production rate and reserves of three vertical wells was anticipated from the deviated well at one-half to two-thirds of the cost.

Open-hole logs confirmed most expectations about basic rock properties. The Yowlumne sand penetrated by the deviated well was shaly, with low porosity indicative of fan margins. Water saturation calculations showed that the lowermost pay intervals had been effectively swept by the waterflood. Consequently, the lower hydraulic fracture treatment was eliminated. Net sand and net pay cutoffs were derived from geologic and reservoir modeling. Permeabilities calculated from the log-porosity vs. core-permeability relationship were fairly low (0.5 to 1.5 md). After hydraulic fracturing, the well produced at an economic rate of 191 BOPD and 477 BWPD.

A high-resolution nuclear magnetic resonance (NMR) log was run to infer producibility, flowing phases, permeability, and water cut. The results were reconciled with core data and empirically derived core-log relationships. The NMR tool was only sensitive to hydrogen in the fluid phases and minimally affected by shaliness of the reservoir. Estimated permeabilities from the NMR tool tended to be higher than those calculated from the established log-porosity vs. core-permeability relationship, but were in agreement with geologic and reservoir modeling estimates of 4.0 to 5.0 md. Based on these permeability estimates, the well should be capable of producing at 729 BOPD and 621 BWPD after hydraulic fracturing. Although an electric submersible pump would be capable of producing an estimated 2,400 bbls of fluid per day, the additional lifting cost was judged to be excessive.

A dipole shear sonic imaging tool was planned for the near-horizontal well to obtain mechanical properties, such as stress values, Young's Modulus, and Poisson's Ratio, to be used for designing hydraulic fracture treatments, but was foregone because of improper wellbore conditions. The high angle of the well prevented running the tool in its full-wave mode. Full wave sonic log data and hydraulic fracture treating pressures from other wells in the field were used to estimate regional mechanical properties for the Yowlumne sand and bounding shales. Relationships were established for the ratio of shear to compressional wave travel time with shale volume (calculated from gamma ray). These relationships were used to calculate Poisson's ratio (ν), the shear modulus (G), and Young's modulus (E). Minimum horizontal shear stresses (σ_x) were then calculated for the Yowlumne sand and bounding shales using pressure data from Schlumberger's repeat formation tester (RFT) tools. Minimum horizontal shear stress values were then calibrated to treating pressure data from a hydraulically fractured well in the field (Gidley et al., 1989).

Mechanical properties and stress profiles were predicted in the area of the deviated well based on each of the following assumptions for pore pressure:

- No pore pressure variation by sand layer
- Permeability-thickness weighted average variation of pore pressures for each layer

The second assumption is the most likely representation for pore pressure. Modeling under this assumption suggests that the vertical growth of the stimulated fractures should be confined to the Yowlumne sand between overlying and underlying shales.

Although this technique of estimating the stress profile is often used for tectonically inactive environments, it is theoretically inappropriate for strike-slip regimes with strong compressional forces, such as found at the Yowlumne field (Gidley et al., 1989). However, it was still useful for observing the relative impact of pore pressures on fracture height.

Borehole breakout data were used to indicate regional stress orientation. Within the Yowlumne sand, borehole breakouts indicate a general north-south maximum principal stress, as discussed in Chapter 3 (Figure 3.25). Regional breakout data from surrounding fields suggest that the north-south maximum stress orientation is consistent with local fold axes and reverse faulting. Vertical fractures established during hydraulic fracture treatments are expected to propagate in the same direction as the azimuth of the deviated well (NNE-SSW). This is the preferred frac azimuth because of the proximity to offset wells and existing waterflood fronts. To minimize the possibility that fractures would orient orthogonal to the wellbore, short fracture half-lengths of 150 to 200 ft were designed for the project well.

To verify the producibility of the reservoir prior to hydraulic fracture treatments, production tests and pressure transient analysis were performed over selected perforated intervals. After repeated casing repairs and cleaning of the perforations, the project well was produced at 220 BOPD and 20 BWPD. After nearly three months on pump, oil production had declined to 160 BOPD, and water cut increased to 35%, in line with earlier estimates.

In summary, the correlation of logging tool measurements with actual core samples was critical to determining many of the reservoir parameters. Porosity measurements and water saturation calculations from the open-hole logs agreed with those from core analyses. The relationships determined between porosity, permeability, and water saturation from the core-calibrated log analysis will prove very beneficial in areas of the Yowlumne field where cores are not available. Stress values, obtained by full wave sonic data and borehole breakout data, were used to determine the expected orientation and height of hydraulic fractures.

The use of advanced logging tools provided information not available from conventional logging tools. Without information obtained from advanced logging tools, it would have been difficult to identify net pay and optimally hydraulically fracture deviated wells at the fan margins. Conventional logs would have measured high porosity, but underestimated effective permeability, providing pessimistic estimates of producibility. Because high porosity and low permeability of interbedded shale and shaly sandstones did not affect NMR measurements, oil production and low water cut were best estimated based on the NMR. Successful demonstration of the use of high-angle wells along the fan margins could increase Yowlumne field reserves by as much as 8.3 MMBO (Niemeyer, 1996).

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Chevron USA Inc.—Buena Vista Hills Field, California (Reservoir Class III): Mike Morea and Tom Zalan

(See Chapter 3 for a complete project overview.) Chevron's project at Buena Vista Hills field in the San Joaquin Basin of California represents the first comprehensive reservoir characterization of Monterey Formation siliceous shales (Figure 3.26). The scope of the project is to use advanced reservoir characterization, involving log and core analysis, seismic, and reservoir modeling, to determine the technical feasibility of implementing a CO_2 enhanced recovery project. The Antelope Shale of the Monterey Formation in the San Joaquin Valley contains an estimated 7 billion bbl of oil-in-place (Toronyi, 1998). Determining appropriate reservoir characteristics and recovery options are important for successful field development.

The Antelope Shale presents a challenge to conventional wireline logging tools and interpretations. The reservoir rock is composed of diagenetically altered silica shells of fossil diatoms, a planktonic plant that thrived in coastal waters in the Miocene Epoch. It has a very high porosity, but such low permeability that the reservoir must be naturally or hydraulically fractured to produce at economic rates. A wide variety of downhole tools have been run to attempt to answer questions about how the reservoir produces and how it would react to enhanced recovery processes. It is unknown how to accurately determine "sweet spots" from log or core data for limited interval completion. It is also unknown how fractures or formation damage affect current production. A working reservoir model will enable producers to drill, complete, and stimulate wells to maximize production at the lowest cost.

Core analysis of 950 core plugs taken from the interbedded sandstone and siliceous shales (Figure 3.27) was completed for determining porosity, permeability, and oil saturation. Core porosity was compared with porosity measurements from three advanced open-hole logs, Accelerator Porosity Sonde (APS), Dipole Sonic Imager (DSI), and Combinable Magnetic Resonance (CMR). A complication for traditional log analysis is that formation matrix density is lower than that normally encountered in sandstones. For typical siliceous shale well core analysis, matrix density clusters in the range from 2.20 to 2.40 g/cc. The lower density skews the porosity derived from conventional density logs when the matrix density is set at the standard 2.65 g/cc for sandstones.

In the Antelope Shale, porosity exists in three generalized void forms: matrix microporosity, molds, and fractures. Micropores represent the greatest void volume, but exhibit highly restricted pore-to-pore connectivity. Moldic pores are volumetrically significant at some depths, and connectivity is dependent on dissolution-enhanced porosity development. These two porosity types are measurable using the advanced logging tools. Effective fracture porosity is commonly concentrated along previously healed cracks or small faults. Apertures are typically narrow, ranging from less than 2 microns to 40 microns. The sandstones are more fractured than the shale intervals. Thin interbeds of sandstones and shales and small-scale fracture porosity are best observed on the Formation Micro Imager (FMI) log (Figure 3.28).

Permeability was estimated by three different methods: conventional porosity measurements on open hole logs, relative permeability from a Modular Formation Tester (MDT) tool, and measurements from the Combinable Magnetic Resonance (CMR) tool. Because of complex pore structure, the higher porosity siliceous shales have much lower permeability than the sandstones. Standard open-hole, empirically based log porosity to permeability transforms do not reflect actual relationships. Unless open fractures are present, fluid movement will be mainly influenced by imbibition.

NMR Tool

NMR logging appears to be valuable for measuring rock parameters such as porosity, bound fluid, hydrocarbon type, permeability, and residual oil saturation in the Antelope Shale. These measurements used in conjunction with other open-hole data gave a good analysis through zones of varying lithology and lamination thickness. The correlation of core porosity to CMR porosity tended to be quite good over most of the productive section. Residual oil saturation calculated using standard cutoffs on the T_2 distribution was similar to core-observed saturation. Additional nuclear magnetic resonance measurements on core samples in the laboratory are planned to further refine the CMR interpretation.

Knowledge of oil viscosity is important for determining the proper enhanced recovery process. Continuous viscosity measurements were attempted through the use of the CMR log processing. The results suggest that there is a relatively laminated oil column of viscosity ranging from 2 to 10 cp throughout the Antelope Shale. Core flood experiments indicated that in the mixed lithology core, CO_2 flooding produced oil at a relatively constant rate (about 0.6 cc/day). CO_2 flooding also resulted in lower residual oil saturation than that from water flooding.

Sonic and MDT Tools

Rock mechanics were analyzed through the use of conventional open-hole logs as well as the MDT and DSI. Formation anisotropy as a function of depth is calculated from the cross-dipole measurements of the DSI tool. Formation acoustic transit times are slow compared to common siliciclastic rocks. The Antelope Shale appears to have less acoustic attenuation than many siliceous shales seen in the region. Shear wave velocity is moderate, ranging from 180 to 280 microseconds per ft. Young's modulus, Poisson's ratio, and pore pressures calculated from the MDT were used to analyze horizontal stress and static rock properties during the planning and simulation of hydraulic fracturing.

Fracture analysis was performed through analysis of the Formation Micro Imager (FMI) data (discussed in Chapter 3). These data added geologic knowledge about deposition; structure; and fracture size, frequency, orientation, and aperture. Comparing these data with DSI anisotropy data improved the understanding of tectonic stresses present in the area.

C/O Tool

For determination of current water saturation, Chevron used the Carbon/Oxygen log. In a reevaluated well (Figure 4.2), a recompletion interval from 4,140 ft to 4,260 ft was selected based on the relatively higher oil saturations (20 to 40%) in selected intervals above and below the top of the Antelope Shale. In the 6 months that elapsed between the coring of the well and running the Carbon/Oxygen log, fluids from the undisturbed region around the wellbore probably moved back into the vicinity of the wellbore. Thus the Carbon/Oxygen log more accurately reflects the actual oil saturation than measurements performed on the core, which was subject to flushing by mud filtrate. In previous wells, conventional core analysis indicated that similar zones would be nonproductive.

Mineral Models

Chevron used a mineral-based formation evaluation strategy to identify potential reservoir intervals. This required accurate knowledge of the average compositions and related properties of individual minerals within the reservoir. Validity of the mineral models had to be verified by comparing mineralogical estimates from logs with mineralogical analysis of corresponding core. After core-calibration, the most accurate model could be used in other wells where cores were not available to determine productive zones and facilitate future well completions.

For the Antelope Shale, three mineralogical models were created from advanced logging suite combinations: 1) Schlumberger's Platform Express Triple Combo, Combinable Magnetic Resonance, and Elemental Capture Sonde; 2) Platform Express Triple Combo and Combinable Magnetic Resonance, and 3) Platform Express Triple Combo only. The models consisted primarily of five mineral components: clay, potassium feldspar, detrital quartz, carbonate, and opal-CT phase biogenic silica (i.e., silica of diatomaceous origin). The percentages of each mineral were either determined directly from the tool measurements or estimated based on the percentage of other minerals present. Each suite gave the same type of output, but more local constraints were applied as the logging suites were reduced to fewer logs. This made model 1 more widely applicable, while model 3 was more locally defined.

Mineral model 2, using the Platform Express Triple Combo and the CMR log, agreed best with mineralogical analysis of the core (Figure 4.3). Clay volume was computed from the T_2 mean of the CMR log. Potassium feldspar was estimated as 25% of the clay volume. The volume of detrital quartz was defined as a linear percentage of the clay and feldspar. The CMR total porosity measurement was used in the computation of grain density, which determines the volumes of limestone and dolomite. The volume of opal-CT biogenic silica was computed by dividing the total quartz volume into detrital and biogenic parts. The modeling effort also derived the permeability from the shallow resistivity log, R_{xo}.

In wireline track 3 of Figure 4.3, volume fractions of mineral components from bulk core mineralogical analysis (solid lines) are plotted against mineral model results (dash lines). From the right limit of log track 3 to the right set of solid and dash lines is the volume of quartz + feldspar. From the right set of solid and dash lines to the left set of solid and dash lines is the volume of clay + pyrite + organic matter. From the left set of solid and dash lines to the left limit of log track 3 is the volume of opal-CT. Based on this log, the mineral model accurately represents the actual (core) mineralogy.

