DOE/BC/14959--12

TECHNICAL PROGRESS REPORT

Title: REVITALIZING A MATURE OIL PLAY:
STRATEGIES FOR FINDING AND
PRODUCING UNRECOVERED OIL IN FRIO
FLUVIAL-DELTAIC RESERVOIRS OF
SOUTH TEXAS

Cooperative Agreement No.: DE-FC22-93BC14959

Institution: Bureau of Economic Geology
The University of Texas at Austin
University Station, Box X
Austin, Texas 78713-8924

Date of Report: March 31, 1995

Award Date: October 21, 1992

Anticipated Completion Date for this Budget: August 31, 1996

Government Award for this Budget Period: \$817,911

Principal Investigators: Noel Tyler and Raymond Levey

Technical Project Officer: Edith C. Allison

Reporting Period: January 1, 1995 - March 31, 1995

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

RECEIVED
DOE/PETC
95 APR 17 AM 10:39
INSTITUTION & ASSISTANCE DIV.

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

76

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

OBJECTIVES

Advanced reservoir characterization techniques are being applied to selected reservoirs in the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) trend of South Texas in order to maximize the economic producibility of resources in this mature oil play. More than half of the reservoirs in this depositionally complex play have already been abandoned, and large volumes of oil may remain unproduced unless advanced characterization techniques are applied to define untapped, incompletely drained, and new pool reservoirs as suitable targets for near-term recovery methods. This project is developing interwell-scale geological facies models and assessing engineering attributes of Frio fluvial-deltaic reservoirs in selected fields in order to characterize reservoir architecture, flow unit boundaries, and the controls that these characteristics exert on the location and volume of unrecovered mobile and residual oil. The results of these studies will lead directly to the identification of specific opportunities to exploit these heterogeneous reservoirs for incremental recovery by recompletion and strategic infill drilling.

Project objectives are divided into three major phases. Phase I, reservoir selection and initial framework characterization, consisted of the initial tasks of screening fields within the play to select representative reservoirs that have a large remaining oil resource and are in danger of premature abandonment and performing initial characterization studies on selected reservoirs to identify the potential in untapped, incompletely drained, and new pool reservoirs. Phase II will involve advanced characterization of selected reservoirs to delineate incremental resource opportunities. Subtasks here include the volumetric assessments of untapped and incompletely drained oil, along with an analysis of specific targets for recompletion and strategic infill drilling. The third (III) and final phase of the project will consist of a series of tasks associated with technology transfer, and the extrapolation of specific results from reservoirs in this study to other heterogeneous fluvial-deltaic reservoirs within and beyond the Frio play in South Texas.

The goals of the industrial associates program that is the source of industry cofunding to this project are (1) to develop an understanding of sandstone architecture and permeability structure in a spectrum of fluvial-deltaic reservoirs deposited in high- to low-accommodation settings and (2) to translate this understanding into more realistic, geologically constrained reservoir models.

SUMMARY OF TECHNICAL PROGRESS

Project work during the first quarter of 1995 consisted of documentation of Phase II tasks associated with the delineation of incremental recovery opportunities in selected Frio fluvial-deltaic sandstone reservoirs in Rincon and T-C-B fields. In order to take full advantage of available data specific to each field and complete project objectives in the remaining available time, final objectives of reservoir delineation efforts have been streamlined for each field area. Present efforts in Rincon field are focusing on the completion of petrophysical modeling and the subsequent apportioning of original-oil-in-place and cumulative production within individual reservoir subunits to identify the locations and delineate the volumes of remaining mobile oil in a variety of untapped and/or incompletely drained compartments. Petrographic studies and special core analyses on Rincon cores have been completed, and the results are currently being integrated to provide the basis for oil and water saturation estimates in selected reservoir subunits. More complete documentation and detailed quantification of reservoir attributes in selected Rincon reservoirs are being pursued because the complete data set that has been acquired for these reservoirs has wide applicability to many other reservoirs in South Texas within the Frio fluvial-deltaic sandstone play. The goal of streamlined T-C-B project studies is the specific recommendation of near-term infill and/or recompletion targets. Completion of T-C-B reservoir delineation and documentation is focusing on the identification and assessment of reserves residing in untapped reservoir compartments as defined primarily through stratigraphic analysis. Documentation during this project quarter also included preparation of material for upcoming professional meetings.

