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APPLICATION OF INTEGRATED RESERVOIR MANAGEMENT AND RESERVOIR CHARACTERIZATION TO OPTIMIZE INFILL DRILLING

Annual Technical Progress Report
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APPLICATION OF INTEGRATED RESERVOIR MANAGEMENT AND RESERVOIR CHARACTERIZATION TO OPTIMIZE INFILL DRILLING

ANNUAL REPORT

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ABSTRACT

Infill drilling of wells on a uniform spacing, without regard to reservoir performance and characterization, does not optimize reservoir development because it fails to account for the complex nature of reservoir heterogeneities present in many low permeability reservoirs, and carbonate reservoirs in particular. New and emerging technologies, such as geostatistical modeling, rigorous decline curve analysis, reservoir rock typing, and special core analysis can be used to develop a 3-D simulation model for prediction of infill locations. Other technologies, such as inter-well injection tracers and magnetic flow conditioners, can also aid in the efficient evaluation and operation of both injection and producing wells.

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. Several techniques, tools and innovative methodologies have been used during the duration of the project. These techniques may apply to all oil and gas reservoirs, but are specifically tailored for use in the heterogeneous, low permeability carbonate reservoirs of West Texas. Conclusions and observations to date are:

1. **Use and Importance of Core data in Geological Reservoir Characterization:** A detailed reservoir characterization can be performed with a minimum of core data, as long a competent geologic model has been constructed, in addition to sufficient wireline log, pressure transient, and historical production data being available. Sufficient core is necessary to define pay and non-pay from petrophysical analysis.

2. **Data Acquisition and Analysis:** Aside from the cross-borehole seismic, all of the data acquisition and analysis techniques used for the integrated reservoir description are readily available.

3. **Material Balance Decline Type Curve Techniques:** This approach gives excellent estimated of reservoir volumes and reasonable estimate of formation flow characteristics. Use of this method to analyze and interpret long term production data is relatively straightforward and can provide the same information as conventional pressure transient analysis.

4. **Waterflood Type Curve Techniques:** Type curve techniques similar to those currently used in decline type curve and pressure transient analysis need to be developed in order to better identify injection well responses and improve the analysis of long term injection data.

5. **Producibility Problems:** Producing problems at North Robertson exist as they do in the majority of heterogeneous, low perm carbonate reservoirs – a lack of reservoir continuity, low waterflood sweep efficiently, early water breakthrough, water channeling, directional permeability, and plugging of injection pores due to poor water quality.

6. **Well Test Data:** Surface pressure acquisition during pressure fall-off tests yields data of sufficient quality for interpretation even when low precision gauges are utilized.

7. **Fracture direction, Communication and Quality:** The preferential fracture direction at the NRU appears to be East-West. Several of the injection wells are in communication. The results of the hydraulic fracture treatments at the NRU have been relatively poor, resulting in extremely short, low conductivity fractures. This preferential fracture direction and magnitude will be measured later during the project through tiltmeter technology.

8. **Water quality Monitoring:** Vital to effective waterflooding, especially in low porosity/permeability reservoirs.

Quality of Data: Reliable high quality data should be taken early and often during surveillance to ensure accurate analyses.

INTRODUCTION

The purpose of this project is to demonstrate the application of advanced secondary recovery technologies to remedy producibility problems in typical shallow shelf carbonate reservoirs of the Permian Basin, Texas. Typical problems include poor sweep efficiency, poor balancing of injection and production rates, and completion techniques that are inadequate for optimal production and injection. Techniques, tools and methodologies used during the project are reservoir characterization, material balance decline curve analyses, type curve analyses, well test data, water quality monitoring and borehole tomography.

RESULTS AND DISCUSSION

OPERATIONS STATUS

During the Field Demonstration Phases of the project a total of 18 wells, 14 producers and 4 injection wells, were drilled and completed on schedule. Eleven (11) wells were drilled during the second quarter of 1996, consisting of nine (9) producing wells and two (2) injection wells. Ten (10) of the wells were drilled to complete waterflood patterns in the North (Section 329) and South (Section 327) 10-acre infill areas of the Unit. An additional off-pattern well, NRU 3319, was drilled in Section 362 of the Unit in a 20-acre location that had not previously been drained by existing producers.

Seven (7) wells were drilled during the third quarter of 1996, consisting of five (5) producers and two (2) injection wells. This phase of drilling consisted of completing waterflood patterns to the West of the wells in Section 329 and Section 327 of the Unit. An additional off-pattern well, NRU 3604, was drilled in a 10-acre location in the southwest corner of Section 324, in an area of the Unit in which reservoir flow simulation predicted extremely high recovery potential. Production flowlines were laid for each new producing well as they were put on production. Injection flowlines were laid for the injection wells as they were completed.

Other operational activities relating to the project which are currently underway include the testing of magnetic flow conditioners to assist in the reduction of scale and paraffin in producing lines and equipment and an inter-well tracing program to aid in obtaining information on directional fluid flow, inter-well communication, and breakthrough time between injector and producer.

ACTIVITY II.1 - MANAGEMENT AND ADMINISTRATION

PROJECT MANAGEMENT AND ADMINISTRATION - *TASK II.1.1*

Project Status

The eighteen 10-acre infill wells drilled as part of the field demonstration portion of the project are all currently in service with no operational problems. These wells consist of fourteen producing wells and four injection wells. The producing wells are currently producing a total of approximately 376 bopd, down from a peak rate of 900 bopd. The four injection wells are currently injecting a total of 140 bwipd.

Unit production is currently averaging approximately 2,600 bopd, 12,000 bwpd and 18,000 bwipd. Current individual production rates for the fourteen project producing wells is tabulated below:

Well #	BOPD	BWPD	MCFPD
505	21	69	6
1509	7	13	9
1511	38	62	22
2705	14	47	10
3017	21	7	9
3018	24	137	41
3319	38	7	60
3532	33	47	13
3533	35	128	10
3534	15	75	10
3535	44	117	20
3537	31	202	10
3538	25	63	12
3604	30	64	10

Core Analysis

A total of 2,730 feet of core was taken from four of the Project wells during the Field Demonstration portion of the Project. This core was taken to the Fina core facility in Midland, Texas and studied and described by a Fina geologic team, headed by the Project Geologist, Brian Pregger.

After the initial review and description at the Fina core facility, the cores are being shipped to David K. Davies & Associates in Houston for more detailed descriptive analyses. At this time, approximately 2/3rd's of the core have been analyzed at the Davies lab. In addition, thin-sections are being made and described from the clipped ends of special core plugs which were taken in all potential reservoir intervals and in all rock types. Thin section analysis will allow comparisons of reservoir quality, pore distribution and geometry, and depositional facies within the reservoir. Capillary pressures will also be run on these clipped ends to give us a representative set of data for each individual reservoir rock type. The special core plugs (1.5 inch by 3 inch) were stored in sealed containers filled with degassed lease crude to preserve the native state of the rock characteristics and fluid content.

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). 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.

Core Petrophysics, Inc performed the special core analysis measurements. Measured properties include relative permeability 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 have been preserved in degassed lease crude oil since they were taken from the well and relative permeability and capillary pressures were measured at reservoir temperature with filtered crude oil and synthetic brine. The relative permeabilities are being 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 have been 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 will have 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.

This report presents the final results of special core analysis tests using core material from the subject wells.

The forty-six 1.5 inch diameter preserved samples were each flushed with stock tank crude oil at reservoir temperature and the permeability to oil was measured. The net confining pressure used in these tests was 500 psi.

The results of gas-oil relative permeability tests indicate an average gas saturation of 13.7 % at Kg/Ko = 1.0 samples from Well 1509. The average gas saturation at a Kg/Ko = 1.0 for samples from Well 3533 was 13.2 %. For samples from Well 1510, the average gas saturation was 11.1 % at a Kg/Ko = 1.0. Oil-gas test results indicate an average final gas saturation of 12.8 % at oil flood-out for samples from Well 1509. Samples from Wells 3533 and 1510 exhibited an average final as saturations of 11.6 and 10.1 %, respectively at oil flood-out. Note, since there was insufficient two-phase flow data for calculation of oil-gas relative permeability data, only endpoint data are reported.

