STATE LANDS ENERGY RESOURCE OPTIMIZATION PROJECT

Final Report

Project coordinated by

Bureau of Economic Geology
The University of Texas at Austin

Cooperative research conducted with

Center for Petroleum and Geosystems Engineering
The University of Texas at Austin

College of Engineering
Texas A&M University

College of Geosciences and Maritime Studies
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Houston Petroleum Research Center
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Center for Applied Petrophysical Studies
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Geology Mapping and Statistics Laboratory
Lamar University

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PREFACE

Project SLERO, for which The University of Texas at Austin Bureau of Economic Geology was the lead contractor and coordinating institution, was a five-university consortium study of hydrocarbon resources on Texas State Lands. The five universities are The University of Texas at Austin, Texas A&M University, the University of Houston, Texas Tech University, and Lamar University, and the entire program was aided by the cooperation of the Texas General Land Office. This 4-year project was funded through the Office of the Governor of Texas.

Project personnel included geologists, petroleum engineers, geophysicists, and chemists. The interdisciplinary nature of this project was directed toward a more thorough understanding of the geologic controls on production and the development of appropriate recovery technologies to address the specific needs of State Lands reservoirs. Transfer of these technologies to industry, in particular to independent operators, is expected to result in increased efficiency of hydrocarbon recovery from State Lands and increased revenue to the Texas Public School Fund. The project was divided into three parts: (1) play analysis and resource assessment, (2) reservoir characterization, and (3) development of advanced extraction technology.

The play analysis and resource assessment part of this research program involved dividing the oil and gas fields on Texas State Lands into geologically based families, such that fields with similar depositional histories, trapping styles, production efficiencies, and extraction difficulties are grouped into "plays." Play analysis provides the framework for making a quantitative assessment of the remaining resources on State Lands. Importantly, even maturely developed oil reservoirs may still contain substantial volumes of both "mobile" oil (oil that is movable at reservoir conditions and that can be conventionally recovered) and "residual" oil (oil that requires expensive and technically complex reservoir stimulation). The relative amounts of these resource types vary among the geologically based plays. Quantifying the amounts of these two types of oil on State Lands, as well as quantifying the remaining natural gas resource, is critical both for designing field development programs and for optimizing the recovery economics of Texas hydrocarbon resources and was the focus of the resource assessment task.

The reservoir characterization part of this project included selection of multiple State Lands fields and reservoirs for site-specific research. Inasmuch as the goal of reservoir characterization was to design advanced field development programs, the specific fields chosen for detailed study were selected within the play analysis framework, and chosen fields typify plays that capture major portions of the total remaining State Lands resource. The process of reservoir characterization itself is multidisciplinary, involving geologists, petroleum engineers, and geophysicists. The details of each reservoir span the range of reservoir types in Texas, from relatively young gas fields in the deep Tertiary sandstones of the Gulf Coast to mature oil reservoirs in the limestones and dolomites of the Permian Basin.

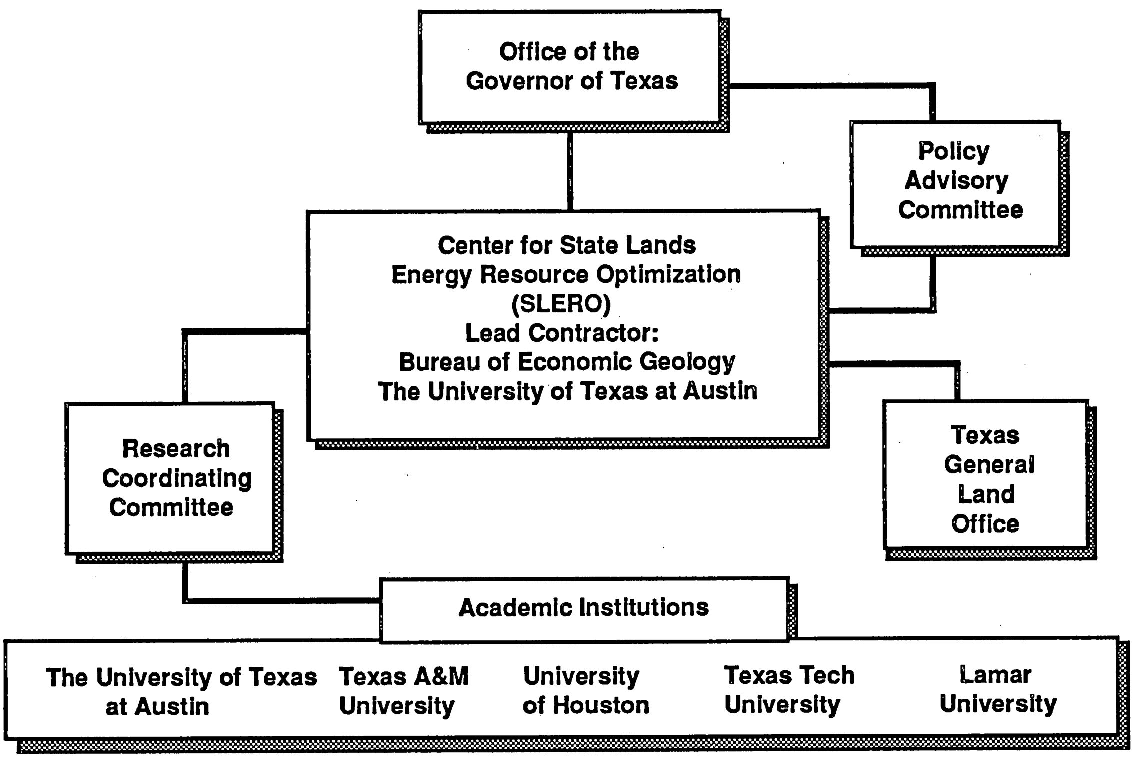
Nine State Lands reservoirs and two subregional study areas underwent characterization research. Reservoir characterization studies comprise geological, petrophysical, and geophysical investigations of the reservoir along with an assessment of original and remaining resources using cores, well logs, and seismic data. This work incorporated the results of petrophysical and diagenetic studies to produce two- and three-dimensional models of reservoir flow units. Seismic studies were designed to improve the existing vertical and lateral resolution offered by conventional seismic techniques by employing such advanced techniques as cross-borehole tomography and high-resolution surface reflection seismic surveys.

The final part of the project, development of advanced extraction technology, used the geologic and engineering models developed within the play framework to design efficient and advanced field development projects. During this stage of the project we worked especially closely with operators of State Lands reservoirs to implement the results of our research as infill drilling, waterflood optimization, and enhanced oil recovery programs. This included drilling of infill wells geologically targeted to tap unswept reservoir compartments, design of waterflood programs to sweep parts of the reservoir incompletely exploited, and design of state-of-the-art carbon dioxide and surfactant floods to sweep residual oil.

We already have success stories resulting from site-specific application of our preliminary results. At Seventy-Six West and Colmena fields, located in Duval County in South Texas, the operator has drilled several successful infill wells sited as the result of SLERO research. In particular, our research has identified an area of approximately 150 acres in the southern part of Seventy-Six West field that is now proven to be oil productive but had not been previously drilled. At Powderhorn field in Calhoun County a well drilled at a location and depth proposed by SLERO researchers tapped a new reservoir. Initial estimates indicate that this new reservoir, and additional opportunities identified by SLERO in previously existing reservoirs, will add between 800 and 900 Mbbl of reserves to this field, which is equivalent to approximately 15 percent of cumulative production since initial field development in the early 1950's. At Keystone field, in the Permian Basin of West Texas, a well drilled in a location recommended by SLERO researchers flowed at an initial rate of more than 150 barrels per day, which makes this the most productive well since initial field development in the 1960's.

As part of the contract deliverable for Project SLERO, the West Texas Geological Society and the Bureau of Economic Geology, The University of Texas at Austin sponsored a technology transfer workshop titled *New Oil and Gas Recovery Technologies Targeted for West Texas Hydrocarbon Reservoirs*. This workshop was held in Midland, Texas on August 20, 1993, and attracted an attendance of 250 petroleum industry professionals. SLERO researchers from participating academic institutions made presentations on play analysis and resource assessment, reservoir characterization, and advanced extraction technology. This opportunity to communicate project results directly to State Lands operators, principally independent exploration and production companies, serves as an important adjunct to published reports. Nonetheless, to ensure that industry representatives were fully appraised of the vast quantity of technical literature generated by this project, each participant in this technology transfer workshop received an abstract volume that included a comprehensive list of publications.

SLERO researchers have received accolades from their science and engineering peers for technical publications that have resulted from this project. Among numerous papers, abstracts, theses, and dissertations based on SLERO research (see the appendix), a comprehensive list of which is included in this final report, six publications that resulted from this research have won Best Paper awards. Two papers presented at the 1992 meeting of the Gulf Coast Association of Geological Societies (GCAGS) won first and third place Best Paper awards, and one paper presented in 1991 won second-place Best Poster award. Two papers presented at the 1992 fall symposium of the West Texas Geological Society (WTGS) won first place awards for Best Oral Presentation and Best Poster Presentation. A paper presented at the 1991 meeting of the American Association of Petroleum Geologists (AAPG) meeting was selected as a "Best of AAPG" paper for presentation at the 1991 meeting of the Society of Petroleum Engineers (SPE). These papers were published in the GCAGS, WTGS, and SPE transactions volumes and are a small part of the publicly available documentation of our research, which will allow operators to apply ideas generated by SLERO to other reservoirs in Texas and elsewhere.



Organizational structure of Project SLERO

BUREAU OF ECONOMIC GEOLOGY

THE UNIVERSITY OF TEXAS AT AUSTIN

Activity 1: State Lands Play Analysis and Resource Assessment

Task 1: Data collection and verification

The State of Texas holds royalty interest in 380 oil reservoirs and 547 gas reservoirs of significant size, that is, having cumulative production of 1 million barrels of oil equivalent. These 927 reservoirs were the focus for data collection, which resulted in a SLERO resource data base. The information collected in this data base was obtained primarily from the hearing files of the Railroad Commission of Texas. Files that proved particularly informative are unitization, injection, maximum efficient recovery (MER), field rules, and discovery files. Additional sources of numerical and descriptive data include:

1. Oil and gas reservoir files compiled by the U.S. Department of Energy, Energy Information Agency, Dallas Field Office.
2. Compilations of field studies published by various regional geological societies, the American Association of Petroleum Geologists, and the Society of Petroleum Engineers of the American Institute of Mining, Metallurgical, and Petroleum Engineers.
3. Publications of the Railroad Commission of Texas, including annual reports and a survey of secondary and enhanced recovery operations.
4. Publications of the Rand Corporation and U.S. Department of Energy on major oil and gas fields in the United States and evaluations of fields targeted for enhanced recovery.
5. Annual reservoir production data and cumulative production data from Dwights Energy Data, Inc., which were supplemented or modified with data from the Railroad Commission of Texas. Latitude and longitude values from Dwights were used to help us map reservoir outlines.
6. Reservoir-specific information provided by individual operating companies.

The accuracy of publicly available quantitative reservoir data varies. Different sources commonly report different values for the same type of data. Where great discrepancies existed, values were selected on the basis of known geologic criteria and consistency with other reservoirs within the same geologically based play. Data were weighted in favor of records that were most recent and/or from sources known to the researchers to be most reliable. Furthermore, data were checked for consistency by making volumetric hydrocarbon calculations. For example, if there were two values for average reservoir porosity, the value that yielded original-oil-in-place or cumulative production figures that agreed with published values was determined to be more accurate.

Task 2: Play analysis

State Lands reservoirs were placed in geologically based plays using a hierarchy of geologic heterogeneity. Geologic information used to define plays include geologic province and subprovince, producing formation, depositional system, diagenesis, tectonic influences, and lithology. These geologic features were placed in a hierarchy of geologic heterogeneity with respect to the influence a feature has on production. This hierarchy was then used as a decision flow path to categorize reservoirs into geologic plays.

The 380 major State Lands oil reservoirs are divided into 50 oil plays. The highest concentrations of these are located along the western margin of the Central Basin Platform in West Texas and in the Rio Grande Embayment in South Texas. The West Texas oil plays containing the most State Lands reservoirs are the Upper Guadalupian Platform Sandstone and the Leonardian Restricted Platform Carbonate plays. Gas reservoirs are predominantly located along the Gulf Coast and have been categorized into 60 geologic plays. The gas plays containing the most State Lands reservoirs are the Downdip Frio Barrier/Strandplain Sandstone of the San Marcos Arch and the Miocene Barrier/Strandplain Sandstone plays.

Task 3: Resource assessment

Integrating the geologic play concept with risk analysis results in a more accurate view of hydrocarbon resources. Geologic plays are based on geologic attributes, such as depositional system and postdepositional physiochemical events. These geologic attributes correspond to engineering parameters. Thus, grouping reservoirs into plays constrains the variability in engineering parameters used to calculate reserves. A type distribution of reservoir hydrocarbon volumes can be made by defining the probability distributions of individual engineering parameters and combining them stochastically. The probability function that best describes this type distribution can then be used to risk-adjust the hydrocarbon volumes of individual reservoirs.

Risk-adjusted oil resource assessment indicates that State Lands contain significant volumes of oil. Original oil in place (OOIP) is at least 5.3 billion stock tank barrels (BSTB) at a 95 percent confidence level, and may be as high as 5.6 BSTB at a 5 percent confidence level. Volumes of oil mobile to water flood range from a high of 1.8 BSTB at 5 percent confidence level to 1.6 BSTB at a 95 percent confidence level. Residual oil volumes, which are the target for enhanced oil recovery, range in probability from 2.1 BSTB at 95 percent confidence level to 2.3 BSTB at a 5 percent confidence level. The State Lands play containing the largest remaining mobile oil resource is the Frio Barrier/Strandplain Sandstone play on the Texas Gulf Coast.

State Lands reservoirs also contain large volumes of gas. Median probability gas resource estimates indicate that the 547 largest gas reservoirs contained 18.9 trillion cubic feet (Tcf) of original gas in place at a 95 percent confidence level. These estimates indicate a cumulative production of 9.9 Tcf, reserves of 2.8 Tcf, and a remaining gas resource of 6.4 Tcf also at a 95 percent confidence level. The largest concentration of State Lands gas on the Gulf Coast is in the Downdip Frio Barrier/Strandplain Sandstone of the San Marcos Arch play and the Frio Deltaic Sandstone, Houston Embayment play. The largest concentration of State Lands gas in West Texas is in the Ellenburger Fractured Dolostone and Siluro-Devonian Carbonate, Deep Delaware, and Val Verde Basin plays.

Activity 2: Reservoir Characterization

Seventy-Six West and Colmena-Cedro Hill fields: Seventy-Six West and Colmena-Cedro Hill fields are 2 of 300 fields of the Jackson-Yegua Barrier/Strandplain sandstone play. Fields of this play produce oil from reservoirs with a geometry of northeast-oriented barrier-bar sandstones and crosscutting, southwest-oriented channel facies, washover sandstones, and tidal-inlet fills. Geologic characterization of Seventy-Six West field demonstrated compartmentalization of the reservoir caused by this complex facies arrangement, and subsidiary structural complications. At Colmena-Cedro Hill field, compartmentalization was also demonstrated, but structural elements play a much more important role in production trends than does the facies architecture. Fault displacement, for example, determines whether the reservoir sandstones are gas-, oil-, or water-saturated at Colmena-Cedro Hill field.

At Seventy-Six West, SLERO researchers proposed several infill-drilling locations designed to exploit zones containing mobile oil that are either inefficiently drained or uncontacted at the existing well spacing. Two wells were drilled and successfully completed as oil producers. The first well produced at the rate of 5 barrels of oil/day (BOPD) with no water and is considered to have intersected a part of the reservoir not previously contacted because surrounding wells produce large volumes of water and oil. The second well produced at the rate of 10 BOPD and 2 bbl of water. From a geological standpoint, this well missed the target channel-fill facies and drilled neighboring beach-ridge sandstones. The result was not surprising, however, because the boundary between these facies is not well defined. Low reservoir pressure was identified early in the study as the main impediment to further oil recovery at Seventy-Six West, and a geologically optimized waterflood was designed to address this problem. The third infill well at Seventy-Six West was selected as a prime location for water injection and will be incorporated in the waterflood design. A plan for a pilot waterflood, which tests only a very small portion of the field and requires conversion of only one poor producing well, was presented to the operator for implementation. The pilot is conservatively estimated to recover an additional 100,000 STB over the life of the field.

