STATE LANDS ENERGY RESOURCE OPTIMIZATION PROJECT

1992 Annual Progress 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
Texas A&M University

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Preface

Project SLERO, for which The University of Texas at Austin Bureau of Economic Geology is the lead contractor and coordinating institution, is 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 is aided by the cooperation of the Texas General Land Office. This is a four-year project funded at the level of $16 million, $8 million of which was granted by the Office of the Governor of Texas and $8 million of which is matched by participating academic institutions.

Project personnel include geologists, petroleum engineers, geophysicists, and chemists. The interdisciplinary nature of this project is 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 is divided into three parts: (1) play analysis and resource assessment, (2) reservoir characterization, and (3) development of advanced extraction technology.

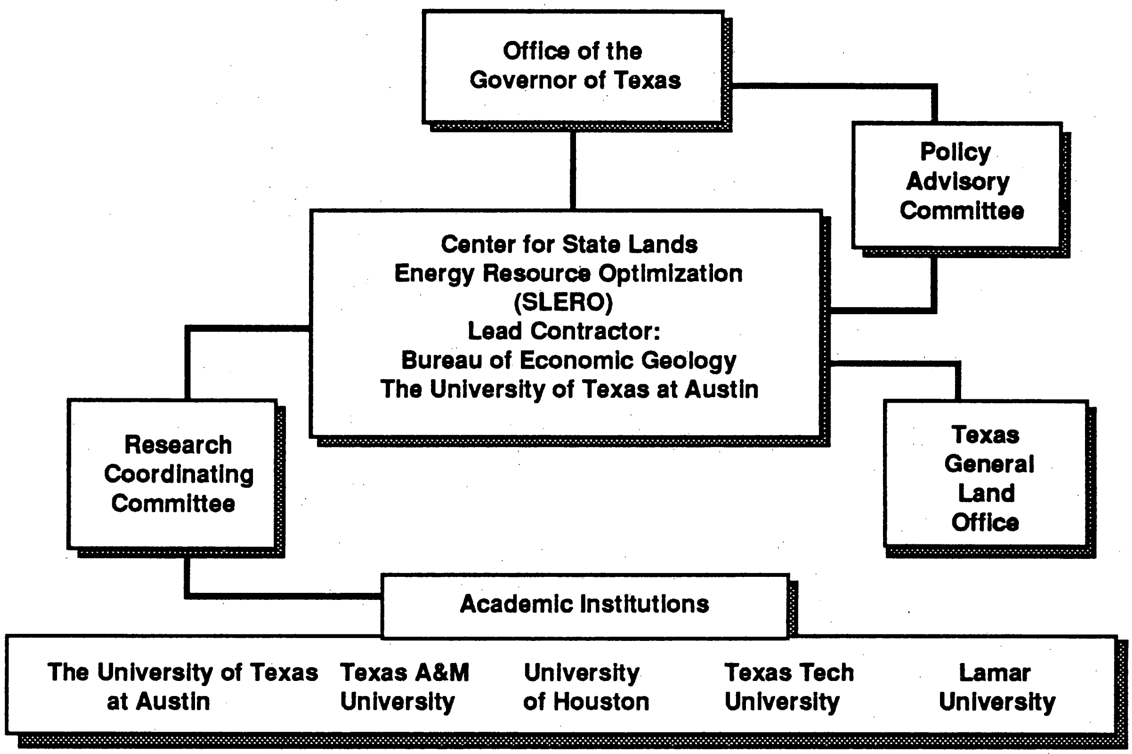
The play analysis and resource assessment part of this research program involves dividing the oil and gas fields on Texas State Lands into geologically based families, such that fields with similar depositional histories, trapping styles, production efficiencies, and extraction difficulties are grouped 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 is the focus of the resource assessment task.

The reservoir characterization part of this project includes selection of multiple State Lands fields and reservoirs for site-specific research. Inasmuch as the goal of reservoir characterization is to design advanced field development programs, the specific fields chosen for detailed study are 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 2 subregional study areas are undergoing characterization research. Reservoir characterization studies comprise geological, petrophysical, and geophysical investigation of the reservoir along with an assessment of original and remaining resources using cores, well logs, and seismic data. This work incorporates the results of petrophysical and diagenetic studies to produce two- and three-dimensional models of reservoir flow units. Seismic studies are 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, uses 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 have 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 includes 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 early 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, in a marine lake along the shore of the Gulf of Mexico, 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 MMbbl 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. Finally, SLERO researchers have received accolades from their peers for technical publications that have resulted from this project. Among numerous papers, abstracts, theses, and dissertations based on SLERO research, two papers presented at the 1992 meeting of the Gulf Coast Association of Geological Societies have won first and third place Best Paper awards and two papers presented at the 1992 fall symposium of the West Texas Geological Society have won first place awards for Best Oral Presentation and Best Poster Presentation. These papers were published in the GCAGS and WTGS 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

Information on reservoirs containing State Lands that have produced more than 1 million stock-tank barrels (MMBSTB) of oil equivalent was collected from the central records office of the Railroad Commission of Texas. Pertinent data were placed in separate oil and gas reservoir data bases. We are calculating reservoir oil volumes and using these results to verify reservoir properties listed in the data base. Verification of engineering numeric data for oil reservoirs is complete, and data for gas reservoirs are now being analyzed. Collection of information on Texas enhanced oil recovery projects is complete and the data have been processed. The geologic formation from which each State Lands gas reservoir produces is currently being verified. Oil production data obtained from commercial sources were used to update 1990 and 1991 annual oil production from State Lands reservoirs, and we are working on a similar update of State Lands gas production.

Task 2: Play analysis

Play analysis focused on digitizing reservoir locations of upper Guadalupian reservoirs and updating the State Lands oil reservoir data base. Structure and thickness maps from several sources were acquired and entered into the computer. Analysis of reservoir locations, coded by producing formation, in conjunction with structure and thickness maps, resulted in more precise play boundary placement. Discrepancies between newly defined play boundaries and reservoir locations were corrected.

Fluvial deltaic plays of the Gulf Coast were also analyzed. Structure maps were digitized and spatially analyzed to determine relationships with reservoir locations. Additional surface fault data were obtained from the UT/BEG Tectonic Map of Texas and entered into the data base. Interrelationships between structures and reservoir characteristics are enhanced through spatial analysis functions.

The outlines of Siluro-Devonian plays were updated. The data base now includes reservoirs satisfying a lower cumulative production cutoff. Siluro-Devonian play boundaries will be reevaluated and refined using these additional reservoir data. Play analysis of Grayburg-San Andres reservoirs was initiated at the close of 1992. Preliminary spatial data were digitized and are being processed for further evaluation.

Task 3: Resource assessment

A new technique was developed to assess State Lands oil reserves. Uncertainty in reserve analysis comes from both the scientific variability of an analysis and the application of additional technology. This uncertainty can be constrained when analyzing reserves within the context of a geologic play. Geologic plays are based on a hierarchy of geologic heterogeneity, which coincides with engineering parameters used to calculate reserves.

Monte Carlo simulation can be applied to combine the effects of scientific and technological uncertainty within the geologic play framework, thus creating reserve probability distributions that accommodate geologic uncertainty and quantify reserve variability potential. Calculating the reserve variability potential of an individual reservoir is a three-step process. First, the original oil-in-place-per-acre characteristic of the play is fit to a general probability distribution function. Next, play probability distribution functions are fit to reservoir recovery efficiency at various stages of reservoir development. Finally, deterministically calculated average original oil in place per acre for individual reservoirs is applied, along with play volumetric and recovery probability distributions, to generate reserve variability potential distributions. Reporting the 50 percentile reserve value along with the 10 to 90 percentile range as the reserve variability potential describes the uncertainty of reserve calculation.

This method allows more accurate State Lands reserve estimates and bridges the gap between deterministic and probabilistic reserve estimate procedures. Geologic assurance is built into the reserve variability potential, and thus we are better able to assess reserve calculations. Applying the concept of reserve variability potential also helps resolve the problem of categorizing reserves into proved, probable, and possible reserves by modeling reserves as a continuum.

The Silurian and Devonian reservoirs of the Permian Basin are major contributors to State Lands oil production. This set of reservoirs was divided into four plays, and oil resources were assessed in detail. The four plays are Thirtyone Deep Water Carbonate, Thirtyone Ramp Carbonate, Wristen Platform Carbonate, and Fusselman Shallow-Water Platform Carbonate. These plays contain 646 reservoirs, which have produced 1,958 MMSTB of oil from a total of 7,745 MMSTB original oil in place. Current reserves are 550 MMSTB, with an additional 2,069 MMSTB of unrecovered mobile oil and 3,176 MMSTB of residual oil in place.

Activity 2: Reservoir Characterization

West Fulton Beach field: A study of West Fulton Beach field was initiated in November 1992 with a data collection visit to the operator. The field is located in Aransas County, on State Lands in Copano Bay. West Fulton Beach is a mature field that produces gas and lesser amounts of oil from the Frio Formation, and is typical of Downdip Frio Barrier/Strandplain Play reservoirs on the San Marcos Arch. It has produced more than 130 billion cubic feet (Bcf) of gas and 6 MMbbl of oil from 32 reservoirs discovered between 1950 and 1968. These reservoirs, located at depths between 6,000 and 8,000 ft, are composed of interbedded sandstone and shale deposited in barrier bar/strandplain and inner shelf settings. Hydrocarbons have been structurally trapped in a northeast-southwest-trending, doubly-plunging anticline. The fold has been cut near its crest by a similar-trending, southeast-dipping growth fault. Individual sandstone reservoir beds range from 5 to 50 ft. Intervening shales vary from 1 to 60 ft in thickness.

Because many of these sandstones were deposited during periods of transgression, reservoir interval could be composed of sandstones that are arranged in a "shingled" fashion, each sandstone body being separated by a thin layer of shale. This would result in significant internal heterogeneity within each reservoir. Additionally, because many sandstones are thin, displacements of as little as 10 ft on minor fold-related faults could isolate reservoir compartments. The combination of internal heterogeneity and minor faulting may have added to the complexity of the many stacked reservoirs by creating numerous compartmentalized reservoirs.

The goal of this study is to increase hydrocarbon reserves on State Lands through the recognition of bypassed natural gas reserves in downdip Frio reservoirs. This will involve a detailed study of important reservoirs at West Fulton Beach that will integrate geologic, petrophysical, and geophysical data. Techniques that prove successful in the study of West Fulton Beach will be communicated to operators of similar reservoirs on State Lands through publications and an oral presentations at scientific meetings and seminars.

The study is nearing the end of the data-gathering phase. Geophysical well logs, structure maps, porosity and permeability data, and well completion summaries have been provided by the operator. Unfortunately, because the field was developed during the 1950's, old-style electric logs are predominant in the log data base and the large number of cores taken during development were destroyed. Additionally, no seismic data are available. A stratigraphic correlation section has been assembled and annotated with core coverage and completion information to assess gross lateral reservoir heterogeneity and the availability of petrophysical data. A computerized base map and data inventory are being prepared.

The remainder of the study will focus on identifying reservoir compartmentalization in the most productive horizons. Interval isopach maps will be prepared to identify anomalies that may be due to faulting. Variations in spontaneous potential log curve shape will be mapped to identify lateral changes in depositional facies. An attempt will be made to calibrate spontaneous potential data to permeability, so that reservoir flow units can be identified and correlated throughout the field. Compartments will then be identified based on fault patterns and lateral boundaries of depositional facies and flow units. Compartment volumes will be calculated and compared with cumulative production figures to identify undrained or incompletely drained areas. Recommendations to drill or recomplete wells based on this information will be made to the operator.

Red Fish Bay field: This reservoir characterization study was initiated in November 1992. Red Fish Bay field, located in Nueces County, 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 contains 50 reservoir sandstones in the middle to upper Frio Formation that have produced more than 23 MMbbl of oil equivalent of oil and gas. The principal trapping mechanism is a large anticlinal closure on the upthrown side of a large regional fault. For individual reservoirs, drive mechanisms vary from gas cap expansion to water drive.

This project has focused on eight sandstone reservoirs (reservoir zones 5, 5A, 5B, 9, 14, 15, 17, and 18) that have produced 75 percent of the cumulative field total. Production from these sandstones has been principally oil. These sandstones occur at depths of 7,300 to 8,500 ft. Regional maximum flooding surfaces have been used to place the reservoir sandstones into a genetic sequence framework. The major reservoir zones consist of upward-coarsening to spiky sandstones, generally less than 30 ft thick, that record deposition in transgressive and highstand systems tracts. The sandstones are interpreted to have been deposited in a shoreface/shelf setting and are interbedded with outer shelf, muddy siltstones.

