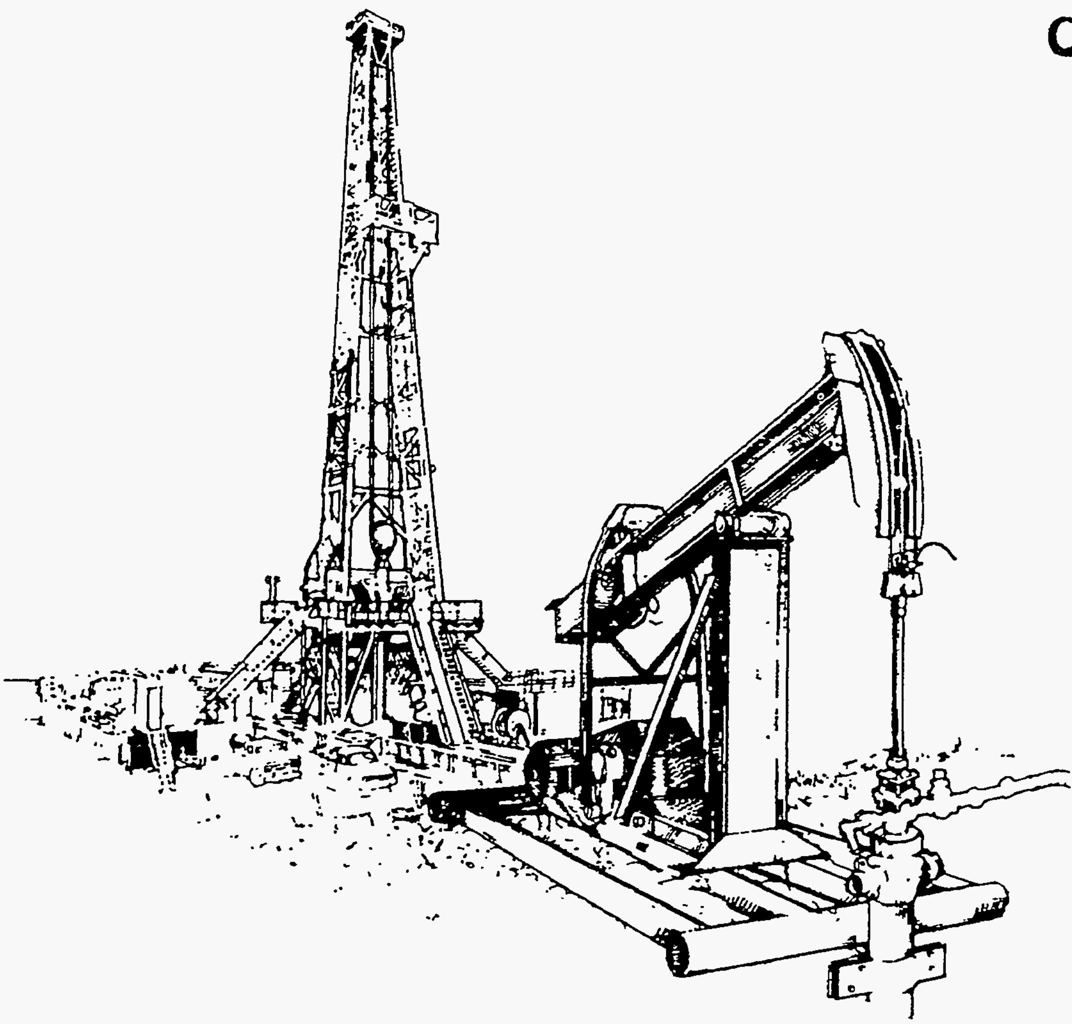
88

Contracts for field projects
and supporting research on . . .

Enhanced Oil Recovery

Reporting Period July–September 1996

DOE/BC--96/4
(DE98000454)
PROGRESS REVIEW
Quarter Ending September 30, 1996



United States Department of Energy

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PROGRESS REVIEW NO. 88

CONTRACTS FOR FIELD PROJECTS AND SUPPORTING RESEARCH ON ENHANCED OIL RECOVERY

Date Published - December 1997

UNITED STATES DEPARTMENT OF ENERGY

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COMPANIES AND INSTITUTIONS

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DOE Technical Project Officers for
Enhanced Oil Recovery

DIRECTORY

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GAS DISPLACEMENT—SUPPORTING RESEARCH

PRODUCTIVITY AND INJECTIVITY OF HORIZONTAL WELLS

Contract No. DE-FG22-93BC14862

Stanford University
Stanford, Calif.

Contract Date: Mar. 10, 1993
Anticipated Completion: Mar. 10, 1998
Government Award: $442,000
(Current year)

Principal Investigator:
Khalid Aziz

Project Manager:
Thomas Reid
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objectives

The objectives of this project include (1) modeling horizontal wells to establish detailed three-dimensional (3-D) methods of calculation that will successfully predict horizontal well performance under a range of reservoir and flow conditions, (2) performing reservoir characterization studies to investigate reservoir heterogeneity descriptions relevant to applications of horizontal wells, and (3) experimental planning and interpretation to critically review technical literature on two-phase flow in pipes and correlate results in terms of their relevance to horizontal wells.

Summary of Technical Progress

During this quarter the following activities were carried out:

• More than 200 two-phase flow experiments with prepacked wire-wrapped screens were completed at the Marathon facility. These experiments include many runs with liquid and/or gas radial inflow at 0, +2°, and –2° inclination angles. All the experiments have been recorded on videotapes for flow pattern visualization and recognition. Data files are being converted to easy-to-use Excel workbooks. The complete analysis of 1995 and 1996 data is under way.

• Example problems were run to calculate exact well indexes for horizontal wells and to assess their influence on production performance. The developed code is being further tested against other available but less-general analytical models.

• Research work on the application of horizontal wells in gas condensate reservoirs has progressed. Some results of available models have been verified, whereas a critical evaluation of results of some other approaches is being undertaken.

- Developed correlations for optimum grid size, breakthrough time, and post breakthrough behavior were further refined. A procedure to derive pseudo functions on the basis of the correlations has been developed and is being evaluated in hypothetical and real field example problems.
- A report on the effects of horizontal well placement and gravity on sweep efficiency was completed as a joint project with the gas injection research group (SUPRI-C) at Stanford.
- A comprehensive study of the effects of heterogeneities on horizontal well performance was conducted. Various issues, such as well models, wellbore pressure drop, cresting models, productivity models, and scale-up methods, were investigated for 20 geostatistical reservoir images generated on the basis of a real field case. As shown in the study, large differences in production rate and water/oil ratio and gas/oil ratio predictions occur as a result of variations in reservoir properties. Also, the effect of well index on simulation results is large. Furthermore, for the example considered in the study, analytical models for critical rate and productivity calculations were found to have limited practical use. A paper on this study will be presented at the SPE International Conference on Horizontal Well Technology in Calgary, Canada, November 18–20, 1996.

CO_2 HUFF 'N' PUFF PROCESS IN A LIGHT OIL SHALLOW-SHELF CARBONATE RESERVOIR

Contract No. DE-FC22-94BC14986

**Texaco Exploration and Production, Inc.
Midland, Tex.**

**Contract Date: Feb. 10, 1994
Anticipated Completion: Dec. 31, 1997
Government Award: $347,493
(Current year)**

**Principal Investigators:
Scott C. Wehner
John Prieditis**

**Project Manager:
Jerry Casteel
National Petroleum Technology Office**

Reporting Period: July 1–Sept. 30, 1996

Objective

The principal objective of the Central Vacuum Unit (CVU) CO_2 Huff 'n' Puff (HnP) project is to determine the feasibility and practicality of the technology in a waterflooded shallow-shelf carbonate environment. The results of parametric simulation of the CO_2 HnP process coupled with the CVU reservoir characterization components will determine if this process is technically and economically feasible for field implementation.

Summary of Technical Progress

Field Demonstration

Figure 1 contains the field demonstration history through mid-July 1996. Subsequent to the daily frequency of testing shown in this figure, the well is now being tested monthly. The well has continued on a steady decline and is producing approximately 45 barrels of oil per day (BOPD) as of the date of this report.

Although production expectations have not been achieved at this specific test site, there was a period that experienced a favorable reduction in operating expenses. During the injection, soak, and flowing periods, there were no electrical costs. Electrical load was also reduced during the initial pumping period when water rates were 33% below predemonstration levels. Although there are a few signs of paraffin buildup and scaling, the lower than forecasted oil production result is believed to be caused by a lack of gas trapping in the matrix because 100% of the injected CO_2 volume was recovered. The metered gas volumes shown in Fig. 1 since early May are in question. The metering accuracy is suspect for periods shortly after installation of the production equipment.

Site-Specific Simulation

A need for model refinement was demonstrated by the differences between predictions and early results (injection rates, pressures, and production). Monitoring of the CVU field demonstration continues on a reduced test frequency. Sufficient data were gathered for a meaningful attempt at history matching. The mechanisms investigated during the parametric simulation were incorporated as warranted. The history matching exercise was completed during the third quarter of 1996. The pursuit of a second demonstration site is being weighed with findings developed during the history matching.

A reasonably close history match was obtained by limiting the gas production during the first 65 d of production to the actual gas production rate experienced in the field test. The gas hysteresis (i.e., the gas trapping mechanism) was also eliminated. Figure 2 shows the history match with the limitations on the initial gas rate.

The two main differences between the predicted performance and the actual performance of the HnP were an

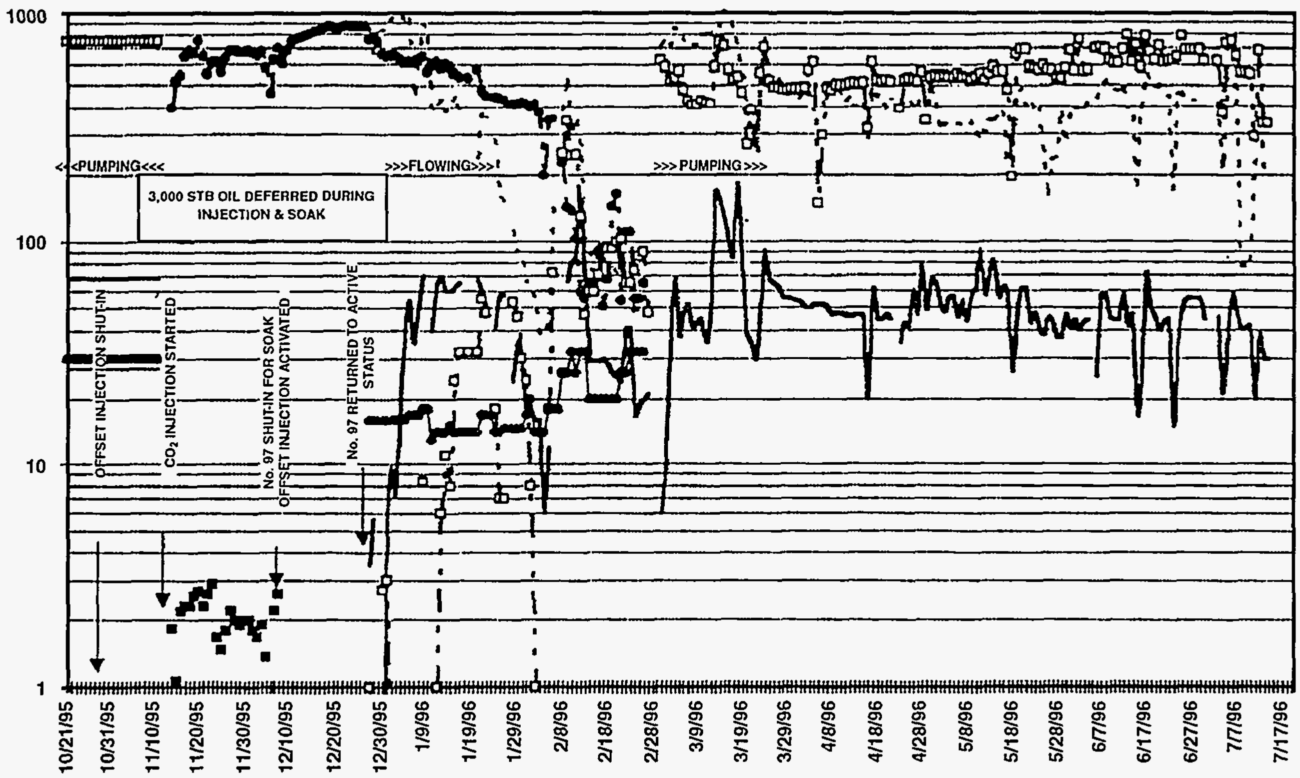

Fig. 1 Field demonstration data through mid-July 1996. —, oil (stock tank barrels per day). -□-, water (bbl/d). – – –, total gas (thousand cubic feet per day). ■, CO_2 injection (million cubic feet per day). —•—, Tbg. pressure (pounds per square inch gage). —•—, choke, ×/64 in.

apparent absence of gas trapping and lower than predicted production rates. A crucial difference between the actual test and the predicted performance was that the total liquid (oil + water) production rates were much lower for the actual test when the well was flowing. The rates were less than the rates before the demonstration and needed to be compensated for in the simulation. The liquid production rate in the simulation was reduced indirectly by placing a limitation on the gas production. For the original site-specific prediction (discussed in previous reports), the well was controlled in the simulation model to maintain the same liquid (oil + water) production rate after the HnP as before, and the gas production was not allowed to exceed 1 thousand standard cubic feet per day (Mscf/d). An actual field limitation of 1 Mscf/d on gas production (the limitation on gas production in the early production period was due to disposal issues) was anticipated. In the actual field test, however, both the initial total liquid production rates and the gas production rates were much less than in the prediction. The gas production was initially around 1 Mscf/d, but it rapidly declined and became less than 100 scf/d before the pump was put back in the well. This was the result of flowing the well, which ultimately loaded up with liquids. The lower early liquid production rates were matched in the simulation model by limiting the simulated gas production rates to the actual gas production rates for the first 65 d the well was placed back on production.

Permitting the well to produce at a gas rate of 1 Mscf/d (drawing down the wellbore fluid level) increased the oil recovered during the simulated HnP. About 3000 stock tank barrels (STB) of incremental oil was recovered during the production period under the 1 Mscf/d limitation scenario, compared with no incremental oil when the gas production rate was reduced to match actual gas production in the demonstration site; however, the incremental oil under the 1 Mscf/d limitation is still only enough to compensate for deferred production during the CO_2 injection and soak phases. The site-specific simulation, which suggests that a high gas rate during production increases oil recovery, is consistent with previous parametric simulations that indicated incremental oil during the production phase was increased when the gas production limitation was removed. Permitting the well to produce at higher gas rates should increase the oil recovered during the HnP, but it is not expected to compensate for more than the oil deferred during the CO_2 injection and soak phases unless a trapped gas saturation is anticipated. Figure 3 shows the difference between the history match simulation with the actual gas production rates and the history match with one change. The change, involving a limitation on the gas production rates during the first 65 d, was removed, and the well was permitted to produce at a gas rate of up to 1 Mscf/d. When the gas limitation was removed, the oil response improved. This suggests not limiting gas production during an HnP.

If the well had been drawn down, higher total liquid rates would have likely been achieved. Also, if total liquid production rates in the actual test had been close to those in the prediction, there would probably have been a large oil spike in production. After the pump was put back in, the liquid rate

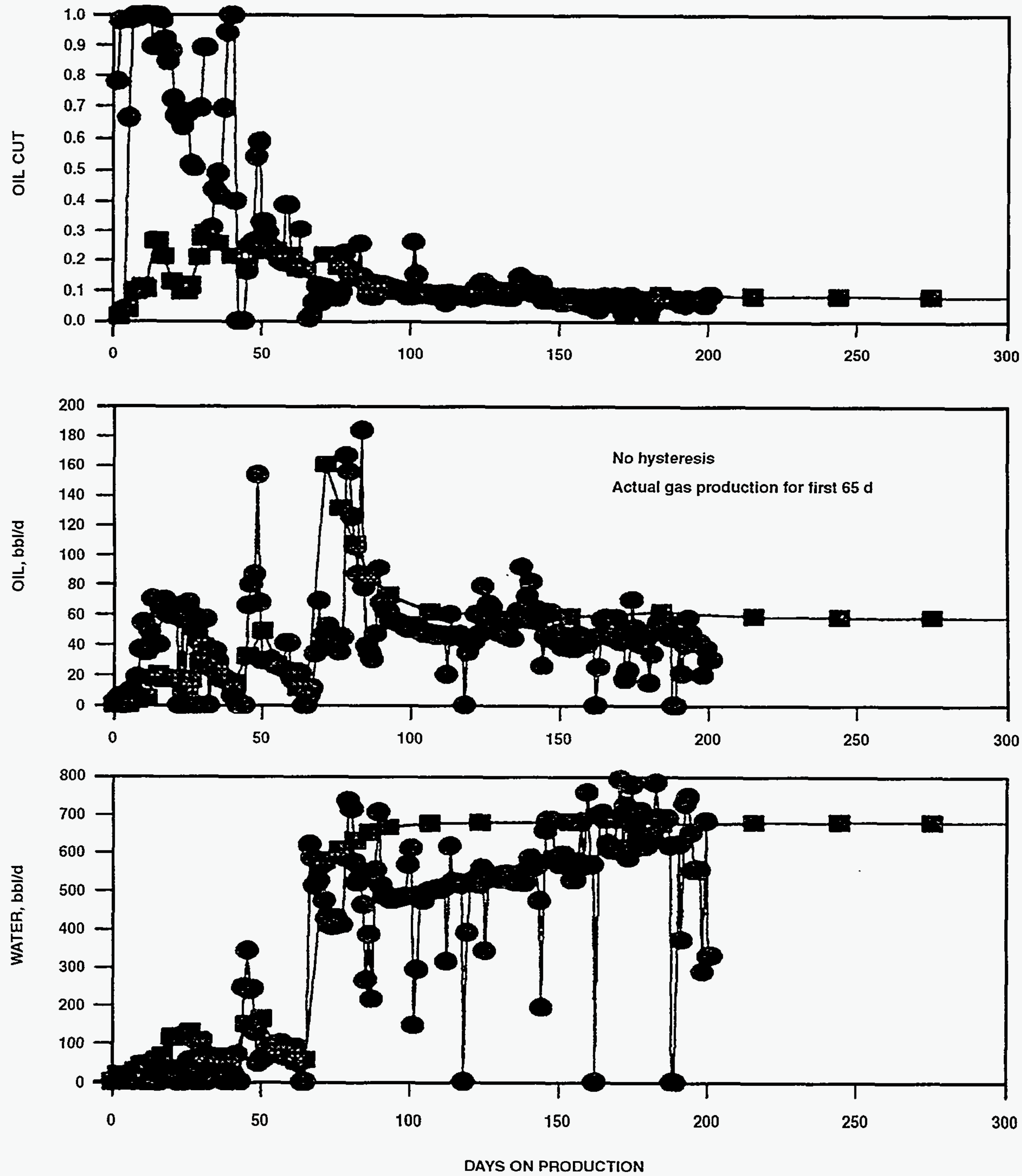

Fig. 2 History match with limitations on the initial gas rate. —●—, actual. —■—, simulation.

in the demonstration site did increase to pre-HnP levels, and the oil rate did spike for a few days. The oil cut stayed above the pre-HnP level for a period of time after the pump was put back in.

In many HnPs that have been described as successful in the literature, the total liquid production rate increased, although the steady oil cut did not. These previous reports of increased total liquid may simply reflect a cleanup of perforations or the wellbore, whereas this demonstration used a wellbore that had been cleaned out several months earlier—eliminating the unknown variable.

Figure 3 shows how the history match is changed when the gas production rates are permitted to increase to 1 MMcf/d. The oil response improves. This suggests not limiting gas production during an HnP.

If gas trapping occurred during the demonstration, it was short-lived because 100% of the injected CO_2 volume was produced. This was the main mechanism required in theory

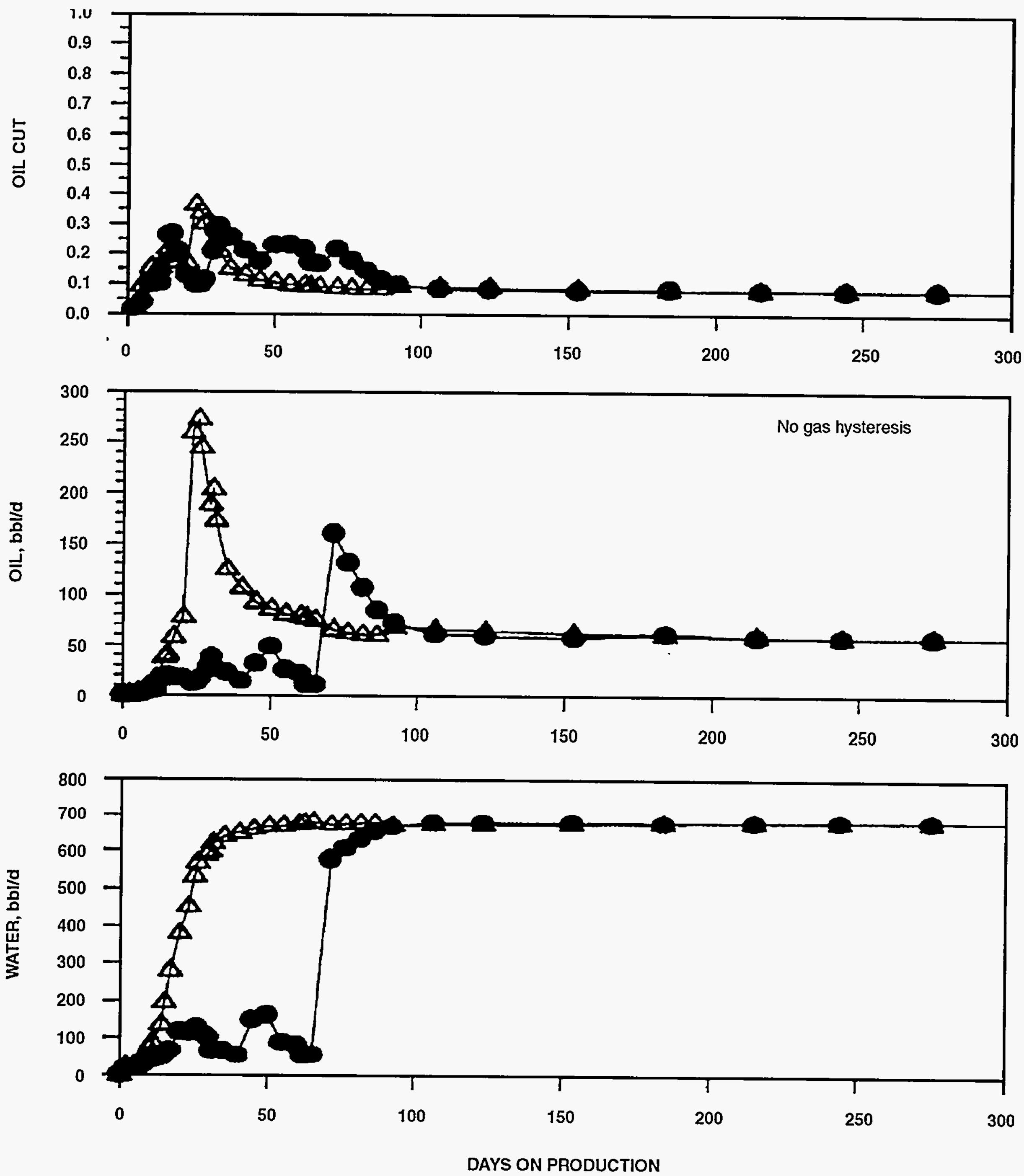

Fig. 3 Illustration showing how the history match is changed when gas production rates are permitted to increase to 1 MMcf/d. —●—, history match with actual gas production. —Δ—, history match with 1 MMcf/d gas limit.

to provide the improved oil recovery profile developed in the parametric and site-specific simulations. Earlier reports detailed the need for a trapped gas saturation. It is theorized that the water production was able to dissolve the trapped gas saturation or the reservoir is not amenable to gas trapping. The simulation predictions (and history matching) do not include dissolved gas in the water fraction. Although this is known to occur on a limited basis, it could not be adequately simulated with the software that was used because of computational instabilities. It is possible that gas trapping cannot occur in this reservoir because of pore throat size, porosity type, lithologic characteristics, or a combination of these that are not currently understood.

