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Instrument No. DE-FC22-94BC14989

Reporting Period 6/13/95 to 9/12/95

"Application of Integrated Reservoir Management and Reservoir Characterization
To Optimize Infill Drilling"

Enclosed please find three copies of the Quarterly Technical Progress Report for the project
for the time period 6/13/95 to 9/12/95.

Please feel free to contact me at 915-688-0670 if there are any questions or comments on
the project reporting.

P. K. Pande
Project Director

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NRU/DOE Task I.1.1 - Project
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**APPLICATION OF INTEGRATED RESERVOIR MANAGEMENT
AND RESERVOIR CHARACTERIZATION
TO OPTIMIZE INFILL DRILLING**

Cooperative Agreement Number: DE-FC22-94BC14989

FINA OIL AND CHEMICAL COMPANY

Report Date: September 12, 1995

Award Date: June 13, 1994

**Anticipated Completion Dates:
Budget Period I - March 12, 1996
Budget Period II - June 12, 1999**

Government Award for Budget Period I: \$1,174,264.00

Program Manager: P.K. Pande

Principal Investigator: Fina Oil and Chemical Company

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Rhonda Lindsey, DOE Bartlesville**

Reporting Period: June 13, 1995 - September 12, 1995

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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: 6/13/95 TO 9/12/95

This Quarterly Progress Report summarizes the technical progress of the project from 6/13/95 TO 9/12/95.

ACTIVITY I.1 - MANAGEMENT AND ADMINISTRATION

PROJECT MANAGEMENT AND ADMINISTRATION - TASK I.1.1

At this stage, the main emphasis on the project is on the geostatistics and reservoir simulation in support of the Field Demonstration for Budget Period II.

The next Technical Committee meeting will be scheduled after the geostatistics and reservoir simulation is completed and recommendations for the Field Demonstration have been formulated.

ACTIVITY I.2 - RESERVOIR CHARACTERIZATION AND ANALYSIS

GEOLOGICAL ANALYSIS - TASK I.2.1

Minor adjustments have been completed on the core/log rock typing algorithm. The algorithm is used to identify pay and non-pay rock types over the entire Unit. The resulting new rock type data will be used in conjunction with injection surveys and temperature surveys to refine flow unit tops for the entire Unit. Subsequently these refined tops will form the basis for updating the development geology at NRU (mapping, cross-sections, etc.).

Production data for the North Robertson Unit has been analyzed using Material Balance Decline Type Curve Analysis. All primary (40-acre) and secondary (20-acre) producing wells have been analyzed to determine total/movable volumes and formation flow characteristics (permeability and skin factor) based on individual well performance. Maps of OOIP, kh, and estimated ultimate recovery (EUR) using primary production data, and maps of kh and EUR using secondary production data have been generated and compare well with the geological interpretation. The amount of "pay" rock type in each well will be cross-referenced with cumulative oil production in an effort to improve the definition of reservoir rock types.

Decline type curve and waterflood performance analyses indicate that the NRU is not performing as well as expected under secondary recovery operations. This indicates the need for a complete review of the fluid flow behavior in the reservoir (required for reservoir simulation), and the completion/stimulation procedures used in the past. This work is critical for determining the placement of the 10-acre infill wells, and for optimization of future completion and stimulation practices. In addition, a new waterflood/water influx performance type curve is being formulated to more accurately monitor the performance of individual wells and patterns. These studies are nearing completion and will be presented at the next Technical Committee meeting.

RESERVOIR PERFORMANCE ANALYSIS - TASK I.2.4 - Continued

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

INTEGRATED RESERVOIR DESCRIPTION - TASK I.2.5

The stratigraphic and flow unit zonation of the Unit has been completed and is being used for the deterministic and geostatistical reservoir description. The work has been reviewed with the University of Tulsa for use in the geostatistics and reservoir flow simulation.