The results using Sample 1A, Well 1509, under native-state conditions indicate an average oil recovery of 43.5 % pore volume or 57.0 % of the oil-in-place for the water-oil cycle of this test. The oil-water cycle indicate a water recovery of 30.7 percent port volume. Due to apparent plugging this sample was tested in cleaned-state condition. These results indicate a recovery of 62.9 % pore volume during the water-oil cycle and a recovery of 48.9% pore volume during the oil-water cycle.

The results of steady-state tests using crude oil at reservoir temperature for Sample 21B indicate an oil recovery of 61.7% pore volume or 70.4% of the oil-in-place during the water-oil cycle. The oil-water cycle resulted in a recovery of 36.7% pore volume of water. Samples 18B and 34B were tested in cleaned state condition, using laboratory oil. These data show an average oil recovery of 51.4 % of pore volume.

The steady-state water-gas relative permeability tests were conducted on samples 3A and 25B. These data indicate residual gas saturations that range from 29.7 to 38.9 and average 34.3 % of pore volume.

Samples from Wells 3533, and 1510 were used in these tests. Tests using samples from Well 3533 exhibited an oil recovery of 38.1% pore volume or 50.8% of the oil-in-place during the waterflood. The results test using samples from Well 1510 indicate an oil recovery of 32.6 % pore-volume or 41.6 % of the oil-in-place during the waterflood. Several samples plugged during either the waterflood or during the oil-flood test. Attempts were made to reverse the effects of core plugging and continue with the tests. This effort was unsuccessful with several samples.

These tests include formation factor and resistivity index measurements. The cementation exponents on an individual sample basis varied from 1.96 to 2.63 at NCS over a porosity range of 5.03 to 15.3. The composite m was determined to be 2.17 by regression.

Individual saturation exponents as determined by regression varied from 1.6 to 3.01 with the composite n = 2.06. At the end of the resistivity test the samples were weighed, then dried and weighed again, after correcting for the salts in solution there was reduction in the dry weights of some samples. This indicates some dissolving of minerals in the sample; this is also indicated by the n becoming smaller at the lower saturations.

The results of high-speed water-oil centrifuge capillary pressure tests indicate a composite average final brine saturation at the end of these tests was 28.6 % pore volume. The average final brine saturation of samples from Well 1509 was 25.2 % pore volume. An average final brine saturation for samples from Well 3533 was 27.7 % pore volume, and the average saturation for samples from Well 3319 was 35.6 % pore volume.

Hydrostatic pore-volume compressibility results indicate a range of compressibilities from 1.25 to 10.7 x E-06 vol/vol/psi at 7,500 psi. Samples from Well 1509 exhibited compressibilities from 1.25 to 4.79 x E-06 vol/vol/psi at 7,500 psi. Similar results were found for Sample 2D from Well 1510 which had a compressibility of 4.95 x E-06 at 7,500 psi. However, samples from Well 3319 (Samples 26C and 39C) exhibited higher compressibilities at 7,500 psi (10.7 and 8.00 x E-06 vol/vol/psi).

The results of viscosity measurements and brine compositions for fluids used in this study are provided in Section 8 of this report.

Section 1 of Volume 2 of this report presents the results of high-pressure mercury-injection capillary pressure tests using trimmed end pieces provided. The results of these tests include capillary pressure, pore throat size histograms, and height above free water calculations.

Test Procedures

Sample and Fluid Preparation

The samples used in these tests were in a native-state condition and provided by Fina Oil andChemical Company representatives. As received, each sample was stored within a sealed glass bottle, submerged under stock tank oil, and cushioned with a layer of sand. Forty-six samples were selected for screening tests as requested by Fina. The samples selected for testing were removed from the jars, labeled with the appropriate sample number, and then mounted in individually heated Hassler-type core holders and heated to 110° F. A net confining pressure of 500 psi was applied to each sample. After reaching temperature and pressure equilibrium, the samples were flushed with filtered crude oil while maintaining a temperature of 110° F. A 100 psi backpressure was established to remove any gas that may have been present. After the flushing step was completed, oil permeability was measured. The oil permeabilities were used to screen the samples for further use in this special core analysis study. Note that all samples labeled as "A" samples, i.e. 1A, 2A, 3A, etc. are from Well 1509, "B" samples are from Well 3533, "C" samples are from Well 3319, and "D" samples are from Well 1510.

Fina representatives provided the stock tank oil used in these tests. Upon receipt, the oil was de-watered using separator funnels. Placing a weighed amount of crude oil into Dean-Stark type toluene distillation apparatus to measure the water volume checked the water content. The water content, after the de-watering step, was found to be satisfactory for these tests. After the de-watering step, the oil was loaded into transfer vessels and an attempt was made to filter the oil through 0.45-micron glass filters. The oil plugged the filters at room conditions, so the vessels were placed into an oven at 110° F. Oil was again filtered in a stepwise manner through 1.0 and 0.45 micron glass filters with more success. After the filtering process was completed, the oil viscosity and density were measured at several temperatures. Note that all filtering and transferring of the crude oil during these tests were performed in closed vessels to minimize the loss of light hydrocarbon components in the oil.

Fina representatives provided the composition of the brine used in these tests. This brine was used for unsteady-state gas-oil / oil-gas tests, reservoir condition unsteady-state water-oil / oil-water tests, absolute brine permeability measurements, and pore volume compressibility tests. After consultation with Fina representatives, a second brine (a high sulfate brine) was used in centrifuge capillary pressure tests and steady-state water-oil / oil- water tests. The second brine was used to prevent dissolution of anhydrite. The viscosity and density data of these fluids and the composition of test brines are provided in Section 8 of this report.

Gas-Oil / Oil-Gas Relative Permeability Tests

Native-State Tests

The 1 ½-inch-diameter native-state samples used for these tests were placed in core holders and dynamically flushed with stock tank crude oil to remove any gas which may have been present. After flushing, the permeability to oil was measured while maintaining the prescribed net confining pressure. The electrical resistivity of the sample was then measured and recorded. The samples were then gas flooded by injecting humidified nitrogen at a constant pressure, while elapsed time and incremental volumes of produced oil and gas were recorded. Relative permeability was calculated from the production data by using the theory of Weige and Johnson-Bossler-Naumann; SPE #1023-G January 1959, which relates relative permeability with core end saturation. Following the gas-flood tests, oil-gas relative permeability tests were performed. The samples were injected with oil under constant rate conditions. During the oil-flood, measurements of incremental volumes of oil and gas were attempted. After the production of gas ceased, the permeability to oil at oil flood-out was measured. After these tests, the electrical resistivity of each sample was measured again and recorded.

Cleaned-State Tests

Samples selected for cleaned-state tests were previously used in other tests described in this study. Upon selection for testing, the samples were vacuum and pressure saturated with test brine. The samples were then mounted in Hassler-type core holder, subjected to the prescribed net confining pressure, and flushed with a 27 cp mineral oil to a near-irreducible water saturation (Swi). After reaching Swi, the oil permeabilities were measured. The samples were then gas flooded by injection of humidified gas at a constant pressure, while elapsed time and incremental volumes of produced oil and gas were recorded. Relative permeability was calculated from the production data by using the theory of Weige and Johnson-Bossler-Naumann; SPE #1023-G January 1959, which relates relative permeability with core end saturation.

Steady-State Water-Oil/Oil-Water Relative Permeability Tests

Native-State Tests

The samples selected for these tests were placed in a core holder designed for steady-state flow measurements. The cell is equipped with outer flow sections of permeable sandstone and the core samples were placed between the outer sections using Kleenex to provide capillary continuity across the rock assembly. Special pressure taps provided a way to measure flowing pressure differentials across the test core. The core holder and sample were heated to 110° F for these tests.

