QUARTERLY TECHNICAL PROGRESS REPORT

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

INSTRUMENT NO. DE-FC22-94BC14989

NORTH ROBERTSON UNIT DEPARTMENT OF ENERGY CLASS II OIL PROGRAM PROJECT

REPORTING PERIOD: 12/13/96 TO 3/12/97

This Quarterly Progress Report summarizes the technical progress of the project from 12/13/96 TO 3/12/97.

ACTIVITY II.1 - MANAGEMENT AND ADMINISTRATION

PROJECT MANAGEMENT AND ADMINISTRATION - *TASK II.1.1*

Project Status

A total of 18 wells, 14 producers and 4 injection wells, were drilled and completed during the Field Demonstration portion of the project. These 18 wells are all currently in service, with the producing wells going on-line between May and September 1996, and the injection wells going into service between August and December 1996. Current Unit production is approximately 3,100 BOPD, of which approximately 800 BOPD is being contributed from the 14 Project 10-acre producing wells (Figure 1). A revision in the Statement of Work was approved to allow for the drilling of additional 10-acre infill wells or injection well conversions as budget constraints allow.

ACTIVITY II.2 - FIELD DEMONSTRATION

IMPLEMENTATION OF FIELD DEMONSTRATION - *TASK II.2.1*

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 up by the Project Geologist, Brian Pregger. The core was originally scheduled to be cut continuously through the entire

Clearfork section, and in most instances entire intervals were cored. However, some sections were unable to be cored due to mechanical difficulties caused by extremely long core times. Several intervals had core times in excess of 200 minutes per foot. The continuous core allows foot by foot comparisons of reservoir quality, rock type, and depositional environment, which all aid in accurate modeling of fluid movement within the reservoir.

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 ½ of the core has 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.

FIELD OPERATIONS AND SURVEILLANCE - *TASK II.2.2*

Operations

All new wells are being operated in accordance with Fina Oil & Chemical's normal operating procedures.

Reservoir Surveillance

The reservoir surveillance dataset is currently being updated by recording pressure transient and cased-hole well log surveys on many of the same wells from which data were acquired during Budget Period I. Pressure transient tests (pressure buildups and pressure falloffs) are currently being recorded to monitor pressure trends in the infill areas, and cased-hole pulsed-neutron logs are being run to monitor changes in water saturation in the near-wellbore area.

Reserves - Incremental vs. Accelerated

Early results indicate that approximately 65% of the production from the new infill wells is incremental, and approximately 35% may be acceleration of existing reserves. The new wells account for approximately 900 STBO/D of the total Unit production, and the amount of incremental production since the Field Demonstration was implemented is between 600 and 700 STBO/D. On an individual well basis, some of the additional production in Section 329 of the Unit appears to be due to acceleration of existing reserves, while most of the additional production in Sections 326 and 327 appears to be incremental. These trends were predicted prior to drilling on the basis of differing reservoir rock types that occur in the two areas. The Section 329 infill area is dominated by grainstone shoal facies with fairly good permeability and porosity characteristics. The reservoir within Sections 326 and 327 is dominated by lagoonal facies with good storage capacity (porosity), but relatively lower permeability and connectivity. We will continue to monitor and report individual well producing characteristics in an effort to quantify incremental reserves added via infill drilling.

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 (varies in Unit)	(±6,150 to 6,200 ft)

We utilized three-stage completion designs to keep the treated intervals between 100 and 250 ft. We performed both CO_2 foam fracs and conventional cross-linked borate fracs. All well's rates have held up extremely well over time for both hydraulic fracture designs. The major factor controlling initial potential appears to be confinement of the vertical completion interval and localized reservoir quality.

ACTIVITY II.3- INTEGRATION/VALIDATION

VALIDATION OF RESERVOIR CHARACTERIZATION - *TASK II.3.1*

Thin Section Analyses

Numerous thin sections of the cored intervals have been prepared. Plans are to use information from these thin sections to enhance our understanding of pore size, pore distribution, rock type, and depositional environment.