Rincon Field Reservoir Studies

Delineation of reservoir architecture

In Rincon field, stratigraphic heterogeneity and variability in reservoir quality exhibited within the Frio D and E reservoirs are directly responsible for the distribution of original-oil-in-place and have also been primary controls on present recovery efficiencies. Reservoir mapping and stratigraphic facies analysis have identified the distribution and geometry of eight separate flow units within the Frio D-E reservoir interval in Rincon field. Evaluation of net-sandstone-thickness patterns and facies distributions based on maps constructed over each reservoir flow unit indicates a systematic evolution of sediment transport styles (**Figure 1**). These are, in sequence, (1) aggradation in the lower-Frio E-4 and E-3 reservoir units, (2) retrogradation in the upper-Frio E-2 and E-1 units, (3) progradation in the lower-Frio D-6 and D-5 units, and (4) a return to aggradation in the upper-Frio D-4 and D-3 units. These different styles of deposition directly affect the reservoir geometry present within each sandstone unit. Aggradational and progradational channel sedimentation creates dip-oriented channel sandstones that may or may not be in communication with each other. Retrogradational units, in contrast, allow reworking of previously deposited sediment into long strike-oriented features that have potential for increased flow communication. Identification of flow barriers within and between individual Frio D reservoir units, which have an overall recovery efficiency of only 29%, are the primary goals of studies in progress to understand styles of reservoir compartmentalization and delineate the location of incompletely drained reservoir zones.

Characterization of petrophysical reservoir attributes

The development of petrophysical models to calculate porosity, permeability, and water saturation in the Frio D and E reservoirs in Rincon field is based on thorough evaluation of wireline core analysis data and on results from petrographic studies and special core analyses. Core porosity and permeability data were integrated with reservoir mapping studies to characterize petrophysical reservoir attributes for various depositional facies and to identify differences between lithofacies types. A database was constructed that integrated measured porosity and permeability values for an associated sample depth with corresponding facies and subfacies types identified from map patterns and electric log signatures, respectively. Core data were divided (1) by reservoir subunit (i.e., D-3, D-4, D-5, and D-6) and (2) by reservoir facies. Facies data were grouped according to channel and bar sandstone facies types as recognized on sandstone isopach maps, and channel facies were further subdivided into vertical subfacies identified from electric log profiles. Basic descriptive statistics, including histograms and linear regressions of porosity vs. permeability, were calculated for each different subgroup of data.

In wells with sufficient core data, distinctly different values were usually recognized for the base, middle, and top portions of an individual channel sandstone unit. Porosity and permeability values exhibit a consistent vertical trend for channel facies with lowest values at channel bases (porosity mean: 16.9%, range 6.9–27.3%; mean permeability: 6 md, range: 0.1–157 md), where development of a mud-chip lag is common. Permeability increases upward through mid-channel (porosity mean: 21.2%, range: 8.2–30.7%; permeability mean: 60 md, range: 0.1–1,530 md) and then decreases at channel tops (porosity mean: 18.4%, range: 10.0–27.9%; permeability mean: 14 md, range: 0.1–185 md) where grain size decreases. This pattern is typical of fluvial channel deposits and reflects changes in grain size that normally occur through an upward-fining sequence. The decreased permeability at the bases of channel units is an important factor in determining the level of vertical communication between two channel units that are vertically stacked with no intervening mudstone. Significant porosity and permeability contrasts at the bases of channel deposits are due to the presence of clay clasts and other poorly sorted ductile fragments. If these components are in high enough concentrations and form laterally persistent beds, they may form partial or complete barriers to flow.