After measurements of an effective oil permeability, using stock tank oil containing iododecane, the relative permeability test was begun using an oil/water injection ratio of approximately 20:1. Note that the test brine for this project was high sulfate brine consisting of calcium sulfate, sodium sulfate, magnesium sulfate and strontium sulfate. The oil used for these tests was the stock tank oil provided by Fina Oil and Chemical Company personnel.

Stepwise changes in subsequent injection ratios and finally only water injection produced an increasing water flood-out step, the procedural steps were reversed and the samples were tested for steady-state relative permeability with oil saturation increasing.

Throughout each test, the oil and water saturation was determined using an X-ray absorption technique. Following the flow test, calibration scans were made. First, after cleaning, the test core was fully saturated with oil in preparation for a required X-ray scan at So = 100 percent. Following cleaning with pentane and air drying, a second calibration scan was obtained at Sw = 100 percent. Note that the test samples were not removed from the steady-state core holder during any of the above steps and that sample cleaning was accomplished by solvent injection. The determinations of water and oil saturation were then made using the following equation.

$$S_w = 1 - S_0 = \frac{\log T_x - \log T_0}{\log T_w - \log T_0}$$

Where:

Tw = radiation transmission at Sw = 1.0
To = Radiation transmission at So = 1.0
Tx = radiation transmission at any water-oil saturation.

The difference between Tw and To was greatly increased by adding an X-ray absorber, iododecane, to the oil. The concentration was 10 volume percent. During scan the X-ray head (i.e., X-ray tube and scintillation counter) traverses the stationary core at a rate of 2.8 cm. per minute.

Saturation at any location along the core can be determined. However, these values usually are averaged and reported as a single saturation value because the test samples are relatively short.

Cleaned-State Tests

Cleaned state tests were performed following the native state tests. The cleaned and dried samples were fully saturated with the sulfate test brine and then flushed to Swi with 27 cp mineral oil. Each sample was then flushed with 1.4 cp laboratory oil containing iododecane. The procedures used in these tests are the same as described for native state-tests.

Steady-State Water-Gas Relative permeability Test Procedures

The samples used for these tests were fully saturated with 100,000 ppm sodium iodide brine. Next, each sample was flushed to near-irreducible water saturation (Swi) using a 25 cp mineral oil. Next, the samples were flushed with 1.5 cp mineral oil to remove the 25 cp oil. Pentane was injected into each core sample to remove the mineral oil. Humidified nitrogen was flushed through the core to remove the pentane, thus leaving the core sample at near-irreducible water saturation plus gas saturation. The water-gas steady-state relative permeability tests were performed using a pore pressure of approximately 200 psi to minimize gas expansion effects during the tests. After measurement of gas permeability at Swi, the relative permeability test was started using a water-gas injection ratio of approximately 1:4,000. Stepwise changes in subsequent injection ratios produced an increasing water saturation condition that ends at trapped gas saturation. All data were collected at conditions of flow equilibrium. Gas and water saturations were measured using an X-ray absorption technique. This technique is described below:

Water-Gas Saturation Calculations

X-ray scans for calibration purposes were made when the core contained only gas and then water. These calibration scans provided a way to measure all partial water-gas saturations. The determination of core gas and water saturation was made using the following equation:

$$S_g = (1 - S_w) = \frac{\log T_x - \log T_w}{\log T_g - \log T_w}$$

Where:

Tg = radiation transmission at Sg - 1.0
Tw = radiation transmission at Sw - 1.0
Tx = radiation transmission at any partial gas-water saturation.

The difference between Tg and Tw is greatly increased by addition sodium iodide, an X-ray absorber, to water. During a scan, the X-ray head (i.e., X-ray tube and scintillation counter) traverses the stationary core at a rate of 2.8 cm. per minute. Saturation at any location along the core can be determined. However, because the cores are short, these values usually are averaged and reported in a single saturation value.

Reservoir Conditions Unsteady-State Water-Oil / Oil-Water Relative Permeability Test

The 1 ½-inch-diameter samples used for these tests were previously used in unsteady-state gas-oil relative permeability tests. Upon receipt, the samples were mounted in Hassler-type core holders and electrical resistance measurements were obtained at the prescribed overburden pressure. The samples were then place in an oven at 110° F and allowed to reach temperature equilibrium. The net confining pressure was also raised to the amount prescribed for each sample. After reaching test temperature, the samples were flushed with stock tank oil and the oil permeability was measured. The samples were then waterflooded with test brine using constant pressure techniques. During the waterflood tests, incremental oil production, time, and pressure drop were periodically measured and recorded. After water flood-out, brine permeability was measured in the forward and reverse flow directions to detect the presence of mobile fines. The procedure was then repeated using oil as the displacing phase instead of water. Increment volumes of water and oil were collected during the oil-flood test. After reaching oil flood-out, a permeability to oil was measured. After the oil-flood, the samples were removed from the oven and electrical resistance measurements were obtained after reaching temperature equilibrium at room conditions. The samples were then removed from the core holders and placed in Dean-Stark type toluene distillation apparatus to determine core liquid saturation. The samples were then cleaned in toluene for 24 hours before drying in an oven at 230° Fahrenheit for 48 hours. After drying, air permeability and helium porosity were measured at the prescribed net confining pressure. Unsteady-state water-oil / oil-water relative permeability test results were calculated from production data using the theories of Weige and Johnson-Bossler-Naumann; SPE #1023-G January 1959, which relate relative permeability to core end saturation.

Room Conditions Unsteady-State Water-Oil Relative Permeability Tests

A Fina Representative selected the 1½-inch-diameter cleaned-state core samples used in these tests. Sample Nos. 7B, 24B, and 26B were mounted in Hassler-type core holders and flushed with a 27 cp. Laboratory mineral oil. After flushing the samples, oil permeability was measured at the prescribed net confining pressure. The samples were then waterflooded with test brine using constant rate techniques. During the waterflood tests, incremental oil production, time, and pressure drop were periodically measured and recorded. After water flood-out, brine permeability was measured in the forward and reverse flow directions to detect the presence of mobile fines. The samples were then removed from the core holders and placed in Dean-Stark type toluene distillation apparatus to determine core liquid saturations. The samples were then cleaned in toluene for 48 hours before drying in an oven at 230° Fahrenheit for 24 hours. After drying, air permeabilities and helium porosities were measured at 2,000 psi net confining pressure. Unsteady-state water-oil relative permeability test results were calculated from production data using the theories of Weige; Johnson-Bossler-Naumann; SPE #1023-G, January 1959 and Conway; SPE #14263, September 1985 and Miller; SPE #12, April 1961, which relate relative permeability to core end saturation.

Electrical Resistivity Measurements

Sample Preparation

Fifteen 1½-inch-diameter samples were used for the resistivity study. The samples were extracted with toluene followed by methanol in a sidearm-style soxhiet extractor to remove hydrocarbons as well as precipitated salt. The samples were then dried to a constant weight at 240 degrees F in a convection oven. Permeability to air and Boyle's Law porosity values (using helium as the gaseous phase) were measured for each sample. The samples were evacuated, then pressure saturated @ 1500 psig with a simulated formation brine prepared from formation brine analysis as provided by representatives of Fina Oil and Chemical Company. Saturations were verified gravimetrically upon removal from the saturating cell.

Formation Factor at net confining stress

Brine saturated porous plates (15 bar) were placed on the downstream ends of each sample. They were then placed in core holders and were flushed with the simulated formation brine at minimum confining stress. Flow was terminated and the net confining pressure (NCS) was elevated to the requested confining stress. Brine volume expelled was recorded and used to calculate porosity at NCS. Flow was resumed and the sample resistance was monitored until stable to ensure that ionic equilibrium was achieved. Resistance and phase angle measurements were made using an alternating current at a frequency of 1000Hz. Sample resistance data were obtained by deducting the porous plate resistance and by making a correction for the phase angle.