At Colmena-Cedro Hill, zones within the reservoir that are either inefficiently drained or bypassed by existing well spacing were also identified. Several infill drilling sites were identified on the basis of SLERO research, and these have been proposed to the operator. Step-out drilling locations were also identified at Colmena-Cedro Hill field. One step-out well has already been drilled and successfully completed as an oil producer. The operator estimated an initial potential between 6 and 10 BOPD and suggested the possibility of an increase in production because field experience has shown that these types of wells improve after a settling period. One infill well was also drilled, and the status of this well has not been finally determined. It was completed as a producer and began to produce 2 BOPD after several weeks on pump. This production rate may also increase because of the improvement these wells typically experience after settling in. Waterflood operations have been maintained over much of the life of Colmena-Cedro Hill field and there is also strong aquifer support. Thus, reservoir pressure is adequate in this field, unlike in Seventy-Six West field where additional oil could be recovered if reservoir pressures were increased.

The research at Seventy-Six West and Colmena-Cedro Hill fields demonstrated reservoir compartmentalization and bypassed mobile oil. These case studies provide models for identifying and exploiting opportunities in other Jackson-Yegua fields on State Lands.

A paper reporting preliminary results of this study was presented orally at the annual meeting of the American Association of Petroleum Geologists and chosen as a Best of AAPG paper for presentation at the annual meeting of the Society of Petroleum Engineers. This paper, written by D. S. Hamilton and titled "Reservoir heterogeneity at Seventy-Six West field, Texas: an opportunity for increased oil recovery from barrier/strandplain reservoirs of the Jackson-Yegua trend by geologically targeted infill drilling," was presented orally at the 1991 annual SPE meeting and published in the transactions volume for that meeting.

Deeper pay potential on Duval County Ranch (regional study): The Duval County Ranch (DCR) has had a lengthy history of oil and gas production from the upper Wilcox, Queen City, and Jackson-Yegua stratigraphic units. This study assessed the potential for further hydrocarbon discoveries on DCR using seismic data and well control. Analysis of seismic data indicates that there are three distinct types of seismic reflections, or seismic facies, in the Wilcox and Queen City units. Seismic Facies 1 (low-amplitude, continuous seismic reflections) and Seismic Facies 2 (short, discontinuous, high-amplitude reflections) are interpreted to be sandstone-rich coastal plain and delta-front/distributary mouth bar deposits, respectively, and rank highly in exploration potential. Seismic Facies 3 consists of continuous, intermediate- to high-amplitude reflections that are interpreted to be mudstone-rich, deep water rock units. Seismic facies 3 does not contain the sandstones necessary to be hydrocarbon reservoirs and is afforded low exploration potential. In the upper Wilcox, the sandstone-rich Seismic Facies 1 and 2 are widespread on the DCR. Deposition of these sandstone-rich units was focused along a zone of structural weakness, the Wilcox Fault Zone, which underlies DCR. The zone of structural weakness also caused growth faulting and development of rollover structures, which enhances potential for hydrocarbon trapping. Sandstone-rich Seismic Facies 1 in the Queen City is dominant in the DCR area. Seismic Facies 2 and 3 are restricted to the southeasternmost part of the study area.

The seismic character of the Yegua and Jackson stratigraphic units is similar to the underlying upper Wilcox and Queen City units and the same three seismic facies are recognized in the broader study area, although only Seismic Facies 1 is widespread over the DCR. In the Jackson-Yegua units, Seismic Facies 1 is associated with sandstone-rich coastal barrier and strandplain deposits. The potential for undiscovered hydrocarbons in this seismic facies, however, is more difficult to assess than in the underlying units because trapping of hydrocarbons is not as easy to predict. Unlike the upper Wilcox, the effect of the Wilcox Fault Zone on Jackson-Yegua units was only minor and is expressed as small-scale faults and gentle flexures. The large rollover structures did not form in the Jackson-Yegua.

In all stratigraphic units, Seismic Facies 1 and 2 appear most prospective when they contain specific horizons of very high amplitude ("bright spot") reflections. The very high amplitudes occur because of the large contrast between low density, gas-filled sandstones and surrounding dense shales. A bright spot anomaly in Queen City sandstones at Lundell field confirms that those bright spots are a direct indicator of gas deposits, and untested bright spot anomalies occur elsewhere in the Queen City Formation and in the Jackson Group. High-amplitude seismic reflections in Jackson sandstones southeast of Seventy-Six West field suggest potential for a field extension or new field discovery. Upper Wilcox Seismic Facies 2 indicates numerous prospective zones on the DCR expressed as discontinuous, very high amplitude reflections. These are associated with a zone in which the Wilcox section is very thick, sand deposition was focused on the down side of growth faults, and rollover structures provide traps. Although the expanded downdip Wilcox trend is prospective for new deep gas pools, this play is mainly south of the DCR, and there is little likelihood of a major deep Wilcox discovery on State Lands.

Other findings of the study are that the lower Wilcox is sandstone-poor in the DCR area and is assigned a very low exploration potential. There is a high-risk deep gas exploration play in the Lower Cretaceous.

In addition to the specific potential field extension targets at Seventy-Six West and Lundell fields, this study has documented general seismic characteristics that identify potential hydrocarbon accumulations in Upper Wilcox, Queen City and Jackson-Yegua units and provides a rationale for their exploration and development.

Keystone field: The Keystone (Colby) reservoir, equivalent to the Queen Formation of Permian (Guadalupian) age, is located in the northwestern part of the Central Basin Platform of the Permian Basin, approximately 10 mi from the platform margin. The trapping mechanism is a combination of structure, a north–northwest-trending anticline, and depositional facies changes. The producing interval is approximately 300 ft thick and occurs at a depth of 3,500 ft.

The reservoir is composed of porous, very fine grained arkosic sandstones interbedded with generally low-porosity dolomite and anhydritic dolomite. Sandstones are interpreted to have been delivered to the shelf margin by eolian transport and reworked in shallow-water marine to peritidal environments. Sandstones deposited in the shallow-water marine environment are fine grained and massive, whereas sandstones deposited in the peritidal environment have a higher clay content and abundant anhydrite nodules. The peritidal sandstones commonly are in gradational lateral contact with nonporous nodular anhydrite beds. Interbedded shallow-water marine and peritidal dolomite is generally finely crystalline mudstone with abundant anhydrite nodules and cements. Some of the carbonate beds contain karst breccias and erosion surfaces. These lithologic features, and the absence of fossils, indicate that the shelf was an intermittently exposed hypersaline environment. These facies are arranged in vertically stacked, upward-shoaling parasequences.

The Keystone (Colby) reservoir is vertically divided into five sandstone-dominated units within a 16-mi^2 study area. Isopach maps of each of these five units and completion interval data indicate that large areas of thick sandstones are not open to well bores. Conservative estimates based on porosities measured in cores and estimates of net pay thickness and saturations indicate that more than 15 MMSTB of mobile oil are not accessed by existing well bores in the study area.

The Keystone (San Andres) reservoir is located in Winkler County in the northwestern part of the Central Basin Platform of the Permian Basin, approximately 10 mi from the platform margin. The principal trapping mechanism is a north–northwest-trending anticline. Since discovery in 1960 this reservoir has produced 2.8 MMbbl of solution-gas driven oil. A pilot waterflood program was initiated in 1992.

The reservoir has been divided into 3 major stratigraphic divisions and 12 flow units on the basis of multiple upward-shoaling cycles of shallow-water marine to tidal-flat carbonate facies. Minor concentrations of siliciclastic material concentrated in tidal-flat rocks impart a gamma-ray signature that allows correlation with well logs. These rocks are now thoroughly dolomitized and cemented with anhydrite and gypsum. Porosity occurs principally as interparticle pores in subtidal packstones.

Most of the well logs in this reservoir are old. However, during the course of this study we were able to obtain several modern log suites and one conventional core from newly drilled wells, and these data were used to calibrate old logs within a part of the field in which a pilot waterflood is under way. Regression analysis of modern logs has yielded relationships between core porosity, measured using non-gypsum-destructive analytic techniques, and neutron, density, and acoustic log response. These relationships were used to calibrate old logs.

Hydrocarbon volume maps (S_o—phi—h) maps and a three-dimensional model indicate three trends of importance in planning for expansion of the waterflood. First, the highest hydrocarbon saturations are centered on an injection well. Second, saturation trends are subparallel to structure, with saturations decreasing in the updip direction. Third, infill wells planned to complete a modified five-spot waterflood pattern include one location in the low-saturation, updip part of the study area, where production is predicted to be low. Incorporation of these saturation trends in development of an expanded waterflood will increase the efficiency of the flood.

A paper reporting preliminary results of this study was named the first-place "Best Oral Presentation" by the West Texas Geological Society. This paper, written by R. P. Major, M. H. Holtz, and R. D. Dommisse and titled "Calibration of porosity logs and delineation of flow units in a San Andres reservoir: Keystone field, West Texas," was presented at the 1992 annual fall symposium of the WTGS and published in the transactions volume for that meeting.

Lavaca Bay field: Lavaca Bay reservoirs are examples of barrier/strandplain gas reservoirs, a common reservoir type in State Lands of the Gulf Coast. The complex nature of these stacked sandstone units, which were deposited as beach ridges and associated features in proximity to fine-grained offshore sediments, results in highly compartmentalized reservoirs. A common consequence of the compartmentalization of these barrier/strandplain reservoirs is that, even in mature reservoirs that have been penetrated by numerous wellbores, some compartments may remain untapped. When this style of reservoir heterogeneity is combined with multiple stacked reservoirs, complex growth faulting, and associated folding, as is common in Tertiary rocks of the Gulf Coast, the opportunities for locating untapped reservoir compartments can be numerous. Moreover, the presence of multiple stacked reservoirs commonly provides opportunities to access untapped compartments by recompleting existing wellbores, which greatly improves the economic efficiency of draining the remaining resource in a mature field.

Lavaca Bay field, located in Calhoun County, Texas, produces gas from the Downdip Frio Barrier/Strandplain Sandstone of the San Marcos Arch play. The productive part of the Frio Formation in Lavaca Bay field is divided into 5 depositional sequences that are subdivided into 26 sandstone/shale units, 20 of which are proven gas-productive reservoirs. Well-log parameters, including net-sandstone thickness, relative spontaneous potential deflection, resistivity, and the products of net-sandstone thickness and relative spontaneous potential were contoured, then integrated with structure maps and production history, to identify separate reservoir compartments. Detailed analysis of one reservoir within the field, Unit 2 of Sequence IV, serves as an example to illustrate these mapping methods.

The Unit 2 of Sequence IV reservoir is divided into five compartments defined by log-derived parameters and production. Two of these compartments contain two or more stacked beach-ridge sandstone bodies that together contain two prospective infill-well locations and one prospective recompletion location. The remaining three compartments contain a single beach-ridge sandstone body. Two of these compartments contain one recompletion target each. The third compartment is relatively small and is adequately drained by an existing well.

Similar analysis of all 26 reservoirs in Lavaca Bay field yielded 10 proposed infill well locations, each of which individually targets from 2 to 8 separate reservoir compartments, and 30 prospective recompletion targets.

A paper reporting preliminary results of this study was named third-place Best Paper by the Gulf Coast Association of Geological Societies. This paper, by J. U. Ricoy, J. S. Yeh, and R. P. Major and titled "Evaluation of reserve-growth potential in barrier/strandplain compartmentalized reservoirs of the Frio Formation, Lavaca Bay field, South Texas," was presented orally at the 1992 annual meeting of the GCAGS and published in the transactions volume for that meeting.

Powderhorn field: Powderhorn (Miocene) field is located in Calhoun County, approximately 5 mi northwest of Port O'Connor. This field is classified as part of the Miocene Barrier/Strandplain Sandstone Play of the UT/BEG *Atlas of Major Texas Gas Reservoirs.* Powderhorn field is located on an anticline in the hanging wall of an up-to-the-coast antithetic fault above a major reactivated Frio growth fault. Powderhorn field contains 11 producing reservoirs. Ten reservoirs produce from combination structural/stratigraphic traps in which lateral seals are created by the deposition of permeable sandstones adjacent to impermeable siltstones and shales.

Since discovery in 1939, total oil and gas production from all Powderhorn reservoirs has been approximately 6 MMbbl of oil and 50 Bcf of gas from an area slightly smaller than than 2 mi^2. The most important reservoir is the 5200 Sand, which has produced more than 4 MMbbl of oil and 1 Bcf of gas from sandstones deposited in washover fan and flood-tidal delta environments. The major gas-producing reservoirs are the 3 Sand and the Miocene No. 1 Sand, which have produced approximately 11 and 30 Bcf, respectively. These reservoirs are developed in fluvial- and distributary-channel fills and crevasse splays. Other Powderhorn reservoirs produce from tidal-inlet fills, barrier cores, and bayhead deltas.

The following maps and sections have been constructed: (1) isopach maps of all reservoir sandstones, (2) facies maps of all reservoir sandstones, and (3) a grid of 14 stratigraphic cross sections. An extensive well data base has been compiled that includes well identifiers, locations, elevations, dates, wireline logs available and obtained to date, conventional and sidewall core intervals, structure tops, sandstone thicknesses, producing reservoirs, initial production test data, and completion, stimulation, and workover summaries.

Conventional two-dimensional common-depth-point seismic data, obtained from the field operator, have been interpreted in the field area. Time-to-depth conversions have been accomplished using synthetic seismograms created from acoustic and density logs from several recently drilled wells. Impedance variation between wells has been modeled using log-derived parameters for density, velocity, porosity, and fluid saturations. Gas saturation has a significant effect on seismic response, and the presence of gas can be detected on existing seismic data in some Powderhorn reservoirs.

Development drilling since the inception of Project SLERO has resulted in four infill producers and one dry hole on an attempted field extension. Most significant was the No. 17 State Tract 49. This well made a deeper pay discovery in the 5300 Sand and added at least 750,000 bbl of oil and an unknown amount of gas to field reserves. This represents an increase of more than 12 percent in the field's oil reserves. The State Tract 49 No. 17 was so successful that a twin well was drilled by the field operator to accelerate production of the newly discovered oil. In total, nearly 1 MMbbl has been added to field reserves since the inception of Project SLERO, an increase of 15 percent over pre-SLERO reserve estimates. Although precise estimates cannot be made until the gas reservoirs have been produced, significant reserves of gas have also been added. Through May 31, 1993, the cumulative production from new wells drilled during Project SLERO has been 90,000 bbl of oil and 0.2 Bcf of gas.

Powderhorn field is an example of successful application of detailed geologic description toward increasing production from mature oil and gas fields in the Gulf Coast province of Texas. Many more barrels of oil and cubic feet of gas are obtainable from multireservoir fields in State waters of coastal Texas when heterogeneous reservoirs are subjected to careful geologic and engineering analysis.

Las Tiendas (Olmos) field: Las Tiendas (Olmos) field is part of the Upper Cretaceous Olmos Deltaic and Delta-Flank Sandstone play. Las Tiendas is representative of the distal downdip portion of the play in Webb and LaSalle Counties, where dry gas is produced from low-permeability shelf sandstones. In 1982 the Olmos Formation in this area was designated as a tight gas formation by FERC and the Railroad Commission of Texas.

Downdip Olmos fields produce from thin-bedded silty and shaly sandstones. Individual sandstone beds are sharp based; the tops of sandstones and the interbedded sandy siltstones and shales are moderately to heavily bioturbated. Where sandstones are more than 1 ft thick or where sand deposition was relatively rapid, unbioturbated sandstones have been preserved. These sandstones are commonly massive or subparallel horizontally stratified; low-angle cross-stratification interpreted as hummocky cross-stratification and current ripples are less common. Moderate- to high-angle cross-stratification is conspicuously absent. These beds are interpreted to be distal delta-front, transitional, and inner shelf deposits on a storm-dominated, low-energy shelf. The unbioturbated sandstones have average permeabilities that range from 0.4 md in the northeast to 0.05 md in the southwest; maximum permeabilities rarely exceed 1 md. Porosity and permeability are reduced by the presence of detrital and authigenic clays and calcite cement.

Sandstone beds are organized into 10- to 50-ft-thick lenses of sand-rich strata separated by 0 to 50 ft of siltstone and shale. Sandstone lenses can be correlated between wells for tens of miles. Individual thin sandstones are at the limits of wireline log resolution but appear to have a more limited lateral extent. Pinch-outs of individual sandstones and updip permeability reduction are primarily responsible for trapping gas. Small (30 to 130 ft) normal faults interrupt regional homoclinal dip and locally trap gas. The shelf sandstones form lenticular, strike-elongate deposits. Lower sandstones lenses are lenticular in plan view, connected to an Olmos delta to the west, and are in transitional contact with shale in all other directions. Upper sandstone lenses are strike-elongate but thicken updip into coeval shoreface deposits.