Depositional Environments

Additional refinements were made to the depositional environment model based on data from recently acquired core taken from the latest 10-acre infill wells. The planned coring program and a cursory description of these cores have been completed. This represents 2,730 ft of core in four wells. The preliminary depositional environments described from this new data are as follows:

<u>Open Shelf</u>

Open Shelf - general
Fusilinid Shoal
Shoal - general

Inter-Shoal

Reef
Reef Center
Reef Talus Apron
Reef Debris Apron

Open Lagoon

Restricted Lagoon

Island Complex
Island Center/Salina
Near Island Beach
Algal Mat
Outer Island Beach

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

Supratidal

There are several significantly new features not noted from previous core descriptions. The first is the presence of large patch reefs and associated porous debris aprons in the Lower Clearfork within Section 327. Previous work suggested that a 'shelf' edge existed to the east of Section 327, and that the large reefs would only exist along this shelf edge. This new core information implies that there is no shelf edge as such, just patch reefs and debris aprons scattered across the Unit. This information 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 reservoir 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 piece of information concerns the MF3 layer (± 6,850 ft) of the Middle Clearfork that has been reinterpreted 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 as a series of small islands and associated carbonate sand beaches. This information is of important economic significance, because there is more natural fracturing in the MF3 zone than previously thought. Further analyses will determine the interconnection and influence of this fracturing from solution collapse breccias.

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 are being 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 have been preserved in degassed lease crude oil since they were taken from the well, and relative permeabilities and capillary pressures are being 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.

The unsteady-state relativity permeability and capillary pressure tests have been completed. Steady-state relativity permeability, electrical property, and compressibility tests are either in progress or will start soon, and should be completed within 8 weeks.

VALIDATION OF RESERVOIR MANAGEMENT ACTIVITIES AND PERFORMANCE ANALYSIS - *TASK II.3.2*

Material Balance Decline Curve Analysis

Early production data from new 10-acre infill wells was analyzed utilizing material balance decline type curve methodologies formulated during Budget Period I. Early rate and fluid level measurements allowed us to verify the results of previous analyses and obtain early estimates of individual well potentials, bottomhole pressures, and formation flow characteristics. A short summary of preliminary results is shown below:

NRU Well	OOIP Calc. (STB)	Est. EUR Calc. (RF = 10%) (STB)	Drainage Area Calc. (acres)	Xf (ft)	kh (md-ft)
Section 327 Infill Area					
NRU 505	879,300	87,928	16.3	316.5	4.81
NRU 1509	621,100	62,105	11.5	199.5	4.38
NRU 1511	851,300	85,128	15.7	133.5	22.59
NRU 2705	524,800	52,476	9.7	73.4	7.12
NRU 3017	503,300	50,327	9.3	119.7	4.77
NRU 3018	755,900	75,594	14.0	220.1	16.99
Section 362 Infill Area					
NRU 3319	1,779,000	177,896	32.9	337.7	9.64
Section 329 Infill Area					

NRU 3532	842,100	84,211	15.6	232.3	7.82
NRU 3533	1,206,000	120,563	22.3	370.7	17.08
NRU 3534	706,200	70,621	13.1	212.8	11.50
NRU 3535	745,800	74,575	13.8	145.8	36.39
NRU 3604	758,300	75,829	14.0	126.0	14.28
TOTALS	**10,173,000**	**1,017,300**			
AVERAGES	**847,711**	**84,771**	**15.7**	**207.3**	**13.11**

VALIDATION OF RESERVOIR SIMULATION - *TASK II.3.3*

Geostatistical

A new reservoir simulation model has been developed for the Section 5 Study Area. This model is termed a four (4) layer model because it utilizes four (4) different permeabilities which were derived honoring the logarithmic distribution of permeability observed in the core data. The layer thickness for each permeability is dictated by the abundance of permeability samples within each of the four permeability ranges. The purpose of this model was to compare and contrast results with the stratigraphic model which averaged permeabilities within geologic units and masked the true variability of permeability. Also, the history matching technique differed in that the average production of the entire 640 acre tract was modeled by a single 40 acre 5 spot pattern. This technique avoids individual well history matches but instead tries to capture the behavior of the study area as a whole.

Results from the new model generated better fits of the secondary (waterflood) performance. When compared to the previous stratigraphic model, both continued secondary operations and 10 acre reduced density forecasts predicted more reserves, although incremental reserves for reduced density predicted by the two models differed little. The new four layer model has proved to be of great value in the reservoir characterization efforts at North Robertson Unit. Major points of the new model are that run time is reduced to 1% of the previous model and grid properties do not require input from the rock log solution. The combination of modeling regional production with a simplified model allows the engineer to examine many hypotheses in a timely fashion.