The mineralogy from mineral model 3 using only the Platform Express Triple Combo agreed with core mineralogy second best. The mineralogy from mineral model 1 using all three logging strings agreed least well with core mineralogy. The lack of agreement has not been explained, but may have been caused by information from the Elemental Capture Sonde conflicting with information from the Platform Express Triple Combo and/or the CMR.

Mineral model 3 using only the Triple Combo was also applied to a well producing from another siliceous shale reservoir in a nearby field. After calibration of the PEF log, the computed log porosity and oil saturation agreed closely with those from core. This suggests that the models from the Buena Vista Hills field can be applied to other siliceous shale fields in the San Joaquin Valley.

Track 4 of Figure 4.3 shows that R_{xo}-based permeability agrees in character and magnitude with core permeabilities. However, the CMR-derived permeabilities were higher than core permeabilities by one to two orders of magnitude because the standard CMR permeability equation does not apply for siliceous shale reservoirs.

In summary, the benefits of advanced logging tools at Buena Vista Hills have been:

- With a major portion of the permeability attributed to microfractures, the Formation Micro Imager has enabled Chevron to determine open fracture distributions, in addition to detailed core to log depth adjustments.
- NMR porosity has been shown to be an accurate predictor of reservoir porosity in siliceous shales. Since the NMR tool measurements are more lithology independent, it is less affected by the density differences between sandstone and shale than conventional logs.
- Used in combination with other data, the Carbon/Oxygen log and the mineral models were extremely useful in selecting the completion zones in the test well.

- The mineral models developed at Buena Vista Hills can probably be successfully applied to other fractured siliceous shale fields in the San Joaquin Valley.

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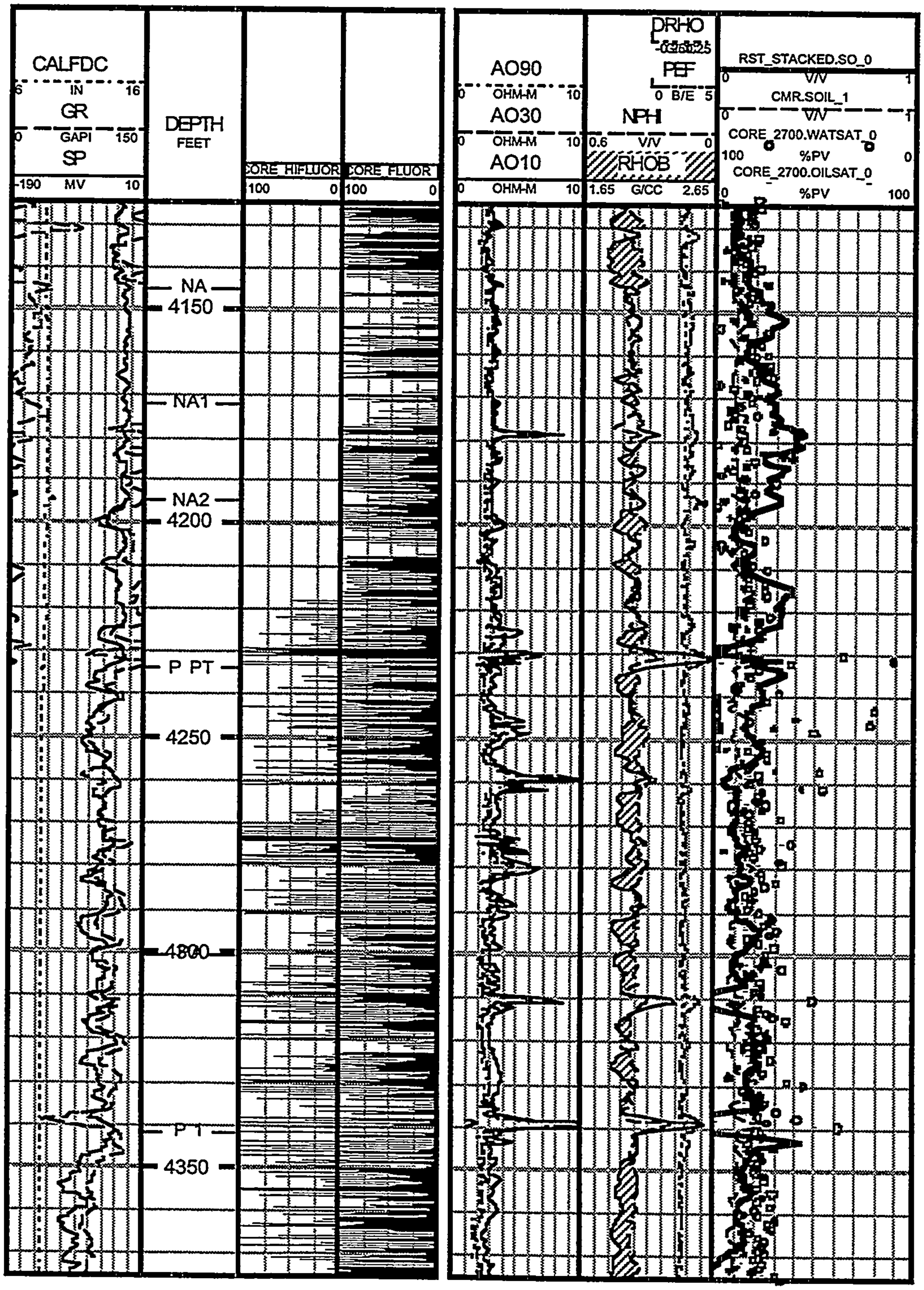

Figure 4.2 – The Carbon/Oxygen log, in the track at the far right, shows consistently higher oil saturations than core in the interval between 4,140 to 4,260 ft. (From Zalan et al., 1998)

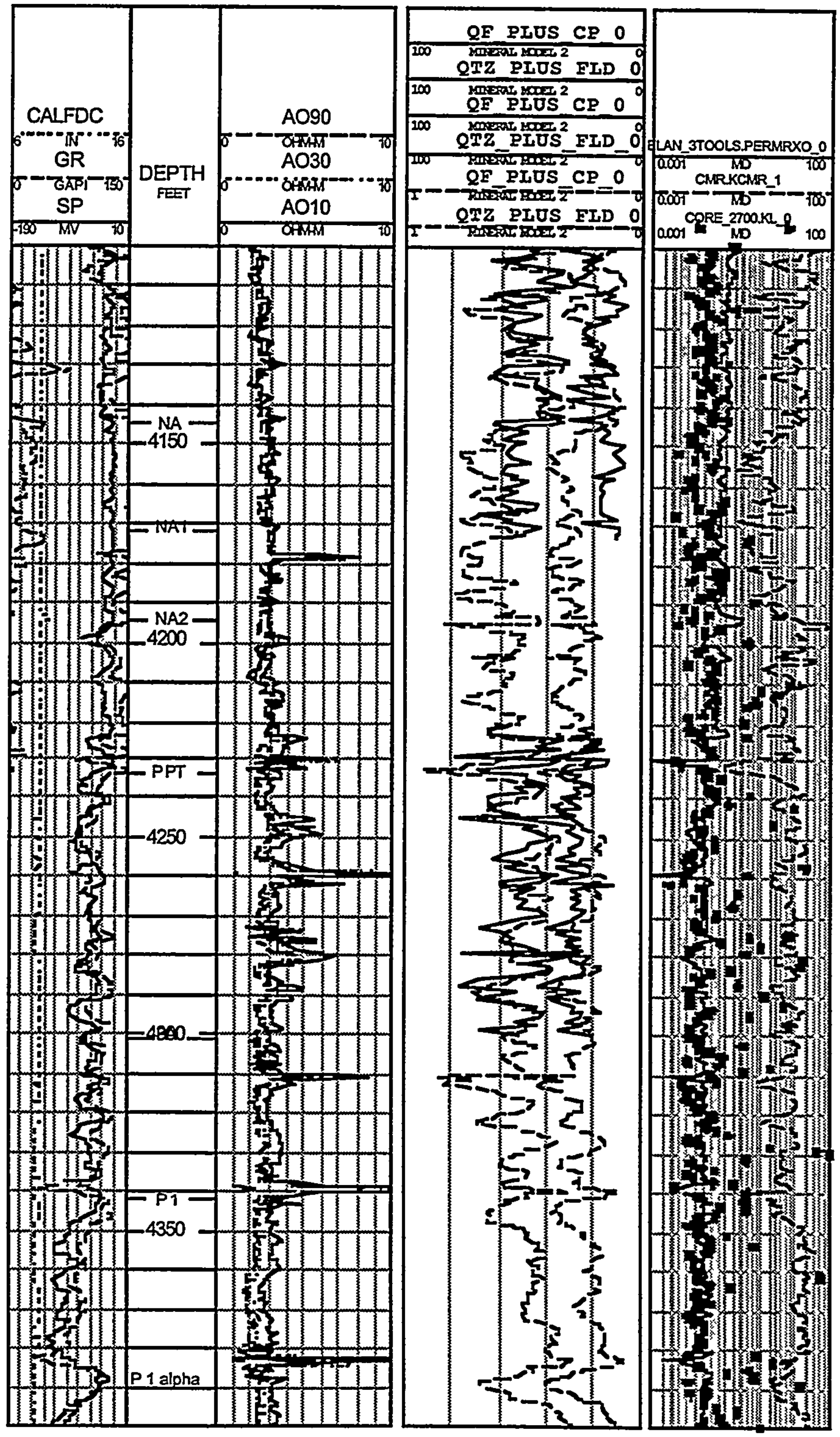

Figure 4.3 – The Schlumberger ELAN mineral model from logs (dashed lines in wireline log track 3) agrees with Chevron core ESTMIN mineralogy (solid lines in track 3); permeability from the shallow resistivity log agrees with core permeability (track 4). (From Zalan et al., 1998)

City of Long Beach—Wilmington Field, California (Reservoir Class III): Scott Walker and Dan Moos

The Wilmington field is located immediately offshore of Long Beach, California (Figure 4.4). The oil-producing structure is a NW-SE trending anticline with several faults separating the field into hydrologically isolated blocks. The producing reservoir is a thick sequence of unconsolidated, clastic slope sediments composed of turbidites. Petrologically, reservoir rocks at Wilmington field are clean arenites separated by layers of sandy clay. Porosities exceed 25% and permeabilities are in the hundreds of millidarcies range. API gravity ranges from 14° in the shallow Tar zone up to 30° in the deeper sections of the field (the Union Pacific, Ford, and 237 zones). Operation of the field, as in the case of many slope and deep basin clastic reservoirs in California, is becoming marginally economic because of the low quality of the produced oil and the strict regulatory environment.

In this project, begun in 1995 in an area of the field delimited by fault blocks and scheduled for completion in 2000, the operator is developing techniques employing advanced logging tools for identification of zones containing bypassed oil for recompletion using techniques such as short-radius and ultra-short-radius laterals. In the Upper Terminal Zone, the intermediate-depth Late Miocene-age zone under investigation for the field test, the oil gravity is 18° to 19° API. This zone has been under waterflood since 1953, and its cumulative production is more than 110 MMSTBO out of an estimated original oil-in-place of 206 MMSTB.

To develop a technique for detecting bypassed oil behind casing, a field test was conducted in a new well, M-499, drilled in the Upper Terminal zone of Fault Block IV, an area previously considered to be watered out. A comprehensive suite of open-hole logs (resistivity, density, gamma-ray, neutron, dielectric, spontaneous potential, and caliper) was run in well M-499 to identify zones with oil saturation greater than 40% for selective completion and to provide a basis for comparison with porosity and saturation measurements from cased-hole acoustic logs. Conventional logs were interpreted for shale content from the gamma ray and for porosity from the density-neutron cross-plot. Water saturation was calculated using Archie's equation with a=1, m=1.8, and n=1.8 based on regression analysis of log and core data from neighboring wells. The measured formation water resistivity for water saturation calculations was 0.311 ohm-m at 72° F. Figure 4.5 shows the log calculated V_{sh}, porosity, and water saturation along with the resistivity and gamma ray log readings. The principal reservoir sands in the Upper Terminal Zone (H_x at 3,120 ft, J at 3,330 ft, and Y at 3,430 ft) and the intervals perforated are also identified.

Acoustic tools such as those run in the M-499 well can record logs in monopole, dipole, and quadrapole modes. By exciting the dipole and the quadrapole modes, shear wave data can be recorded even in very unconsolidated, slow formations where shear-wave transit times could be significantly larger than 200 micro-sec/ft. The high energy and low frequencies employed by these acoustic tools allow recording of acoustic waves with little attenuation, and the logs are suitable for recording in both open holes and cased holes (Chen and Eriksen, 1991; Blangy et al., 1993; Moos et al., 1997). Compressional-wave velocities can be determined from interpretation of monopole waveforms and shear-wave velocities from interpretation of the dipole or quadrapole waveforms.

Dipole and monopole data were recorded (Moos et al., 1995) both before and after the installation of the casing to determine respectively, the shear-wave (dt_s) and the compressional-wave (dt_p) transit times within the formation. The open-hole and the cased-hole data recorded in the M-499 well are compared in Figure 4.6. The shear-wave dt_s values in both cased and open-hole logs are very similar, but for the compressional waves, cased-hole transit times (dt_p) are higher than those for the open-hole case.