Formation resistivity factors were calculated from these test results. Cementation exponents (m) were calculated on an individual sample basis assuming a = 1.0 (where a is the Y axis intercept of a plot of formation Factor Vs porosity). The average m for all samples was determined by regression assuming a = 1.0.

Resistivity Index at net confining stress

At the conclusion of the formation factor testing, each sample was injected with humidified nitrogen gas at selected pressures to displace the brine through a porous plate on the downstream side of the sample. The brine volume produced at each pressure was measured volumetrically and was recorded to determine sample saturation. At each pressure, resistance and phase angle measurements were also made. Sample resistance data were corrected for phase angle and porous plates. The resistivity indices, corresponding water saturations and the saturation exponents (n) were calculated from these test results. At the conclusion of the tests the samples were removed from the core holders and weighed to verify the final saturations gravimetrically. These data are reported in tabular and graphical form in the resistivity section.

High-Speed Centrifuge Capillary Pressure Tests

Samples selected for water-oil / oil-water centrifuge capillary pressure tests were trimmed to the appropriate length for centrifuge tests and placed into the centrifuge apparatus under test brine. The brine used in these tests was a high sulfate brine described in Section 8. The oil saturation was decreased by stepwise increase of the rotational speed of the centrifuge. The volume of oil displaced at each speed was volumetrically measured after attaining saturation equilibrium. Following this, the samples were tested for oil increasing centrifuge capillary corresponding core end saturations were calculated.

Hydrostatic Pore Volume Compressibility Test

The 1½-inch-diameter core samples used these tests were cleaned in hot toluene and alcohol and placed in an oven and dried at 240° F overnight. After drying, the air permeability and helium porosity of each sample was measured at standard conditions of 400 psi confining pressure. The samples were then vacuum and pressure saturated with test brine. After saturation, the samples were mounted in Hassler-type core holders and flushed with test brine while maintaining a backpressure to insure 100 percent brine saturation. The samples were placed in an oven at 90° F to insure constant temperature conditions. After allowing the samples to stabilize at a 500 psi net overburden pressure, the net confining pressure was increased in a stepwise manner to 1,000, 3,500, 4,500, 5,500, 6,500, and 7,500 psi. The fluid expelled from the core was measured after each pressure increase, and these data were used to calculate the percentage of pore volume reduction at each met overburden pressure. Hydrostatic pore volume compressibility was calculated from the pore volume reduction data. During these series of measurements, the pore pressure was zero.

High Pressure Mercury Injection Capillary Pressure Tests

Trimmed end-pieces from the samples used in other special core analysis tests were received from Fina representatives. These samples were trimmed to the appropriate size for mercury injection tests and then cleaned in hot toluene and alcohol. After cleaning, the samples were dried in an oven at 240° F. The samples were placed in a desiccator to cool after the drying step. Helium porosity measurements were obtained using a modified Boyles Law helium porosimeter before mounting the samples in the mercury injection apparatus. Mercury was then injected into the sample using pressures that ranged from 1 to 60,000 psia. From the resulting data, capillary pressure relationships and pore throat-size distributions were computed.

Hydraulic Fracture Design

Analysis of the open-hole well log data and the rate-pressure data from the hydraulic fracture jobs performed on the 10-acre infill wells at NRU indicates that only minor adjustments may need to be made before future wells are fracture-stimulated. Overall, the HF designs performed by the service companies resulted in stimulations with excellent conductivity. By utilizing the available core, well log, and rock-log data, we were able to improve the targeting of the productive intervals within the three major Clear Fork intervals. By using three separate fracs in the majority of the wells we obtained better fracture penetration and improved conductivity.

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/Clear Fork 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 appear to act as source beds for the higher quality reservoir rock. These intervals include:

Lower Clear Fork:	MF4 and MF5 zones	(±7,000 to 7,200 ft)
Middle Clear Fork:	MF1A, MF2, and MF3 zones	(±6,350 to 6,500 ft, and ±6,750 to 6,900 ft)
Upper Clear Fork:	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 both CO2 foam fracs and conventional cross-linked borate fracs using a new premium frac fluid on an equal number of new wells, with 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 carrying capacity

polymer specific enzyme breaker aids in post-frac cleanup
90% of original fracture conductivity retained

Pre-frac cleanup acid jobs have been performed to remove near-well damage using between 1000 and 3000 gallons of 15% acid. Most intervals have been perforated for limited-entry fracturing (>2bbl 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 has ranged from 25,000 gallons of fluid and 42,000 lbs of sand to 76,000 gallons of fluid and 157,000 lbs sand. Both 16/30 and 20/40 Ottawa sand were utilized as proppants. Resin-coated sand was 'tailed-in' for most frac jobs to reduce sand flowback during production. The conventional fracs have been flowed back immediately at 1 barrel per minute to induce fracture closure, while the foam fracs have been shut-in 2-5 days after stimulation to allow the CO2 to migrate into the formation.

All jobs have been radioactively traced to estimate vertical fracture propagation. Using this information, we have been successful in avoiding fracturing down into an underlying water zone in the Lower Clear Fork, and we have been able to avoid any fracture communication between stages. All hydraulic fracture jobs were designed to yield fracture half -lengths of approximately 200 ft.

Evaluation

Post-frac pressure transient tests performed over specific completion intervals indicate that we are obtaining fracture half-lengths between 80 and 150 ft with average radial flow skin factors approximately -5.0. However, as these tests were short-term post-frac pressure drawdown tests performed on pumping wells as they were cleaning up, the accuracy of the results could be uncertain.

Material balance decline type curve analyses performed on each new producing well after six to twelve months of production indicated that the average fracture half-length was slightly over 200 ft, and that the average near-wellbore skin factor was about -5.7. These values compare extremely well with the design criteria for the frac jobs.

Rock Properties

We were able to record full-wave sonic logs on most of the 10-acre infill wells. Using the compressional and shear travel times and the bulk density obtained from well logs, we calculated rock mechanical properties such as shear modulus, bulk modulus, Young's modulus, and Poisson's ratio.

In many cases, we were unable to get good fracture closure pressures from the rate-pressure data obtained from the frac jobs performed to date. Even for wells that were treated with conventional borate crosslinked fluids and force-closed, it was often difficult to pick a unique value for closure pressure as an insufficient amount of data was recorded during flowback. For the most part, we know that the fracture closure pressure for each individual zone is between 4000 and 5000 psi. Fortunately, we could use the available open-hole log data to obtain good estimates for both closure and initiation pressures.

The reliability of this data depends primarily on the difference between the static and dynamic values for bulk modulus, Young's modulus, and Poisson's ratio that are used to calculate both closure and initiation pressures. The well-log derived data is considered dynamic data due to the method in which it is measured. The input required for fracture design is static mechanical property data. We plan to obtain the lab data required for this comparison by performing tests on approximately 30 core samples in the near future. However, it would appear that the dynamic full-wave sonic data used to calculate closure pressure yields results that compare very well with what we have noted from the frac jobs. This is not unexpected as the dynamic and static mechanical properties for harder (carbonate) rocks such as the Clear Fork tend to be similar, while for more friable rock (sandstone), the static and dynamic properties can differ greatly.

Once we are certain of the relationship between the static and dynamic properties, we can then build transforms between typically-recorded open-hole log data (such as gamma ray and bulk density) and the rock mechanical properties--and no extravagant log suites will be required to obtain data for frac designs. Due to the fact that there are no extreme variations of rock mechanical properties throughout the Clear Fork section, we have already recorded sufficient full-wave sonic data to design fracture treatments throughout the Unit.

The major problem in an active waterflood environment is to get an accurate handle on reservoir/pore pressure, since it is also required to estimate both the fracture closure and initiation pressures. In many areas of the Unit, pore pressure can vary greatly due to uneven waterflood support. The Formation Test data obtained during the initial 10-acre infill drilling program was a great data source for estimating pore pressure across the Unit. On a related topic, it is interesting to note that for the Tract 35 wells in which we obtained relatively poor full-wave sonic data (NRU 3533, 3537, and 3538), we also had trouble fracture-treating the wells. The sonic data may have been adversely affected by gas coming out of solution from high pressure water flows known to exist in the Lower Clear Fork interval. These same flows could have adversely affected cementing and fracturing operations.