The field operator has not conducted any geological studies of the field. Because of the presence of multiple reservoirs, and because the field has been produced by various competing operators, there is potential for inefficiently drained reservoir sandstones with bypassed, behind-pipe reserves. The operator is primarily interested in using this study to locate resources that may be recoverable through recompletions and/or deepening of existing wells.

More than 150 well logs have been acquired. Approximately 100 of these consist of electric logs dating from the 1950's and 1960's. Fifteen post-1970 wells have more complete log suites. Production data are not available from the operator. Reservoir production statistics, along with completion/recompletion and well potential test data, are being compiled so that the production history of individual wells can be assessed. Many of the wells have dual completions and commingled production from separate reservoirs, further complicating attempts to assign production on a well-by-well basis for each reservoir.

The well completion and production histories, in conjunction with structural cross-sections and subsurface maps, will be used to identify bypassed, behind-pipe reserves. This will allow evaluation of further hydrocarbon potential within these major reservoir units. Bypassed mobile oil reserves may also exist in inefficiently drained reservoirs that are compartmentalized due to faulting, or to facies imposed variation in sandstone thickness and lateral and vertical reservoir heterogeneity. These opportunities will be assessed using well log facies maps, contour maps of production data, reservoir drainage patterns, and reservoir drive mechanisms.

Keystone field: The Keystone (Colby) reservoir, equivalent to the Queen Formation of Permian (Guadalupian) age, is located in Winkler County, on 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. 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 4.6 MMSTB of mobile oil are not accessed by existing wellbores on State Lands.

The San Andres reservoir at Keystone field, which is approximately 400 ft thick, produces solution-gas-driven oil from a depth of 4,000 ft. Evaluation of logs and drill cuttings and comparison with cores from an analog reservoir provide the basis for a geologic description.

The reservoir is composed of an upward-shoaling sequence of subtidal grainstone/packstone that is thoroughly dolomitized and partially cemented with sulfates. The upward shoaling sequence is capped by tidal-flat deposits, principally finely crystalline mudstone. Locally, postdepositional leaching has increased porosity and permeability and altered some anhydrite to gypsum. The combined effects of depositional environment and postdepositional leaching control rock properties used to define five reservoir flow units.

The Keystone (San Andres) reservoir produces oil principally from units I and II in the updip, western part, and principally from unit IV in the downdip, eastern part, of the study area. Several opportunities for recompletion in units I and II are present in an area of more than 4 mi^2 surrounding the crest of the structure, where relatively few wells are in communication with these proven productive reservoir zones.

A limited number of acoustic, neutron, and density porosity logs are available for the Keystone (San Andres) reservoir. The presence of abundant gypsum in the reservoir, however, complicates the use of neutron and density logs for porosity measurements. The bound water of hydration within gypsum crystals is recorded as porosity by neutron logs, and the low density of gypsum relative to that of dolomite and anhydrite causes density logs to overestimate porosity.

We have applied two methods of porosity analysis to the small number of modern log suites available. The two porosity calculations, an acoustic-core calibration based on an analog reservoir and a mineralogy model calibration, were compared. The acoustic-core calculation yielded a higher porosity solution and, importantly, indicated a higher net pay. Indeed, the acoustic-core porosity calculation indicates reservoir quality rock in both the upper zone and lower zone, but the mineralogy-model calculation indicates production only in the upper zone. We are currently conducting a log and core calibration using a new core recently cut in a well on State Lands at Keystone field. It is anticipated that log and core calibration using this new rock material, which is being analyzed using modern non-gypsum-destructive techniques, will eliminate the uncertainty in calibration of porosity logs.

Preliminary results of our study of both the Colby and San Andres reservoirs at Keystone field were published in 1992. R. P. Major and Q. Ye wrote "Lateral and vertical reservoir heterogeneity in siliciclastic peritidal facies, Keystone (Colby) reservoir, West Texas," and R. P. Major, M. H. Holtz, and R. D. Dommisse wrote "Calibration of porosity logs and delineation of flow units in a San Andres reservoir: Keystone field, West Texas." Both of these papers were presented orally at the fall symposium of the West Texas Geological Society and published in the transactions volume for that meeting, and Major, Holtz, and Dommisse won the first place Best Oral Presentation award.

Preliminary results of our research have also been used by the operator in planning reservoir development activities. A well drilled in 1992 at a location in the Keystone (San Andres) reservoir recommended by UT/BEG researchers flowed at an initial rate of more than 150 bbl/d, making this the most productive well since initial field development in the 1960's.

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 product 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 the preliminary results of this study was awarded third place "Best Paper" award by the Gulf Coast Association of Geological Societies. This paper, authored 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 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. The field is classified as part of the Miocene Barrier/Strandplain Sandstone play. The field structure is an anticline in the hanging-wall of an up-to-the-coast antithetic fault above a major reactivated Frio growth fault. Some reservoirs are structural traps, but most are combination structural/stratigraphic traps in which closure is partly due to pinch-out of sandstone units.

Powderhorn field contains 11 producing reservoirs. The lowermost reservoir is the 5200, or No. 5, 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 No. 3 and No. 1 Sands, 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. Since discovery of the field 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 of less than 2 mi^2.

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 in some Powderhorn reservoirs on the existing seismic data.

Development drilling in the field 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 Apache No. 17 State Tract 49. This well made a deeper pay discovery 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 field oil reserves. A twin well was drilled by the field operator to accelerate production of the newly discovered oil. In total, nearly 1 million barrels of oil 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.

Las Tiendas (Olmos) field: The Las Tiendas (Olmos) field is included in 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 log resolution, but appear to have a more limited lateral extent. Pinchouts 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 trap gas locally. 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 shale out 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 MCFPD 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. Well spacing rules range from 40 to 320 acres for these fields. Because of the wide spacing of wells and low permeabilities of the reservoir sandstones, significant gas reserves remain on State Lands in the Las Tiendas area. These reserves can be exploited profitably with a geologically targeted drilling program after gas prices return to approximately $2/Mcf.

<u>Delaware Mountain Group</u> (regional study): Study of the Permian (Guadalupian), Delaware Mountain Group focuses on shallow sandstone reservoirs in the Bell Canyon and Cherry Canyon Formations in Culberson and Reeves Counties. A regional sequence stratigraphic study of the Delaware Mountain Group integrates newly acquired seismic data with a grid of subsurface cross sections.

This stratigraphic framework has identified three orders of cyclicity in the Delaware Mountain Group. Because reservoir sandstone is volumetrically dominant, the most important controls on hydrocarbon accumulation are low-permeability siltstone seals that impede updip hydrocarbon migration and influence hydrodynamic charge relations. At the top of each low-order cycle, the additive effects of marine deepening at all scales of cyclicity constructively combine to form vertical and lateral seals.

Hydrodynamic trapping within base-level-rise portions of long-term cycles controls hydrocarbon accumulations in Delaware Mountain Group reservoirs. Clastic sediment starvation and highstand shedding of basinal carbonates produced laterally extensive low-permeability and low-porosity strata, which form vertical seals, whereas compartmentalization of lower energy, laterally discontinuous reservoir sandstone forms lateral seals.

The PDB-3 well from Dimmitt field in Loving County, Texas, represents a composite reference well that was tied to regional cross sections and the seismic grid to help establish a sequence stratigraphic framework. Five regional stratigraphic cross-sections were constructed and identify three orders of cyclicity in the Delaware Mountain Group. Low-order cycles approximate the Brushy Canyon, Cherry Canyon, and Bell Canyon Formations and form asymmetric, up to 500-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. Large-scale cycles consist of five to eight intermediate-scale cycles characterized by 10- to 150-m-thick eolian-derived turbidite successions. Intermediate-scale cycles contain two to seven high-frequency symmetric cycles that are 2 to 30 m thick and are bounded by siltstones. High-frequency cycles form an upward-bed-thickening hemicycle of thinly interbedded sandstone and siltstone, ripple-laminated sandstone, and erosive-based, structureless sandstone overlain by an upward-bed-thinning hemicycle of similar facies in reverse order. Approximately 60 short-term, genetic sequences have been identified and regionally correlated.

Seismic lines oriented along the Guadalupian platform margin were tied to synthetic well logs from subsurface cross sections to better constrain the platform margin configuration. These data were used to relate depositional patterns in the Delaware Mountain Group to the changing platform margin geometry.

<u>Screw Bean field:</u> This field, which produces oil from the Bell Canyon and Cherry Canyon Formations of the Delaware Mountain Group, was chosen for site-specific reservoir characterization in the context of the regional Delaware Mountain Group study.

Cores form Screw Bean field, in Culberson and Reeves Counties, were calibrated to well log suites to establish a genetic stratigraphic framework, which was used to map the distribution of reservoir sandstones and siltstone seals. Computer generated isopach, sandstone isolith, lithofacies, and net pay maps were completed and integrated with production information from the study area. Hydrocarbon bubble maps from Bell Canyon reservoirs were compared with geologic maps to evaluate reservoir compartmentalization.

Reservoir characterization of the Cherry Canyon Formation has focused on production from the Manzanita Limestone Member. Six cores from the Manzanita were used to identify five genetic sequences that are characterized by carbonate facies, which are overlain by thin reservoir sandstones. Isopach maps of these genetic sequence show an overall landward-stepping stacking pattern and an upward-thinning of sandstone facies.

<u>Seventy-Six West and Colmena-Cedro Hill fields:</u> Geologic characterization of Seventy-Six West and Colmena-Cedro Hill fields concluded early in 1992, and focus of the research effort since then has been to incorporate results of the infill wells that were recommended from the study and to write a

comprehensive report. The report is complete and will be published in The University of Texas at Austin, Bureau of Economic Geology publication series.

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 heterogeneous reservoirs consisting of a mosaic of strike-elongate barrier-bar sandstones, crosscutting 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 determines whether the reservoir sandstones are gas-, oil-, or water-saturated at Colmena-Cedro Hill field.

Several infill drilling locations were proposed at Seventy-Six West field to exploit zones containing mobile oil that are either inefficiently drained or uncontacted at the existing well spacing. Two wells have already been drilled and successfully completed as oil-producers. The first well produced at a rate of 5 barrels of oil per day (BOPD) with no water and is considered to have intersected a part of the reservoir not previously contacted because surrounding wells produce at water cuts of 85 to 98 percent. The second well produced at a rate of 10 BOPD and 2 barrels of water per day (BWPD). From a geological standpoint, the 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. A third well was selected as a prime location for water injection and will be incorporated in the ongoing waterflood design. Engineering analysis is still in progress, but a pilot waterflood has been designed and presented to the operator for implementation. The pilot, which tests only a very small portion of the field and requires conversion of only one poor producing well, is conservatively estimated to recovery an additional 100,000 STB over the life of the field. A tracer test is proposed as a follow-up to the pilot waterflood and will guide future waterflood design. Results of the first and third infill wells have further emphasized the already recognized problem of low reservoir pressure, and this impediment will be addressed by the full-scale, geologically optimized waterflood.

Results of the study at Colmena-Cedro Hill also indicate zones within the reservoir that are either inefficiently drained or bypassed by the existing well spacing, and several infill drilling locations have been proposed to exploit those zones containing remaining mobile oil. 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 wells produce at higher rates when they have been flowing for a longer time. One infill well was also drilled, and its status has not yet been determined. It was completed as a producer and began to produce a couple of barrels per day after several weeks on pump. This production rate may also increase because of the improvement these wells typically experience over time. Waterflood operations have been maintained over much of the life of the Colmena-Cedro Hill field, and there is also strong aquifer support. Thus, reservoir pressure is adequate in this field, unlike Seventy-Six West field where additional oil could be recovered if reservoir pressures were increased.

Deeper pay potential on Duval County Ranch (regional study): Potential for commercial hydrocarbon accumulations below the Jackson Group on the Duval County Ranch (DCR) was assessed using seismic data. The regional stratigraphic framework was interpreted from a grid of high-quality seismic lines shot in 1988. The 1988 data were augmented by numerous 1960's and 1970's seismic lines of lesser quality. Seismic markers at or near the top and base of the Yegua, Queen City, and Upper Wilcox units were successfully correlated throughout the data set.