Porosity Estimation

In consolidated formations, relationships like the Wyllie time-average equation may be used to determine porosity from compressional wave velocities (Wyllie et al., 1958). In unconsolidated formations like those in the Wilmington field, the Wyllie time-average equation cannot be applied and alternative relationships between porosity and velocity which are appropriate for unconsolidated formations should be used (Moos et al., 1997). Furthermore, compressional wave velocities are sensitive to both porosity and the fluids saturating the rocks. This is particularly true in unconsolidated formations, where compressional wave velocity is most strongly affected by saturation. Shear-wave velocities are relatively unaffected by fluid content and consequently provide a better measure of porosity in these types of formations.

From observations in unconsolidated formations in other fields, it is believed that the shear-wave transit times are controlled both by the shale content as well as the porosity of the rock. In the Wilmington Field, the relationship between porosity, shale content, and the transit times was modeled by assuming that the porosity was directly proportional to the shale content and inversely proportional to the shear-wave transit times. This empirical field relationship was used to compute porosity from the shear-wave transit time data. Porosities computed from the cased-hole dipole shear-wave logs were compared with total porosity calculated from open-hole density and neutron logs (Figure 4.7). The shear-wave-derived porosity shows fair agreement with the total porosity, indicating that the shear-wave tool may be viable for determining porosity in unconsolidated formations.

Saturation Estimation

Pore fluid saturation varies over a large range in the Wilmington field. The success of the acoustic tool to measure saturation variations in cased-holes was expected to be strongly dependent upon the amount of velocity change attributable to fluid saturation changes. Consequently, in the computation of the fluid bulk modulus, the effect of variations in fluid saturation on the pore fluid compliance had to be taken into account (see Batzle and Wang, 1992 for a discussion of the compliance of reservoir fluids). Based on average mineralogy determined from grain counts, the bulk rock modulus was computed for representative rock containing approximately 40% quartz and 60% feldspar. The fluid and rock bulk moduli were then used to compute the bulk modulus of the fluid-saturated rock (Gassmann, 1951).

Computations were made for representative reservoir crudes, for brine, and for the limiting cases when the rock is 100% and 0% saturated with gas. Laboratory acoustic measurements using representative crudes and other reservoir fluids revealed the following:

- Drastic decrease in compressional wave velocity and in the compressional to shear-wave velocity ratio was observed for both 14° and 24° API crudes with depth. The compressional velocity change was equally drastic for both the 14° and 24° API oil. The corresponding change for brine was negligible.
- The compressional wave velocity change was more pronounced with increase in gas saturation.
- The ratio of the compressional to shear-wave velocities computed for brine- and oil-saturated sands showed that as shear-wave transit time decreases, the ratio of compressional to shear-wave velocities also decreases. There is a sharper drop in the velocity ratio as the gas saturation increases, and the ratio reaches very low values when the rock is entirely gas saturated. The velocity ratio hardly changes when the saturate is brine, indicating that it should be fairly easy to discriminate between oil and brine.

For a given rock and crude, the acoustic log hydrocarbon indicator (ALHI) (Williams, 1990) is a measure of the difference between the measured V_P/V_S ratio and that predicted for a water-saturated rock from the shear-wave velocity (dt_s). A cross-plot of V_P/V_S vs. the shear-wave transit times recorded behind the cased hole over the interval from 3,120 to 3,540 ft at well M-499 is shown in Figure 4.8. The ALHI lines for shales and sandstones, which show the velocity ratios and transit times for 100% water saturated rocks, are also plotted on the figure. Points falling below the ALHI lines have hydrocarbon saturation. Saturation estimates from the acoustic logs can be based on normalized distance of the points below the 100% water line. Scatter in the data reflects lithologic variations in the properties of the rock itself.

Figure 4.9 compares the oil saturation distributions obtained from calculations made from the open-hole logs using Archie's equation and the distributions from cased-hole acoustic logs using the ALHI method. The following observations can be made from the plot:

- Zones with high oil saturation identified from open-hole log interpretations and selected for perforation were also detected using the acoustic logs.
- Several unperforated zones with high oil saturations are indicated on both the open-hole as well as the cased-hole logs.

Shaly zones (gamma ray above 90 API) and zones with shear wave porosity below 19% have been discarded for the plot of Figure 4.9. There is a generally good agreement of oil saturation distributions in the Upper Terminal zone obtained from open- and cased-hole logs. However, a few zones with high oil saturation in acoustic logs, but poor or low saturation on the conventional logs, may be rejected for completion on the basis of geological constraints and production information. A second data set recorded in an injection well is clearly differentiated based on the ALHI plot from the intervals in M–499 with high oil saturation.

Production tests were conducted treating well M–499 as if it were a recompletion of an existing well. Three sands (H_x, J, and Y) were perforated through cemented casing using five 0.5-inch holes per foot. The net production rate of well M–499 was the highest, and its water-oil ratio was the lowest compared to nine wells in the vicinity. This result was especially encouraging, considering that well M–499 was located quite close to the injectors in the down dip part of the structure.

In summary, the field test of the multi-pole acoustic logs conducted in the Wilmington field showed that the acoustic logs could provide reliable estimates of formation porosity and oil saturation behind steel casing in unconsolidated sediments, provided precautions are taken to acquire reliable data. Good porosity values were computed from shear-wave data in cased wells using an empirical relationship between porosity, shear-wave transit time, and shale content. The porosity data agree well with interpretations of open-hole density-neutron logs. Oil-saturated zones identified behind casing in well M–499 agree fairly well with those identified from open-hole log interpretations.

This Reservoir Class III project has spun off a Small Business Innovative Research (SBIR) project funded by DOE to improve the ability to quantify saturations with this method and to generalize the method for application to a wider range of reservoirs (Moos and Zwart, 1998).

Recoverable reserves in just two fault blocks addressed in the current project are expected to increase by as much as 5.3 MMBO. Extending the techniques developed in this project to the remainder of the Wilmington field could result in 28 MMBO of additional reserves. Other slope-basin and basin clastic reservoirs in the Los Angeles basin and southern California coastal region might realize over 700 MMBO of additional reserves by implementing these techniques.

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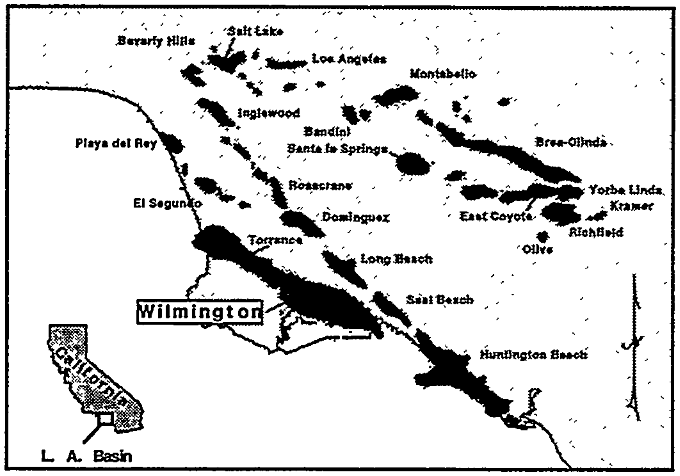

Figure 4.4 – Location map of the Wilmington field in the Los Angeles Basin. (From Moos et al., 1996)

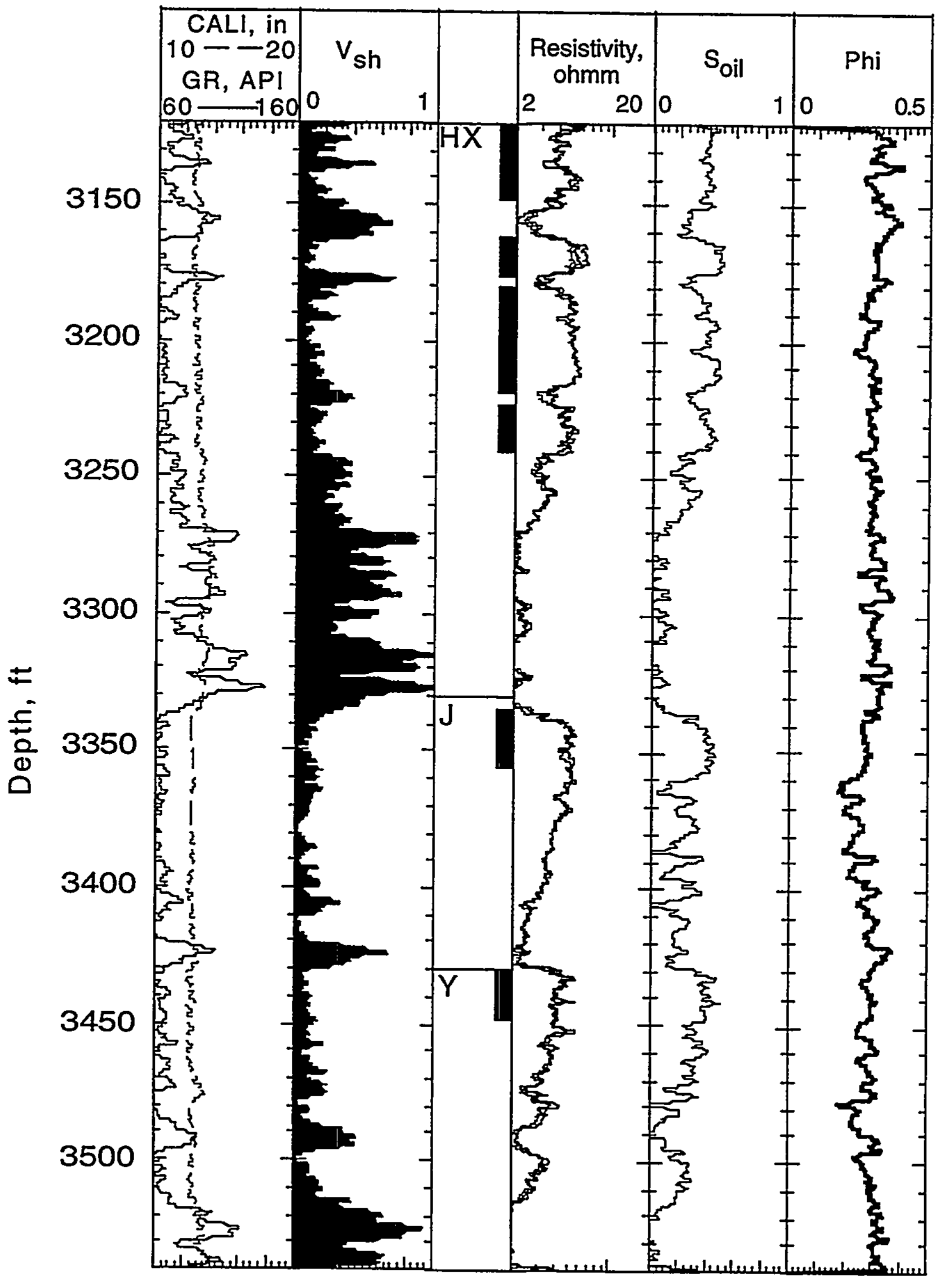

Figure 4.5 – Composite of conventional log data for well M-499 with calculated water saturation, porosity, and volume of shale. (From Moos et al., 1995)

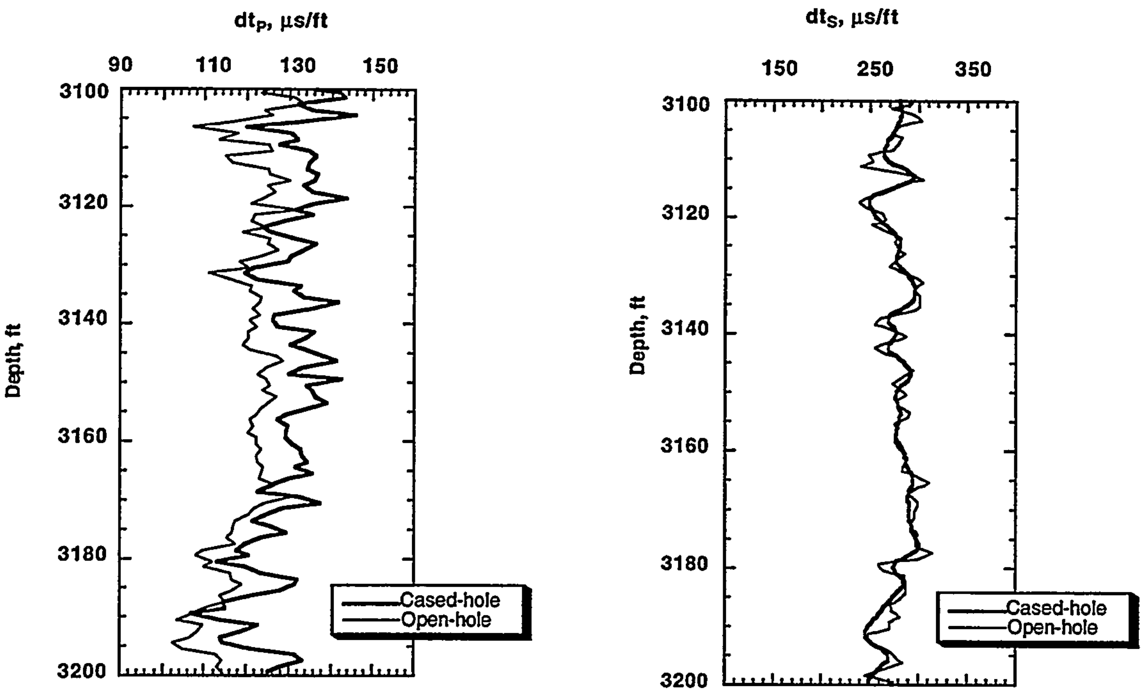

Figure 4.6 – Comparison of P-wave and S-wave sonic responses in cased vs. uncased hole in the M-499 well. (From Moos et al., 1995)