Evaluation of log facies and sandstone distribution for each of the reservoir subunits (**Figure 1**) revealed three primary depositional facies types: (1) channel (dip-elongate) sandstone reservoir units, (2) bar (strike-oriented) sandstone reservoir units, and (3) overbank (levee and crevasse splay) units. Channel units, on average, possess slightly higher values of porosity and permeability (20.5% mean porosity, 60.8 md mean permeability) than the bar sandstone units

(mean porosity of 18.5%, mean permeability of 24.4 md). Overbank facies have lower porosities (mean 17.9%) and substantially lower permeabilities (mean 12.3 md) than either channel or bar sandstones. Mean permeability values for thin, upward-coarsening log patterns interpreted to be crevasse splays are 25 md (range 0.3–199 md) and are 5 md (range 0.1–54 md) in units with serrate log responses classified as levee facies. These poorer quality overbank facies generally are not significant reservoirs. Mean values of porosity and permeability for bar sandstone facies and for all channel facies were crossplotted, and the resulting equations for the regression lines demonstrate the different porosity-permeability relationships between these reservoir types (**Figure 2**). Similar porosity values have a lower corresponding permeability for channel sandstone facies than for bar sandstone facies. These two relationships will be incorporated into petrophysical porosity modeling.

Petrographic and special core analyses

Petrographic studies were conducted on 22 samples selected from the Frio D and E reservoirs to identify framework compositions, textures, cement types, and distribution, and to determine pore geometries within these sandstones. Samples selected are representative of each of the various reservoir facies and petrophysical rock types identified from core description and the statistical analysis of core data from throughout the study area. Sandstone grain size ranges from lower fine grained (0.15 mm) to pebbly lower medium grained (0.3 mm), with a mean grain size of 0.25 mm. Most samples are poorly sorted, and sand grains are angular to subrounded. Rincon sandstones are classified as feldspathic litharenites, with an average composition of 17 percent quartz, 33 percent feldspar, and 50 percent rock fragments ($Q_{17}F_{33}R_{50}$). The majority of lithic fragments are volcanic rock fragments; on average they compose 59 percent of all rock fragments and 18.7 percent of whole-rock volume. Authigenic cements include minor grain-rimming chlorite and kaolinite, but by far the most dominant cement is ferroan calcite (**Table 1**), which occurs as an intergranular cement with a sparry, nonpoikilotopic crystal habit. Most samples are only sparsely cemented and contain abundant, commonly oversized (as much as 0.45 mm in greatest dimension), pores. In heavily calcite-cemented samples (low porosity), cemented areas are commonly as much as two framework-grain diameters wide and four grain diameters long.

Most of the visible thin-section porosity in these sandstones appears to be secondary and is developed as voids within partially dissolved framework grains (mainly feldspars and VRFs) and as oversized pores that once contained framework grains and/or calcite cement. Only minor primary porosity (average: 1.5 percent), identified as small intergranular voids at least partially lined with chlorite or calcite crystals growing into the voids within areas of closely spaced framework grains, was observed. These sandstones underwent at least two stages of dissolution, a leaching of framework constituents and subsequent dissolution of pore-filling calcite cement. Total visual porosity varies considerably from 2.5 percent of whole-rock volume in heavily calcite-cemented samples to 28.0 percent in heavily leached samples (average: 15.7 percent). The major diagenetic control on reservoir quality in these sandstones is the volume of calcite cement. Where calcite-cement volume is low because of dissolution and creation of porosity, sample porosity is higher. Calcite dissolution was a significant diagenetic stage that was magnified by the preceding and contemporaneous leaching of framework grains, particularly feldspars and VRFs. There is only minimal porosity-occluding ductile deformation of shaly rock fragments, which are consistently rare, and pressure solution at grain boundaries of carbonate lithic fragments.