Structure is dominated by a faulting style common to the Gulf Coast. Large listric growth faults extend from the surface, through Tertiary and Cretaceous strata, and possibly as deep as the Triassic rocks. Growth faulting was most active during Wilcox time, when clastic deposition was focused at the unstable shelf-slope break. Downdip thickening of the sedimentary section, with development of rollover structures, is pronounced in the Wilcox deposits. Deep-seated withdrawal of Jurassic salt, or evacuation of unstable marine muds, may have contributed to the growing accommodation space. Adjustment along the faults continued to the present, with small-scale faulting and gentle flexuring of the Jackson Group and Yegua Formation in the shallow subsurface and subtle topographic expression at the surface.

Three principal seismic facies are recognized in the Upper Wilcox and Queen City stratigraphic intervals in the DCR area. The seismic facies display a pronounced basinward trend as facies 1 passes to facies 2 and then to facies 3. Low-amplitude, continuous seismic reflections characterize seismic facies 1, and are interpreted as coastal plain deposits. Seismic facies 2 consists of short, discontinuous, high-amplitude reflections attributed to delta-front and distributary-mouth bar deposition. The long, continuous, intermediate- to high-amplitude reflections of seismic facies 3 are associated with deeper water basinal deposits. Shelf margin progradation caused basinward advance of these seismic facies by Queen City time, such that coastal plain deposits of facies 1 dominated the DCR area. Seismic facies 2 and 3 were restricted to the southeastern part of the study area. Because of shelf margin progradation, the effect of the Wilcox Fault Zone over sedimentation was minor compared to that during Upper Wilcox deposition. In the Yegua and Jackson stratigraphic intervals, seismic facies 1 is present over most of the DCR area, whereas seismic facies 2 is absent and seismic facies 3 is of very limited extent. The Wilcox Fault Zone exerted little control over the deposition of these units, and further margin progradation occurred.

Seismic facies 1 and 2 with the Upper Wilcox and Queen City Formations and seismic facies 1 in the Yegua Formation and Jackson Group are interpreted to be sand-prone and are high-graded in exploration potential. Specific horizons within these seismic facies become prospective when associated with very high amplitude "bright spot" reflections. In the Queen City Formation, for example, a bright spot anomaly at Lundell field was correlated to proven gas and condensate production. A potential extension to this field exists and is defined by a high amplitude "bright spot" anomaly located in an adjacent downthrown, fault-bounded block. The anomaly covers an area of approximately 10 mi^2. Untested bright spot anomalies occur elsewhere in the Queen City Formation and also in the Jackson Group. High-amplitude seismic reflections at Seventy-Six West field correlated with the oil-productive Jackson sandstones. An area to the southeast of the field with similar but untested high-amplitude reflections represents another potential field extension. The seismic data indicate structural gain occurs in this area in the form of an anticline on the upside of a large listric growth fault.

Upper Wilcox seismic facies 2 has numerous untested zones with discontinuous, very high amplitude reflections. These are associated with a zone of expanded Wilcox section where sandstone deposition was focused on the down-side of the growth faults, and rollover structures provide closure. The trend of greatly expanded Wilcox section, the Deep Wilcox Trend, which has created much interest from the operators and landowner of DCR, is located mostly down-dip of the Ranch, and potential for discovery of fields such as Seven Sisters East or Rosita Northwest is restricted to the southeastern corner of the Ranch.

Other findings of the study are that the Lower Wilcox appears to be sandstone-poor in the DCR area and is assigned a very low exploration priority, and there is a high risk deep gas exploration play in the Lower Cretaceous.

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

Activity 2: Reservoir Characterization

<u>Task 1: Laboratory analysis and theoretical modeling</u>

The final report for this project, "Permeability and the Distribution of Wetting and Nonwetting Phases in Complex Pore Geometries," by Mohan Javalagi, W. R. Rossen, and M. M. Sharma, has been completed and was available for distribution in January 1993.

In this report, capillary-pressure data are presented for cores from the Keystone (Colby) reservoir. These data are being used for simulation of waterflood operation in this reservoir. It was concluded that thin-section permeability estimation offers a potential means of determining permeability from drill cutting in cases where core plugs are not available.

<u>Task 2: Interpretation of well-log data</u>

Detailed petrophysical log analysis has been performed on wells in Lavaca Bay and Keystone (Colby) fields, with the objective of developing interpretation models for the determination of porosity, water saturation, and permeability. Four key wells in each field were chosen, all of which had data on digital tape. In addition, a user-friendly interface for computer-based log interpretation is under development. The objective is to make it possible for smaller operators who lack in-house professional log analysts to perform computer-based interpretation of their logs using data provided on floppy disks.

Four key wells in Lavaca Bay field, Alcoa Fee No. 9, Alcoa Fee No. 11, ST27-3, and ST38-3, have conventional logging suites consisting of resistivity and the three standard porosity tools, neutron, density, and acoustic. In addition, either natural gamma ray spectroscopy or electromagnetic propagation logs and sidewall core data are available for each well.

Interpretation is being performed using the Schlumberger statistical matrix equation solver known as ELAN. Logs can be reconstructed using this approach, using the known tool responses and the mineral and fluid volumes calculated by the solver, allowing for a comparison to the actual logs. The parameters can be adjusted for the best possible reconstruction. The solution is not unique, and geological constraints are required. We have achieved the best results using two models, sandstone and shale, with the calculated volume of illite used to select the appropriate model at each 6-inch depth increment.

The sandstones in Lavaca Bay field appear to be composed of the common Gulf Coast minerals: volcanic ash, smectite, illite, orthoclase, plagioclase (albite or oligoclase), carbonate cements (calcite or dolomite), and quartz. Illite is considered the dominant clay. There are insufficient log measurements to determine the volumes of this many minerals, so some assumptions were made. Matching of sidewall core data was used, along with good reconstruction of the logs, as a criterion for success. The lack of geochemical logs, or even shallow resistivity logs, greatly reduces the probability of accuracy in the interpretation. Also, log quality is poor in many respects. For example, pad-type tools in all wells have problems, the natural gamma-ray has problems over large intervals in the wells where it was run, and apparent telemetry failures occur in random sections of some wells.

Four key wells in Keystone field, Keystone Cattle Company Nos. 401, 403, 405, and 406, are on the edge of the structure and show very poor porosity development. Unfortunately, these are the only wells with reasonably modern logs and digitally recorded data on tape. Preinterpretation work, such as depth matching and splicing, was performed on these wells and ELAN interpretation was attempted, but results were poor. Work will continue on these wells in 1993.

Software development was begun in the last quarter of 1992 on a user-friendly interpretation program that small operators could run on an 80486-based PC to interpret logs provided by a service company on floppy disk in LAS format. The emphasis in this project is on a new approach to the interface, making it possible for someone without specialized log analysis experience to perform basic interpretation in an easy, intuitive way. Coding has been done on some fundamental functions, such as reading LAS files and drawing the logs on the screen. An advanced object-oriented paradigm is being used.

Task 3: Measurement of reservoir heterogeneity using tracer data

We constructed a new description of reservoir heterogeneity in the parts of Sections 61 and 62 of Seventy-Six West field that were included in our reservoir simulation studies. This new description is based on well logs and sidewall core analysis, and provides a more realistic estimate of tracer flow than the preliminary results presented last year. The initial water saturation distribution was also updated and calculated from the producing water cut for each well and from the fractional flow curve. The newly drilled (Oct. 1991) producing Well 62-29 was included in our new simulations. We simulated waterflooding using UTCHEM for the same area of the reservoir as last year, considering Well 62-18 as a water injection well. The waterflood response is very fast and results in an increase in oil production rate in this area of Sections 61 and 62 from 40 bbl/d to a peak value of 70 bbl/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 bbl/d. Cumulative oil production after 20 yr is 206,000 STB, which is an increase of about 152,000 STB 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.

We also used UTCHEM to simulate interwell tracer tests, which involve the injection of chemical tracers into Well 62-18 and monitoring the tracer production from producing wells. We have been simulating interwell tracer tests to illustrate how these could be used to help better understand waterflood performance. These tests could also be used to improve the design of the waterflood and aid in reservoir description by delineating flow barriers, such as faults and facies limits. We also evaluated the use of partitioning tracers, such as tertiary butyl alcohol, because, by comparison with nonpartitioning tracers such as tritium or thiocyanate, an average oil saturation in the waterflood-swept volume of the reservoir can be estimated. All of these applications appear to be feasible and useful at Seventy-Six West field. A more detailed report on our waterflooding and tracer injection recommendations has been provided to the operator.

We also simulated a newly developed single-well backflow tracer test to estimate reservoir rock wettability under Seventy-Six West field conditions. This novel method is described and illustrated in great detail in the dissertation of Luiz Ferreira (1992), which is the basis for a report in preparation. 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 to form alcohols by hydrolysis. 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, and 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 the estimated waterflood performance and improve the efficiency of its design. This would increase oil recovery and the profitability of the waterflood.

Task 4: Construction of data model

We worked on expanding the quantity of data available in the archive, and maintaining the archive of data so that it is accessible from any location on the Internet. Special attention has continued to focus on network access mechanisms so that the data may be easily distributed to remote sites working on this project. The goal of this work has been to document the data available and to allow as many access mechanisms as possible.

Work on expanding the quantity of data available is still being carried out as two basic tasks: the development of programs that will ease the task of entering data as they are gathered and the collection of data from some of the fields that are being studied. The programs that have been developed allow easy entry of data from standard forms, such as those used by the Railroad Commission of Texas, to be entered into a known-file format. This shortens the length of time required to enter the data and increases the reliability of the data entered through this process. Programs that were developed during the past year were largely based on programs developed previously, primarily to minimize development time and to promote consistency in the format of the output data files that the programs generate.

Future work will focus on the documentation of existing data and expanding the quality of data available. These are the two most important aspects of this phase of the project at this time for which further work must be done.

Activity 3: Advanced Extraction Technology

Task 1: Waterflood surveillance and optimization

Waterflood Studies of the Keystone (San Andres) reservoir: The Keystone (San Andres) reservoir (Winkler County) has an estimated 36 MMbbl of mobile oil, of which only 2.6 MMbbl (7%) has been recovered. The objective of this project is to determine the well pattern for optimum waterflood recovery.

Depositional and diagenetic heterogeneities make this reservoir difficult to model. The first task was to obtain a complete reservoir characterization. Log and production data from this and analogous San Andres reservoirs were collected. The geological characterization, including flow units and calibration of porosity logs, was obtained from UT/BEG.

A 40-acre pilot zone was chosen for a finite-different reservoir simulation study. A five-spot model that will include Wells 403, 180, 316, 317, and 318 is being tested. Well 403 was recently drilled and a complete set of logs was obtained. Although five different flow units have been identified in the reservoir, the initial simulation studies have been done with the use of three layers. When petrophysical data become available from a recently cored well, additional layers will be included. A streamtube waterflood simulator is also being developed to allow field-wide studies of pattern effects of the proposed waterflood.

Further work with both simulators will include the use of different waterflooding patterns and recompletions in order to increase oil recovery.

Simulation Studies of Seventy-Six West field: Compartments 2 and 6 in Section 62 of Seventy-Six West field are being studied. This region contains parts of a beach ridge and channel facies. There are currently eight wells in this region. Two new wells, Prospects 3 and 4, are proposed by this study, bringing the total number of wells to 10.

An initial water saturation distribution was estimated based on the current water cut and a fractional flow versus saturation relationship. The fractional flow curve was developed using Corey-type oil and water relative permeability curves and oil and water viscosities of 28.5 and 0.7 cp, respectively. The high value of oil viscosity gives a mobility ratio that is very unfavorable for waterflooding. The rock compressibility was modified to accommodate free gas present in the reservoir, and was estimated to be 3×10^{-4} psi^{-1} for 5 percent gas saturation. The pore volume was then reduced by the volume occupied by the gas. Where laboratory results for rock and fluid properties were not available, reasonable estimates were made using appropriate correlations.

A waterflooding scheme is proposed whereby injectors are placed on the periphery, where water saturation is high, and producers are in the center, where water saturation is low. All wells, producers and injectors, have been consigned to operate on bottomhole pressure constraint. The following different cases were studied:

	Flow restriction	New wells
Case 1	No	No
Case 2	Yes	No
Case 3	No	Yes
Case 4	Yes	Yes

Flow restriction means that the transmissibilities at the boundaries between the beach ridge and the channel facies were reduced to model the flow barrier presented by the change in facies. It was found that modeling the flow restriction does not significantly affect the response of the reservoir. This may be because most of the wells are in the beach ridge portion, where very little flow occurs across the facies boundary. However, the addition of Prospects 3 and 4 resulted in a significant increase in field production rates and cumulative production.