Near-wellbore gas trapping of CO_2 has been cited as one possible cause of reduced injectivity following water-alternating-gas (WAG) injection methods employed in most miscible CO_2 floods. The offset East Vacuum Grayburg San Andres Unit miscible CO_2 flood operated by Phillips is one of the few Permian Basin CO_2 floods that has not experienced appreciable reduction in injectivity during 11 yr of WAG operations, even though many of the other shallow-shelf carbonate reservoirs experience 30 to 50% reductions in water injectivity following the introduction of CO_2 to the reservoirs. If it can be inferred that reduced injectivity in WAG operations is related to gas trapping, then Vacuum field is not a good candidate for further testing of the HnP technology. Oxy has been experimenting with HnP technology in the Welch field and has had HnP results favorable enough to expand the program. An offset miscible CO_2 flood within the Welch field experienced reduced injectivity in WAG operations. This suggests that the technology should be applied to another reservoir that has documented WAG injectivity reductions. This option is being pursued. The HnP technology might become a valuable indicator of potential injection rates when designing a miscible CO_2 flood. Injectivity is one of the main parameters affecting the economics of these large-scale projects. The failure of the HnP might indicate favorable expectations of injection, whereas a positive response may suggest injectivity reductions—thus the need for the parallel implementation of the HnP technology.

The oil cut in the actual HnP was very high, better than 0.90 for a period of time. The predicted oil cut did not reach such high levels. The high oil cut could not be achieved in the simulation. Although the oil cut was very high, the actual oil rate was quite small in this period, as was water production. The capability of accurately measuring these small volumes may have an influence on the calculated oil cut in the initial production period. It is also possible that water relative-permeability curve hysteresis may be required to limit the water production in the simulation. This option is not available in the commercial simulator used. If the total liquid production rate in the actual test during the flowing period had been close to that in the prediction, there would have been a large oil spike in production. After the pump was put back in, the liquid rate in the demonstration site did increase to pre-HnP levels, and the oil rate did spike up for a few days. The oil cut stayed above the pre-HnP level for a period of time after the pump was put back in.

The simulation also suggests that an error in the measured gas production rate may have occurred shortly after the pump was put back in. The metered volumes plateaued after the 100th day rather than continuing to decline. Metered gas volumes from the demonstration site also suggest recovery was 40% higher than the volume injected. Figure 4 compares the measured and simulated gas production for the history match.

Figure 5 compares the site-specific prediction with the history match case in which the gas production rate was permitted to reach 1 MMcf/d. The site-specific forecast also had a 1 MMcf/d gas production limitation. The main difference between these two cases is that the forecast had gas trapping (i.e., gas hysteresis), whereas the history match case did not. The absence of the residual gas saturation delays and reduces the predicted oil production.

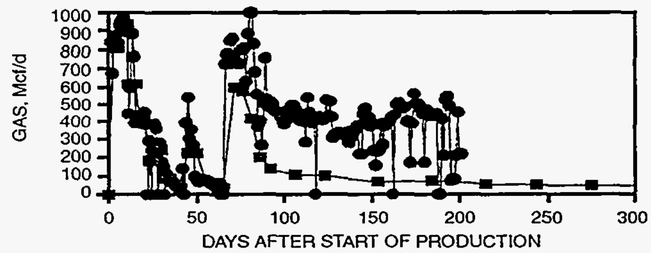

Fig. 4 Comparison of measured and simulated gas production rates for the history match. —●—, measured. —■—, simulation.

The history matching efforts validate the decision to not attempt any more HnP at CVU. In addition to requirements about a trapped gas saturation, there appears a "rate" requirement for a successful HnP that cannot be tolerated because of disposal limitations at CVU. If the total liquid production rate during the HnP cannot be maintained at the same level (or at least a high fraction) as the pre-HnP level, then the HnP will not be successful because the oil rate will be too small (even though the oil cut might be improved). If this CVU well is typical, a successful HnP may not be possible for a well that must be converted from pumping status to flowing status and back again. The liquid production rate during the flowing period would be too low. This work suggests that improved rates may be possible if higher gas volume production equipment can be used.

Cost and Economic Considerations

The actual costs associated with the field demonstration components of the project are included in Table 1 under the heading No. 1 (Pumped). A number of nonrecurring charges

TABLE 1

Field Demonstration Costs

Demonstration	No. 1 (Pumped)	No. 2 (Pumped)	No. 2 (Piped)
	Days		
Deferred production	43	20	20
	Thousands of Dollars		
Test separator	34.2	0	0
CO_2 commodity/ *transport/pump*	142.3	79	19
Wireline	5.9	6	6
Downhole*	19.5	15	15
Surface†	42.8	20	20
New tbg.	15.6	0	0
In-line heater	6	0	0
Miscellaneous	17.8	10	10
Total	284.1	130	70
DOE share (45%)	127.8	58.5	31.5
CVU share (55%)	156.2	71.5	38.5

*Pulling Unit etc.
†Contract labor, welding, transport, etc.

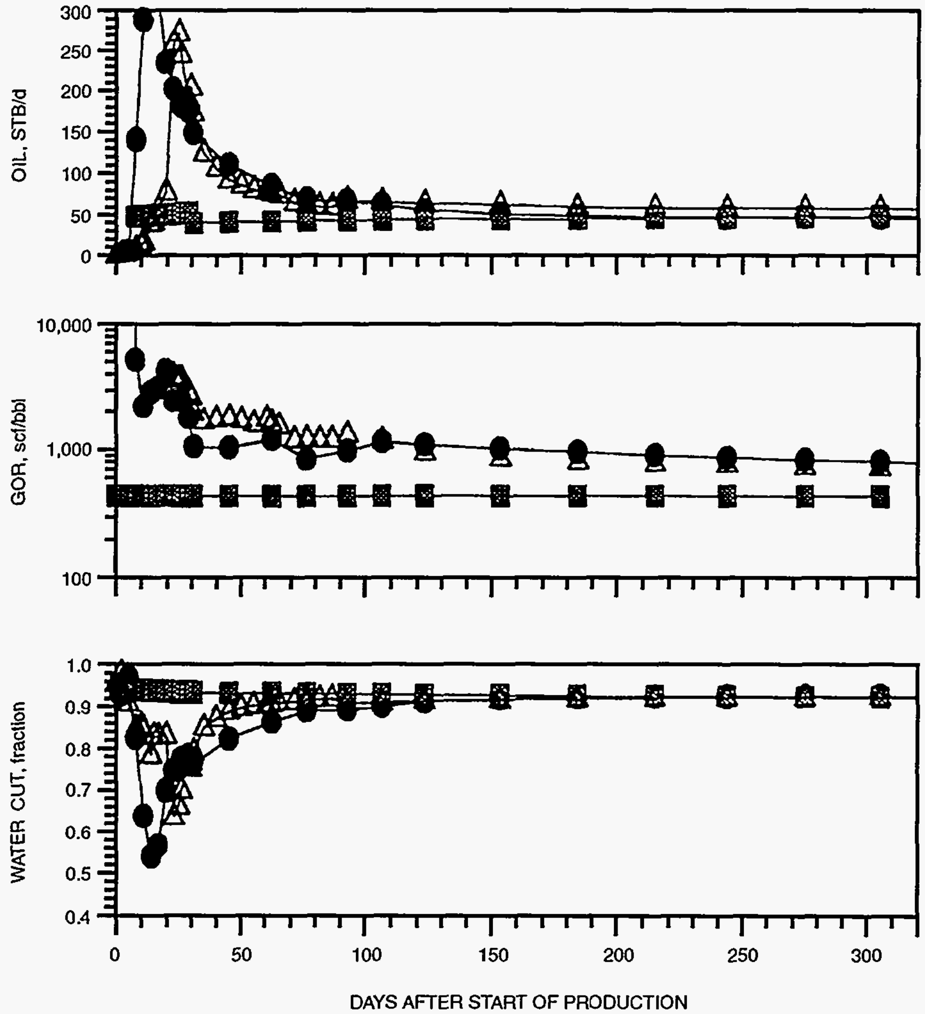

Fig. 5 Comparison of site-specific prediction with history match case in which gas production rate was permitted to reach 1 MMcf/d (50 MMcf CO_2 injected volume, 2 MMcf/d CO_2 injection rate, 1 MMcf/d maximum gas production). ●, HnP with hysteresis. □, waterflood. Δ, HnP history match without hysteresis and with 1 MMcf/d gas limit.

were identified that would not be included if a second demonstration site were chosen at CVU. The volume of CO_2 would not be as large, and thus pump time would be reduced. The soak period would also be scaled back. This second option is depicted in the table as No. 2 (Pumped). The cost of a second site at CVU would be about half the cost of the first site. As originally hypothesized, the largest benefit of this technology would come from coupling it to a miscible CO_2 flood (having pipeline CO_2 available as the project was implemented and expanded). This last scenario is included in the table as No. 2 (Piped). The availability of pipeline CO_2 makes a significant impact on the cost of the demonstration. The piped CO_2 scenario would cost about one quarter of the first demonstration.

Table 2 shows some simple relationships depicting the basic economics of the HnP demonstration along with the two options previously discussed. The same naming convention is applied. In addition to some nonrecurring items, the field demonstration costs were heavily influenced by the cost of delivering and pumping the CO_2. As shown in Table 2, the

TABLE 2

Field Demonstration Economics (back of the napkin)

Demonstration	No. 1 (Pumped)	No. 2 (Pumped)	No. 2 (Piped)
CO_2 volume, MMscf	50	25	25
CO_2 cost, $/Mscf	2.85	3.16	0.76
Deferred production, STB	2924	1360	1360
Total cost, $M	284.1	130	70
Equivalent bbls @ $18/STB	15,800	7,200	3,900
Breakeven utilization, Mcf/STB	3.2	3.5	6.4

planned CO_2 volume would not be as large for a second demonstration. This directly impacts the amount of deferred production.

The project becomes more attractive if pipeline CO_2 is available. If an $18/STB sales price for crude oil is assumed, the necessary volume of recovery to reach a pseudo-break-even point is calculated. The cost reductions available for the No. 2 (Piped) case begin to look encouraging. The CO_2 utilization in this case looks reasonable at 6.4 Mscf/STB—similar to miscible CO_2 flooding cases. The recovery for the No. 2 (Piped) case is similar to expectations derived from the compositional simulations when a trapped gas saturation develops in the near-wellbore vicinity.

Additional benefits were noted. First, even though recoveries in this demonstration accounted for only the deferred production, there were reduced electrical requirements during the injection, soak, and flow periods. Second, there were reduced water-handling requirements for an extended period of time. These benefits, coupled with the potential to recover additional oil, suggest that further investigation is warranted if the technology is applied to a reservoir amiable to gas trapping.

Technology Transfer

The Petroleum Recovery Research Center continues to provide updates on the project in its quarterly newsletter. Also, the Petroleum Technology Transfer Council is providing complete quarterly and annual technical reports on an industry bulletin board called GO-TECH to provide a timely dissemination of information to those interested.

A paper was presented at a workshop on Integration of Advanced Geoscience & Engineering Techniques of Class II DOE Projects in Roswell, N. Mex., on August 22–23, 1996.

THERMAL RECOVERY—SUPPORTING RESEARCH

MODIFICATION OF RESERVOIR CHEMICAL AND PHYSICAL FACTORS IN STEAMFLOODS TO INCREASE HEAVY OIL RECOVERY

Contract No. DE-FG22-93BC14899

University of Southern California
Los Angeles, Calif.

Contract Date: Feb. 22, 1993
Anticipated Completion: Feb. 21, 1996
Government Award: $150,000
(Current year)

Principal Investigator:
Yanis C. Yortsos

Project Manager:
Thomas Reid
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objectives

The objectives of this research are to continue previous work and to carry out new fundamental studies in the following areas of interest to thermal recovery: displacement and flow properties of fluids involving phase change (condensation–evaporation) in porous media, flow properties of mobility control fluids (such as foam), and the effect of reservoir heterogeneity on thermal recovery. The specific projects are motivated by and address the need to improve heavy oil recovery from typical reservoirs as well as from less conventional fractured reservoirs producing from vertical or horizontal wells.

Thermal methods, particularly steam injection, are currently recognized as the most promising for the efficient recovery of heavy oil. Despite significant progress, however, important technical issues remain open. Specifically, knowledge of the complex interaction between porous media and the various fluids of thermal recovery (steam, water, heavy oil, gases, and chemicals) is still inadequate, and the interplay of heat transfer and fluid flow with pore- and macro-scale heterogeneity is largely unexplored.

Summary of Technical Progress

Vapor–Liquid Flow

During this quarter work continued on the development of relative permeabilities during steam displacement. Two directions were pursued, one based on the use of a pore-network description of steam displacement[1] and another based on a double-drainage process. The pore-network simulator is being used to predict the behavior of steam injection in a fractured system, which was previously examined experimentally in this laboratory. Researchers here have also developed a model for double drainage that allows for the calculation of three-phase relative permeabilities as a function of the saturation of the respective phases, the history of the displacement, and the ratio in interfacial tensions. This work is complete, and a technical paper is in preparation.[2] Also, a macroscopic approach is being used for the analysis of the stability of phase change fronts in porous media.

In a related study, researchers here continued investigating the effect of gravity override during injection of a gas phase (such as steam) in porous media. Published work to date cannot predict the thickness of the gravity tongue as a function of the various process parameters. An analytical formalism was developed that predicts the shape of the interface in the presence of gravity override in a homogeneous porous medium in the absence of capillary effects. Also, the effect of the gravity and capillary numbers on the thickness of the gravity tongue is being investigated. It has been shown that the thickness scales as a power law of the inverse of the capillary number and that it vanishes at large values of the latter. This has implications for predicting gravity override by conventional computer simulations, where in the absence of capillarity the tongue thickness should scale with the simulation grid size.

Finally, the countercurrent flow of liquid and vapor in the presence of gravity is being investigated. As a result of this process, a variety of applications in heavy oil recovery have been found. Displacement mechanisms that are studied by pore-network simulation and experiments are of current interest.

Heterogeneity

Work continues on the optimization of recovery processes in heterogeneous reservoirs with the use of optimal control methods. The theory addresses the injection strategy that maximizes the recovery efficiency of a multiple-well system at various defined targets (e.g., at water breakthrough or at a fixed water cut). During this quarter experiments were carried out in a Hele-Shaw cell with two controlled injection wells and one production well. Experiments were conducted in homogeneous as well as heterogeneous cells with a particular form of heterogeneity. The results agreed reasonably well with the simulations on the basis of optimal control theory. Current work involves the conduction of additional experiments and improvement of the numerical scheme for optimal control. The emphasis is on the effect of heterogeneity on the optimal control predictions.

Work was completed on the effects of correlations (for example, with the use of *fractional Brownian motion* statistics) during invasion percolation with gradients (e.g., as the result of viscous or gravity forces) in long-range correlated systems. Work was also completed on the problem of inverting capillary pressure data to infer the true pore-size distribution with the use of a pore-network approach.[2] Finally, an approach was developed to explain the origin of stabilized displacements in immiscible displacements in porous media from pore-network level studies.[3] This explains the remarkable ability of the Buckley–Leverett equation to simulate displacements.

Research has begun on two new projects dealing with the identification of permeability heterogeneity. The first involves the development of a new technique that allows the identification of the permeability semivariogram from multiple-well pressure transients.[4] This technique uses the theory of small fluctuations, which leads to a Volterra integral equation describing the ensemble-average behavior of the well pressure, from the inversion of which the permeability semivariogram can be obtained. The second project deals with the identification of the entire permeability field from tracer profiles [e.g., those obtained from a computerized tomography (CT) scan]. Researchers here have developed the particular algorithm to invert the data and find good agreement with synthetic data.

Chemical Additives

Work continued on the behavior of non-Newtonian fluid flow and on foam displacements in porous media. Work proceeds in two parallel directions. One direction involves the development of a generic theory for finding the minimum threshold path in a disordered system. This part is almost complete, and a technical paper was prepared on this subject. The other effort involves the application of this theory to pore networks to determine the conditions for foam formation and mobilization. A paper on the results shows how to compute parameters related to foam flow in porous media, such as the minimum pressure gradient for onset of foam flow, the fraction of trapped foam, etc. A Ph.D. dissertation was also completed this quarter on this subject.[5]

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GEOSCIENCE TECHNOLOGY—SUPPORTING RESEARCH

ANISOTROPY AND SPATIAL VARIATION OF RELATIVE PERMEABILITY AND LITHOLOGIC CHARACTERIZATION OF TENSLEEP SANDSTONE RESERVOIRS IN THE BIGHORN AND WIND RIVER BASINS, WYOMING

Contract No. DE-AC22-93BC14897

University of Wyoming
Laramie, Wyo.

Contract Date: Sept. 15, 1993
Anticipated Completion: Sept. 14, 1996
Government Award: $239,353
(Current year)

Principal Investigator:
Thomas L. Dunn

Project Manager:
Robert Lemmon
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objectives

The objectives of this multidisciplinary study are designed to improve advanced reservoir characterization techniques. The objectives are to be accomplished through (1) an examination of the spatial variation and anisotropy of relative permeability in the Tensleep sandstone reservoirs of Wyoming; (2) the placement of that variation and anisotropy into paleogeographic, depositional, and diagenetic frameworks; (3) the development of pore-system imagery techniques for the calculation of relative permeability; (4) reservoir simulations testing the impact of relative-permeability anisotropy and spatial variation on Tensleep sandstone reservoir enhanced oil recovery (EOR); and (5) geochemical investigation of the spatial and dynamic alteration in sandstone reservoirs that is caused by rock–fluid interaction during CO_2-enhanced oil recovery processes.

Summary of Technical Progress

The analysis of the Tensleep sandstone is complete, and the final report is being prepared. Several of the key results of the project are included in this report.

Regional Frameworks

Reservoir heterogeneity in terms of barriers and baffles to fluid flow in the Tensleep sandstone is primarily controlled by the processes that take place during both accumulation and preservation of the eolian system. Accumulation-related small-scale heterogeneity is caused by grain-packing variation associated with stratification types and erosional bounding surfaces within the eolian units. Laterally extensive marine dolomitic units form the large-scale heterogeneities; they result from fluctuations in relative sea level, which cause preservation of the eolian units. The large-scale heterogeneities in the Upper Tensleep sandstone are observed and traceable across portions of the Bighorn Basin. These same units are not traceable south into the Wind River Basin to any credible extent. The smaller scale features have lateral maximum extents ranging from thousands of feet to a few feet.

A hierarchy of flow units exists within the Tensleep eolian units. These flow units are defined by erosional bounding surfaces formed by bed-form surface processes during accumulation of the eolian sediments. The erosional bounding surfaces commonly separate tightly packed wind-ripple laminae above the surface from more loosely packed wind-ripple and grain-flow laminae below. This results in fluid flow being greater parallel to the boundaries than across the boundaries.

Bed-form reconstructions with the use of outcrop foreset orientation and outcrop photomosaics indicate that the compound cross-strata of the Tensleep were produced by compound crescentic bed forms migrating to the south-southwest with superimposed bed forms on some portions of the lee face migrating to the west.

Well-log cross sections were used to correlate six eolian-marine sequences across the Bighorn Basin. Individual sequences tend to thicken to the west, but they show localized variations in thickness related to local subsidence changes. The Tensleep was placed into a sequence stratigraphic framework such that the erosional bounding surfaces capping the marine dolomitic units are equivalent to sequence boundaries. Correlation to a relative sea-level curve suggests that the sequence boundary and the eolian accumulation formed during the time of falling relative sea level.

Borehole images can be used to identify erosional bounding surfaces in eolian cross-strata and classify them according to the depositional processes that formed them. After structural dip is removed, foreset and bounding surface dip direction and dip orientation data can be used to recreate the configuration of the dunes that formed the Tensleep eolian accumulations. Bed-form reconstruction can be used to model the three-dimensional geometry of flow units enclosed by erosional bounding surfaces. Such models can be used to distribute heterogeneous porosities and permeabilities into reservoir flow models. These models can also be used as input into horizontal drilling and completion designs.

The depth interval of the Tensleep sandstone interval is relatively small, and therefore the variation of thermal exposure and the range of extent of diagenesis are small. The variation of diagenesis on spatial variations in relative permeability is confined to the variations of cementation within a given interval and therefore more strongly controlled by either depositional factors (i.e., local operation of preservation and accumulation processes) or related to current exposure. Some evidence indicates that absolute (gas) permeability heterogeneity (commonly examined in outcrop analog) is not always a good indicator of two-phase permeability in the subsurface.

Relative-Permeability Anisotropy and Heterogeneity

Eighty-four samples of subsurface and outcropping eolian sandstone were measured for directional oil–water relative permeability. Included in the sample set were samples of the lamination types dominant in Tensleep reservoirs and of key sedimentary bounding surfaces. This study has made explicit measurements of directional variations in relative permeability (i.e., anisotropy) in Tensleep reservoir sandstones. The measurements show an anisotropy exclusive of variations in gas permeability, and, in general, the vertical oil permeability is lower than the horizontal oil relative permeability. A comparison of companion gas permeabilities and relative permeabilities indicates that gas permeability anisotropy is not always an indicator of oil–water relative permeability. The relative-permeability anisotropy is also demonstrated by the differences in the amount of oil produced before water breakthrough. Cores measured across bounding surfaces and laminations produced a greater fraction of their total oil before water breakthrough. After breakthrough, these cores tend to rapidly produce increasing amounts of water. This piston-like displacement across the fabric and baffles within the reservoirs has implications for effective drainage and development.

For maximum piston-like displacement across the bounding surfaces, primary production through horizontal radial flow should produce the greatest flow across these surfaces. The placement of wells with respect to the orientation of the bed forms is the key. Areas that are past breakthrough may show improved incremental recovery from horizontal wellbores drilled such that they penetrate the greatest number of second-order bounding surfaces. In this directional approach, the better post-breakthrough recovery properties parallel to laminations and bounding surfaces are used. These properties are demonstrated in field behavior and in two-phase flow reservoir simulations.

Pore Image Analysis

Expressions were developed to derive oil–water relative permeability from pore image analysis data collected with polished thin sections viewed with a scanning electron microscope (SEM) equipped with a backscattered electron detector. The expressions are derived principally from the Kozeny–Carmen equation.

From this study, water saturation, oil relative permeability, and water relative permeability values were predicted and observed to closely follow the measured values. The approach is relatively quick and can be further developed to improve site-specific sensitivity. The approach can easily reduce the cost of relative-permeability analysis two-thirds.

CO_2 Coreflood—Formation Alteration and Wellbore Damage

Regional water chemistry variations of the Tensleep, Bighorn Basin, Wyoming, show four formation water chemistry types. These four types were analyzed for susceptibility to scale and formation damage. Overall, Tensleep oil fields on the western Bighorn Basin have higher susceptibility to wellbore scale and formation damage as the result of CO_2 flooding. Also, the risk of wellbore scale increases with higher initial water saturation.

Technology Transfer

Technology transfer of the results of this project has covered a variety of media and venues, including the Internet and numerous informal contacts with industry representatives.

The exhibit booth of the Institute for Energy Research (IER), which includes highlights of this research, has been another important mode of informal technology transfer. Many people in the petroleum industry have learned of this research through this exhibit booth and from the researchers who are on hand to discuss it. Recently, the booth was on display at the Capitol offices for the 1996 Wyoming legislative session, where it was seen by all the legislators, several of whom are in the petroleum industry and all of whom have constituents who are affected by oil revenues. Also, the exhibit booth and the results of this research were shown at the Wyoming Governor's Conference on Energy and Minerals in Casper and at a reservoir characterization conference in Denver sponsored by the Gas Research Institute and the Independent Petroleum Association of Mountain States. Attendance at these events resulted in numerous requests for more information and for copies of our annual reports.

World Wide Web site (http://ierultra1.uwyo.edu) includes past technical reports and a considerable portion of the data and results of this study. Since May 1996, when researchers began collecting this type of data, the web site has been visited over 600 times.

This DOE project has resulted in two masters' theses, one in petroleum engineering and one in geology.[1,2] Both students have gone on to work in the petroleum industry. Other published papers are shown in Refs. 3 and 4.

A paper entitled "Geologic Interpretation of Relative Permeability Anisotropy in Eolian Sandstones, Tensleep Sandstone, Wyoming" was presented at the Rocky Mountain Association of Geologists and the Denver Geophysical Society Reservoir Characterization Symposium, Denver, Colo., September 13, 1996. A paper entitled "Reservoir Heterogeneity as a Function of Accumulation and Preservation Dynamics, Upper Tensleep Sandstones, Bighorn Basin, Wyoming" was presented at the Rocky Mountain Section of the Society of Economic Paleontologists and Mineralogists luncheon, Denver, Colo.

