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FOSSIL ENERGY

APPLICATION OF INTEGRATED RESERVOIR MANAGEMENT AND RESERVOIR CHARACTERIZATION

Final Report
March 2000

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APPLICATION OF INTEGRATED RESERVOIR MANAGEMENT AND RESERVOIR CHARACTERIZATION TO OPTIMIZE INFILL DRILLING
FINAL REPORT
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ABSTRACT

Reservoir performance and characterization are vital parameters during the development phase of a project. Infill drilling of wells on a uniform spacing, without regard to characterization does not optimize development because it fails to account for the complex nature of reservoir heterogeneities present in many low permeability reservoirs, especially carbonate reservoirs. These reservoirs are typically characterized by:

- Large, discontinuous pay intervals
- Vertical and lateral changes in reservoir properties
- Low reservoir energy
- High residual oil saturation
- Low recovery efficiency

The operational problems we encounter in these types of reservoirs include:

- Poor or inadequate completions and stimulations
- Early water breakthrough
- Poor reservoir sweep efficiency in contacting oil throughout the reservoir as well as in the nearby well regions
- Channeling of injected fluids due to preferential fracturing caused by excessive injection rates
- Limited data availability and poor data quality

Infill drilling operations only need target areas of the reservoir which will be economically successful. If the most productive areas of a reservoir can be accurately identified by combining the results of geological, petrophysical, reservoir performance, and pressure transient analyses, then this "integrated" approach can be used to optimize reservoir performance during secondary and tertiary recovery operations without resorting to "blanket" infill drilling methods.

New and emerging technologies such as geostatistical modeling, rock typing, and rigorous decline type curve analysis can be used to quantify reservoir quality and the degree of interwell communication. These results can then be used to develop a 3-D simulation model for prediction of infill locations. The application of reservoir surveillance techniques to identify additional reservoir "pay" zones, and to monitor pressure and preferential fluid movement in the reservoir is demonstrated. These techniques are: long-term production and injection data analysis, pressure transient analysis, and advanced open and cased hole well log analysis.

The major contribution of this project is to demonstrate the use of cost effective reservoir characterization and management tools that will be helpful to both independent and major operators for the optimal development of heterogeneous, low permeability carbonate reservoirs such as the North Robertson (Clearfork) Unit.

EXECUTIVE SUMMARY

The purpose of this project was to demonstrate useful and cost effective methods of exploitation of the shallow shelf carbonate reservoirs of the Permian Basin. The techniques used to attain this exploitation can be applied to all oil and gas reservoirs, but are specifically tailored for use in the heterogeneous, low permeability carbonate reservoirs of West Texas. Techniques and tools used, and the conclusions drawn, during the implementation of this project were:

1. **Geological Reservoir Characterization, Importance of Core:** A detailed reservoir characterization can be performed with a minimum of core data, as long as a competent geologic model has been constructed, and there is sufficient wireline log, pressure transient, and historical production data available for analysis. It is vital to have sufficient core to define pay and non-pay rock types from petrophysical analysis and to develop a rock/log model.
2. **Data Acquisition and Analysis:** Aside from the Tiltmeter work performed as part of the project, all of the data acquisition and analysis techniques used for this integrated reservoir description are readily available and economically available to all operators.
3. **Material Balance Decline Curve Techniques:** This approach gave excellent estimates of reservoir volumes (moveable and total), and reasonable estimates of formation flow characteristics. Using this method to analyze and interpret long-term production data is relatively straightforward and can provide the same information as conventional pressure transient analysis, without the associated cost of data acquisition, or the loss of production.
4. **Producibility Problems:** Problems at the North Robertson Unit are similar to those associated with the majority of heterogeneous, low permeability carbonate reservoirs – a lack of reservoir continuity, low waterflood sweep efficiency, early water breakthrough, water channeling and wellbore conformance discrepancies.
5. **Well Test Data:** Surface pressure acquisition during pressure falloff tests yields data of sufficient quality for interpretation. This is an efficient and cost-effective surveillance tool.
6. **Fracture Direction, Communication:** The preferential fracture direction at the North Robertson Unit is east-west. Several of the injection wells are in communication, and CO_2 fracture treatments have broken through in offset wellbores. Tiltmeter work performed as part of the Project confirmed this fracture direction.
7. **Rock Typing/Core Log Model:** The Core log model developed at the North Robertson Unit can be a helpful aid in identifying potential pay within the formation of interest. With the use of core data, this model can be developed, allowing the operator to estimate permeability using a standard set of open hole logs.
8. **3-D Reservoir Simulation:** A dual-porosity model was constructed for the North Robertson Unit, which yielded excellent history matching and allowed for infill development forecasting and validation.
9. **Special Core Analysis:** A special core analysis program was performed to improve the characterization and description of the reservoir and to provide better reservoir property data for flow simulation.

STATEMENT OF WORK

The Statement of Work (SOW) for the NRU Project was divided into two Budget Periods. The objectives of the project as presented in the final revision of the **Statement of Work** on **July 20, 1993** were:
For **Budget Period One -** to concentrate on constructing an **integrated reservoir description**, developing a **reservoir management plan**, evaluating these by use of **3-dimensional reservoir simulation**, and developing a specific **Field Demonstration** recommendation.
The **Second Budget Period** was to consist of implementation of the **Field Demonstration, monitoring performance**, and performing **validation activities**. Both Budget Periods contained extensive **Technology Transfer** activities.

The objectives of both Budget Periods were realized, and documented through reporting required by the Project, and numerous technical writings, presentations and workshops. This Final Report will summarize the activities undertaken as part of the Project, and will provide final conclusions derived from use of each of the technologies applied to the Project. Each of the Project objectives will be addressed, with extensive discussion concerning the 3-dimensional simulation and Tiltmeter applications, since these were both works in progress at the time of the last technical reportings. Status of the wells drilled and completed during the Project were also addressed, with updated production/injection performance.

OPERATIONAL STATUS

During the Field Demonstration portion of the Project, a total of 18 wells, 14 producers and 4 injection wells, were drilled and completed on schedule. Ten of the producing wells were drilled to complete 10-acre waterflood patterns in Sections 329, 327 & 326. An additional off pattern well was drilled in Section 362 in a 20-acre location that had not previously been drained by existing producers.

Production from the fourteen producing wells peaked at a rate of 900 BOPD. At the time of the DOE Project termination (June 1999), production from the subject wells totaled 319 BOPD and 949 BWPD. Individual well tests are given below:

Well #	BOPD	BWPD	MCFPD
505	16	66	5
1509	13	20	9
1511	33	69	22
2705	12	50	10
3017	17	7	9
3018	22	134	41
3319	30	6	60
3532	22	57	13
3533	29	102	10
3534	4	33	10
3535	35	95	20
3537	26	178	10
3538	34	55	12
3604	26	77	10

RESERVOIR PERFORMANCE ANALYSIS *TASK I.2.4*

Material Balance

Production data for the North Robertson Unit was analyzed using Material Balance Decline Type Curve Analysis. All primary (40-acre) and secondary (20-acre) producing wells were analyzed to determine total/movable volumes and formation flow characteristics (permeability and skin factor) based on individual well performance. Maps of OOIP, kh, and estimated ultimate recovery (EUR) using primary production data have been generated and compare well with the geological interpretation.

Decline type curve and waterflood performance analyses indicate that the NRU is not performing as well as expected under secondary recovery operations. This indicated the need for a complete review of the fluid flow behavior in the reservoir (required for reservoir stimulation), and the completion/stimulation procedures used in the past. This work is critical for determining the placement of the 10-acre infill wells, and for optimization of future completion and stimulation practices.

Pressure Transient Tests

Pressure transient (buildup and falloff) data were used to estimate reservoir pressure and formation flow characteristics. The estimated bottomhole pressures from buildup surveys conducted during 1985-1991 and the current pressure falloff and buildup tests were tabulated for use in the geostatistical analysis and reservoir stimulation. The analyses of the buildup tests indicate that the hydraulic fracture treatments were relatively ineffective (short fracture half-lengths) in creating good pressure sinks at the wellbore due to the presence of large, discontinuous gross pay intervals containing many individual layers, and possessing no effective barriers to vertical fracture propagation. Future completions, stimulations, and hydraulic frac jobs will target specified pay intervals as defined by the core/log model in order to improve completion efficiency and interwell conformance.