Simulation results show that, after 21 years of production, the proposed waterflooding scheme results in a production of 408 MSTB of oil, which is 337 MSTB more than would be produced if the region were continued in its current mode of operation. Current recovery represents 6.5 percent of the original oil in place (OOIP). The waterflooding scheme brings the cumulative oil production of the region under study to 1,456 MSTB, which represents an ultimate recovery of 23 percent of OOIP.

Future plans consist of the following: (1) Identify zones that have been bypassed by the proposed waterflooding scheme so that modifications can be made that would result in a further increment in oil production. (2) Study cases where one new well is present instead of two. In one case, include only Prospect 3, and in another case, include only Prospect 4. Other possibilities include changing the locations of infill wells. (3) Study cases with different assignments of production/injection wells. (4) Assign a permeability field distribution, generated using the Turning Bands Method, to the region, observe the changes in the response to waterflooding, and compare these with the response of the scheme delineated above.

A pattern waterflood will also be considered because it should be more efficient, although the present location of wells poses a hindrance to any well-defined pattern. These studies will serve as a basis for additional recommendations.

Task 2: Development of inhibitive muds for well bore stability

Three types of tests were performed using drilled cuttings obtained from Well 62-30 of Seventy-Six West field. These tests included compositional studies, linear swelling tests, and the "Du Pont" test. In all tests, cuttings were used instead of the conventional cores in hopes that methods could be developed for determining the optimum inhibitive drilling fluid for unstable well bores. In the fields selected for SLERO research, cuttings are available in most cases but cores are available in only a very few cases.

Cuttings from 14 shale zones at depths between 300 and 1,300 ft were obtained from Well 62-30 of Seventy-Six West field. These cuttings were ground to smaller than 2 mm, and adsorption isotherms and cationic exchange capacity tests were performed. It was found that the cuttings displayed a rather high degree of adsorption, with the average water content being between 10 and 15 percent when equalized in a relative humidity environment of 96 percent. Also, cationic exchange capacity (CEC) for these shales was between 20 and 24 meq/gm, compared to the CEC values of 5 meq/gm previously obtained for cores taken in Las Tiendas field. This finding suggested that the core did not represent the most troublesome formation in the field. For comparative purposes, pure sodium montmorillonite (bentonite) has a CEC value of approximately 80.

In order to perform a satisfactory CEC test, it was found necessary to improve on standard methods for performing such analyses on shales. A nine-step procedure was developed and published.

To conduct the linear swelling tests, a compaction cell was designed and fabricated. The shales were compacted to downhole stress conditions and swelling tests were performed using different fluids. The compaction cell was made by machining a 2-inch-diameter by 2-inch-long cylinder of steel such that it has a 0.5 inch bore through the center. A 0.5-inch piston was also fabricated and was used in a hydraulic press to compact the samples. This device produced 0.5-inch-diameter by 1-inch-long test pellets.

When preparing test pellets, cuttings were first ground to a particle size less than 80 mesh, mixed with deionized water to a level of 12 weight percent, placed within the compaction cylinder, and then compacted at a stress level of 7,000 psi for 18 hr. After the pellets had been removed from the compaction cell, swelling tests were performed. Cuttings obtained from 1,300 ft, when placed in deionized water, produced 3.8 percent expansion after 24 hr. A 3 percent KCl solution produced 1.9 percent expansion and a 4 percent NaCl solution produced 2.5 percent expansion. Additional studies were performed on shale obtained from a depth of 300 ft, and results using deionized water, 3 percent KCl solution, and 4 percent NaCl solution were identical to the results reported above for the 1,300-ft shale. These results were very encouraging because the same order and relative level of swelling was experienced in previous tests that used cores. This suggests that the drill cuttings procedure may be a reasonable substitute for testing cores. We again found that the preferred water-base drilling fluid for preventing swelling of shale contains 3 percent KCl.

Midway through our studies a paper was published in which a "Du Pont" shale disintegration test was described. This method allows the determination of what is referred to as a "swelling index," a "hardness index," and a "disintegration index." The Du Pont test uses compacted shale pellets very similar to those described above. The primary difference is that a 1/8 inch steel rod is placed within the pellet as it is compacted so that when the pellet is removed, the 1/8 inch rod can be grasped with a rotating device and the pellet can be rotated in the test fluid as disintegration proceeds. By periodically measuring the weight loss from the pellet during the test, it is possible to determine the swelling and disintegration index.

After the shale has been rotated at approximately 1,500 rpm for 1 hr, the pellet is removed and the surface hardness is determined using a "hardness index" indicator, which measures the depth to which a sharp point penetrates the surface after applying a specified load. Fabrication of test pellets from shale from Seventy-Six West field is currently in progress, and these tests are planned for 1993.

Task 3: Advanced recovery screening and evaluation

Although our tracer and waterflood simulations (reported under Activity 2, Task 3: Measurement of reservoir heterogeneity using tracer data) show that injection of water has the potential to quickly increase oil production at Seventy-Six West field and is likely to be economic, we realized during this study that the high oil viscosity of 26 cp is not favorable for waterflooding and that adding polymer to the water might be worth evaluating as a method to improve the waterflood performance. In fact, most of the characteristics of the Cole C sandstone and fluids are very close to those of an economically successful polymerflood done in Chateaurenard field by Elf Aquitaine. Therefore, we evaluated polymerflooding for Seventy-Six West by doing both coreflooding experiments and field simulations.

Cores are not available for Seventy-Six West field, so we conducted the corefloods using an outcrop sandstone of similar permeability. Seventy-Six West crude oil was used and both waterfloods and polymerfloods were done at reservoir temperature. 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 are useful in indicating that polymerflooding does recover substantially more oil than waterflooding with this viscous crude oil, as well as recover it with less injection and production of water. Complete information on these experiments will be available in the dissertation of M. Wang, which is expected to be completed in August 1993.

Ten three-dimensional polymerflood simulations were made using our chemical simulator UTCHEM. These simulations are the same as the waterflood simulations except for the addition of different amounts of polymer to increase water viscosity. The addition of polymer does appear 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 yr of the flood, the oil recovery increased by 84,000 STB. This result is for only one polymer injector (Well 62-18). Other wells in Seventy-Six West field should also be considered for polymerflooding and would likely increase the production substantially more. An additional 0.91 STB of oil was recovered per lb of polymer injected compared to the waterflood. The polymer used in this case was hydrolyzed polyacrylamide, which costs about $1/lb depending on the source and amount. Thus, the chemical cost per additional STB of oil is very low, ~$1.10. This is about the same cost as similarly successful polymerfloods.

We conclude, based upon analogy with other successful polymerfloods, our laboratory experiments, and our field simulations, that polymerflooding should be further considered at Seventy-Six West field. However, some experience with waterflooding, preferably with interwell tracers included, should be available before actually starting polymer injection, even if further study indicates a favorable result. This is so that some knowledge of water injectivity and other important but currently unknown factors can be used to refine the predictions and optimize the design.

Task 4: Gas production performance and optimization

Three gas recovery projects are currently underway for Lavaca Bay field. The first project involves reservoir engineering analysis to determine the pressure compartmentalization of the field. This project has been completed and a final report is in preparation. The work succeeded in verifying most of the compartment assignments determined by geological studies by UT/BEG. However, some of the compartment assignments were modified based on the pressure analysis studies. One of the major outcomes of this study was identification of poorly drained compartments. Some compartments have been targeted for further study to determine possible infill well locations.

The gas production study was to perform decline curve analysis in order to make predictions of future recovery from various reservoir compartments. The objective was to have a methodology for economic comparisons of infill drilling locations. Such analysis required rate vs. time projections, which are usually supplied either by means of decline curve analysis or through 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 for analyzing gas reservoir data. The techniques developed in this study can be used either with historical rate vs. time data or with known reservoir properties. Several of the Lavaca Bay compartments have been analyzed with our proposed procedure. This work is also substantially complete, and a formal report will be available in the spring of 1993.

A third effort that was initiated last year is development of pseudosteady-state flow calculations for irregularly shaped reservoirs. The purpose of this work is to be able 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. Thus far we have been able to successfully perform the required computations in two dimensions. We are in the process of refining the computational accuracy so that the calculations can be made in heterogeneous reservoirs in three dimensions. This work shows great promise to provide a procedure for doing gas flow determinations with the use of PC-level computations. We envision that the 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

The objectives of the work performed in this reporting period were to: (1) develop and demonstrate nuclear magnetic resonance (NMR) imaging techniques to quantitatively determine saturation distributions during dynamic displacement experiments, (2) develop a system for production measurements during dynamic displacement experiments, and (3) clean core samples for dynamic displacement experiments to determine fluid flow functions.

There have been a number of applications of NMR imaging to observe the distribution of fluid in porous media. Most of these studies provide qualitative, or at best semi-quantitative, measures of the amount of fluid phase observed at each location. We have developed a method to quantitatively estimate saturation distributions during steady and dynamic displacement experiments using NMR imaging techniques. This method provides a way to overcome difficulties in quantitative evaluation of NMR imaging that arise from the short transverse relaxation times associated with fluids in porous media. This method is based on accurate estimation of the intrinsic magnetization intensity on a pixel-by-pixel basis from observed magnetization intensity using a procedure for parameter estimation and model selection. Consequently, saturation distributions, which are proportional to intrinsic magnetization profiles, can be quantitatively evaluated.

For saturation measurements in steady experiments, the results obtained using NMR can be compared with those obtained gravimetrically for verification of the accuracy of quantitative NMR imaging techniques. The gravimetric method can be used for obtaining saturation distributions during dynamic displacement experiments. Therefore, we have developed a different approach to provide an independent verification of the NMR results. We have developed a technique based on measurement of production during dynamic displacement experiments. This new approach takes advantage of the fact that the dielectric coefficient of oil is much lower than that of water. By collecting the produced fluids and measuring the capacitance of oil and water, the amount of oil in the collection device can be determined. We designed and fabricated a prototype electric capacitance device and developed a production measurement system.

Core samples were cleaned using the Dean-Stark method and a mixture of solvents. NMR images of the core samples were taken after the cleaning process. These showed that the cleaning process was efficient and much of oil in the core samples was removed. After complete cleaning, these core samples were prepared for dynamic displacement experiments.

Two immiscible dynamic displacement experiments were performed. Core samples were prepared in cylindrical shape with a 1-inch diameter and a 2-inch length. Deuterium oxide (D_2O) was used as the aqueous phase, and n-hexadecane was used as the oleic phase. During each experiment, the core sample was initially saturated with the oleic phase and the aqueous fluid phase was injected. NMR imaging was conducted to measure the saturation distributions along the core sample, and a capacitance measurement device was used to determine volume of oil displaced from the core. The pressure drop across the core sample was also measured. We will calculate the relative permeability and capillary pressure functions using data from these experiments.

The Aleman and Slattery model for estimating three-phase relative permeabilities has been evaluated by comparison with published results of three-phase experiments. Previously during the project, a procedure was developed allowing the model to estimate the required values of residual oil saturation. This procedure was incorporated in the model for this evaluation.

Oak and others reported the results of three different core samples in the literature. Whereas the required two-phase tests were conducted on each of the three samples, the oil/gas two-phase experiments for two samples were not valid for model evaluation. The oil/gas should be run at connate water saturation, but this was not the case for one of the samples. As the experiment progressed, the water saturation diminished from 29 to 22 percent. No duplicate test was performed. Gas trapping studies were conducted on a second sample. The initial gas rates for the three-phase experiments and oil/gas two-phase tests differed greatly, averaging 35 cc/min and 3 cc/min, respectively. In addition, oil and water relative permeabilities of the three-phase experiments prior to the injection of gas did not match the oil/water two-phase data, differing by a factor of three. Because of these problems, we chose to concentrate our examination on a different sample.

Oak and others estimated the combined saturation error in their experimental work to be less than 2.5 percent, which translated to an experimental criteria of a maximum absolute 2 percent saturation measurement being acceptable for any absent phase. For example, prior to gas injection in the three-phase experiments, the gas measurement may deviate no more than 2 percent from zero. In examining the results of the experiments, it was found that a 2 percent systematic error in saturation measurement translates to a large potential error in three-phase results for points below 0.02 oil relative permeability. Thus, only three-phase data with oil relative permeability above 0.02 were used in model evaluations.