We were able to estimate values for fracture closure pressure and fracture initiation pressure for each zone of every well utilizing the available open-hole log data. Areal maps were also constructed based on the mean values for closure and initiation pressure for each completed interval in every well. The following relationships were used:

$$\text{Fracture Initiation Pressure, FIP} = 2*\left[\left(\frac{\lambda}{1-\lambda}\right)*(p_{ovbn} - \alpha p_{pore})\right] + \alpha p_{pore} + \sigma_{tensile}$$

$$\alpha = \text{Biot's constant} = 1 - \frac{K}{K_{ma}}$$

$$\text{Fracture Closure Pressure, } \sigma_x = \left[\left(\frac{\lambda}{1-\lambda}\right)*(P_{ovbn} - P_{pore})\right] + P_{pore}$$

for which:

λ = Poisson's Ratio
P_{ovbn} = Overburden Pressure » 1.0 psi/ft
P_{pore} = Pore Pressure » 0.45 psi/ft (Clear Fork - current conditions)
$\sigma_{tensile}$ = Tensile Strength, psi/ft (negligible)
K = Bulk Modulus, psi*10^6
K_{ma} = Bulk Modulus of Pure Matrix, psi*10^6

Note, that after fracture initiation, that Biot's constant in the direction of least principal stress (horizontal, in this case) is no longer a function of rock compressibility, and may be assumed to be equal to 1, and therefore, is not included in the expression for closure pressure.

Therefore, for a typical Clear Fork interval, under current stress conditions, we have:

$$FIP = 2*\left[\left(\frac{0.28}{1-0.28}\right)*(1.0-[0.3*0.45psi/ft])\right]+0.3*0.45psi/ft = 0.808psi/ft$$

$$\sigma_x = \left[\left(\frac{0.28}{1-0.28}\right)*(1.0-0.45)\right]+0.45 = 0.664psi/ft$$

Net Pressure Analyses (Nolte Plots)

The calculated bottom hole treating pressures taken from the frac jobs performed during the initial 10-acre infill drilling program were utilized together with the calculated values of log-derived closure stress for each individual completion interval to construct Nolte plots. The characteristic shape of the plot gives a qualitative indication of the way in which the fracture propagated, and what its geometry might be.

Several diagnostic net pressure plots taken from SPE #14263 by Conway, et al. September 1985, of Halliburton Services, September 1985, show the different fracture geometries that correspond to specific responses on the Nolte plot. We note that for the most part, the hydraulic fracture jobs at NRU appear to be Type II (Perkins and Kern) and Type III (Penny) for which vertical fracture propagation is extensive or uncontrolled. This is what we would expect in a formation with no major barriers to vertical fracture growth. Fortunately, the vertical growth is not so rapid as to cause a premature screenout in most cases. The few jobs that did screenout prematurely were wellbore screenouts due to insufficient injection rate or pressure. In addition, some of these frac designs called for 16/30 proppant, which requires a greater fracture width than 20/40 sand (see Design Example below).

Fracture Simulation

The accurate determination of rock properties and formation stresses are extremely important parts of the overall hydraulic fracture design. However, they are far more important in areas in which there is a great variation in rock mechanical properties. If a 3-D fracture simulator is utilized to design a frac job, these properties should be input on a layer-basis, and layers with distinctly different properties (reservoir and rock) should be separated. For the Clear Fork at North Robertson, most of the interval contains layers with very similar properties. The layers possessing distinctly different characteristics usually are not extensive enough to alter (i.e., confine) vertical fracture propagation.

Example 2-D fracture simulations were performed using both the PKN and GDK models for all three completion intervals in well NRU 3534. Because we have a fairly good idea of how the fractures are propagating vertically from the work we have performed previously, we can input a good estimate of gross frac height that is a required input to the 2-D model. In addition, instead of using individual layer reservoir and rock properties, lumped or average values are input to the 2-D model. By comparing the results for NRU 3534 with the 3-D frac designs for the Lower and Middle Clear Fork intervals, we see that for the smaller LCF interval that the 2-D model agrees fairly well with the 3-D results. However, when the interval becomes larger, such as for the MCF interval, and the variations in layer properties are slightly more pronounced, the results generated by the two models vary appreciably. This indicates the importance of having a layer-by-layer reservoir description input capability, and a 3-D fracture simulator.

At the same time, changing most of the rock mechanical properties by as much as 50% will have little impact on the fracture dimensions—as long as the changes are consistent. The value input by the service company for Young's modulus is approximately half of what we calculated from the open-hole log data (another reason to do those static-dynamic core tests). They obviously felt more comfortable with a value of 5.6×10^6 than the actual value of 11.5×10^6. But this change makes little difference since they have normalized every layer so that there is no great variation in Young's modulus between layers.

Future Data Requirements

After we have performed the necessary static-dynamic core data comparison, and built a transform to utilize basic open-hole log data as described above, no further acquisition of rock mechanical properties data should be needed for the Unit wells.

If money is to be spent in acquiring useful data for frac design, we should focus on the following:

1. obtain accurate values for the leak-off coefficient and closure stress from a limited number of minifrac tests,
2. optimize the frac fluid rheology (i.e., increasing viscosity) to improve the proppant-carrying characteristics of the frac fluid, and,
3. find the proppant that meets our conductivity requirements (see below).

Design Example

From a performance and cost-effectiveness standpoint, it would appear that BJ's 35 lbm/gal Spectra-Frac G fluid will work well for hydraulic fracture jobs in the Clear Fork at the North Robertson Unit. It would also seem that a max sand concentration of 8 ppg with an 8 ppg RC sand tail-in will be sufficient for our purposes, although higher sand concentrations can be considered. The example calculations below are for the Lower Clear Fork with the following characteristics:

Depth to mid-perfs = 7050 ft
net height (pay) = 100 ft
gross height = 200ft
design fracture half-length = 250 ft
injection rate = 30 bpm
proppant = 20/40 Ottawa sand
frac fluid = 35 ppg gel
max sand concentration = 8 ppg
frac job pumped down 5.5" OD casing

1. Dimensionless Fracture Conductivity:

We want to achieve a dimensionless fracture conductivity, Cf_D, of at least 10.0, and a fracture half-length of around 250 ft. Designing for dimensionless conductivities greater than 10 will increase the cost of the frac job; however, the stimulated production rate will not increase greatly. Due to conductivity reduction caused by proppant crushing and various chemical processes, we actually need to design for a dimensionless fracture conductivity of 30.0, as long-term fracture conductivity for a sand proppant will be reduced to about 30% of the initial value. Therefore:

$$wk_f \; Cf_D \, \Pi \; \chi f k_{oil}$$

$$wk_f=(30)(\Pi)(250 \text{ ft})(0.05 \text{ md})=1178.1 \text{ md-ft}$$

20/40 Ottawa sand meets our conductivity requirements for the closure stress (4500 psi) and temperature (115°F) in this interval. Neither Jordan sand, nor Brady sand meet the conductivity requirement. A proppant should be chosen so that the conductivity requirements are met, the created fracture width is large enough to safely receive the proppant, and the diameter of the perforations is large enough to prevent premature screen-out. The diameters for each individual proppant size may be calculated as:

Proppant Diameter, in. =0.4114*((1./(small mesh**1.06))+(1./(large mesh**1.06)))

For 20/40 proppant, diameter = 0.02543 in.
For 16/30 proppant, diameter = 0.03295 in.
For 12/20 proppant, diameter = 0.04672 in.

As a rule of thumb the fracture width should be at least three times the proppant diameter.

Therefore:

For 20/40 proppant, required frac width = 0.0763 in.
For 16/30 proppant, required frac width = 0.0989 in.
For 12/20 proppant, required frac width = 0.1402 in.