FIELD OPERATIONS AND SURVEILLANCE *TASK II.2.2*

Well Stimulation

As a result of the data acquisition process (core and logs) during the Field Demonstration phase of the project, we have found that we could identify discrete intervals within the Glorieta/Clearfork section that contribute most to production. These are intervals of relatively high permeability and porosity reservoir, which are separated by larger intervals of lower permeability and porosity rock that act as source beds for the higher quality reservoir rock. These intervals include:

Lower Clearfork: MF4 and MF5 zones	(±7,000 to 7,200 ft)
Middle Clearfork: MF1A, MF2, and MF3 zones	(±6,350 to 6,500 ft, and ± 6,750 to 6,900 ft)
Upper Clearfork: CF4 zone	(±6,150 to 6,250 ft)

We have utilized three-stage completion designs to keep the treated intervals between 100 and 250 ft. We have performed CO_2 foam fracs and conventional cross-linked borate fracs using a new premium frac fluid on an equal number of new wells, which yeilded outstanding results for both designs. The advantages of each type of frac design are listed below:

CO_2 Foam Fracs:

exceptionally clean frac fluid
increased relative oil permeability
created solution gas drive reduces cleanup requirements
formation of carbonic acid for near-well stimulation
reduction in interfacial tension helps remove water blocks

Cross-linked Borate :

exceptionally clean frac fluid
low fluid loss without formation-damaging additives
excellent proppant-carrying capacity
polymer-specific enzyme breaker aids in post-frac cleanup
90% of original fracture conductivity retained

Pre-frac cleanup acid jobs were performed to remove near-well damage using between 1000 and 3000 gallons of 15% acid. Most intervals were perforated for limited-entry fracturing (>2 bbl per perforation), with average injection rates between 30 and 40 barrels per minute, depending on the size of the interval. The size of the frac jobs ranged from 35,000 gallons of fluid and 55,000 lbs of 16/30 sand to 70,000 gallons of fluid and 150,000 lbs of 20/40 sand. Resin-coated sand was 'tailed-in' for all frac jobs to reduce sand flowback during production. The conventional fracs were flowed back immediately at 1 barrel per minute to induce fracture closure, while the foam fracs were shut-in 2-5 days after stimulation to allow the CO_2 to soak into formation.

All jobs were radioactively traced to estimate vertical fracture propagation. Using this information, we were successful in avoiding fracturing down into an underlying water zone in the Lower Clearfork, and we were able to avoid any fracture communication between stages. All hydraulic fracture jobs were designed to yield fracture half-lengths of approximately 150 ft. Post-frac pressure transient tests performed over specific completion intervals indicate that we are obtaining fracture half-lengths between 80 and 120 ft with average radial flow skin factors of approximately –5.0. Detailed frac work is presented in the "Quarterly Technical Progress Report" for the 4th Quarter 1997.

Oil Fingerprinting

Surface oil samples were collected from each interval completion on all new wells for oil fingerprinting analysis. The samples were sent to D.B. Robinson Fluid Properties, Inc. in Houston, Texas for compositional analysis. The oil samples were processed using centrifuge and filtration processes to remove suspended water and other organic material to obtain the best representative sample from each producing interval.

As with most shallow-shelf carbonate reservoirs in the Permian Basin, we are dealing with a large productive interval, in which small individual zones contribute most of the production. Traditional methods for identifying zonal contributions do not work well in this Glorieta/Clearfork interval because the wells do not flow naturally. As an example, in order to record a production log survey, flow must be induced through artificial means that are not representative of the 'normal' reservoir flow mechanisms.

Coring Operations

A total of 2,730 feet of core was taken from four (4) wells during the Field Demonstration portion of the Project as part of an intensive effort to collect needed rock data. Geologists were very careful to capture high quality data from the core by following these rigorous procedures:

(1) The core was pulled from the barrel and loaded into six-inch (6") PVC tubes that were immediately filled with degassed lease crude and then sealed.

(2) The core was carefully laid out at the lab ensuring that care was taken to properly mark depths and lost core intervals.

(3) One inch by one inch (1" x 1") plugs were taken <u>every</u> foot, exactly one-tenth (0.1) feet below the foot mark. All plugs were measured by Core Lab for helium porosity, air permeability, and grain density. All of this data was loaded into a geological-petrophysical computer database program and then depth shifted.

(4) 'Whole' core analyses were taken at promising-looking reservoir intervals. Data was loaded into the computer database and depth corrected.

(5) One and one-half inch by three inch (1.5" x 3") Special Core Analysis (SCAL) plugs were taken in all potential reservoir intervals and in all rock types. These plugs were stored in sealed containers filled with degassed lease crude to preserve the native state of the rock characteristics and fluid content.

(6) Fina slabbed all core at their own facility to maintain high quality assurance.

(7) Depositional environment and rock type using Dunham's classification were described from the slabbed core.

(8) Permeabilities and porosities were measured from a selected one-hundred fifty feet (150') of the NRU 3533 core using Core Labs PDK-100 mini-permeameter machine. Three (3) permeability traces, one-tenth inches (0.1") apart, were recorded. Measurements were taken vertically each one-tenth inch (0.1"). Acoustic-measured porosities were also recorded, using one trace down the center of the core slab, every one-tenth inch (0.1").

The original schedule called for cutting 1,200' of continuous core through the entire Clearfork Formation from three (3) separate wells, for a total of 3,600'. This continuous core gives the ability to make foot by foot comparisons of reservoir quality, rock type and depositional environment which ultimately helped to correct model fluid movement within the reservoir. However, due to significant mechanical difficulties caused by very long core times, often greater than 200 minutes per foot, parts of the section were not cored.

The data was used to help quantify the extent of small scale vertical and lateral heterogeneity, refine the depositional model and improve the understanding of the relationship between porosity and permeability. This data will also assist in the process of choosing additional 10-acre drilling locations within the NRU Clearfork Formation.

OPEN HOLE LOGGING

The base logging suite for the 10-acre infill consisted of:

- Mud Logging
- Dual Laterolog
- Micro Laterolog

- Micro-Spherically Focused Log (R_{xo} device)
- Compensated Neutron Log
- Compensated Spectral or Litho-Density Log (includes PE)
- Spectral Gamma Ray Log
- Sonic Log

In addition to the aforementioned logging suite, to more accurately characterize permeability, fluid content and rock fabric, Fina utilized:

- High Frequency Dielectric Log
- NMR Log
- Borehole Imaging Log.

By using multiple geologic "filters" it is possible to dramatically reduce the scatter on porosity versus permeability crossplots, thereby providing more robust algorithms. "Filters" include devices such as depositional environment data, shallowing upward sequence tops, rock type data, mud log data and numerous open-hole log responses (PE, Spectral Gamma-Ray, Invasion Profile, etc.). Neural network technology allows for the combination of curve data in order to locate unique permeability signatures.

As a result of the data acquisition process (core and logs) during the Field Demonstration Phase of the Project, Fina identified discrete intervals within the Glorieta/Clearfork section that contributed most to production. Intervals of relatively high permeability and porosity reservoir, which are separated by larger intervals of lower permeability and porosity rock that act as source beds for the higher quality reservoir rock. These intervals include:

Lower Clearfork: MF4 and MF5 Zones	(+/-7,000'-7,200')
Middle Clearfork MF1A, MF2, and MF3 Zones	(+/-6,350'-6,500' and +/-6,750'-6,900')
Upper Clearfork: CF4 Zone (varies in Unit)	(+/-6,150'-6,200')

PRESSURE TRANSIENT TESING

Between February and August 1997, pressure buildup tests were recorded on four wells at Fina Oil & Chemical's North Robertson Unit (NRU) for which simultaneous measurements of pressure-time data were made using both down-hole memory gauges and acoustic well sounder (AWS) devices at surface. These tests were conducted to determine the feasibility of performing future pressure buildups using AWS technology alone. The results of the field trial on three Unit wells are presented below. The bottom hole gauge failed on one well (NRU #3527) and no data comparison could be made.

Data Analysis Procedure

The AWS and memory gauge data for each well were analyzed as follows:

1) Perform graphical comparisons of raw AWS and memory gauge pressure data for each well. The AWS shut-in pressure was referenced to the bottom hole gauge depth for each case.

2) Perform preliminary match of raw AWS pressure data using the type curve for a well with a infinite conductivity vertical fracture in infinite-acting homogeneous reservoir, including wellbore storage (all NRU wells are hydraulically fractured). The pressure and pressure derivative data (Δp and $\Delta p'$) were matched on the pressure type curve, and the pressure integral and pressure integral derivative data (Δp_i and $\Delta p_i'$) were matched on the pressure integral type curve for completeness. Estimates of effective permeability to oil, fracture half-length (or pseudoradial skin factor), and dimensionless wellbore storage were obtained for later use, below.

3) The raw AWS pressure-time data were imported into PanSystem 2.4™ and matched using the appropriate model. The results of the preliminary type curve matches performed in step (2) were utilized as initial matching parameters for data matching in Pan System. Final estimates were obtained for effective permeability to oil (κ_0), fracture half-length (χ_f) or pseudoradial skin factor (s_{pr}), wellbore

storage (C_s or C_{Dxf}), and an estimate for average reservoir pressure based on the well/reservoir model utilized (p^*).

4) The results were then imported into a software graphics package in order to generate semilog and log-log plots for later graphical comparisons between the AWS analysis results and the bottom hole memory gauge analysis results.

5) Steps (3) and (4) were then repeated after generating an Integrally-smoothed AWS data set. The analysis results for both the raw and smoothed data sets were identical for each case, therefore data smoothing is probably not necessary for data analyzed in this report.

6) Steps (2) through (5) were then repeated for the bottom hole memory gauge data.

7) Semilog and Log-Log summary plots were then generated to show analysis results for both the AWS and memory gauge data sets. The memory gauge results were taken as the "correct" evaluation for each well.

8) Extrapolated estimates of average reservoir pressure, $\overline{p}$, for both the AWS and memory gauge data were made using the equation for a rectangular hyperbola (RHM). This method has been shown to yield excellent estimates for $\overline{p}$ when boundary-dominated (BDF) data is available, and acceptable estimates of $\overline{p}$ when BDF data is not available. It is also much easier to apply than other pressure extrapolation techniques, such as the Modified-Muskrat Method. For the three wells that are analyzed in this report, we have no BDF data, and very little pressure data in the radial flow (middle time) region. For this reason, we place no great confidence in our estimates for $\overline{p}$, however, they are certainly more realistic estimates for average reservoir pressure than p^* from semilog analysis, particularly when there are little, if any, radial flow data available for analysis.