Task 2: Induced chemical gas drive

The objective of this project is to investigate the effects of surfactant in carbonated water imbibition/production processes for enhanced oil recovery in fractured, low-permeability reservoirs. Laboratory tests have shown that cycled carbonated water imbibition/production along with the associated gas drive process can improve oil recovery rates and recovery efficiencies. In the present work, the focus is on the use of surfactant with carbonated water to enhance the imbibition and greatly improve the effectiveness of the induced solution gas drive mechanism. The experiments of such chemical processes have been conducted under simulated reservoir conditions in order to obtain suitable data for future field applications.

The experiment is to observe the processes of oil being recovered from rock by imbibition and solution gas drive. All measurements were conducted under reservoir conditions of 2,000 psi and 50°C. Imbibition was allowed to take place until no more changes in oil saturation were observed. The solution gas drive was then applied by releasing the system pressure rapidly from 2000 to 0 psi. Nuclear magnetic resonance imaging (NMR) was used to monitor the spatial and temporal variation of oil saturation within the rock sample during this process. By analyzing recorded NMR data, the effectiveness of each process can be studied.

Three different processes using different imbibition fluids were studied. Among them the process using carbonated water had the largest imbibition rate, whereas the process using carbonated water/CD1050 solution had the lowest. This was seen from the fact that during the same amount of time the former process produced the more oil through imbibition alone. The slower imbibition rate in the latter process was due to the lower interfacial tension between the oil and water phase, which lowered the effective capillary force. However, the solution gas drive was most effective when carbonated water/CD1050 solution was used as the fluid, as indicated by the larger drop in rock oil saturation when system pressure was released at the end of imbibition. This observation confirmed our expectation that the existence of surfactant in the imbibition fluid can greatly increase the efficiency of the solution gas drive mechanism. Our results indicated that in water-wet rock systems, although using surfactant may slow down imbibition, proper design of the recovery process may still increase the overall recovery efficiency because of the effectiveness of the solution gas drive mechanism when surfactant is present.

The imbibition process in reservoir rock is affected not only by the interfacial tension between different liquid phases but also by the wetting characteristics at liquids/solid interfaces. The kerosene experiments were performed on presumably water-wet rocks with fluids that would not alter the rock surface wettability. Such systems are not realistic because most reservoirs have mixed wettability. The ordinary imbibition process becomes less effective in oil-wet systems. Because surfactants have the ability to alter surface wetting characteristics, increased imbibition rates are possible with such additives, particularly for oil-wet rock systems.

In further experiments, crude oil was used as the oil phase. The deposition of asphaltene from crude oil onto water-wet rock surfaces during the experiment alters the rock surfaces from water-wet to oil-wet. Filtered crude oil had a viscosity of 12.79 centipoise. The rock was allowed to sit at room temperature for approximately 10 hr after the oil saturation. Again, three solutions were used to displace oil from the rock samples. The surfactant solution contained 0.3 weight percent CD1045.

The imbibition rates of all processes were considerably lower than those of kerosene. This was probably because the viscosity of crude oil was much higher than that of kerosene (~2 centipoise) and because deposition of asphaltene onto the rock surfaces slowed down the imbibition. However, it was observed that the imbibition rate of the carbonated water/CD1045 process was almost the same as that of carbonated water alone. This may indicate that surfactant can increase the imbibition rate in crude oil systems. Furthermore, as in the kerosene tests, surfactant greatly enhanced the solution gas drive mechanism.

Multiple imbibition/production cycles were applied to some of the samples. During these processes, the imbibition and solution gas drive processes were used repeatedly every 3 hr on the same sample to recover as much oil as possible. When the surfactant was present, oil production due to solution gas drive was much greater than if there were no surfactant. These measurements show that surfactant may greatly increase total oil production when imbibition and production phases of the process are cycled. In general, the results of our experiments are very promising, and they indicate that chemical induced solution gas drive processes may offer effective recovery mechanisms for fractured, low-permeability carbonate reservoirs.

We also performed several experiments to investigate the effects of different pressure release rates on solution gas drive. In these tests, a rock sample was flushed and saturated with carbonated water/surfactant solution under normal high-pressure and high-temperature conditions. At the end of saturation, the system pressure was released from 2000 psi to 0 psi at different rates ranging from 0 to 10 min. The proton profiles of water within the rock during the process were recorded by NMR. It was observed that the rate of pressure release did not have a great effect on the total amount of recovered oil, although the recovery rate became lower as the pressure release rate was decreased. However, when the pressure release rate was further decreased, the total amount of the recovered oil also became lower. It was also observed that, under our experimental conditions, most of the gas evolution occurred when pressure was released below 300 psi. These tests indicated that the solution gas drive process would be most effective when applied to low-pressure reservoirs.

Task 3: Integrated characterization technology

The objectives of this investigation of the Keystone (San Andres) reservoir are to generate multiple realizations of reservoir properties, primarily porosity and permeability. This will enable design of optimal recovery schemes and location of new infill drilling targets. The method used for construction of these different realizations is conditional simulation, which is a stochastic modeling technique. It entails probabilistic modeling of reservoir properties that addresses the two major problems of reservoir characterization: scaling of flow properties and uncertainty due to missing information. Fractal geostatistics provides the framework for dealing with these problems.

After consultations with researchers at UT/BEG, Block B-2, Section 13 was picked as the study area. This block was picked based on the availability of recent logs and the possibility that one of the wells in the block would be cored in the near future.

Well logs for the 400 series wells in Block B-2 were digitized and analyzed. Log-core relationships derived from a published study of an analog field were used because there were no core data from the Keystone (San Andres) reservoir. The initial modeling of porosity and permeability consisted of vertical 2-D cross sections. The vertical log data were used for conditioning the data. Multiple non-unique realizations for the cross sections were generated to account for the uncertain character of the inter-well region. All the realizations were averaged to yield a single representation of porosity and permeability variation. From this analysis, the interval could be classified as a layered system. The top layer has low porosity and permeability, the middle layer is thick and has the highest porosities and permeabilities. The bottom layer is a low-porosity and -permeability layer.

The next phase of the project consisted of developing horizontal 2-D sections. The method of analysis was the same as before; semivariogram, spectral density, and rescaled range analyses were conducted to yield the parameters governing the spatial structure. These 2-D planes, when "stacked," can produce a three-dimensional picture of porosity and permeability variations. However, these realizations may not capture the perpendicular correlations, that is, the vertical variation of properties. This work is in progress, and results for analysis should be available in the near future.

The final results indicate the nature and extent of porosity and permeability variations in the Keystone (San Andres) reservoir. This stochastic approach to modeling reservoir heterogeneities is necessary due to uncertainties in the inter-well region. These results, coupled with other reservoir data such as fluid and pressure data, will enable a comprehensive reservoir analysis to examine exploitation strategies.

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

We developed a two-cell material balance model that provides a simple, rapid method of simulating pressure and rate response of a commingled or compartmentalized gas reservoir. The model simulated a constant rate drawdown and incorporated deliverability equations to estimate the flowing bottomhole pressure, which could be used to match the well flowing pressure.

The pseudo-steady state, constant pressure solution of layered gas wells was studied. The rate-time solution from this model was used to study the rate decline of the wells in the Olmos Formation reservoir at Las Tiendas field. Log-log plots were generated to study the flow regime and to estimate the reservoir characteristics.

Activities planned for next year are to use the constant pressure solution in layered gas reservoirs to interpret rate history in Las Tiendas field, investigate the effects of well interference on short-term P/Z versus Gp plots, and apply the results of this research to Las Tiendas field data.

Activity 3: Advanced Extraction Technology

Task 1: Improved recovery research

Fracture studies: The effects that microfractures have on oil recovery due to water imbibition have been studied. Unadulterated and carbonated water imbibition cases were investigated using a fluid pressure of 800 psi. Water was enriched with CO_2 at 500 psi carbonation pressure. Nuclear Magnetic Resonance (NMR) methods were used to study the effects that microfractures have on the surrounding rock matrix during oil production by water imbibition.

The presence of microfractures in a dual porosity system introduces several factors that assist oil displacement. These factors are capillary forces that drive available water into the microfractures and an increase in the area available for water imbibition into the rock matrix. Inclusion of CO_2 into the imbibed water will improve oil recovery even further because there will be an increase in oil mobility and a reduction in the operating pressure below the carbonation pressure after the core had been allowed to imbibe the carbonated water and induce a solution gas drive effect. This may cause a substantial increase in oil recovery from the fracture system and rock matrix.

The presence of microfractures should increase oil production relative to production from homogeneous rock. Oil will be produced from the microfractures and increased oil production will occur because of creation of water channels contacting additional rock matrix.

During tests of oil production from homogeneous rock samples oil recovery increased with the inclusion of CO_2 in the imbibing fluid. Unadulterated water imbibition recovered insignificant amounts of oil, whereas 4.0 percent OOIP was recovered by carbonated water. This might be the case for many reservoirs that show very little or no oil production when contacted by brine.

During tests of oil production from fractured rock samples 1 mm thick, NMR images were used to illustrate the interplay between capillary and gravity forces in a microfracture. The water saturation profile final conditions were 2.58 mm deep but only 0.35 inch high in a 2-inch-diameter core. Oil overlaid the water throughout the extent of the fracture. It was obvious that gravity plays a major role in the displacement process. Images that average rock thickness of 5.0 mm were taken at 2.75 mm (measured to the center of the image) from the microfracture/matrix face. These images show decreases in oil saturation but only in the lower regions, close to the areas where water moved into the microfracture. Four different sets of NMR proton profiles were used to monitor oil movement inside the system: (1) one set perpendicular to the microfracture (parallel to the large-scale fracture) at 0.5 inch (12.8 mm) from the macrofracture, (2) one set perpendicular to the microfracture and 2.0 inches (50.8 mm) from the macrofracture, (3) one set parallel to the microfracture but separated by a distance of 4.25 mm, and (4) one last set considering all the oil in the system, including oil trapped inside the microfracture.

NMR images of the fluids trapped in the microfracture show that infiltration of water was almost immediate. After the initial infiltration of water, the height and depth of the water invaded zone remains virtually unchanged, with only small oscillatory variations. Saturation changes obtained from profiles perpendicular to the microfracture taken at 0.5 inch and 2.0 inches from the macrofracture (sets 1 and 2 listed above) demonstrated that there is no oil flow from the rock matrix to the microfracture at 2.0 inches depth. Oil flow was observed at 0.5 inch.

Crude oil phase behavior: Gas chromatographic analysis of Keystone (San Andres) field crude oil was performed on a gas chromatograph-mass spectrometer (GC-MS). Fractional distillation of the oil was done and 10 fractions were accumulated. Viscosity of all these fractions was measured using a Cannon-Fenske viscometer at temperatures ranging from room temperature to 210°F. For these measurements, ASTM standards D445-88 and D446-89A were followed. Specific gravity and boiling points of all the fractions were also measured.

The equipment for phase behavior, viscosity, and compositional analysis has been streamlined. The whole system includes a Ruska PVT apparatus, a rolling ball viscometer, and a 5880 Hewlett Packard gas chromatograph, upgraded for high-pressure sampling (up to 4000 psi). After initial familiarization with the Ruska mercury free PVT system this has been checked for any troubles. The leaks spotted have been taken care off and the system has been pressure tested. The system has valves, a two cells arrangement (pump cell and floating piston cell), and a magnetic stirrer for proper mixing and phase isolation. In the PVT system, fluid movement is controlled by two computer operated positive displacement pumps. The PVT system will provide very accurate measurement of phase volumes.

Fluid viscosity measurements will be done by rolling ball viscometer. The fluids from PVT cells can be loaded into the viscometer via a manifold at the cell pressure. The temperature of the viscometer can be raised to the same level. Viscosity is proportional to the time taken by a small-diameter ball rolling through a tubing containing the fluid. The viscometer has been calibrated for the proportionality constant using a viscosity standard.

A Hewlett Packard 5880 gas chromatograph has been upgraded to sample on-line live oil and CO_2 mixtures. This upgrading has been done 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 the thermal conductivity detector and to the flame ionization detector via appropriate columns. These loops also contain switching valves for back-flushing to minimize column contamination. All sampling and switching valves operate through an air-actuated digital valve interface. The valves are operated from gas chromatograph keyboard key strokes.

The whole system has been installed and all other gas plumbing connections have been fixed. The pressure testing is in progress, and the system will be fully operational in the near future.