Gas production in Las Tiendas field averages approximately 50 Mcf per day per well for 75 wells; cumulative production for the field is more than 20 Bcf of gas through 1990. Las Tiendas is one of six larger (10 to 50 Bcf) Olmos fields that together form a continuous producing trend in northwest Webb and southwest LaSalle Counties. Cumulative production from the downdip trend is more than 150 Bcf. These fields were discovered and initially developed simultaneously between 1970 and 1974. Many wells were assigned to fields without geological or geographical consideration, so field boundaries are highly overlapping over the continuous producing area. Required well spacing ranges from 40 to 320 ac for these fields. Because of the wide spacing of wells and the low permeabilities of reservoir sandstones, significant gas reserves remain between wells on State Lands in the Las Tiendas area. These reserves can be exploited profitably with a geologically targeted drilling program at average gas prices of $2 to $3 per Mcf.

A paper reporting preliminary results of this study was named first-place Best Paper by the Gulf Coast Association of Geological Societies. This paper, by K. T. Barrow, G. B. Asquith, and G. L. Causey and titled "Shaly sand analysis as an indicator of hydrocarbon production potential in the Olmos Formation, Las Tiendas trend, South Texas," was presented orally at the 1992 annual meeting of the GCAGS and published in the transactions volume for that meeting.

Delaware Mountain Group: (subregional study): The Guadalupian stratigraphy of the Delaware Basin consists of depositional cycles at a range of scales. A classification based on multiple scales of cyclicity, designated as low-, intermediate-, and high-order, is used to emphasize comparable scales of cyclicity. Three orders of cyclicity have been regionally correlated and are inferred to record the combined effects of changes in sediment supply, tectonic movement, and sea level.

Eight low-order cycles are recognized in the DMG, four in the Brushy Canyon, two in the Cherry Canyon, and two in the Bell Canyon. These form asymmetric, up to 300-m-thick siliciclastic successions with minor carbonate interbeds. The proportion of sandstone relative to limestone and siltstone increases vertically. Low-order cycles are bounded by regionally correlative carbonates and siltstones. They consist of two to four intermediate-order, more symmetrical cycles characterized by 10- to 100-m-thick successions that are inferred to represent basin-floor to intraslope submarine lobe complexes. Twenty-three intermediate-order cycles are correlated across the northern Delaware Basin. Intermediate-order cycles contain two to seven high-frequency symmetric cycles that are 2- to 30-m thick and are bounded by thin organic-rich siltstone beds. Each high-order cycle typically forms an upward-bed-thickening succession of thinly interbedded sandstone and siltstone, ripple-laminated sandstone, and erosive-based, structureless sandstone followed by an upward-bed-thinning succession of similar facies in reverse order. The highest energy (reservoir) portion of these cycles contains up to 5-m-thick, laterally discontinuous, erosive-based, amalgamated, and overlapping sandstone lenses that are interdigitated with thinly interbedded to interlaminated sandstones and siltstones. Thinly interbedded sandstones and siltstones display in some instances waning-flow, Bouma B-C-D sequences and/or traction-generated low-angle cross stratification, asymmetrical to symmetrical ripple-laminations, flaser laminations, and inverse grading that is inferred to represent bottom-current reworking. Interlaminated organic-rich siltstone and sandstone form meter-thick successions that are bundled into 2-cm-thick packages. This style of sedimentation reflects deposition of airborne silt and very fine grained sandstone that punctuates the normal hemipelagic sedimentation.

Because reservoir sandstone is volumetrically dominant, the most important control on hydrocarbon accumulation in the DMG is related to the development of low-permeability seals that impede updip hydrocarbon migration and enhance downdip hydrodynamic trapping. The change from structureless sandstone to interlaminated sandstone and siltstone, organic-rich siltstones and carbonate mudstones occurs within relative sea-level rise portions of long-term cycles. Hence, vertical and lateral seal occurrence is selective to the top of low-order cycles where the additive effects of marine deepening at all scales of cyclicity constructively combine to promote deposition of seal facies. Clastic-sediment starvation and highstand shedding of basinal carbonates produce laterally extensive low-permeability and low-porosity strata that form vertical seals, whereas compartmentalization of lower energy, laterally discontinuous reservoir sandstone forms lateral seals.

Screw Bean field: Bell Canyon and Cherry Canyon fields in the Screw Bean field area produce from multiple Delaware Mountain Group reservoir horizons that are characterized by a low primary recovery efficiency (17 to 21 percent) and high water cut that reduces cumulative production. Structural contours on the top of both Bell and Cherry Canyon Formations indicate local monoclinal dip to the southeast, with no structural closure. Hydrocarbon accumulations are generally related to a lateral facies change to low permeability lithologies along the updip margin of submarine lobe complexes and component sandstone lenses. Additional oil accumulations are trapped by downdip-to-the-southeast hydrodynamic flow.

Detailed facies analysis of core has identified five lithofacies with distinct petrophysical attributes. These include (1) structureless sandstone (reservoir facies), (2) organic-rich siltstone (lutite), (3) very thinly laminated sandstone and siltstone, (4) thinly bedded ripple-laminated sandstone and siltstone, and (5) nodular carbonate mudstone and wackestone with wispy siltstone laminae. Acoustic and gamma-ray log traces were calibrated to core and plotted against core facies to quantitatively define log facies.

The upper portions of the Bell and Cherry Canyon Formations form intermediate-order stratigraphic cycles that consist of symmetrical high-order cycles. The distribution and occurrence of reservoir flow units are in a predictable position within these high-order cycles. In the upper Bell Canyon Formation, high-order cycles are characterized by an overall back-stepping stacking pattern with submarine lobe thicks including reservoir sandstones systematically displaced to the northwest. The upper Cherry Canyon Formation (Manzanita Limestone Member) also displays a back-stepping stacking pattern of high-order cycles; however, there is also a systematic shift in sandstone thicks from the southeast to the northwest.

Reservoir flow units are represented by structureless sandstone that is best developed at the turnaround from relative sea-level fall to rise of short-term cycles. Reservoir flow units form multiple, broad (300- to 1000-m-wide), thin (2- to 5-m-thick), lenticular, and overlapping sandstone lenses. Reservoir sandstones are well sorted, have a mean grain size of 0.09 mm, and are classified as feldspathic litharenites. They are characterized by high primary porosity (15 to 26 percent) and average permeability (0.1 to 200 md). These sandstone lenses are inferred to represent multiple small-scale and short-lived channels that are encased within elongate deposits of distal basin-floor submarine lobe complexes that are 1- to 2-km wide and 10-km-long. Sandstone lenses within discrete lobes form thin, laterally discontinuous and poorly interconnected flow units that are bounded by low-permeability siltstones and thin carbonates. Consequently, reservoir flow units are highly compartmentalized indicating a significant opportunity for substantial reserve additions along the updip margin of discrete submarine lobes.

Results from this study highlight the significant potential for reserve additions in the DMG. Techniques to recover the remaining oil include (1) recompletion of wells that perforate only one reservoir but contain multiple untapped reservoir horizons, (2) deepening of wells that only penetrate the top 50 ft of the Bell Canyon Formation, and (3) infill drilling in undrilled fairways that contain multiple reservoir horizons that are productive in adjacent producing trends and occur in updip positions along the margins of discrete basin-floor submarine lobe complexes.

A paper based in part on this study won the first-place "Best Poster Presentation" award by the West Texas Geological Society. This paper, written by Charles Kerans, W. M. Fitchen, M. H. Gardner, M. D. Sonnenfeld, S. W. Tinker, and B. R. Wardlaw, titled "Styles of sequence development within uppermost Leonardian through Guadalupian strata of the Guadalupe Mountains, Texas and New Mexico," was presented at the 1992 annual fall symposium of the WTGS and published in the transactions volume for that meeting.

Red Fish Bay field: Red Fish Bay field, in Nueces County, Texas, is part of the downdip Frio Barrier Island/Strandplain to Shoreface/Shelf play. The field was discovered in 1950 and is located 5 mi southeast of Aransas Pass in Corpus Christi Bay and Red Fish Bay. Red Fish Bay field has 50 reservoir sandstones in the middle to upper Frio Formation that have produced more than 23 MMBoe of oil and gas. The trapping mechanism is a large anticlinal closure on the upthrown side of a large regional growth fault, in addition to a depositional facies change to increasingly more shaly sediments to the east and northeast.

Our research focused on 18 major reservoirs in the upper Frio Formation that occur at depths of 7,300 to 8,500 ft (Railroad Commission of Texas reservoirs 10-A; 10 Lower; 5; 5-A; 5-B; 9; 8;14; 14-A; 14 Up; 14 Up, N; 15; 15-A; 15 Up; 17; 17 L; 17 Up; and 18). These reservoirs account for more than 75 percent of the cumulative field production and have yielded mostly oil. This study focused on these prolific reservoirs because they offered the best opportunity for locating significant bypassed resources. In addition, more than 180 exploration and production wells penetrate the upper Frio, permitting detailed subsurface mapping and reservoir characterization. Declining hydrocarbon production from these reservoirs has caused the field operators to consider them to be depleted, and recent drilling activity has targeted deeper Frio reservoirs.

The major objective of this project was to characterize the upper Frio reservoirs and to identify regions that are underexploited by existing well completions. The study was directed toward increasing primary hydrocarbon recovery by recommending appropriate recompletion and infill-drilling strategies to the field operator. The multiple stacked reservoirs afford opportunities to access untapped reservoirs by recompleting existing wellbores. Infill-drilling targets also have been delineated, especially stacked reservoirs within a single borehole, a situation that improves drilling economics.

Most of the well logs from the more than 180 wells drilled in Red Fish Bay field are 1 in = 100 ft scale electric logs dating from the 1950's and 60's, although detailed well logs at a scale of 5 in = 100 ft were obtained for approximately one-third of the wells. Fifteen wells of post-1970 age have more complete modern logging suites. Porosity and permeability data exist for cored intervals in 10 wells. Completion/recompletion data, well potential test information, and production statistics were compiled from data obtained from the Railroad Commission of Texas and from commercial sources.

Regional maximum flooding surfaces were used to place reservoir sandstones into a genetic sequence stratigraphic framework. The shale flooding surfaces and reservoir sandstones were correlated throughout the 18-mi^2 Red Fish Bay field, and structure maps for each of the 18 reservoirs and 7 flooding surfaces were prepared. Stratigraphic cross sections, well log SP character, and sandstone isopach maps indicate that the major reservoir sandstones were deposited in a shoreface to shelf setting and are interbedded with shelf mudstones. Reservoir sandstones are laterally continuous and exhibit minimal abrupt lateral facies transitions. The sandstones generally thin basinward to the east and northeast, where they grade into distal shelf mudstones.

The oil-water and gas-oil contacts in each reservoir were identified from log and production data, and these fluid contacts were used to delineate the reservoirs. The reservoirs are coincident with structural closure, indicating minimal facies- or fault-induced internal compartmentalization, which is confirmed by production and pressure data. The east and northeast reservoir limits are defined by the basinward transition to more distal mudstones. Reservoir maps, sandstone isopach maps, and completion data indicate that extensive areas with thick sandstone development are untapped by existing wellbores. Prospective recompletion and infill-drilling opportunities have been identified in each reservoir, except for the 5-A and 5-B reservoirs, which were efficiently exploited and have been waterflooded. Twenty recompletion opportunities have been identified. Infill-drilling targets were delineated in each oil reservoir and in their associated underexploited gas caps.

These bypassed resources have been confirmed by log analysis of recently drilled wells that penetrate the shallower reservoirs but were completed in deeper Frio targets. These recent wells postdate most of the upper Frio production and record resources that remain unexploited. Detailed petrophysical analysis of well logs and core data document high porosity and hydrocarbon saturation in proposed recompletion opportunities. This petrophysical analysis has also evaluated the relative permeabilities for water and oil in each recompletion interval and predicted the production potential.

Conservative estimates of hydrocarbon volumes based on reservoir mapping and porosities and saturations derived from core data and well log analysis indicate that in one reservoir, zone 14, approximately 4 MMSTB of mobile oil remains in place and that 1 MMbbl of this oil could be produced during primary recovery via recompletions and infill drilling. Hydrocarbon volumes of the other reservoirs are being estimated, and these estimates will be used to assess remaining reserve growth potential in Red Fish Bay field.

West Fulton Beach field: West Fulton Beach field is located on State Submerged Lands in Copano Bay, Aransas County. Its 34 separate reservoir intervals in the upper to lower Frio Formation (6,000 to 8,000 ft deep) are typical of the Downdip Frio Barrier/Strandplain of the San Marcos Arch play. Cumulative production through 1989 has exceeded 24 Bcf of gas and 8 MMbbl of oil. Hydrocarbons have been structurally trapped on the hanging wall of a northeast–southwest-oriented, southeast-dipping normal fault. Minor parallel and perpendicular faults near the crest and flanks of the field, respectively, have partitioned some reservoirs. Daily production is approximately 600 Mcf and 20 bbl of oil and condensate from eight producing wells. Thirty wells have been abandoned.

The reservoirs have been grouped by the original field operator into 11 intervals, lettered A through K, on the basis of subregionally mappable shales, which represent flooding surfaces. Reservoirs are concentrated in the A through E and G through H sections. These 11 intervals vary in thickness from 110 to 280 ft and are considered 5th-order genetic stratigraphic units (GSU). The 34 productive reservoir intervals vary from 10 to 60 ft thick and are 6th-order GSU's, which, along with similar unproductive intervals, compose the 5th-order units. The lowermost 6th-order GSU's in a 5th-order package are seaward-stepping (progradational), whereas the uppermost are landward-stepping (retrogradational). Reservoir architecture and potential for compartmentalization differ between these two styles of units. Reservoirs tend to be concentrated in the upper, landward-stepping 6th-order units of the 5th-order GSU's.

Individual reservoir sandstones vary from 2 to 60 ft in thickness and were deposited in barrier bar, strandplain, inner shelf, and, rarely, middle shelf settings. Barrier bar and strandplain sandstones are thicker (10 to 60 ft) and more laterally continuous, whereas shelf sandstones are thinner (2 to 15 ft) and more discontinuous. The greatest potential for compartmentalization exists in inner shelf sandstone reservoirs due to their thin-bedded and less continuous nature and their ability to be partitioned by small faults with throws as small as 10 ft.

Numerous products of this project have assisted in characterizing the reservoirs and locating future potential. Structure contour maps of the 11 flooding surfaces illustrate increasing reservoir dip with depth and highlight possible infill potential downdip from the crest and along the flanks of the field due to structural compartmentalization of some reservoirs. Detailed structural and stratigraphic cross sections (vertical scale of 1 inch = 20 ft) show the internal architectural styles of selected reservoirs and indicate possible infill potential due to stratigraphic compartmentalization. Net sandstone/SP log shape maps of nine individual reservoir intervals document the location of maximum sandstone thickness and quality, suggesting the optimum locations for infill and recompletion targets.

A meeting will be held in August with the field operator to transfer the results of this study. The operator has been actively pursuing recompletion candidates and is considering a five-well infill/redevelopment program. It is anticipated that the outcome of this study will affect the locations of future recompletions and infill wells, resulting in more efficiently drained reservoirs and greater ultimate oil and gas production.

Alabama Ferry field: Alabama Ferry field, Leon County, Texas, is located on the south edge of the East Texas Basin, 25 mi northwest of the upper Glen Rose shelf margin formed during the early

Cretaceous. Alabama Ferry field is unique among other Glen Rose reservoirs of the East Texas Basin in that its location does not appear to be directly related to salt domes and pillows. This reservoir has been considered to be a true stratigraphic trap and representative of other potential upper Glen Rose grainstone reservoirs that could occur in an extensive belt 50 mi wide and more than 300 mi long from Leon County south to the Texas/Mexico border. Production from the Alabama Ferry north unit (AFNU), which contains two State Lands blocks, is from a 2- to 40-ft-thick grainstone reservoir. The reservoir is approximately 1 mi wide and 5 mi long and occurs at depths of 9,000 to 9,500 ft in the 70-ft-thick Lower Cretaceous Upper Glen Rose "D."

Alabama Ferry field was discovered in 1983, and production was initiated in 1986; the AFNU was established in 1991. The AFNU is developed irregularly up to 160-acre spacing; production from this unit was 6.9 MMbbl of oil and 20 Tcf of gas through April 1993. Water injection began in 1991, and through April 1993 a total of 19.8 MMbbl of water had been injected.