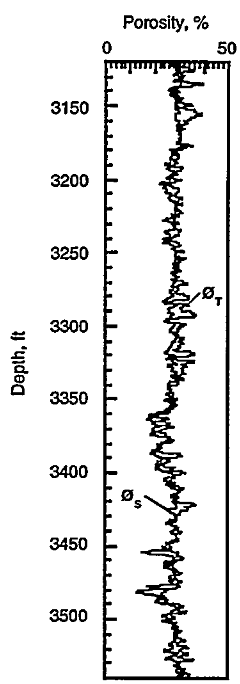

Figure 4.7 – Comparison of cased-hole sonic porosity (Φ_S) and open-hole density-neutron total porosity (Φ_T) in the M-499 well. (From Moos et al., 1995)

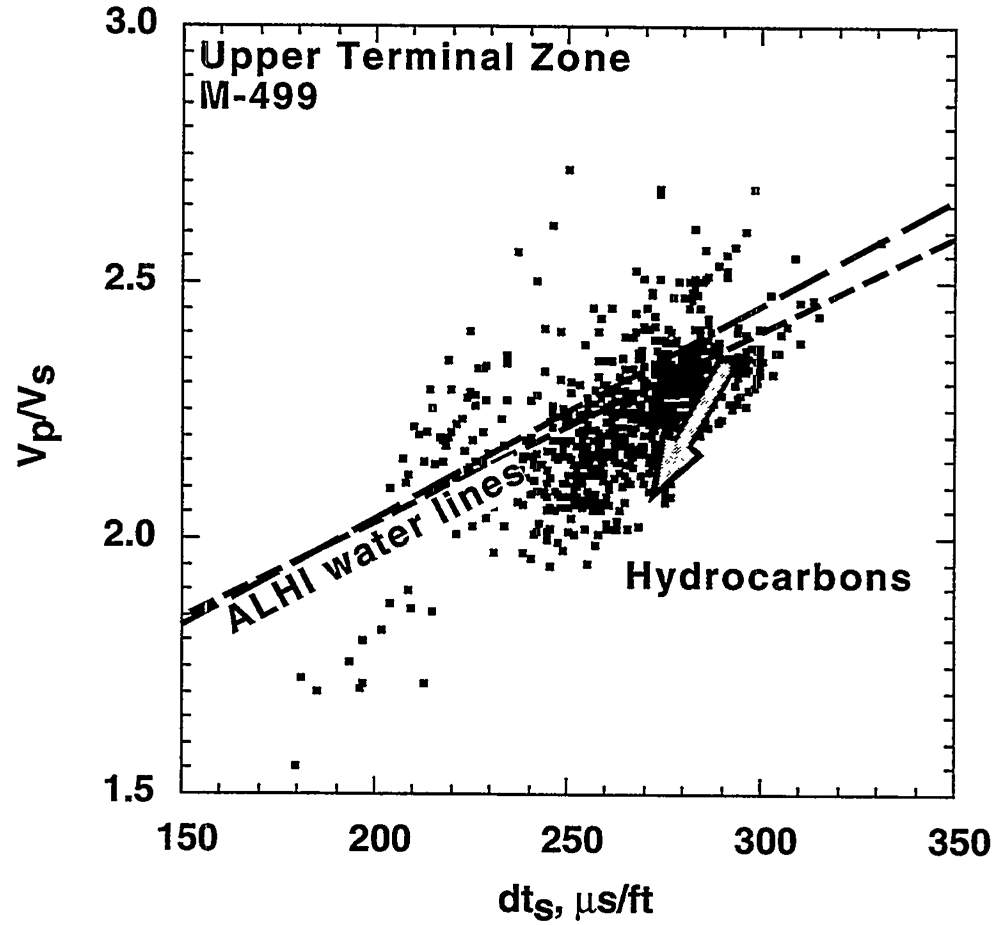

Figure 4.8 – Cross plot of V_p/V_s vs. dt_s showing the ALHI water lines of Williams; plotted data are from the Upper Terminal zone of the M-499 well. (From Moos et al., 1995)

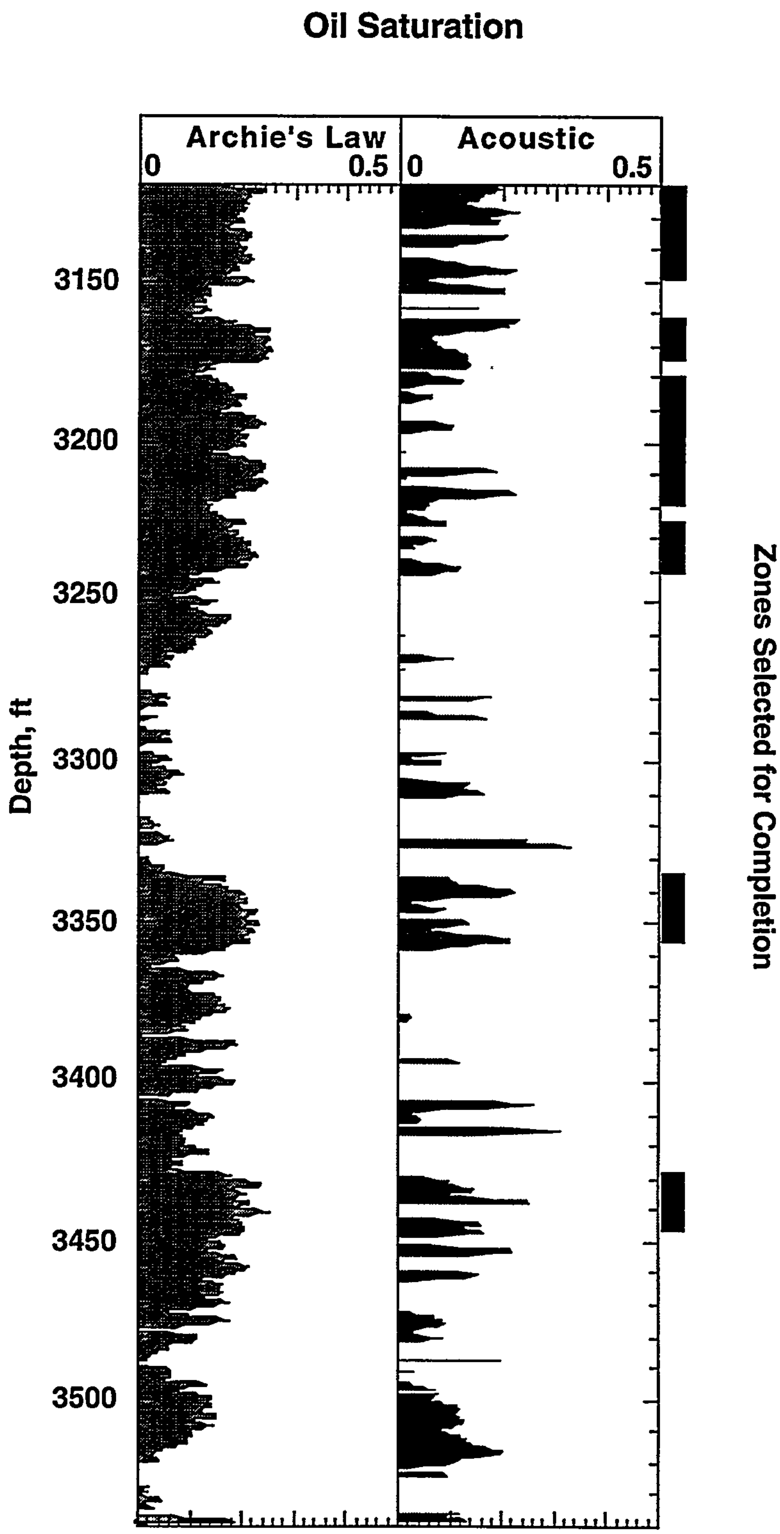

Figure 4.9 – Oil saturation predictions based on Archie's law and on sonic data for the M-499 well; also shown are the intervals selected for completion based on Archie's law analysis. (From Moos et al., 1995)

Strata Production Company—Nash Draw Pool, Texas (Reservoir Class III): Bruce Stubbs

(See Chapter 2 for a complete project overview.) At Strata's Class III field demonstration project in the Nash Draw unit in the Permian Basin of Southeast New Mexico (Figure 2.20), the basic problem is low recovery typically observed in similar slope and basin clastic reservoirs. Objectives of the project are to demonstrate how advanced reservoir characterization and reservoir management techniques can significantly improve oil recovery (Stubbs, 1998). Early in the project, it became evident that accurate methods for predicting the distribution of remaining oil saturation, estimating original oil-in-place, measuring productivity, and optimizing completions were necessary. The methods would have to be developed using existing core and gamma ray, neutron, density, and resistivity logs (Stubbs, 1997). A core-calibrated log analysis procedure, called Advanced Log Analysis (ALA), was developed by the operator and is discussed in Chapter 2. A nuclear magnetic resonance (NMR) tool and a digital array sonic tool were also run in an infill well to provide additional reservoir data and improve completion design. Enhanced recovery options including waterflood, lean gas or CO_2 injection, and horizontal wells are being considered to optimize production performance.

The Nash Draw unit produces from the Permian Delaware Mountain Group (Brushy Canyon and Cherry Canyon members) from 14 separate sandstones (Figure 2.22) deposited as part of a submarine fan/channel complex in a 4,000-ft sequence. Depositional strike is generally north/northeast-south/southwest with productive sandstones draping over subtle structural noses and/or closures. Post-depositional compaction may play a part in the trapping mechanism. Lateral variations in porosity and permeability limit the extent of the reservoirs and provide the stratigraphic components of the traps. Average net pay thickness of the reservoir sandstones is 90 ft with porosity ranging from 12 to 20% and permeability ranging from 0.5 to 18 md. The most prolific production comes from the basal sandstones of the Brushy Canyon Member.

Six new wells were drilled in the Nash Draw unit for reservoir characterization and stimulation studies of the producing reservoirs. Multiple sidewall cores and a whole core were obtained for laboratory analysis. The 203-ft whole core was analyzed for porosity, permeability, oil and water saturation, grain density, and presence of oil shows. The core data were used to prepare a transform to correct the log density-neutron cross-plot to yield a true porosity (Figure 2.23). The permeability of each zone was calculated by performing regression analysis of log porosity and core permeability. These data were used to calibrate the logs, identify high residual oil saturation zones, and determine the productivity of each interval.

NMR Tool

A nuclear magnetic resonance (NMR) tool was run in a new well to provide additional data on permeability, porosity, and residual oil saturation. The results were compared to other wireline logs and whole core analysis. The NMR tool was 80 to 90% accurate in predicting potential oil productive zones, and approximately 90% accurate in predicting permeability, even for beds approaching a half-foot in thickness. While this is a potentially useful method for predicting permeability in noncored wells, it provided only marginal improvement in identifying additional oil zones beyond those identified by the core-log modeling (ALA procedure). Based on the cost of running and interpreting the NMR log, the ALA procedure was believed to be just as accurate in predicting oil productive zones at a much smaller incremental cost per well. Strata does not plan to run an NMR tool in other infill wells.

Digital Array Sonic Tool

Well No. 29 in the Nash Draw Pool was drilled in May 1997 to confirm a seismic anomaly. The high seismic amplitude of the Brushy Canyon "L" zone (see Figure 2.22 for zone definition) was selectively perforated and acidized from 6,825 ft to 6,870 ft with 23 perforations. The perforations were "balled" out to ensure all were open and taking fluid. Results of the acid treatment indicated good fluid entry with a 30% oil cut and a good show of gas.

The Digital Array Sonic tool was used to assist in hydraulic fracture design for the well. Mechanical rock properties derived from the log consisted of Young's Modulus, Poisson's Ratio, and the fracture gradient. A fracture pressure log was calculated at half-foot depth intervals and is shown in the right column in Figure 4.10. This frac log indicates barriers at the shale-lime sequence on the top of the Bone Spring at 6,890 ft and in the upper "K" zone at 6,740 ft or 6,690 ft. This indicates a potential gross frac height ranging from 140 to 200 ft.

The fracture stimulation was designed for 216.5 ft of height and 360.5 ft of propped fracture half-length. (If the actual height reached was only 140 ft, the length would be approximately 400 ft). The zone was fractured with 65,000 gallons of 35 lb/1000 gal crosslinked gelled water carrying 216,880 lb of 16/30 sand at an average rate of 14.5 bbl/min.