Deterministic

At the end of Budget Period I of the North Robertson study, several technology transfer workshops were presented. These workshops provided an opportunity for various team members to review all phases of the study and discuss the current status of the reservoir description from the perspective of each of the disciplines involved. This review suggested an improved reservoir description for the simulation models which could yield a more accurate history match without requiring an additional aquifer layer, aquifer functions, or many of the modifications made to the initial reservoir and well descriptions in the previous studies. This alternative description involved a <u>dual-porosity</u> approach in which the simulation lawyers are divided into two rock groups: the very low permeability matrix and the higher permeability flow zones. The Glorieta and Upper Clearfork layers consist primarily of the low permeability matrix with few higher permeability streaks. The Middle and Lower Clearfork layers have a larger proportion of the higher permeability rock. The poor quality matrix has high water saturations (irreducible and capillary) and contributes to reservoir performance primarily through expansion of fluids into the higher permeability streaks. Nearly all of the true fluid flow occurs in these higher quality layers which are connected to the wells by hydraulic fractures. During the early portion of the history period, water production occurred through expansion of fluids (oil, gas and water) in the matrix, which forced water into the higher permeability layers and eventually to the wells. When water injection began, water flowed directly from injector to producer through the hydraulic fractures and higher permeability layers, by-passing much of the low quality matrix. As can be imagined, this reservoir description can give very different predictions of future reservoir behavior than the previous description.

During the first quarter of 1997, the following tasks were completed:

1. The Section 329 Glorieta-Clearfork reservoir simulation model was converted from a fully compositional fluid characterization (7 components) to a standard black-oil fluid characterization.

2. A modified Todd-Longstaff miscible fluid treatment was added to the standard black-oil model developed in (1).

3. A dual-porosity reservoir description was added to the single-porosity model developed in (1).

4. Both a dual-porosity formulation and the modified Todd-Longstaff miscible treatment were added to the single-porosity, standard black-oil model developed in (1).

5. The nineteen-layer, dual porosity, standard black-oil model in (3) was converted to a ten-layer, dual-porosity, standard black-oil model.

In addition, the new black-oil laboratory fluid data was analyzed and incorporated into the simulation models. This was accomplished through the following tasks:

1. New laboratory data was compared to previous data.

2. A new equation-of-state fluid characterization was generated and tuned.

3. Black-oil fluid properties from tuned equation of state were generated.

4. New compositional and black-oil characterizations in simulators were tested.

The work listed above was performed primarily to answer the following questions:

1. Can the Clearfork reservoir behavior be accurately simulated using a black-oil fluid characterization?

2. Is the reservoir behavior better represented by a dual-porosity geologic characterization than by the single-porosity description used previously?

3. Can the number of layers in the simulation model be reduced from twenty to ten, without a significant loss of accuracy?

Based on the results of this work, the answer to each of these questions is yes. A better history match was obtained with the black-oil, dual-porosity model than with the previous compositional, single-porosity model. Most importantly, the match was obtained relatively easily with few modifications to the original reservoir and well descriptions. No aquifer layer or aquifer functions were required. Multiple relative permeability and capillary pressure tables were not needed. It was not necessary to assume that injection water was leaving the reservoir or that some of the produced water had entered the reservoir from an outside source. Modifications to matrix porosities and permeabilities were not required. Changes to the completion intervals of the well were generally not necessary. And it was possible to perform hydraulic fracture stimulations in the model at the dates of the actual stimulations. In general, the only modifications required to the initial reservoir description were to adjust the properties and distribution of the high-permeability layers. Nearly all modifications were performed on a layer basis with little need to vary reservoir characteristics within layers.

These improvements to the reservoir descriptions of the simulation models resulted directly from the integrated approach to reservoir management in this study. The work performed by the various team members is constantly being integrated into a single, consistent reservoir characterization which evolves as new data and improved interpretations become available. This continuing evolution of the reservoir characterization greatly facilitates the optimization of infill drilling in the North Robertson Unit.

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***ACTIVITY II.4*- TECHNOLOGY TRANSFER**

NEWSLETTERS - *TASK II.4.2*

The second Project Newsletter will be distributed during the second quarter of 1997.

PUBLICATIONS AND PRESENTATIONS - *TASK II.4.3*

Published Papers and Professional Meeting 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 Glorieta Formations, North Robertson Unit, Gaines County, Texas."