The AFNU reservoir section is composed of three porous and permeable skeletal-intraclast-ooid grainstones separated by nonporous shales and low-porosity ooid grainstones. Thus, there is a distinct vertical partitioning within the reservoir. Because of the grainstones offlap to the north, only two of the porous zones occur in any single well. Porosity is both interparticle and moldic and is best developed in the upper part of the grainstones where skeletal content is high. Grainstones with high content of ooids generally have low porosity and occur at the base of the grainstone units.

From 1986 through December 1990, prior to waterflood, 3.3 MMbbl of oil had been produced along with only 2,401 bbl of water. However, just prior to waterflood, production from most wells had declined to approximately one-third of that volume produced during the first 6 months. In January 1991, waterflood was initiated, and production in most wells at least doubled that of December 1990 and in some even surpassed initial monthly production. Post-waterflood production from January 1991 to April 1993 was 3.6 MMbbl, slightly higher than pre-waterflood production.

Within 1 year of initiation of waterflood, water breakthrough occurred, and some production wells began producing huge volumes of water. Through April 1993, 2.4 MMbbl of water had been produced, and the operator is now considering methods by which the more permeable zones can be blocked to flood water. This study has provided the operator with a reservoir framework (maps and cross sections) showing distribution of geologic facies and porosity and permeability and maps of oil and water production, which together can provide support data for reservoir modification. Using these tools, high-permeability zones in wells producing large volumes of water can be identified and properly controlled to decrease water production and increase oil and gas production by more effectively flooding other less-permeable zones.

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Activity 2: Reservoir Characterization

Task 1: Laboratory analysis and theoretical modeling

The first objective of this project was to develop a method to estimate permeability from thin-section images and to apply this method to State Lands reservoirs. Permeability estimation from thin sections offers means to determine permeabilities over a wide range of conditions, including those for which cores are not available, and thereby improve predictions of reservoir performance. The second objective was to measure capillary-pressure data to obtain a better petrophysical evaluation of the Keystone (Colby) reservoir, to determine the initial distribution of oil and water in the reservoir, and to develop P_c-S_w curves.

We conducted a literature review of methods using a centrifuge to measure fluid distributions and capillary-pressure curves. Using an epoxy that hardens while the rock sample spins in the ultracentrifuge, we imaged fluid distributions at a variety of capillary pressures in a sandstone core. We investigated mathematical models to relate these fluid distributions to relative permeabilities. In addition, capillary-pressure data for the Keystone (Colby) reservoir were measured and distributed.

Task 2: Interpretation of well log data

Red Fish Bay field: An analysis of the available logs in Red Fish Bay field was performed. We selected for study seven key wells that had the most complete logging suites, including spontaneous potential, deep resistivity, acoustic travel time, density, neutron porosity, gamma-ray, and caliper. Corrected logs were ported to the Multi-Well data base (MWDB). The multiwell crossplots indicated five cases of log miscalibration, which were corrected, enhancing the quality of the interpretation markedly.

An advanced statistical interpretation program was used to derive the lithology, porosity, and water saturation in upper Frio reservoirs in each of the key wells. Results compared favorably with those of UT/BEG researchers. The analysis discovered the presence of hydrocarbons, possibly oil, in the eighth sandstone of three wells. The logs also indicate that the tenth sandstone is predominantly hydrocarbon-bearing throughout the field. This sandstone is gas-bearing over most of the field, but it is likely to produce oil from the tenth sandstone in the wells to the south.

This log analysis study demonstrated that it is better to use the Qv log, which is readily computed from the spontaneous potential and mud and connate water properties, for estimating reservoir flow capacity because this is a more linear estimate of effective porosity. Considerable potential for bypassed pay has been delineated by this study.

Lavaca Bay field: The goal of the log analysis study of Lavaca Bay field was to determine the well logging parameters and an interpretation model that can be used to estimate water saturation, porosity, and permeability for reserve calculations.

Four key wells were selected for detailed analysis based on their having the most comprehensive data sets. Logs available on digital tape were dual induction, acoustic, compensated neutron, electromagnetic propagation, and natural gamma spectroscopy. Conventional sidewall core analyses were also available for these four wells. The interpretation was performed using a statistical matrix equation solver that determines the specific volumes of minerals and fluids. The advantage of using this approach is that logs can be reconstructed from the interpretation and compared to the measured logs to provide a mathematical justification for the parameter selection. A simple mineral model containing three minerals (quartz, illite, and albite) was assumed.

Permeability was estimated using Herron's mineral model, taken from the literature. Porosity and permeability were very close to those measured in core, and water saturation was close to that measured from core in sandstones. This model has been applied to five other wells in the field. The results indicate that this simple mineral model can estimate petrophysical parameters reasonably, which should aid in better geological reservoir characterization to identify unproduced hydrocarbons.

Task 3: Measurement of reservoir heterogeneity using tracer data

A new description of reservoir heterogeneity in parts of Sections 61 and 62 of Seventy-Six West field was generated for reservoir simulation studies. Waterflood response was considered using well 62-18 as a water injection well. The waterflood response was found to be very fast, resulting in an increase in oil production rate from 40 STB/D to a peak value of 70 STB/D after only 4 months of water injection. Wells 1, 9, and 29 are the main contributors to the increase in oil production rate, and well 29 shows the highest production rate at a peak value of 22 STB/D. Cumulative oil production after 20 years is 206 MSTB, which is an increase of about 152 MSTB of oil over the estimated production without waterflooding. These estimates have a very large uncertainty associated with them because of the paucity of data and resulting uncertainty in the reservoir properties. This uncertainty can be reduced by using tracers, as discussed below.

Our chemical flood simulator, UTCHEM, was used to simulate interwell tracer tests, which involve the injection of chemical tracers into well 62-18 and monitoring tracer production from producing wells. Interwell tracer tests were simulated to illustrate how these could be used to help better understand field waterflood performance. These tests could also be used to improve design of the waterflood and to aid reservoir description by delineating flow barriers such as faults and facies limits. The use of partitioning tracers was also evaluated because partitioning tracers can be used to estimate the average oil saturation in the waterflood-swept volume of the reservoir. All of these applications appear to be feasible and useful at Seventy-Six West field.

Third, a newly developed single-well backflow tracer test was simulated to estimate reservoir rock wettability under Seventy-Six West field conditions. This novel method is described and illustrated in great detail in the Ph.D. dissertation of Luiz Ferreira (1992). Briefly, the single-well backflow tracer test consists of a sequential injection of reservoir brine containing tracers, followed by a tracer-free oil buffer. The tracers are esters that partition between the oil and water phases and react by hydrolysis to form alcohols. Nonpartitioning and nonreacting water and oil tracers are also used for the purpose of material balance. The well is shut in for a period of time to allow hydrolysis and phase redistribution, then the well is produced. Using the information obtained during this test, it is possible to infer the preferential rock wettability by matching the data using the UTCHEM simulator. The resulting estimates of relative permeability could be used in subsequent waterflood simulations to reduce the uncertainty of estimated waterflood performance and improve the efficiency of its design. The result of such an analysis is increased oil recovery and profitability of the waterflood.

Task 4: Construction of data model

This task consisted of archiving and maintaining data and other information collected by this project. An additional task was developing and maintaining various methods of access so that the data can be used by researchers. The goal of this work has been to document the data available and allow as many access mechanisms as possible for users to obtain the data. Special attention has focused on network access mechanisms so that the data may be easily distributed to project workers at remote sites.

Data for the various research areas of this project were collected from a number of sources. Although some data were forwarded to the archive from the researchers who collected the data, the majority of data in the archive was collected by going to public sources, such as the Railroad Commission of Texas, and obtaining data that were relevant to the project. These data primarily consisted of production and engineering data for wells that were drilled in the State Lands areas of interest. To facilitate in the data entry process, a number of programs were developed that allowed an operator to read data from the collected forms and enter them into a data base. This shortened the time required to enter the information into the archive and also aided in maintaining a standard format. Some optical scanning of the collected forms was also done to further increase the amount of data collected. Digitized well-log data were collected and translated into standard well-log data formats for access by researchers. The formats selected for use were the LIS and LAS formats. Both are widely used in the petroleum industry.

A number of different access mechanisms were developed to allow researchers to access the data. These access mechanisms included anonymous ftp, Data Access Language (DAL), and DECnet access. In the latter stages of the project, methods were developed to allow access to the data through wide area information services such a gopher, the world wide web (WWW), and wide area information services (WAIS). The primary goal of this phase of the project was to make the data collected in the archive available through the largest number of mechanisms possible.

Activity 3: Advanced Extraction Technology

Task 1: Waterflood surveillance and optimization

Seventy-Six West field is one of nearly 300 fields in the Jackson-Yegua Barrier/Strandplain Sandstone play. In addition to primary recovery, past recovery processes include a pilot fireflood and a waterflood. Currently the oil wells in this field are produced by conventional rod and downhole pump assemblies.

The complex reservoir geometry of Seventy-Six West field has created significant fluid-flow anisotropy. As a result, mobile oil has been trapped or bypassed in compartments poorly swept by the current well spacing and in zones poorly contacted by waterflood. Of the estimated 25 MMSTB of original oil in place (OOIP), the field has produced approximately 4.7 MMSTB of oil in its 36-year production history. If no further development is implemented, the field is projected to produce an additional 347 MSTB before estimated abandonment in the year 2007.

This study was aimed at evaluating the current status of the northeastern area of the field. It proposes new schemes for efficient recovery of the remaining oil by geologically targeted infill drilling and waterflood optimization. The injection of water should repressurize the reservoir, providing necessary energy to drive oil to the producing wells. Different waterflood scenarios were studied using a numerical simulation approach. Simulation results indicate that waterflooding can significantly improve oil recovery. Recovery can be further improved by combining infill drilling with a waterflood. The waterflood can be optimized by an appropriate injection scheme to reduce the amount of water injected without significantly reducing the amount of oil recovered.

The purpose of an additional study was to determine how to optimize oil recovery from Keystone (San Andres) field in Winkler County by infill drilling and waterflood optimization. The study area included State Lands in Sections 13 and 14 of Public School Lands Block 2.

The Keystone San Andres reservoir had an estimated OOIP volume of 60 MMSTB at discovery in 1960. Since that time this reservoir has produced 2.6 MMSTB, and it now contains an estimated 33.4 MMSTB of remaining mobile oil. Primary production has been declining at 9.5 percent per year since 1980. To maintain production, a pilot waterflood program was initiated. Production wells are characterized by a high initial potential and low primary recovery. The depositional and diagenetic history of this field makes it highly heterogeneous. A reservoir model was developed using production, core, log, and tracer data. A 10-acre reservoir simulation model using five layers was created. Individual layer production was evaluated, and different water injection rates and permeability directions were studied. An areal simulation was also conducted with a streamline simulator to identify the different flow paths obtained by use of three different infill-drilling and waterflood patterns: (1) base case—continuation of existing operations using only one injection well, (2) use of five-spot patterns, and (3) use of nine-spot patterns.

The study showed that waterflooding can double recovery over that of primary production, but because of low permeabilities, very high injection pressure would be required to maintain acceptable injection rates. Low permeability also causes a slow reservoir response to the waterflood. The conversion of wells from producers to injectors would be required to accelerate the reservoir response to waterflooding and to improve sweep efficiency. A number of cases have been simulated, and specific recommendations for improved recovery were developed.

Task 2: Development of inhibitive muds for wellbore stability

Drilling records and electric logs were reviewed for seven State Lands reservoirs: Seventy-Six West, Las Tiendas, Lavaca Bay, Keystone (Colby), Delaware Mountain Group, Keystone (San Andres), and Colmena.

Based on availability of cores and the severity of drilling problems experienced, mud/shale reaction rates were investigated using cores obtained from Las Tiendas field. This study consisted of mud/shale swelling-pressure tests, which measure the degree of hole enlargement anticipated, and mud/shale dispersion tests, which measure the rate of solids buildup in drilling muds. Swelling tests consisted of exposing the shale core samples to eight different drilling mud types. Results showed the lignosulfonate mud, which was the mud type used to drill the well from which the core was obtained, produced a total swelling after 24 hours of 3.8 percent. In comparison, the KCl/polymer mud had a total swelling of 1.2 percent. It was concluded that if problems arose when drilling such shales, the KCl/polymer mud should be used. The least inhibitive fluid evaluated was deionized water. It allowed the shale to swell 5.5 percent, leading to the conclusion that untreated water-base muds should be avoided when drilling these shales.

Dispersion tests, which measure the rate at which shale-drilled cuttings "disperse" into the drilling fluid, were also performed on the Las Tiendas core. Of the eight drilling muds tested, the KCl/polymer mud proved to be the most inhibitive. Only 3 percent of the shale dispersed into the mud. Both the lignosulfonate and the deionized water muds had dispersion rates in the 50 to 58 percent range.

After reviewing core samples from other State Lands fields chosen for study, we concluded that no suitable cores were available for shale inhibition testing. It was then decided that a new procedure, using drilled cuttings ground to a fine powder and compacted into suitable test pellets, was the only method of evaluating drilling muds for these reservoirs. We studied Seventy-Six West field using the cuttings technique. Swelling tests were performed using samples obtained from well 62-30 at depths of 300 to 1,300 ft. It was observed that an inhibitive mud containing 3 percent KCL reduced swelling by 50 percent.

This study has clearly shown that it is possible to evaluate both cores and shale cuttings for their reactivity with various drilling muds and thus reduce drilling costs in these fields. Also, the KCl/polymer muds are preferred when shale instability is a problem.

Task 3: Advanced recovery screening and evaluation

Tracer and waterflood simulations have shown that water injection has the potential to quickly increase production at Seventy-Six West field and is likely to be economic. However, we also realized during the waterflood study that, because of a high oil viscosity of 26 cp, adding polymer to injection water might be viable as a method of improving waterflood performance. In fact, most of the characteristics of the Cole C sandstone reservoir at Seventy-Six West and the reservoir fluids are very close to those of an economically successful polymerflood described in the literature for Chateaurenard field. Therefore, we evaluated polymerflooding for Seventy-Six West field by conducting both coreflood experiments and field simulations.

Cores are not available for Seventy-Six West field, so corefloods were conducted using an outcrop sandstone of similar permeability. Seventy-Six West crude oil at reservoir temperature was used for both waterfloods and polymerfloods. Although precise values for oil recovery cannot be estimated from these experiments because of the differences in heterogeneity, relative permeability, and other factors, the experiments did indicate that polymerflooding recovers substantially more oil than waterflooding.

Three-dimensional polymerflood simulations were made using our chemical simulator UTCHEM. The addition of polymer appears to be worth careful consideration based upon the increase in oil recovery predicted by these simulations. For example, by adding 500 ppm of polymer to the water for the first 4 years of the flood, oil recovery increased by 84 MSTB. This is for only one polymer injector (well 62-18). Other wells in Seventy-Six West field should also be considered for polymer flooding and would likely increase the production substantially more. An additional 0.91 STB of oil per pound of polymer injected was recovered compared to that of the waterflood. The polymer studied in this case was hydrolyzed polyacrylamide, which costs about $1 per pound, depending on the source and amount. Thus, the chemical cost per additional oil produced is very low, on the order of $1.10 per STB of oil. This cost is about the same as that experienced by Elf Aquitaine in their commercial flood of Chateaurenard field and by other similar successful polymerfloods.

We conclude, based upon analogy with Chateaurenard, our laboratory experiments, and our field simulations, that polymerflooding should be considered at Seventy-Six West field. However, some experience with waterflooding, preferably using interwell tracers to evaluate effectiveness, should be available before actually starting a polymer flood, even if further study indicates a favorable result.

Lastly, we evaluated the use of polymer gel for improved conformance in the Cole C sandstone reservoir of Seventy-Six West field. We simulated the injection of polymer with chromium as the crosslinking agent in the same well used in our waterflood and polymerflood simulation studies. Although the behavior of this process is complex and generalizations are difficult, the potential for improved oil recovery using conventional near-wellbore gel treatments under the assumed conditions does not appear to be very great.

Task 4: Gas production performance and optimization

Three gas recovery projects were designed for Lavaca Bay field. The first project involved reservoir engineering analysis to determine pressure compartmentalization of the field. This work succeeded in verifying most of the compartment assignments determined by UT/BEG geological studies. However, some of the compartment assignments were modified based on pressure analysis. One of the major outcomes of this study was identification of poorly drained compartments, which present opportunities for infill drilling.