References

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2. J. D. Humphreys, *Determination and Geologic Interpretation of Relative Permeability Anisotropy and Heterogeneity in Eolian Depositional Units of the Tensleep Sandstone, Wyoming,* M. S. Thesis, University of Wyoming, 1996.
3. M. Carr-Crabaugh and T. L. Dunn, Reservoir Heterogeneity as a Function of Accumulation and Preservation Dynamics, Tensleep Sandstone, Bighorn and Wind River Basins, Wyoming, in *Paleozoic Systems of the Rocky Mountain Region*, M. W. Longman and M. D. Sonnenfeld (Eds.), Rocky Mountain Section, Society of Economic Paleontologists and Mineralogists (Society for Sedimentary Geology), pp. 305-320, 1996.
4. W. P. Iverson, T. L. Dunn, and I. Ajdari, *Relative Permeability Anisotropy Measurements in Tensleep Sandstone*, paper SPE 35435 presented at the 10th SPE/DOE Symposium on Improved Oil Recovery, Tulsa, Okla., April 21–24, 1996.

GYPSY FIELD PROJECT IN RESERVOIR CHARACTERIZATION

Contract No. DE-FG22-95BC14869

University of Oklahoma
Norman, Okla.

Contract Date: Apr. 6, 1995
Anticipated Completion: Apr. 5, 1997
Government Award: $350,000
(Current year)

Principal Investigator:
Daniel J. O'Meara, Jr.

Project Manager:
Robert Lemmon
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The overall objective of this project is to use the extensive Gypsy Field laboratory and data set as a focus for developing and testing reservoir characterization methods that are targeted at improved recovery of conventional oil. The Gypsy Field laboratory consists of coupled outcrop and subsurface sites that have been characterized to a degree of detail not possible in a production operation. Data from these sites entail geological descriptions, core measurements, well logs, vertical seismic surveys, a three-dimensional (3-D) seismic survey, cross-well seismic surveys, and pressure-transient well tests.

The project consists of four interdisciplinary subprojects that are closely interlinked: modeling depositional environments, upscaling, sweep efficiency, and tracer testing. The first of these aims at improving the ability to model complex depositional environments that trap movable oil. The second entails testing the usefulness of current methods for upscaling from complex geological models to models that are more tractable for standard reservoir simulators. The third investigates the usefulness of numerical techniques for identifying unswept oil through rapid calculation of sweep efficiency in large reservoir models. The fourth explores what can be learned from tracer tests in complex depositional environments, particularly those which are fluvial dominated.

Summary of Technical Progress

During this quarter the main activities involved modeling depositional environments. A problem to estimate the permeability from core measurements and transient pressure data was considered. Of particular interest was the dependence of the estimated permeability on pressure measurements. Researchers here established mathematical conditions under the estimated permeability, which is determined as a function of the pressure data that varies smoothly with respect to small changes in the data. This investigation is a key step in the study of the resolution properties of model-based estimation test problems.

RESERVOIR CHARACTERIZATION

VISUAL DISPLAY OF RESERVOIR PARAMETERS AFFECTING ENHANCED OIL RECOVERY

Contract No. DE-AC22-93BC14892

Michigan Technological University
Houghton, Mich.

Contract Date: Sept. 29, 1993
Anticipated Completion: Sept. 28, 1996
Government Award: $272,827
(Current year)

Principal Investigator:
James R. Wood

Project Manager:
Robert Lemmon
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The objective of this project is to provide the small- to medium-size oil-field operators with the tools necessary for an enhanced oil recovery evaluation of the same quality and sophistication that only large international oil companies have been able to afford to date.

Summary of Technical Progress

Project Administration and Management

The Multimedia Database Management System (MDMS) has been transferred to the commercial software package Toolbook. Maps of the southern San Joaquin Valley oil fields and the Pioneer area, core photos, core data, and thin-section and scanning electron microscope (SEM) photomicrographs of core materials, structural cross sections through Pioneer Anticline, an atlas of photomicrographs illustrating typical diagenetic features observed in San Joaquin Valley petroleum reservoirs, elemental and spectral data collected on Fourier transform infrared spectroscopy (FTIR) standards, and all quarterly reports submitted to the Department of Energy (DOE) for this project were scanned into the MDMS. All data and information are accessible through pull-down menus and a table of contents with hot links. A tutorial is presented up front to guide users through the MDMS and instruct them on the various ways in which data can be viewed and retrieved. Version 1.0 of the MDMS was written to CD-ROM and distributed to participants in a technology transfer workshop in Bakersfield, Calif., in September

1996. Version 1.1, which contains additional information and has been reorganized for easier use, is nearing completion.

All measured and computed log curves (computed curves represent such parameters as porosity, water saturation, and clay content which were calculated from the measured log traces with the use of specially developed algorithms) for the 45+ project wells on Pioneer Anticline are now in the MDMS in digital log ASCII (LAS) format and can be exported to any commercial log evaluation program for manipulation and analysis. All log curves were written to the CD-ROM in digital format.

A search engine was developed in Microsoft Access that can be used to retrieve logs from the CD-ROM. Any desired log curve can be located with the use of queries and then exported from the CD-ROM to temporary Access tables created on the computer's hard drive. Once in the Access tables, log curves can be manipulated or transferred to log evaluation packages, such as GeoGraphix's QLA2 or Crocker's Petrolog program, for analysis and plotting. A tutorial describing how to use the search engine was written and is now available as on-line help.

Log evaluation is being carried out at differing levels of sophistication in the programs PfEFFER, QLA2, Crocker Petrolog, and Symbiolog. Maps and cross sections are being prepared with GeoGraphix Exploration System (GES) software; three-dimensional (3-D) visualizations were prepared with the MatLab software.

Data Collection

With the use of their newly developed log-evaluation program Symbiolog, Digital Petrophysics, Inc. (DPI) completed the analysis of all Pioneer project wells. An innovative procedure was developed for the use of modern log suites, calibrated to core data, to evaluate wells for which only old electric logs (e-logs) are available. This procedure was used to calculate such parameters as porosity, water saturation, and clay content, which are not directly measured by these old logs. The evaluation procedure is based on an iterative process in which petrophysical data collected on core material are calibrated to logs in wells with full modern log suites. Porosity, water saturation, clay content, etc., are calculated from the full-log suite with the use of algorithms and then cross-checked against values measured in core. The same parameters are then calculated with only the basic e-log suite. Algorithms are adjusted until parameters derived from the core, the full-log suite, and the e-log-only suite all show reasonable agreement within the logged interval. When an acceptable level of agreement is achieved, the algorithms can be used to calculate porosity, saturation, and lithology in old e-log-only wells.

Successful results were achieved. Porosity, saturation, and lithology were calculated for all wells in the Pioneer study area, including wells with full modern log suites, wells with intermediate-aged log suites, and wells drilled in the 1930s and 1940s for which only e-log suites are available. The computed curves for all 45+ project wells were delivered to Michigan Technology University.

All measured and computed log curves are stored in the MDMS in LAS format and are retrievable with the use of Microsoft Access as a search engine. The programs PfEFFER, QLA2, Crocker Petrolog, and Symbiolog are being used for log evaluation. PfEFFER is a simple, inexpensive ($290) log-evaluation software package developed by the University of Kansas researchers; QLA2 is an intermediate-level log-evaluation package suitable for general use by exploration and development geologists that is provided as a module with the GeoGraphix Exploration System; and Crocker Petrolog and Symbiolog are sophisticated log-evaluation programs suitable for use by formation-evaluation specialists. A comparison of the different programs was presented at a technology transfer workshop.

Data Analysis and Measurement

Current efforts concentrate on obtaining better standards for Opal A and computerized tomography. Because the Fourier transform infrared spectroscopy (FTIR) work represents an M.S. thesis research project, it will continue after the completion of this DOE contract.

A researcher from DPI picked the tops of the Etchegoin formation, the Monterey formation, the Reef Ridge sand, and the Reef Ridge shale in all project wells and constructed fault-plane maps for all faults in the vicinity of Pioneer field. The data were used to construct 3-D visualizations of the Pioneer anticline in MatLab. The results of the 3-D visualizations, with "slice and dice" capability, are quite impressive and were presented at the technology transfer workshop.

Final analysis of all well logs from all Pioneer project wells was completed with the use of the program Symbiolog.

Customized parameter tables were developed from core data and modern log suites for use in special algorithms that compute lithology, percent clay, percent shale, matrix type, porosity, and water saturation from old e-log data, and the results were plotted in log form. These calculations were performed on all 45+ Pioneer project wells, and computed curves were generated.

Modeling

The geochemical modeling program CHILLER was used to model fluid–rock interaction. This has very practical significance because of active steamflooding of the Monterey and Etchegoin formations elsewhere in the southern San Joaquin Valley. Geochemical mass transfer work using CHILLER was also performed.

Basin modeling work on fluid flow out of the deep San Joaquin Basin continued. With the use of the program MatLab, a number of new applications for constructing 3-D surface and volume visualizations and pseudo-seismic cross sections were developed. These new applications were demonstrated at the technology transfer workshop with the use of data from Pioneer anticline.

One-dimensional basin modeling with the use of the program BasinMod, which focused on analysis of the Elk Hills 934-29R well in the Naval Petroleum Reserve, the deepest well (24,442 ft) in the San Joaquin Valley, is complete. Results were presented in a talk and poster display at the technology transfer workshop.

More 3-D visualizations of the Pioneer Anticline continue to be developed in MatLab. The formation-top and fault-trace data were loaded into MatLab, and excellent 3-D surface and volume visualizations, which can be rotated to any orientation and sliced at any angle for viewing, were constructed. The capability to map accurate fault intersections on formation-top contour maps and project fault planes in 3D at any dip angle desired was added. Results were presented at the technology transfer workshop.

MatLab is being used to produce "pseudo-seismic" sections from spontaneous potential and gamma-ray logs. With the use of this program, individual pseudo-seismic logs (log traces whose amplitudes have been color-coded to resemble seismic amplitude traces) can easily be selected from a map-view window and then displayed as well-log or pseudo-seismic cross sections.

The ability to use ER Mapper, Version 5.0, is being developed to input and output several types of graphics files to GeoGraphix. ER Mapper is a module that provides the GES with Geographic Information System (GIS) capabilities. Plans are to import aerial and satellite photos into GeoGraphix, where surface maps and surface data (roads, surface facilities, etc.) can be overlayed on the photographic images.

Technology Transfer

A paper on the BasinMod study of the deepest well in the San Joaquin Valley is being prepared for publication.

On Sept. 24, 1996, project staff held a technology transfer workshop in Bakersfield, Calif. Twenty-two participants from the major oil companies, independents, government agencies, and the oil and gas consulting community attended. Cores from the McKittrick Front calibration wells (including portions of the 700-ft research core from the McKittrick Front 418 well) were on display along with core from selected intervals in the Elk Hills 934-29R well that was used in the Geohistory modeling study. Poster displays accompanied the cores. All participants received a workshop notebook that summarized project results and Version 1.0 of the MDMS CD-ROM. During the summer of 1996, GeoGraphix was used to evaluate reservoir continuity and heterogeneity in a 130-well lease in the Kern Front Field. The project results were released by Santa Fe for presentation at the workshop.

FIELD DEMONSTRATION IN HIGH-PRIORITY RESERVOIR CLASSES

REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY–SUNSET FIELD, SAN JOAQUIN BASIN, CALIFORNIA

Contract No. DE-FC22-95BC14937

University of Utah
Salt Lake City, Utah

Contract Date: June 14, 1995
Anticipated Completion: Mar. 13, 2000
Government Award: $637,891.00
(Current year)

Principal Investigator:
Steven Schamel

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The objective of this project is to reactivate ARCO Western Energy's idle Pru Fee lease in the Midway–Sunset field in California and conduct a continuous steamflood enhanced oil recovery (EOR) demonstration aided by an integration of modern reservoir characterization and simulation methods. Cyclic steaming is being used to reestablish baseline production within the reservoir characterization phase of the project. During the demonstration phase, scheduled to begin in January 1997, a continuous steamflood EOR will be initiated to test the incremental value of this method as an alternative to cyclic steaming. Other economically marginal Class III reservoirs with similar producibility problems will benefit from insight gained in this project. The objectives of the project are to (1) return the shut-in portion of the reservoir to optimal commercial production, (2) describe accurately the reservoir and recovery process, and (3) convey the details of this activity to the domestic petroleum industry, especially to other producers in California, through an aggressive technology transfer program.

Summary of Technical Progress

Cyclic Steaming Baseline Tests

One of the main objectives of Budget Period 1 was to return the Pru Fee property to economic production and establish a baseline productivity with cyclic steaming. By the end of the second quarter of 1996, all Pru producers except well 101 had been cyclic steamed twice. Each steam cycle was around 10,000 bbl of steam per well. No mechanical problems were found in the existing old well bores.

After the first round of steam cycles, the new Pru 101 well was producing much better than the existing Pru wells. In fact, two of the old producers had no response to the first steam cycle. Several possible explanations for the difference in performance include (1) error in steam measurement/allocation, (2) misplacement of steam in the reservoir, and (3) formation damage in the older wells.

In each of the second steam cycles, only one well was steamed at a time; one dedicated steam generator was used to make sure that the measured volume of steam was accurate. Injection tracer surveys were also run in each well during the cycle to determine the vertical profile of steam entry into the reservoir. The surveys indicated some variability of vertical profiles from well to well. None of the profiles, however, appeared to be particularly unfavorable in terms of heat distribution. There were no obvious small thief zones taking all the steam and leaving the rest of the interval unheated. All the steam is being confined to the Monarch reservoir with most of the heat distributed above the tubing tail, as expected.

Temperature Observation Well

Temperature logs were run in the temperature observation well (T.O. 1) to determine the heat distribution in the reservoir away from the producers. No temperature changes were noted in the T.O. well until well 101 (the closest producer to T.O. 1) was cyclic steamed, which indicates that the injected steam is heating only a limited area around each producer.

As shown in Fig. 1, the only heating observed in the Monarch reservoir appears at the top of the reservoir. This implies that, although the vertical heat distribution is favorable at the producers, the heat quickly migrates to the top of the reservoir and leaves most of the oil unheated. This may be due to the small, partially depleted interval observed at the top of the Monarch in the whole core and open-hole logs taken from well 101. Even a small gas saturation in the reservoir would likely provide a "path of least resistance" for preferential flow of steam because of more favorable relative permeability as compared with the heavy oil saturated sand.

Another significant temperature increase was noted in the T.O. well in the Tulare reservoir around 500 ft from surface. This indicates that part of the steam injected to mobilize oil in the Monarch reservoir is actually leaking up into the Tulare. Researchers now suspect that this was due to an old wellbore that was not adequately abandoned several years ago. The well has since been reabandoned, which should solve this problem.

Production

Total Pru Fee production following the first steam cycle was about 70 bbl of oil per day (BOPD) and 300 bbl of water per day (BWPD). Because of concerns about steam placement and measurement, the second round of steam cycles was started before production had stabilized from the first cycle. The drop in production during the second cycle is mainly due to producers being taken off line to inject the second steam cycle.

The total lease production resulting from the first steam cycle was lower than expected because of poor performance in the old existing wells. Post-steam oil rates in the older wells were less than 10 BOPD, as compared with the post-steam oil rate in the new Pru 101 well of 30 BOPD.

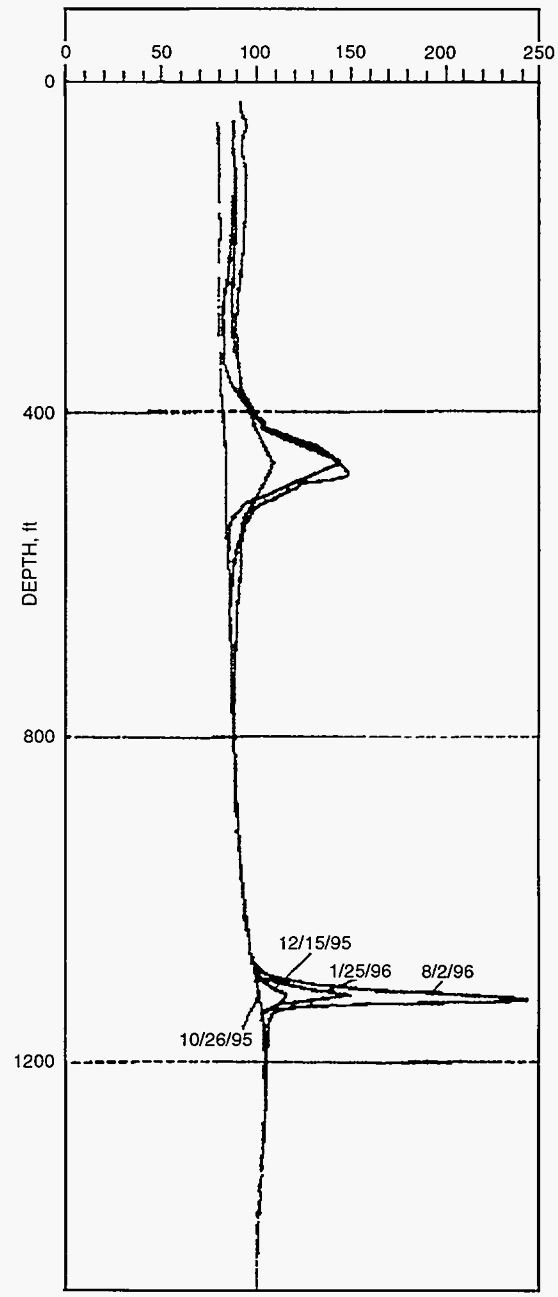


Fig. 1 Temperature observation well 1 (T.O.1) near the center of the Pru Fee property, with recordings during the period of first-cycle steam injection showing steam migration upward into the Tulare formation and the upper, depleted zone of the Monarch sand reservoir.

Early production results following the second steam cycle are encouraging, however. Some wells, such as producer D-1, are responding better to the second steam cycle. Time will tell whether this trend will continue. If it does, this may indicate that, although the old wells may have a high near wellbore skin as compared with a new well, they may still have the potential to be economic producers as the reservoir heats up with continued injection.

Conclusions

After several years of being shut in, the existing producers on the Pru lease are in reasonable mechanical condition and can therefore be used as viable producers in whatever development plan researchers determine is optimum. Production response to cyclic steam is very encouraging in the new producer; however, productivity in the old producers appears to be limited in comparison. Effectively heating the entire reservoir will be the key challenge in economically developing the Pru lease.

Reservoir Simulation

Effects of reservoir characteristics, such as the presence of bottom water, dip, thinning pay, and reservoir heterogeneities, on three different thermal processes—cyclic, "pure" steamflood, and "cyclic" steamflood—have been evaluated with the use of the two-dimensional (2-D) and three-dimensional (3-D) simulations. Results of preliminary 3-D modeling were described in the fourth quarterly report for 1995.

Conventional practice in the Midway–Sunset field is to complete the injectors over the bottom third of the reservoir pay zone and the producers over the complete pay interval. With the use of a generic two-well homogeneous model, three different completion scenarios were investigated: (1) injection and production over the entire pay interval, (2) injection over the bottom third of the pay interval and production over the entire interval (this is the current standard production mode), and (3) injection and production over just the lower and upper third of the pay interval, respectively. These completion practices were evaluated in a homogeneous reservoir dipping at 30°; both updip and downdip injection strategies were investigated.

Also, an 11-layer 2-D model with eight wells (four injectors and four producers) was used to perform additional sensitivity studies. Preliminary geologic analysis of the reservoir had revealed that the pay zone consisted of thick uniform layers separated by thin lower permeability layers. The production response was evaluated as the permeability contrast between the high- and the low-permeability zones, and the thickness of the lower permeability layers was varied. Once again, the three different processes were studied. Results of the 2-D sensitivity studies will be included in a later quarterly report.

Technology Transfer

At the 1996 annual convention of the American Association of Petroleum Geologists the project team presented an invited paper in the session Application of New Technologies to Enhance Oil Recovery,[1] which summarizes the purpose of the project and the technical results to date.

Reference

1. S. Schamel, C. Forster, M. Deo, R. Swain, M. Simmons, D. Sprinkel, and R. Adams, *Integrated, Multidisciplinary Reservoir Characterization, Modeling and Engineering Leading to Enhanced Oil Recovery from the Midway–Sunset Field, California,* paper presented at the 1996 annual American Association of Petroleum Geologists Convention, San Diego, Calif., May 19–22, 1996.

ADVANCED RESERVOIR CHARACTERIZATION IN THE ANTELOPE SHALE TO ESTABLISH THE VIABILITY OF CO_2 ENHANCED OIL RECOVERY IN CALIFORNIA'S MONTEREY FORMATION SILICEOUS SHALES

Contract No. DE-FC22-95BC14938

Chevron U.S.A. Inc.
Bakersfield, Calif.

Contract Date: Feb. 7, 1996
Anticipated Completion: June 11, 1998
Government Award: $2,334,048
(Current year)

Principal Investigator:
Stephen C. Smith

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The primary objective of this research is to conduct advanced reservoir characterization and modeling studies in the Antelope shale reservoir. Characterization studies will be used to determine the technical feasibility of implementing a CO_2-enhanced oil recovery (EOR) project in Buena Vista Hills field. The Buena Vista Hills pilot CO_2 project will demonstrate the economic viability and widespread applicability of CO_2 flooding in fractured siliceous shale reservoirs of the San Joaquin Valley. The research consists of four primary work processes: reservoir matrix and fluid characterization, fracture characterization, reservoir modeling and simulation, and CO_2 pilot flood and evaluation. Work done in these areas is subdivided into two phases or budget periods. The first phase of the project focuses on the application of a variety of advanced reservoir characterization techniques to determine the production characteristics of the Antelope shale reservoir. Reservoir models based on the characterization work will be used to evaluate how the reservoir will respond to secondary recovery and EOR processes. The second phase of the project will include the implementation and evaluation of an advanced EOR pilot in the West Dome of the Buena Vista Hills field.

Summary of Technical Progress

The Buena Vista Hills field is located about 25 miles southwest of Bakersfield, in Kern County, Calif., about 2 miles north of the city of Taft and 5 miles south of the Elk Hills field (Naval Petroleum Reserve No. 1). The Antelope shale zone was discovered at the Buena Vista Hills field in 1952 and has since been under primary production. Little research was done to improve the completion techniques during the development phase in the 1950s, so most of the wells are completed with about 1000 ft of slotted liner. The proposed pilot consists of four existing producers on 20-acre spacing with a new 10-acre infill well drilled as the pilot CO_2 injector. Most of the reservoir characterization of the first phase of the project will be performed with the use of data collected in the pilot pattern wells.

The project took a major step with the drilling of the pilot injector well, the Chevron Murvale 653Z-26B, sec. 26, T. 31 S., R. 23 E. The well spudded on July 1 and was completed on July 29 at a total measured depth of 4907 ft. The well was cored continuously through the entire Brown shale and the productive portion of the Antelope shale to just below the P2 electric-log marker. The entire cored section was deviated to the west at 20° (see Fig. 1).

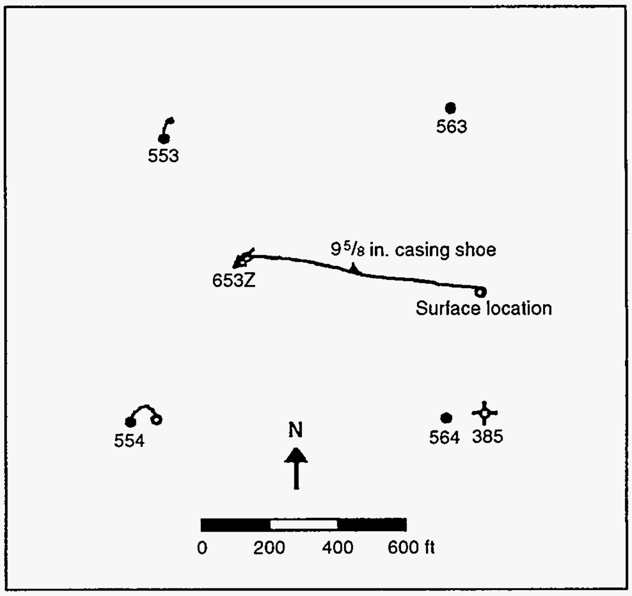


Fig. 1 Pilot demonstration project area.

