**Application of Advanced Reservoir Characterization,
Simulation, and Production Optimization Strategies to
Maximize Recovery in Slope, and Basin Clastic Reservoirs,
West Texas (Delaware Basin)**

**Quarterly Report
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TECHNICAL PROGRESS REPORT

Title:	APPLICATION OF ADVANCED RESERVOIR CHARACTERIZATION, SIMULATION, AND PRODUCTION OPTIMIZATION STRATEGIES TO MAXIMIZE RECOVERY IN SLOPE AND BASIN CLASTIC RESERVOIRS, WEST TEXAS (DELAWARE BASIN)
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OBJECTIVES

The objective of this project is to demonstrate that detailed reservoir characterization of slope and basin clastic reservoirs in sandstones of the Delaware Mountain Group in the Delaware Basin of West Texas and New Mexico is a cost effective way to recover a higher percentage of the original oil in place through strategic placement of infill wells and geologically based field development. Project objectives are divided into two major phases. The objectives of the reservoir characterization phase of the project are to provide a detailed understanding of the architecture and heterogeneity of two fields, the Ford Geraldine unit and Ford West field, which produce from the Bell Canyon and Cherry Canyon Formations, respectively, of the Delaware Mountain Group and to compare Bell Canyon and Cherry Canyon reservoirs. Reservoir characterization will utilize 3-D seismic data, high-resolution sequence stratigraphy, subsurface field studies, outcrop characterization, and other techniques. Once the reservoir-characterization study of both fields is completed, a pilot area of approximately 1 mi² in one of the fields will be chosen for reservoir simulation.

The objectives of the implementation phase of the project are to (1) apply the knowledge gained from reservoir characterization and simulation studies to increase recovery from the pilot area, (2) demonstrate that economically significant unrecovered oil remains in geologically resolvable untapped compartments, and (3) test the accuracy of reservoir characterization and flow simulation as predictive tools in resource preservation of mature fields. A geologically designed, enhanced-recovery program (CO₂ flood, waterflood, or polymer flood) and well-completion program will be developed, and one to three infill wells will be drilled and cored. Through technology transfer workshops and other presentations, the knowledge gained in the comparative study of these two fields can then be applied to increase production from the more than 100 other Delaware Mountain Group reservoirs.

SUMMARY OF TECHNICAL PROGRESS

Geophysical Characterization

Interpretation of the 3-D seismic data was completed this quarter. The acquisition of 3-D seismic data for this project was designed specifically to target Delaware Mountain Group reservoirs. An older 2-D seismic grid was used to determine the survey design; a minimum of 48 nominal fold is needed to image Bell and Cherry Canyon reservoirs. For the first time a key subsurface horizon above the Ramsey reservoir sandstone, the top of the Lamar Limestone, was imaged with 3-D seismic data. This surface had not previously been imaged satisfactorily because of shallow statics problems in the area. Interpretation of the data included coherence cube evaluation to highlight discontinuities; this technique was effective in delineating the field outline. This is believed to be one of the first uses of the coherency cube in a Delaware Mountain Group reservoir. A residual map of the Lamar identified a residual high that is associated with the Ramsey sandstone thick. Ramsey sandstone thickness in Ford Geraldine unit is 1/4 wavelength of the seismic data. The amplitude family of attributes had the highest correlations with the reservoir properties of average porosity and porosity x thickness. The best correlation coefficients were less than 0.4 when all the wells were used.

Reservoir Characterization

Subsurface Field Studies.—On the basis of core descriptions and study of the outcrop analog, Ramsey sandstones at Ford Geraldine unit are interpreted as having been deposited by sandy high- and low-density turbidity currents that carried a narrow range of sediment size, mostly very fine sand to coarse silt. The sands were deposited in a basin-floor setting by a channel-levee system with attached lobes. Channel facies are approximately 1,200 ft wide and 15 to 35 ft deep. They consist of massive and crossbedded sandstones interpreted to have been deposited from high-density turbidity currents (Lowe, 1982). Channel margins are characterized by rippled and convoluted sandstones interbedded with minor siltstones. Channel-margin deposits are interpreted as channel levees formed by overbanking of low-density turbidity currents. Levee deposits are composed of ripple-laminated and convoluted sandstones interbedded with minor siltstones. Lobe sandstones are interpreted as being deposited at the mouth of the channel by high-density turbidity currents. They were identified by massive and graded sandstones with load and dewatering structures such as dish structures, flame structures, and vertical pipes—features that indicate rapid deposition and fluid escape.