Another gas production study was decline-curve analysis to predict future recovery from the various reservoir compartments in Lavaca Bay field. The objective of this study was to develop a methodology for making economic evaluations of infill-drilling locations. These analysis required rate versus time projections, which are usually accomplished by decline-curve analysis or reservoir simulation. Because reservoir simulation studies are seldom justified for small fields such as Lavaca Bay, we have developed gas-decline-curve relationships that can be used for forecasting purposes. These relationships are based on theoretically correct gas-flow equations, and they provide a simple method of analyzing gas reservoir data. The techniques developed in this study can be utilized either with historical rate versus time data or with known reservoir properties. Several of the Lavaca Bay compartments have been analyzed using this procedure.

A third effort was to develop pseudosteady-state flow calculations for irregularly shaped reservoirs. The purpose of this study was to determine flow-rate capacities of multiple-well, irregularly shaped reservoirs without the use of complete finite-difference reservoir simulation. Our approach has been to develop a simplified procedure using commercial finite-element software. We succeeded in developing a method to make these calculations in three dimensions, but as of the completion of the project, we had not been able to implement procedures for heterogeneous reservoirs. However, as a result of this research, we have obtained funding from the Gas Research Institute to continue this project and extend the methodology to waterdrive gas reservoirs. This work shows great promise to provide a procedure for making gas-flow determinations using PC-level computations. We envision that this approach will be amenable for use by even the smallest independent operators.

COLLEGE OF ENGINEERING
TEXAS A&M UNIVERSITY

Activity 2: Reservoir Characterization

Task 1: Multiphase properties of porous media

Many decisions are required in order to optimize oil recovery from existing petroleum reservoirs, such as where wells should be located, what fluids should be injected, and what injection and production schedules should be used. Computer simulation of reservoir fluid flow behavior is normally used to help make such decisions. It is important for effective decisionmaking that we be able to accurately predict the fluid displacement processes as well as make accurate estimates of the physical properties used in mathematical models.

Many methods for recovering oil from petroleum reservoirs involve the flow of multiple fluid phases in porous media, such as oil and water (two-phase flow) or oil, water, and gas (three-phase flow). In spite of its fundamental importance for oil recovery, many aspects of multiphase flow in porous media are not well understood. A key problem has historically been the lack of available measures of the distribution of fluids within rock samples. Conventional laboratory experiments provide only measures of what goes into, or out of, a sample. With modern instruments that have become available in the medical profession, specifically X-ray CT scanning and magnetic resonance imaging (MRI), there is the potential for learning, in a noninvasive manner, the distribution of the various fluid phases within porous media. Such capabilities can greatly expand our ability to understand and simulate flow of fluids in porous media. This, in turn, can lead to more efficient, and additional, recovery of fluids from petroleum reservoirs.

In this work we have developed MRI techniques for quantitative determination of the amount of various fluid phases at various locations within porous media. We have demonstrated the use of these techniques in dynamic displacement experiments in which oil is displaced by water. We intend to use these measurements to determine other properties important for describing multiphase flow in porous media, namely capillary pressure and relative permeability curves. These methods have been used to determine properties of core samples from State Lands reservoirs.

One of the physical properties often required for computer simulation of reservoir flow behavior is three-phase relative permeability. Although numerous two-phase relative permeability studies exist, three-phase experiments are limited due to their complexity. To overcome these difficulties, several models have been proposed for three-phase estimations. The Aleman and Slattery model, an alternative to the prevalently used Stone methods, has been extended to provide a self-consistent prediction for residual oil saturation. As originally developed, the Aleman and Slattery model required an independent estimate of residual oil saturation. If this estimate was too low, the model could, in certain situations, predict infinite values. The new procedure, which allows the model to internally generate residual oil values, has eliminated this problem.

Previous experimental studies of three-phase relative permeabilities have been analyzed. Only the data from one published study were found to be sufficiently accurate or complete enough for model evaluations. In comparison of this data set with available models, the extended Aleman and Slattery model appears to give the best representation, but a definite conclusion is premature. More experimental data with a wider variety of processes are required.

This research project provides MRI techniques for characterizing fluid properties in oil recovery processes and a new procedure for accurately evaluating reservoir properties. Thus, this project helps improve the oil recovery from Texas State Lands.

Task 2: Induced chemical gas drive

An important fraction of the remaining oil resource base in Texas State Lands is in low-permeability, fractured reservoirs where recoveries by conventional methods are extremely low. Statewide, more than 20 billion barrels are in place in Austin Chalk, Ellenburger, and Spraberry reservoirs alone. However, recoveries by conventional methods are low, typically less than 10 percent, and production rates are below economic limits.

A surfactant-based imbibition/solution drive process has been developed that holds significant promise for application as a single well treatment in low-permeability, fractured reservoirs. This process utilizes a carbonated surfactant slug in a multicycle injection-soak-production sequence to increase production by enhancing imbibition rates and promoting an induced solution gas drive (SGD) mechanism. Imbibition is enhanced through surfactant- and CO_2-simulated alternations in wetting- and CO_2-stimulated decreases in oil viscosity. Solution gas drive arises from the evolution and expansion of dissolved gas because of pressure decline during production. The presence of surfactant promotes the formation of an in situ foam, which decreases the mobility of the gas phase and significantly enhances the effectiveness of the solution gas drive mechanism.

We conducted laboratory tests to evaluate this process for different oils (kerosene and crude oil) in low-permeability dolomite rock samples with water-wet and oil-wet surfaces. During these tests, advanced NMR imaging methods were used to track the temporal and spatial variations of oil saturation within the core samples. This provided a basis for evaluating the relative contributions of the imbibition and solution gas drive mechanisms.

The tests with kerosene in water-wet media clearly showed the effectiveness of CO_2 in promoting higher imbibition rates and in stimulating solution gas drive. In these tests, the surfactant improved solution gas drive production, but the effect was marginal. In crude oil tests, surfactant-based carbonated water imbibition and production was clearly superior to that observed with carbonated water alone. The surfactant systems were particularly effective in rock samples with mixed or oil-wet conditions. The surfactant appears to alter the wetting state of the rock and promote imbibition significantly beyond that possible with water alone or with water containing dissolved CO_2. Additionally, during the production phase, the SGD mechanism is significantly enhanced with the presence of surfactant. Oil recoveries in excess of 50 percent were possible with multicycle treatments using carbonated surfactant systems. In contrast, only 20 percent recovery was possible with carbonated water alone.

Our tests indicated that using a carbonated surfactant solution as the imbibition fluid can significantly improve recovery efficiency and recovery rate in both water-wet and oil-wet media. The success of these initial laboratory tests provides encouragement to the possible use of this technique as a single well soak treatment for low-permeability, fractured reservoir environments. This process would be particularly effective when applied as a multicycle treatment.

Task 3: Conditional simulation of reservoir heterogeneity using fractal geostatistics

Conventional methods of reservoir description are so-called "deterministic methods" because reservoir description is dependent on some predetermined rules. Recent advances in reservoir characterization have focused on probabilistic or "stochastic methods," which account for uncertainties in the reservoir description by generating equally probable descriptions or "realizations." Such a realization is a conditional simulation, that is, the realization is conditioned by the data used to generate it. Each realization honors all measured data. In deterministic techniques, the spatial structure of the reservoir properties become distorted by the time the description is complete. Conventional techniques also do not distinguish between the scale of measurement of different sources of data. Conditional simulation techniques overcome both of these problems and are, therefore, vastly superior to deterministic techniques. Fractal geostatistics is one of the methods of performing stochastic reservoir characterization, and we have applied this method to analysis of Keystone (San Andres) field.

The purpose of this study is to compare spatial heterogeneities in reservoir properties, such as porosity and permeability, and generate fractal fields of properties that honor the data and their spatial structure. The permeability fields are indicators of the type of heterogeneities that exist in the reservoir and give us insights into the flow performance variables. This has a direct bearing on the success of a displacement mechanism such as waterflooding, which is being tested in Keystone (San Andres) field.

Keystone (San Andres) field is a West Texas carbonate reservoir, and reservoir properties such as porosity and permeability are extremely heterogeneous. Porosity and permeability vary spatially, and their structure is important in evaluating the pilot waterflood or in selecting locations for infill wells. The reservoir contains significant amounts of gypsum and, therefore, the neutron and density logs are not useful tools to measure porosity. We used acoustic logs from the recent 400 series wells in Block B-2 Section 13, where a well was cored. The core data were used to build a local porosity-permeability transform. Fractal geostatistics were used to characterize porosity structure. Multiple realizations of porosity were generated, with each realization honoring the acoustic-log-derived porosities at the well locations. The porosity-permeability transform was used to generate permeability fields.

We have studied only the State Lands portion of Keystone (San Andres) Field, and the results are, therefore, strictly applicable only to that area. However, we anticipate similar patterns of heterogeneities in the rest of field because of our experience with conditional simulation studies in other West Texas carbonate reservoirs.

The Keystone (San Andres) reservoir has a layered structure. Vertical heterogeneities are better captured compared to horizontal heterogeneities. A spherical variogram is adequate to capture porosity structure. Analysis of larger portions of the field can indicate areas for infill drilling.

Task 4: Use of P/Z plot to characterize gas reservoir heterogeneities

A general material balance model for layered and compartmentalized gas reservoirs has been developed. Fetkovich and others used a material balance model to characterize the depletion performance of a two-layered gas reservoir without crossflow. Hower and Collins developed a material balance model for a two-compartment gas reservoir. A general two-cell material balance model has been developed, and this model extends the former and includes the latter as special cases. This model is simple and can be used to interpret production data for a volumetric gas reservoir with either of these heterogeneities. When operated in the layered mode, the model incorporates the effects of interlayer crossflow, differential depletion, gas storage, and layer productivity. When operated in the compartmentalized mode, the model includes the effects of intercompartmental flow and gas storage. The model can be used to predict the performance of a two-compartment gas reservoir and is easier to use than a conventional reservoir simulator. Comparison of results between the two indicates good agreement.

Activity III: Advanced Extraction Technology

Task 1: Improved recovery research

Oil production due to water imbibition: Conventional waterflooding methods of oil recovery are difficult to apply when reservoirs show evidence of natural fractures because injected water advances through these paths of high permeability. Oil remains trapped in the rock matrix system and cannot be displaced. Laboratory studies have shown that imbibition may be an effective method of oil recovery. The imbibition displacement technique may offer an alternative oil recovery method for naturally fractured reservoirs. Imbibition is a method of oil recovery in which capillary pressure drives water into the rock matrix, displacing the oil located in the matrix.

This research was conducted to evaluate the effect that both fracture and spacing of fractures have on oil recovery by pure or carbonated water imbibition. Experimental work was carried out in homogeneous and longitudinally fractured rock samples of low permeability (8.9 md average). Homogeneous rock samples had a simulated transverse fracture in front of the imbibition face, whereas fractured rocks samples had one and two longitudinal symmetrical induced fractures. Nuclear Magnetic Resonance (NMR) sets of longitudinal and transverse profiles and images were recorded to visualize and quantify changes in fluid saturation inside rock samples.

Glass beads with an average diameter of 435 μm were distributed as a proppant along the longitudinal fracture faces to ensure that induced fractures remained open when the system was pressurized. Imbibition fluids were injected across the interface at a flow rate of 0.3 cc/min. The working system pressure was 750 psi, and the pressure drop across the rock sample was maintained at zero. NMR oil saturation profiles show that the percent of original oil in place (OOIP) recovered from the rock matrix system was not uniform throughout the samples. The greatest change in oil saturation took place close to the imbibition faces. This was verified by the oil saturation curves generated from NMR profiles. Pure and carbonated water imbibition cumulative oil recovery curves exhibited an exponential relationship between time and recovery.

The presence of one and two longitudinal microfractures increased oil recovery due to (1) pure water imbibition by approximately 3.5 and 8 times when compared to oil recovery from homogeneous rock samples and (2) increased oil recovery by carbonated water imbibition by approximately 1.6 times when compared to oil recovery from homogeneous rocks. Additionally, rock samples exhibiting one and two fractures have almost equal percent of oil recovery, that is, 8.2 percent.

Phase behavior and solubility studies of carbon dioxide in crude oil and water: This is a study of phase behavior, viscosity measurement, and compositional analysis of a CO_2 and Keystone (San Andres) reservoir crude oil mixture. The objectives of this research were to develop an integrated experimental setup that could measure equilibrium phase volumes, phase compositions, and physical properties, such as viscosity and density of the CO_2 and crude oil mixture at temperatures and pressures representative of reservoir environments. These parameters are needed to design a successful CO_2-flooding project.

A gas chromatographic analysis of Keystone (San Andres) crude oil was performed on a gas chromatograph-mass spectrometer. Later, a more elaborate gas chromatographic analysis of this crude oil was made using a 5880 Hewlett Packard gas chromatograph. Oil was fractionally distilled into 10 fractions in the temperature range of 180° to 430°C. The kinematic viscosity of all fractions was measured using a Canon-Feske viscometer for temperatures ranging from room temperature to 210°F. For these measurements, ASTM standards D445-88 and D446-89A were followed. Specific gravities and boiling points of all the fractions were also measured. Details of these procedures are in a paper to appear in the *Latin American Research Journal.*

The experimental equipment used for this setup consists of a Ruska mercury-free PVT system, a rolling ball viscometer, and a 5880 Hewlett Packard gas chromatograph. The gas chromatograph was upgraded and designed for high-pressure and high-temperature sampling. A Hewlett Packard 5880 gas chromatograph was upgraded by incorporation of a loop designed to sample on-line live oil and CO_2 mixtures. This upgrading was achieved by incorporating a sampling loop in the PVT flow lines. The loop consists of three 4-port sampling valves. There are three other loops to take the sample to a thermal conductivity detector and flame ionization detector via the appropriate chromatographic column to facilitate analysis of the gaseous or liquid phase. These loops also contain switching valves for back-flushing to reduce column contamination. All sampling and switching valves operate through an air-actuated digital valve interface. The valves are operated from the gas chromatograph via keyboard key strokes. The viscometer was calibrated for the anticipated viscosity range using viscosity standards.

After validation of the experimental technique, analysis of CO_2 and Keystone (San Andres) crude oil mixture was begun. This experimental analysis will help in understanding the drive mechanism and ultimate recovery during a CO_2-flooding process. The data obtained from this study and other experiments, such as slim tube and core flooding, will guide reservoir development and management strategies. Flooding has developed into one of the most economically attractive enhanced oil recovery processes. This advanced extraction technology is most appropriate for State Lands fields in West Texas, where abundant amounts of CO_2 are available nearby. CO_2 flooding can extract up to 95 percent of original oil in place and, consequently, can produce millions of barrels of oil from State Lands oil fields that are not responding to ordinary production techniques.

Task 2: Simulation of paraffin deposition and removal in reservoirs and wellbores

There were two main objectives of this research: (1) to develop a simulator that models paraffin deposition and removal within reservoirs and (2) to develop a simulator that models paraffin deposition and removal within wellbores. The first objective has been completed and has been documented in a Ph.D. dissertation and a Master's thesis. The second objective will be complete in December and will be documented in a Ph.D. dissertation.

The main objective in developing the paraffin reservoir simulator was to document the serious reduction in production rates that result from a slight amount of paraffin (wax) in the reservoir. This reduction is a consequence of solid paraffin particles being deposited within the pores of the reservoir. When a small amount of these solid particles are present in the reservoir, they plug the pores and drastically reduce the oil production rate. Three mechanisms were incorporated into the paraffin reservoir simulator to model this process of reservoir damage.

The first mechanism incorporated into the paraffin reservoir simulator was the solubility of paraffin in the oil. In other words, how much paraffin can the oil hold in solution, and when the oil is saturated with paraffin, how much solid paraffin would appear. To understand these natural phenomena, the ideal solution theory was used. This theory specified the amount of paraffin that was in the liquid phase and how much solid paraffin was present in the pores of the reservoir.

The second mechanism that was incorporated into the paraffin reservoir simulator was deposition of solid paraffin particles within a pore of the reservoir. As the solid paraffin particles flow through the reservoir, some of the particles become entrapped within the pores, causing paraffin deposition. To understand this complex process, filtration theory was used. This theory dictated the quantity of solid paraffin particles that would be deposited on the inner surface of pores.

The third mechanism incorporated into the paraffin reservoir simulator was the reduction in permeability (capability to flow) of the reservoir caused by paraffin deposition. As solid paraffin is entrapped within the pores, pore throats are plugged. This plugging effect reduces the oil flow rate. To understand this reduction in productivity, results from published laboratory experiments were used. The results from these experiments specify the amount of reduction in oil flow rates that comes from some solid paraffin particles depositing within the pores of the reservoir.