Reservoir Matrix and Fluid Characterization

Coring Program

The Chevron Murvale 653Z-26B well was cored below the $9^5/_8$-in. casing shoe from 3955 to 4907 ft with 99.5% recovery with the use of a Baker–Hughes–Inteq ARC 425 core bit. The 4-in. core was recovered in a 4.25-in.-inside-diameter fiberglass inner barrel. Once cut, the core was handled to minimize disturbance. The rig crew used a chain to unscrew stands of drill pipe while pulling the core out of the hole so that the core was not rotated after it was cut. The inner barrel was pulled from the outer barrel in the derrick and placed in a core "shuttle," a piece of casing with a removable cap, for transport to the rig catwalk. Once laid down, the core was pulled from the shuttle with a hand winch onto a horizontal steel rail level with the catwalk. The inner barrel was then cleaned and marked with depth and core and section number and cut into 3-ft sections. Next, a number of samples were collected at the well site for immediate core analyses, including anelastic strain recovery, gas desorption, and wettability. The 3-ft sections were then capped, the air inside was displaced with helium, and the sections were immediately refrigerated to 34 °F and shipped to the laboratory. The core was then scanned for gamma-ray spectroscopy and density, laboratory wettability samples were taken, the core was slabbed lengthwise into $^1/_3$ (for viewing) and $^2/_3$ (for sampling) sections, and 1-in. plugs were cut every foot for Dean Stark cleaning and porosity, permeability, and fluid saturation (PK&S). Profile permeametry was performed on the $^1/_3$ section of core. Composite photographs of the $^1/_3$ core section were taken in white and ultraviolet light, and the images were digitized. PK&S samples are still about $1\,^1/_2$ months away from completion. Many of the subsequent core analysis tasks are awaiting completion of the PK&S analysis.

Wireline Logging Program

Over the $9^5/_8$-in. cased interval, 803 to 3940 ft, Schlumberger ran Platform Express [array induction (AIT), three detector density, compensated neutron, microcylindrically focused log, gamma ray, and spontaneous potential (SP)]. Over the cored interval, 3940 to 4907 ft, Schlumberger ran Platform Express, Elemental Capture Sonde, Combinable Magnetic Resonance, Electromagnetic Propagation Tool, Accelerator Porosity Sonde, Hostile Natural Gamma-ray Sonde, Formation Micro Imager (FMI), Dipole Sonic Imager (p and s mode and anisotropy mode), and Modular Dynamics Tester (MDT). Repeat SP passes were made during the log run with an AIT/SP sonde. Because of the low reservoir permeability anticipated, the MDT was run on drill pipe. The resistivity–density–neutron log over the cored interval is shown in Fig. 2.

Preliminary Findings

The slabbed core and FMI image display common small-scale fractures; however, no major open fracture zones were intersected by the well. The P point to P1 interval appears to contain more sand and is slightly more fractured than the Brown shale and deeper Antelope shale. Reservoir wettability measured with well-site wettability techniques appears mixed or equally oil and water wet, although the Antelope near P2 appears to be more water wet. The SP recorded with the AIT/SP is identical in quality to full Platform Express SP. Reservoir pressure in the brown shale appears to be around 1500 psi, whereas throughout the Antelope it appears to be about 400 psi.

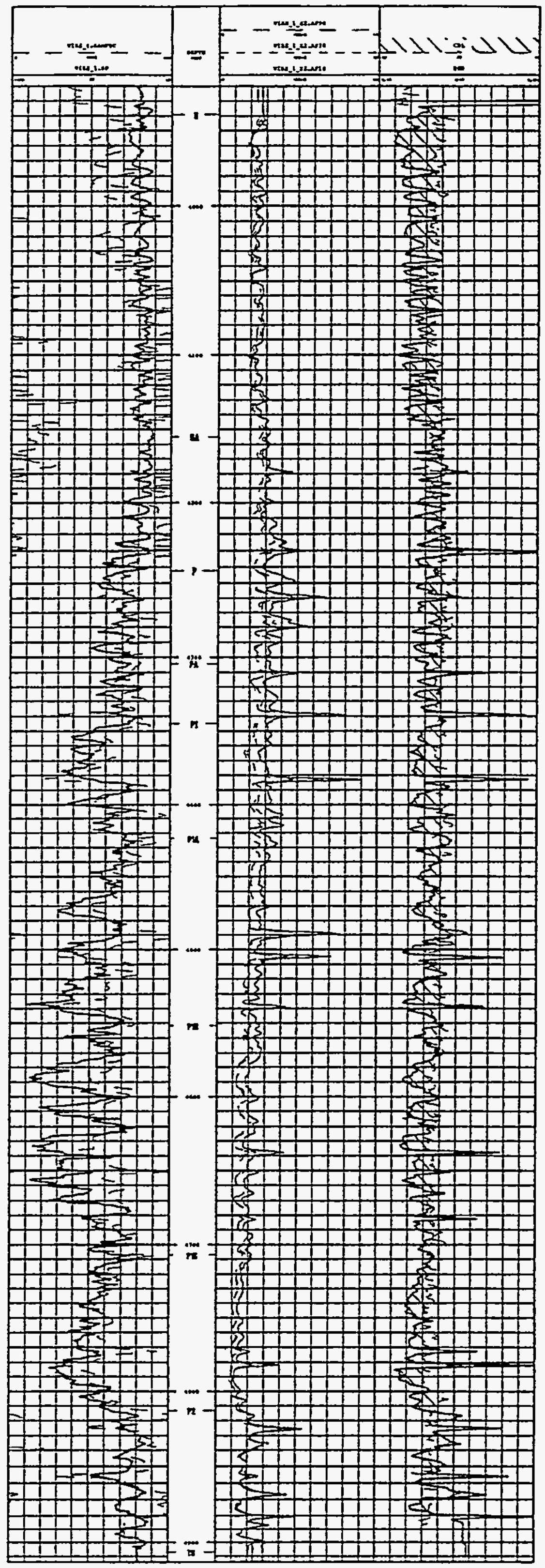


Fig. 2 Resistivity–density–neutron log for Chevron Murvale 653Z-26B well. (Art reproduced from best available copy.)

Regional Tectonic Synthesis

The regional structural grain and preferred orientation of most tectonic and physiographic features observed in the southern San Joaquin area are intimately connected with and dominated by the northwest-trending San Andreas Fault system. This is particularly evident in the area west of Bakersfield and surrounding the Buena Vista Hills, where neotectonism continues to exert profound control upon the preferred orientation of most linear structural elements as well as upon stream and river channels, valleys, and topographic scarps. Some recent investigations in the San Joaquin Basin, which have relied upon various remotely sensed data sets to measure the preferred orientation of geomorphic features, have observed that these surficial features are consistently oriented approximately N. 40 to 45° W. north of the San Andres Fault and N. 55 to 60° W. south of the fault.

If structural control of all (or nearly all) the physiographic features observed is assumed, a rigorous investigation for the tectonic geomorphology of the Buena Vista Hills and surrounding areas should provide new information regarding the location and age of unobservable (buried) fracture sets and fault displacements in a large oil- and gas-producing basin. A series of strategically located outcrops could be used to confirm important structural orientation data in areas with abundant measurements acquired from remote sensing analysis. This approach would allow contract participants to rapidly compile regional tectonic data for later kinematic and dynamic analysis. Given the geographic scope of the proposed investigation, Thematic Mapping (TM) imagery and perhaps radar imagery would appear to be the most viable data sets with which to ascertain preferred orientation of surface geomorphic structures. The ATLAS hyperspectral data appear to be best suited for examining outcrop to determine the relationship between fracture density and other fracture attributes at those scales of structural observation.

Advanced Resources International has begun to acquire remote sensing data of the Buena Vista Hills area for the regional tectonic analysis. They have received hyperspectral (ATLAS) data acquired by NASA on Oct. 5, 1993, and side-looking airborne radar (AIRSAR) data acquired by NASA on Apr. 4, 1994. They have purchased TM imagery from the EROS Data Center acquired on Sept. 15, 1986. All the data sets have been copied to compact discs for storage. After processing, the resulting images will be interpreted as part of the preliminary tectonic analysis.

APPLICATION OF RESERVOIR CHARACTERIZATION AND ADVANCED TECHNOLOGY TO IMPROVE RECOVERY AND ECONOMICS IN A LOWER QUALITY SHALLOW SHELF CARBONATE RESERVOIR

Contract No. DE-FC22-94BC14990

Oxy USA, Inc.
Midland, Texas

Contract Date: Aug. 3, 1994
Anticipated Completion Date: Dec. 31, 1996
Government Award: $2,023,000
(Current year)

Principal Investigator:
Archie R. Taylor

Project Manager:
Chandra Nautiyal
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The Oxy West Welch Unit (WWU) project was designed to demonstrate the use of advanced technologies to enhance the economics of miscible CO_2 injection projects in lower quality shallow-shelf carbonate reservoirs. The research and design phase primarily involves advanced reservoir characterization and the demonstration phase will implement the reservoir management plan based on an optimum miscible CO_2 flood as designed in the initial phase.

Summary of Technical Progress

The reservoir characterization phase is near completion with the tomography currently being integrated into the petrophysical and three-dimensional (3-D) seismic interpretations. The petrophysical analysis has yielded both an improved net pay criteria and a method for calculating permeability from log response. The 3-D seismic has enhanced the ability to distribute the reservoir properties between wellbore control points.

During the reporting period, work was completed on the CO_2 stimulation treatments and the hydraulic fracture design. Analysis of the CO_2 stimulation treatment provided a methodology for predicting results. The hydraulic fracture treatment proved up both the fracture design approach and the use of passive seismic for mapping the fracture wing orientation.

CO_2 Stimulation Treatments

All the CO_2 injection occurred during the first annual reporting period, but monitoring of the test wells has continued. Evaluation of the data generated from the five well treatments has demonstrated that the process can be economic with pipeline CO_2 in some cases. Figure 1 shows the incremental oil production vs. the wellbore porosity feet for actual and predicted recovery. The incremental oil production is calculated from production above the rate before treatment, which allows for reduced base production while the well is actually flowing or producing with very high fluid levels. Lost or deferred production from the period the well is shut in for injection or soaking is not included in the incremental oil calculation.

In the calculation of incremental oil recovery, fractional flow theory and laboratory pressure–volume–temperature data are used to estimate the volume of oil affected by a treatment. The treated radius is calculated by using the average gas saturation from the gas/oil fractional flow curve with the total CO_2 volume pumped and the total pore volume in the volumetric equation. The CO_2 volume dissolving in water and the free gas volume are estimated to determine the CO_2 volume available for swelling oil. This volume determines the CO_2 mole fraction in the oil and the oil swelling factor. With the use of the oil swelling factor, the incremental oil is calculated from the difference in oil saturations before and after swelling and the residual oil saturation to waterflooding.

On the basis of the work to date, an estimated 40 thousand stock stank barrels of oil will be produced during the first year of the project by the treatment of 17 producing wells.

Hydraulic Fracturing

Initial passive seismic results from the fracture treatment on the 4807 well were not as anticipated. The initial interpretation identified 30 seismic events that have at least 5 clear signals from different stations. Results from the 30 events show that one wing of the fracture extends over 500 ft to the east with 1 event occurring at 90° to and 500 ft from the east end of the fracture. Propagation of the other wing appears to have gone to the southeast for over 1000 ft. The seismic events, however, at the ends of the fracture suggest that the fracture grew out and then upward completely out of the main pay.

The falloff analysis gave more conventional results and showed an effective fracture half-length of 400 ft when 60 ft pay thickness was assumed. This is similar to the fracture area predicted by the fracture modeling. The post-fracture model, however, shows that the fracture grew out of zone at the well bore with a fracture height of 174 ft and a half-length of 180 ft.

The 3-D seismic fault maps showed that the reason the orientation was different was the presence of a deep fault running parallel to the fracture orientation observed with passive seismic. This changed the stress field in a very

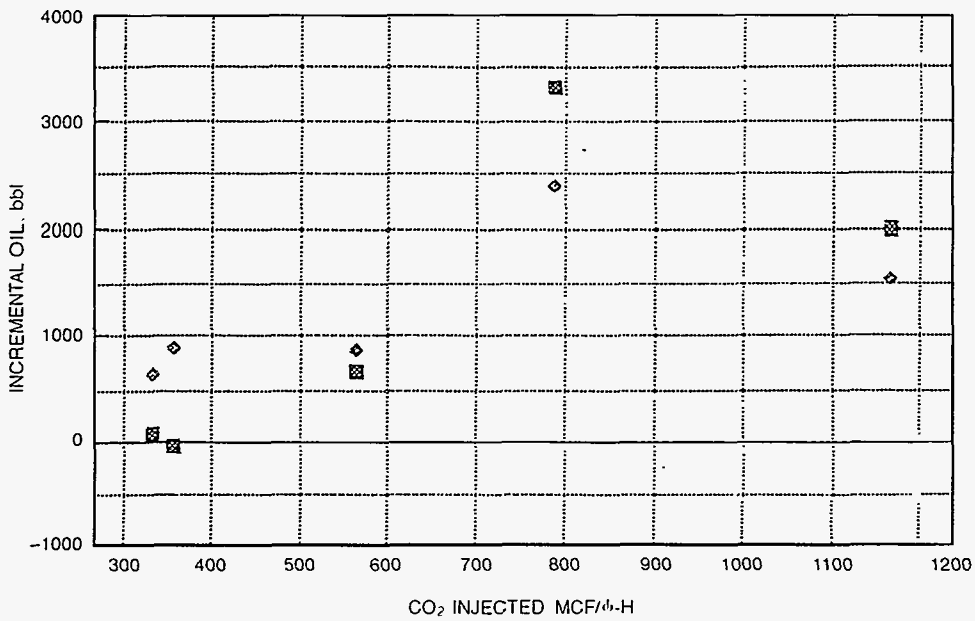


Fig. 1 Incremental oil recovery vs. thousand cubic feet (MCF) of CO_2 injected per porosity foot (ϕ-H). □, actual. ◇, predicted.

localized region around the fault. The change in stresses changed the orientation of the fracture as the fracture grew away from the wellbore and encountered the different stress field.

Petrophysical Analysis

Open-hole logs were used to calculate permeabilities for wells in the area. Figure 2 shows the comparison of the log, core plug, and whole-core permeabilities where core and modern open-hole logs were available for the same wells. The interval where core and log calculated permeabilities failed to match was described as oolitic in the core description; otherwise differences in sample interval size caused the apparent difference in core and log calculated permeabilities.

Grids of porosity and permeability values, for use in the numerical simulator, were then generated with the use of well-log and core data. Wellbore data values that were obviously too high were discarded for the initial grid generation. These discarded values were from cased-hole compensated neutron logs.

3-D Seismic Interpretation

Depth structure maps of the base of the Woodford and the Atoka horizons were generated from the 3-D seismic volume. These were used to better define the deep-seated (Pennsylvanian and deeper) faulting that lies beneath the producing San Andres formation. A coherency slice map of the base of Woodford horizon was produced to help delineate the small faults in the deep section. This information aided in the hydraulic fracture orientation evaluation.

The surface seismic data have been reprocessed to decrease the bin spacing. Advances made since the initial processing in 1992 were used to enhance the data. The result is a greatly improved seismic section with increased signal-to-noise ratio, more dense areal spacing, and higher frequencies. Figures 3 and 4 compare the before and after sections, respectively.

Tomography

Integration of the cross-well seismic velocities and wellbore data showed a distinct correlation to core porosity; however, the correlation appeared limited at a maximum value. As a result, cross-well velocities were modeled, with a one-dimensional (1-D) model, to better define the time interval in which the tomography event should be picked. The model resolves variations in picking arrivals from changes in source waveform as the result of changing source positions and changes in receiver orientation resulting in phase and polarity changes between receiver stations.

Compression-wave and shear-wave processing are complete for the 15 lines. The early results show that the shear-wave data give more detail than the compression-wave data collected at the same sampling rates. This is due to the lower shear-wave velocities, which result in more accurate processing.

Integration of the petrophysical and 3-D seismic data with the tomograms is currently under way.

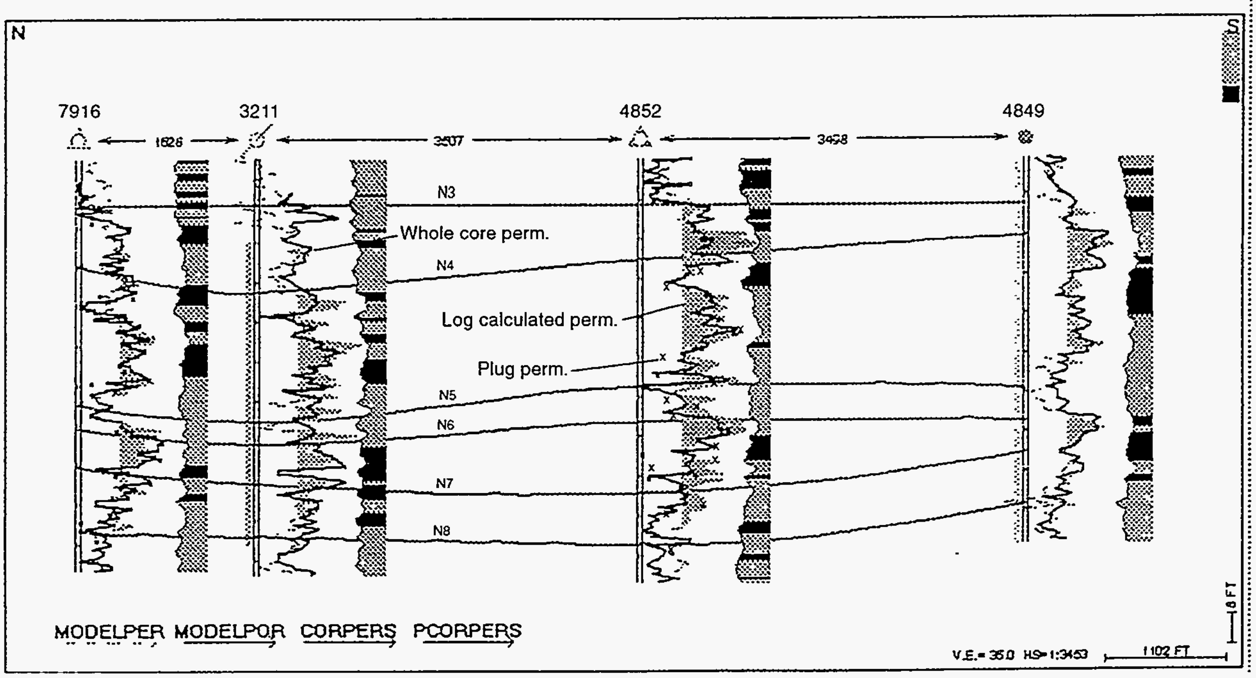


Fig. 2 Cross section showing the comparison of log, core-plug, and whole-core permeabilities for Welch field, Dawson County, Tex. The shaded gray to the right of the wellbore is the log-calculated permeability. Plug permeability is represented by (x) and whole-core permeability is the solid line. The geocolumn shows intervals of >50 Ω in black, which indicates an oil-wet system. (Art reproduced from best available copy.)

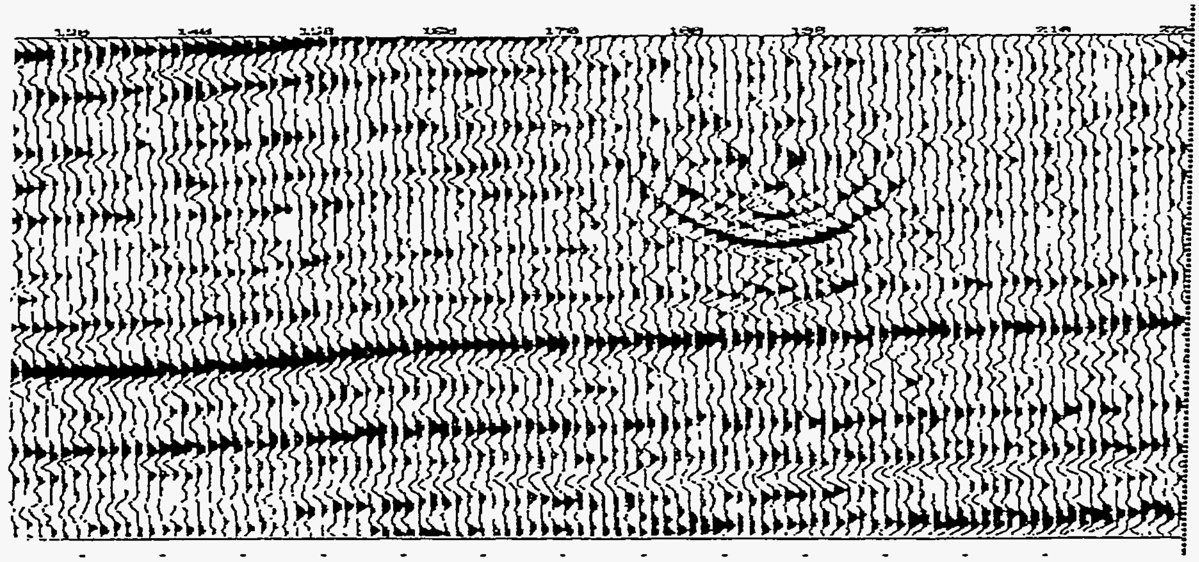


Fig. 3 1992 processed seismic section. (Art reproduced from best available copy.)

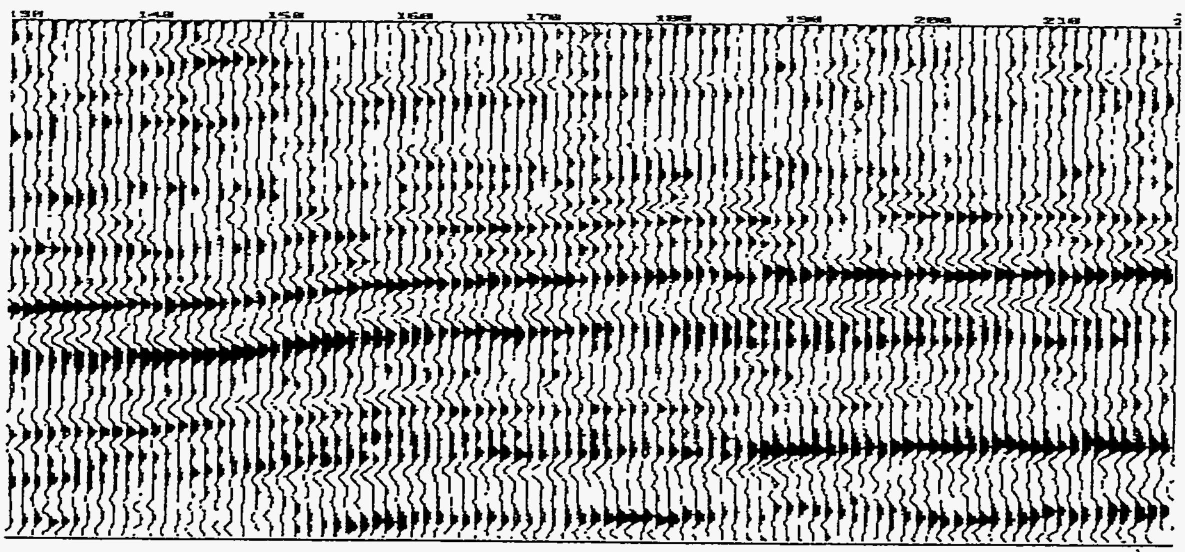


Fig. 4 Current processing seismic section with smaller bin spacing. (Art reproduced from best available copy.)

Reservoir Simulation

A preliminary history match was made for the base geologic model, and the results were used to make limited forecasts for screening economics. The grid is 57 × 65 × 9 layers, which results in an approximate 80-ft grid size to minimize the numerical dispersion effects. Steady-state simulations and production type curves were used to provide permeability and effective thickness multipliers for the history match. The steady-state simulations matched the late waterflood history when reservoir saturations were relatively constant, thus setting the permeability–thickness needed for the history match. The type curves are plots of water/oil vs. fraction of oil recovered to determine the net pay thickness needed to modify the reservoir description to match the historical performance. As the result of using the different relative permeabilities by rock type in the base geologic model, slight improvements in the history match were created.

As shown from the history match, effective water injection was about 60 to 70% during most of the flood history. The model shows that most losses occurred when surface injection pressures were at 1800 psi during the late 1970s and 1980s. Because injection pressures were lowered in 1990, injection volumes are close to 100% effective. This result correlates well with the fracture gradients from the available step-rate tests.

IMPROVED OIL RECOVERY IN MISSISSIPPIAN CARBONATE RESERVOIRS OF KANSAS—NEAR TERM—CLASS II

Contract No. DE-FC22-93BC14987

University of Kansas
Lawrence, Kans.

Contract Date: Sept. 18, 1994
Anticipated Completion: Sept. 17, 1998
Government Award: $3,169,252

Principal Investigators:
Timothy R. Carr
Don W. Green
G. Paul Willhite

Project Manager:
Chandra Nautiyal
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The objective of this project is to demonstrate incremental reserves from Osagian and Meramecian (Mississippian) dolomite reservoirs in western Kansas through application of reservoir characterization to identify areas of unrecovered mobile oil. The project addresses producibility problems in two fields: specific reservoirs target the Schaben field in Ness County, Kans., and the Bindley field in Hodgeman County, Kans. The producibility problems to be addressed include inadequate reservoir characterization, drilling and completion design problems, and nonoptimum recovery efficiency.