Temperature logs were run at three, four, and six hours after the fracturing treatment to determine fluid entry. The temperature logs indicated that the majority of the fracturing treatment was confined within the 115-ft interval from 6,745 ft to 6,860 ft. There was an indication of greater cooling and large volumes of fluid entry from 6,750 ft to 6,810 ft. The temperature logs confirmed that the lower "K", "K-2" and "L" zones were stimulated by the fracturing treatment. Subsequent production tests indicated that fluid production rates were similar to expectations.

In summary, the magnetic resonance imaging log compared well with results obtained from core-log modeling techniques. It accurately predicted permeability, and confirmed the presence of pay intervals. The information provided by the Digital Array Sonic log used for hydraulic fracture stimulation design was fairly accurate. The gross fracture height of 140–200 ft predicted by the sonic log data was close to the predominant fluid entry interval of 115 ft indicated by the temperature log. There were zones of greater fluid entry within the main treated interval, also identified by the fracture pressure gradient plot.

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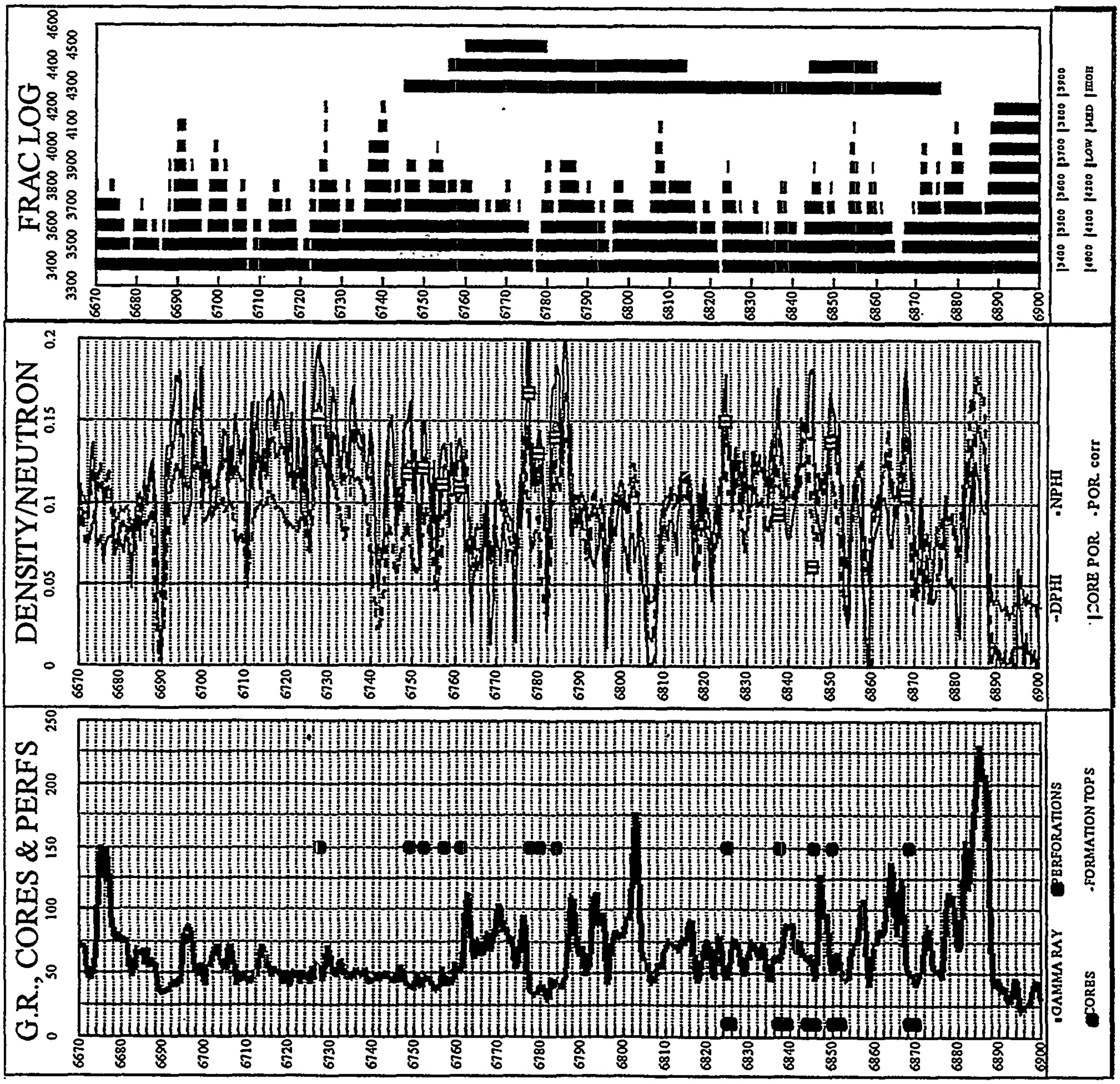

Figure 4.10 – The fracture pressure log generated from digital array sonic data for Nash Draw Pool well No. 29. (From Stubbs, 1997)

Summary of the Use of Advanced Logging Tools

A wide variety of advanced logging tools are available for direct measurement of reservoir properties. Although conventional tools can measure many of the same common reservoir properties (e.g., porosity, rock composition, fluid saturation, etc.); advanced tools may measure those properties under conditions unsuited for conventional logging or may measure entirely different rock and fluid properties. The focus of advanced tools (not including borehole imaging tools, which are discussed in chapter 3) employed in the Reservoir Class Program projects has been on targeting remaining recoverable oil in existing (cased-hole) wells or in newly drilled infill wells. The tools used are those that have strengths in determination of the types, amounts, and distribution of fluids in the subsurface. Specific questions being addressed by the tools are:

- Types, amounts, and distribution of porosity
- Types and amounts of liquid/gaseous hydrocarbons
- Types and amounts of other fluids
- Mobility of hydrocarbons vs. other fluids (i.e., permeability and relative permeability)
- Mechanical properties of rocks and fluids

Many of the advanced logging tools can also provide detailed information on fluid and rock properties at different times in the life of a well at minimal additional cost.

Different advanced tools also measure reservoir properties at different scales. Some tools measure only small volumes of the formation surrounding the wellbore and may provide good vertical resolution and accurate measurements of borehole effects, but do not measure any significant depth into the formation beyond the flushed zone. Other tools with greater depth of penetration into the formation may not provide vertical resolution to accurately measure separate thin beds, but can measure reservoir properties undisturbed by drilling fluids at a distance from the wellbore.

The rapidly spreading popularity of NMR tools is strongly reflected in the variety and number of their applications in the Reservoir Class Program projects. NMR tools were successfully employed to gain a more accurate representation of recoverable oil than was available from conventional logs in reservoirs from all three Reservoir Classes. In more than one instance these tools identified subsequently recovered reserves that would have been overlooked using only conventional logs. Sonic tools played a substantial role in identifying bypassed oil and in designing effective fracture stimulation.

In every application, advanced tools were not called in as "black box" solutions to improved recovery. The selection of these specialized tools for use and the design of their application parameters were governed by previous knowledge of the reservoir gained from other sources.

Analysis of rock and fluid samples obtained from the reservoir played a major role in understanding and calibrating advanced tool response, as did careful comparison with the responses of conventional logging tools. The potential benefits of current advanced logging tools and the positive results obtained in many of the Reservoir Class Program projects may convince operators of the cost-effectiveness of many of the advanced tools. An important realization for operators is that the advanced logging tools discussed are not meant to replace, but instead complement, conventional logging tools under typical applications and reservoir conditions.

CHAPTER 5

THE STATUS OF LOGGING TECHNOLOGIES: WHAT NEXT?

The use of wireline logging is entering a new era in the domestic and international petroleum industry. The characteristics of this new era are amply reflected in the research, development, and demonstration projects supported and cost-shared by DOE in its National Oil Program. A very large portion of the remaining U.S. domestic oil resource is found in geologically complex reservoirs in a mature to super-mature state of development. Fluvial-dominated deltaic reservoirs, shallow shelf carbonate reservoirs, and slope-basin and deep-basin clastic reservoirs (i.e., the reservoirs being focused on in Classes I, II, and III of DOE's Reservoir Class Program) alone contain more than 50% of the remaining oil in place in domestic reservoirs in DOE's Total Oil Recovery Information System (TORIS) database. In these reservoirs, however, the continued operation of both individual wells and entire reservoirs is threatened by marginally economic conditions resulting from low production rates and high operating costs. Economically recovering the huge remaining oil target in these geologically complex reservoirs requires a more complete and more accurate understanding of their architecture, diagenesis, structure, petrophysical properties, fluid distribution, and rock-fluid interactions than has ever been needed before. Accurate models on the scale of every well and even on an interwell scale incorporating all these reservoir aspects are necessary to target, contact, and retrieve remaining oil.

Fortunately, this need for advanced reservoir description and understanding comes at a time when the ability to extract and use the tremendous amount of information contained in wireline logs representing almost every wellbore also is maturing. Computer hardware and software capabilities now make possible complex, fieldwide analysis of wireline data to create uniform reservoir models for input to reservoir decision making. Some advanced tool applications such as borehole imaging have only been made possible by increased computing capabilities. An additional advantage to the small-to-medium independent operators who are increasingly becoming operators of aging reservoirs with low profit margins is that many of the voluminous data-processing tasks associated with complex, field-wide wireline log analysis can now be performed on personal computers. Just a few years ago these tasks required mainframe computers. The advancement in tandem of computing capabilities and logging technologies has been notable. Continuation of this trend will probably play the major role in defining wireline logging applications in the future.

This chapter discusses (1) the demonstrated general utility of the logging technologies reviewed as applied in DOE programs, (2) the integration of information provided by wireline technologies with information provided by other data sources to perform reservoir characterization, (3) the challenges that are faced in designing optimum logging technology applications on both reservoir-wide and single-well scales, and (4) current tool development research and future RD&D opportunities related to logging technologies.

Utility of Logging Technologies Applied in the Projects Reviewed

In the preceding chapters, discussion of advanced logging techniques was divided into three parts for individual treatment: core-log modeling, borehole imaging, and advanced tools. This division was made primarily for convenience of discussion of technologies that were prominent in Reservoir Class Program and other DOE field demonstration projects and was not meant to suggest that these are the only, or even the most meaningful, divisions under which to consider the status of wireline logging. Many projects have used all three aspects in their reservoir description and evaluation. The selection of logging technologies employed by the operators has been a function of the type of information identified as necessary in each reservoir management situation.

Core-Log Modeling

Core-log modeling is perhaps the most intriguing of the three divisions from the point of view of both potential and underutilization. These techniques made major contributions to reservoir description in a number of Reservoir Class Program projects, but generally have not been identified as advanced logging technologies.

In the projects reviewed, several situations led to development of core-log models for reservoir description. Most commonly, special consideration began when a single, accurate, and simple predictive mathematical relationship could not be established between porosity and permeability as measured in reservoir cores. Additional common incentives for developing core-log models were a complete or near absence of wireline logs for measuring a critical reservoir parameter such as porosity, or when existing logs for one reason or another did not measure a property with the desired accuracy (e.g., resistivity measurement for calculation of accurate fluid saturations in thin beds). The spectrum of approaches observed was wide.

Each application was custom-designed around the information available as well as the information needed. In some cases, the approach was as straightforward (though this does not necessarily imply simple) as calibration of "old" logs against core data or against modern logs. In cases where complex pore systems were present and permeability distribution was the object of prediction, as in the shallow shelf carbonate systems dealt with in the Fina and Oxy projects, the calibration process involved several facets including detailed pore system analysis and laboratory analysis of fluid-flow characteristics.

The potential of advanced core-log modeling as a reservoir descriptive tool hinges on its cost-effectiveness. Using these techniques, a well-constrained 3-D petrophysical model of the reservoir can result with virtually no gathering of new data from the reservoir in many cases. Investment in core-log models is mainly labor-intensive in analysis of digital log data and description/measurement of pore system characteristics.

Core-log modeling techniques, given their cost-effective potential for detailed and consistent reservoir description appear to be underused by industry as a whole, probably because of the relatively recent appearance and widespread availability of computer hardware and software for performing these analyses. Inexperience coupled with a lack of recognition because these are *techniques* rather than a physical tool also is a contributor to underuse.

Borehole Imaging

Borehole imaging is a newly evolved group of technologies (of video, acoustic, and resistivity types) whose full potential probably has also yet to be realized, but as demonstrated in the DOE-supported and cost-shared projects reviewed, these tools are being investigated with enthusiasm on all fronts: onshore and offshore, in vertical and horizontal wells, and in both siliciclastic and carbonate rocks. Borehole imagers bring primary strengths to the logging arsenal: high resolution and the ability to detect not only the presence but also the orientation of discontinuities. Imaging tools also have the unique characteristic of providing information on a scale larger than the scale of actual measurement (i.e., sedimentary structures and the orientation of surfaces separating sediment packages often provide, by analogy with known depositional models, information on interwell- and reservoir-scale architecture).

High resolution characterizes all three imaging tool types, but it has proved exceptionally useful in resistivity imagers, which can quickly allow evaluation of fluid saturations in thin beds. This feature has proven very valuable for identifying or confirming of thin bypassed pay intervals in clastic reservoirs of Class I and Class III.