Another main objective in developing the paraffin reservoir simulator was to document a common thermal technique, which can increase the production rates of reservoirs with paraffin deposition problems. This substantial increase in oil production rates would result from thermally reducing oil viscosity and eliminating the solid paraffin particles that were deposited within the pores.

The last mechanism that was incorporated into the paraffin reservoir simulator was the amount of heat needed to melt the solid paraffin. In other words, how much heat is needed to get a substantial increase in the oil production rate and how long would the reservoir maintain these high rates? To understand this thermal stimulation technique, conservation of mass and energy was used. These conservative laws could specify the amount of heat that was needed to increase oil production rates if proper paraffinic enthalpies were employed.

Enthalpies for paraffinic oil, which relate the increase in temperature with the increase in heat content, have been published. Yet, to use these published values, one must know the boiling point of the paraffinic oil. Because this information is not readily available, a new method to calculate enthalpies for a paraffinic oil was developed. With these new enthalpies, the increase in oil rates that come from heating the reservoir could be calculated.

With all the mechanisms incorporated into this paraffin reservoir simulator, this simulator can be used to study methods to increase the oil production rates from Texas State Lands reservoirs that have paraffin deposition problems.

Task 3: Controlled rheology surfactants

The objective of this project was to investigate the feasibility of exploiting the unique rheological properties of surfactant solutions, which exhibit a shear induced structure (SIS), for improving the sweep efficiency for enhanced oil recovery (EOR) from very heterogeneous formations such as the Keystone (San Andres) reservoir. The surfactant chosen was hexadecyl trimethyl ammonium salicylate (C16TMASal) in concentrations from 500 to 1,200 wppm in water and salt solutions of various concentrations.

The non-Newtonian viscoelastic rheological properties of these fluids were measured, and their flow behaviors were characterized in various porous media, including uniform packed beds and formation core samples having an extremely wide range of permeability. Laboratory displacement tests were also conducted using a representative core and reservoir fluids from Keystone (Colby) well no. 401 and a 500 wppm surfactant solution as a displacement fluid following a waterflood.

The results of both the viscosity and relaxation time rheological measurements clearly showed the formation of the SIS network structure at a critical shear rate, which is independent of surfactant concentration but is influenced by salt concentration. The packed bed and core tests showed an increase in flow resistance of one to three orders of magnitude above that of Newtonian fluids over a critical range of flow (or shear) rates, with the highest resistance occurring in media with the highest permeability. The core displacement test in a core with a permeability of 1.65 md indicated an increase in oil recovery of about 8.4 percent higher than that attained by waterflood alone.

These results were presented on a generalized plot of dimensionless flow resistance as a function of an effective shear rate for the porous medium. The flow resistance is as much as three orders of magnitude greater than that for a Newtonian fluid. All data for surfactant concentrations between 500 and 1,000 wppm in packed bead beds (200 to 750 μm bead size) and in core samples (permeability varied over a range of greater than 10^6) converged to a common asymptotic line. However, the shear rate at which the increased resistance was observed was significantly higher for the packed beds than for the formation cores.

The effectiveness of the SIS surfactants is attributed to the strong enhancement of viscoelastic properties imparted to the solution by the network structure, which forms at a critical shear rate. The very large increase in flow resistance in high-permeability media and the much lower increase in low-permeability media indicate that these solutions should be excellent displacement fluids for EOR in very heterogeneous reservoirs, such as those of State Lands fields in West Texas.

COLLEGE OF GEOSCIENCES AND MARITIME STUDIES

TEXAS A&M UNIVERSITY

Activity 2: Reservoir Characterization

Task 1: Data-base assembly

The data base for Project SLERO has been constructed and tested and is operational. Data from Seventy-Six West field were entered into the data base. Graphic displays of both cadastral and subsurface are available either individually or combined.

The basic idea of a Geographic Information System (GIS), to receive data in tabular, graphical, or digital format, was tested and was successful. The GIS is also capable of real-time retrieval of any portion of the data both in graphic display and as statistical tables. The interrelationships of the surface and subsurface data are visible in any conjunction desired by the investigator. The ability of the GIS to provide a "new look" at the data base appears to be more than satisfactory.

Task 2: Diagenetic control on sandstone reservoir properties

The goal of this project is to characterize the texture and mineralogy, history of fluid-rock interactions, and effects of these interactions on petrophysical properties of reservoir sandstones of the Delaware Mountain Group (DMG) on State Lands in West Texas. These sandstones have high porosity but low total recovery of original oil in place.

The DMG sandstones have undergone, in sequential order, the following four major stages of diagenesis: (1) early cementation by carbonate, sulfate, and halite minerals, which preserved much of the intergranular volume that otherwise would have been lost to mechanical compaction, (2) fluid-rock interactions during deep burial that resulted in dissolution of cementing and detrital minerals, creating prevalent secondary porosity, (3) widespread authigenesis of clay minerals, which decreased reservoir quality by forming abundant microporosity and blocking pore throats, and (4) precipitation of late carbonate, silicate, and oxide minerals, which are important relicts of late fluids. The abundance and nature of existing porosity in the DMG sandstones are, therefore, controlled by diagenesis.

An understanding of the nature and source of the fluids that interacted with DMG sandstones during deep burial is essential to both exploration and production. Paucity of detrital clays in the DMG precludes clay transformation being the fluid source. Detailed analyses of the abundant siltstones in the section show the following: (1) Organic matter in the DMG siltstones is of the abundance, type, and state of thermal maturity that could generate sufficient carboxylic and carbonic acids, which interacted with the sandstones to create secondary porosity and authigenic minerals. (2) Oil in reservoir sandstones was derived from interbedded siltstones, as evidenced by biomarker analysis. (3) Late authigenic carbonate minerals have isotope composition indicative of derivation in part from organic matter. (4) Formation of organometallic complexes, especially for titanium, further shows that organic ligands derived from degradation of DMG organic matter were present in pore fluids in abundance during late-stage diagenesis.

A detailed study of the mineralogy, chemistry, and morphology of authigenic clay minerals in DMG sandstones has been made because of their intimate control on fluid withdrawal properties. Chlorite and interlayered chlorite/smectite (C/S) dominate the clay mineral assemblage, with minor amounts of illite and illite/smectite. At least three types of chlorite, based on structural and morphological data, have been recognized. Chlorite type is stratigraphically controlled, and each type shows specific effects on porosity and permeability of reservoir sandstones. Furthermore, trace element analysis of organic matter and authigenic clay minerals established source-sink relations between the two. Thus, fluids carrying products of organic matter degradation played a major role, not only in dissolution but also in authigenesis.

This study presents a diagnostic evaluation of DMG reservoir sandstones. Hydrocarbon production from these important sandstones will be increased only when results of this study are taken into consideration in the design of enhanced recovery programs.

Task 3: Subregional reservoir characterization of Lavaca Bay

This study involves characterization of two sandstone reservoirs, the Melbourn and F39 Sands, in Lavaca Bay field of South Texas. The study area is part of the Greta/Carancahua Barrier Strandplain system in the Frio Formation. The Frio Formation is a progadational wedge, existing as a major stratigraphic unit that has yielded 6 billion barrels of oil equivalent. The Frio Formation is divided into lower, middle, and upper units based on well log correlation. An area of 35.6 mi^2 is covered in the study. Lavaca Bay field was discovered in 1964 and is still gas productive. The field contains 19 gas reservoirs and 1 oil reservoir.

The prospect for more gas to be produced from the Melbourn and F39 Sands is promising based on well-log correlations and estimation of gas in place from material balance analysis of production data. There are similarities in well-log characteristics between the producing and nonproducing wells. Production data, well-log data, and core data were studied to delineate the existence of areas with high gas potential. Characterization of the reservoirs is important for evaluating future exploration and development. The use of these data helps in reservoir description and identification of additional potential reserves. The main objective of this study is to locate new recompletion opportunities in existing wells and to locate sites for infill drilling.

Characterization of the Melbourn and F39 Sands was accomplished by optimizing existing data to reduce cost and time involved. Spreadsheet calculations were used for log interpretation. Various log interpretation models were tested to select methods suitable for accurate evaluation based on lithology and other characteristics.

The parameters selected for comparison are ratio of the water saturation to the flushed zone water saturation (S_w/S_{xo}) and the bulk water saturation (Sw•phi). The ratio S_w/S_{xo} is an index of hydrocarbon movability. If S_w/S_{xo} approaches unity, the hydrocarbon is immovable, indicating no recovery of gas. If S_w/S_{xo} is approximately 0.8 or lower, presence of producible hydrocarbon in the reservoir is indicated. The bulk water saturation (Sw•phi) is the product of porosity and water saturation. Sw•phi represents the quantity of water per unit volume of the formation. A low value of Sw•phi indicates a low water saturation and, thus, potential for gas. Resistivity logs measure the ability of fluid-containing rock to conduct electrical current. Hydrocarbons are nonconducting and have high resistivity. High resistivity is used to recognize gas zones. This classification is further confirmed with low S_w/S_{xo} and Sw•phi.

S_w/S_{xo}, Sw•phi, and deep resistivity was mapped for each sandstone unit in the field. The Melbourn Sand reservoir is divided into three units, and the F39 Sand is divided into two units. The division of units within reservoirs is based on the sandstone-shale sequences. Mapped areas not currently producing gas and having combinations of high resistivity, low S_w/S_{xo}, and low Sw•phi are interpreted to be gas saturated. These areas are highlighted and recommended for further exploitation. Recommendations made for recompletion of wells are judged by the calculated S_w/S_{xo} and Sw•phi of nonproducing wells being less than or equal to that of the producing well. We have identified five sites for infill drilling and recompletion opportunities in the Melbourn and F39 reservoirs.

Task 4: Application of high-resolution seismic imaging to improve bed-geometry definition

We have worked on three subtasks: (1) processing seismic data from Seventy-Six West field, (2) processing seismic data from Powderhorn field, and (3) aiding in design of a high-resolution, three-dimensional seismic survey of Powderhorn field.

Seventy-Six West field: Magnetic tapes of digital seismic data were in SEG-Y format, which allowed us to read the data onto our VAX computer. Unfortunately, there were no observer's logs. We edited the tapes, removing bad traces, eliminating noise spikes, removing powerline interference, and so forth. We stacked the traces after determining the normal-moveout and static corrections and plotting the data. The resulting plotted data were substantially improved over the originally plotted data, which had not been edited. There were several bad traces on the data tapes and, after additional filtering and editing, we obtained a seismic section that was comparable to that generated by an industry laboratory. However, the data do not have a sufficiently high signal-to-noise ratio to achieve the high resolution we had hoped to achieve.

Powderhorn Field: We digitized acoustic and density traces from well logs (eight acoustic logs and two density logs) for input to computer programs that generate and plot synthetic seismograms. These synthetic seismograms were to be compared with high-resolution seismic data shot near the wells. We generated synthetic seismograms using well-log data and compared the results with the data on a seismic line provided by the field operator. We also correlated acoustic logs with density logs for two wells for which we have both logs. Most wells have only acoustic log data and both acoustic and density logs are needed to generate synthetic seismograms. We have found that the density and acoustic data correlate fairly well for these two logs, and we are confident that the synthetic seismograms generated using acoustic logs alone are accurate.

The reformatted data tapes were read onto the campus Cray YMP/4A supercomputer, which has DISCO, a seismic-data-processing software package. Shot diagrams were generated for the data, the geophone geometry was determined, and the seismic traces edited. There were a few noisy traces, which would likely cause difficulties during later processing, and these were eliminated from the data set.

We have (1) completed editing of the data, (2) generated common-mid-point (CMP) gathers, (3) determined the static corrections to compensate for variations in geophone and shot elevations as well as variations in the velocity and thickness of the near-surface weathered zone, (4) determined the root-mean-squared (rms) or stacking velocities, (5) stacked the traces to generate a seismic section, (6) determined the interval velocities so that the travel times of the seismic section can be correlated with depth, and (7) deconvolved the seismic data to broaden its frequency response so that the resolution could be improved. The seismic section was compared with synthetic seismograms generated using well log data. The comparison was sufficiently accurate that the reflection events on the seismic section could be correlated with the geologic strata inferred from well logs.

High-resolution three-dimensional survey: Design of a high-resolution, three-dimensional survey of Powderhorn field was completed. Although this survey has not actually been conducted because we were unable to arrange for the donated services of a commercial seismic data acquisition company, these plans are available for operators of State Lands leases in the Miocene Barrier/Strandplain Sandstone play to use as a model for reservoirs in this trend.

Benefit to hydrocarbon production from Texas State Lands: Much of the hydrocarbon production from State Lands is from established fields, and much of this resource is being bypassed because of reservoir heterogeneity. If the resolution of seismic data used to determine original locations of the wells could be improved, these data could be used to determine where infill wells should be drilled to access bypassed hydrocarbons. In addition, it is clear that greater resolution of seismic data can be achieved with modern techniques if proper care is taken in obtaining the data. In this task we investigated how older data could be reprocessed to give the desired higher resolution, and we have determined the survey parameter values needed to obtain higher resolution from new surveys.

Task 5: Quantification of microgeometry of sedimentary rocks by digital analysis of thin sections

Thin sections of rock samples (30-µm thick) provide insight into the structure of the grains and pores that make up those rocks. Digital image analysis is used to rapidly quantify these microstructures. By measuring the sizes and shapes of both the pores and grains in a sedimentary rock, theoretical models can predict the basic properties of the rock. These properties include porosity, permeability, and formation factor. Porosity is a measure of the percentage of sample volume that is not occupied by grains. This measurement of the "empty" space inside the rock gives an upper estimate to how much fluid (oil and water) can exist in the pore structure of the sample. Whereas porosity indicates how much fluid can exist in a rock, it says nothing about how easily one can extract that fluid. Permeability is the measure of how rapidly fluid can flow through the sample and is, therefore, directly related to oil-recovery rates. Formation factor is an electrical property of rocks, which is important in making saturation calculations from well logs.

We have developed new image-processing procedures to analyze thin section images. Data extracted from these images (pore sizes and shapes, grain sizes and shapes) are merged with theoretical models to develop permeability estimates. Grain- and pore-size distributions fall directly out of our analysis, as does a direct measure of porosity. These imaging methods developed at the TAMU Rock Physics Laboratory have been used on a variety of rock samples. Pore-size distributions have been extracted from image data and compared to laboratory measurements of the same samples. These experiments revealed that image-derived parameters can be used to extract a "characteristic" pore width for most sandstones, which is crucial for successful permeability estimation. The modeling theories were tested using samples of known porosity and permeability with excellent results.

One Ph.D. student worked on this study as a major part of his dissertation. There have been three presentations at national meetings on various aspects of this work as well as one manuscript currently being resubmitted for publication.

Image analysis offers a wealth of information from a single thin section. Multiple thin sections from multiple cores can be analyzed rapidly, bypassing the need for multiple laboratory experiments run on core samples. Cores from the Texas State Lands can be sectioned and analyzed in this fashion as a standard part of regular core analysis. Using the information gained from this type of study could save both time and money.

Task 6: Sulfate scaling investigation

Precipitation of materials from solution is an important process in oil fields. Pipe clogging by sulfates and carbonate precipitation, for instance, can lead to increased production costs and premature degradation of reservoir quality. Little is fundamentally known about the dissolution and precipitation of sulfates and carbonates in the fluids that typify oil fields, namely brines. The purpose of this research was to provide a firm chemical basis for predicting scaling of oil field pipes. The specific goals of this research were to provide a better understanding of dissolution and precipitation of sulfates and carbonates in brines and to test a published theoretical model for calcite precipitation kinetics.

The stoichiometric Henry's Law constant (K_H^*) and dissociation constants (K_1^* and K_2^*) for the carbonic acid system were experimentally determined in various aqueous solutions from 0 to 90°C to high ionic strengths by the solubility method and the eMF method. Experimental results were in good agreement with previous measurements in dilute solutions, as reported in the literature. Stoichiometric activity coefficients for $CO_{2(aq)}$, HCO_3^-, and CO_3^{2-} were calculated from these experimental data. Pitzer parameters for interactions between the carbonic acid species ($CO_{2(aq)}$, HCO^-_3, and CO_3^{2-}) and major ions (Na^+, K^+, Ca^{2+}, Mg^{2+}, Cl^-, and SO_4^{2-}) were obtained by regression analysis.