Task 2: Well stimulation research

The objectives of this study are to determine how the fracture fluids clean up and how various parameters affect cleanup and well performance. This research will develop new methods to analyze post-fracture well test data, including the effects of fracture fluid cleanup, fracture-face skin damage, and wellbore/fracture storage, and it will provide general and specific analysis procedures for production performance and test data from fractured wells such as those in Las Tiendas field.

We have used a 3-phase, 3-D reservoir simulator to model gas-water-fracture fluid flow in hydraulically fractured gas reservoirs. We will investigate the effects of various parameters on fracture fluid cleanup behavior and well performance in both single- and multilayer gas reservoirs. We will develop new pressure transient analysis methods for fractured well test data, including the effects of fracture fluid cleanup, fracture-face skin damage, and wellbore/fracture storage. Finally, we will provide analysis procedures for well production performance and well test data for hydraulically fractured wells in Las Tiendas field.

We have made extensive simulation runs on six fractured wells for which data were available. The simulation of these six actual gas wells has revealed several important aspects of fracture fluid cleanup behavior and well production performance. For single-layer formations, a systematic simulation plan has been carried out to study the effects of various factors on fracture fluid cleanup behavior and well production performance. Formation damage around the fracture was identified as a key factor. Any other factor which leads to "equivalent" near-fracture formation damage can become significant in fracture fluid cleanup and gas production behavior. For multilayer, anisotropic formations, simulation runs have been made to study cleanup and well production performance. It is very important to describe and simplify the original reservoirs properly. Any improper simplification may lead to an overestimate of post-fracture gas production.

Accurate numerical solutions have been obtained for elliptical finite-conductivity fractures, including fracture-face skin damage and wellbore storage. Constant flow rate is assumed. These new solutions have been presented in type curves of pressure and pressure derivatives. New techniques were obtained for post-fracture well test analysis.

For hydraulically fractured gas wells, including effects of fracture fluid cleanup, fracture-face skin damage, and wellbore/fracture storage, post-fracture production and buildup simulation runs were made for single- and multilayer reservoirs. New analysis techniques have been used, and good interpretations for fracture and formation properties have been obtained. These post-fractured well test data are difficult, if not impossible, to analyze with current techniques.

Next year we plan to modify our current numerical model to include constant flowing bottomhole pressure cases. Flux along an elliptical finite-conductivity fracture will be computed accurately. Again, fracture-face skin damage will be included in the model. We will expand the current single-layer numerical model to a multilayer model in elliptical coordinates. Fracture-face skin damage and fracture storage for each layer and overall wellbore storage for the fractured well will be included. We will expand the current model for a slightly compressible liquid to include gas, and more production data and post-fracture well test data (both field and simulated) will be analyzed with newly developed techniques.

During the past year the existing paraffin reservoir simulator has been changed, and a paraffin wellbore simulator has started. The paraffin reservoir simulator is now complete, and the paraffin wellbore simulator needs more work. We have made some changes to the paraffin reservoir simulator. The solubility of the paraffin component in liquid paraffin as well as liquid oil and liquid gas has been programmed. Effects on the oil density of temperature, pressure, and the amount of solution gas have been programmed, as have the effects of temperature and pressure on the paraffin density. Calculation of the vapor density has been changed from the ideal gas law to a real gas. The assumption that the volume of gas in the liquid phase can be obtained by calculating a vapor phase volume has been eliminated. A standing pressure- and temperature-dependent solution gas calculation has been added. The Lee Gonzalez and Eakin gas viscosity correlation has also been added. Finally, the enthalpy calculations have been dramatically changed.

New enthalpy calculations have been added to the existing paraffin reservoir simulator. A Lee-Kesler three-parameter equation of state for petroleum fractions was used to calculate these new enthalpies. This equation of state will be used to model the enthalpies of the gas pseudocomponent in the liquid phase, and the paraffin pseudocomponent in the liquid and solid phases. The equation of state will include the Joule-Thomson effect and the effect of changes in enthalpy due to phase changes. These enthalpy changes can be put into the following four categories: (1) changes due to temperature changes, (2) changes due to pressure changes, (3) changes due to compositional changes, and (4) changes due to phase changes.

The enthalpy changes due to temperature and pressure changes have been thoroughly studied, programmed, and tested for single-component systems. The testing included a comparison of the programmed enthalpies to a commercial equation of state and to measured enthalpies. The calculated enthalpies were consistently as close as or closer than the measured enthalpies.

Measured enthalpies for various hydrocarbon mixtures do not exist to our knowledge. Therefore, the programmed enthalpies were compared to a commercial equation of state package for verification. The enthalpies of various complex hydrocarbon mixtures were compared. Results obtained from this test were excellent. The enthalpy program was then coupled into the existing paraffin reservoir simulator. The calculation of critical properties for the complex three-phase (vapor, liquid, and solid) mixtures has also been included in the simulator. These critical properties are needed to calculate the three-phase enthalpies. Additional work was done to the paraffin reservoir simulator energy equation to correctly model the heat transfer due to phase changes. This work was needed to include the latent heat of vaporization and the latent heat of formation into the energy equation.

The paraffin reservoir simulator is now complete, and work conducted in 1993 will be focused on the paraffin wellbore simulator. The paraffin wellbore simulator is still being developed to study paraffin deposition and thermal removal methods. The model currently has two thermal removal methods, (1) downhole heater and (2) electric tubing heating. The model consists of two phases, vapor and liquid. After the paraffin precipitation is programmed, paraffin deposition and thermal removal will be programmed. Next, hot oil injection, hot water injection, and steam injection will be programmed. A number of subroutines have been added. By coupling the wellbore simulator to the reservoir simulator, a general paraffin simulator will be developed. This simulator can be used to study paraffin deposition and removal in wellbores and reservoirs.

College of Geosciences
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Activity 2: Reservoir Characterization

Task 1: Diagenetic control on sandstone reservoir properties

The Permian Delaware Mountain Group in the Delaware Basin consists of very fine grained (mean grain size <0.10 mm) subarkosic sandstones and abundant siltstones. Detrital clay content is very low (<5%) in these sediments. Analyses of reservoir sandstones by optical and scanning electron microscopy show that the sandstones have undergone four major stages of diagenetic alterations: (1) During early burial they were extensively cemented by calcite, anhydrite, and halite, and these cements allowed preservation of a high percentage of intergranular porosity that would otherwise have been lost to compaction with increasing burial depth. (2) During deep burial, abundant secondary porosity developed by dissolution of cement and detrital minerals. Porosity in these sandstones is dominantly of secondary, or dissolution, origin. (3) During porosity generation there was widespread authigenesis of clay minerals. Clay minerals line, fill, and dissect pore spaces, forming microporosity, and block pore throats, thus decreasing reservoir quality. (4) Formation of dolomite, Fe-Mn dolomite, quartz and feldspar overgrowths, and precipitation of titanium oxide minerals marked late diagenesis. Reservoir rock properties of the Delaware Mountain Group sandstones are strongly controlled by diagenetic processes. Abundance and nature of porosity (i.e., effective porosity vs. microporosity) are largely the results of diagenesis.

Interactions between pore fluids and sandstones created the diagenetic record observed. Aqueous species (e.g., carboxylic acids, carbonic acids, and metal cations) derived from degradation of organic matter in Delaware Mountain Group siltstones modified pore fluid pH and Eh, cation activities, and mineral solubilities in the sandstones, and controlled the entire diagenetic history. During early burial, organic matter alteration in the zone of sulfate reduction yielded HCO_3- and calcium ions to pore water; and promoted cementation. Organic matter also reduced iron and manganese oxides in the sediment, mobilizing these metals. Data corroborating this interpretation of early diagenesis are: (1) A strong inverse correlation between calcite iron and manganese content and calcite sulfur content. (2) Low calcite $\delta^{13}C$ values, which indicate an organic input into calcite carbon. (3) Calcite $\delta^{18}O$ values that yield cool temperatures (<15°C) for precipitation of calcite when used in the paleotemperature equation. The temperatures generated indicate precipitation in a deep basinal, very shallow burial setting. (4) Depleted $\delta^{34}S$ values in pyrite associated with calcite cement, which are indicative of a bacterially derived source for sulfur in pyrite.

During deep burial, thermal degradation of organic matter supplied acidic species that removed calcite cement and created secondary porosity. Organic matter in the Delaware Mountain Group is of the abundance, type, and state of thermal maturity that could generate carboxylic and carbonic acids in volumes sufficient to have created secondary porosity. Correlation of siltstone organic matter with oil in Delaware Mountain Group sandstone reservoirs shows that the siltstones were the source of much of the oil. Thus, the Delaware Mountain Group kerogen has undoubtedly also generated carboxylic acids, carbonic acids, and water. Low $\delta^{13}C$ values of late-stage authigenic products are further evidence of an organic contribution to pore water carbonate carbon. The formation of authigenic titanium oxides indicates that titanium mobility was elevated by formation of organometallic titanium complexes, which is the only natural mechanism for enhancing titanium solubility. Organic ligands derived from degradation of Delaware Mountain Group organic matter must, therefore, have been present in pore water in sufficient amounts during late burial.

Results of neutron activation analysis of Mn, Zn, Ni, Co, V, and Cr in organic matter and authigenic clay minerals in Delaware Group sandstones have established a source-sink relation. The various lines of tracer evidence indicate that fluids carrying the products of organic matter degradation moved from the organic rich siltstones into the sandstones, where authigenic products formed and preserved a record of ambient pore-water chemistry.

Because petrophysical properties of the Delaware sandstones are strongly affected by the distribution, abundance, and nature of authigenic clay minerals, a detailed study of the mineralogy, chemistry, and morphology of these minerals has been made. Chlorite and interlayered chlorite/smectite (C/S) dominate the clay mineral suite and occur with lesser and variable amounts of illite and illite/smectite (I/S). Interstratification in the mixed-layer phases is random and minor, less than 20 percent. Chlorite-to-smectite ratio increases with depth, as indicated by changes in expansiveness within the chlorite structure. The structural and morphological variability of chlorites appears to be stratigraphically controlled, and represents a diagenetic progression beginning with a smectite precursor, through an interstratified intermediate, to a more ordered form.

Current research focuses basinal variations in reservoir diagenesis and provenance of Delaware Mountain Group sandstones and controls on diagenesis and oil production. The major objectives of both studies are to determine the temporal and spatial changes in reservoir rock quality on a basinal scale and the factors affecting these differences. Delaware Group sandstone samples have been acquired and prepared. Laboratory analyses of these samples by optical and electron microscopy, electron microprobe, and X-ray diffraction methods are in progress.

Task 2: Subregional reservoir characterization of Lavaca Bay

Lavaca Bay in Calhoun County is one of the gas fields that lies within the Greta/Carancahua Barrier Strandplain system of the Frio Formation. The Frio Formation has been divided into nine depositional sequences based on lithostatigraphic correlation of well logs established by J. U. Ricoy (UT/BEG). Two of the reservoirs, the Melbourn sandstone and the F39, are being analyzed in detail using available log and production data. The integration of these data helps in the description and characterization of the reservoirs. The main objective is to locate new recompletion opportunities in existing wells and to locate infill drilling sites.

Electric logs and scout tickets from 62 wells in the vicinity of Lavaca Bay are available from commercial sources. General information concerning the study area and some structure maps were obtained from the Railroad Commission of Texas and UT/BEG. Some additional well logs have been acquired from UT/BEG.

The study area was divided into two blocks, Blocks A and B, based on well density. Current work is concentrated in Block B, which is the southern part of Lavaca Bay. The preliminary study involves mapping the physical log readings of the reservoir sandstones. This includes correlation of spontaneous potential and gamma ray for the continuity of the reservoir sandstone between wells. The area for detailed analysis is delineated by picking areas having high resistivity, net-sand thickness and apparent gas saturation from log analysis. A more detailed log analysis was done using the dual water model and shaly sand model to correct for shale effects. The movable gas per acre-foot is calculated from the difference between the water saturation in the flushed and uninvaded zone.

The Melbourn sand in sequence VII is a thick sandstone body that is producing as a single well reservoir in State Tract 42. We are completing the material balance and volumetric estimates of the gas in place. P/Z plots and contour maps have been generated for this purpose.

Another reservoir sandstone, F39 in sequence III, is currently being analyzed. The State Tract 26 well 5, which has gas production from the F39 reservoir, is analyzed and evaluated. This well will be used as a base well for correlation of other wells in the field. Log analysis is done with the help of a spreadsheet that includes necessary borehole corrections.