GEOSTATISTICAL ANALYSIS - TASK I.2.6

The geostatistical reservoir description has been generated for the first modeling area (Section 329) utilizing a stepwise approach which includes the following sequence:

- Rock Type Simulation
- Porosity Simulation
- Permeability Simulation
- Upscaling of Petrophysical Properties

The methodology is detailed below:

Rock Type Simulation: The first step in the geostatistical reservoir description is to simulate the underlying rock types which determine the petrophysical properties. The rock type data are first transformed into categorical variables (may be represented mathematically in a "binary" type format). Isotropic and anisotropic variograms describing the spatial relationships are then generated. The anisotropic variograms provide information on the direction of maximum or minimum continuity and anisotropy ratio. Sequential gaussian simulation is then used to estimate rock type values at specific points. This involves defining a search neighborhood around sampled locations.

GEOSTATISTICAL ANALYSIS - TASK I.2.6 - Continued

Porosity Simulation: For the porosity simulation only the points that have the same rock type as the unsampled points are used in the simulation process. As with the rock type simulation, spatial analyses using variograms are performed. This is followed by sequential gaussian simulation to assign porosity values as a function of rock type at unsampled locations.

Permeability Simulation: The conditional permeability distribution for each rock type is generated by plotting permeability and porosity. These permeability data are then divided into several porosity classes. For each porosity class, the cumulative conditional distribution (ccdf) of the permeability is then generated. Finally, knowing the porosity and rock type of a grid node, the ccdf plot is used to assign a random permeability to a specific grid node. In this way, all permeability data will be honored, including extreme values (i.e., high permeability streaks) that may affect reservoir performance.

Upscaling of Petrophysical Properties: Upscaling is required to assign grid block permeabilities and porosities since rock type, porosity and permeability data are generated geostatistically on a very fine grid with one foot vertical intervals. This is accomplished using a tensor method.

Geostatistical reservoir descriptions are also being generated for the Section 5 and 327 modeling areas.

RESERVOIR SIMULATION - TASK I.2.7

The results of both deterministic and geostatistical reservoir simulation are being compared in the modeling areas. The goal is to ascertain the advantages and/or disadvantages of the deterministic vs. the geostatistical techniques. Although it is more time consuming to obtain the reservoir description for geostatistical simulation, it should yield a more realistic representation of the actual reservoir flow mechanisms, heterogeneities, and compartmentalization which are present. Differences are expected in the predictive mode for simulations considering different geologically targeted infill drilling options, since many options may have equal or similar probabilities of success.

The deterministic simulation for the Section 329 area has been completed. Predictive runs have been made to determine the best option for infill drilling. Economics are being performed on various development configurations. The model has also been set-up at Fina, Midland as well as University of Tulsa. At Fina, the model has been converted to run on simulation software from Scientific-Software-Intercomp (SSI). Initialization and history matching for the Section 5 and 327 models are underway.

Initialization parameters for the models are as follows: Two PVT regions are being used, one for the Glorieta, Upper Clearfork, and Middle Clearfork; and the second region for the Lower

RESERVOIR SIMULATION - TASK I.2.7 - Continued

Clearfork. Available steady-state and unsteady state relative permeability data are being used primarily to define displacement endpoints. Historical oil and water production data are also being used as relative permeability data for the history match. Initial water saturations are being obtained using well log data from the 20-acre infill wells (which were drilled after unitization, 1987).

ACTIVITY I.3 - INTEGRATED RESERVOIR MANAGEMENT

INTEGRATED RESERVOIR MANAGEMENT - TASK I.3.1

Well Deepenings: Twenty-two well deepening candidates were identified (10 producing wells and 12 injectors) on the basis of the flow unit and kh and Øh mapping exercises that were performed with the core/log model results. The deepening candidates are all located along the northern periphery of the Unit. Subsequent log analysis and simulation modeling in Section 329 of the Unit has indicated that the actual deepening potential may be somewhat less than what was estimated initially in that particular area.