9) All results for each well were then summarized in tabular form.

Individual Well Analyses

Well NRU 207

Well #207 was drilled and completed as an oil producing well during the 20-acre infill program in March 1987. Between 1987 and 1991, 80% of all original 40-acre wells were converted to water injectors, with the other 20% remaining as producers, primarily along the Unit periphery. Well #207 is located near the center of Section 5, which is located in the southeast corner of the NRU. Texaco's SYCO Unit is located to the east, and EXXON's Robertson (Clear Fork) Unit is located to the south. The results are shown in tabular form in **Table 1.**

Table 1 - Summary of Results for Well NRU #207

NRU 207

			RAW DATA		
			AWS Data		
ko, md	xf, ft	spr	CDf	p*, psia	pbar, psia
0.031	11.7	-2.88	0.1174	3390	2577
			BH Memory Data		
ko, md	xf, ft	spr	CDf	p*, psia	pbar, psia

0.051	7.1	-2.37	0.3628	2585	2144

SMOOTHED DATA

AWS Data

ko. md	xf, ft	spr	CDf	p*, psia	pbar, psia
0.031	11.7	-2.88	0.1174	3390	2577

BH Memory Data

ko. md	xf, ft	spr	CDf	p*, psia	pbar, psia
0.051	7.1	-2.37	0.3628	2585	2144

Well NRU 905

Well #905 was also drilled and completed as an oil producing well in 1989 during the 20-acre infill program. Well #905 is located near the northeast corner of Section 7, which lies along the southern periphery of the NRU. EXXON's Robertson (Clear Fork) Unit is located approximately ½ mile to the south.

Table 2 - Summary of Results for Well NRU #905

NRU 905

RAW DATA

AWS Data

ko. md	xf, ft	spr	Cs1, bbl/psi	Cs2, bbl/psi	p*, psia	pbar, psia
0.0734	1.3	+0.28	0.0061	0.0092	3924	3565

BH Memory Data

ko. md	xf, ft	spr	Cs1, bbl/psi	Cs2, bbl/psi	p*, psia	pbar, psia
0.0688	1.4	+0.21	0.0052	0.0089	4131	3715

SMOOTHED DATA

AWS Data

ko. md	xf, ft	spr	Cs1, bbl/psi	Cs2, bbl/psi	p*, psia	pbar, psia
0.0734	1.3	+0.28	0.0061	0.0092	3924	3565

BH Memory Data

ko. md	xf, ft	spr	Cs1, bbl/psi	Cs2, bbl/psi	p*, psia	pbar, psia
0.0689	1.4	+0.21	0.0052	0.0089	4125	3715

Well NRU 2703

Well #2703 was drilled and completed as an oil producing well in 1988 during the 20-acre infill program. Well #2703 is located near the center of Section 326, which is in the south-central region of the NRU. EXXON's Robertson (Clear Fork) Unit is approximately 1 mile to the south. The results are shown in tabular form in **Table 3.**

Table 3 - Summary of Results for Well NRU #2703

NRU 2703

RAW DATA

AWS Data

ko. md	xf, ft	spr	CDf	p*, psia	pbar, psia
0.043	22.5	-3.53	0.1426	3103	2373

BH Gauge Data

ko. md	xf, ft	spr	CDf	p*, psia	pbar, psia
0.044	27.2	-3.72	0.0465	2850	2137

SMOOTHED DATA

AWS Data

ko. md	xf, ft	spr	CDf	p*, psia	pbar, psia
0.043	22.5	-3.53	0.1426	3104	2373

BH Gauge Data

ko. md	xf, ft	spr	CDf	p*, psia	pbar, psia
0.045	2.6	-3.67	0.0479	2869	2137

AWS Conclusions

We found that the AWS pressure buildup data analyses yielded fairly similar results to those obtained from the memory gauge analyses for the formation flow characteristics (effective permeability, fracture half-length (or pseudoradial skin factor). However, estimates for average reservoir pressure varied by 150 psi to 450 psi for the three wells analyzed. Due to the low permeability of the Clearfork Formation, it is usually not feasible to shut in producing wells long enough to see any boundary-dominated features from which accurate estimates of well drainage area or average reservoir pressure can be made. For this reason, the difference in the shut-in pressure measurements between the AWS system and bottomhole memory gauge does not condemn the use of the AWS system alone. However, if the goal of the analyst is to obtain reservoir volume by increasing the length of the shut-in period, then bottom hole gauges should be utilized.

In addition, the difference in the character of the recorded pressure-time data (*i.e.*, anomalies) between the AWS system and the bottom hole memory gauge was significant for all three wells. The pressure-time profile was extremely different for well NRU 2703. For example, what appeared to be a changing wellbore storage (afterflow) or crossflow characteristic on the AWS data was not present in the memory gauge data.

Performing these comparisons for the Clearfork interval at the NRU is an extreme test for AWS technology. Because we are dealing with a 1,200′ test interval, with individual layers possessing different flow characteristics and pressures, it is often difficult to interpret bottom hole memory gauge data, let alone surface-acquired AWS data. Unfortunately, testing the entire interval at once is the only economic way to perform pressure transient tests at the NRU.

VALIDATION OF RESERVOIR CHARACTERIZATION *TASK II.3.1*

GEOLOGY/DEPOSITION

The depositional environments described from the core samples are as follows:

Open Shelf
- Open-Shelf General
- Fusilinid Shoal
- Shoal - General
- Inter - Shoal

Reef
- Reef Center
- Reef Talus Apron
- Reef Debris Apron

Open Lagoon

Restricted Lagoon

Island
- Island Center
- Near Island Beach
- Algal Mat
- Outer Island Beach

Tidal Flat
- Algal Mat
- Tidal Channel
- Shallow Sub-Tidal Silty Dolostone

Supratidal

The first significant new feature is the presence of large patch reefs and associated porous debris aprons in the Lower Clearfork within Section 327. Initial work suggested that a "shelf' edge existed to the east of Section 327, and that large reefs only existed along this edge. New core information implied there was no "shelf' edge, just patch reefs and debris aprons scattered across the Unit. This could help explain the erratic distribution of good producing wells in the south-central portion of the Unit. It is important to note that the debris aprons and shoals around these reefs typically have good quality. In addition, smaller and less well developed reefs and bioherms have been noted in the upper portions of the Middle Clearfork and Upper Clearfork.

The second new feature concerns the MF3 layer (+/-6,850') of the Middle Clearfork that is interpreted as a solution collapse breccia with associated open natural fractures. These features were caused by dissolution of carbonate beneath extensive exposure surfaces. The presence of these surfaces is supported by presence of coal beds, abundant "fresh" water plant debris zones, erosion lag soils and some root casts. Parts of the Unit were only partially exposed, most probably a series of small islands and associated carbonate sand beaches. This information became of significant economic importance since there is more natural fracturing in the MF3 Zone that initially thought.

Fina has described four basic rock fabrics in this Unit:

Homogenous. Is made up of relatively uniformly distributed lateral and vertical porosity and permeability. A good example was found within selected portions of the MF1A layer. This zone is not perfectly homogenous but is much closer to this type than all other zones in the Clearfork.

Fractured. Is made up of solution collapse breccias as described above. Fractures are 2"-4" in length and very roughly estimated to be 4"-6" apart. The fractures that are not open have been plugged with anhydrite. Portions of the MF3 layer are a good sample of this fabric.

Bimodal. Is made up of two distinct pore sizes. The larger size pores are typically formed from the dissolution of fossil debris and the smaller pores are typically intercrystalline in origin.

Heterogeneous. Is made up of anhydrite nodules and porous dolostone. This fabric is common throughout much of the Glorieta/Clearfork section. The size and distribution of these anhydrite nodules vary dramatically.

Paleontologic Analysis

A total of 125 feet of the new core from three wells was analyzed by Fred Behnken of FHB Stratigraphic Services, Midland, Texas, for the purpose of documenting the faunal assemblage in the Clearfork reservoir. Analysis revealed the presence of several bryozoan genera, codiacean and coralline red algae, rugose corals, gastropods, crinoids, brachiopods of the composite type, foraminifera, and several genera of fusulinid foraminifera. Of particular interest is the occurrence of cyclostome bryozoa as the main frame-builder of the patch reefs in the Lower Clearfork. The bryozoa have erect, laminar and bifoliate growth forms, which appear to have formed an effective sediment baffle. These growth forms are massive and robust, indicating a moderate to high energy depositional environment. Six genera of cyclostome bryozoa were identified in these reefs. The reefs contain bryozoa both in growth position and as desegregated, overturned fragments floating in a muddy matrix. Core analysis reveals that the reefs themselves are non-porous and tight. Surrounding reef talus and reef debris aprons are, however, very porous and permeable, containing some of the highest permeability in the Clearfork.

Also of interest is the occurrence of two distinct populations of fusulinid foraminifera. Most common are larger (4-15 mm) Parafusulina spp. Fusulinids, present in shoals and deeper water sediments. Less common are smaller (0.15-1.5 mm) Schubertella spp. Fusulinids. These smaller forms appear to occur in more restricted environments of the lagoonal side of the reefs, rather than the more seaward, open-shelf facies containing most of the larger forms. This difference could be a function of either physical sorting or ecological preference; either way it seems to be a good environmental indicator.