Note, if we wish to use a proppant size of 16/30 or above, we must design for a fracture with a width greater than 0.0989 in. or we may screen-out.

In addition, the perforation diameter should be at least six times the proppant diameter:

For 20/40 proppant, required perf diameter = 0.1526 in.
For 16/30 proppant, required perf diameter = 0.1978 in.
For 12/20 proppant, required perf diameter = 0.2804 in.

This should not be a problem since we used 0.41 in. diameter holes on all wells, and the perforation diameter will only increase during injection due to friction-related wear.

The permeability of 20/40 Ottawa sand is 180,000 md. For this particular proppant, we will need to design for a fracture width of at least:

$$w = \frac{1178.1 md - ft}{180{,}000 md} = 0.006545 \text{ ft} = 0.07854 \text{ in}$$

Note: this is greater than our minimum width required of 0.763 in. (from above).

2. Proppant Volume Required:

Previous Clear Fork field experience indicates that for a 100 ft frac interval, the fracture will grow both up and down approximately 50 ft, therefore the gross height is approximately 200 ft for a 100 ft net height.

Proppant Volume = (2 wings)(250 ft)(0.006545 ft)(200 ft)(7.48 gal/ft^3)
= 4,895.7 gals

For $_{propp}$ = 0.38:

Lbm Proppant = (Volume)(SG Proppant)(Density H_2O)(1 -)
= (4,895.7 gal)(2.65)(8.34 lbm/gal)(1 - 0.38)
= 67.084 lbm

3. Fracture Fluid Viscosity:

We would like to have a frac fluid viscosity between 50 cp and 100 cp for perfect proppant support and to achieve a well distributed proppant pack. For previous 10-acre infill well stimulation's, viscosity was usually between 25 cp and 30 cp. We may want to try to increase viscosity to provide better proppant transport, increase fracture width and improve conductivity. Optimum results were obtained when the jobs were pumped at injection rates between 30 BPM (small jobs - LCF) and 40 BPM (large jobs - MCF/UCF).

$$\text{Shear Rate,} \quad \gamma\text{,} = \left(\frac{2n'+1}{3n'}\right) * \left(\frac{6 * q_{inj,onewing}}{h_{net} * width^2}\right)$$

Where:

n'=Power Law Index $\approx$ 0.45 for 35 ppg HPG gel

$q_{inj.onewing}$ = 30 bpm/2 = 15 bpm

width,w=0.006545 ft = 0.07854 in (see above)

h_{net} = 100 ft (see above)

Therefore:

$$\gamma\text{,} = \left(\frac{2*(0.45)+1}{3*(0.45)}\right) * \left(\frac{6*15bpm}{100ft*(0.006545ft^2)}\right) = 29{,}569 bbl/\min - ft^3$$

$$\gamma\text{,} = 29{,}569 bbl/\min - ft^3 * 5.6148 ft^3/bbl * 1\ \text{min}/60\ \text{sec} = 2767.1\ \text{sec}^{-1}$$

$$\text{Apparent Viscosity, } \mu_{app} = 47{,}880 * K' * \gamma^{(n'-1)}$$

Where:

K'=Consistency Index $\approx$ 0.04 for 35 ppg Hpg gel

Therefore:

$$\mu_{app} = 47{,}880*0.04*(2767.1\ \text{sec}^{-1})^{(-0.55)} = 24.5\ \text{cp}$$

We should then be looking for a frac fluid with properties that yield a slightly higher viscosity for future work as discussed above.

4. Tubular Design (Limited Entry Perforating):

$$P_{surf} = BHTP - P_{hyd} + \Delta P_{fric} + \Delta P_{pf}\ \Delta P_{fe} +$$

Where:

$BHTP$ = bottom hole treating pressure, psi
P_{surf}=surface injection pressure, psi
P_{hyd}=hydrostatic pressure, psi
ΔP_{fric}=friction pressure drop through tubulars, psi
ΔP_{pf}=friction pressure drop through perforations, psi
ΔP_{fe}=fracture entry friction, psi (assume negligible)
Average frac gradient for Lower Clear Fork at NRU = 0.664 psi/ft

At a mid-perf depth of 7050 ft:

$$BHTP = \text{Frac Gradient*Depth}=0.664 \text{ psi/ft*}7050 \text{ ft} = 4681.2 \text{ psi}$$

$$P_{hyd,pad}=\text{Hyd.Grad.*Depth} = 0.44 \text{ psi/ft*}7050 \text{ ft} = 3102 \text{ psi}$$

For 5.5" casing at an injection rate of 30 bpm and 8 ppg frac sand:

$$\Delta P_{fric}=\text{Fric.Grad.*Depth*Corr.Factor}$$

From SPE Monograph 12, Fig. 9-17:

$$\text{Corr.Factor} \approx 0.075556\text{*sand conc.}+1.0=1.6045$$

$$\Delta P_{fric}=0.05 \text{ psi/ft*}1.6045\text{*}7050 \text{ ft} = 565.6 \text{ psi}$$

$$\Delta P_{pf}=\frac{0.2369 * \rho_{ff} * i_{pf}{}^{2}}{d_{perf}{}^{4} * \alpha^{2}}$$

Where:

ρ_{ff}=frac fluid density, ppg
i_{pf}=injection rate/perforation, bbl/min-perf
d_{perf}= perforation diameter, in
α = discharge coefficient $\approx$ 0.9

To increase the fluid pressure within the wellbore during fracturing, and increase the chance of propagating a fracture with sufficient half-length, we will use limited entry perforating (i.e.,[3] 2 bbl/min-perf). For an injection rate of 30 bpm we would use 15 holes. A ballout acid job must be performed prior to each frac job to ensure the perf holes are open. As an example, assume 12 of the 15 holes are open after the pre-frac acid job, therefore:

$$d_{perf}=0.41 \text{ in}$$

$$\Delta P_{pf} = \frac{0.2369 * 8.46 ppg * 2.5 bbl / \min - perf^2}{0.41 in^4 * 0.9^2} = 547.3 psi$$

Therefore:

$$P_{surf}=4681.2 \text{ psi} - 3102 \text{ psi} + 565.6 \text{ psi} + 547.3 \text{ psi} = 2692.1 \text{ psi}$$

The maximum allowable surface pressure should be <u>no less than</u>:

$$P_{surf,max} = 2692.1 \text{ psi} + \text{safety factor} = 2692.1 + 1500 = 4192.1 \text{ psi}$$

The maximum bottom hole pressure during screen-out for 8 ppg sand will be:

$$P_{BH,\max} = P_{surf,\max} + \text{Hyd. Grad (8 ppg slurry)} * \text{Depth}$$

$$\text{Slurry Dens. (8 ppg)} = \frac{(8.0 lbm + 8.34 lbm)}{(8 lbm / (2.65 * 8.34 lbm / gal) + 1 gal)} = 12.0 lbm / gal$$

$$\text{Hyd. Grad (8 ppg slurry)} = 0.052 * 12.0 \text{ lbm/gal} = 0.624 \text{ psi/ft}$$

$$P_{BH,max} = 4192.1 \text{ psi} + 0.624 \text{ psi/ft} * 7050 \text{ ft} = 8591.3 \text{ psi}$$

$$\underline{\Delta P_{burst,surf} = P_{BH,\max} - P_{hyd} = 8591.3 psi - 3102 psi = 5489.3 psi}$$

For 5.5", 15.5 #/ft or 17.0 #/ft casing, this will require C-75 or better. If the safety factor were reduced to 1000 psi, 17 #/ft J-55 or K-55 would be acceptable.

The fracture initiation pressure gradient for the Lower Clear Fork is approximately 0.81 psi/ft. In order to initiate the fracture, the initial BHTP will have to be between 5150 and 5800 psi for the Clear Fork.