The advantage of borehole images (i.e., acoustic and resistivity images) over cores is related to the information needed and the reservoir's characteristics. Certain types of sedimentary information, especially information at a small scale approaching pore size, are better obtained by coring. If property contrasts permit quality imaging, slightly larger features, such as sedimentary structures in siliciclastic rocks, may be more accurately analyzed in terms of their full information content by borehole imaging. In thin reservoirs at shallow depth, oriented core may have a cost advantage over imaging in many instances, but the economies of scale of borehole imagers are realized in thick reservoirs at greater depth where the cost of obtaining comprehensive descriptive coverage by coring becomes prohibitive. Also note that as borehole-imaging tools have been applied with increasing frequency, the cost per application has decreased dramatically. This trend will probably continue as their application and interpretation become yet more common and efficient.

Advanced Tools

New tools to measure desired reservoir properties are constantly developed. Many operators in the past, perhaps because of their lack of knowledge of the types and capabilities of tools available, have been reluctant to try advanced logging tools. Operators were then, as now, concerned about the cost benefits of additional logging runs and the extra interpretation time often necessary for meaningful results. Repeated failures of early tool designs may have convinced operators that such advanced tools were not required to effectively characterize the reservoir. Applications of advanced tools such as those observed in the Reservoir Class Program projects are demonstrating that many new tools have a substantial contribution to make to reservoir understanding if care is taken to select the proper tools and implement them properly. The projects reviewed clearly convey the message, however, that no tool constitutes the "magic bullet" that unravels all reservoir problems or opportunities single-handedly. It is the integration of advanced logging tools with conventional logging tools and other sources of information in these projects that is demonstrating impressive capabilities to solve specific reservoir characterization problems.

Enhanced resolution of thin sandstones is made possible by developing tools such as the microresistivity imager, the modular formation tester, and the new array induction tool. Electromagnetic propagation and nuclear magnetic resonance tools are capable of measuring fluid composition and saturations, bound water in clays, and pore structures near the borehole. Spectroscopy tools have been developed to provide detailed rock compositions for mineralogical modeling. High-resolution microresistivity imaging and acoustic logging techniques allow identification of fractures and depositional heterogeneities at the scale of sedimentary structures. Realizing what the advanced logging tools cannot yet do is almost as important as learning what they can do. Even in the laboratory, measurements of other parameters are made on core samples, and the Darcy equation is used to calculate the permeability of a sample. Neither can advanced wireline tools measure producibility, either oil-water ratio or absolute flow rate, directly; although the NMR tools offer some hope along these lines.

Integrating Wireline Logging and Other Information Sources

For each of the logging technology applications in DOE's Field Demonstration Program and related projects summarized in this volume, project operators were asked to provide comments on the general utility of the technology to the project and to quantify its contribution to the project's success (or lack of success). Although a few situations were encountered where a particular technology was judged to be not as cost-effective as alternative methods for obtaining the same or similar information, or a technology did not perform technically as well as expected or hoped, in most instances project operators were unable to quantify precisely the contribution made by the logging technologies in terms of bbls of incremental oil or incremental dollars.

The reason for this inability is that in most projects information from logging technologies has been highly integrated with information from other sources such as seismic, well tests, production/injection data, outcrop analog data, etc. This high degree of integration produced a single model of the reservoir (often incorporating uncertainty expressed through application of geostatistics) that was subsequently used for reservoir decision making through simulation. The production and economic results of implementing those decisions could not be accurately apportioned back to the individual technologies' contributions.

Optimum Design of Logging Technology Applications

Observing the problems encountered, the solutions offered, and the resulting consequences in numerous DOE projects executed in domestic reservoirs that are for the most part in the mature to super-mature stage of their development, led to several conclusions related to the optimal design of reservoir logging programs. Omissions, flaws, and inconsistencies that were inconsequential over the past history of exploiting these reservoirs later became critical information shortcomings at a time when detailed reservoir knowledge was a necessity to maintain production and profitability.

"Routine" or Reservoir-Wide Logging Suites

By negative example, aging domestic reservoirs emphasize the importance of designing early in the reservoir's life optimum logging suites that have a long-term outlook on reservoir descriptive needs. Ideally, collection of adequate rock and fluid samples from the reservoir at the outset of development will help define the nature of reservoir heterogeneities that need to be measured and modeled (e.g., petrophysical properties such as porosity and permeability, presence of fractures, sedimentary features such as sedimentary structures or thin bedding). Such knowledge will guide the selection of logging tool types, tool configurations, and borehole conditions to optimally recognize and measure those heterogeneities that critically affect fluid-flow in the subsurface. Maintaining application of the same suite of logs in every well as the field develops allows for accurate reservoir modeling and process recovery prediction throughout the life of the reservoir.

In the ideally managed reservoir, inconsistencies would be further minimized at the time of collecting log data in each well by using the same logging tools whenever possible, by empirically calibrating the tools frequently, by making multiple logging runs at optimum speeds in each borehole to reduce error, and by optimizing and homogenizing the borehole environments under which the tools are run. Core-log models based on wireline logs run under these conditions will have much lower associated uncertainty when used to predict reservoir parameters.

In existing reservoirs, ideal circumstances are seldom encountered. In these reservoirs it is important to establish consistency and quality control as described in the previous paragraphs for all re-drill, extension, and infill wells, but operators have shown that there are additional techniques that can help to alleviate information deficiencies and attain acceptable reservoir description. Many have taken special data processing pains to minimize the effects of inconsistencies introduced by using different log suites, different logging tools (often run by different logging companies), and highly variable borehole conditions in the reservoirs they are describing. Running cased-hole logs in older wells and comparing their responses to open-hole logs run in newer wells has proven to be an effective way to tie information from old wells into newly developing models. Other techniques that have been employed include new log analysis techniques to squeeze more information from "old" logs, combining and comparing "old" log data with core data and with other subsurface information, and calibrating "old" logs against new cased-hole logs run in the same wells or against newer logs run in nearby wells.

Special-Purpose Tools Run to Gather Specific Information

Special-purpose tools, which includes most of the tools discussed in Chapters 3 and 4 under borehole imaging and advanced tools, are those that are run by operators seeking to gather reservoir information that is not currently available either from existing reservoir sample data (e.g., cores, cuttings, fluid samples) or from existing or routinely-run wireline logs. This information is usually gathered to fill gaps in knowledge about reservoir characteristics that are expected to have significant influence on the reservoir model, which will in turn be used to predict reservoir performance. The tools are selected based on the specific information needed in the reservoir management context of the project and are generally not run on a large number of wells.

The need for the special kinds of information provided by these tools is just now becoming apparent as operators take on the task of highly detailed characterization of the reservoirs of Classes I, II, and III in an attempt to recover elusive remaining oil in place. The complexity of the models needed is greater than ever before, and even for many of the technologically sophisticated operators involved in these projects, use of many advanced logging tools is somewhat experimental at this point. Technologies are being investigated to evaluate their capabilities in cost-effectively providing critical information as more and more reservoirs require more detailed, accurate, and complete information for additional economic recovery. As an industry, we are just beginning to learn about optimal selection and implementation of these tools to provide the answers needed.

Many of the design considerations discussed for conventional logging on a reservoir-wide basis apply to special-purpose tools as well. Specifically, it is always important to understand the reservoir context under which the tools are run. This generally entails a review of conventional logs along with all other available reservoir-descriptive information to establish the features of the reservoir model against which the special tool response will be interpreted. Of great importance, and a common theme in the successful application of special-purpose tools in the projects reviewed, was the attention paid to calibrating the tools on a case-by-case basis against cores, fluids, and other log responses. It is apparent that the response of some special-purpose tools has a different set of characteristics depending on the types of reservoir rocks and fluids encountered. Different reservoir classes, therefore, may require different application and interpretation methods for a given tool type. Optimizing borehole environments for most of these special-purpose tools is critical and may also be a function of the types of reservoir rocks and reservoir fluids present.

Current and Future Research, Development, and Demonstration

Work is currently underway developing the new logging tools and techniques that will become the "advanced tools" of the near future. DOE is sponsoring a significant part of this research and development. In addition, demonstrations of logging technology application in DOE's Field Demonstration Program and related projects suggest numerous topics for RD&D to improve the performance of existing logging technologies and to develop new technologies to complement and supplement those already being developed and applied.

Current DOE Efforts/Emerging Technologies

Wireline logging is but one of a wide variety of emerging data collection, interpretation, and modeling technologies where additional research is being encouraged and pursued by DOE. In a review of projects funded through the DOE's National Oil Program, several projects were identified which involved advanced research in new logging tool designs and interpretation techniques. Logging technology makes up less than 10% of DOE-funded research in reservoir description and reservoir management. Significant advances in logging technology from this research, however, should encourage private industry participation for further development and stimulate additional industry efforts to increase R&D support.

Wireline-logging research topics under DOE sponsorship are related to downhole seismic, deep formation resistivity, and neutron log responses. Focus areas include:

- Interwell characterization and process monitoring
- Fluid characterization behind casing
- Modeling of logging tool response

Wireline Microseismic Tomography:

The importance of interwell continuity relationships has been realized for more than 20 years, but few tools have been developed to measure an appreciable distance from the wellbore. Recent advances in crosswell tomography have been able to bridge the gap between sonic logs and reservoir-wide 3-D seismic by providing resolution down to several meters. Los Alamos National Laboratory is currently developing a microseismic monitoring technology, which can detect conductive reservoir fractures at 100s of meters from a borehole (Project ID:FEW A053). Slim-hole geophone array (SLGA) receivers are being developed which can be deployed in production tubing (2 3/8 inches and greater in diameter) and in small-diameter boreholes. SLGA receivers were successfully used to detect microearthquakes induced by hydraulic stimulation in order to determine fracture orientation and extent in the Austin Chalk, Giddings field, Texas, and the 76 field, Clinton Co., Kentucky (Phillips et al., 1996). The seismic behavior was consistent with modeling and confirmed by post-stimulation drilling and production.

Resistivity-Based Techniques

At present, enhanced recovery processes are monitored using widely spaced boreholes that sample formation properties only in the vicinity of the borehole. Current research in crosshole electromagnetic (EM) methods can extend resistivity logging into the region between boreholes, providing better reservoir characterization on a resolution scale of several feet. Because electrical conductivity changes with both fluid saturation and temperature, the EM method has ideal potential for tracking pore fluid changes associated with waterflooding and steam injection. However, advanced technologies are required for collecting multifrequency electromagnetic data and high-resolution imaging of formation resistivities.

A joint Lawrence Livermore National Laboratory and Lawrence Berkeley National Laboratory program, with industry participation from Schlumberger-Doll Research, involves the construction of a field system and imaging hardware and software to perform EM monitoring (Project ID: FEW 0031). The technique has been tested and was found to be effective at well spacings from 50 to 500 meters. Two field tests in central California have demonstrated the ability to map discontinuous reservoir structure (Project ID: FEW 0011). At the Lost Hills oil field (a Reservoir Class III reservoir), the data provided an image of electrical conductivity changes associated with underground steam injection. At the Richland Field Station, the same technique imaged conductivity changes associated with salt-water injection. Tool modifications are being made to allow for rapid crosshole measurements in 4 hours or less. At present, resistivity measurements are being made in open holes. Efforts are underway, however, to measure resistivity at low frequencies through steel casing. Software code is being developed to optimize the signal-to-noise ratio.

Although formation evaluation through casing with nuclear measurements has been available for many years, currently no commercial tools exist for measuring resistivity through casing. Important potential applications include obtaining resistivity data in wells where open-hole logs could not be run because of poor hole conditions and monitoring reservoir waterfloods over time. The tools being designed must account for the effects of cement and high conductivity casing which attenuate signals and make the accurate measurement of formation resistivities difficult. Concerns over mud filtrate invasion, dissipation effects, and accurate formation water resistivity determination also are being addressed. Recent through-casing resistivity modeling has revealed some positive results. ParaMagnetic Logging has licensed its new technology, the

Through Casing Resistivity Tool (TCRT), to Schlumberger, Western Atlas Logging Services, and Atlantic Richfield Company. Currently, Western Atlas and Schlumberger are both testing tool prototypes. The potential application of this innovative tool is enormous; however, the tool's reliability must be proven before widespread application occurs.

Array induction tools are some of the newest log types. Halliburton's High Resolution Induction (HRI) tool, Western Atlas' High Definition Induction Logging tool, and Schlumberger's Array Induction Imager (ARI) all measure formation resistivities in open holes in which wellbore fluids exhibit low to moderate conductivities. Array induction logging is particularly useful in oil-based and synthetic muds and in water-based muds with low to medium salinity. The several-foot depth of investigation of deep resistivity measurements can be used to distinguish between water-bearing and hydrocarbon-bearing formations, determine true formation resistivity for calculating water saturation, and indicate movable hydrocarbons. Vertical resolution can be adjusted to match the vertical resolution of simultaneously run neutron and density logs to enhance formation evaluation in thin beds and laminated sand-shale sequences.