We plan to make a volumetric estimation of the gas in place per acre-foot at each well location in the Melbourn and F39 reservoirs and compare these results with gas in place from material balance estimates from single well data. The gas in place will be mapped, and the area having the highest estimated value will be the recommended area for further exploitation.

Task 3: Application of high-resolution seismic imaging to improve bed-geometry definition

During 1992 we worked on three tasks: (1) processing seismic data from Seventy-Six West field, (2) processing seismic data from Powderhorn field, and (3) aiding in the design of a high-resolution, three-dimensional (3-D) seismic survey for Powderhorn field.

Work on Seventy-Six West field has been terminated for the reasons given below. We continue to work on Powderhorn field data and are making some progress with this task. It is not complete, but we expect to have some definitive results by the end of the project period. Some progress has been made on design of the high-resolution, 3-D survey, but there appears to be little possibility that funds will be available to acquire these seismic data.

Seventy-Six West field: Magnetic tapes of digital seismic data for this field were provided by UH/AGL. These were correlated vibroseis data and were in SEG-Y format, which allowed us to read the data onto our VAX computer. Unfortunately, there are no observer's logs and this resulted in difficulties because there are important data in the observer's logs. Although we were able to work around this problem, the lack of the logs caused us additional work and, consequently, delay.

We have made good progress in editing the tapes (removing bad traces, eliminating noise spikes, removing powerline interference, etc.), stacking the traces after determining the normal-moveout and static corrections, and plotting the data. The resulting plots data are substantially improved over the originals, which were not edited. There were several bad traces on the data tapes. After additional filtering and editing of the data, we obtained a seismic section that was comparable to the paper records. However, the data do not have sufficient signal-to-noise ratio to give the high-resolution sections we hoped to achieve, and this part of the project was terminated.

Powderhorn field: We have digitized the acoustic and density traces for eight acoustic logs and two density logs for input to computer programs that generate and plot synthetic seismograms. These synthetic seismograms will be compared with high-resolution seismic data shot near the wells.

We have correlated acoustic logs with density logs for the two cases for which we have both logs in the same well. Most of our well logs have only the acoustic-velocity data, and both acoustic and density logs are normally needed to generate synthetic seismograms. We have found that density and acoustic velocity correlate fairly well for our two logs, and we are confident that we can use acoustic logs alone to generate the synthetic seismograms.

The reformatted data tapes have been read onto the campus Cray YMP/4A supercomputer which has DISCO, a seismic-data-processing software package. Shot diagrams have been generated for the data, the geophone geometry has been determined, and the seismic traces have been edited. There were a few noisy traces, which would have caused difficulties with later processing, and they have been eliminated from the data set. We are in the process of completing the editing, generating common-mid-point (CMP) gathers, determining the static corrections to compensate for variations in geophone and shot elevations, determining the stacking velocities, and stacking the traces to generate a seismic section. This seismic section will be compared with the synthetic seismograms generated using the well-log data. We also plan to increase the high-frequency content of the data so that we can generate a high-resolution seismic section.

A preliminary design of the high-resolution, 3-D survey of Powderhorn field has been completed and the survey is being coordinated at TAMU/CG. Unfortunately, there appears to be little possibility that the survey will ever be completed because funding for the execution of the survey by Halliburton, Inc., has not been forthcoming. There are insufficient SLERO funds to perform the survey without additional contributions from outside sources. It was hoped that the field operator would be interested in funding the seismic survey, but this is unlikely without a contribution from Halliburton.

Task 4: Quantification of microgeometry of sedimentary rocks by digital analysis of thin sections

This year has seen progress on several fronts. Back Scattered Electron (BSE) images have been examined and found to be very useful in the segmentation of pore space from the rest of the rock sample. Data from these types of images are still being compared to data acquired using standard microscopy methods to determine whether the extra cost in both time and money is warranted.

Permeability estimation from thin sections has progressed well this year. A model taken from published literature and modified at TAMU/CG for use in digital image analysis has shown great promise. Preliminary analysis showed tremendous correlation between laboratory measured and image estimated permeabilities. These measurements were made on only a handful of samples and, as of this date, it is too early to judge the robustness of the method. The method and parameters are described in detail in a paper currently in revision.

Two other procedures that were examined in greater detail this year were estimation of formation factor from images and grain and pore orientation determination. The former will be very important in permeability estimation. We have been using literature-derived estimates for formation factors to be included in the aforementioned permeability model. Development of a method of estimating formation factors from images will allow for permeability estimates based solely on image-derived parameters.

Two dimensional grain orientations can be measured on sandstones with relative ease. However, only theoretical work on extrapolating data acquired from differently oriented thin sections into three dimensional grain orientation has begun. Similar problems exist for defining the three-dimensional pore orientation.

Fluorescent light images have been examined in some detail during the past year. Problems still exist with normalizing the incident ultraviolet radiation and with achieving consistent fluorescence from the spiked epoxies. Fluorescent images do give the analyst more qualitative information about the structure and distribution of the pore space. More research will be necessary before this technique will yield substantive quantitative information.

Task 5: Sulfate scaling investigation

Efforts during the past year focused on the production of calcium carbonate vein and fracture filling in the laboratory in an effort to extend and test previous models. Special emphasis was placed on a few carefully controlled experiments.

Calcium carbonate minerals, dominantly calcite, commonly fill veins and fractures in rocks. As such, they clog fracture porosity and can have a major influence on petroleum reservoir quality. To date, understanding fracture filling by calcite has proceeded on nearly a case-by-case basis, with few predictive models available for the spatial and temporal distribution of filled fractures. Moreover, the conditions and rates under which fractures fill up are poorly understood. In order to better predict the distribution of calcium carbonate cements, we have undertaken a major new effort to precipitate calcite in the laboratory under conditions that approach those in the subsurface.

Four experiments were done during the last year, each taking 6 to 8 weeks. Using a specially designed flow-through apparatus, saturated solutions of calcium carbonate were flowed over iceland spar plates at rates of approximately 2 ml/d. The pH of the solution going into the apparatus and coming out was monitored on a daily basis. At the end of the experiments, the volume, distribution, and crystal shape of the precipitate was measured in preparation for comparison with models developed previously under SLERO funding. Our research to date indicates that the fluid flow in our apparatus in extremely sensitive to apparatus geometry. We have been taking steps to make the flow more laminar. However, even with nonlaminar flow, the distribution of calcite is somewhat like what we have expected from modeling efforts, although the amount of precipitate dropped from solution does not match model predictions to date.

Task 6: Estimation of clay content from electrical measurements of shaly sandstones

The year began with a continuation of accuracy and precision tests on the two- and four-electrode electrical impedance measurement systems designed for brine-saturated rocks to be measured over the frequency range .001 Hz to 40 MHz. Accuracy of these systems is determined by using standard resistors, standard brines, and rock samples of different lengths.

Several models have been proposed to relate the complex dielectric response of brine saturated rocks to the chemistry of the saturating solution and to the microgeometry of the rock. However, predicted changes in the complex dielectric response with solution chemistry and with microgeometry have often been smaller than measurement uncertainty. The significance of these calibrations and error analyses is that we have been able to reduce the measurement errors to a level that allows us to detect variations in the complex dielectric response caused by changes in solution chemistry, such as ion type, and changes in the microgeometry, such as anisotropy.

During February, research on this project concentrated on refining our understanding of the difference between surface water in clay-free rock samples and surface water in clay-bearing samples. At that time, the conclusion was that the correct surface-water conductivity equation for clay-free rocks should be based on the assumption that the double-layer thickness is the Debye length when the pore throat is significantly wider than the Debye length. For clay-bearing rocks, a slightly different equation results from the assumption that clay particles force surface water to behave as if it were in capillaries, all of which are less than a Debye length in width. Preliminary tests with these two equations and data on clean and shaly rocks indicated that there was an average difference of 85 percent between the equations for water conductivities in the range 8.62 to 0.534 S/m.

During March, we reanalyzed the possible theoretical effects of charged clay platelets on the frequency dependent electrical properties of shaly materials using a simplified model for the membrane polarization around charged spheres immersed in electrolytic solutions under a thin double layer approximation. The polarization is defined through a coupled electro-diffusional mechanism occurring in a Guoy-Chapman double layer using Fixman's approach. The predictions that this model gives for a shaly sandstone response will be checked for validity against our measurements on sandstone samples in which the solution concentration was varied.

In April, we began incorporating microscopic polarization mechanisms into our double-embedding effective medium model for the complex dielectric response of brine-saturated rocks. To test these models we are using dielectric data collected on samples saturated with KCl brines with varying electrolyte concentrations, and a $CaCl_2$ brine that had the same conductivity as one of the KCl brines. These tests indicated that the complex dielectric response is controlled by a fixed layer of charge on the surface of the grains.

During May, work on this project was principally concerned with the special problems encountered when dealing with rock samples that are saturated with low-concentration saline solutions. Most of the problems center around the role of the surface properties of the rock. Among the questions that have yet to be completely resolved are: How much does the surface layer increase in volume for decreasing electrolyte concentration? Is this volume change significant enough to require that it be taken into account in our electrical model when dealing with multiple salinity data measurements?

Due to dissolution of the rock matrix, a sample that is initially saturated with a low-concentration solution will tend to alter the conductivity of that solution in the pore space on a time scale that is important during sample measurement. If we do not know the true solution conductivity during the measurement, our current model cannot work.

The main product of a dissertation completed in June is the development and testing of a new model for the electrical properties of shaly sands. It has proven successful in working simultaneously with both conductivity and dielectric data from three domains. These data domains are: water conductivity (salinity), frequency, and water saturation. The most important feature of the model is a unique method of accounting for surface conductivity and surface dielectric constant.

We have further analyzed the surface properties of rocks from electrical data. This new research is attempting to incorporate additional electrochemical theory into the existing model by focusing on the behavior of colloidal particles immersed in an electrolytic solution, in the presence of an electric field whose frequency is varied.

In July, work progressed on improving the model predictions as a function of water saturation. Resistivity versus water saturation plotted on a log-log graph is typically linear for clean sandstones or for shaly sandstones with concentrated brines (low Rw). Such linear behavior is predicted by Archie's law, which implies negligible surface conduction and constant geometry. In the cases where these kinds of data exhibit curvature, Archie's law is a poor model. It is not known whether the curvature is due to changing geometry of conduction paths, or whether it is due to changing relative importance of surface conductivity. Results so far indicate that our model can fit curved saturation-domain data with careful choice of surface conductivity, while keeping geometry factors constant.

In the resistivity versus water saturation research, a new idea that was implemented in August was to solve for the water conductivity at partial saturation. We know the water conductivity at full saturation, but we suspect that it might be changing during the drainage process. In one data set, drainage occurred by drying of the rock samples. During this type of drainage, pure water is evaporated and the salt ions may become more concentrated in the remaining solution. Thus, we suspect that a more accurate way to model such data is to allow for increasing water conductivity as saturation is decreased.

In September, we developed a new model for the complex dielectric response of brine-saturated sandstones in which electrochemical and interfacial polarizations are modeled for a distribution of grain sizes. Simulation of the complex dielectric response shows that, over the frequency range of 0.1 Hz to 1.0 MHz, the model is in good agreement with the data. In this simulation, all of the model parameters are constrained by independent measurements of sample microgeometry and surface chemistry (i.e., there are no adjustable parameters). For frequencies less than 0.1 Hz, the electrochemical polarizations occur over multiple grain lengths. Work continues on developing a harmonic grain model to account for these multiple grain interactions.

During October and November we continued to work on a method to invert dielectric data for a distribution of relaxation times. Using our theory for the dielectric response of rocks, the relaxation time distribution obtained from the inversion can be directly related to the distribution of grain sizes for the sample. This work will be submitted for publication to the *Journal of Chemical Physics*.

Toward the end of the year we reported on some recent progress that had been made in the area of publications and presentations. In October, two manuscripts were submitted to the journal *Geophysics*. The titles of these papers are: "Dielectric and conductivity of clay-bearing rocks in the frequency domain" and "A model for dielectric constant and resistivity index as functions of water saturation and critical saturation in shaly sands." In addition, another manuscript is in preparation for submittal to *Physical Review B* titled "The electrical impedance of brine-saturated rocks: superposition of electrochemical and interfacial polarizations." A presentation on the same topic was given in December at the American Geophysical Union fall meeting.