Special Core Analysis (SCAL)

Approximately 120 preserved (3 inch by 1.5 inch) core plugs were cut from the new whole core in 10-acre infill Wells 1509, 3533, 1510, and 3319 in order to obtain a representative sampling of all 'pay' rock types that were defined during Budget Period I. Thin-section descriptions and capillary pressure measurements are being obtained from the clipped ends of all 120 core plugs.

The SCAL plugs were further screened both visually (thin-sections and slabbed core), and by using a computerized axial tomography (CT) scanning machine at Texas A&M University to eliminate the plugs that possessed major barriers to flow (which is almost always in the form of anhydrite nodules) as shown in **Fig. 3**. A CT number of 2550 and above indicates the presence of extensive anhydrite. Pure dolomite has a CT number of about 2350 and the number for pure limestone is around 2250. CT numbers less than 2200 are indicative of good porosity or fracturing.

These studies allowed us to choose 46 plugs, representing the reservoir rock types (Rock Types 1, 2, 3, and 5), for special core studies. The special core analysis program is intended to improve the characterization and description of the reservoir and to provide better reservoir property data for flow simulation.

The special core analysis measurements were performed by Core Petrophysics, Inc. Measured properties include relative permeabilities for oil, water and gas at steady and unsteady-state conditions; centrifuge capillary pressure for oil and water; mercury capillary pressure and pore throat size distribution; formation factor and resistivity index; and rock compressibility. The core samples were preserved in degassed lease crude oil when they were taken from the well, and relative permeabilities and capillary pressures were measured at reservoir temperature with filtered crude oil and synthetic brine. The relative permeabilities measured at net reservoir stress conditions.

The SCAL program was originally intended to measure properties for each of the four significant reservoir rock types, so that the properties could be correlated with the rock types. The plan called for relative permeability and electrical property measurements on 17 plugs and capillary pressure measurements on 17 other plugs, with the plugs distributed with proportions of 5:5:5:2 in rock types 1,2,3 and 5, respectively. This has turned out to be impractical since the permeabilities of the SCAL plugs were too low to permit measurement of the desired properties in a reasonable amount of time for generally all but the highest quality rock type (Type 1). Therefore only Rock Type 1 underwent a complete set of SCAL measurements. This rock type constitutes a small portion of the rock volume but has the greatest effect on reservoir productivity.

Detailed SCAL data is presented in the Quarterly Technical Progress Report" for the 3rd Quarter 1997.

TILTMETERS

Introduction

This paper presents both downhole and surface tiltmeter hydraulic fracture mapping results of five fracture treatments (in two wells) located in the North Robertson Unit. The field is under waterflood and both injectors and producers are generally fracture treated in three stages at depths of roughly 6,000 to 7,100 feet. Surface tiltmeter mapping was performed on all five treatments to determine hydraulic fracture azimuth and dip. Downhole tiltmeter mapping was performed on 2 treatments in one well to determine the fracture geometry (height and length). In addition, other diagnostic technologies such as fracture modeling and radioactive tracers were used and their results and conclusions are discussed in conjunction with tiltmeter mapping. Understanding hydraulic fracture growth is of critical importance for evaluating well placement and the risk of communication between producers and injectors and to assess fracture staging, perforating and well performance issues.

Both injection wells and producers are generally fracture treated in three stages. The target zones were the oil-producing Lower, Middle and Upper Clearfork carbonate formations at depths of roughly 6,000 ft to 7,100 ft. Knowing the azimuth, dip and geometry of hydraulic fractures is critical for evaluating well placement strategies for waterflood applications. Surface and downhole tiltmeter fracture mapping are technologies that provide these important measurements of fracture azimuth, dip and geometry[1-6]. Tiltmeter fracture mapping has previously shown that fracture azimuth and dip can change dramatically in waterflood areas due to local

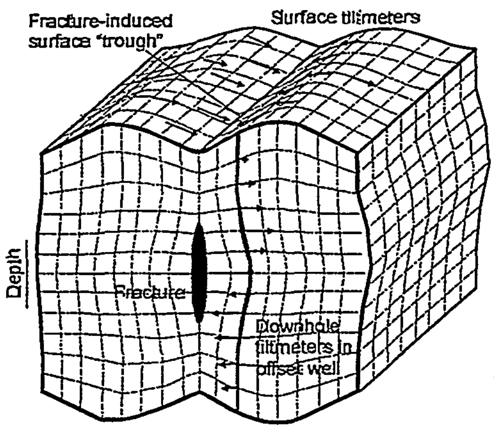


Figure 1: Principle of tiltmeter fracture mapping

variations in reservoir pressure[5]. This can result in hydraulic fracture reorientation that can cause waterfloods to "short circuit", thereby significantly reducing sweep efficiency. Tiltmeter fracture mapping technology was used to:

1. Measure the hydraulic fracture azimuth, dip and geometry and to evaluate the risk of communication between producers and injectors,
2. Quantify hydraulic fracture geometry to understand the performance of both producers and injectors,
3. Calibrate hydraulic fracture models to optimize fracture treatments, and
4. Evaluate the effect of perforating schemes on fracture geometry and staging.

The project included two wells. The NRU 1514 was fractured in three stages, and the NRU 3019 in two stages. Surface tiltmeter mapping was performed for all stages on both wells. Downhole tiltmeter mapping was performed on two stages in the NRU 1514.

All treatments used 20 to 25 lbs/Mgal crosslinked gel, and about 600 bbls clean volume containing 70,000 lbs of 20/40 sand (2 to 8 ppg ramp) pumped at about 30 bbls/min.

Tiltmeter Fracture Mapping

The principle of tiltmeter fracture mapping is simply to infer hydraulic fracture geometry by measuring the fracture-induced rock deformation[2]. The induced deformation field radiates in all directions and can be measured either downhole with wireline-conveyed tiltmeter arrays or with a surface array of tiltmeters. Surface tiltmeters measure the fracture direction, dip and depth to fracture center, whereas downhole tiltmeters measure the geometry of the hydraulic fracture. **Figure 1** shows a schematic diagram of the induced deformation field from a vertical fracture as seen both downhole and at the surface. The deformation field of a purely vertical fracture measured by surface tiltmeters is a trough that runs along the fracture direction with "bulges" on either side. The symmetry of the "bulges"on both sides of the trough indicates fracture dip. The deformation of a purely horizontal fracture is a single bulge centered roughly at the wellhead, with no associated trough. Downhole tiltmeter mapping[1-2] is performed by placing a wire-line conveyed tiltmeter array (7 of 12 tools) in an offset wellbore at the depth of the fracture interval. A vertical fracture will create a characteristic "bulge" at the offset wellbore from which fracture geometry is inferred.

Results

Surface Tiltmeter Mapping

The results presented are for five stages (including one minifrac) in the Clearfork formation in the NRU 1514 and NRU 3019. In short, all treatments created fractures that were virtually vertical and propagated roughly along an east-west azimuth. It appears that the fractures in the NRU 1514 propagated in a slightly more northeasterly direction than the ones in the NRU 3019. The orientation uncertainty for fracture azimuth and dip was less than +/- 6 degrees in the NRU 1514. In the NRU 3019 the uncertainty was higher (up to +/- 15 degrees) due to noisier environment. The tiltmeter results reinforced the operator to continue to develop on a line drive pattern. We must keep in mind, though, that this data set (five fracture treatments, two wells) is fairly small and may not be representative of the entire Clearfork field. Local changes in pore pressure could alter fracture azimuths.

Tables 1 and **2** summarize the results from surface tiltmeter mapping. **Figure 2** shows the plan view of all fracture stages including a minifrac that was done prior to Stage 2 in the NRU 3019.

Figure 3 shows an example of a 3-D deformation map created by the Stage 1 hydraulic fracture in the NRU 1514 (exaggerated for visual purposes). This makes it easier to recognize the trough, which follows an N 79° E ± 5° azimuth at the surface. North and South are somewhat rotated in this picture for better 3-D visualization. The dots represent the surface tiltmeter sites.