Reservoir Surveillance

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 downhole 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 (Dp and Dp¢) were matched on the pressure type curve, and the pressure integral and pressure integral derivative data (Dpi and Dpi¢) 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 2.4ä 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 (k 0), fracture half-length (c *f*) or pseudoradial skin factor (spr), wellbore storage (Cs or C Dx*f*), 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, 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 p when boundary-dominated (BDF) data is available and acceptable estimates of 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 DF 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 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

Conclusions From Analyses

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 Clear Fork 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 make. 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 Clear Fork 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.

Inter-well Tracer Program

An inter-well tracer program was designed for the North Robertson Unit with the objective of obtaining critical information in regards to preferential (directional) fluid flow, breakthrough time between injectors and producers, and to evaluate the potential of direct communication between injector and producer. The wells selected for the tracer program are Wells #3539 & #1504. The goal in the selection of a tracer material for the injected water was to choose a tracer that would travel through the formation with the injected water and whose behavior would mimic that of the water. There exists a number of good water phase tracers currently available, each having their own distinct advantages and disadvantages. The tracers can be divided into two main groups, chemical tracers and radioactive tracers.

The chemical tracers would include thiocyanate ion, iodide ion, bromide ion, nitrate ion, low molecular weight alcohols and various types of fluorescent dyes. Their advantages are that they are relatively inexpensive and usually can be detected at low concentrations by gas chromatography or analytical chemical methods. Their principal disadvantage is the logistics that may be involved in their use. Under certain design situations, such as large distances between wells or thick pay sections, tens of thousands of pounds of chemical may be required to obtain the minimum analyzable concentration at the producing wells. The cost associated with the transportation of that amount of chemical to location, the time involved in mixing the chemical in a base fluid and injection of the chemical into the well may over shadow the cost of the chemical itself. Under these conditions, the total cost of using chemicals as a tracer may be significantly higher than the use of radioactive materials.

Currently available radioactive tracers for waterflood applications include tritium, the radioactive isotope of hydrogen, in the form of tritiated water, thiocyanate ion labeled with carbon fourteen, and the isotope cobalt 60 in the form of cobalt hexacyanide. The radioactive tracers have the advantage that they can be identified in extremely low concentrations (parts per billion) therefore, only very small amounts need to be injected. This also allows for easier transport and injection as compared with chemical tracers. Their only disadvantages are that, due to the fact that the materials are radioactive, only trained/certified personnel can handle them and some of the analysis techniques are more costly than in the case of chemical tracers.

Of the water phase radioactive tracers, tritiated water is the preferred material and is the standard that judges all other tracers. Since it is water, it has the exact flow properties of the injected water and, therefore, will behave analogous to the injected water in the formation. This means that there will be no lagging the flood front or holdup in the reservoir. In addition, tritiated water is a beta emitter, meaning that it gives off low energy radiation, thereby requiring only very thin shielding. In fact, in the concentrations found in the produced water during a tracer test, the radiation is so low that it will not penetrate a sheet of paper. Of the water phase radioactive tracers, tritiated water is the lowest cost, easiest to detect, and has an excellent record of successful use as a water phase tracer.

The next most frequently used water phase tracer is thiocyanate ion. It behaves as a non-adsorbing anion (such as chlorine ion) in the reservoir and will travel through the reservoir without loss. It can be used in a normal chemical form, as discussed above, or a radioactive carbon fourteen atom can be substituted for the carbon twelve atom. In this form it is known as labeled thiocyanate. This substitution makes it possible to analyze for the tracer at very low concentrations as is done in the radiocarbon dating on archaeological specimens. The main advantage of carbon fourteen labeled materials is that only small amounts are required for tracer applications. For example, 10 Ci of labeled thiocyanate would produce approximately the same detectable concentrations as several thousand pounds of thiocyanate in the normal chemical form. The main disadvantage of the labeled thiocyanate is that the analysis is more complicated, and thereby more costly than the analysis for chemical thiocyanate.

The third most widely used radioactive water phase tracer is cobalt hexacyanide. It is a gamma emitter and therefore has a slightly higher energy level than tritiated water. It is extremely stable at higher temperatures and due to its anionic nature will not be adsorbed onto the clays on the formation face. It has all the advantages of the other, previously discussed, water phase radioactive tracers. Its main disadvantage is that due to the analysis technique used, larger samples are required than with the other radioactive tracers.

In selecting the best materials to be used as tracers for a project, the following areas are always considered:

1. Environmental safety
2. Detectability
3. Stability in the reservoir
4. Economics

During the design process for the tracer program, sensitivities are performed to assure that the peak concentrations predicted at the producer wells never exceed the NPC unrestricted discharge limit for the subject tracer. In other words, the levels allowed by the NPC in drinking water. This guideline is used for both chemical and radioactive tracers. The end result is that tracer quantities were chosen so that the produced fluids will be non-hazardous and detection levels will be within an effective analytical range even when assuming wide variations in flow patterns.

For the investigation of possible communication in each pattern it is recommended that one chemical and one radioactive inter-well tracers be used. Both of the recommended tracers, tritiated water and fluorescent dye, are good water phase racers, as discussed above, and when used in combination can give additional reservoir information not available when using only a single tracer. The combined use of these tracers allows the distinguishing between communication down a fracture and communication through a high permeability layer. This can be extremely important as the exact cause of the communication will dictate the type of workover required to shut-off the communication.

The exact quantity of each tracer to be used is based on the distance between injectors and producers, the volume of injected water treated, the permeability distribution existing in the reservoir, the analytical limits of the tracer and mixing which occurs in the reservoir. A streamtube type simulator was used to model the flow of tracer in each formation layer. This streamtube simulator was used to calculate the amount of each tracer material required at the injector in each pattern area to result in a detectable concentration at the producing wells surrounding the subject injector.

The reservoir properties in each of the pattern areas were assumed to be the same except for the net and gross thickness of the Clear Fork formation. These properties are summarized in the following table:

Reservoir Property	**Pattern Area #1 (WIW#1504)**	**Pattern Area #2 (WIW#3539)**
Gross Thickness	565 feet	300 feet
Net Thickness	430 feet	250 feet
Avg. Porosity	7.5%	7.5%
Avg. Permeability	1.5 md	1.5 md
Permeability Range	0.001-100 md	0.001-100 md
Avg. Water Saturation	60%	60%

The initial set of simulation runs were based on "average" Clear Fork reservoir properties for each well and actual injection and producing rates in each pattern. The first case in each pattern area was run using the total net pay thickness. A sensitivity was also run using only the percentage of net pay taking fluid in each injection well. This thickness was determined from analysis of the injectivity profiles run on each subject injector. Table No. 1 summarizes the results of these base case and model sensitivity cases.

MODEL PROPERTIES	PATTERN AREA #1		PATTERN AREA #2	
Kavg (md)	1.5	1.5	1.5	1.5
Porosity (%)	7.5	7.5	7.5	7.5
Sw (%)	60	60	60	60
Total h (ft)	430	235	250	50
Dykstra-Parson's Permeability Coefficient (v)	0.82	0.82	0.82	0.82
Injection rate (bwipd)	67	67	10	10
Producing rate (bfpd)	60	60	229	229
Tritiated Water (Ci)	**1.9**	**1.0**	**20**	**3.0**
Breakthrough Time (days)	**716**	**391**	**2411**	**482**

Table No. 1: Summary of Model Simulation Runs Showing Thickness Sensitivities

Based on these model runs (and others) it was recommended that 1 curie of tritiated water was injected into well #1504 and 3 curies injected into well #3539. This was designed to allow for reasonable breakthrough times and result in detectable tracer concentrations at the offset producing wells. The tritiated water was injected into both wells on March 24, and the sampling process was begun. As of the report date, no tracer has been detected in offsetting producers.

Sampling Program

Samples of the produced water were analyzed prior to injection of any tracer to obtain a background reading of existing chemicals in the reservoir. Following the injection of the tracer, samples of the produced water are being taken at predetermined intervals and analyzed for the presence of tracer.