Neutron Transport Modeling

Not only do new tools and acquisition techniques need to be developed, but also improved interpretation techniques are needed to squeeze more information out of the responses of conventional logs. Computer simulation of various neutron and radiation transport phenomena could allow better interpretation of nuclear well log data. The geometry involved with neutron measurements is 3-D and time-dependent, and only a small fraction of the return radiation is detected. Lawrence Livermore National Lab is currently developing a deterministic neutron transport code which will be applied to neutron well log tool design, implementation, and interpretation (Project ID Number: ACTI-026/107). This deterministic approach will supplement and complement the standard Monte Carlo approach.

Reference

Phillips, W. S., J. T. Rutledge, T. D. Fairbanks, T. L. Gardner, M. E. Miller, and B. K. Schuessler, 1996, Reservoir fracture mapping using microearthquakes: Austin Chalk, Giddings Field, TX, and 76 Field, Clinton Co., KY: SPE 36651, SPE Annual Technical Conference and Exhibition, Denver, Colorado, October 7 – 9, p. 895909.

RD&D Needs for the Future of Wireline Logging

Common pursuits and common problems in many of the projects reviewed under DOE's Field Demonstration and related programs suggest several fronts on which further research, development, and demonstration might make logging technologies yet more useful. Although the areas for potential advance overlap the artificial boundaries between logging technology types established in this volume, the three categories still serve well as a framework for discussion.

Core-Log Modeling

From the projects reviewed, it becomes apparent that, as an industry, we do not yet completely understand the information cryptically gathered and stored in the responses of wireline logging tools, many of which have been in common use for several decades. The wide variety and often trial-and-error application of core-log modeling approaches used to obtain new information from existing logs point to the work that remains to be done in establishing consistent and efficient methodologies for building core-log models. There are several things that can be done to make future core-log models more effective.

Methodologies are needed for both old and more modern reservoirs. More studies of reservoirs with "old" logs need to be performed, with digital recalibration of logs against existing core materials, new cores and reservoir fluid samples, and newer-vintage logs. Many additional carefully controlled logging application studies in new wells accompanied by detailed geological and petrophysical "ground-truthing" or calibration will also be required. Performing these kinds of methodology- and model-development studies in reservoirs belonging to analog groups such as those found in DOE's Reservoir Class Program would expedite and simplify application of core-log models to a large number of reservoirs quickly and with minimal effort. Perhaps more sophisticated reservoir petrophysical parameters, such as relative permeabilities or wettabilities, could be included as core-log modeling targets, as well as the conventional air permeabilities that have been the object of many such studies in the past. Many of the core-log models being developed today use cross plotting as a fundamental method for comparing of core and log values. Additional techniques such as multivariate analysis and use of neural nets probably should be investigated in additional depth (Jackson, 1993).

Such studies will:

- Demonstrate and enable selection of the best available logs for reservoir description in existing reservoirs
- Enable design of optimum logging tool suites for meaningful description of newly discovered reservoirs in the development stage, possibly identifying tools currently labeled as "advanced" to be run on a routine (every well) basis

- Identify the true spectrum of information contained in the responses of a wide variety of logging tools
- Enable identification by elimination the desired properties for measurement by new-concept logging tools

Borehole Imaging

Borehole imaging tools (video, acoustic, and resistivity) are rapidly moving toward full use by industry. In just the last few years, cost has decreased appreciably and industry experience in interpreting responses has increased. There are yet some areas, however, where further research, development, and demonstration might improve utility and performance.

From the usage of these tools in DOE's Field Demonstration Program and related projects, one might conclude that the utility of both acoustic and resistivity imaging tools has not been fully realized in carbonate reservoirs and perhaps needs further development and demonstration. Some credence is lent by the fact that both acoustic and resistivity contrasts are usually lower in carbonate rocks, and of the projects reviewed, most of the successful applications have been in siliciclastic reservoirs. The sampling of projects reviewed here, however, is small and does not fully justify such a conclusion. Industry has experienced numerous successful applications of both types of imaging tools in carbonate environments.

The potential utility of acoustic and especially resistivity imaging tools for wellsite decision making has perhaps not yet been fully realized because of complex and time-consuming data processing and interpretation requirements that stand between the raw tool response and the interpreted images. Further developing techniques for reducing and streamlining these requirements, perhaps through automated/intelligent processing algorithms coupled with high-speed processing capabilities employed in the field, should result in a great increase in the utility of these imaging tools.

The high resolution and high content of potentially useful information captured by borehole imagers, coupled with the steady decrease in their cost of application, suggests that such tools might soon be considered to join the suite of logs run at every borehole. Quantitative incorporation of such information into core-log models may provide tremendous improvements in reservoir description over that obtained using current logging suites.

Advanced and Emerging Tools

New tools or tool combinations are still needed to directly measure critical reservoir properties such as permeability, pore structure, and producibility. Enhancements to existing tools should be made to measure with increased precision and vertical resolution and at greater distances from the wellbore in the interwell region (Jackson, 1984). For mature fields, advanced logging tools are needed for cost-effective and accurate measurements of all reservoir parameters in steel-cased holes with various styles and types of completion (Prensky, 1994). Further advances must also emphasize new interpretation techniques through the use of user-friendly software.

Most fields have a variety of rock and fluid data available from different logging suites and vintages. For advanced logging tools to be more widely applied, there must continue to be a push toward developing integrated models using existing log data and information derived from a range of conventional and advanced logging tools. Concurrence of estimates of log-derived properties, such as permeability, based on tools employing fundamentally different measurements and physics, would increase the interpreter's confidence in the computed results. The introduction of new tools and techniques that measure at the same vertical resolution with different depths of investigation will also significantly improve integrated log interpretation.

Drilling costs account for almost 60% of well completion costs. With associated risks of one well in 15 for wildcats, or one well in 6 for extension wells in being commercially productive, the costs involved in searching for new reserves are high. Reserves must be sufficient to cover the dry hole costs of previous unsuccessful efforts. Current studies at Los Alamos National Laboratory are investigating the feasibility of drilling micro-boreholes (~1 inch). This capability would open up the possibility of directly measuring subsurface reservoir properties and delineating reservoir boundaries at a fraction of the cost of current drilling technology. Realizing the full benefits of micro drilling will require miniaturization of conventional logging tools and development of new instruments for fluid detection and monitoring reservoir processes.

Few major oil company research labs are still involved in new research beyond solving daily drilling, completion, and production problems. There is almost total reliance on the logging service companies to generate new hardware and software technology. However, the long lead time involved for new tool development and the unsettled state of the U.S. domestic industry continue to have a dampening effect on the development of new logging technologies. Because development costs are extremely high and the payoff increasingly uncertain, new developments tend to be incremental rather than revolutionary. Further investment by both industry and government will be needed to help alleviate some of the risks involved in new tool developments and encourage the push toward making prototype tool designs and making technologies commercially available.

References

Jackson, J. A., 1984, Nuclear magnetic resonance well logging: The Log Analyst, v. 35, no. 5, p. 16-30.

Jackson, S. R., 1993, Reservoir assessment and characteriztion, *in* J.M. Deterding, F.D. Sutterfield, and T.E. Burchfield eds., Final Report, National Institute for Petroleum and Energy Research (NIPER), Department of Energy, Report NIPER-685, December, p. 17-101.

Prensky, S. E., 1994, A survey of recent developments and emerging technologies in well logging and rock characterization: The Log Analyst, v. 35, no. 2, p.15-45.

In Conclusion...

The new era of wireline logging now being entered owes its existence almost exclusively to the new-found ability to efficiently handle, process, and display large volumes of data. This capability allows deeper insight into the detailed distribution of reservoir petrophysical properties than ever before possible and leads to more accurate reservoir performance and economic predictions for selecting from a wide variety of potential improved recovery options. A further significant development is the ability to perform many of these tasks on relatively inexpensive computing equipment that is finally within the means and expertise of most reservoir operators.

Most of the field demonstration projects reviewed have been performed in aging domestic reservoirs, many of which have undergone waterflooding for many years and are approaching their economic limits under current operations. In these and other problematic reservoirs, an accurate model of the reservoir is crucial to make decisions about pursuing improved recovery by infill drilling, recompletions in bypassed zones, waterflood optimization, enhanced recovery process selection and implementation, etc. Logging technologies have played a critical role in developing the required improved reservoir models, especially through core-log modeling applied on a reservoir-wide scale, a technique that has not received its fair share of attention in the past. Also critical to model development are specific advanced logging tools run to supply missing important information about reservoir properties or conditions. Equally important is the fact that logging technologies have been intimately integrated with other information sources of all types (e.g., information from seismic, core, well test, production/injection, and other data) to create the improved models. Because of this high degree of integration, although it is often a relatively straightforward task to assess the technical success of a particular logging technology application, it is in many cases difficult or impossible to assign the dollar value gained from that application.

The numerous demonstrations of logging technology reviewed in these projects overwhelmingly points to one major conclusion: There is no substitute for calibration. In every instance where new techniques were being developed or new tools were being applied, great care was taken to understand tool responses in the context of everything that could be learned about the reservoir from other sources. In most cases (whether reservoir-wide core-log models or borehole imager or other advanced tool responses were being interpreted (log responses were calibrated directly against core information. This fact suggests that most proper applications of wireline logs will probably involve core-log calibration at one scale of consideration or another. Detailed and iterative geological input including thorough study of reservoir rocks, fluids, and rock-fluid interactions is necessary for developing reservoir model information from wireline log data.

With the rapid development of new and widespread capabilities for consistent and accurate reservoir-wide description of petrophysical properties from wireline tools that has been demonstrated in these projects, certain problems inherited from a past when wireline log information was considered only on a well-by-well basis have arisen. Predominant among these problems are the lack of uniformity in logging programs within individual reservoirs and the lack of established quality control procedures in the execution of those programs. Both shortcomings strongly affect the information content of the reservoir models that can be obtained. At the same time that researchers are developing ways to further minimize the effects of these shortcomings, we need research, development, and demonstration of logging program protocol to reduce these problems in reservoirs that are currently being developed.

DOE's participation in the projects of its Field Demonstration Program has served as an invaluable source of risk abatement to encourage innovative application of existing wireline technologies and experimental, yet judicious, application of advanced technologies to improve reservoir characterization. The strong technology transfer aspect of the projects has made the detailed context of the successes and the shortcomings of these technology applications available to the entire industry through government and technical society publications and through workshops and symposia sponsored by individual operators, DOE, and the Petroleum Technology Transfer Council.

The Reservoir Class Program projects form the core of the logging technology demonstrations co-sponsored by DOE. As such, these are the projects most abundantly represented in this volume. Tremendous benefits stand to be gained by imitative application of the demonstrated wireline technologies to analog reservoirs in each of the three depositional reservoir classes represented. Needless random trials, false starts, and outright failures can be avoided and successes can be propagated manyfold to locate and recover millions of bbls of remaining oil that would otherwise be left behind.

Much of what we are learning about reservoir characterization through application of wireline logging technologies in what are for the most part the aging reservoirs in Reservoir Classes I through III can be applied both now and in the future in aging reservoirs of all depositional classes. From these projects we are gaining useful insights into reservoir management techniques and will continue to learn what to do, as well as what not to do, in developing reservoir models for reservoir decision-making through integrating wireline log and other data types.

APPENDIX A

PROJECT CONTACT INFORMATION

Appendix A contains an Alphabetical List of Projects reviewed in this volume by contractor and a project-by-project compilation of project contacts and related information that may be used to obtain updates and additional information about individual project progress and results.

The Alphabetical List of Projects keys each project to its Reservoir Class and to the chapter or chapters in which logging technology applications are discussed. The list also gives the page number in Appendix A where project contact information may be obtained.

The compilation of project contacts is arranged first by order of Reservoir Class and then alphabetically by operator within each Reservoir Class. Contacts for the University of Wyoming Tensleep project (not a Reservoir-Class-related project) are listed last.