In Section 329, a review of existing completion data has indicated that the MF6 flow unit is predominately a water producer. This eliminates the deepening potential for all injection wells in the area as they are already drilled and completed to the base of MF5. Several producers in the area still have MF4 and MF5 deepening potential in the Lower Clearfork, and further analyses are being performed to verify this potential. Moving southeast along the shelf edge, there are still several wells with MF4 - MF6 deepening potential, and as we move in this direction away from Section 329, the oil-producing potential of the MF6 flow unit increases

Well NRU 3603 (Section 324) was deepened approximately 110 ft through the base of the MF6 flow unit at $\pm$ 7300 ft. The interval was cored and a full suite of open hole logs was recorded to obtain additional information on the Lower Clearfork interval. Both log and core analyses revealed approximately 40 to 50 ft of net pay within the interval, and with movable oil indicated from the log analysis and a moderate amount of oil stain on the core (with good fluorescence through the pay intervals), it was felt that this should be a productive interval. The well was perforated using bullet guns in order to reduce the injection pressure required to breakdown the formation during the acid job. The frac job was designed to create a vertically-confined fracture with a half-length of 260 ft. A tip screenout was noted during the job. The well is currently being placed on pump and will be put on test for several weeks to evaluate the potential of this lower zone (isolated from existing producing interval with a packer).

A field implementation strategy for further deepenings is currently being developed and will be documented in future reports and covered at future Technical Committee meetings.

INTEGRATED RESERVOIR MANAGEMENT - TASK I.3.1 - Continued

Additional Completions: Wells with additional completion potential in the Lower Clearfork have been identified based on initial simulation modeling and the TDT logging program. A ranking process is being developed to rank the best wells for additional completion. Field implementation for additional completions is expected during the next few quarters.

Pressure Falloff Tests: Ten tests have been completed using surface pressure data acquisition. Initial results show that the current reservoir pressure in areas around the injection wells is between 3000 and 4000 psia. All of the injection wells analyzed appear to be well stimulated, however, this is most likely the result of extensive fracture propagation due to continuous injection at or near the fracture pressure of the formation. A few tests indicate that offset injection wells may be in contact with each other via hydraulic fractures. Falloff data acquisition will continue in order to get as much usable data as possible for simulation history matching and subsequent infill drilling.

**Figure 2 - Pressure Falloff Data and Analysis for NRU 301
(indicates communication with offset injector)**

Pressure Build-Up Tests: Additional bottomhole pressure buildup surveys are presently being recorded throughout the Unit to confirm the results of the pressure falloff program (which utilizes

INTEGRATED RESERVOIR MANAGEMENT - TASK I.3.1 - Continued

surface pressure data acquisition) to provide further data for pressure matching during reservoir simulation, and to locate areas of the reservoir (if any) which have not been effectively repressured. A new pressure data acquisition technique will be utilized for several of the tests in which data is sent uphole real-time using radio signals via the wellbore strata. It is felt that the use of this emerging technology is in keeping with the goals of this project for the identification of such techniques. While the cost of the survey is only slightly more than the usual pressure buildup test, this method allows pressures to be monitored real-time at surface to determine how a test is proceeding and when it may be terminated.

Figure 3 - Pressure Buildup Data and Analysis for NRU 905
(performed using real time data transmission from downhole to surface)

In addition, in some future tests both surface and downhole pressure acquisition techniques will be used in order to compare the relative data quality from both test types. By measuring the surface pressure and monitoring fluid level height during the test, a buildup can be performed without the cost associated with pulling a well to run downhole shut-in devices. However, due to the low reservoir permeability of the Clearfork/Glorieta in this area, if a well is not shut-in downhole, extremely long wellbore storage periods result, and it is often difficult to obtain quality

INTEGRATED RESERVOIR MANAGEMENT - TASK I.3.1 - Continued

test results. In addition, as wellbore fill is a major problem in this area, it is always a good idea to tag the fill or clean out the well prior to testing in order to acquire representative data.

Six pressure buildup tests have been completed, and at least four more are planned for the fourth quarter of 1995. Initial results indicate that the average reservoir pressure in the areas surrounding the producing wells is between 1600 and 3000 psia, and the pressure level appears to be directly correlated to the degree of reservoir continuity between injectors and producers.