The proposed channel-levee and lobe model for Ramsey sandstone deposition suggests greater lateral heterogeneity of reservoir sandstones exists at Ford Geraldine unit than previously thought (Ruggiero, 1985 and 1993). Progradation, aggradation, and retrogradation of the system resulted in lateral and vertical offset of channel, levee, and lobe facies. Laminated siltstones and lutites provide the greatest amount of depositional heterogeneity because of the grain size and permeability contrast between sandstones and siltstone facies. The sandstones facies all have similar grain sizes, and thus there may not be much permeability contrast and inhibition of flow at sandstone-on-sandstone contacts, for example, where channels incise into lobe facies.

By comparing core analyses with point-count data from thin sections, the influence of parameters such as grain size, detrital mineralogy, and volume of authigenic cements on porosity and permeability were analyzed. No statistically significant correlation exists between porosity or permeability and depositional properties such as grain size, percent sand-size grains, sorting, or ductile grain volume (90 percent confidence level). This is unusual for a sandstone, but probably is a result of the narrow range of detrital grain sizes available in the eolian source area. Whereas most sandstones have ranges of grain size and volumes of detrital clay matrix in different facies, little variation among facies exists in the Ramsey sandstones. As a result, porosity and permeability have very similar distributions in channel, levee, and lobe facies. Porosity and log permeability distributions are negatively skewed, and the low values represent sandstones that have been cemented by calcite.

There is a statistically significant relationship between volume of cement and both porosity and permeability. Calcite is the most important component of total cement, and it has the greatest impact on reservoir quality. In samples with more than 15 percent calcite cement, permeability is reduced to less than 3 md and porosity to less than 15 percent. Thus, the main controls on porosity and permeability in the Ramsey sandstones are authigenic cements, particularly calcite, and to a lesser extent, chlorite.

The distribution of calcite cement in Geraldine Ford field can to some extent be determined from the cores because highly calcite-cemented zones have a distinct white color. Calcite-cemented intervals were noted and described along with other sedimentary features in the core and thus can be mapped on cross sections. Highly calcite-cemented sandstones occur in all three sandstone facies—channel, levee, and lobe. Most cemented zones in the core are approximately 0.5 to 1 ft thick; their

dimensions are unknown, but we assume they are not laterally extensive or continuous. Although they can occur anywhere within the vertical Ramsey sandstone section, they are more common near the top and base of sandstones. The source of some of the calcite may be from the adjacent siltstones, which would explain the greater abundance of calcite near the sandstone-siltstone contacts. There may also have been at least a partial internal source of calcite in the sandstones, detrital carbonate rock fragments and fossils. Additional petrographic work is planned to determine if detrital carbonate content varies with facies or stratigraphic level.

Petrophysical Characterization.—Petrophysical characterization of the Ford Geraldine unit was completed this quarter. With the old neutron and gamma-ray logs normalized, Vcl determined, Rw mapped, Rt determined, core-porosity to log-data and core-porosity to core-permeability transforms derived, and reliable values for cementation (m) and saturation (n) exponents calculated, petrophysical maps were constructed.

Average porosity for the Ramsey sandstone in the Ford Geraldine unit exhibits a general northeast-southwest trend of high porosity, but the areas of highest porosity values are broken up. In contrast, the distribution of porosity-feet exhibits a strong linear northeast-southwest trend of high porosity-feet (8 to 10 ft), with the greatest thickness (>10 ft) in the northeast part of the unit (shelfward). The trend of porosity-ft follows the trend of total thickness of the Ramsey sandstone. The decrease in average porosity and porosity-feet to the northwest and southeast is the result of a loss of reservoir rock along the edges of the Ramsey channel complex. The separation of high average porosity into different areas may be caused by diagenesis, but further work is necessary to evaluate this hypothesis.

Using the core porosity to permeability transform together with core-porosity to log-porosity transforms, average permeability and permeability-feet maps were constructed. Like average porosity, the average permeability and permeability-feet distributions have a general northeast trend, but zones of highest permeability and permeability-feet are separated into isolated pods. The permeability-feet distribution exhibits a strong linear trend of high (>1000) permeability-feet to the northeast that reflects the total Ramsey sandstone thickness. Some of the highest average permeability occurs along the margins of the field, in what is interpreted to be the levee facies. Lower permeability occurs near the center of the field, following the trend of the Ramsey 1 channel facies. Increased volumes of authigenic chlorite or calcite cement in the channel facies may explain this trend.