Our experimental data at 25°C and 1 atm were used to evaluate Pitzer parameters taken from the literature. The Pitzer ion-interaction model, in association with the ion pairing model and Pitzer parameter data sets from both Harvie's group and Pitzer's group, provides proper estimates of activity coefficients within the range of experimental uncertainty. Two important ion pairs in the carbonic system, $CaCO_3^o$ and $MgCO_3^o$, must be defined and included in the model, in addition to HSO_4^- and $MgOH^+$, in order to obtain correct total activity coefficients for CO_3^{2-} ions. The new Pitzer parameters for the carbonic acid system were consistent with parameters for other systems from either Harvie's group or Pitzer's group. A chemical model based on thermodynamic constants and osmotic and activity coefficients estimated from Pitzer equations were found to accurately predict calcite solubility as reported in the literature.

Calcite solubility in synthetic brines (Na-K-Ca-Mg-Cl-SO_4) was measured from 0 to 90°C in open systems from both undersaturation and supersaturation. It was found that calcite solubilities predicted using the Pitzer model with parameters from this study were generally in good agreement with experimental solubility data obtained from undersaturation. However, this was not the case when equilibrium was approached from supersaturation. The discrepancy between experimental data and predicted data may result from the fact that adsorbed and/or coprecipitated ions (such as Mg^{2+} and SO_4^{2-}) on calcite surfaces tend to maintain a metastable equilibrium between the surface and bulk solution.

Pitzer parameters for apparent molal volume and compressibility can be used to correct for the effect of pressure on activity coefficients. These parameters were obtained for $NaHCO_3$ and Na_2CO_2 from 0 to 45°C by regression analysis of experimental data. The solubility of calcium sulfate (both gypsum and anhydrite) can be predicted by the chemical model in Na-K-Ca-Mg-Cl-SO_4 solutions up to 200°C and 1,000 bars. Experimental data at other temperatures and in other systems are needed in order to complete the parameterization for the multicomponent system

$$Na^{+}\text{-}K^{+}\text{-}Ca^{2+}\text{-}Mg^{2+}\text{-}Cl^{-}\text{-}SO_4^{2-}\text{—}OH^{-}\text{-}HCO_3^{-}\text{-}CO_3^{2-}\text{-}CO_{2(aq)}.$$

Model predictions agree very well with experimental calcite solubility in water and seawater up to 1,000 bars at 0 to 25°C.

Chemical modeling of scale formation in pipes through which fluids flow from the reservoir to the surface can be predicted with data obtained for the carbonic acid system and mineral solubility. The modeling results indicated that scaling of calcium sulfate can be avoided if the cooling speed can be elevated or flow rate can be slowed. Scaling of calcium carbonate cannot be similarly prevented.

Calcite solubility in sedimentary brines under typical burial conditions is controlled by solution composition, in situ temperature, and pressure. Mixing of different sources of waters in the subsurface may be very important for formation of secondary porosity because it causes undersaturation when concentrated brines are mixed with dilute meteoric waters in a closed system.

To test some of the ideas we devised an experimental apparatus for flowing supersaturated solutions over a variety of substrates. We began with the substrate on which we would expect the most precipitated calcite, Iceland Spar calcite. Our experimental apparatus consisted of a PVC channel (15 mm × 2 mm ×100 mm) floored by Iceland Spar calcite. A solution supersaturated with respect to calcite, which was completely equilibrated with PCO_2 at 1 atm at room temperature, precipitates on the Iceland Spar calcite as the solution passes through the channel. The pH and volumetric flow-rate of the solution were monitored during the experiments. A prominent decrease (0.4±0.05) in pH relative to the initial value indicated that the concentration of ions in the solution changed as calcite precipitated. From the change in pH, we calculated the amount of newly precipitated calcite in the channel using both reaction chemistry and reaction kinetics. The chemical model, which is based only on the change in concentration of ions during calcite precipitation, shows that the calculated measured masses are very close. The kinetic model at present is off by about 50 percent. We have obtained new reaction constants (k) and reaction orders (n) experimentally. The amount of precipitate hyperbolically decreases away from the solution inlet, presumably as the saturation state decreases with calcite precipitation. Flow rate and pH are the two main factors controlling calcite precipitation. These experiments will contribute to an understanding of the kinematics of vein filling and pipe clogging and the development of calcite microstructures in veins.

Task 7: Estimation of clay content from electrical measurements of shaly sands

Electrical resistivity logs are one of the primary tools used to estimate the amount of oil or gas within a reservoir. Most rocks are saturated with water below the water table, which is much more electrically conductive than either oil or gas. Therefore, formations that are saturated with either oil or gas are much more resistive than surrounding formations, which are saturated with water. Oil and gas reserves are detected by locating very resistive zones using resistivity logs. This method works very well in formations that do not contain significant amounts of clay. However, in clay-bearing formations (i.e., shaly sands) oil reserves are often not detected because clay causes the formation to be nearly as conductive as surrounding water-saturated formations. Thus, determining the amount of clay within the formation may help detect new reserves and/or obtain better estimates of in-place oil and gas in old reservoirs.

We have developed a new method of estimating the clay content of shaly sands from electrical-impedance measurements. The electrical impedance is a measure of both the resistance and the capacitance of a material. We have tested our model using an extensive suite of laboratory data that were collected in the TAMU Rock Physics Laboratory and compiled from the literature. The validity of this method is indicated by the ability of the model to match the electrical impedance of shaly sands as a function of clay content, salinity, frequency, and water saturation. Because electrical-impedance measurements can be made within a borehole (similar to resistivity logs), this method may be used to estimate the clay content of a formation.

This work involved both theoretical and experimental investigations. Two Ph.D. students worked on different parts of this project for their dissertations. The results of this work were presented at five national meetings, and five articles have been written on different aspects of this work.

Many of the hydrocarbon fields on Texas State Lands are undergoing secondary phases of oil recovery. This involves steam flooding and other methods of enhanced oil recovery to increase the rate of hydrocarbon production from existing wells. It also involves drilling new wells into new areas of an existing field. In both the enhanced oil recovery efforts and in evaluation of new wells it may be very useful to obtain estimates of clay content in the formation. In these cases, our new method could be used to estimate the clay content from an electrical impedance log.

Task 8: Fracture containment

This study began in September 1990. The objectives of this task included development and validation of computer models for describing the growth of hydraulic fractures, with emphasis on simulating vertical containment of fractures. Las Tiendas (Olmos) field in Webb County was determined to be well suited for hydraulic fracturing studies because this field produces from a tight sand and most wells in the field have been fractured.

A study area containing approximately 16 wells producing from the Olmos Formation was selected based on data availability. Preliminary analysis of data and modeling seemed to indicate that created fracture height, based on numerous stimulation proposals, has been under estimated in the Olmos reservoir. Four wells in the study area were selected for more detailed fracture containment studies. Calculation of in situ stress profiles and mechanical rock properties needed for vertical fracture height growth calculations were performed based only on initial stimulation pressure data and available well logs. Many assumptions were needed due to the lack of additional logs and other field-wide data. Using these height-growth estimates, a two-dimensional fracture model was used to calculate fracture geometry. Gas production was simulated using these fracture geometries. Simulated production matched actual production fairly well. These vertical fracture height growth estimates far exceed initial service company estimates.

An additional five wells from the study area were selected for analysis. Fracture containment studies were performed on these five wells in order to verify that previous findings were representative of field-wide trends. Results supported previous findings from containment studies.

In order to optimize fracture treatment size based on vertical containment, the treating pressure must be estimated accurately. Pressures available from service company stimulation reports are surface pressures. Direct measurement of downhole treating pressure is expensive and uncommon. Even downhole measurements include perforation friction and possibly other unknown pressure losses. A number of assumptions were needed to calculate downhole treating pressures for the studied wells. We examined how changes in treating pressure influence vertical fracture growth and treatment size for the selected wells. Very small changes in treating pressure were found to greatly influence vertical fracture growth, depending on the in situ stress differences between pay zone and bounding layers. Calculated in situ stress profiles for selected wells in Las Tiendas field showed only small differences between the pay zone and bounding layers, making vertical fracture growth highly sensitive to treating pressures.

Data for three State Lands wells were obtained to confirm these trends. Analysis supported previous findings from containment studies. Once again, many assumptions were made due to the lack of additional logs and other field-wide data. Cost estimates for acquiring additional logs and other field wide data were obtained. Based on the performance of past fracture treatments, acquiring these additional data is more than justified. Analysis showed that the cost of acquiring additional logs and other field-wide data could have been offset by the decrease in cost of performing a smaller optimal treatment that would have also been more effective. Optimal fracture treatments in tight gas sand reservoirs on State Lands would increase productivity and ultimate recovery.

HOUSTON PETROLEUM RESEARCH CENTER

UNIVERSITY OF HOUSTON

Activity 2: Reservoir Characterization

Task 1: Application of high-resolution seismic imaging to improve bed-geometry definition

Research has focused on developing the use of crosswell seismic methods for characterizing reservoir heterogeneity and extent in a producing oil field on State Lands. Areas of research included field evaluation of seismic borehole energy sources, high-resolution tomographic reconstruction of seismic velocities, determination of attenuation characteristics of interwell lithology, development of software for tomographic reconstruction techniques, and construction of a data base of geophysical and geological data for statewide access.

Borehole seismic energy source evaluation: Field tests were performed with four different downhole energy sources: an airgun, a piezoelectric "bender," a "sparker," and an explosive source. Each of these sources has strengths and weaknesses that make it more useful for a particular project than another. One of the most important characteristics of a downhole energy source is the level of energy that is output. In this respect, the airgun and the explosive source had the highest energy levels. On the other hand, the frequency content of the transmitted signal determines the degree of resolution of the final image. We found that the piezoelectric "bender" was able to emit the highest frequency levels and that the "sparker" was intermediate in both energy output and frequency content.

Tomographic reconstruction: A compressional wave velocity tomogram was successfully produced for the region between two wells in Seventy-Six West field. Using results from well-log correlation and an acoustic log, we were able to confirm the presence of the 20-ft-thick Frio Formation sandstone on the tomogram. Comparison of velocities from an acoustic log from a nearby, newly drilled well with the velocity tomogram shows good correlation in the region of best resolution in the tomogram. Correlation is good despite the fact that the acoustic log comes from a well approximately 0.5 mi from the region imaged. Variations in layer thickness and position are reasonable for what might be expected when comparing the tomogram to a log that lies along geological strike.

Attenuation measurements: An attenuation study of interwell lithology between two producing wells in Seventy-Six West field has yielded valuable results. Calculations for inverse attenuation (Q) were done at nine different depths and nine different frequencies from 500 to 3,500 Hz. These frequencies are one to two orders of magnitude above the frequencies normally possible in seismic exploration. The averaged Q values ranged from approximately 40 to 130 and distinguished lithological changes at 10-ft depth increments. We have interpreted the high Q values as resulting from horizontal wave propagation through shales and the lower Q values as being representative of sandstones.

Tomography software developments: A variety of software has been developed to prepare and process crosswell data recorded in Seventy-Six West field. These algorithms have been directed at enhancing the signal-to-noise ratio of the data, removing incoherent and coherent noise in both the time and frequency domain, interactive and automated picking of first arrival times, raytracing schemes for use in tomographic reconstruction, and creating inversion methods, also used in tomographic reconstruction.

These programs have utilized both established concepts and new developments and modifications designed to improve efficiency and performance. They have potential for wide application in both industry and academic research.

SLERO data base: A project for creating a Graphical User Interface facilitating easy access to multiple engineering, geophysical, and economic data bases is now functional. This data base, which includes references to maps and well logs, was designed to permit easy access to multiple types of data for researchers throughout the state.

Although conventional seismic methods have been responsible for prodigious additions to the reserves in State Lands reservoirs, it will be the application of high-resolution seismic methods that will most contribute to maximizing production from these reserves. Using these innovative, high-resolution crosswell seismic methods offers the potential for delineating reservoirs at a scale never before achievable. This enhanced reservoir characterization will provide invaluable information for engineers and geologists to increase hydrocarbon production on State Lands.

CENTER FOR APPLIED PETROPHYSICAL STUDIES

TEXAS TECH UNIVERSITY

Activity 2: Reservoir Characterization

Task 1: Petrophysical determination of volume of clay

Correct determination of volume of clay (V_{cl}) is critical to shaly sandstone analysis because it is used to determine values of effective porosity and effective water saturation, which are used to calculate net pay thickness. The net pay thickness is used to help differentiate commercial from noncommercial gas wells and to determine in-place gas reserves.

The problem in the Las Tiendas field area is that 50 percent of the wells do not have gamma-ray logs, which are the best logs for determining the volume of clay. The only clay-indicating log present in all of the wells was the spontaneous potential (SP) log, but because of the effects of hydrocarbon suppression and thin beds, the SP log was unsuitable for V_{cl} determination. The solution was to determine laboratory-derived values of V_{cl} and use these values to calibrate the SP-derived V_{cl} values using mathematical transforms. Thirty core samples of Olmos Formation sandstone at Las Tiendas field were used to determine V_{cl} by a combination of settling techniques and X-ray diffraction. These 30 V_{cl} values were used to derive a transform so that the SP-derived V_{cl} data could be used for shaly sandstone analysis. Computer software was created to aid calculation of V_{cl} from log data and to create transforms to calibrate log data to laboratory data. In addition, detailed clay mineralogy analysis, including X-ray diffraction and SEM analysis, was conducted on these 30 samples. This work was completed in 1991 as a Master's thesis.

Task 2: Development of shaly sandstone analysis techniques for "old" well log results verified by engineering data

The results of Task 1 provided the key to doing shaly sandstone analysis in the Olmos Formation at Las Tiendas field using the SP log to determine reliable values for V_{cl}. These results have been published and are available to Texas independent oil operators. The next step was to determine effective porosity and effective water saturation values (i.e., shaly sandstone analysis) using both old and new logging suites.

The problem was how to determine effective porosity when there are so many types of porosity logs available. Some wells had only acoustic logs, some only density logs, and a few had both density and neutron logs. The key was to determine the correct matrix parameters for acoustic and density logs. The matrix values that were determined (ITTma = 59 usec/ft and rma = 2.72 gm/cc) proved to be very important to final net pay determination. Without these correct matrix values, net pay would be a function of log suite and not cumulative gas production. With these correct matrix values and the correct V_{cl} values, effective porosity was accurately determined.

The final phase of the project was to determine the effective water saturation and calculate net pay, then calculate hydrocarbon pore-feet thickness and relate it to cumulative gas production in order to see if our analysis could be used to determine which are the better gas wells. Effective water saturation determination was also made difficult by the diverse logging suites because the method of calculating effective water saturation is, in part, a function of available logs. Our analysis showed that, due to the diverse logging suites, two methods of determining effective water saturation must be used. These methods are the Automatic Compensation and Fertl. Net pay was calculated using the following cutoffs: (1) V_{cl} = 30 percent, (2) effective porosity = 10 percent, and (3) effective water saturation = 50 percent. Hydrocarbon pore-feet thickness was then determined for the net pay interval.

A cross plot of cumulative gas production versus hydrocarbon pore-feet thickness exhibited at +0.8 correlation coefficient, indicating that shaly sandstone analysis, when combined with laboratory data, can be used to differentiate the better gas wells in Las Tiendas field. Our work further illustrated that, in order to have 1.0 Bcf of gas production, 1.5 hydrocarbon pore-feet was required. Also, net pay in both the Olmos A and B sandstones was required. The results of this work were published in 1992 and were presented at the Gulf Coast Association of Geological Societies meeting in Jackson, Mississippi, where a paper authored by authored by K. T. Barrow (UT/BEG), G. B. Asquith, and G. L. Causey won a first-place Best Paper award. In 1993, Asquith presented the results of this work in Corpus Christi and discussed the petrophysics of the Olmos sandstones with 35 Texas independent operators who are working the Las Tiendas trend.

Task 3: Application of new techniques for analyzing bimodal porosity reservoirs and calculating reserves on State Lands

Prior to initiation of Project SLERO, Asquith published a paper describing a new method of conducting shaly sandstone analysis that used the amount of clay-bound, water-filled microporosity to correct total water saturation to effective water saturation. Because this method required only shallow- and deep-resistivity logs and a density log, it was decided to try the method on the Olmos Formation at Las Tiendas field. However, this project was not continued into the second year of the Las Tiendas study because 50 percent of the wells did not have density logs and, when the method was applied to those wells that did have density logs, the calculated effective water saturations were unreasonably low.