NORTH ROBERTSON UNIT

10-ACRE PRODUCING WELLS

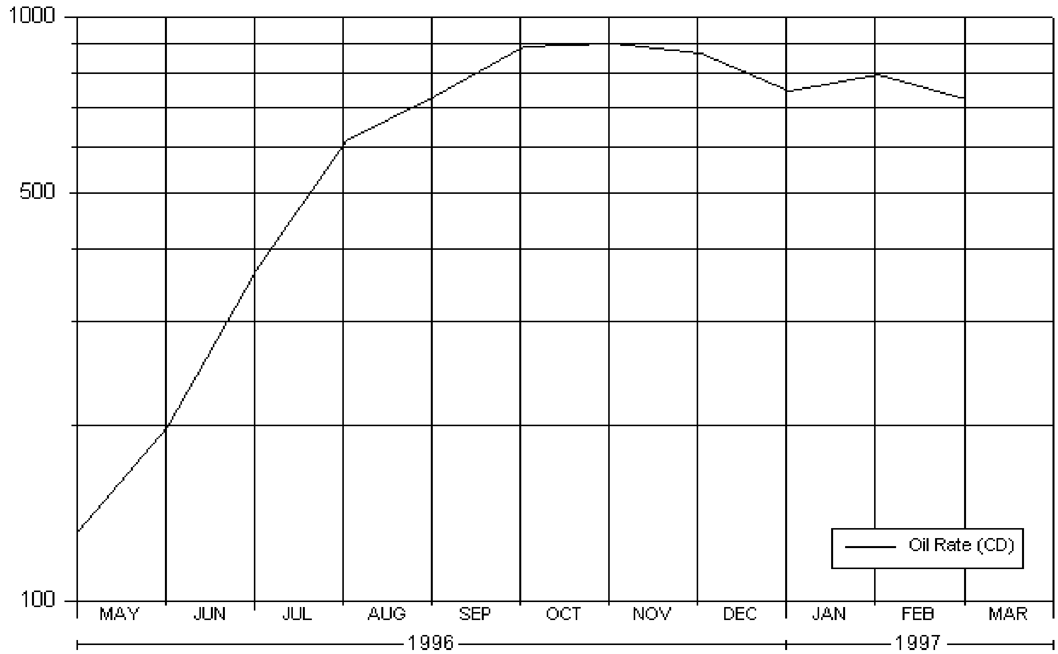

FIGURE 1

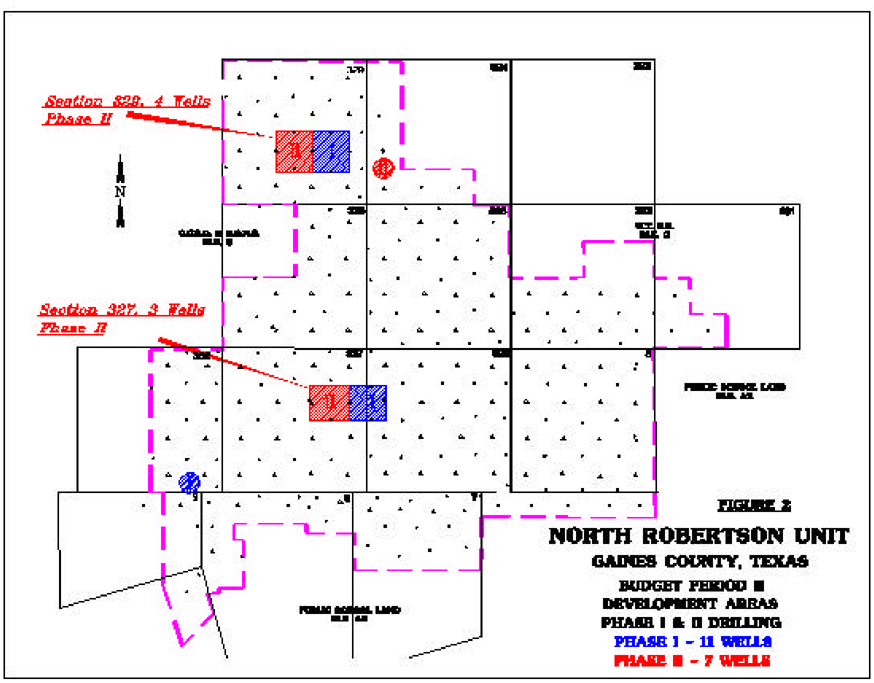

FIGURE 2

NORTH ROBERTSON UNIT

GAINES COUNTY, TEXAS

BUDGET PERIOD II

DEVELOPMENT AREAS

PHASE I & II DRILLING

PHASE I - 11 WELLS

PHASE II - 7 WELLS