The distribution of average bulk volume water (BVW) was mapped in order to determine water saturations (S_w) northeast of sections 25 and 30, where no resistivity logs were run. To obtain S_w in the northeast part of the unit, average BVW values were extrapolated to the northeast, and BVW values assigned to wells with porosity logs. Water saturations (S_w) were calculated in these wells by the formula $S_w = BVW_{avg}/\phi$, then these S_w values were averaged and mapped. The distributions of BVW and S_w both show an increase to the northeast, which is to be expected because that direction is down structural dip

Mobil oil saturations (MOS) were calculated by the formula $MOS = (1.0 - S_w) - ROS$. The values for residual oil saturation (ROS) were calculated using the porosity-ROS transform. High MOS values are concentrated to the southwest (up-dip) and in the central portions of the Ford Geraldine unit where the better reservoirs are located.

The calculation of net pay was based on the following cut-offs: V_{cl} 15 percent, ϕ 15%, and $S_w < 60$ percent. As should be expected, there is a greater thickness of net pay to the southwest (up-dip) and in the central portions of the unit. The distribution of hydrocarbon pore-feet ($S_o \times \phi \times H$) shows a strong northeast-southwest trend of high $S_o \times \phi \times H$ values (>5 ft) down the central portions of the unit that correlates best with the porosity-feet distribution. The slight loss of $S_o \times \phi \times H$ to the northeast is to be expected due to the more down-dip position.

Initial potential of the Ford Geraldine unit wells had areas of high initial potential (>300 BOPD) in areas at the northern and southern ends of the unit. In many cases, the areas of high potential do not coincide with thickest Ramsey sandstone. Some areas of high initial potential also have high primary recovery, but not all. Primary oil recovery has two separate areas of high oil recovery. One is located in the southwest, up-dip part of the unit and the other is located in the northeast, down-dip part of the unit. An examination of the Ramsey sandstone distribution reveals that there is a lower Ramsey 1 sandstone and an upper Ramsey 2 sandstone. The high oil recoveries to the southwest are trapped in the Ramsey 1 sandstone that lenses out into a lower permeability facies to the SW. The high recoveries to the northeast are from both Ramsey 1 and Ramsey 2 sandstones. Because the Ramsey 2 sandstone lenses out into a lower permeability facies near the central part of the unit, the oil in the Ramsey 2 is in a separate reservoir.

Outcrop Characterization

Interpretation of the processes that deposited the sandstones of the Delaware Mountain Group has long been controversial, and this controversy is of practical importance because different depositional models predict very different sandstone distribution, geometry, and continuity. Applying the correct depositional model is critical to effective reservoir development, but subsurface data commonly do not provide the interwell-scale information needed to differentiate between competing depositional models. Thus, a key component of our reservoir characterization effort was to investigate well exposed analogs of the subsurface reservoirs.

Stratal relationships indicate that upper Bell Canyon sandstones exposed in outcrop 24 mi west of Ford Geraldine unit were deposited in channels with levees and attached lobes. Channels are up to 60 ft thick and 1,000 ft across, but they may amalgamate to form bodies that are 3,000 ft across. The channels have erosive bases and are composed largely of cross-stratified sandstones. The channels are flanked by wedge-shaped bodies interpreted as channel levees, which are composed of thin-bedded sandstones and siltstones. They are 5 to 15 ft thick and several thousand feet long. Away from the channels the levees thin and interfinger with organic-rich siltstones interpreted as interchannel deposits. In a basinward direction the channels bifurcate and terminate in lobes that are up to 30 ft thick and between 1 and 10 miles wide. The lobes have a broad lenticular geometry and dip gently into the basin, where they interfinger with sheets of laminated siltstones. This depositional model developed from outcrop can be widely applied by operators to reservoirs that produce from Delaware Mountain Group sandstones.

Producibility Problem Characterization Recovery Technology Identification and Analysis

Ford Geraldine unit has had a long production history. After primary production started to decline, a pilot waterflood was started in 1969 in the center of the field. The waterflood was then extended to the entire field in the five stages. The demonstration area was waterflooded in stage 5 in 1980. There is some evidence that during primary depletion, water from an adjoining aquifer encroached into this area. Therefore, most of the wells in area 5 were producing at high water cuts before the waterflood was started. In 1981, CO₂ injection was started for tertiary recovery in the central part of the reservoir and was gradually expanded into a major part of the reservoir. However, CO₂ flooding has not been implemented in the demonstration area.