Table 1. Surface tiltmeter fracture mapping results for NRU 1514

Stage	Slurry Volume (BBL)	Mid. Perf Interval	Fracture Azimuth	Fracture Dip
S1	675	7090	N 79° E ± 5°	89° S ± 3°
S2	611	6835	N 80° E ± 6°	83° S ± 3°
S3	700	6283	N 75° E ± 4°	86° S ± 3°

Table 2. Surface tiltmeter fracture mapping results for NRU 3019

Stage	Slurry Volume (BBL)	Mid. Perf Interval	Fracture Azimuth	Fracture Dip
S1	727	6780	N 86° E ± 15°	81° N ± 9°
S2 Mini	122	6259	N 96° E ± 9°	89° S ± 6°
S2	703	6259	N 95° E ± 5°	90° ± 5°

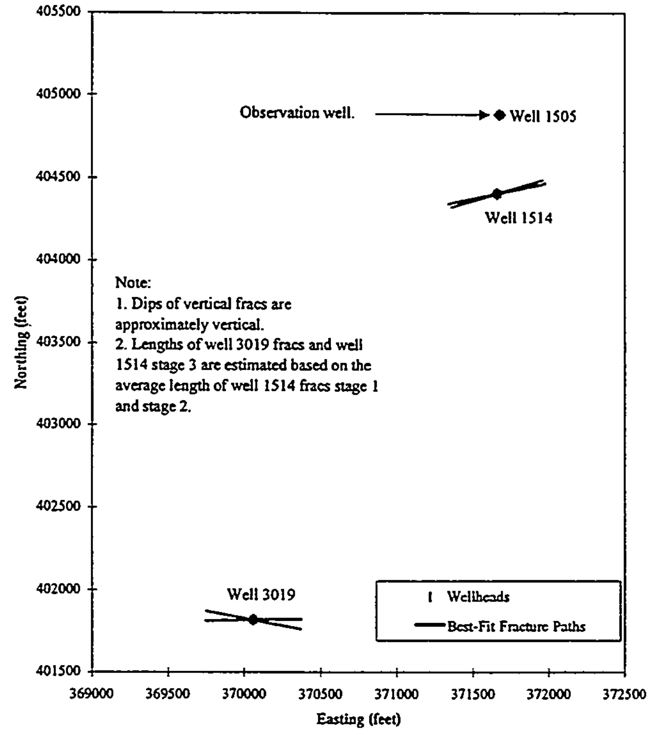
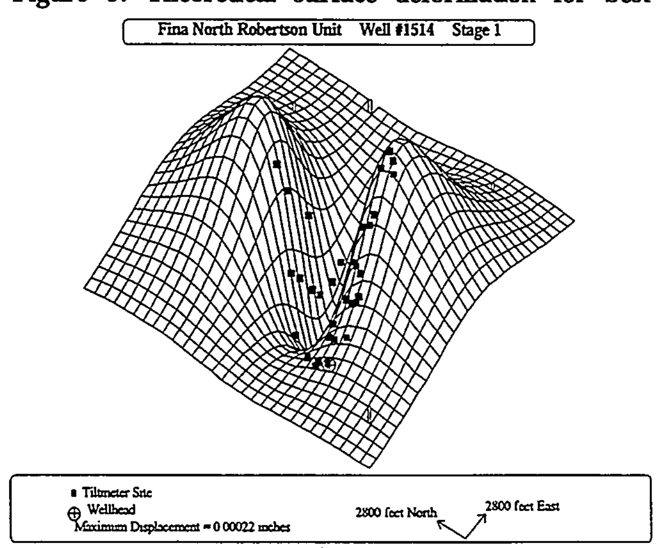


Figure 2: Plan view of hydraulic fracture azimuths in wells NRU 1514 and NRU 3019

Figure 3: Theoretical surface deformation for best-fit



fracture in the NRU 1514 (Stage 1)

Downhole Tiltmeter Mapping

The results presented are for two fracture treatment stages (Lower Clearfork and Middle Clearfork) in the NRU 1514. Originally, we planned to deploy two downhole tiltmeter arrays in two observation wells. However, due to unsuitable well conditions in one observation well, we were only able to deploy one downhole tiltmeter array in the observation well NRU 1505. **Figure 2** shows a map of the well locations. The distance between the observation well (NRU 1505) and the treatment well (NRU 1514) was about 500 feet. The downhole array consisted of seven individual tiltmeters. The positioning of a second array along the fracture azimuth would have improved the accuracy of fracture length. Therefore, fracture length results have a fairly large uncertainty.

Figure 4 shows the downhole tiltmeter signals for Stage 1. The solid line shows the theoretical tilt signal, which is matched to the actual measured signals (dots). Note that the fracture center (minimum tilt magnitude) is above the perforated interval. This indicates a strong tendency to upward fracture growth. Downward fracture growth is limited to about 60 feet below the perforated interval. **Table 3** summarizes the observed fracture geometry. In principal, fractures grow radially with unconfined height growth.

Table 3 - Downhole tiltmeter fracture mapping results for Stage 1 in Well NRU 1514

Stage	Slurry Volume (bbls)	Sand (lbs)	Height (ft)	Half-Length (ft)
S1	675	67,000	410 ± 40	350 ± 50

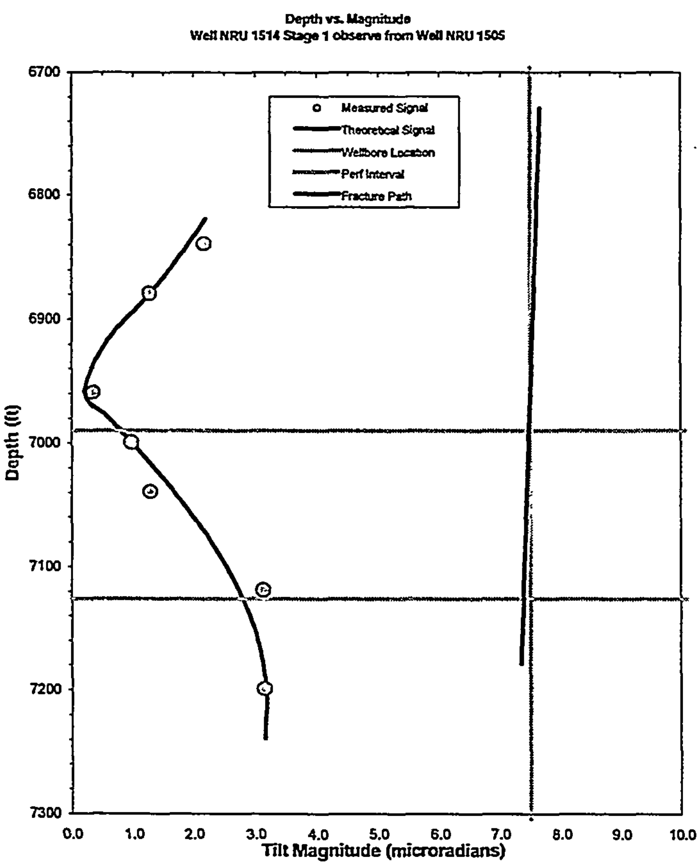


Figure 4: Measured and theoretical tilt signals for Stage 1 in well NRU 1514

Figure 5 shows the downhole tiltmeter signals for Stage 2. Again the solid line shows the theoretical tilt signal, which is matched to the actual measured signals (dots). Note that the fracture center (minimum tilt magnitude) is now slightly below the perforated interval. This indicates a slight tendency to downward fracture growth. However, the fracture also shows significant upward growth. **Table 4** summarizes the observed fracture geometry. Similar to Stage 1, fractures grow radially with unconfined height growth. When comparing Figs. 4 and 5 it is evident that both stages are overlapping substantially. A more detailed discussion of the fracture geometry and position along the wellbore will follow after the fracture modeling section.

Table 4 - Downhole tiltmeter fracture mapping results for Stage 2 in Well NRU 1514

Stage	Slurry Volume (bbls)	Sand (lbs)	Height (ft)	Half-Length (ft)
2	611	74,000	500 ± 100	280 ± 60

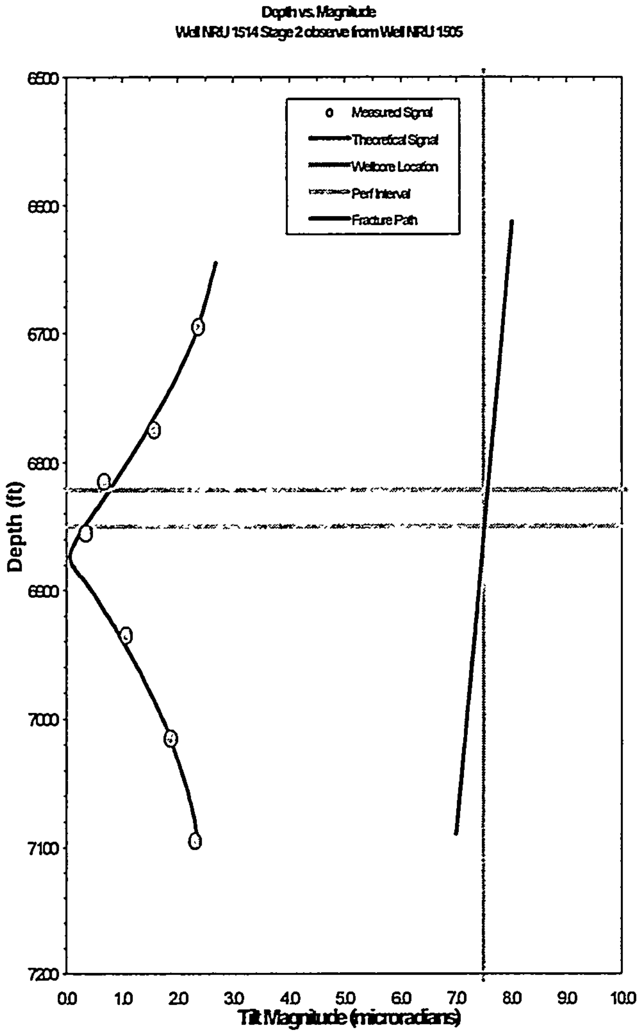
Figure 5: Measured and theoretical tilt signals for Stage 2 in well NRU 1514

Fracture Modeling

This section outlines fracture modeling results based on net pressure matching. The modeling was performed with a 3-D fracture simulator. **Tables 5** and **6** summarize the most important treatment parameters and modeling results for both the NRU 1514 and NRU 3019.