Summary of Technical Progress

Reservoir Characterization

The geologic reservoir characterization for the Schaben field is complete and has been presented at several national and regional meetings. Much of the geologic and production data, including maps, cross sections, and core analyses, are available online at the reservoir, lease, and well levels. The uniform resource locator (URL) is http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.html.

A reservoir simulation study is under way for the Schaben field. The initial area of study is sec. 30, T. 19 S., R. 21 W. This is one of the most prolific producing areas within Schaben field. For this study, a Silicon Graphics workstation with the Western Atlas VIP Executive simulation software is being used. The VIP simulator is a conventional black oil simulator equipped with a graphics interface. The objectives of the simulation are to (1) determine the characterization and distribution of the various reservoir parameters, (2) develop a material balance model that will history match production to date, and (3) use the model to investigate and predict different enhanced oil recovery processes in an effort to optimize oil recovery.

The geological model provided digitized contour maps for the top and bottom of the Mississippian, net pay interval, porosity, permeability, water saturation, and individual well data. An initial simulation grid was developed over the area of interest. Two files were developed in a format compatible with the VIP software. The initialization file contains all the rock and fluid parameters as well as the grid-generated data. The recurrent file consists of the history of the wells that includes location, date of completion, perforation intervals, wellbore radius, skin factor, stimulation history, production history, pressure constraints, and any other information related to individual wells. The initial model has been run for sec. 30 and consists of a single-layer reservoir. Researchers here are in the process of adding a second layer to simulate the underlying water aquifer. Reservoir parameters will be modified to obtain a history match with past production.

When the reservoir simulation is complete, the results can be evaluated, the geologic model can be modified, reservoir management techniques can be developed, and the potential for deepening and recompletion of existing wells and targeted infill drilling can be evaluated.

Technology Transfer

Technology transfer is an ongoing process that includes access to information through the Internet, almost daily inquiries, and formal presentations. The manuscript on the pseudoseismic approach as demonstrated at Schaben field will be part of the publication related to the Gulf Coast Society of Economic Paleontologists and Mineralogists conference entitled "Stratigraphic Analysis Utilizing Advanced Geophysical, Wireline and Borehole Technology for Petroleum Exploration and Production."

THE USE OF INDIGENOUS MICROFLORA TO SELECTIVELY PLUG THE MORE POROUS ZONES TO INCREASE OIL RECOVERY DURING WATERFLOODING

Contract No. DE-FC22-94BC14962

Hughes Eastern Corporation
Jackson, Miss.

Contract Date: Jan. 1, 1994
Anticipated Completion: June 30, 1999
Government Award: $547,413
(Current year)

Principal Investigators:
Lewis R. Brown
Alex A. Vadie

Project Manager:
Rhonda Lindsey
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The objective of this work is to demonstrate the use of indigenous microbes as a method of profile control in waterfloods. It is expected that, as the microbial population is induced to increase, the expanded biomass will selectively block the more-permeable zones of the reservoir and thereby force injection water to flow through the less-permeable zones and improve sweep efficiency.

This increase in microbial population will be accomplished by injection of a nutrient solution into four injectors. Four other injectors will act as control wells. During Phase I, two wells will be cored through the zone of interest. Special core analyses will be performed to achieve the optimum nutrient formulation. During Phase II, nutrient injection will begin, the results will be monitored, and adjustments to the nutrient composition will be made, if necessary. Phase II also will include the drilling of three wells for postmortem core analysis. Phase III will focus on technology transfer of the results. One expected outcome of this new technology will be a prolongation of economical waterflooding operations (i.e., economical oil recovery should continue for much longer periods in the producing wells subjected to this selective plugging technique).

Summary of Technical Progress

Phase I: Planning and Analysis

The work for Phase I of the project was divided into seven tasks. The first five, which are complete, are the drilling of two new injection wells for the acquisition of cores and other data, on-site handling of cores, core analysis to determine microbial enhanced oil recovery requirements, microbial analyses of cores, and laboratory waterflooding test of live cores.

The last two tasks of Phase I, acquisition of baseline data and analysis of baseline results, continued this quarter, and Phase II tasks began.

Acquisition of Baseline Data

The acquisition of baseline data is continuing.

Analysis of Baseline Data

The analysis of baseline data is continuing.

Phase II: Implementation

Nutrient injection and the analysis of results have begun.

Design of Field Demonstration

Completed.

Drill Three Additional Wells

Planning for drilling of three additional wells began. The three wells will each be cored and the cores analyzed to try to detect microbial growth and determine oil and water saturations in the waterflooded sand. Locations for the three wells were surveyed, and two were found to be in wetlands or crossing wetlands. To minimize environmental impact, the two locations were moved about 500 ft each to avoid the wetlands. All three sites have been permitted, and construction of the NBCU 2-5 No. 2 site is complete. Turnkey drilling bids were obtained, and the NBCU 2-5 No. 2 will spud in early October.

Analysis of Results

Chemical and microbiological analyses are continuing on samples from wells in all patterns. Gas chromatographic data from all patterns continue to be evaluated for evidence of microbial activity.

To date, neither nitrate nor phosphate has been detected in any of the producing wells. When the data for the producing wells in the test patterns were compared with the data for the producing wells in the control patterns, no significant differences (within 5% level of probability) were found for the following parameters: aerobic heterotrophs, aerobic oil-degrading microorganisms, anaerobic heterotrophs, anaerobic oil-degrading microorganisms, sulfide content, sulfate content, potassium content, hardness, or chloride content.

Both the sulfate content and the sulfide content of the fluids from both the control producers and the test producers were significantly lower (within 5% level of probability) in the last six months than in the first six months, whereas none of the other parameters being monitored showed any significant changes between these two time periods. Although it is perhaps premature to draw any permanent conclusions, it is tempting to speculate that this decrease in sulfide content is a result of (1) the injection of nitrate into the reservoir and (2) enhanced activity by nitrate-reducing microorganisms in the reservoir. Both actions have been reported in the literature to have an adverse impact on sulfate-reducing bacteria, which produce sulfide from sulfate.

Coreflood experiments that parallel the feeding regimes now being employed in the field are complete. Four core plugs prepared from the last remaining cores obtained from the Phase 1 drilled well (34-3-No. 2) were monitored with emphasis on flow rate through the plugs. The two cores receiving molasses had the greatest decrease in flow rate. The core plug receiving only nitrate and phosphate exhibited some decrease in flow rate. The control core plug exhibited only a slight decrease in flow rate.

Monthly collection of produced fluids from the test and control wells in all patterns continued. Produced fluids are separated, and the following experiments are conducted on the separated samples:

- Gas chromatography of oil samples for the wells in all patterns to detect changes in the paraffinic profile of reservoir oil caused by microbial activities.
- API gravity and absolute viscosity under reservoir temperature.
- pH of separated produced water.
- Surface tension (ST) of produced water (water–air).
- Interfacial tension (IFT) for produced oil–water system.

The pH, ST, and IFT experiments are conducted to detect any abnormal changes in the properties of reservoir fluids as the result of microbial activities.

Fluid production rates of the wells in all patterns are determined at well sites. Collected data from the field along with the generated water/oil ratio are being tabulated and plotted accordingly, and performance of the wells in all patterns is being analyzed.

IMPROVED OIL RECOVERY IN FLUVIAL-DOMINATED DELTAIC RESERVOIRS OF KANSAS—NEAR TERM

Contract No. DE-FC22-93BC14957

University of Kansas
Center for Research, Inc.
Lawrence, Kans.

Contract Date: Apr. 4, 1995
Anticipated Completion: Dec. 31, 1998
Government Award: $2,007,446
(Current year)

Principal Investigators:
Don W. Green
G. Paul Willhite

Project Manager:
Rhonda Lindsey
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The objective of this project is to address waterflood problems of the type found in Cherokee Group reservoirs in southeastern Kansas and in Morrow sandstone reservoirs in southwestern Kansas. Two demonstration sites operated by different independent oil operators are involved in this project. The Stewart field, located in Finney County, Kans., is operated by North American Resources Company. The Nelson lease, located in Allen County, Kans., in the N.E. Savonburg field, is operated by James E. Russell Petroleum, Inc. General topics to be addressed are (1) reservoir management and performance evaluation, (2) waterflood optimization, and (3) the demonstration of recovery processes involving off-the-shelf technologies that can be used to enhance waterflood recovery, increase reserves, and reduce the abandonment rate of these reservoir types.

In the Stewart Project, Budget Period 2 objectives consist of the design, construction, and operation of a field-wide waterflood with the use of state-of-the-art, off-the-shelf technologies in an attempt to optimize secondary oil recovery. To accomplish these objectives, the second budget period has been subdivided into five major tasks: (1) design and construction of a waterflood plant, (2) design and construction of a water injection system, (3) design and construction of tank battery consolidation and gathering system, (4) initiation of waterflood operations and reservoir management, and (5) technology transfer.

In the Savonburg Project, Budget Period 2 objectives consist of continual optimization of this mature waterflood in an attempt to optimize secondary and tertiary oil recovery. To accomplish these objectives, the second budget period has been subdivided into six major tasks: (1) waterplant development; (2) profile modification treatments; (3) pattern changes, new wells, and wellbore cleanups; (4) reservoir development (polymer flooding), (5) field operations; and (6) technology transfer.

Summary of Technical Progress

Stewart Field Project

Waterflood Operations and Reservoir Management

During this quarter, workovers were attempted on the Haag Estate No. 1 and No. 2 wells to return both wells to producing status (both wells have been temporarily abandoned since NARCO took over operations on 4-1-95). The Haag Estate No. 2 had a minimum of three separate casing leaks over a long interval, and the decision was made to pump test this well beneath a packer and evaluate redrill options. The production from the pump testing of the Haag Estate No. 2 has been averaging 0.5 to 1.0 bbl of oil per day (BOPD) and 15 to 20 bbl of water per day (BWPD). The Haag Estate No. 1 was worked on until it was determined that the tubing was stuck at 1900 ft as the result of more than 350 ft of fill in the tubing-casing annulus from 1900 to 2250 ft and additional fill from 3400 to 4100 ft. The workover was suspended on this well to evaluate potential risks and repair costs vs. redrill options.

The monitoring of production, injection, and water supply volumes and pressures continued. Total injection rate of approximately 5600 BWPD was maintained except for a period of time of about 9 d from 9-8-96 to 9-18-96. During this period field injection rates were approximately 2850 BWPD while the Carr 2-2 WSW was being worked on because of a downhole motor failure on the submersible pump. Cumulative water injected in the Stewart field since flood startup is 1,632,801 bbl as of 10-1-96.

Testing of producing wells with test trailers and fluid-level guns continued. Oil production increased to approximately 300 BOPD during the quarter as the result of waterflood response. This brings the total increase to approximately 585 BOPD. Waterflood response has been confirmed at a total of 13 producing wells and is suspected at another 5 producing wells. Allocation of injection volumes in injection wells is ongoing, depending on response in producers and injectors. Daily production and injection rates for the field are shown in Fig. 1.

Well servicing was performed as necessary (pump changes, minor well work, and speed up pumping units). The Sherman 3-9 WSW was also pulled because of a motor failure in the submersible pump. Approximately 90% of the producing wells have been electrified in the ongoing field electrification program.

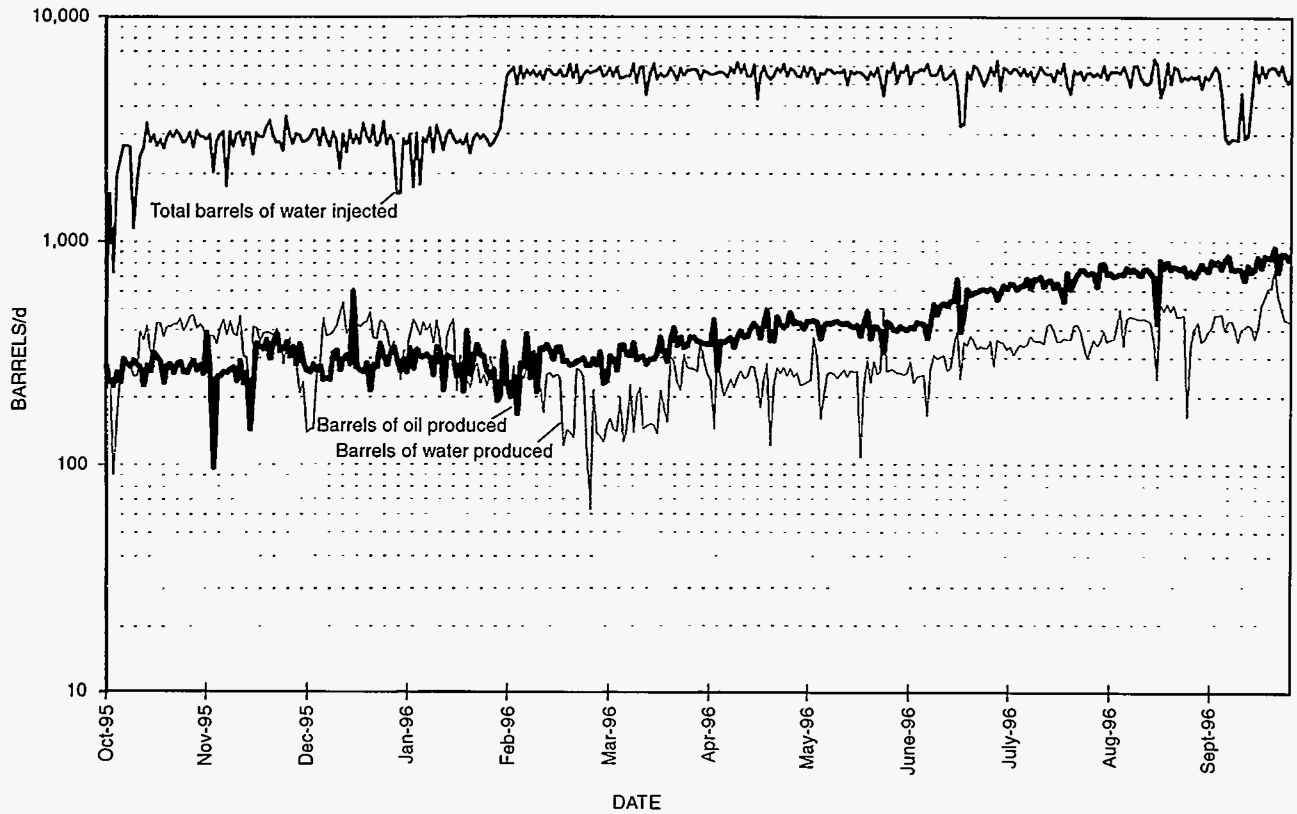


Fig. 1 Stewart field waterflood daily totals.

Technology Transfer

Articles pertaining to the increase in production as the result of waterflood response were published in *Enhanced Energy Recovery News, Improved Recovery Week*, and local newspapers throughout western Kansas.

Savonburg Field Project

Water Plant Development

The testing of chemicals and altering operational modes for the air flotation process continues. Quality water has been maintained, but at a somewhat elevated cost for chemicals and filters. A Halliburton turbine meter was installed at the injection pump discharge, and the new Ecosol digital meter was installed in the transfer line. Scaling problems are occurring at the meter and transfer pump on the raw water side. All injection trunk lines and headers were flushed and cleaned. Corrosion coupons were installed at various points in the injection system. Results indicate a high degree of corrosion in a majority of the coupons.

Profile Modification Treatments

Four batches of channel block material were injected into H-14. The first two batches were not adequate, and two additional batches were injected. The producers were sampled during the placement, and no polymer was found. Producers were shut in at the end of the job to allow the material to gel. At the time of new injection, a Halliburton turbine meter and a continuous pressure recorder were installed on the wellhead.

Pattern Changes and Wellbore Cleanup

In July, wells H-3 and H-17 were serviced because of holes in the 1-in. pump string. In August, wells H-3 and H-17 were pulled again because of holes in the 1-in. pump string.

In September, wells H-10, H-13, H-3, and K-54 were pulled because of holes in the 1-in. pump string. A packer was set in O-1 to determine if circulation occurred behind pipe with a positive flow. A coiled tubing unit was placed on well RW-6, and 50 gal of 28% acid, 2 gal of ESA-91, 2 gal of ESA-96, and 1/2 gal of ESA-50 were spotted on the bottom. The solution was displaced into perforations with 3 bbl of water.

Field Operations

Normal field operations have included (1) monitoring wells on a daily basis; (2) repairing water plant, piping, and wells as required; (3) collecting daily rate and pressure data; and (4) solving any other daily field operational problems that might occur. Production statistics are summarized in Table 1.

Technology Transfer

A paper titled "Development of An Improved Waterflood Optimization Program from the Northeast Savonburg Waterflood" was presented at the SPE/DOE Tenth Symposium on Improved Oil Recovery, April 21–24, 1996, in Tulsa, Okla.

TABLE 1

Savonburg Field Oil Production

Month	Oil production, BOPD	Month	Oil production, BOPD
October 1993	26.4	April 1995	22.4
November 1993	30.7	May 1995	25.0
December 1993	32.0	June 1995	23.9
January 1994	30.8	July 1995	26.8
February 1994	30.9	August 1995	25.2
March 1994	30.3	September 1995	24.8
April 1994	29.1	October 1995	24.4
May 1994	28.5	November 1995	24.4
June 1994	30.3	December 1995	26.3
July 1994	28.9	January 1996	28.0
August 1994	24.6	February 1996	29.2
October 1994	23.0	March 1996	27.2
November 1994	25.7	April 1996	26.7
December 1994	27.8	May 1996	26.6
January 1995	27.0	June 1996	24.9
February 1995	25.3	July 1996	25.4
March 1995	22.4	August 1996	26.5

IMPROVED RECOVERY DEMONSTRATION FOR WILLISTON BASIN CARBONATES

Contract No. DE-FC22-94BC14984

Luff Exploration Company
Denver, Colo.

Contract Date: June 10, 1994
Anticipated Completion: Dec. 31, 1997
Government Award: $1,778,014

Principal Investigators:
Mark A. Sippel
Larry A. Carrell

Project Manager:
Chandra Nautiyal
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

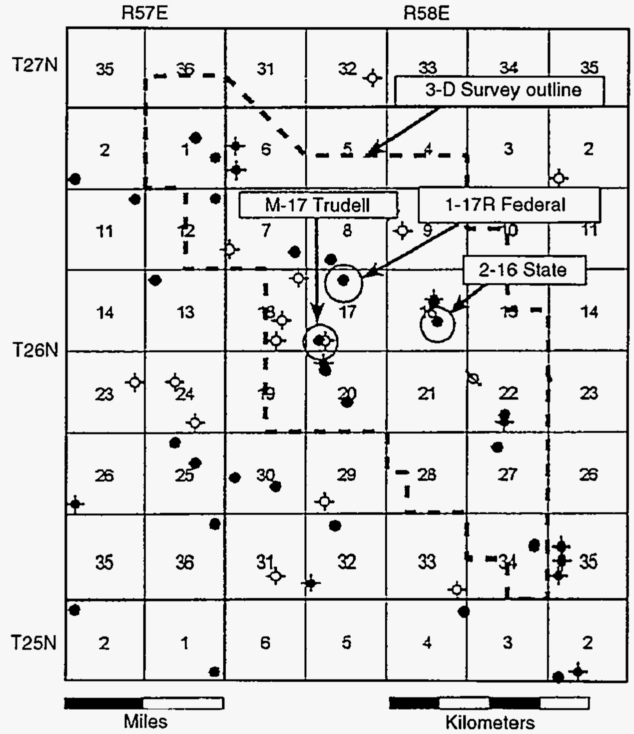


Fig. 1 Map of North Sioux Pass field, Richland County, Mont.

Objectives

The objectives of this project are to demonstrate targeted infill and extension drilling opportunities, better determinations of oil in place, methods for improved completion efficiency, and the suitability of waterflooding in certain shallow-shelf carbonate reservoirs in the Williston Basin, Montana, North Dakota, and South Dakota.

Improved reservoir characterization with the use of three-dimensional (3-D) and multicomponent seismic is being investigated for identification of structural and stratigraphic reservoir compartments. These seismic characterization tools are integrated with geological and engineering studies. Improved completion efficiency is being tested with short-lateral and horizontal drilling technologies. Improved completion efficiency, additional wells at closer spacing, and better estimates of oil in place will result in additional oil production by primary and enhanced recovery processes.

Summary of Technical Progress

Ratcliffe Core Analysis

An oriented core (10.2-cm, 4-in. diameter) was obtained through the Ratcliffe interval (2676.9 to 2703.1 m, 8783 to 8869 ft) at the 1-17R Federal, North Sioux Pass field (see Fig. 1). A Schlumberger formation microimaging (FMI) log was also run across the interval. Several fractures were observed in the core. Core Lab ran a fracture analysis of the core and established an orientation for the fractures. The FMI log was able to image the fractures observed in the core and produced a fracture orientation similar to the work performed by Core Lab. Conventional porosity–permeability studies were done with special core studies for wettability, capillary pressure, and oil–water relative permeability. An evaluation of the electrical logs indicates a productive thickness of 4.6 m (15 ft), an average porosity of 8.8%, and water saturation of 46%. The majority of the productive rock is in a 2.1-m (7-ft) interval at 2684 m (8806 ft). Core porosity of this interval averages 12.9% with a geometric-mean permeability of 4.9×10^{-4} μm^2 (0.5 mD) and maximum permeability of 1.3×10^{-3} μm^2 (1.3 mD). The porosity log and core interval of the Ratcliffe in the 1-17R Federal well are shown in Fig. 2.

The core was slabbed for petrographical analysis. The core has been photographed, and several thin sections have been obtained.

Ratcliffe Reentry Lateral Completions

Two wells in the North Sioux Pass field [M-17 Trudell and 2-16 State (Fig. 1)] have been selected for reentry lateral completion in the Ratcliffe. The laterals will be drilled out from 14-cm ($5^1/_2$-in.) casing with steered-motor technology with planned extensions of 610 m (2000 ft). Orientation of the laterals will be normal to the fracture orientation observed from the 1-17R Federal core and FMI log data. The reentry lateral drilling activity has been delayed because of limited availability of special tubulars for the work string. These tubulars are now available, and the work is scheduled to commence in November.

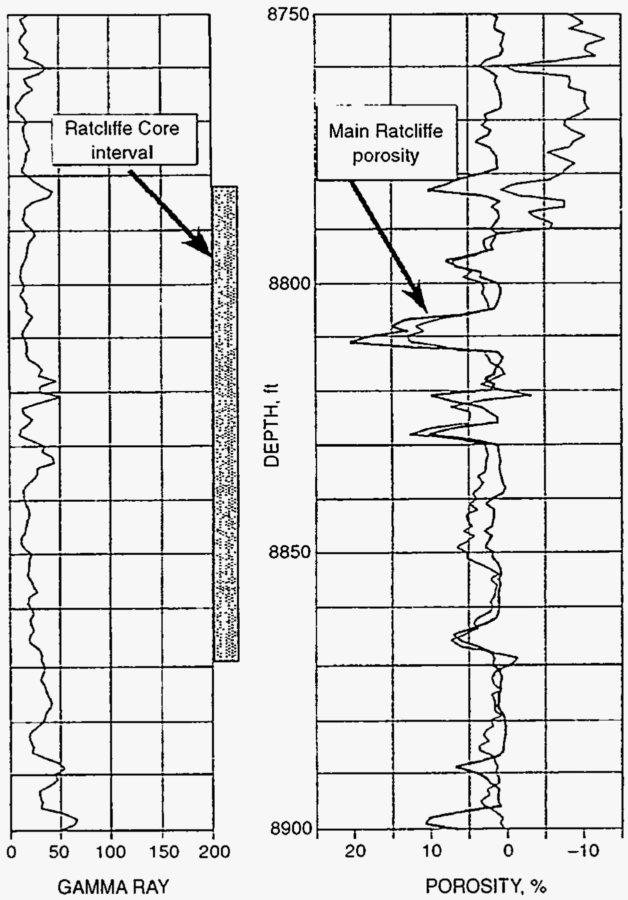


Fig. 2 Porosity log across the Ratcliffe interval from 1-17R Federal, North Sioux Pass field.

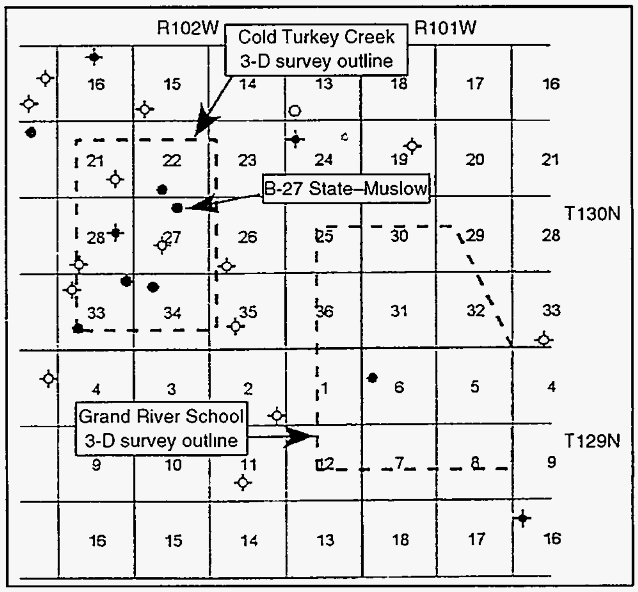


Fig. 3 Map of Cold Turkey Creek and Grand River School fields, Bowman County, N. Dak.