Further analyses verify that well stimulation and hydraulic fracturing are still major concerns on the newer (1987 - 1991) producers, and these problems are currently being addressed by utilizing cased-hole dipole sonic logs to find untreated intervals, estimate fracture height growth from the initial stimulations, and to compile data on rock mechanical properties that have been estimated in the past. New stimulation and fracturing techniques will be utilized on the well deepenings and some recompletions will be attempted on existing wells in an attempt to find optimum methods for completion and stimulation prior to drilling 10-acre infill wells. A stimulation database will be set up to determine which stimulation methods, fluids, and volumes produce the best completions.

Conformance Control Workovers: These workovers are being considered to address communication problems. These phenomena are typical of waterfloods in low permeability carbonate formations, and result in early water breakthrough and poor sweep efficiency. Results from the core/log model analyses and geostatistical simulation will be used to target only zones which contribute significantly to production. By producing from (and injecting into) only the major pay intervals, well conformance should improve significantly.

The conformance problem between existing injection and producing wells occurred due to the fact that all current injectors were completed, stimulated, and fractured as producing wells. When these wells were put on injection, the Lower Clearfork interval, into which most of the hydraulic fracture propagated, will usually take the most water. This has resulted in poor sweep efficiency in many areas. Future injection well completions must be performed so that water is injected equally into all identified pay intervals.

TDT Logging: The evaluation of the current water saturation profile throughout the unit will be done using Thermal Decay Time (TDT) logs. The new data can be compared with original water saturation data for reservoir surveillance purposes, and is being used as an additional history match parameter for reservoir simulation. In addition, several by-passed pay intervals have been identified that will be completed in the near future. Six surveys have been completed to date, and several more will be completed during the fourth quarter of 1995.

The TDT may also be used in conjunction with a production logging survey to identify zones which contribute most to production, and to verify or disprove previous conclusions regarding the relative contributions of the Glorieta, Upper, Middle, and Lower Clearfork. Since these wells do

INTEGRATED RESERVOIR MANAGEMENT - TASK I.3.1 - Continued

not produce naturally (pumping wells), flow will be induced by injecting nitrogen to create an artificial pressure drop in the area of a downhole packer-type flowmeter tool. Production rate and fluid density will be measured. An initial survey was unsuccessful due to the inability to initiate a stable flow rate. The test design will be modified, and if feasible, another survey will be attempted in the near future. If successful, this work will be extremely valuable when well deepenings, recompletions, and infill drilling are performed.

Figure 4 - Water Saturation Monitoring with TDT Logs - NRU 3527

ACTIVITY I.5 - TECHNOLOGY TRANSFER

NEWSLETTERS - TASK I.5.2

A Project Newsletter has been developed. Software bugs in the desktop publishing software have prevented final completion. A new version of the software is being installed for fine-tuning the final version.

PUBLICATIONS AND PRESENTATIONS - TASK I.5.3

Technology transfer activities for the project this Quarter were:

PUBLICATIONS AND PRESENTATIONS - TASK I.5.3 - Continued

Published Papers and Professional Meeting Presentations:

- SEG Development and Production Forum, June 11-16, 1995, Snowmass, CO
"Cooperative Projects to Improve Reservoir Management" Attended by
Louis Doublet, Texas A&M University (project oral presentation).

- SPE Forum Series In North America, Snowmass, CO

"Risk and Confidence In Reserves Evaluation", July 30 to August 4, 1995,
Attended by Tom Blasingame, Texas A&M University.

"Multidisciplined Analysis and Solutions to Rejuvenating Old or Marginal
Fields", August 6-11, 1995. Attended by Louis Doublet, Tom Blasingame,
Texas A&M University, and Paul Hunt, Mobil (project oral presentation
and poster session).

Technology Transfer activities scheduled for Next Quarter are:

Published Papers and Professional Meeting Presentations:

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

SPE 30774, "Decline Curve Analysis Using Type Curves: Water
Influx/Waterflood Cases".

SPE 30601, "Simulation of Geological Model Using Multipoint
Histogram".