As an example, **Figs. 6** to **9** show the net pressure history match and resulting fracture geometry for Stages 1 and 2 in the NRU 1514. Net pressures were very low during the initial injections (< 100 psi) but increased to about 350 psi at the end of the job. Net pressure matching reveals radial fracture growth due to little stress contrast in a fairly continuous carbonate formation. The downhole tiltmeter results confirmed this modeling approach by showing radially unconfined fracture growth.

In all cases we assumed a Young's modulus of 7,000,000 psi. Closure pressures were estimated from minifracs prior to the main job. Stepdown tests showed no significant near-wellbore tortuosity or perforation friction.



Model results indicate that average proppant concentrations are very low, about 0.3 to 0.6 lbs/ft^2. The low proppant concentration is caused by substantial fracture height growth. Such low proppant concentrations could lead to very low fracture conductivities. The effect of damage will be more severe in producing wells where both gel damage and high effective stresses (~4,500 to 5,000 psi) could reduce the conductivity of a very low-density proppant pack even further. However, the main question still is : In spite of low fracture conductivity, is dimensionless conductivity sufficient? This is a function of reservoir permeability. In injectors the effective stress on the proppant will be low but gel damage remains and additional damage may arise from the injected water.

Table 5 - Summary of NRU 1514 Fracture Engineering Results

S1… Lower Clearfork
S2… Middle Clearfork
S3… Upper Clearfork

Stage	Net Pressure (psi)	Length (ft)	Propped Length (ft)	Heigh t (ft)	Propped Height (ft)	Prop. Conc. (lbs/ft^2)
S1	390	211	201	403	384	0.50
S2	325	201	185	416	383	0.56
S3	100	246	160	650	447	0.61

Stage	Slurry Volume (bbls)	Sand (klbs)	Injection Rate (bbls/min)	Closure Stress (psi/ft)	Efficiency Mini/Main (%)	C_L (ft/min$^{1/2}$)
S1	675	67	30	0.71	50 / 33	0.00072
S2	611	74	30	0.72	62 / 27	0.00028
S3	700	77	30	0.742	62/ 65	0.00030

Table 6 - Summary of NRU 3019 Fracture Engineering Results

Stage	Net Pressure (psi)	Length (ft)	Propped Length (ft)	Height (ft)	Propped Height (ft)	Prop. Conc. (lbs/ft^2)
S2	250	290	227	600	471	0.30
S3	185	280	241	590	508	0.35

Stage	Slurry Volume (bbls)	Sand (klbs)	Injection Rate (bbls/min)	Closure Stress (psi/ft)	Efficiency Mini/Main (%)	C_L (ft/min$^{1/2}$)
S2	715	73	30	0.71	50 / 65	0.00052
S3	705	73	30	0.74	54 / 57	0.00072

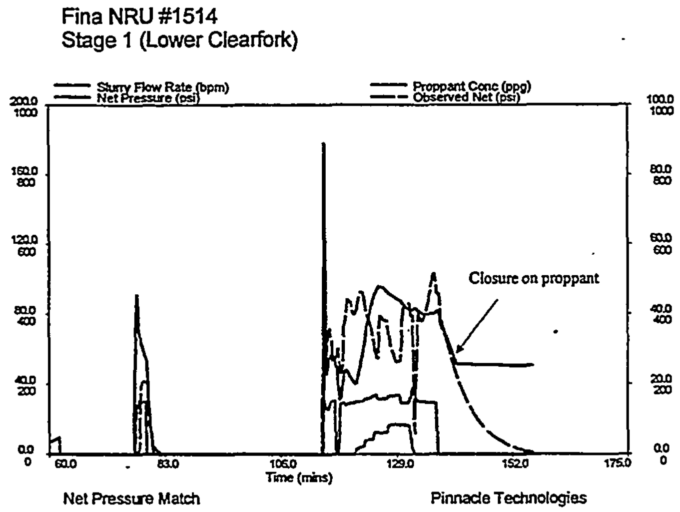


Figure 6: Net Pressure Match: NRU 1514 Stage 1

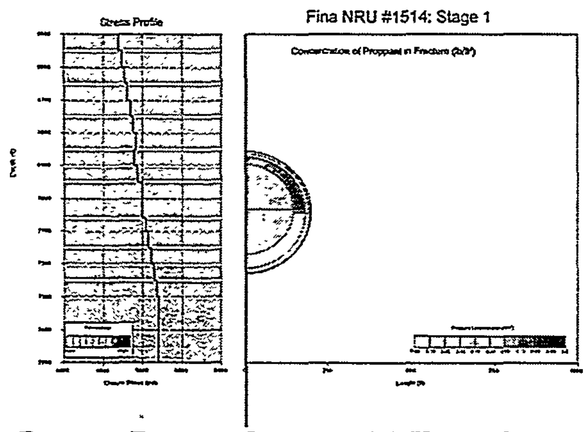


Figure 7: Fracture Geometry: NRU 1514 Stage 1

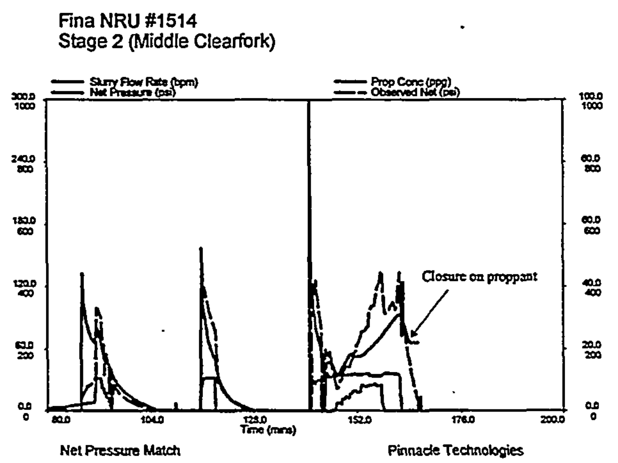


Figure 8: Net Pressure Match: NRU 1514 Stage 2

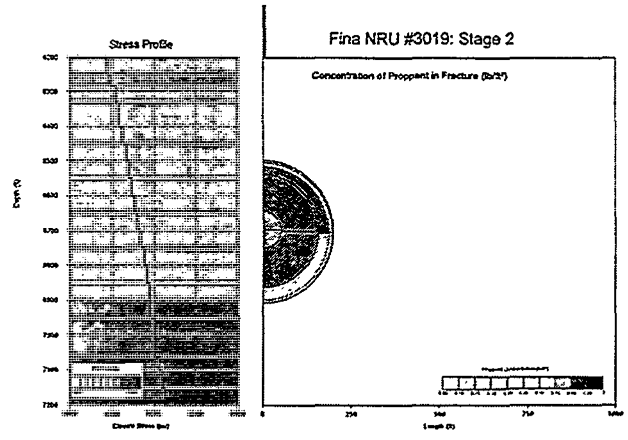


Figure 9: Fracture Geometry: NRU 1514 Stage 2

Discussion

Figure 10 summarizes fracture geometry estimates from downhole tiltmeter fracture mapping, 3-D fracture modeling and radioactive tracer logs. Below is a discussion of these results.

Downhole Tiltmeter Mapping and Fracture Modeling

Based on the downhole tiltmeter fracture mapping results, current treatment designs and staging appear to achieve sufficient interval coverage for the first two stages in the Clear fork formation. Potentially, it may be possible to eliminate a fracturing stage. Since downhole tiltmeter mapping was not performed for Stage 3, it is not clear if the fracture actually covered the interval as depicted in **Fig. 10.**

Net pressure matching indicated the potential for extreme upward height growth for Stage 3 (**Fig. 10**), which would leave parts of the Clearfork (between Stages 2 and 3) unstimulated. The hydraulic fractures in Stage 1 and 2 appear to overlap substantially by about 350 feet. Stage 1 grew more up than down. It is not clear what causes this substantial overlap but it may be due to a lower stress zone above Stage 1. Since Stage 1 appears to have grown to a point above the perforated interval of Stage 2, it is also possible that the two fractures were in communication and Stage 2 actually may have reopened the Stage 1 fracture, which caused the overlapping. Net pressure modeling of Stage 2 does not give any clear indication of communication between fractures.

Net pressure analysis using a 3-D fracture model shows that the modeled fracture height is within reasonable range of the measured one (**Fig. 10**). It appears that in this reservoir, fracture modeling can give reasonable engineering estimates of fracture geometry.