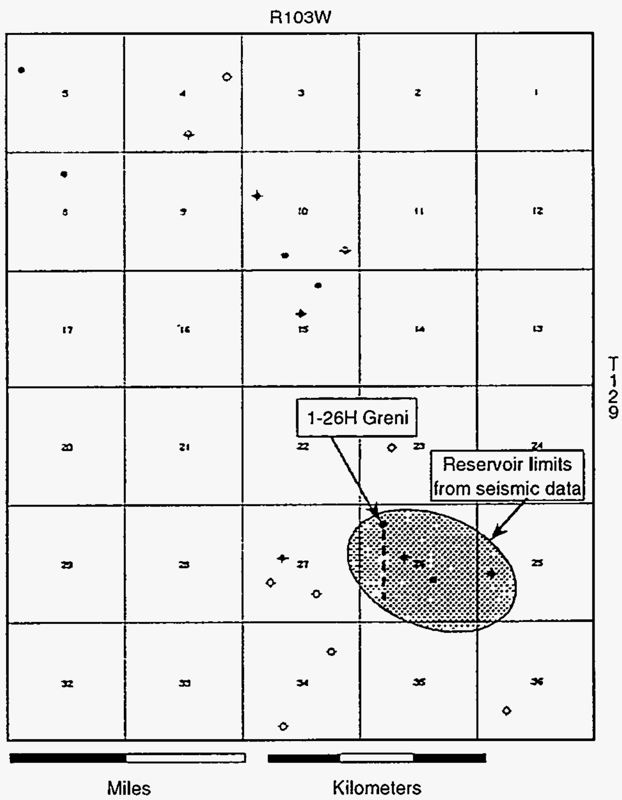


Fig. 4 Map of State Line field, Bowman County, N. Dak.

Red River Targeted Drilling

Drilling operations are under way at the B-27 State-Muslow well in Bowman County, N. Dak. (Fig. 3). The vertical well was targeted from a 3-D seismic survey over Cold Turkey Creek field. The well is expected to be at total depth by November 1. Contiguous cores will be cut across the entire upper Red River section (64 m, 210 ft). These cores will cover all four porosity benches (A, B, C, and D zones) in the Red River. Sonic and density logs will be obtained for further synthetic-seismogram study and evaluation of the 3-D seismic survey.

Luff Exploration Company participated in the drilling of a horizontal completion in the Red River B zone reservoir at State Line field, Bowman County, N. Dak. (Fig. 4). The 1-26H Greni well is the fourth well on a small Red River feature. The well is completed as a producer and will provide important production data for the evaluation of incremental reserves through horizontal completions from older fields that were previously depleted by vertical wells.

Red River Lateral Drilling

Drilling operations for a horizontal injection well at Buffalo Field (North Area) will begin in November after completion of the B-27 State-Muslow well. The Red River B zone is the target of the horizontal completion at the M-20H Stearns well (Fig 5.). The Red River B zone will be logged and drillstem tested through a vertical hole. The well will then be replugged and the horizontal section drilled. The state of South Dakota has approved a 4-week water injection test. The lateral extension is planned to be 1219 m (4000 ft) and will be

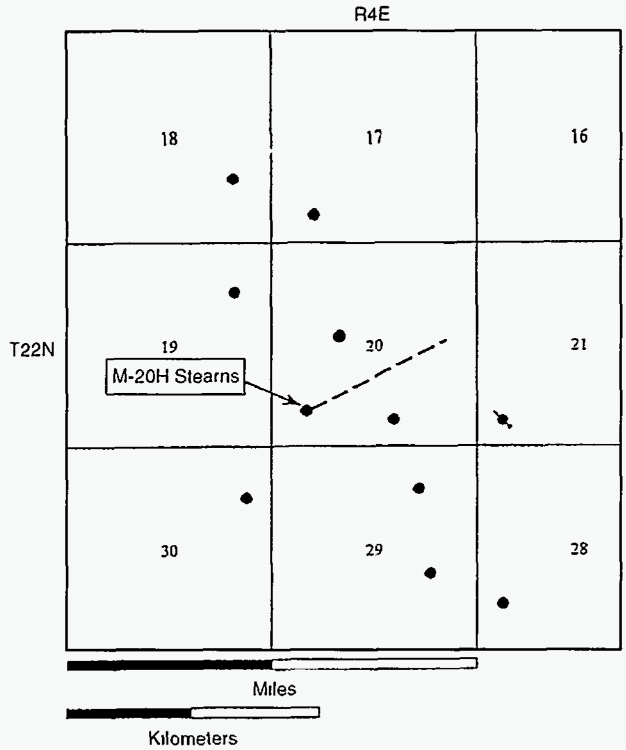


Fig. 5 Map of Buffalo field (north area), Harding County, S. Dak.

between two existing vertical wells. The success of the water-injectivity test will be an important step toward unitization and development of a field-wide waterflood project. The project has obtained water injectivity and pressure buildup data from nearby wells. These hard data will be used to construct computer simulation models for projected water-flood recovery with horizontal completions.

Red River Geophysical Survey

A 3-D seismic survey was acquired over Grand River School field in Bowman County, N. Dak. (Fig. 3). Data processing is complete. Interpretation work is integrating the new data with the nearby Cold Turkey Creek 3-D survey and waiting on the new sonic and density logs to be obtained at the B-27 State-Muslow (Cold Turkey Creek) well. Reprocessed two-dimensional (2-D) seismic data are being integrated into both the Cold Turkey Creek and Grand River School 3-D surveys.

Ratcliffe Geophysical Survey

A 3-D seismic survey is under way at North Sioux Pass field, Richland County, Mont. (Fig. 1). Seismic evaluations of the Ratcliffe from this survey will be included as part of the Ratcliffe reservoir characterizations for the project.

Conclusions

Field demonstrations are in progress to collect data for evaluation of horizontal completions in both Red River and Ratcliffe. A vertical well in Red River will test attribute analysis of 3-D seismic data for the prediction of porosity development. Additional seismic acquisitions and interpretation are in progress for both Ratcliffe and Red River. A water-injectivity test in a new horizontal completion in the Red River B zone at Buffalo field is scheduled for next quarter.

INCREASING HEAVY OIL RESERVES IN THE WILMINGTON OIL FIELD THROUGH ADVANCED RESERVOIR CHARACTERIZATION AND THERMAL PRODUCTION TECHNOLOGIES

Contract No. DE-FC22-95BC14939

City of Long Beach
Long Beach, Calif.

Contract Date: Mar. 30, 1995
Anticipated Completion: Mar. 29, 1999
Government Award: $2,184,000
(Current year)

Principal Investigator:
Scott Hara

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The objective of this project is to improve thermal recovery techniques in a slope and basin clastic reservoir in the Wilmington field, Los Angeles County, Calif., with the use of advanced reservoir characterization and thermal production technologies.

Summary of Technical Progress

The project continues to make good progress but is slightly behind schedule. Estimated costs are on budget for the work performed to date. Technical achievements accomplished during the quarter include placing the first two horizontal wells on production following cyclic steam stimulation.

Compilation and Analysis of Existing Data

A computer database of production and injection data and previous reservoir studies was compiled for the FB II-A Tar zone. Digitized and normalized log data were completed for 171 wells (more than 600 wells penetrate the Tar zone in the fault block). The digitized logs include the electric or induction and the spontaneous potential and/or gamma ray. The log data from the 171 wells are distributed throughout the fault block and will provide the base case log file for developing the three-dimensional (3-D) stochastic geologic and reservoir simulation models. Another 100 logs will be digitized and normalized to use as "confirmation" logs for the stochastic modeling. Conventional cores throughout the zone were obtained from the previous operator in 9 of the 171 wells used to correlate the formation rock and log data.

Advanced Reservoir Characterization

The basic reservoir engineering technical work is complete, and several draft reports covering the various aspects of the study were completed this quarter.

The tracer program has been delayed because the main hot-water distribution line was temporarily disconnected to accommodate the surface landowner. Laboratory work has been completed to identify nonradioactive reservoir tracers effective in high-temperature (500 °F) environments. The tracer program includes two tracers, ammonium thiocyanate and lithium chloride, which will be bulk injected into the "T" and "D" zones in the water-alternating-steam pilot injectors in January 1997 after the hot-water injection system is reconnected. The tracers will follow the liquid phase of the injected fluids rather than the steam phase. Computer software has been developed to map formation permeability in 3-D from production and injection data. A compositional model at a major research company in California is being used to test the software.

The high-temperature core work has been delayed until laboratory procedures for measuring rock compaction caused by steamflooding can be incorporated into the original proposal to perform steam pot tests and measure the geochemical effects of high-temperature steam on the reservoir rocks and fluids. All of the special core work will be used in the thermal reservoir simulation model.

A 3-D deterministic geologic model is being used to develop the 3-D stochastic geologic model and was used for drilling the observation and horizontal wells.[1] The deterministic model correlates 18 sand tops in the Tar zone. All existing cores were visually inspected, and the core and log data were evaluated to develop a core-based log model, a porosity–permeability model, and a rock–log model. These models will provide the rock and reservoir data for the stochastic geologic model in locations where only well log data exist.

Two deterministic geologic draft reports were completed this quarter. One report will provide information to the Los Angeles Basin oil producers regarding which reservoirs they operate that are analogous to the Tar zone in the Wilmington field. The other report analyzes the possibility of fluid movement across faults using production and injection data and capillary transition and oil–water contact data. This analysis is being used in the basic reservoir engineering and reservoir simulation modeling.

On the stochastic geologic model, a neural network analyzer has been developed to analyze the similarities of various zones and subzones in terms of sequence stratigraphy with the use of gamma-ray and spherically focused logs.[2] Sample stochastic grid-block models are being test run on FB II-A logs with the use of the 3-D Earth-Vision™ visualization software to ensure compatibility. Work on actual examination of the FB II-A well-log data for variogram modeling requirements of geostatistical modeling is in progress. Of particular interest is whether log normalization and environmental correction work can significantly affect log character with regard to variogram modeling. The application of facies distribution and heterogeneity description is being examined with the use of indicator modeling. The technical work on using production data to condition stochastic images is complete, and a report should be completed soon.

Reservoir Simulation

The STARS™ thermal reservoir simulation program by the Computer Modeling Group (CMG) of Calgary and the R10,000 Onyx RE2 workstation by Silicon Graphics Incorporated (SGI) have been selected for the stochastic modeling. Benchmark tests performed by the project team, CMG, and SGI confirmed the capabilities of the software and hardware platforms. Purchase and installation of the simulation software and computer hardware were completed in September 1996.

Reservoir Management

Four horizontal wells (two steam injectors and two producers) were drilled in late 1995. The two injection wells, 2AT-61 and 2AT-63, were selectively completed with 11 quarter-inch limited entry perforations per well over the last 600 ft of the horizontal section to inject a calculated 1500 bbl of cold water equivalent steam per day (BCWESPD). Cyclic steam injection began in December 1995 at low rates of 300 BCWESPD per well and increased to 1500 BCWESPD per well after breaking down the perforations with high-pressure water. The purpose of the cyclic steam injection is to consolidate the formation sands around the perforated completions and to stimulate initial oil production.

Well 2AT-61 completed cyclic steam injection on May 3 after injecting 101,329 bbl of cold water equivalent steam (BCWES) and began producing on June 13 at an initial rate of 1000 bbl per day (BPD) gross and 25 BPD net oil. Production gradually increased to 1340 BPD gross and 32 BPD net oil by August 2 and stabilized until the well was idled August 13 for a pump change. While changing the pump, no sand fill was found, which indicates a successful sand consolidation job. The well was placed back on production August 23 at the previous rates, idled from September 12 to 23, and restarted at the previous rates through the end of the quarter. Well 2AT-63 completed cyclic steam injection on June 20 after injecting 140,339 BCWES and began producing on July 27 at 800 BPD of 100% water. The well produced all water until August 16, when the rates changed to 845 BPD gross and 5 BPD net oil, which continued to September 10 when the well was idled. The well was restarted on September 23 and produced 800 BPD gross and 15 BPD net oil until the end of the quarter. Initial gross production rates have met expectations, but oil production rates are disappointing compared with the projected peak oil rate of 300 BPD net oil per well. The reasons for the poor oil production will be evaluated during the next quarter.

Production well UP-955 was completed with 48 0.29-in. perforations and placed on cyclic steam injection in June. Production well UP-956 was completed with 36 0.29-in. perforations and placed on cyclic steam injection in August 1996. Both wells will complete steam injection and be placed on production next quarter.

The 2100-ft steam transmission line under the Cerritos Channel was placed in service in mid-December 1995 and has performed very well with no problems to date.

Four existing steam injection wells were converted to hot-water injection from March 1995 to February 1996. Hot-water injection rates ranged from 500 to 3000 BWPD during this period. No incremental production response was observed. Hot-water injection was discontinued in February because of surface owner requirements to move the hot-water injection lines. Plans are to restart hot-water injection by November 1996.

Technology Transfer

Several draft technical reports covering the various aspects of the study were completed.

The project team made presentations on the major activities completed and the status of the project to representatives from the DOE Bartlesville Project Office on September 19 in Tidelands' office in Long Beach.

The project team is conducting an innovative program to transfer the dozens of anticipated technological advances from the project. Several project team members are significantly involved in the planning of the 1997 Society of Petroleum Engineers Western Regional Meeting scheduled in June 1997 in Long Beach, Calif., and a two-volume book on the geology and operation of slope and basin clastic oil and gas reservoirs. A new home page was created for the project on the Internet (http://www.usc.edu/peteng/doe.html). A CD-ROM of the project is complete for content and is in the editing process.

An article was published in the September 1996 issue of *The American Oil and Gas Reporter* on how 3-D mapping and horizontal wells breathe new life into mature oil fields, which is specifically about this DOE Class III project.[1]

References

1. C. Phillips, D. Clarke, and L. An, 3-D Modeling, Horizontal Drilling...Give New Life To Aging Fields, *Am. Oil Gas Report.*, 106-115 (September 1996).
2. I. Ershaghi and M. Hassibi, *A Neural Network Approach for Correlation Studies in a Complex Turbidite Sequence*, paper SPE 36720 presented at the 1996 SPE Annual Technical Conference in Denver, Colo.

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

Contract No. DE-FC22-95BC14936

University of Texas at Austin
Austin, Tex.

Contract Date: Mar. 31, 1995
Anticipated Completion: Mar. 30, 1997
Government Award: $1,010,208

Principal Investigator:
Shirley P. Dutton

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objectives

The primary 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 (FGU) and the 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. For reservoir characterization, three-dimensional (3-D) seismic data, high-resolution sequence stratigraphy, subsurface field studies, outcrop characterization, and other techniques will be used. When the reservoir-characterization study of both fields is complete, a pilot area of approximately 1 square mile 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 [carbon dioxide (CO_2) flood, waterflood, or polymer flood] and a 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

Seismic interpretation continued on the FGU 3-D survey. The top of the Lamar Lime and the top of the Manzanita Lime were picked and interpreted, and the horizons are being refined across the survey. Work on the seismic attributes of instantaneous phase, instantaneous frequency, and reflection strength is continuing. The imaging of the top of the Lamar with seismic data is a noteworthy technological success. The top of the Lamar has not previously been satisfactorily imaged with seismic data because of shallow statics problems in the area The top of the Lamar was imaged in areas where the seismic data have a value of 48-fold or greater to stack.

Reservoir Characterization

In addition to using 3-D seismic data, the project is also characterizing heterogeneity of Geraldine Ford and West Ford fields with the use of subsurface logs and cores. All logs have been digitized and entered into the Landmark software OpenWorks™ along with core-analysis and perforation data. Tops have been picked in the main reservoir intervals of both fields, and a grid of cross sections in West Ford field and Ford Geraldine Unit has been produced. A complete suite of structure maps and isopach maps of key reservoir surfaces and intervals has been made.

All whole cores received from Conoco for this study have been slabbed. A total of 3370 ft of core from 63 wells from the FGU and Ford West field have been described. Approximately 400 ft of core from 8 wells located in the FGU remain to be described.

A major focus of the project this quarter was petrophysical characterization of the FGU. Because most of the wells in the unit were drilled and logged in the 1950s and early 1960s, special techniques had to be used to maximize the information that could be derived from old logs. A new technique was developed to determine the value of saturation exponent (n), which is used to calculate hydrocarbon saturation of a reservoir from geophysical logs. This approach uses water saturations measured by core analysis; these data are generally available in mature fields that have few or no relative-permeability curves.

The gamma-ray logs were normalized previously. This quarter, all the FGU and West Ford field wells that have "old" nonporosity neutron logs were normalized. Core porosity vs. core permeability crossplots were then constructed to determine porosity cutoffs on the basis of permeability and a porosity–permeability transform. With the use of core porosity and log data, sonic travel times and normalized neutron porosities were crossplotted to determine log–core porosity transforms.

An examination of the wells with resistivity logs revealed that in many wells only a deep Laterolog was run. For the determination of true formation resistivity (R_t), a deep Laterolog™–R_t transform was developed that was based on data from wells with shallow Laterologs™ or micro-resistivity logs (Microlaterologs™ or micro-Spherically Focused Logs™) in addition to deep Laterologs™. Without this transform, oil saturation would be underestimated in all the wells with only deep Laterologs™.

A combination of both core and log data was then used to determine values for cementation exponent ($m = 1.83$) and saturation exponent ($n = 1.90$) for use in the Archie water-saturation equation. Crossplots of core porosities and core water saturations, when compared with log-derived porosities and log-derived water saturations, indicated very similar values, thus verifying the log-derived data. The next step in the analysis will be to calculate bulk volume water (BVW) values in all the wells with resistivity logs and map BVW across the field. BVW values can then be assigned to the many wells (80%) with no resistivity logs on the basis of their location on the BVW map. Water saturation can then be calculated in the wells without resistivity logs by the equation $S_w = BVW/porosity$. With water saturations calculated in all the wells that have a porosity log, a hydrocarbon pore-foot map can then be constructed.

Two different independent approaches were used to determine a value for saturation exponent (n) for the Ramsey sandstone in the FGU, including a new approach that was developed as part of this study. In the traditional approach, core and log data from well FGU 156 were used.

A weakness in the procedure, however, is the use of only five saturation exponents (n) to represent the average saturation exponent for the entire field. To help verify the average n value of 1.90, a new procedure was developed (see Table 1). The new procedure also involved the use of both core and log data, but water saturations (S_w) were determined from core-analysis data, not from the relative-permeability curves. The advantage of using the core-analysis water saturations is that much more data can be analyzed to obtain saturation exponent. With the use of core porosities and core water saturations from 5 wells (192 depths) plus true formation resistivity values (R_t) from the same depths, the ratio of R_t/R_0 was calculated [R_0 = (l/core porosity^1.83)], and a crossplot of S_w vs. R_t/R_0 was constructed. The slope of the best-fit line (i.e., n) on the crossplot (assuming $R_t/R_0 = 1.0$ @ $S_w = 100\%$) was 1.97. A saturation exponent (n) of 1.97 compares very well with the 1.90 value determined from the relative-permeability curves but is based on much more data. The larger data set used to determine that n = 1.97 should result in more reliable log-derived water saturations.

TABLE 1

Data for Calculating Saturation Exponent

a = 1.0; m = 1.83; R_w = 0.092 @ T_f

Depth, ft	Core porosity, %	R_t	S_w,*%	n
2575	15.65	9.25	47	1.60
2583	26.2	7.90	38	2.07
2583	25.8	7.54	37	1.94
2593	23.8	7.96	40	2.00
2599	26.0	6.44	39	1.89
				average n = 1.90

* S_w from relative-permeability curves.

Note: a, tortuosity factor; m, cementation exponent; R_w, resistivity of formation water; R_t, true formation resistivity; T_f, formation temperature; S_w, water saturation; and n, saturation exponent.

Outcrop Characterization

Detailed characterization of outcrops located on the Cowden Ranch, Culberson County, Tex., is currently under way to develop an architectural model of reservoir heterogeneity based on outcrop observations of the Bell Canyon formation and to refine current models that account for the deposition of these sandstones. The detailed study site was selected because it represents a well-exposed basinal deep-water system, it displays many similarities to deep-water reservoirs in the Delaware Basin, and the outcrops provide an excellent opportunity for defining the 3-D facies architecture.

Quantitative geologic data will be collected from laterally continuous exposures over several kilometers, and this information will be used to construct realistic models of reservoir heterogeneity. The site is being characterized by describing facies successions and correlating the bounding discontinuities that terminate the successions along closely spaced transects. As a result, the correlations are largely descriptive rather than interpretative.

The exposures have been photographed with a large-format camera, and the images have been assembled into mosaics that provide complete coverage of the outcrop. Within the study area, more than 20 lithologic logs spaced at intervals of approximately 1000 ft have been measured. Key surfaces and facies successions have been correlated between each log in the field and recorded on the photomosaics. The data are currently being assembled into a cross section from which both qualitative and quantitative information on the geometry, dimensions, and continuity of sandstone and mudstone beds can be extracted.

Whereas it has long been recognized that laterally extensive, organic-rich siltstones, interpreted as marine condensed sections, subdivide the mid-Permian Bell Canyon formation into a number of genetic stratigraphic units, the processes responsible for deposition of the sandstones have remained the source of controversy. Relationships within a single genetic unit indicate that the sandstones were largely deposited by turbidity currents during the progradation, aggradation, and retrogradation of a submarine fan and channel-levee system.

The basal organic-rich siltstone is conformably overlain by thin beds of laminated siltstones and massive to graded fine sandstones that coarsen and thicken upward. The succession is up to 10 m thick and displays a lobate geometry that is 5 to 10 km in length. The basal succession is locally cut out by a series of vertically and laterally stacked, lens-shaped sandstone bodies which are up to 20 m thick and 200 to 300 m in width and which can be traced to the south for 5 km between adjacent outcrops. The lens-shaped bodies are flanked by 1- to 6-m-thick, upward-fining successions of thinly bedded, ripple-laminated siltstones and sandstones that progressively thin and fine away from the lens-shaped bodies over the distance of a few hundred meters. The deposits are conformably overlain by an organic-rich siltstone. The relationships described are consistent with turbidity current model. Basal sandstone was deposited by unconfined flows on the lower to middle portion of a submarine fan. The overlying lens-shaped sandstone bodies that pass laterally into ripple-laminated siltstones were deposited by a system of channels and levees on the mid to upper portion of the fan.

Technology Transfer

Three abstracts based on work performed for this project were submitted to the 1997 AAPG Annual Meeting in Dallas, Tex., in April 1997. A paper was submitted for oral presentation in a session on New Concepts in Deep-Water Reservoir Sand Development. Two papers were submitted to a poster session on Results of Joint DOE/Industry Programs.

PREPARATION OF NORTHERN MID-CONTINENT PETROLEUM ATLAS

Contract No. DE-FG22-96BC14844

University of Kansas
Lawrence, Kans.

Contract Date: Aug. 30, 1996
Anticipated Completion: Aug. 31, 1997
Government Award: $250,000

Principal Investigator:
Lee C. Gerhard

Project Manager:
Chandra Nautiyal
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objectives

The objectives of the second-year program will be to continue and expand upon the Kansas elements of the original program and provide improved online access to the prototype atlas. The second year of the program will result in a prototype digital atlas sufficient to demonstrate the approach and to provide a permanent improvement in data access to Kansas operators. The ultimate goal of providing an interactive history-matching interface with a regional database remains for future development as the program covers more geographic territory and the database expands. The long-term goal is to expand beyond the prototype atlas to include significant reservoirs representing the major plays in Kansas, Nebraska, South Dakota, North Dakota, the Williston Basin portion of Montana, and the Denver–Julesburg Basin of eastern and southeastern Colorado.

Primary products of the second-year prototype atlas will be online accessible digital databases covering two additional petroleum plays in Kansas. Regional databases will be supplemented with geological field studies of selected fields in each play. Digital imagery, digital mapping, relational data queries, and geographical information systems will be integral to the field studies and regional data sets. Data sets will have relational links to provide opportunity for history-matching, feasibility, and risk-analysis tests on contemplated exploration and development projects. The flexible "web-like" design of the atlas provides ready access to data and technology at a variety of scales from regional to field, to lease, and finally to the individual wellbore. The digital structure of the atlas permits the operator to access comprehensive reservoir data and customize the interpretative products (e.g., maps and cross sections) to his/her needs. The atlas will be accessible in digital form on line with the use of a World Wide Web browser as the graphical user interface.