Task 7: Fracture containment

The objectives of this task include development and validation of computer models for describing the growth of hydraulic fractures, with emphasis on simulating vertical containment of fractures. Las Tiendas field, which produces from an Olmos Formation reservoir in Webb County, Texas, 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 underestimated. Four wells in the study area were selected for more detailed fracture containment studies. Calculation of in-situ stress profiles and mechanical rock properties for four wells, which is 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 data. Vertical fracture height growth was calculated to be on the order of 200 ft for all four wells. Using these height growth estimates, a 2-D GDK 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.

Logs from an additional five wells in the study area were digitized. Fracture containment studies were performed on these five wells to verify that previous findings were representative of field-wide trends. Results supported previous findings from containment studies, although vertical fracture height growth exceeded 210 ft for two of the five wells. It appears that results from wells analyzed to date are representative of fieldwide trends.

We obtained cost estimates for acquiring additional logs and other fieldwide data. These costs can be offset by lowering fracturing costs, with optimal treatment design. Based on the performance of past fracture treatments in this reservoir, acquiring this additional data is more than justified.

Results from GRI's 1992 fracture propagation modeling forum, in which a single data set was given to several companies actively using different types of hydraulic fracturing models, showed very little agreement between predicted fracture geometries. Vertical fracture height predictions varied by as much as a factor of two and propped fracture half length predictions varied by as much as a factor of five. There appear to be very different approaches to modeling of hydraulic fracturing, further emphasizing the need for continued research.

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 the 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.

We plan to obtain data for additional wells. We need to confirm that trends found from analysis of wells in the study area apply to wells elsewhere in the field. We will continue computer modeling of multilayered systems using finite element techniques.

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 continues on developments of crosshole seismic methods in producing State Lands oil fields. Areas of research include tomographic reconstruction of seismic velocities, determination of attenuation characteristics, field evaluation of seismic borehole energy sources, development of software for tomographic reconstruction, and construction of a data base for statewide access.

Tomographic reconstruction: A P-wave velocity tomogram was successfully produced for the region between two wells at Seventy-Six West field. Using results from well-log correlation and an acoustic log, we have been able to confirm the presence of Frio Formation sandstone on our tomogram.

Correlation of the acoustic log from Well 62-30 with the tomogram produced for the zone between Wells 62-15 and 62-18 shows good correlation in the region of best resolution in the tomogram. Correlation is good despite the fact that 62-30 is approximately 0.25 to 0.50 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 which lies essentially along strike.

Attenuation measurements: An attenuation study of Seventy-Six West field crosshole data recorded in July 1990 has been completed. Calculations for Q were done at nine different depths from 500 to 590 ft in increments of 10 ft. At each depth, Q was calculated for each of nine different "bender" input frequencies from 500 to 3500 Hz. Q values ranged from approximately 40 to 130. At first glance, these Q values seem too high. However, we have interpreted the high values as resulting from horizontal wave propagation through a medium with anisotropic properties; that is, shales. Evidence for this can be seen in literature values for Q. An interesting correlation was noted when Q was plotted against the electric log. Q values appear to vary inversely with electric log values.

Results of the attenuation study were presented November 8–11, 1992, at the 3rd annual Archie conference in Galveston, Texas, and November 18, 1992, at the 2nd SEGJ/SEG International Symposium on Geotomography in Tokyo, Japan. Results were also shown on a poster at the UH/AGL booth at the 1992 Society of Exploration Geophysicists meeting in New Orleans, Louisiana.

New borehole seismic energy source: Two field tests of a newly constructed downhole explosive source were conducted. The tool performed well after the right combination of detonator and explosive was found. Data recorded from the test were of good quality. We are satisfied with the tool configuration and would use it for subsequent crosshole data acquisition.

Tomography software developments: Random errors have been added to travel times collected from Seventy-Six West field to test the robustness of the reconstruction algorithm proposed in the literature. The robustness of the algorithm, in turn, gives us confidence about the tomographic velocity reconstruction. The convergence properties of the algorithm have also been studied. This study will aid in the design of future data collection configurations.

A program was written to estimate the arrival times of the first arrival signals from seismic crosshole experiments. It uses two different approaches that can be selected by the user according to the quality of the field data. Experiments demonstrate that even the enhanced method of indirect estimation cannot pick the first arrival times correctly for all traces when the signal to noise ratio is very low. A combination of the above program and "PICK_FIRST," an interactive first arrival time picking program, was developed to form a complete package.

SLERO data base: The project for creating a Graphical User Interface facilitating easy access to the multiple engineering, geophysical, and economic data bases is now functional. This data base was completed and written as an MS thesis in computer science. The coding and testing for the project on the unified interface to distributed data bases was also completed and presented as an M.S. thesis in computer science. The system is ready for installation at any interested SLERO site(s).

Center for Applied Petrophysical Studies
Texas Tech University

Activity 2: Reservoir Characterization

Task 1: Log Analysis, Delaware Mountain Group

Cores of Delaware Mountain Group rocks were examined at UT/BEG and samples were selected for core analysis and thin section work at TTU/CAPS. Sixty-two core samples were obtained from the AC Fee

No. 2 well and 216 core samples from the AB Fee No. 1 well. Well files for 15 wells were received from UT/BEG for this study. These files included log suites and scout tickets. The files for the AB Fee No. 1 were included in this set of files.

Several zones that tested water in the AB Fee No. 1 well have been analyzed to determine Rw. These analyses indicate that Rw(SP) = 0.2 ohm-m at formation temperature and Rw(Rwa) = 0.15 ohm-m at formation temperature. The higher Rw value from the SP log is probably the result of not being able to establish a reliable shale base line. The similar magnitude of SP deflection in all the sandstones indicates that Rw is relatively constant.

Nine water analyses were obtained from the Delaware Group sandstones in Screw Bean field. The Rw values ranged from 0.06 ohm-m to 0.21 ohm-m at 75°F. Because of the Rw variations in this field, these values will be critical in our petrophysical analysis. Logs through the Delaware Mountain Group from Reeves County, Texas, were digitized. Analysis on the AB Fee No. 1 well indicates that reliable log analysis can be done with a log suite composed of gamma-ray, deep and shallow resistivity, and acoustic logs. The gamma-ray log can be used to determine reliable Vcl values. However, the log derived Vcl data will be checked with laboratory Vcl data from the cores.

An abstract titled "Recognizing Bell Canyon and Cherry Canyon behind pipe pay sands in Reeves and Culberson Counties, Texas," by G. Asquith, M. Arnold, and G. Causey, was submitted for the Southwest Section American Association of Petroleum Geologists meeting in Fort Worth, and a manuscript for the transactions volume for this meeting is complete. Also the Corpus Christi Chapter of the Society of Professional Well Log Analysts has requested a talk on our petrophysical work in Las Tiendas field, and this presentation will be made in April 1993.

An abstract for a poster session at the 1993 American Association of Petroleum Geologists meeting in New Orleans titled "Variations in cementation exponent (m) and fracture porosity, Permian Bell Canyon and Cherry Canyon sandstones, Reeves and Culberson Counties, Texas," by G. Asquith, M. Arnold, and M. Tomerson, has been accepted.

Task 2: Improved saturation distribution calculations based on Delaware Mountain Group data

In January, G. B. Asquith, M. Arnold, John Harris, and Mark Thomerson met with Noel Tyler and Mike Gardner (UT/BEG). During this meeting, plans were finalized to shift the Texas Tech research emphasis to the Delaware Mountain Group in West Texas. A base map and logs from two wells were obtained for analysis. In addition, core samples from the same two wells, AB Fee No. 1 and AC Fee No. 2, were examined and samples were selected.

Samples consist of 62 samples from well AC Fee No. 2 and 216 samples from well AB Fee No. 1. Of the first group of 62 samples, 46 were cut horizontally and 16 were cut vertically. The second group of 216 samples consisted of 108 cut horizontally from different depths and 108 cut vertically from depths corresponding to those from which the horizontal cores were cut. These core samples were analyzed and thin slices were cut for further analysis. Also, 25 of the vertical plug samples from well AB Fee No. 1 were dried at ambient temperatures for clay analysis.

Analysis of the first group of 62 cores was completed and the data transmitted to UT/BEG. The porosities ranged from almost zero to 21.7 percent, and permeabilities were on the order of 3 md, with a maximum of 10 md. The low permeability and high porosity is reasonable because the rock is a very fine-grained sandstone or siltstone. Four of the higher permeability cores were sent to TAMU/CG for further studies. Analyses of the samples in the second group are still being conducted and should be complete early in 1993. The values of porosity and permeability are of the same magnitude as those from the other sample set. Porosity, permeability, and capillary pressure data will be available to SLERO researchers interested in the Delaware Mountain Group. TTU/CAPS researchers will use these data to calibrate a computer program that will smooth the data using the Leverett J-function.

Water samples were obtained from wells AC No. 2, AX No. 2, and AQ No. 4 in Screw Bean field. Water resistivities were determined and found to be 1.028 (AC No. 2), 0.1576 (AX No. 2), and 0.1671 (AQ No. 4) ohm-m. Note the anomalous value for well AC No. 2, which is likely due to the waterflood being conducted in the field.

Activity 3: Advanced Extraction Technology

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

We met with Noel Tyler and Mike Gardner (UT/BEG) in January 1992 to plan studies of carbon dioxide well stimulation in Delaware Mountain Group reservoirs. This process is a single-well process and is also known as carbon dioxide "huff and puff." It involves injecting carbon dioxide in a well for a short period, as little as a few hours, and allowing the well to remain shut in for a few days so that carbon dioxide will diffuse into the oil phase. This causes the oil formation volume factor to increase (swells the oil) and also causes the oil viscosity to decrease substantially. In due time, the well is put back on production and, if conditions were favorable for the process, the production rate will be substantially greater than it was before the stimulation. A paper was presented at the Thirty-Ninth Annual Southwestern Petroleum Short Course (April 1992) on enhanced oil recovery methods. The use of cyclic carbon dioxide injection for western Texas fields was emphasized.

The software for this project has been critically reviewed, and updating is under way. The software consists primarily of an r-z simulation model and accompanying data preparation programs. The simulator handles three-phase immiscible flow of oil, gas, and water. We recently purchased two 486 33 MHZ personal computers with non-SLERO funds, and these PC's will be used to continue development of the simulation model. The PC platform was chosen to make the simulator accessible to independent operators for a low front-end cost.

Carbon dioxide viscosities, densities, and compressibility factors are being examined in the literature. These data are difficult to obtain in laboratory studies because of the fairly extensive mass transfer between oil and carbon dioxide. Thus, there are needs for accurate correlation models. Compressibility factors for carbon dioxide were taken from the literature, as were viscosity and density functions for oil and carbon dioxide systems. These literature references also discussed relative permeability effects for oil and carbon dioxide systems. These results, with modifications, will be used to update our radial simulator.

Geology Mapping and Statistics Laboratory
Lamar University

Activity 1: 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 to UT/BEG. We digitized the following curves from each log, if present: spontaneous potential, gamma ray, neutron, and bulk density.

Task 1: Construction of completion/recompletion data base for State Lands leases

In March and July of this year we traveled to Austin to collect data from UT/BEG and the Railroad Commission of Texas. Seven oil fields on State Lands were selected as study areas. These include Walker, White & Baker, Priest & Beavers, Abell, Malicky, Means North, and Netterville fields. Data on each of these fields, including W-1 forms, W-2 forms, plats, if available, hardcopy maps of the pertinent areas, and digital map information, were obtained at the Railroad Commission of Texas. Well logs, scout tickets, and completion cards were purchased from commercial sources.

Information was collated and entered into a computer data base. This information includes well name, well numbers, American Petroleum Institute number, Railroad Commission number, lease name, field name, original operator's name, present operator's name (if known), type of log run, completion/recompletion date, potential test data from Form W-2, type of completion, top of pay, total depth, plug-back depth, producing interval(s), and locations.

Construction of production of maps that display the pertinent fields is in progress. We have received digital map data sets on these areas and are presently using a C++ program (written here by J. G.

Pittman) to convert these data into a format acceptable for computer mapping programs. We have succeeded in transferring lines, points, and irregular lines (e.g., rivers and streams) satisfactorily. Text is currently transferred in approximately correct fonts rotated correctly, but with slightly imprecise locations. The mapping programs that are being used are CPS-PC, Radian Corporation, and Personal Computer Mapping System (PCMS), Zycor Inc. We have also utilized the Calcomp 9100 series digitizing tablet in an attempt to produce these maps, but given the existence of available data this does not seem to be a good general solution. We should be able to produce three maps, one of Walker, White & Baker, and Priest & Beavers fields, one of Abell, Malicky, and Netterville fields, and one of Means North field.