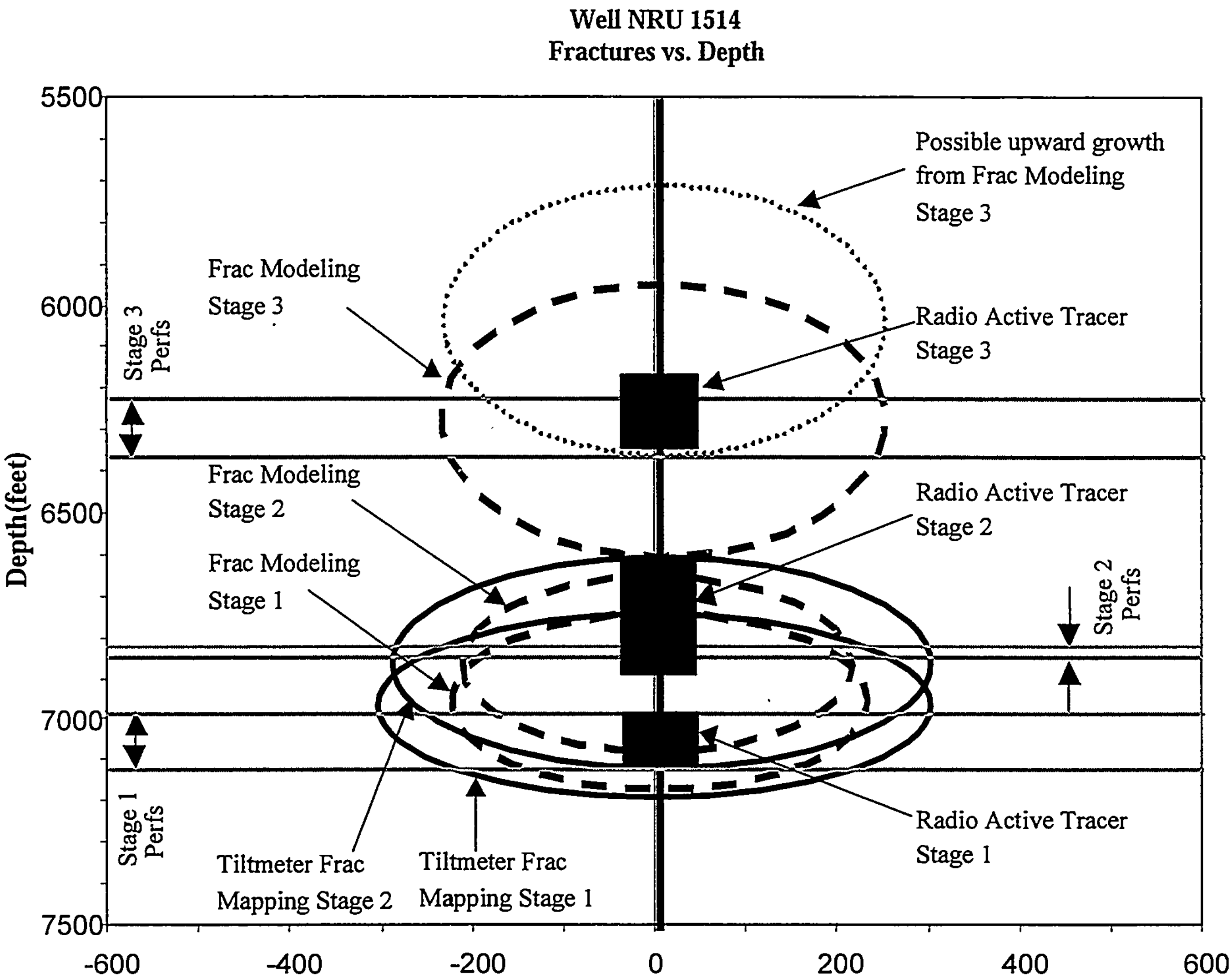


Figure 10: Fracture Geometry: DH-Tilt Mapping, Fracture Modeling and RA-Tracers in Well NRU 1514. (Fracture modeling - dashed lines, tiltmeter mapping - solid lines)

However, fracture modeling cannot be predictive about the fracture center location along the wellbore (i.e. fracture growing more upwards or downwards), especially if the fractures grow in such a radial fashion. This makes it hard to predict from fracture modeling whether fracture stages will overlap or not. Downhole tiltmeter mapping, however, can determine the position of the fracture center.

Comparison with Radioactive Tracers

Tracers show substantially less fracture height in both stages (e.g. Stage 1 - 110 feet versus 410 feet from downhole tilt mapping). This discrepancy may be caused by the fracture not completely aligning itself with the wellbore (slight dip from vertical as indicated by surface tiltmeter mapping with dips of 83 to 89 degrees). For example, a 100 foot fracture section with a 2 degree dip from vertical would result in a 3.5 feet displacement away from the wellbore. This distance would put the fracture outside the range of tracer scans.

The tracer scan shows no counts in the lower sets of perforations in Stage 1. This seems to indicate that the lowest set of perforations was not broken down properly. However, tiltmeter mapping shows fracture growth down below those perforations to a depth of about 7,180 feet with the fracture growing more up than down. In Stage 2 tracers show more height growth in the upward direction but hardly any downward growth. Tiltmeters indicate both upward and downward growth with about 500 feet of total height.

What is the best treatment size?

From fracture modeling it appears that doubling the treatment size in Stage 1 (NRU 1514) would not substantially increase the propped fracture length (only by about 3%). However, the height is increased by 30% and the proppant concentration could be increased from 0.56 lbs/ft^2 to 0.85 lbs/ft^2. Pumping only half the current treatment sizes would reduce the fracture length by 20%, the frac height by 15% and the proppant concentration to 0.37 lbs/ft^2.

Current designs appear to achieve fracture lengths that cannot be substantially increased by increasing treatment size. However, further optimization may be possible with respect to the staging of treatments and desired fracture conductivity. This will require production tests (or injectivity tests) and well test analyses to determine the actual dimensionless fracture conductivity and how it affects the actual effective fracture length.

What impact did perforation strategy have?

It appears that the overall fracture geometry was not impacted significantly by perforation strategy. Stage 1 was perforated over 130 feet with a limited entry strategy. Stage 2 was perforated as a 30-foot point source and Stage 3 was perforated as a multiple point source over 130 feet. All three configurations created radially unconfined fractures. However, RA tracers showed that in the cases of limited entry and multiple point source configurations the lowest set of perforations were not broken down. In Stage 1 this may have created a bias to upward frac growth (also indicated by the downhole tiltmeters), but it may also just be an artifact of larger stresses in the zones below and general tendencies of fractures to grow more up than down.

Conclusions

1. Surface tiltmeter mapping showed that fractures are virtually vertical with a slight dip and grow roughly along an East-West azimuth. Fractures seem to grow slightly more in a southwest-northeasterly direction in the NRU 1514 than in the NRU 3019.
2. The tiltmeter results reinforced the operator to continue to develop on a line drive pattern, and not to flood using a 10- acre 5-spot pattern.
3. Fractures grow radially and unconfined. Downhole tiltmeter mapping measured hydraulic fracture heights of about 400 to 500 feet and fracture half-lengths between 220 and 400 feet.
4. Current treatment designs and staging strategies achieve sufficient interval coverage for the first two fracture stages. Potentially, it may be possible to eliminate a fracturing stage.

VALIDATION OF RESERVOIR SIMULATION *TASK II.3.3*

3-D SIMULATION/MODELING

Deterministic Modeling/Simulation

Scientific Software-Intercomp, Inc, (SSI) performed reservoir stimulation and engineering studies of the Clearfork formation of the North Robertson Unit. This report describes the available data, the methodology employed, and the conclusions of the study.

The following work was completed for the deterministic reservoir simulation portion of the North Robertson Clearfork study:

1) Single-Porosity, Nineteen Layer, Black Oil Simulation Studies

   Section 329
   Section 327
   Section 005
   Southern Development Model (NRDM1)

2) Single-Porosity, Nineteen Layer, Miscible Black Oil Simulation Studies (CO2 Injection Cases)

   Section 329
   Section 327
   Section 005
   Southern Development Model (NRDM1)

3) DOE Workshops (Technology Transfer)

4) Testing and Development of Dual-Porosity, Ten Layer, Black Oil Simulation Models

5) Testing and Development of Dual-Porosity, Ten Layer, Miscible Black Oil Simulation Models

6) Dual-Porosity, Ten Layer, Black Oil Simulation Studies

   Section 329
   Section 327
   Section 005
   Section 326
   Section 325 (Completion: End of January 1998)

7) Dual-Porosity, Ten Layer, Black Oil Simulation Studies

   Section 362 (Completion: End of February 1998)

8) Update of Reservoir Characterization for New Lab Data and Data from New Wells

9) Full-Field, Dual-Porosity, Ten Layer, Black Oil Simulations

The primary objectives of this study were:

- To provide an understanding of the recovery processes occurring within the Clearfork formation of the North Robertson Unit,
- To evaluate locations for infill wells and to analyze their subsequent performance.
- To increase the economic value of the North Robertson Unit by determining an "optimum" future development scenario involving targeted infill drilling, waterflood modification, and CO_2 injection.

These primary objectives were achieved through the following phases:

- Determination of an accurate characterization of the reservoir rock and fluid properties for use in the simulation models.
- Construction and calibration of a reservoir simulation model that represents the historical rock, fluid and well behavior of the North Robertson Clearfork formation.
- Development of a detailed understanding of the factors controlling fluid recovery in this reservoir.
- Development of a calibrated simulation model of the North Robertson unit which can be used by TotalFina in the future to evaluate field development choices.
- Recommendation of actions to improve the rate of oil recovery, the efficiency of oil recovery, the ultimate oil recovery and the net present value of the field.