To make reliable predictions of tertiary recovery from the demonstration area, fluid-flow simulations of CO₂ flooding have been initiated. These simulations will be based on stochastic permeability distributions and geologic characterization of the reservoir. However, from the available production data and other information about the reservoir, preliminary estimates of tertiary recovery from the demonstration area can be made.

Original oil in place (OOIP) was calculated for the five staged areas in which the unit was waterflooded. Total OOIP is estimated to be 83.5 MMSTB (Million Stock Tank Barrels). This is a conservative figure because in this reservoir, OOIP has been estimated as high as 110 MMSTB. Primary, secondary, tertiary, and cumulative (primary+secondary or primary+secondary+tertiary) recovery were calculated by area as a percentage of OOIP. Area 5, the demonstration area, has only primary and secondary recovery. Area 3N, in the north-central part of the unit, is the only area with below average production. The poor performance of this area is probably a result of the anomalous geologic and petrophysical features observed here. The 3N area includes the area of thin Ramsey 1 sandstone and low average porosity, net pay, and $S_o \times \phi \times H$. The primary and secondary recovery performance of the demonstration area is comparable to the other better producing areas of the reservoir. Post-waterflood oil saturations in the whole reservoir can be expected to be similar. Therefore, it is reasonable to assume that the demonstration area will perform similarly to the other areas in tertiary recovery.

The overall primary recovery in the reservoir was 14.5 percent of OOIP. Secondary recovery was 8.6 percent, and tertiary recovery to December, 1995 was 7.9 percent of OOIP. Tertiary recovery does not include the demonstration area. Using the average 7.9 percent tertiary performance of the rest of the reservoir, it is estimated that 904,000 STB of oil can be recovered from the demonstration area with a CO₂ flood. This is a conservative estimate; the results of the planned flow simulations are expected to confirm or exceed this estimate.

Because the reservoir simulation was not completed by the end of the quarter, a no-cost extension to the project was requested and granted by DOE to June 30, 1997. The results of the simulation will be used by Conoco, the Bureau of Economic Geology, and DOE to determine the feasibility of moving to Phase II, the demonstration phase.

Technology Transfer

A successful technology transfer workshop titled "Reservoir Characterization of Permian Deep-Water Sandstones, Bell Canyon Formation, Geraldine Ford Area, West

Texas (Delaware Basin)” was held on March 25, 1997, in Midland, Texas, co-hosted by the West Texas Geological Society (WTGS). The workshop was attended by approximately 90 people. The following handout of key figures and summary text was distributed to the participants:

Dutton, S. P., Asquith, G. B., Barton, M. D., Clift, S. J., Cole, A. G., Gogas, J., Malik, M.A., and Pittaway, K. R., 1997, Reservoir characterization of Permian deep-water sandstones, Bell Canyon Formation, Geraldine Ford area, West Texas (Delaware Basin): The University of Texas at Austin, Bureau of Economic Geology, unpublished course notes for technology transfer workshop, March 25, 1997, Midland, Texas, unpaginated.

Permission was granted by DOE to move the second Phase 1 workshop and the field trip, which were originally scheduled to be held in March also, to the fall of 1997. The officials of WTGS thought that the workshops would have a much higher total turnout if they were spread out, instead of having them within a few weeks of each other. The field trip was moved to the fall in anticipation of better weather at that time of year.

In addition to the workshop, two talks based on the project were presented.

“Petrophysics of the Ramsey Sandstone, Ford Geraldine Unit, Reeves and Culberson Counties, Texas” talk presented by G. B. Asquith on February 20 at the Permian Basin Well Log Society, Midland, Texas.

“Petrophysics of submarine-fan sandstones of the Ramsey Sandstone reservoir, Ford Geraldine Unit, Delaware Basin, Texas” talk presented by G. B. Asquith on March 21 at the Society of Independent Professional Earth Scientists, Austin, Texas.

PLANNED ACTIVITIES

Work in the upcoming quarter will focus on one activity: simulation of a CO₂ flood in the proposed demonstration area. Conoco's final decision to move to Phase 2 of the project cannot be made until completion of the reservoir simulation of the demonstration area and subsequent economic analysis of the results.

REFERENCES

- Lowe, D. R., 1982, Sediment gravity flows: II. Depositional models with special reference to the deposits of high-density turbidity currents: *Journal of Sedimentary Research*, v. 52, p. 279-297.
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