Table 1: Summary of petrographic data for Rincon sandstones

Depth	Res. zone	Depositional Facies	Gr. size (mm)	Phi size	Framework constituents			Lithic grain compositions			CaCO ₃ cement	Visual porosity estimates			
					Q	F	R	Vrf	Srf	Cht		1° Ø	2° Ø	Total Ø	% total 2°
3872.0	D-5a	Channel-mid	0.15	2.75	11	30	59	68	26	5	7.5	1.5	20.0	21.5	93%
3876.0	D-5a	Channel-base													
3879.0	D-5b	Channel-mid	0.21	2.25	16	41	43	69	22	9	4.0	0	27.0	27.0	100%
3884.0	D-5b	Channel-mid	0.3	1.75	16	30	54	60	25	15	4.5	4.5	17.5	22.0	80%
3891.0	D-5b	Channel-base	0.3	1.75	25	27	48	59	27	13	14.0	0.5	16.5	17.0	97%
3895.0	D-6	Channel-mid	0.30	1.75	11	35	54	47	42	11	15.0	2.0	14.0	16.0	88%
3900.0	D-6	Channel-base	0.30	1.75	13	30	57	56	38	6	22.5	2.0	4.0	6.0	67%
3945.0	E-1	Channel-top	0.15	2.75	7	45	48	73	22	4	7.5	1.0	14.5	15.5	94%
3950.0	E-1	Channel-mid	0.30	1.75	12	36	52	63	29	8	4.5	3.5	15.0	18.5	81%
3954.0	E-1	Chan-mid (cc)	0.30	1.75	14	37	49	66	28	5	32.5	0	1.5	1.5	100%
3959.0	E-1	Channel-base	0.30	1.75	10	43	47	58	32	10	14.0	2.0	14.5	16.5	88%
3964.0	E-2	Splay	0.21	2.25	21	46	33	94	0	6	0	0	2.5	2.5	100%
3967.3	E-2	Channel-top	0.21	2.25	30	43	27	58	24	18	10.5	12.5	4.5	17.0	26%
3969.3	E-2	Channel-mid	0.30	1.75	23	34	43	89	7	4	4.0	18.5	8.0	26.5	30%
3974.6	E-2	Splay	0.21	2.25	15	27	58	64	29	7	24.5	5.0	7.0	12.0	58%
3987.0	E-3	Channel-top	0.21	2.25	18	29	53	46	51	2	8.5	2.5	25.5	28.0	91%
3988.7	E-3	Chan-mid (cc)	0.21	2.25	21	30	49	55	33	11	25.0	1.0	5.5	6.5	85%
3990.9	E-3	Channel-mid	0.21	2.25	19	28	53	59	32	9	9.0	12.5	13.5	26.0	52%
3997.5	E-3	Channel-mid	0.25	2.0	21	23	56	57	30	14	8.0	12.5	9.5	22.0	43%
3999.6	E-3	Channel-base	0.25	2.0	16	34	50	47	44	9	5.5	3.5	18.0	21.5	84%
4008.3	E-4	Channel-mid	0.30	1.75	23	25	52	41	46	13	9.0	11.5	18.0	29.5	61%

Key: Q=Quartz, F=Feldspar, L=lithics, Vrf=volcanic rock fragment, Srf=sedimentary rock fragment (clastic), Crf=carbonate rock fragment (intraformational), 1° Ø=primary porosity, 2° Ø= secondary porosity, Total Ø= total visual porosity (1° + 2°), 2° Ø (% total)=percentage of total visual porosity that is secondary.

Fifteen samples from the Frio D and E reservoir zones in two wells were selected for special core analyses. These samples represent the range of petrophysical rock types identified from core description and were chosen to demonstrate differences (if any) in measured petrophysical values (1) between the base and top of a single-story sandstone unit, (2) between the base and top of a multistoried/stacked channel unit, (3) in a thin crevasse splay sandstone, and (4) in carbonate-cemented and noncarbonate-cemented sandstones. Formation resistivity measurements were conducted to define the cementation exponent m , which is an important variable in the equation used to calculate formation water saturation (**Table 2**). Reported data on m values from the Frio in South Texas are very limited, and those reported Frio values are all less than the value 2.0, which is the standard default value generally used in the Archie equation for sandstones characterized by intergranular porosity. Higher values of m result in higher calculated water saturation values, which will in turn result in lower estimates for oil-in-place. Accurate estimates of water saturation are critical to delineating reasonable volumes of oil-in-place, and measurements of m on our own core samples will provide the best possible estimates of values and variations in S_w in these Frio reservoir rock types.