The initial phases of this study developed a detailed description of the rock and fluid properties of the Clearfork reservoir, and the characteristics and behavior of wells in the NRU. Much of the data used to develop this description was provided by Team Members in the DOE Project. These data, along with the available field and lab data, were used to develop the geological, petrophysical, fluid and well descriptions required by the simulation models. After developing an understanding of the reservoir rock and fluid characteristics, a detailed numerical reservoir simulation model was constructed. The simulations in this study were performed using SSI's SimBest II reservoir simulator in three-dimensional, dual porosity, three phase standard black-oil mode, and Landmark's VIP reservoir simulator in three-dimensional, dual porosity, three phase, standard black oil mode. The characteristics of the reservoir, derived from the initial geological and petrophysical phases of the study, were quantified, mapped, and digitized for use in the simulator. The data derived from the initial engineering phases (including rock and fluid characteristics, well production and injection data, well completion and workover histories, etc) were assembled, checked for accuracy, and input to the simulation model. Model fluid properties for the miscible and standard black-oil simulations were derived from compositional equation of state analyses using the available lab data.

The reservoir and well descriptions in the model were calibrated by adjusting these descriptions until the historical well performance as calculated by the simulator matched the performance as measured in the field. During the history-matching process, a complete record of changes to the initial rock and fluid characteristics was recorded. All changes were maintained within the observed range of values in the field. History match parameters included produced gas-oil ration, water cut, and reservoir pressure on a well-by-well basis.

The history simulations were analyzed in order to develop a detailed understanding of the factors controlling fluid recovery in this reservoir. This understanding, combined with the reservoir conditions existing at the end of the history period and the results of analyses performed by other team members, were used to design development scenarios to be tested during the prediction phase of the study.

Prior to the simulation of the prediction cases, the productivity and injectivity indices of all wells producing or injecting at the end of history were calibrated for each completion layer. In addition, a method was devised to calculate the productivity/injectivity indices of new wells, and of new completions in existing wells, based on reservoir quality and the calibrated of surrounding wells. It was assumed that all production wells were on pump by the end of the history period. No wellbore curves were generated for use in this study.

A total of six prediction cases were designed and simulated in this study. Four of these were sensitivity cases. The first prediction case started at January 1, 1999 and was a continuation of the current scheme. The second case was started at April 1 1996 and assumed that no new wells were drilled, and no subsequent conversions to injection were performed. All cases were simulated to December 31, 2028 (a total of thirty seven years from the end of history). Each prediction case was designed based on the results of previous simulations and the development scenarios of interest.

The original work performed by Fina in this study identified thirty-seven layers in the Glorieta and Clearfork. These layers were correlated between all wells in the Unit. Nineteen of these layers were considered flow zones. These flow zones are separated by eighteen tight layers. The most significant of the tight zones consists of the Tubb. The early simulation work included these nineteen flow zones. The tight zones were not required to be specified as layers in the simulation, since they did not contribute to reservoir behavior, except to act as flow barriers.

During the course of the study, changes were made to the reservoir characterization which allowed the number of layers to be reduced. In particular, the model was converted from single-porosity mode to dual-porosity mode. This change allied each simulation layer to represent both low-perm matrix and higher-perm flow zones. Unlike the tight zones discussed previously, the low-perm matrix contains oil, gas, and water, and contributes to reservoir behavior primarily through expansion of these fluids as reservoir pressures decrease. The effects of gravity drainage, imbibition, and diffusion may also contribute to the transfer of fluids from the matrix to the higher-perm layers.

The ability to represent higher-perm layers within a low-perm matrix greatly improved the quality of the simulation results. The simulator was able to accurately represent the historical well performance with only minor modifications to the initial reservoir descriptions. This indicates that the reservoir behaves as a heterogeneous, layered system. This type of system is consistent with sediments of the geologic environments previously mentioned. These sediments are layered, often thin-bedded, and have a high degree of heterogeneity.

The use of the dual-porosity model allowed a reduction in the number of layers from nineteen to ten in the models. Tests indicated that the quality of the simulation results was not significantly affected. The following table illustrates the various layering systems used in this study.

SUMMARY OF SIMULATION LAYERS

Geologic Layer	Original Layers	Final Layers
GL1A, GL1, GL2	1,2,3	1
GL3, GL4, CF1	4,5,6	2
CF2, CF3	7,8	3
CF4, MF1A	9,10	4
MF1, MF1B	11,12	5
MF2, MF2A, MF2B	13, 14, 15	6
MF3	16	7
MF4	17	8
MF5	18	9
MF6	19	10

ROCK TYPING

A rock type is defined as an interval of rock with unique pore geometry. David K. Davies analyzed approximately 1871 feet of slabbed core in an effort to build a rock log model for the NRU. Rock types were discriminated on the basis of:

1. Volume proportions of Pore types
2. Integration of data form capillary pressure and core derived porosity-perm analyses.
3. Lithology

Eight Rock Types were distinguished within the pay zone based upon the variations in lithology and pore structure. These eight Rock Types are characterized by a wide range of measured values of porosity and permeability. This dispursion of data reflects changes in the volumetric distribution of pore types and lithology within these rocks. Detailed information on the rock type characteristics is provided in the 1995 and 1998 'Annual Technical Progress Report'.

The slabbed core from NRU Well Nos. 1510, 3319, and 3533 was described foot by foot noting vertical variations in lithology, texture, depositional facies, fracturing and oil impregnation. Graphic description logs were prepared. Environments of deposition were determined. David K. Davies also described and interpreted depositional environments and diagenesis from other cores within the Unit earlier in the project.

Thin Section Analysis

The trimmed ends of 311 core plugs from the three wells were used to prepare thin sections, dry polish in a grit-free environment, impregnated with super clean blue epoxy resin and stained with Alizarin Red "S" dye. This analysis yields information concerning textural, compositional, diagenetic, and pore geometry.

Automated Image Analysis

Automated image analysis of 90 thin sections using SEM and computer system to quantify variations in pore geometry was performed. This data was integrated with the results of pore cast analysis of 15 samples and SEM analysis of 15 samples for purposes of Rock Type identification.

X-Ray Diffraction Analysis

The trim ends of 36 core plugs were used for x-ray diffraction. All samples were cut into two sections. One portion of the sample was ground to a fine powder with a McCrone mill and back-loaded into an aluminum sample holder. Powdered samples were scanned from 2-40 degrees 2-theta at a speed of 1 degree/minute with an x-ray diffractometer employing copper K-alpha radiation. Bulk powder diffraction yielded information concerning the minerolgy of the samples. A second portion of the sample was used to prepare oriented clay fraction specimens for analysis. The resulting sample was oriented on a glass slide and scanned from 2-40 degrees 2-theta with an x-ray diffractometer employing copper K-radiation. The analysis of oriented clay-fraction mounts provided semi-quantitative information concerning the nature and abundance of clay minerals within the samples.

Pore Casts

Pore casts were prepared for 14 specially selected samples. Fourteen SEM analyses were substituted for the pore cast analyses. The pore cast data was integrated with the results of automated image analysis to identify Rock Types for 90 rock samples.

Rock Type Algorithms

Rock Types were related to porosity and perm data. Rock type specific algorithms are developed that relate phi and k to each Rock Type. Rock types were first identified for all core feet, then were related to log responses. Log response characteristics were determined for each Rock Type using algorithms specifically designed using data from the above tasks. A vertical log profile was produced for each foot of cored and logged section in all wells showing Rock Type and permeability.

PUBLICATIONS AND PRESENTATIONS

SPE Annual Technical Conference and Exhibition, October 22-25, 1995, Dallas, TX.

- SPE 30774, "*Decline Curve Analysis Using Type Curves: Water Influx/Waterflood Cases.*"
- SPE 30601, "Simulation of Geological Model Using multipoint Histogram."

SPE Permian Basin Oil and Gas Recovery Conference, March 27-29, 1996, Midland, TX.

- SPE 35183, "*Identification and Distribution of Hydraulic Flow units in Heterogeneous Carbonate Reservoir: North Robertson Unit, West Texas.*"
- SPE 29594, "*An Integrated Geologic and Engineering Reservoir characterization of the North Robertson (Clearfork) Unit.*"
- SPE 35161, "*Pressure Transient Data Acquisition and Analysis using real Time Electromagnetic Telemetry.*"
- SPE 35205, "*Evaluation of Injection Well Performance Using Decline Type Curves.*"

SPE/DOE Symposium on Improved Oil Recovery, April 21-24, 1996, Tulsa, OK.

- SPE/DOE 35433, "*Flow Unit Characterization of a Shallow Shelf Carbonate Reservoir: North Robertson Unit, West Texas.*"

1997 Annual DOE/BDM International Reservoir Characterization Technical Conference, March 2-4, 1997, Houston, TX.

- Oral presentation and poster session on project material.
- *"Improved Characterization of Reservoir Behavior by Integration of Reservoir Performance Data and Rock Type Distributions."*

Oklahoma Geological Society Circular, *Platform Carbonates in the Southern Mid-Continent*, (in press), K.S. Johnson, March 1997.

- *"Environments of Deposition for the Clear Fork and Glorieta Formations, North Robertson Unit, Gaines County, Texas."*

1997 BDM/DOE Annual Contractor Review Meeting, June 16-20, Houston, TX.

- Oral presentation

1998 PBS/SEPM Core Workshop, February 26, Midland, TX.

- Display of core taken during DOE field demonstration

1999 WTGS Core Workshop, February 4, Midland TX.

- Core workshop at Fina Core Facility utilizing core taken during DOE field demonstration

2000 SPE Permian Basin Oil and Gas Recovery Conference, Midland, TX. March 21-23, 2000

- "*Tiltmeter Hydraulic Fracture Mapping in the North Robertson Field, West Texas.*"

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