The following sampling schedule is being followed for the inter-well tracer program proposed above:

Time (weeks)	Sample Frequency (per well)	Number of Samples (per well)
Base	1 sample	1
1	1 per day	7
2-4	3 per week	9
5-20	1 per week	16
21-78	2 per month	29

Total samples per well for 1.5 years: 62

The tracer will remain in the reservoir for an indefinite period of time. The presence of watered out intervals, fractures, poor cement bond, or faults in the field can lead to rapid breakthrough. For this reason it is extremely important that samples be taken frequently immediately after (if not during) tracer injection. Less frequent samples are necessary as time goes on.

Every third sample will be analyzed for detection of the tracer. If tracer is detected, then back samples will also be analyzed to determine the exact time of breakthrough. Following this schedule, there would be a total of 62 samples/ 21 analyses per well for the first 1.5 years. AS of the time of this report, there have not been any indications of tracer breakthrough in any of the samples taken at the 12 offset producing wells. Sampling is continuing according to the original schedule.

Magnetohydrodynamics

One of the major operational problems at the North Robertson Unit is the existence of paraffins and scales in both the produced and injected fluids. In an effort to reduce the amounts of both paraffin and scale in these fluids, magnetic fluid conditioning tools were placed in strategic locations to test their effectiveness in several different situations. In early March, tools were placed in the production string on 3 producing wells, Nos. 1203, 2228 & 604, on Injection well #3101, and on the 6" water transfer line running from Battery #3 to the central injection facility. Millipore filter tests were run prior to installation at these locations in order to monitor effectiveness. The first set of test data are provided at the conclusion of this section.

Paraffins in crude oil formations normally are in a liquid state, but precipitate from the crude when the equilibrium temperature and pressure change. As crude oil comes up the production tubing, the majority of cooling occurs in the flowing fluid as gas breaks out of solution. This cooling effect causes paraffin crystals to form in the flowing liquid. This is defined as the cloud point. Because of their tacky nature, they often adhere to and build up on tubing walls. Where flow lines are exposed to significantly colder outside temperatures, the pipe wall itself can also become a site for deposition.

Paraffin formation and deposition take place by four mechanisms: chemical, mechanical, electrical and thermal. A properly designed magnetic system can alter the chemical, mechanical, and electric properties of the crude as it passes through the magnetic fields. These changes have the effect of also altering the thermal (cloud point) mechanism.

Magnetic Fluid Conditioning tools work by directing fluids through strong permanent magnetic fields within the tool. This alters the physical characteristics of crude by increasing the solubility of the oil and decreasing the cloud point (up to 60 degrees F.), pour point and viscosity. The altered growth pattern of paraffin and scale crystals decreases the sediment and emulsions formed by the paraffin and water molecules locking together which in turn inhibits the buildup of solids in the well and production equipment.

Crude oil is a hydrocarbon/mineral mixture with varying chain lengths and electrical potential. In its natural state there is randomness to the orientation of the molecules. A magnetic field will interact with any substance that carries a charge in any fluid. As charged crystal nuclei pass through magnetic fields, they encounter considerable forces that interact with them. Applying Faraday's law of electromagnetism and colloidal physics, as ironically charged minerals and asphaltenes flow through the MFC, the electrical charges on the crystal nuclei and the growing crystallites are affected at the surface. This alters the growth of the crystals in general and on specific planes as they are oriented in one direction and tumbled, allowing them to cluster together to form colloids on a microscopic level. This then allows nuclear seeding for the paraffins.

The total combined surface of the colloids collectively is exponentially greater than the casing surface of the production tubing causing the paraffin deposition to be on that of the colloids and less free paraffins in the crude oil to cause a paraffin zone. While in this paraffin coated colloidal state the surface tension and the mechanical adhesions of the sticky paraffins to one another and to the tubulars are reduced.

From recent, limited, observations in the field, MFC appear to affect the adhering properties of paraffin particles that form in the flowing oil. Paraffin particles formed in untreated oil appear to be gooey and tacky. Those in treated oil were more brittle and less tacky. The end result is a change in solubility and a lower cloud point (temperature at which paraffin starts to come out of solution). In addition, the temperature of deposition, viscosity, and pour point are altered, all of which serve to inhibit paraffin and scale formation. A good analogy is to think of powder sugar and how it tends to stick to everything but when it is clustered together to form granular sugar it tends to roll off surfaces.

Over time the colloids of the treated crude will return to its normal state of randomness so close placement of the MFC uphole to where paraffin normally starts to form is essential to help the crude oil retain the colloidal effect and maintain the tubulars free of paraffin. Typically only one unit installed below the deepest paraffin zone will normally yield excellent results. Under certain conditions, multiple paraffin zones or high volume wells, that cause the colloids to break up and have return to its natural state, an additional MFC unit may be required to reform the colloids.

The only test data available to date is on the 6" transfer line from Battery #3 to the central injection station. Prior to installation, the following volumes were measured on millipore tests using a standard .45 micron filter:

Jan 7 - 180 ml
Jan 8 - 240 ml
Jan 9 - 300 ml
Jan 23 - 200 ml
Mar 3 - 190 ml

Following the installation of the magnetic fluid conditioners, the following results were obtained:

April 6 - 410 ml
April 21 - 380 ml

Also, the pressure required to move fluids through this line from the battery to the injection facility has decreased approximately 10 psig since installation of the magnets.

The magnet installation on Injection Well # 3101 has apparently had no effect on performance. Injection rates and pressures have remained constant. However, Well # 604, one of the 3 producing wells which had the magnets installed in the production string had a rod part and required that the rods and downhole pump be pulled out of the hole. Surface inspection of the rod string indicated no presence of paraffin. In the past, this well has had severe paraffin problems.

Deterministic Modeling/Simulation

The following work has been completed to-date for the reservoir simulation portion of the North Robertson Clear Fork 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)

The following work remains to be done for the reservoir simulation portion of the North Robertson Clear Fork study:

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

Section 362 (Completion: End of February 1998)

2) Update of Reservoir Characterization for New Laboratory Data and Data from New Wells

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

Updating the Rock-Log Model

Extensive work has been done on updating the rock-log model using data from the newly drilled wells in the project area. The well log database was reviewed and compared to the data obtained from the new wells. Necessary edits were made, and the entire data set was normalized.

Porosity data from the new cores demonstrated some disparity with the porosities calculated from logs using the original algorithms of Phase I. The porosity algorithm used in Phase I was subsequently modified using the new data. This resulted in an overall decrease in calculated porosity, but produced a closer agreement with the core data.

The algorithm used in the calculation of water saturation was also modified. This involved varying the value of the cementation exponent "m" by rock type based upon the new electrical properties data obtained from the core. The value of "m" was varied as a function of porosity and rock type. Type 1 rocks have values of approximately 2 while Types 2, 3, and 4 have values in the range of 2.1 to 2.3. The saturation exponent "n" values measured in the new cores did not appear unusual, so these were not varied, as was "m".

Solutions were then run on the log suites of the 122 wells in the Phase I database and on 10 of the new 10-acre wells. The new solutions were then loaded into the deterministic model being developed by SSI. The remaining 10-acre wells are still being worked on, and will be integrated with the full data set when finished.

CONCLUSION

The use of specialized techniques, such as geostatistical modeling, rigorous decline curve analysis, reservoir rock typing and special core analysis is proving to be a great aid in the selection of infill locations at the North Robertson Unit. The results of the eighteen (18) wells which were drilled as part of this project are significantly better than previous infill wells, which were drilled with less regard to reservoir performance or characterization. Other technologies, such as magnetic flow conditioners and inter-well injection tracers, should also aid in the production and operation of these wells. These new technologies can help to counteract for the complex nature and high degree of heterogeneity present in low permeability reservoirs such as the North Robertson Unit, and provide better data for use in developing an accurate 3-D simulation model.

PUBLICATIONS AND PRESENTATIONS

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 Glorietta Formations, North Robertson Unit, Gaines County, Texas."*

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

- Oral presentation

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