Mercury-injection capillary pressure measurements were also performed on 15 samples to determine the distribution of pore throat sizes and to estimate irreducible water saturation. Results, just received, are presented in **Table 3**. These estimates of S_{wirr} will be used in subsequent resource calculations. Core flood tests were also conducted to acquire data on residual oil saturation (S_{or}) and end-point relative permeability. These results are currently being evaluated. We had no previous residual oil saturation data for these reservoirs, and values for S_{or} reported for reservoirs throughout the Frio play range widely from 10% to 38%. S_{or} data are

obviously critical to obtaining reasonable estimates of remaining mobile oil. Petrographic data are being integrated with results from capillary pressure and formation resistivity tests to identify variations in pore geometry that may influence saturation, and the possible controls on these variations. Detailed observations of pore geometry of selected samples using scanning electron microscopy are currently being made to supplement this work.

Table 2: Summary of measured petrophysical values of porosity, permeability, formation resistivity, and calculated cementation exponent (m) for Rincon field reservoir units. Values for measured porosity and m for aggradational D sandstones are significantly higher than those measured from underlying E reservoir units. High formation resistivity corresponds to low-porosity samples heavily cemented with calcite.

Unit	Depth	Visual Porosity	Measured Porosity	Measured Perm. (md)	Formation resistivity factor	Cementation exponent (Archie m)	Calcite cement % volume
D-5a	3872	0.22	0.30	172.0	13.85	2.18	7.5
D-5a	3876		Disintigr.	—	—	—	—
D-5b	3879	0.27	0.30	102.0	13.64	2.40	4.0
D-5b	3891	0.17	0.32	320.0	15.52	2.40	14.0
D-6	3895	0.16	0.18	121.0	19.69	1.73	15.0
E-1	3950	0.19	0.22	130.0	14.78	1.80	4.5
E-1	3954	0.02	0.09	0.4	45.79	1.57	32.5
E-1	3959	0.17	0.20	370.0	14.15	1.82	14.0
E-2	3967.3	0.17	0.22	36.5	16.25	1.83	10.5
E-2	3974.6	0.12	0.16	7.2	25.20	1.74	24.5
E-3	3987.0	0.28	0.22	61.0	14.57	1.78	8.5
E-3	3988.7	0.07	0.11	3.3	44.58	1.73	25.0
E-3	3990.9	0.26	0.26	747.0	12.51	1.90	9.0
E-3	3999.6	0.22	0.23	98.0	16.82	1.90	5.5
E-4	4008.3		0.18	27.5	20.47	1.74	—

Table 3: Comparison of reservoir units and corresponding depositional facies identified from core descriptions with irreducible water and residual oil saturations determined from mercury-injection capillary pressure measurements and core flood tests. Higher water saturations are present in the upper E and Frio D reservoir units, as well as in calcite-cemented sandstones. Smaller pore throat size distributions are characteristic of finer grained top channel facies and samples with abundant carbonate cement.

Unit	Depositional Facies	Sample Depth	Residual Oil Sat. (S_{or})	Irreducible Water Sat. (S_{wi})	Med. pore throat size (microns)	PHI size	Per. (md)	Cement. exponent (Archie m)
D-5a	Channel-mid	3872.0	0.260	30.0	50	0.299	172.0	2.18
D-5b	Channel-mid	3879.0	0.393	30.0	15	0.297	102.0	2.40
D-5b	Channel-base	3891.0	0.154	36.0	21	0.319	320.0	2.40
D-6	Channel-mid	3895.0	—	25.0	85	0.179	121.0	1.73
E-1	Channel-mid	3950.0	0.453	20.0	80	0.224	130.0	1.80
E-1	Chan-mid (cc)	3954.0	0.624	37.0	3	0.087	0.4	1.57
E-1	Channel-base	3959.0	0.147	15.0	118	0.234	370.0	1.82
E-2	Channel-top	3967.3	0.244	23.5	21	0.218	36.5	1.83
E-2	Splay	3974.6	0.194	17.0	39	0.157	7.2	1.74
E-3	Channel-top	3987.0	0.189	21.0	70	0.221	61.0	1.78
E-3	Chan-mid (cc)	3988.7	0.286	36.0	10	0.111	3.3	1.73
E-3	Channel-mid	3990.9	0.227	18.8	200	0.264	747.0	1.90
E-3	Channel-base	3999.6	0.298	15.0	72	0.226	98.0	1.90
E-4	Channel-mid	4008.3	—	27.0	40	0.176	27.5	1.74