Regional data sets and field studies will be free-standing entities that will be made available on line through the Internet to users as they are completed. Technology transfer activities will be ongoing from the earliest part of this project, providing data information sets to operators before the full digital atlas compilation.

Summary of Technical Progress

As part of the first-year project, "Pages" and data schema for the atlas overview and field studies were developed and made accessible through the World Wide Web. The atlas structure includes access to geologic, geophysical, and production information at levels from the national to the regional, to the field, to the individual well. Several approaches have been developed that provide efficient and flexible screening and search procedures. The prototype of the digital atlas is accessible through the Kansas Geological Survey Petroleum Research Section (PRS) home page at **http://www.kgs.ukans.edu/PRS/PRS.html**. The Digital Petroleum Atlas (DPA) home page is available directly at **http://www.kgs.ukans.edu/DPA/dpaHome.html**. This atlas is one of the most visited pages on the Kansas Geological Survey web site.

All project personnel are hired. Criteria and procedures, developed as part of the first-year Atlas Project, are being used to identify and select two additional plays in Kansas. Work is under way to gather the necessary data to make a final play selection.

Technology Transfer

Technology transfer is under way through presentations at national and regional meetings and through the use of monthly electronic updates and the online availability of the DPA products. Project information and quarterly progress reports are linked to the DPA home page.

BASIN ANALYSIS OF THE MISSISSIPPI INTERIOR SALT BASIN AND PETROLEUM SYSTEM MODELING OF THE JURASSIC SMACKOVER FORMATION, EASTERN GULF COASTAL PLAIN

Contract No. DE-FG22-96BC14946

University of Alabama
Tuscaloosa, Ala.

Contract Date: Aug. 29, 1996
Anticipated Completion: Aug. 22, 2001
Government Award: $80,000
(Current year)

Principal Investigator:
Ernest A. Mancini

Project Manager:
Rhonda Lindsey
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objectives

The objectives of this project are to provide improved access to information available in the public domain by inventorying data files and records of the major information repositories in the Eastern Gulf Coastal Plain and making these inventories easily accessible in electronic format. The producers in the region maintain that the accessibility of oil and gas information is the single-most important factor to assist them in finding new hydrocarbon discoveries and in improving production from established fields.

Summary of Technical Progress

Subcontracts are being drafted to initiate the anticipated work effort between the University of Alabama and the Geological Survey of Alabama and Mississippi Office of Geology.

The project was discussed with a number of faculty members from departments of geology in the region. A letter will be sent to the various department chairs to facilitate the acquisition of theses and dissertations related to the petroleum geology of the Mississippi Interior Salt Basin.

The project was also discussed with representatives from several service companies that provide land grid, geological, and geophysical data related to the wells and fields located in the Mississippi Interior Salt Basin area.

DESIGN AND IMPLEMENTATION OF A CO_2 FLOOD UTILIZING ADVANCED RESERVOIR CHARACTERIZATION AND HORIZONTAL INJECTION WELLS IN A SHALLOW SHELF CARBONATE APPROACHING WATERFLOOD DEPLETION

Contract No. DE-FC22-94BC14991

Phillips Petroleum Company
Odessa, Tex.

Contract Date: June 3, 1994
Anticipated Completion: Jan. 2, 2001
Government Award: $2,659,515
(Current year)

Principal Investigator:
John S. Chimahusky

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objectives

The first objective is to use reservoir characterization and advanced technologies to optimize the design of a carbon dioxide (CO_2) project for the South Cowden Unit (SCU) located in Ector County, Tex. The SCU is a mature, relatively small, shallow-shelf carbonate unit nearing waterflood depletion. The second objective is to demonstrate the performance and economic viability of the project in the field. This report includes work on both the reservoir characterization and project design objective and the demonstration project objective.

Summary of Technical Progress

Drill, Reactivate, and Convert Wells

A step-rate test was run on reservoir characterization well RC-3 during mid-July to determine the reservoir fracture pressure in the vicinity of the two horizontal injection wells. The results of this step-rate test were used to establish the maximum injection pressure for the horizontal injectors.

Before horizontal injection wells 6C25H (H-1) and 7C11H (H-2) were placed on CO_2 injection, injection profile surveys and falloff tests were conducted under water injection to verify that there was an acceptable distribution of injection along the lateral section and to determine the mechanical condition and completion efficiency in the horizontal wells.

The injection profile work for the first horizontal well, well 6C25H, was done by Cardinal Surveys Company. This consisted of a continuous flowmeter, quartz pressure sensor, temperature surveys, capacitance, and gamma-ray probe conveyed on 1.25-in. coiled tubing. Good results were obtained, even though the survey was done at relatively low injection rates under a very small pressure differential into the formation. The survey showed that the injection water was entering the formation along most of the length of the lateral section.

Injection pressure measurements were made and a pressure falloff test was run during the water injection period in well 6C25H. High-quality falloff data were obtained. Initial pressures matched closely those of the simulation model predictions along the horizontal traverse, and permeability data derived from radial flow periods matched well with the history-matched permeabilities in the model. The length of the effective intervals taking fluid derived from model verification matching agreed with the injection profile survey results. The pressure falloff results indicated that a good acid stimulation had been obtained from the coiled-tubing acid wash completion in the horizontal section. On the basis of the favorable results in the injection profile and falloff data, the well was placed on CO_2 injection during early July and slowly brought up to capacity injection at a bottomhole injection pressure slightly below the calculated formation parting pressure (from step-rate results on RC-3). The injection rate stabilized very close to the expected rate forecasted in the model.

The injection profile survey on the second horizontal well, well 7C11H, was conducted by Halliburton who used a different procedure. They opted to run a logging and injection program wherein coiled tubing and wireline were run in the injection well simultaneously with a Y-block and coiled-tubing side-entry assembly attached to the coiled tubing below the spot valve. The tool consisted of positive and negative gamma rays and temperatures. A slug of more than 1 gal of radioactive gel with 50-μm sand was used rather than the standard injection procedure of 1 cm^3 per station. A flowing temperature log and velocity shots were used to determine fluid entry. Results of the second injection profile survey were somewhat ambiguous and difficult to interpret. Halliburton's interpretation indicated injection fluid movement throughout all but the last 150 ft near the toe of the horizontal interval. In-house interpretation of the results, however, indicated that a good portion of the injected water could be entering the reservoir near the toe of the well.

A pressure falloff test was also run in well 7C11H. This test did not show the same behavior as that demonstrated in the first well. The test showed early linear flow behavior rather than early radial flow as in the first horizontal well. This second well was drilled approximately normal to the preferential parting direction indicated in earlier micro-frac tests conducted in two reservoir characterization wells. A step-rate test conducted on the well showed a shift toward linear flow behavior and possible fracture extension above 2600-psi bottomhole injection pressure.

Low-volume injection of CO_2 in the horizontal injection wells commenced in early July following testing. Higher volume CO_2 injection into wells 6-25H and 7-11H commenced August 14 and August 29, 1996, respectively.

Water injection commenced in vertical water-alternating-gas (WAG) injection wells 2-26W and 2-27W in early July. Bottomhole pressure surveys were run in both vertical injection wells during early August, immediately before CO_2 injection. CO_2 injection began July 19, 1996, in well 2-26W at an initial wellhead pressure of 890 psig, and on July 22, 1996, in well 2-27W.

Wells 5-02 and 8-18 were converted for use as water injection wells and are waiting injection-line tie-in. Wells 7-02, 7-05, and 6-02 were reactivated for production.

Construct, Modify, and Upgrade Facilities for Injection and Production

All of the required private lots in sec. 17 of the SCU have been purchased. The sixth lot will not be purchased because it is too expensive. Precautionary monitors and alarms will be installed along the lot line to protect the owner. This has been discussed and agreed on with the Texas Railroad Commission to meet Rule 36 requirements. The main 250-acre tract of land where CO_2 flood facilities are located is currently being leased. Purchase of the land is anticipated in November.

Of the 21 hydrogen sulfide (H_2S) premised monitors, 20 have been installed and are operational. An additional H_2S monitor along the perimeter fence behind the private lot that was not purchased will be added. If H_2S is detected by any of the monitors, an alarm is sent via radio to the Phillips Petroleum Odessa office SCU Supervisory Control and Data Acquisition (SCADA) computer, which, in turn, pages an operator on call with an alpha-numeric pager. If the operator on call cannot be reached, a list of people will be called until someone acknowledges the alarm.

The perimeter fence, which will prevent public entrance into the project area, provide protection from exposure to H_2S, and protect against vandalism, is approximately 95% complete. The fence will be completed now that all the private lots have been purchased.

Installation of injection runs to all four of the CO_2 WAG injection wells is complete. Installation to the water injection wells is complete for wells 5-02 and 8-18. Tie-in of additional wells will be ongoing as wells are prepared for injection.

Construction and installation of the water and CO_2 (WAG) manifold are complete. Since completion of the manifold with the CO_2–water meters, the meters have been modified to improve CO_2 measurement. Replacement of the old water injection system is also essentially complete except for the lateral to injection well 5-02.

Construction of the new Tract 6 satellite facility is 90% complete; however, the satellite facility will not be put into operation until the unit experiences significant CO_2 production.

Production Operators, Inc., completed construction of their reinjection facility on June 21, 1996. The facility will continue to be idle until CO_2 production increases enough to justify operating the compressors.

No additional field work on cathodic protection has been completed this quarter. Evaluation of the collected data from the well logs is ongoing, and redesign of the system with the use of the new data continues. A decision to install the field-wide cathodic protection will be made during the fourth quarter of 1996.

The SCADA system is operating. Installation of producing well pump-off controllers is 95% complete.

The total volumes purchased for injection in all the wells for the quarter were:

Month	CO_2, MSCF
July	10,446
August	90,687
September	232,190
Total	333,323

Technology Transfer

A paper entitled "Reservoir Characterization of an Upper Permian Platform Carbonate in Preparation for a Horizontal-Well CO_2 Flood, South Cowden Unit, West Texas," was submitted to the Oklahoma Geological Survey (OGS). This paper was previously presented as a poster session at the March 1996 Platform Carbonates of the Southern Midcontinent meeting sponsored by the OGS. The OGS plans to publish 1000 copies of the meeting proceedings.

GEOLOGICAL AND PETROPHYSICAL CHARACTERIZATION OF THE FERRON SANDSTONE FOR THREE-DIMENSIONAL SIMULATION OF A FLUVIAL–DELTAIC RESERVOIR

Contract No. DE-AC22-93BC14896

Utah Geological Survey
Salt Lake City, Utah

Contract Date: Sept. 29, 1993
Anticipated Completion: Sept. 29, 1996
Government Award: $285,892
(Current year)

Principal Investigator:
M. Lee Allison

Project Manager:
Robert Lemmon
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The objective of this project is to develop a comprehensive, interdisciplinary, and quantitative characterization of a fluvial–deltaic reservoir that will allow realistic interwell and reservoir-scale modeling to be used for improved oil-field development in similar reservoirs world-wide. The geological and petrophysical properties of the Cretaceous Ferron sandstone in east-central Utah will be quantitatively determined. Both new and existing data will be integrated into a three-dimensional (3-D) representation of spatial variations in porosity, storativity, and tensorial rock permeability at a scale appropriate for interwell to regional-scale reservoir simulation. Results could improve reservoir management through proper infill and extension drilling strategies, reduce economic risks, increase recovery from existing oil fields, and provide more-reliable reserve calculations. Transfer of the project results to the petroleum industry is an integral component of the project.

Summary of Technical Progress

Four activities continued this quarter as part of the geological and petrophysical characterization of the fluvial–deltaic Ferron sandstone in the Ivie Creek case-study area: (1) petrophysical analyses, (2) geostatistics, (3) reservoir modeling, and (4) technology transfer.

Petrophysical Analyses

Petrophysical measurements were made on 87 Ferron sandstone core plugs collected from the Ferron sandstone No. 2-Ivie Creek parasequence set (Kf-2-Iv) during the 1995 field season and processed through Amoco Production Research's Geoscience Evaluation Module (GEM). The measurements consisted of (1) saturated, dry, and grain densities; (2) effective and Boyle's Law porosities; (3) air permeability; (4) magnetic susceptibility; (5) qualitative and quantitative mineralogy; (6) compressional and shear-wave velocities as a function of effective pressure; and (7) thin-section-image analysis.

The major findings from preliminary analyses of these data are: (1) clay content has little effect on velocity but carbonate cementation increases velocity (via its reduction of porosity, not by directly increasing rigidity modulus), (2) a major source of velocity dispersion is the expansion that these outcropping rocks have undergone as the result of uplift and erosional exhumation, (3) only carbonate content has a significant effect on porosity from possible mineralogic controls, (4) porosity strongly controls permeability with kaolinite content a much smaller influence where diagenetic kaolinite lines pores closing pore throats and therefore decreasing permeability, (5) carbonate dissolution is a major control on Ivie Creek petrophysical patterns, and (6) the velocity structure is not representative. The porosity and permeability structures still retain their original link to grain size in spite of subsequent cementation and carbonate dissolution, so the applicability of fluid-flow modeling to deep exploration plays is not strongly impacted.

Ferron well logs from outside the Ivie Creek case-study area were analyzed for comparison of petrophysical responses with those observed in Ivie Creek core plugs and geophysical logs. The database search for all wells with both sonic and density logs of the Ferron identified 31 such wells. Of these wells, 24 had accurate sonic and density logs with minimal gas effect. Velocities and densities for these wells were analyzed for velocity/porosity patterns which were compared with the results of Ivie Creek data. A comparison was made of the discrete-core compressional velocity measurements with velocity and density measurements from geophysical logs from the Ivie Creek No. 3 core hole. Agreement is generally good despite the different measurement techniques and the different measurement volumes.

Thin sections were made from selected core plugs with varied lithology, lithofacies, and permeability values. All Ferron samples fall within a broad category of quartzo-feldspathic arenites, although they vary in the degree or amounts of grain types. Most sorting is moderate, with Kf-2-Iv shoreface sandstones (hummocky cross-stratified, horizontally bedded, or bioturbated) tending to be the "cleanest." This is expected given that the Kf-2-Iv is from wave-dominated (and reworked) sediments. The Ferron sandstone No. 1 Ivie Creek parasequence set (Kf-1-Iv) samples are typically "dirtier," contain more lithics and altered grains, and are more compact (probably the result of rapid sedimentation from fluvial-dominated deltas).

Very little if any primary porosity remains in any of the samples. Almost all the porosity of any significance is secondary porosity controlled by the dissolution of carbonate phases (carbonate, dolomite, and possibly siderite). Where such secondary porosity is present, quartz and clay (kaolinite) cements largely remain with some interspersed minor carbonate and/or iron cement.

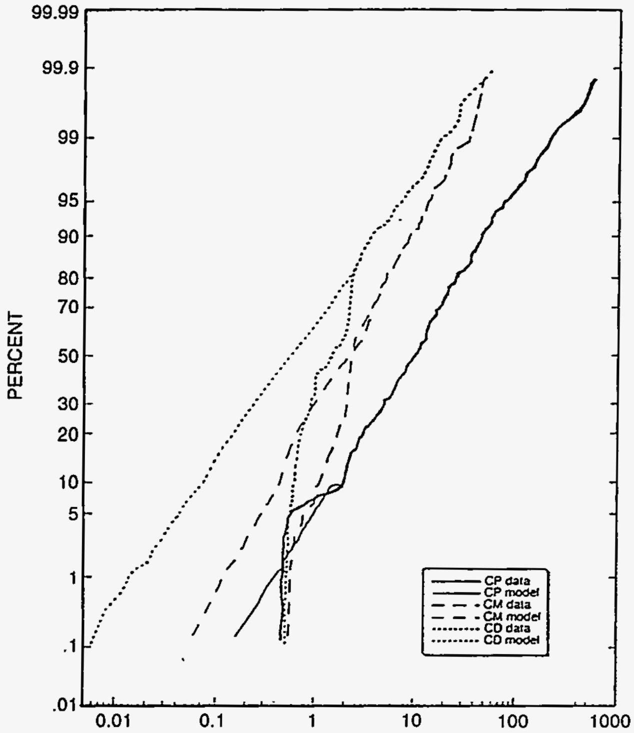
There appears to be a strong correlation between porosity and grain size in that the coarser grain sizes (generally fine to medium or coarse) tend to have more and larger pores. Coarser grained sandstones tend to be more quartz rich and are relatively cleaner with less matrix. Organic matter may form small-scale permeability barriers, and coarser grained samples with better porosity generally contain less organic matter. Fine-grained samples tend to have more organic matter as well as more concavo–convex grain contacts resulting in reduced porosity.

Geostatistics

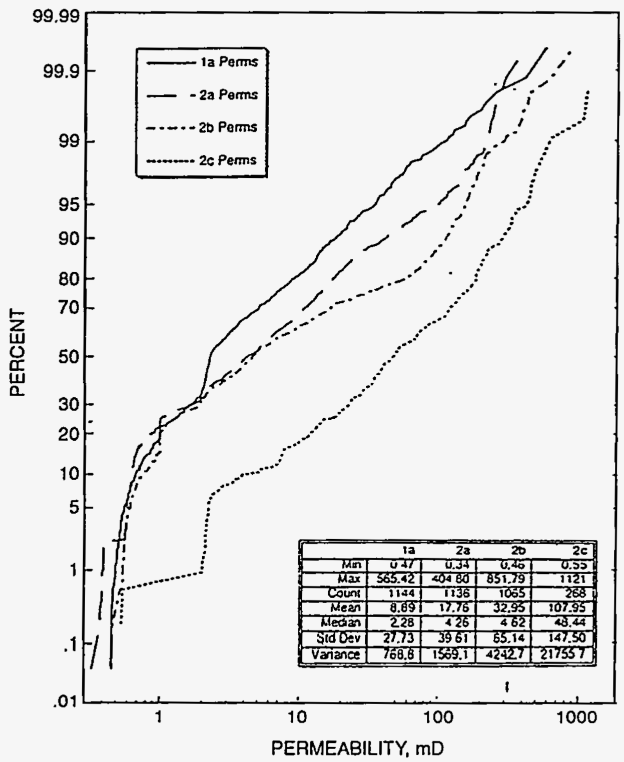
Geostatistical work this quarter was devoted to (1) populating the Ferron Sandstone No. 1 Ivie Creek-a parasequence (Kf-1-Iv-a) with petrophysical data and (2) investigating statistical relationships between geologic features and permeability data and among various geologic features for the Kf-2-Iv in the Ivie Creek case-study area. In order to run fluid-flow simulations for the 3-D facies model, the model must be populated with petrophysical data. The approach to be used requires that each lithofacies within the model be populated by the geometric mean of the permeability data. The geometric mean of the data is used in regions where fluid flow is neither parallel nor perpendicular to the strata. Plotting the permeability data for each facies on a log-normal plot shows data spikes at about 2 millidarcys (mD) and 0.5 mD that correspond to instrument limits. An approach to account for these values is to model these low-permeability values by extrapolating the log-normal trend observed in the higher permeability values (part a of Fig. 1).

Lithofacies panels (lithofacies, sedimentary structures, and grain sizes) for the Ivie Creek amphitheater were used to generate a deterministic distribution of permeability. Each of three panels was discretized into 4 ft × 4 ft blocks, and a number code was assigned for each attribute [for example, clinoform proximal (CP) lithofacies = 2]. These attribute values were loaded into the computer with accompanying spatial coordinates. The rules for assigning permeability values to each block were calculated from the transect data. Geometric mean permeability values were calculated for all known combinations of facies, sedimentary structures, and grain size.

Statistical analyses were calculated for the Kf-2-Iv. These included (1) summary statistics (mean, median, and others) for each parasequence and lithofacies, (2) histograms, (3) cumulative probability plots, (4) relative percentage bar

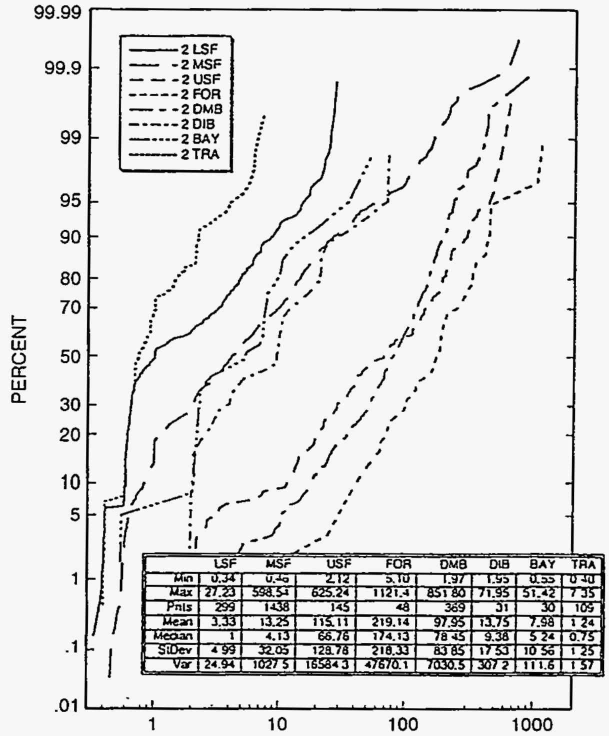


(a)



	1a	2a	2b	2c
Min	0.47	0.34	0.46	0.55
Max	565.42	404.80	851.79	1121
Count	1144	1136	1065	268
Mean	8.89	17.76	32.95	107.95
Median	2.28	4.26	4.62	48.44
Std Dev	27.73	39.61	65.14	147.50
Variance	768.8	1569.1	4242.7	21755.7

(b)



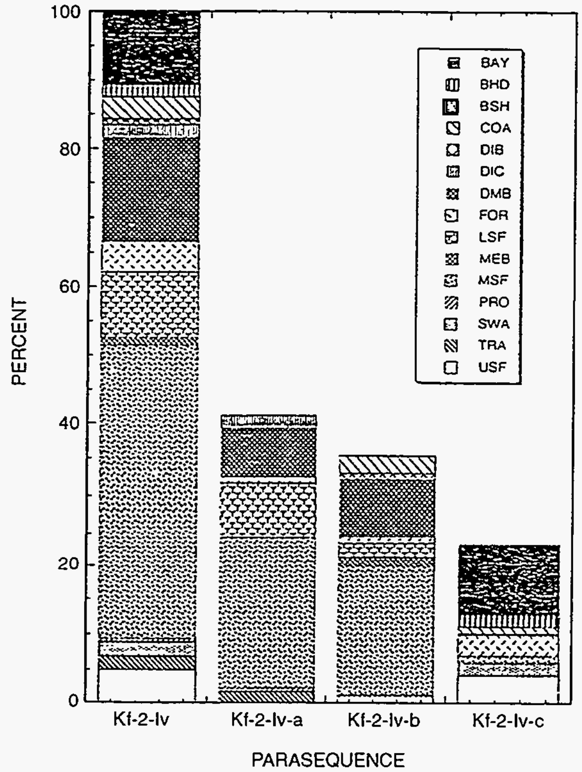
	LSF	MSF	USF	FOR	DMB	DIB	BAY	TRA
Min	0.34	0.46	2.12	5.10	1.97	1.95	0.55	0.40
Max	27.23	598.54	625.24	1121.4	851.80	71.95	51.42	7.35
Pnts	299	1438	145	48	369	31	30	109
Mean	3.33	13.25	115.11	219.14	97.95	13.75	7.98	1.24
Median	1	4.13	66.76	174.13	78.45	9.38	5.24	0.75
StDev	4.99	32.05	128.78	218.33	83.85	17.53	10.56	1.25
Var	24.94	1027.5	16584.3	47670.1	7030.5	307.2	111.6	1.57

(c)

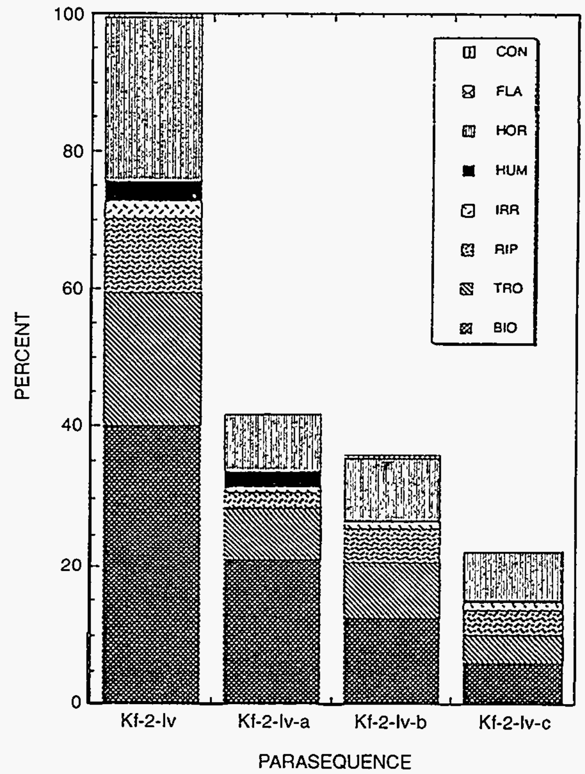
Fig. 1 Cumulative percent permeability plots from the Ferron Sandstone, Ivie Creek case-study area: (a) model data and raw data from the Kf-1-Iv-a parasequence, (b) raw data from the Kf-1-Iv-a parasequence and the a, b, and c parasequences of the Kf-2-Iv, and (c) lithofacies vs. permeability from the Kf-2-Iv. Abbreviations for lithofacies: CP, clinoform proximal; CM, clinoform medial; CD, clinoform distal; LSF, lower shoreface; MSF, middle shoreface; USF, upper shoreface; FOR, foreshore; DMB, distributary mouth bar; DIB, distal mouth bar; BAY, bay fill; and TRA, transgressive.

plots, and (5) cross-plots. The Kf-2-Iv is a wave-modified, fluvial–deltaic system as compared with the Kf-1-Iv-a, which is a fluvial-dominated system. This difference is reflected in the cumulative permeability plots, which show much higher values for the Kf-2-Iv than for the Kf-1-Iv-a (part b of Fig. 1). The lithofacies identified within the permeability transect data range from lower shoreface to foreshore, mouth-bar, bay, and transgressive facies (part c of Fig. 1).