ALPHABETICAL LIST OF PROJECTS BY CONTRACTOR

ARCO Western Energy Inc.—Yowlumne Field, California

Reservoir Class III
Chapter 3–Borehole Imagers
Chapter 4–Advanced Tools

Bureau of Economic Geology—Geraldine Ford Field, Texas, Plus Additional "Old" Log Projects

Reservoir Class III
Chapter 2–Core-Log Models

Chevron USA Inc.—Buena Vista Hills Field, California

Reservoir Class III
Chapter 3–Borehole Imagers
Chapter 4–Advanced Tools

City of Long Beach—Wilmington Field, California

Reservoir Class III
Chapter 4–Advanced Tools

Columbia/Lamont-Doherty—Eugene Island Field, Louisiana Offshore

Reservoir Class I
Chapter 3–Borehole Imagers

Fina USA Incorporated—North Robertson Unit, Texas

Reservoir Class II
Chapter 2–Core-Log Models
Chapter 3–Borehole Imagers
Chapter 4–Advanced Tools

Inland Resources Inc./Lomax Exploration Company—Monument Butte Unit, Utah

Reservoir Class I
Chapter 3–Borehole Imagers
Chapter 4–Advanced Tools

Oxy USA Inc.—West Welch Unit, Texas

Reservoir Class II
Chapter 2–Core-Log Models
Chapter 3–Borehole Imagers

Phillips Petroleum Company—South Cowden Unit, Texas

Reservoir Class II
Chapter 3–Borehole Imagers

Pioneer Natural Resources Inc./Parker and Parsley Development Co.—Spraberry Trend, Texas

Reservoir Class III
Chapter 2–Core-Log Models
Chapter 3–Borehole Imagers

Strata Production Company—Nash Draw Pool, Texas

Reservoir Class III
Chapter 2–Core-Log Models
Chapter 4–Advanced Tools

University of Alabama—East Frisco City Field, Alabama

Related to Reservoir Class I
Chapter 3–Borehole Imagers

University of Kansas—Schaben Field, Kansas

Reservoir Class II
Chapter 2–Core-Log Models

University of Tulsa—Glenn Pool Field, Oklahoma

Reservoir Class I
Chapter 2–Core-Log Models
Chapter 3–Borehole Imagers

University of Wyoming—Oregon Basin Field, Wyoming

Non-Reservoir-Class Project in Eolian Deposits
Chapter 3–Borehole Imagers

Utah Geological Survey—Bluebell Field, Utah

Reservoir Class I
Chapter 3–Borehole Imagers

Columbia/Lamont-Doherty—Eugene Island Field, Louisiana Offshore: Roger N. Anderson

Contract Title: Dynamic Enhanced Recovery Technologies.
Project ID: DE-FC22-93BC14961

Contractor:
Columbia University, Lamont-Doherty Earth Observatory
Project Partners:
Pennzoil Corporation, Houston, TX
Cornell University, Ithaca, NY
Louisiana State University, Baton Rouge, LA
Michigan Technological University, Houghton, MI
Woods Hole Oceanographic Institute, Woods Hole, MA
Hypermedia Corporation, Barker, TX
Pennsylvania State University, University Park, PA
Engineering Animation Incorporated, Ames, IA

Principal Investigator:
Roger N. Anderson
Columbia University
Lamont-Doherty Earth Observatory
Box 20
Low Memorial Library
New York, NY 10027

Phone: (914) 359-2900
Fax: (914) 359-1631
E-mail: anderson@Ideo.Columbia.edu

Project Status: Completed in April 1996

Inland Resources Inc./Lomax Exploration Company—Monument Butte Unit, Utah: Bill Pennington and Dennis Nielson

Contract Title: Green River Formation Water Flood Demonstration Project.
Project ID: DE-FC22-93BC14958

Contractor:
Inland Resources Inc.
Project Partners:
University of Utah, Salt Lake City, UT
University of Utah Research Institute, Salt Lake City, UT

Principal Investigator:
Bill Pennington
Inland Resources Inc.
410 17th Street, Suite 700
Denver, CO 80202

Phone: (303) 292-0900
Fax: (303) 893-0113

Other contact for Borehole Imaging:
Dennis L. Nielson
Energy and Geoscience Institute
University of Utah
423 Wakara Way, Suite 300
Salt Lake City, UT 84108

Phone: (801) 585-6855
Fax: (801) 585-3540
E-mail: dnielson@egi.utah.edu

Project Status: Completed in March 1996

University of Tulsa—Glenn Pool Field, Oklahoma: Balmohan G. Kelkar and Dennis R. Kerr

Contract Title: Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance (Glenn Pool Field, OK).
Project ID: DE-FC22-93BC14951

Contractor:
University of Tulsa
Project Partners:
Uplands Resources, Tulsa, OK
Amoco Production Company, Tulsa, OK
Joshi Technology International Inc., Tulsa, OK
Principal Investigator:
Balmohan G. Kelkar
University of Tulsa
Office of Research
600 South College Avenue
Tulsa, OK 74104

Phone: (918) 631-3036
Fax: (918) 631-2091

Other Contact for Core-Log Modeling:
Dennis R. Kerr
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Office of Research
600 South College Avenue
Tulsa, OK 74104

Phone: (918) 631-3020
Fax: (918) 631-2091
E-mail: geos_drk@centum.utulsa.edu

Project Status: In progress, expected completion in February 1999.

Utah Geological Survey—Bluebell Field, Utah: Craig D. Morgan

Contract Title: Increased Oil Production and Reserves from Improved Completion Techniques in the Bluebell Field.
Project ID: DE-FC22-93BC14953

Contractor:
Utah Geological Survey
Principal Investigator:
Craig D. Morgan
Utah Geological Survey
1594 West North Temple, Suite 3110
P.O. Box 146100
Salt Lake City, UT

Phone: (801) 537-3370
Fax: (801) 537-3400
E-mail: nrugs.cmorgan@state.ut.us

Project Status: In progress, expected completion in September 1999.

Project Information Web site: www.ugs.state.ut.us/bluebell.htm

University of Alabama—East Frisco City Field, Alabama (Research and Development by Small Independent Operators Project): Ernest A. Mancini

Contract Title: Fullbore Formation MicroImager Applications Designed to Reduce Operational Costs Associated with the Development of Frisco City Sandstone Reservoirs.

Contractor:
University of Alabama
Project Partners:
Cobra Oil and Gas Corporation
Schlumberger Well Services

Principal Investigator:
Ernest A. Mancini
Department of Geology
P.O. Box 870338
202 Bevill
Tuscaloosa, AL 35487

Phone: (205) 348-4319
Fax: (205) 348-0818

Project Status: Completed in August 1996.

Project Information Web site: egrpttc.geo.ua.edu

Fina USA Incorporated—North Robertson Unit, Texas: Jerry Nevans, David K. Davies, and Bill Dixon

Contract Title: Application of Integrated Reservoir Management and Reservoir Characterization to Optimize Infill Drilling.
Project ID: DE-FC22-93BC14989

Contractor:
Fina USA Incorporated
Project Partners:
University of Texas, Permian Basin Center for Energy and Economic Diversification, Petroleum Industry Alliance, Odessa, TX
University of Tulsa, Tulsa, OK
Mobil Oil Company, Midland, TX
Texas A&M University, College Station, TX
Schlumberger Wireline Services, Midland, TX
David K. Davies and Associates, Kingwood, TX

Principal Investigator:
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Fina USA Incorporated
Exploration and Production
6 Desta Drive, Suite 4400
Midland, TX 79705

Phone: (915) 688-0623
Fax: (915) 686-7034
E-mail: BET3KFK8@IBMMAIL.COM

Other contact for core-log modeling:
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David K. Davies and Associates
1410 Stonehollow Drive
Kingwood, TX 77339

Phone: (281) 358-2662
Fax: (281) 358-3276
E-mail: dkdavis@earthlink.net

Project Status: In progress, expected completion in June 1999.

Oxy USA Inc.—West Welch Unit, Texas: Rebecca Egg, Archie Taylor, and Greg Hinterlong

Contract Title: Applications of Reservoir Characterization and Advanced Technology Improves Recovery and Economics in Lower Quality Shallow Shelf San Andres Reservoirs.
Project ID: DE-FC22-93BC14990

Contractor:
Oxy USA Inc.
Project Partners:
Advanced Reservoir Technologies, Addison, TX
University of Texas Permian Basin Center for Energy and Economic Diversification, Odessa, TX
Hickman and Associates, Midland, TX
Halliburton Services, Midland, TX

Principal Investigator:
Rebecca Egg
Oxy USA Inc.
P.O. Box 50250
Midland, TX 79710

Phone: (915) 685-5897
Fax: (915) 685-5888
E-mail: rebecca_egg@oxy.com

Project Status: In progress, expected completion in September 2000.

Phillips Petroleum Company—South Cowden Unit, Texas: Rex Owen, Matt Gerard, and Ken Harpole

Contract Title: Design and Implementation of a CO_2 Flood Utilizing Advanced Reservoir Characterization and Horizontal Injection Wells in a Shallow Shelf Carbonate Approaching Waterflood Depletion.
Project ID: DE-FC22-94BC14991

Contractor:
Phillips Petroleum Company
Principal Investigator:
Rex Owen
Phillips Petroleum Company
Exploration and Production
Permian Basin Region
4001 Penbrook
Odessa, TX 79762

Phone: (915) 368-1203
Fax: (915) 368-1330

Other Contact for Borehole Imaging:
Matt G. Gerard
Phillips Petroleum Company
Room 1340 M
Plaza Office Building
Bartlesville, OK 74005

Phone: (918) 661-7588
Fax: (918) 662-2106

Project Status: In progress, expected completion in January 2001.

University of Kansas—Schaben Field, Kansas: Timothy Carr and Willard Guy

Contract Title: Improved Oil Recovery in Lower Meramecian (Mississippian) Carbonate Reservoirs of Kansas.
Project ID: DE-FC22-93BC14987

Contractor:
University of Kansas Center for Research Inc.
Project Partners:
Ritchie Exploration Inc., Wichita, KS

Principal Investigator:
Timothy R. Carr
University of Kansas
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Project Status: In progress, expected completion in May 1999.

Project Information Web site: www.kgs.ukans.edu/DPA/Schaben/schabenMain.html.

ARCO Western Energy Inc.—Yowlumne Field, California: Michael S. Clark and Mike L. Laue

Contract Title: Economic Recovery of Oil Trapped at Fan Margins Using High Angle Wells and Multiple Hydraulic Fractures.
Project ID: DE-FC22-95BC14940

Contractor:
ARCO Western Energy Inc.

Principal Investigator:
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Project Status: In progress, expected completion in September 2001.

Bureau of Economic Geology—Ford Geraldine Field, Texas: Shirley Dutton and George Asquith

Contract Title: Application Of Advanced Reservoir Characterization, Simulation, and Production Optimization Strategies to Maximize Recovery in Slope and Basin Clastic Reservoirs, West Texas (Delaware Basin).
Project ID: DE-FC22-95BC14936

Contractor:
Bureau of Economic Geology of the University of Texas at Austin
Project Partners:
Orla Petco, Midland, Texas

Principal Investigator:
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Project Status: In progress, expected completion in June 2000.

Chevron USA Inc.—Buena Vista Hills Field, California: Mike Morea and Tom Zalan

Contract Title: Advanced Reservoir Characterization in the Antelope Shale to Establish the Viability of CO_2-Enhanced Oil Recovery in California's Monterey Formation Siliceous Shales.
Project ID: DE-FC22-95BC14938

Contractor:
Chevron USA Incorporated
Project Partners:
Advanced Resources International Incorporated, Denver, CO
Stanford University, Stanford, CA
Core Laboratories Incorporated, Bakersfield, CA
Terra Tek, Incorporated, Salt Lake City, UT
Stratamodel Incorporated, Houston, TX

Principal Investigator:
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Project Status: In progress, expected completion in June 2001.

City of Long Beach—Wilmington Field, California: Scott Walker and Dan Moos

Contract Title: Increasing Waterflood Reserves in the Wilmington Field through Improved Reservoir Characterization and Reservoir Management.
Project ID: DE-FC22-95BC14934

Contractor:
City of Long Beach
Project Partners:
Tidelands Oil Production Company, Long Beach, CA
Stanford University, Stanford, CA
Magnetic Pulse, Houston, TX

Principal Investigator:
Scott Walker
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301 E. Ocean Blvd., Suite 300
Long Beach, CA 90802

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Fax: (650) 322-6508
E-mail: moos@geomi.com

Project Status: In progress, expected completion in March 2000.

Pioneer Natural Resources Inc./Parker and Parsley Development Co.—Spraberry Trend, Texas: Chris Whigham

Contract Title: Advanced Reservoir Characterization and Evaluation of CO_2 - Gravity Drainage in the Naturally Fractured Spraberry Reservoir.
Project ID: DE-FC22-95BC14942

Contractor:
Pioneer Natural Resources Incorporated
Project Partners:
New Mexico Petroleum Recovery Research Center, Socorro, NM
Spic Consulting, Calgary, Alberta
Lincoln Elkins, Lakewood, CO
University of Texas - Permian Basin, Odessa, TX

Principal Investigator:
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Phone: (915) 683-4768
Fax: (915) 571-5460

Project Status: In progress, expected completion in July 2000.

Strata Production Company—Nash Draw Pool, Texas: Bruce A. Stubbs

Contract Title: Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico.
Project ID: DE-FC22- 95BC14941

Contractor:
Strata Production Company
Project Partners:
New Mexico Petroleum Recovery Research Center, Socorro, NM
Scott Exploration Inc., Roswell, NM
Pecos Petroleum Engineering, Roswell, NM
Institute for Improved Oil Recovery, Houston, TX
Bob Hardage, Austin, TX

Principal Investigator:
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Project Status: In progress, expected completion in September 2000.

Project Information Web site: http://baervan.nmt.edu/REACT/Links/nash/strata.html

University of Wyoming—Oregon Basin Field, Wyoming (Tensleep Sandstone Eolian Deposits): Mary Carr-Crabaugh and Thomas L. Dunn

Contract Title: Anisotropy and Spatial Variation of Relative Permeability and Lithologic Character of Tensleep Sandstone Reservoirs in the Bighorn and Wind River Basins, Wyoming.
Project ID: DE-AC22-93BC14897

Contractor:
University of Wyoming
Project Partners:
Marathon Oil Company, Littleton, CO

Principal Investigator:
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Project Status: Completed in January 1997.