T-C-B Field Reservoir Studies

In T-C-B field, work this quarter has focused on compartmentalization styles and infill opportunities in the Scott/Whitehill reservoir interval of the middle Frio Formation. This interval has been subdivided into four sections, the upper and lower Scott and the upper and lower Whitehill. Net sandstone maps have been prepared for these intervals, which range in gross interval thickness from 20 to 45 ft. Net sandstone maps show a series of dip-oriented sandstone thicks representing individual channelbelts or areas of vertically overlapping channelbelts. Upward-increasing sandstone content within the Scott/Whitehill interval, accompanied by changing compartmentalization style, may reflect changing accommodation and avulsion rates in the upper delta plain as a consequence of varying relative base level. A tentative model of fluvial response to base level has been developed and may be very useful in allowing operators to predict the degree of compartmentalization in a reservoir on the basis of its position within a depositional cycle.

In addition, the operator has begun interpretation of a recently acquired three-dimensional seismic data volume covering the bulk of the study area. These data indicate complex faulted patterns in the lower Frio section that are oriented differently from those interpreted with two-dimensional seismic data. In addition, time structure-contour maps of markers in the middle Frio, near the Scott reservoir, yield more complete information on the subtle structural highs causing trapping at this level. Increases in precision over subsurface well control and two-dimensional seismic data will be crucial to explaining the distribution of trapped hydrocarbons in the Scott/Whitehill interval.

A preliminary assessment of the residency of remaining reserves in the Scott/Whitehill interval has been carried out by integrating the identified stratigraphic compartmentalization with new structural interpretations. Several infill and recompletion candidates in the upper Whitehill and lower Scott reservoirs have been tentatively defined (**Figure 3**). High water cuts in some completions in these reservoirs need to be explained before the operator acts upon these recommendations. Mechanical failure in these completions has been investigated and is unlikely. The answer may lie in the interaction of the low-relief structure with a strong water drive and complex reservoir compartmentalization.

Technology Transfer Activities

In addition to specific project tasks, a Bureau of Economic Geology Report of Investigations on playwide resource assessment and identification of remaining oil potential in the Frio fluvial-deltaic sandstone play¹ was completed and published. Results highlighting project studies on playwide reservoir assessment² and results from initial reservoir characterization studies in each field area³⁻⁴ were presented at the American Association of Petroleum Geologists during the annual meeting in March 1995. In addition to these presentations, two papers discussing aspects of the Rincon⁵ and T-C-B⁶ field studies were accepted for presentation at the 1995 Gulf Coast Association of Geological Societies Meeting in October.

A vital part of the technology transfer activity is face-to-face meetings whenever feasible with the geologic staff of operators to impart the techniques of detailed reservoir characterization. Meetings with operator representatives from both T-C-B and Rincon fields were held over the past project quarter. Additionally, several requests for meetings with additional interested parties were received during the AAPG meeting in March.

PLANNED ACTIVITIES

Results from calculations of reservoir areas and volumes for each reservoir subunit in the productive Frio D-E interval in Rincon field are being integrated with results from petrophysical modeling to generate more accurate original-oil-in-place calculations for individual reservoir units. Known production will be subtracted from initial oil in-place volumes of target reservoir intervals to calculate the remaining volume of reserves. Results of detailed petrophysical studies are being

used to map hydrocarbon storage (So₀h) and transmissivity (kh) for selected zones to identify and assess the potential of incompletely drained reservoir compartments.

In T-C-B field, emphasis will be on delineating untapped reservoir compartments that may be targeted for incremental recovery. Activities in this coming quarter will focus on refining the structural and stratigraphic interpretation of the Scott/Whitehill reservoir interval to explain past high water-cut completions and identify specific infill drilling and recompletion candidates. Identification of net sandstone and depositional facies distributions in the 21-B reservoir interval in the lower Frio is also scheduled to delineate reservoir compartment boundaries and supplement structural interpretations by the operator using data from a recently acquired 3-D seismic survey. Further work requested by the operator to focus on additional opportunities will also be provided.