It was later discovered that the reason this method did not work in the Olmos Formation is that there is a high percentage of iron-rich chlorite in these sandstones. The presence of iron-rich chlorite made the density log record an abnormally low porosity, which resulted in an overestimation of bound water. The overestimation of bound water, in turn, resulted in an underestimation of effective water saturation.

Task 4: Log analysis of Delaware Mountain Group sandstones

Late in 1991, Noel Tyler (UT/BEG) met with Marion Arnold and George Asquith (TTU/CAPS) and requested that they initiate a study of Delaware Mountain Group sandstones in West Texas. The reason for the move was that the State of Texas has vast land holdings in the Delaware Basin and the Delaware Mountain Group sandstones are oil productive.

The Permian Delaware Mountain Group consists of up to 3,000 ft of commonly thick, very fine grained sandstones and siltstones interbedded with thin limestones and organic-rich shales. In some wells, as many as 12 individual sandstones may be oil productive. However, productive versus nonproductive sandstones in the Delaware Mountain Group are very difficult to distinguish using well logs. The reasons for this difficulty are:

1. Lack of complete logging suites
2. "Delaware effect" on the laterolog

3. The presence of residual oil saturations, even in water productive sandstones

4. The very fine grain size

5. The presence of clay minerals

6. High porosities and low permeabilities

For problems (1) and (2) there is nothing that can be done except to encourage operators to run better logging suites in Delaware Mountain Group sandstones. We are doing this every time we give a presentation based on Project SLERO research. The remaining problems (3 through 6) can be solved by detailed petrophysical study.

It should be mentioned here that the decision to initiate petrophysical study of Delaware Mountain Group sandstones was a timely one because, in the spring of 1993, after only 3 months of limited advertisement, a Delaware Mountain Group symposium was held in Carlsbad, New Mexico. This symposium was attended by 160 independent operators from New Mexico and Texas. At this symposium George Asquith and Mark Thomerson presented papers on SLERO-sponsored research. This interest in the Delaware, as shown by the symposium attendance, illustrates how important this oil play is in West Texas and New Mexico.

Clay Mineralogy of the Delaware Mountain Group: The clay mineralogy of Delaware Mountain Group sandstones is a critical factor in log analysis because knowledge of clay mineral content is used to correct log porosities to core porosities. These corrections are of particular importance in the Delaware Mountain Group because the pore throats in these very fine grained reservoirs are very small. Clay mineralogy analysis consisted of scanning electron microscope, x-ray, and petrographic analyses. The results from samples of the Bell Canyon and Cherry Canyon Formations of the Delaware Mountain Group indicate the following:

1. Clay minerals are authigenic and dispersed.

2. Clay minerals are iron-rich chlorite and mixed-layer illite-smectite.

3. The volume of clay determined from laboratory data is less than the volume of clay determined from logs.

The results of clay mineralogy analysis, together with core analysis conducted in our laboratories, were used for log analysis of Delaware Mountain Group sandstones.

Log Analysis of the Delaware Mountain Group: The first step in log analysis of Delaware Mountain Group sandstones was to use data from clay analysis to correct log porosities to core porosities. This step is important because our plots of core porosities versus core permeabilities indicated that, with a porosity of 15 percent, the resulting permeability is only 1.0 md. Therefore, to accurately predict the productive permeable intervals from log data, log porosities must be calibrated to core porosities. Cross plots of core porosities versus acoustic and neutron-density porosities corrected for clay demonstrated very good agreement, indicating the importance of clay analysis. More important was the observation that density porosity uncorrected for clay, when calculated with a matrix density of 2.65 gm/cc, was close to core porosity. This observation is important because independent operators often cannot obtain clay analysis data and, by using uncorrected density porosity, can obtain a porosity value close to core porosity.

In addition to core porosities and permeabilities, cementation exponents (m) were determined in our laboratory. The average value for (m) was 1.80. In standard log analysis of sandstones, an (m) value of 2.00 is normally used. This lower value of (m) results in a 10 percent reduction in the calculated value of water saturation, which has a profound effect on the evaluation of productive versus nonproductive Delaware Mountain Group sandstones. As a result, this also affects calculation of oil reserve volumes. The results of (m) measurements and porosity analyses were presented at the national meeting of the American Association of Petroleum Geologists (AAPG) and at the Southwest AAPG meetings in the spring of 1993. Two additional papers have been submitted for the Southwest AAPG meeting in the spring of 1994.

Using these clay-corrected porosities and a cementation exponent (m) of 1.80, water saturations were calculated and net pay was determined for several wells using the following cutoffs: (1) V_{cl} = 15 percent, (2) effective porosity = 15 percent (Ka = 1.0 md), and (3) water saturation = 60 percent. In addition to defining potentially productive zones using net pay, a series of log cross plots were utilized to aid in defining productive versus nonproductive Delaware Mountain Group sandstones. These cross plots included: (1) R_t porosity versus density porosity, (2) Archie water saturation versus ratio water saturation,

(3) R_{xo}/R_{mf} versus R_t/R_w (Dew plot), and (4) R_t porosity versus R_{xo} porosity. The R_t porosity versus R_{xo} porosity plot is of particular importance in analysis of the Delaware Mountain Group because it could be used to define sandstones containing moveable oil. Indeed, often the log analyst encounters Delaware Mountain Group sandstones that contain oil but produce only water because the oil is not movable. All of our log analysis procedures were presented at either the Delaware Mountain Group Symposium or the Southwest AAPG meeting in the spring of 1993.

The final phase of our petrophysical study is the use of capillary pressure curves, which were constructed by core tests conducted in our laboratory. This work has concentrated on determination of irreducible water saturations for Delaware Mountain Group sandstones that range from 10 to 20 percent and the construction of log-derived relative permeability curves for water and oil. These relative permeability values may prove to be an additional logging method that can be used to define productive versus nonproductive Delaware Mountain Group sandstones. Capillary pressure curves are also being used to determine the amount of structural closure necessary to obtain different water saturations. The results are:

SW (5)	Amount of closure (ft)*
60	66
50	135
40	258
30	417

*Averages from 18 capillary pressure curves with Ka≥1.0 md or 15 percent porosity

In addition to our publications and presentations, we are conducting technology transfer by working with Texas independent operators who have Delaware operations or potential Delaware productivity in the State of Texas. One of these operators has a Delaware project in State Lands in Reeves County. Using the logging techniques developed during Project SLERO, the operators report that two Delaware sandstones appear to be productive on State acreage.

Petrophysical analyses of the Olmos Formation and Delaware Mountain Group sandstones in Texas have provided independent operators with both the laboratory data and the log analysis techniques necessary to better differentiate productive from nonproductive intervals. The importance of this work to the independent operators can be demonstrated by the attendance at public presentations of our SLERO-sponsored research. In April 1993 a presentation on log analysis of Olmos Formation sandstone was given in Corpus Christi, and this meeting was attended by 35 operators. In May 1993 a presentation on log analysis of Delaware Mountain Group sandstones was given in Midland, and this meeting was attended by 102 operators. These two presentations were given at local well log societies and set attendance records for the 1992–1993 year.

Task 5: Improved calculations of saturation distribution in Delaware Mountain Group and Las Tiendas field data

Core analysis of the Delaware Mountain Group: Sixty-two core samples from the AC Fee No. 2 well and 178 samples from the AB Fee No. 1 well were analyzed in our laboratory for porosity, permeability, and cementation exponent (m). An additional 38 vertical core samples were collected from the AB Fee No. 1 for complete clay analyses. Porosities for AB Fee No. 1 ranged from 1.5 to 26.6 percent, permeabilities ranged from 0.04 to 59.5 md, and (m) ranged from 1.025 to 2.125. Porosities for AC Fee No. 2 ranged from 0.3 to 21.2 percent, permeabilities ranged from 0.01 to 9.381 md, and (m) ranged from 1.011 to 2.702. The complete data set, including capillary pressure curves, is on file at UT/BEG.

Core analysis of Olmos Formation sandstones from Las Tiendas field: Cores were analyzed from three wells in Las Tiendas field. Six samples were studied from the J. T. Maltsberger No. 1. Porosities ranged from 10 to 16 percent, and permeabilities ranged from 0.03 to 0.21 md. Twelve core samples were selected from the Murexco Leyendecker No. 1, and these had porosities ranging from 2.65 to 15.93 percent and permeabilities ranging from 0.004 to 0.34 md.

Interfacial tension measurements: A key factor in calculating water saturations from capillary pressure data is the interfacial tension (IFT) between oil and water in oil reservoirs or for gas and water in gas reservoirs. These values for IFT must be considered at reservoir conditions of pressure, temperature, and the compositions of the hydrocarbons and water. For the purpose of better estimating IFT's, tests were conducted using distilled water and 14 different oil samples. A total of 60 data points were obtained by using a Du Nuoy Tensiometer to take IFT measurements between oil to air, air to oil, oil to water, water to oil, water to air, and air to water. The results of comparing these data were inconclusive but did prove that the additive value principle for results from parachors must be avoided for estimating IFT's in the reservoir.

Capillary pressure analysis: Capillary pressure data collected from Las Tiendas field cores were used to determine irreducible water saturations. Capillary pressure curves were used to develop a Leverett J-function curve that was used to develop techniques for improving the accuracy of calculations of the vertical distribution of water saturation. We believe that this approach will improve the accuracy of calculations of initial gas in place.

Activity 3: Advanced Extraction Technology

Task 1: Cyclic carbon dioxide development in Delaware Mountain Group reservoirs

The cyclic carbon dioxide injection (CCDI) process is a single-well process in which carbon dioxide is injected immiscibly into an oil zone. The process is conducted in three stages, or steps: (1) injection of carbon dioxide, (2) shutting the well in to allow the carbon dioxide/oil system to come to equilibrium (this is called the soak time), and (3) putting the well back on production at a higher oil-producing rate. The time involved in performing these stages will vary from well to well. However, to give an idea of the stage times, a typical cycle might involve injecting carbon dioxide for 2 weeks, soaking 4 weeks, and producing the stimulated well 6 months to a year before having to repeat the cycle.

This process is considered by most legal and tax entities to be an enhanced oil recovery (EOR) process. However, it does not increase ultimate oil recovery by decreasing the residual oil saturation, as would be expected from a miscible carbon dioxide flood. It does increase ultimate recovery by increasing oil production rates and, thus, extending the economic life of a well beyond that expected for a nonstimulated well.

The main advantage of this process, especially for small operators, is that it does not require large up-front investments. Ideally, a STB of oil should be recovered for each MSCF of gas injected. The amount of carbon dioxide required to stimulate an individual well will depend on the thickness and other properties of that well. However, a typical carbon dioxide slug size may be on the order of 500 tons (17.25 MSCF per ton) at an estimated cost of $25,000 for materials. This compares well with the millions of dollars often expended up front for other EOR processes, such as miscible carbon dioxide flooding. It should also be noted that geology/engineering costs will be lower for a single-well process. Conditions between wells have a major effect on results for frontal drives. However, it does not matter if wells in an area are even in communication for the single-well cyclic, or huff and puff, processes to work. Thus, extensive pilot tests are not needed and the overall reservoir definition is less critical.

The success of the cyclic carbon dioxide injection (CCDI) process depends primarily on oil-swelling and oil-viscosity reduction to increase oil-production rates. Carbon dioxide is highly soluble in most crude oils, and the consequent reduction of oil viscosity and increase in oil volume factor (swelling) increases the oil mobility significantly in most cases. Success also depends on the oil saturation at the time of the stimulation. As might be expected, the higher the oil saturation, the greater the increase in production. If some free gas, usually hydrocarbon, is available it will be moved away from the well bore area and will provide pressure support by gas expansion during the production period. Some investigators believe that the wettability changes due to carbon dioxide injection into the reservoir may enhance results. However, no conclusive information is currently available to support this assertion, and we have ignored that factor in this study.

Some crude oils precipitate asphaltenes when contacted with carbon dioxide. This may be a sufficiently serious problem that severe plugging of the well will result. Whether or not this happens needs to be determined by laboratory tests. It is also better to have laboratory tests conducted to determine the solubility of carbon dioxide in a particular crude oil and the accompanying reduction in oil viscosity and increase in oil volume (swelling). These variables should be determined as a function of pressure at reservoir temperature.

There are few published results of tests of cyclic carbon dioxide injection, sometimes called huff and puff, field projects. Thus, mathematical simulation was chosen as the best tool available for identifying the best combinations of rock and fluid conditions to determine if a well is a good candidate for a CCDI project. We developed our own software for this simulation because none was commercially available. Our simulation is a two-dimensional (R-Z:radial, vertical) three-phase simulation model. The three phases are oil, water, and carbon dioxide gas. It has been found that hydrocarbon gases, if present, are moved quickly to the outer periphery of the system. Additionally, the carbon dioxide phase is always immiscible with the oil for the CCDI process. Therefore, black oil assumptions are valid for the simulator. The strongly implicit procedure (SIP) was selected to solve the pressure equation. This process has been thoroughly tested and is highly stable and suitable to use in an R-Z model.

Data and test results from 10 reservoirs are available to calibrate the model. Depths vary from 1,300 ft to 13,000 ft, pay thicknesses vary from 6 ft to 58 ft, rock permeabilities vary from 10 md to 3,000 md, and porosities vary from 13 to 32 percent. The data from the AB Fee No. 1 and AC Fee No. 2 wells are not good prospects for application to this process. These results will be reported as a Master's thesis.

GEOLOGY MAPPING AND STATISTICS LABORATORY

LAMAR UNIVERSITY

Activity 1: State Lands Play Analysis and Resource Assessment

Task 1: Data collection

In March and July of 1992, a research assistant traveled to Austin to collect data from UT/BEG and the Railroad Commission of Texas. Seven State Lands oil fields were selected as study areas. Information on each of these fields was obtained at the Railroad Commission. This included W-1 forms, W-2 forms, plats, if available, and hardcopy maps of the pertinent areas. Digital map information, well logs, scout cards, and completion cards were purchased from commercial sources. These data will be archived at UT/BEG.

Task 2: Data compilation

This information was collated and entered into a computer data base using Microsoft Excel software. This information includes well name, well number, American Petroleum Institute (API) number, Railroad Commission (RRC) number, lease name, field name, original operator's name, present operator's name (if known), type of logs run, completion/recompletion data, potential test data from W-2 forms, type of completion, top of pay, total depth, plug-back depth, producing interval(s), and locations. A copy of this data base will be archived at UT/BEG.

Task 3: Map production

We have constructed maps that display pertinent fields. We have obtained digital map data sets from the Railroad Commission of Texas and have used a C++ program (written in our laboratory by J. G. Pittman) to convert these data into a format acceptable to the mapping programs that we have available. We will produce four maps covering fields for which we collected data. The computer program that converts Railroad Commission data into the required format for mapping programs will be capable of converting Railroad Commission data for any other quadrangle.

Throughout Project SLERO, Lamar University has served a data-gathering function. We have acquired well logs for various fields for the project, digitized between 80 and 100 well logs, and acquired and worked with various maps. The work we have completed has been made available to other SLERO researchers for further study and analysis of hydrocarbon production from Texas State Lands.

Activity 2: Reservoir Characterization

Task 1: Digitization of well logs from Keystone field

We received approximately 26 Keystone field well logs from UT/BEG. These logs were digitized, checked, and edited in the Logdigi and Logprint programs before being returned. We digitized the following curves for each log, if present: spontaneous potential (SP), gamma ray (GR), neutron, and bulk density.

APPENDIX: PUBLICATIONS RESULTING FROM THE STATE LANDS ENERGY RESOURCE OPTIMIZATION PROJECT

Papers, Chapters, and Monographs

Asquith, G. B., Thomerson, M. D., and Arnold, M. D., 1993, Recognizing Bell Canyon and Cherry Canyon "behind pipe" pay sandstones, Reeves and Culberson Counties, Texas: American Association of Petroleum Geologists Transactions and Abstracts, 1993 Southwest Section Geological Convention, p. 1–11.

Asquith, G. B., Thomerson, M. D., and Arnold, M. D., submitted, Variations in cementation exponent (m) and fracture porosity, Permian Delaware Mountain Group Sandstones, Reeves and Culberson Counties, Texas: Transactions Southwest American Association of Petroleum Geologists Convention, Ruidoso, New Mexico.

Barrow, K. T., Asquith, G. B., and Causey, G. L., 1992, Shaly sand analysis as an indicator of hydrocarbon production potential in the Olmos Formation, Las Tiendas, South Texas: Transactions, Gulf Coast Association of Geological Societies, v. 42, p. 13–26. (*Won first-place Best Paper award.*)

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Abstracts

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