Characterization of Heterogeneity Style and Permeability Structure in a Sequence Stratigraphic Framework in Fluvial-Deltaic Reservoirs (Matching Funds Source)

Because of the worldwide importance of resources in fluvial-deltaic reservoirs, a consortium of oil companies is funding research at the Bureau of Economic Geology aimed at reservoir characterization of fluvial-deltaic depositional systems. The goals of this program are to develop an understanding of sandstone architecture and permeability structure in a spectrum of fluvial-deltaic reservoirs and to translate this understanding into more realistic, geologically constrained reservoir models. Our approach is to quantify the interrelationships between sequence stratigraphy, depositional architecture, diagenesis, and permeability structure through detailed outcrop characterization. This industrial associates program is the source of the 50-percent cofunding for the Bureau's Class I Oil Project.

The project is currently focused on the Upper Cretaceous Ferron Sandstone, a deltaic system deposited in a high-accommodation setting in Utah and the Lower Cretaceous Fall River Formation, a deltaic system deposited in a low-accommodation setting in South Dakota and Wyoming. The Ferron comprises seven short-term stratigraphic cycles arranged in a seaward-stepping, vertically stacked, and landward-stepping stacking pattern. Because major unconformities are absent and sediment preservation is high, depositional elements are the major control on fluid flow. Permeability structure, as determined from more than 10,000 minipermeameter data points, is strongly related to lithofacies distributions within depositional elements.

In comparison, the Fall River Formation is composed of shallow-marine facies tracts locally incised by valley-fill deposits. Detailed work in two canyons with good exposures of the Fall River has characterized the facies, permeability structure, and architecture of valley-fill sandstone successions. Preservation of depositional elements is low in this setting, and unconformities control permeability distribution. Pronounced lateral changes in permeability occur where valley fills of different character are juxtaposed. The interpretations of the Fall River that were developed by studying the formation in outcrop are being used to guide flow modeling of Buck Draw field, which produces oil from the Fall River Formation in the nearby Powder River Basin.

REFERENCES

- 1 Holtz, M.H., and McRae, L.E. (1995), Identification and assessment of remaining oil resources in the Frio fluvial-deltaic sandstone play, South Texas: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 227, 46 p.
- 2 Holtz, M.H., and McRae, L.E. (1995), Modeling reservoir attributes and estimating additional hydrocarbon potential for redevelopment in fluvial-deltaic reservoirs: An example from the Frio fluvial-deltaic sandstone play in South Texas (abstract) *in* Petroleum Technology of the World, official program for the 1995 annual convention of the American Association of Petroleum Geologists, Houston, p. 42-43A.
- 3 McRae, L.E., and Holtz, M.H. (1995), Reservoir architecture and permeability characteristics of fluvial-deltaic sandstone reservoirs in the Frio Formation, Rincon field, South Texas (abstract), *in* Petroleum Technology of the World, official program for the 1995 annual convention of the American Association of Petroleum Geologists, Houston, p. 64A.
- 4 Knox, P.R., and McRae, L.E. (1995), High-resolution sequence stratigraphy: the key to identifying compartment styles in Frio Formation fluvial-deltaic reservoirs, T-C-B field, South Texas (abstract), *in* Petroleum Technology of the World, official program for the 1995 annual convention of the American Association of Petroleum Geologists Houston, p. 51A.
- 5 McRae, L.E., and Holtz, M.H. (1995), Strategies for optimizing incremental recovery from mature reservoirs in Oligocene Frio fluvial-deltaic sandstones, Rincon field, South Texas: Transactions, Gulf Coast Association of Geological Societies, v. 45, *in press*.
- 6 Knox, P.R., and McRae, L.E. (1995), Application of sequence stratigraphy for prioritizing mature reservoirs for incremental growth opportunities, An example from Frio fluvial-deltaic reservoirs, T-C-B field, South Texas: Transactions, Gulf Coast Association of Geological Societies, v. 45, *in press*.