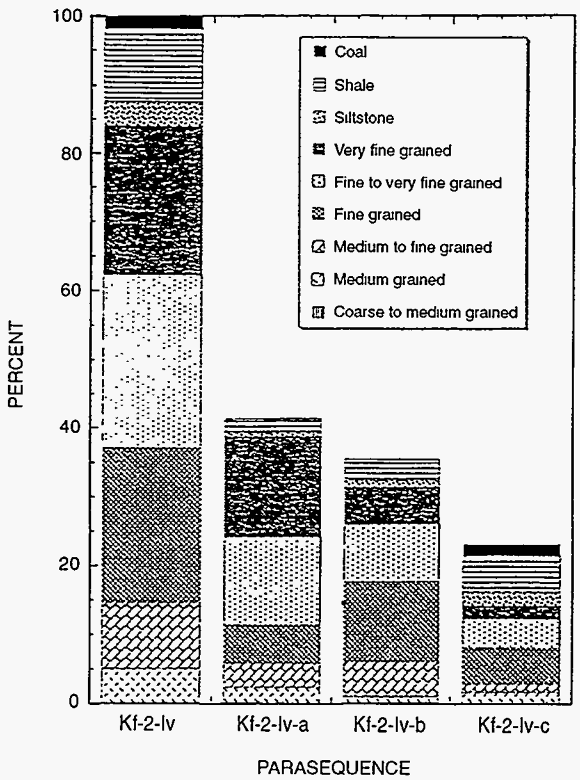
Each parasequence is characterized by a particular suite of lithofacies, grain sizes, and sedimentary structures as shown in the summary plots of Fig. 2. The major lithofacies in the parasequences of the Kf-2-Iv is middle shoreface followed by distributary mouth bar and lower shoreface (part a of Fig. 2). The grain-size distributions (based on megascopic observations) were calculated for the four parasequences (part b of Fig. 2). The primary control on permeability is grain size; however, data analysis implies that grain sorting also plays a role. The relative frequency of sedimentary structures was calculated for the four parasequences (part c of Fig. 2). Bioturbation is the most common sedimentary structure in three of the parasequences followed by horizontal and trough-cross-stratified bedding.



(a)



(c)



(b)

Fig. 2 Statistical analyses of the Kf-2-Iv parasequence set as a whole and the three parasequences within it (a, b, and c), Ivie Creek case-study area: (a) histogram showing lithofacies distribution, (b) histogram showing grain-size distributions (megascopic observations), and (c) histogram showing relative frequency of sedimentary structures. Abbreviations for lithofacies: BAY, bay fill; BHD, bay-head delta; BSH, backshore; COA, coastal plain; DIB, distal mouth bar; DIC, distributary channel; DMB, distributary mouth bar; FOR, foreshore; LSF, lower shoreface; MEB, meander belt; MSF, middle shoreface; PRO, prodelta; SWA, swamp; TRA, transgressive; and USF, upper shoreface. Abbreviations for sedimentary structures: CON, convoluted/contorted; FLA, flaser bedded; HOR, horizontally bedded; HUM, hummocky cross-stratified; IRR, irregularly laminated; RIP, ripple cross-laminated; TRO, trough-cross-stratified; and BIO, bioturbated.

The stratigraphic sections reveal overall coarser grain size and a higher degree of bioturbation (Fig. 2) than in the Kf-1-Iv-a analysis conducted in previous quarters. A comparison of average permeability values for a given grain size–sedimentary structure combination suggests that, for a specific grain size, permeability decreases as the sorting of the sedimentary structure decreases.

Reservoir Modeling

During the quarter, work focused on designing and implementing the numerical modeling strategy. This work included developing and testing methodology for generating stochastic permeability fields and modeling subsurface fluid flow. Geostatistical analyses and geological modeling of the local-scale region are essentially complete, and preliminary fluid-flow simulations have been performed for both the two-dimensional (2-D) and 3-D model domains.

The modeling strategy was finalized following completion of the field-based characterization activities needed to develop input to both geostatistical models and fluid-flow simulators. All modeling work will be focused on the Ferron Sandstone No. 1 Ivie Creek-a parasequence (Kf-l-Iv-a), a fluvial-dominated deltaic unit exposed at the Ivie Creek case-study area. Three primary modeling tasks are identified. Tasks I and II involve simulating primary oil production and waterflooding in 2-D model domains containing the clinoform geometries (Fig. 3) characterized in the field activities. In Task III primary oil production and waterflooding will be simulated within 3-D model domains containing upscaled renditions of the clinoform geometry.

During the quarter clinoform geometries of the Kf-1-Iv-a parasequence were incorporated in both 2-D and 3-D gridded model domains. Also, the deterministic and stochastic routines needed to distribute permeability and porosity within the clinoform-based model domains have been developed and tested. Preliminary 2-D and 3-D fluid-flow simulations also demonstrate that the simulation tasks outlined are ready to proceed. Work performed during the coming quarter should yield significant progress toward completion of these modeling tasks.

A key objective of the Ferron Sandstone project flow simulation studies is to incorporate outcrop-based geology and petrophysical properties into the flow models. The extent to which this can be done depends on the relative spatial scales of the flow model, the geological mapping, and the petrophysical data. If the flow modeling is done at a scale much smaller than that of the geological mapping, then it is difficult to constrain the flow model with the use of outcrop-derived architecture. Where flow modeling is done at a scale much larger than that of the geological and petrophysical data, averaged data are used (e.g., a large flow model may be based on the spatial distribution of facies, each having specific petrophysical properties, rather than representing the more detailed depositional architecture).

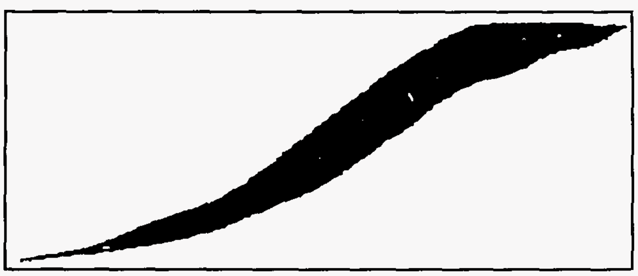


Fig. 3 Sketch of an idealized clinoform geometry similar to those mapped within the KF-1-Iv-a parasequence on cliffs found at the Ivie Creek case-study area.

2-D Simulations (Tasks I and II)

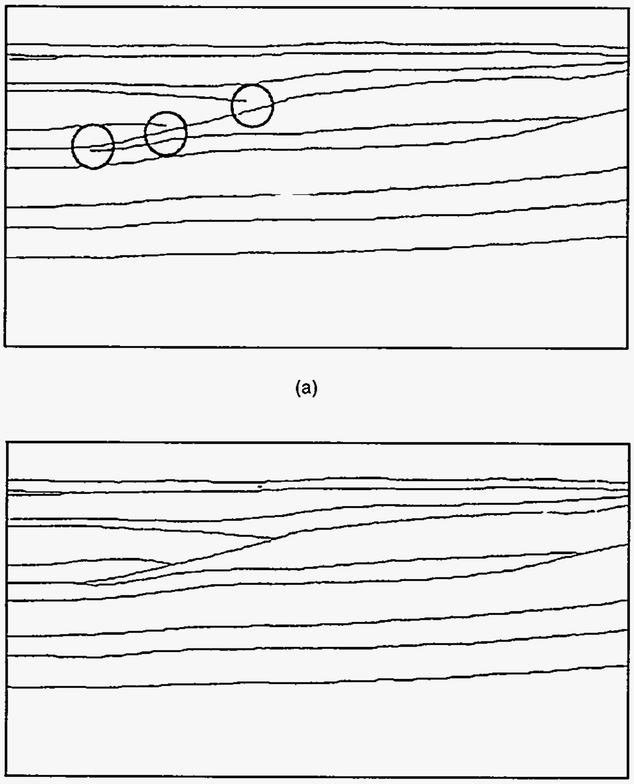
The 2-D flow simulations of the Ivie Creek amphitheater are done at a spatial scale near the scale of the outcrop mapping and somewhat larger than the vertical spacing of outcrop permeability measurements. Because the scales of the data and the flow simulations are so closely matched, the Ivie Creek case-study area provides an uncommon opportunity to examine how the architecture of delta-front deposits influences the spatial distribution of petrophysical properties and hence multiphase fluid flow in the subsurface.

Developing tools for integrating outcrop architecture into flow-simulation models was the focus of the quarter's activity. Several steps were required to convert the digitized line drawings of architecture provided by the project geologists into a grid that is used to distribute petrophysical properties and for flow modeling. These include (in chronological order): (1) resolving gaps in the linework; (2) converting the linework to polygons (closed regions in space); (3) gridding polygonal regions to enable distribution of properties within individual polygons; and (4) merging individual polygons, with distributed properties, into a flow-simulation model (TETRAD-3D).

The basic architectural element of the Ivie Creek delta-front deposits is the clinoform (Fig. 3), a roughly sigmoidal shape representing an episode of deposition (and thus of delta-front progradation). At the distal end, a clinoform laps onto previously deposited sediments (often older clinoforms). Proximally, a clinoform is truncated by either a younger clinoform or a parasequence boundary. Clinoforms are therefore closed regions of space; however, the linework obtained from the geologists included many clinoforms that were not completely enclosed. Lines often ended dangling in space without terminating against another boundary (part a of Fig. 4). This was usually caused by digitizing, although in some cases it was a result of geological uncertainty about the extent of a clinoform and its relationship to its neighbors. Digitizing problems were resolved manually by extending the line(s) enclosing a clinoform until it terminated against another clinoform, a parasequence boundary, or extended beyond the Ivie Creek case-study area (part b of Fig. 4). Geological uncertainties were resolved in consultation with project geologists. These linework boundaries were used to define clinoforms as unique polygons (in proper spatial positions) that could then be modeled as individual objects.

Once the boundaries of each clinoform are defined, the clinoform must be gridded in order to assign petrophysical properties in the fluid-flow simulator. With the use of a deterministic or stochastic approach, petrophysical properties are then assigned to each grid block in the interior of a clinoform. Part b of Fig. 5 illustrates a gridded version of the clinoforms shown in part a of Fig. 5 with the black grid blocks representing thin regions where the properties of bounding surfaces are specifically represented. Two computer programs were written to accomplish these tasks. The gridding program was designed to allow different gridding increments in the x and z directions.

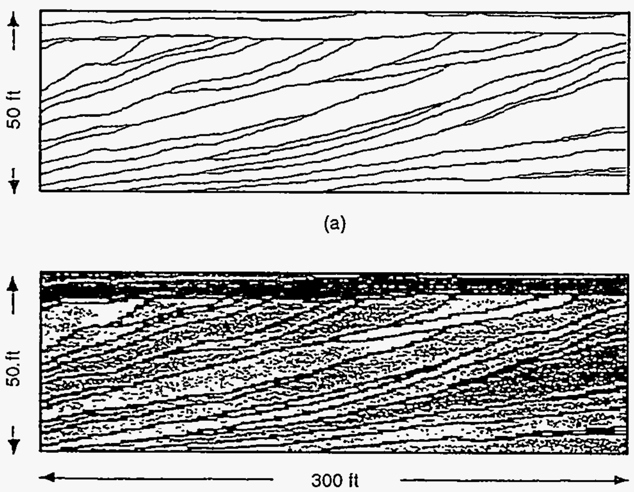
Each computer program was tested numerous times. The codes were used to create a simple test model of a portion of the Ivie Creek amphitheater for preliminary flow simulations. A few flow simulations have now been run, but the



(a)

(b)

Fig. 4 Expanded view (not to scale) of some of the clinoforms mapped in the Kf-1-Iv-a parasequence at the Ivie Creek amphitheater with (a) gaps between lines marking clinoform boundaries (shown by circles), and (b) closed polygons with each clinoform represented as a single closed form.



(a)

(b)

Fig. 5 Sample model domain showing (a) closed polygons representing individual clinoforms and (b) digitized polygon set with bounding surfaces represented as black grid blocks with finite height and width.

results have not been closely examined and so are not presented here.

3-D Simulations (Task III)

The detailed 3-D petrophysical model needed to study the Kf-1-Iv-a parasequence at the Ivie Creek amphitheater was completed this quarter. Although the grid block size (20 ft by 20 ft by 4 ft thick) is much larger than those used in the 2-D simulations, it is still much smaller than what might be used in typical reservoir simulation studies. This block size was selected to provide insight into the way that lumped clinoform geometries might influence the interwell sweep efficiency of different oil production strategies. Preliminary 3-D simulations have been completed for a simple homogeneous case with TETRAD-3D. Full-scale simulations of both the homogeneous and heterogeneous petrophysical models are ready to begin.

Continuing Effort to Create Synthetic Clinoform-Like Objects

Previous quarterly reports have outlined the planned use of a stochastic code to generate packages of stacked clinoform-like objects that resemble the features mapped in the Kf-1-Iv-a parasequence at the Ivie Creek amphitheater. The modeled result is being improved by integrating a new set of soft rules based on geological inferences. This is an empirical approach where the algorithm will be modified to produce new versions of the clinoform packages that more closely approximate the geometry of the clinoform packages mapped in outcrop. Over the past year a series of statistical measures have been developed that characterize the clinoform geometry mapped in the Ivie Creek photomosaics. These statistical measures will be used to constrain models of synthetic clinoform structures and then populate the clinoforms with permeability and porosity values following Tasks I and II. The results of 2-D fluid-flow simulations performed on model domains containing the synthetic clinoform packages will be compared with simulation results obtained with the deterministic clinoform geometries identified in the field. This approach is expected to provide a basis for creating the synthetic 2-D and 3-D clinoform geometries needed to model oil production in reservoir systems where similar geological environments are encountered.

Technology Transfer

Project material was displayed at the Utah Geological Survey (UGS) booth during the American Association of Petroleum Geologists (AAPG) Rocky Mountain Section meeting held in Billings, Mont., July 28–31, 1996, and at a UGS co-sponsored symposium entitled the Geology and Resources of the Paradox Basin held in Durango, Colo., September 20–21, 1996.

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

Contract No. DE-FC22-94BC14989

Fina Oil and Chemical Company
Midland, Tex.

Contract Date: June 13, 1994
Anticipated Completion: June 12, 1999
Government Award: $7,572,930
(Current year)

Principal Investigator:
J. W. Nevans

Project Manager:
Rhonda Lindsey
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The objective of this project is to demonstrate the application of advanced secondary recovery technologies to remedy the producibility problems in a typical shallow-shelf carbonate (SSC) reservoir of the Permian Basin, Tex. The technologies to be demonstrated are (1) development of an integrated reservoir description created with the use of reservoir characterization and reservoir management activities and integration and modeling of the data from three-dimensional (3-D) simulation, (2) development of an integrated reservoir management plan through optimization of completion and stimulation practices and reservoir surveillance, and (3) field demonstration of the geologically targeted infill drilling and waterflood program.

Summary of Technical Progress

Project Management and Administration

As part of the field demonstration phase of the project, 18 10-acre infill wells have been drilled. Of the 14 producing wells drilled to date, 12 are currently on production and 10 are pumped-off and producing at stable rates. Current unit production is approximately 3600 to 3700 stock tank barrels of oil per day (STBOPD), and approximately 850 STBOPD incremental production has been added to date (Fig. 1). The remaining producing well and 4 injection wells are currently being completed. A change in the Statement of Work has been approved so that additional 10-acre infill wells can be drilled during the next quarter as budget constraints allow.

Production flow lines are laid for each new producing well as the well is put on production. Injection lines are being laid for the injection wells as they are completed. All data required for the validation of the Budget Period I reservoir characterization, reservoir management, and reservoir simulation studies are being acquired and analyzed during the field demonstration period.

Field Demonstration

Implementation of Field Demonstration

Drilling and completion. The drilling phase of the field demonstration proceeded smoothly and was completed on schedule. Eleven Phase I wells (nine producing wells and two water injection wells) were drilled between March 15 and July 5, 1996. Ten of the wells were drilled to complete waterflood patterns in the north (sec. 329) and south (sec. 327) 10-acre infill areas of the Unit. An additional off-pattern well, North Robertson Unit (NRU) 3319, was drilled in sec. 362 of the Unit in a 20-acre location that had not previously been drained by existing producers (Fig. 2).

The 7 Phase II wells (5 producing wells and 2 water injection wells) were drilled between July 3 and August 20, 1996. The Phase II locations were chosen during a team member meeting at the end of June, and location selection was based on data acquired during Phase I. Phase II drilling consisted of completing waterflood patterns west of the Phase I wells in secs. 329 and 327 of the Unit. An additional off-pattern well, NRU 3604, was drilled in a 10-acre location in the southwest corner of sec. 324 in an area of the Unit in which reservoir flow simulation predicted extremely high recovery potential. The off-pattern wells drilled during the field demonstration will be given additional injection support by converting two to three offset producers to injection wells in the near future.

Core analysis. As part of an intensive effort to collect needed rock data, 2730 ft of core in four wells was taken. The data will be used to help quantify the extent of small-scale vertical and lateral heterogeneity, refine the depositional model, improve understanding of the relationship between porosity and permeability, and help in the selection of additional 10-acre infill drilling locations within the NRU Clearfork formation.

An attempt was made to cut cores continuously through the entire Clearfork section, but parts of the section were not cored because of significant mechanical difficulties as the result of very long core times—often greater than 200 min/ft.

Field Operations and Surveillance

Interval testing and preproduction. The two injection wells in sec. 329 will be preproduced for a 3- or 4-week period (as per the Texas Railroad Commission) before placing them on injection in order to obtain the early "flush" production in the near-well area that is a producing characteristic of the reservoir. Also, near-wellbore wettability tests will be

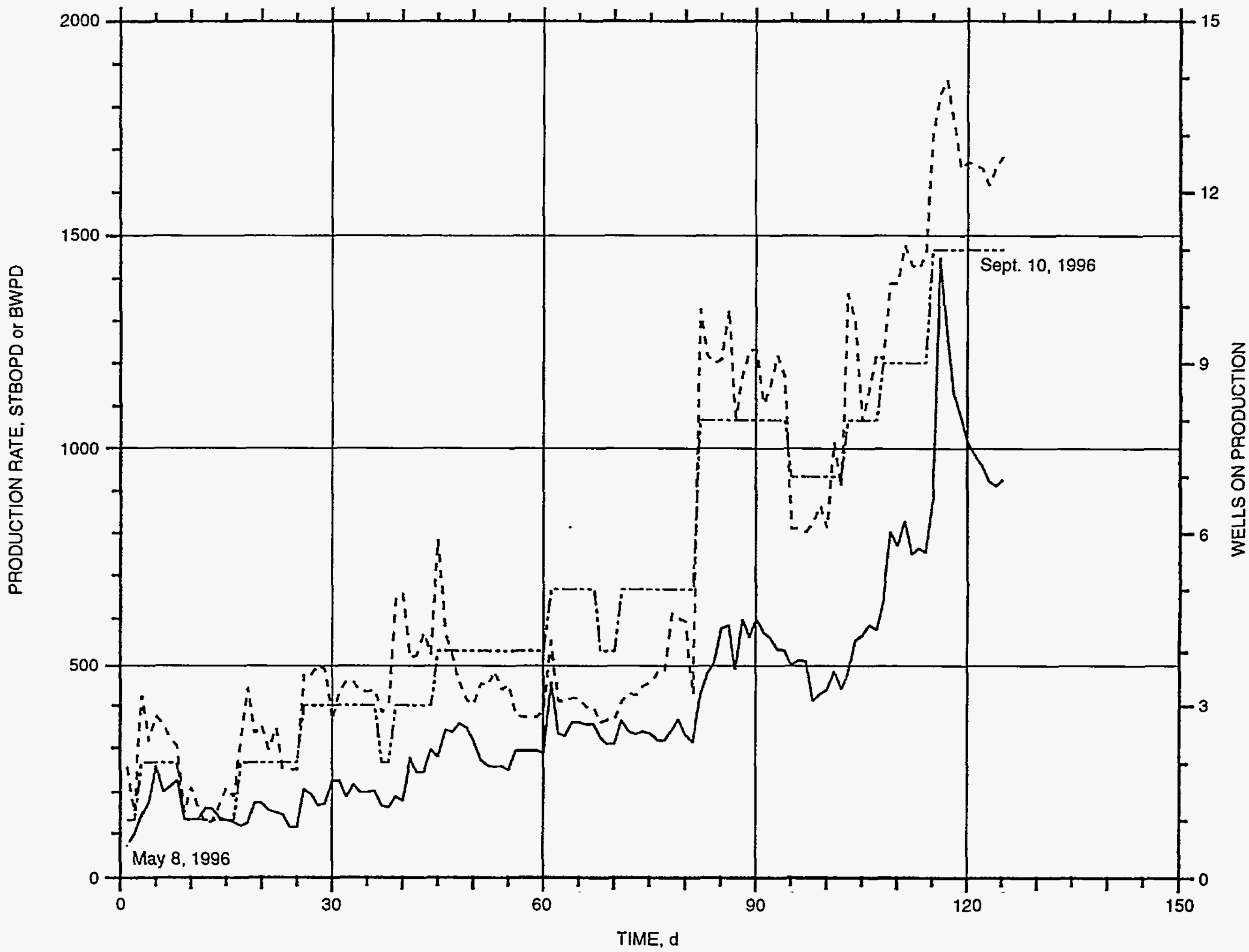


Fig. 1 Incremental production increase as the result of new 10-acre infill wells, North Robertson Unit. —, incremental oil. – – –, incremental water. — – –, wells on production.

conducted to try to optimize both injection and production in all wells. Previous special core data have shown that the Clearfork interval possesses either oil-wetting tendencies or mixed wettability characteristics. Plans are to verify or disprove this both in the field and in the lab during the new special core studies.

Interval testing was performed on the lower Clearfork zone on two wells and on the middle Clearfork zone on two wells in order to determine the relative contribution of each completed interval to production. Pressure drawdown data were also recorded as each well's producing fluid level was pumped down, and pressure-transient analyses were performed to provide information concerning the production efficiency of each zonal completion. The results of these tests are summarized in the Reservoir Management section.

Well stimulation. As a result of the data acquisition process (core and logs), discrete intervals within the Glorieta/ Clearfork section that contribute most to production can be identified. 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	(±7000 to 7200 ft)
Middle Clearfork:	MF1A, MF2, and MF3 zones	(±6350 to 6500 ft and ±6750 to 6900 ft)
Upper Clearfork:	CF4 zone	(±6150 to 6250 ft)

Three-stage completion designs have been used to keep the treated intervals between 100 and 250 ft. With the use of a new premium frac fluid, both CO_2–foam fracs and conventional cross-linked borate fracs were performed on an equal number of new wells with outstanding results for both designs.

All jobs have been radioactively traced to estimate vertical fracture propagation. This information has helped to avoid fracturing down into an underlying water zone in the lower Clearfork and to avoid any fracture communication between stages. All hydraulic fracture jobs were designed to yield fracture half-lengths of approximately 150 ft. Post-frac pressure-transient tests performed over specific completion

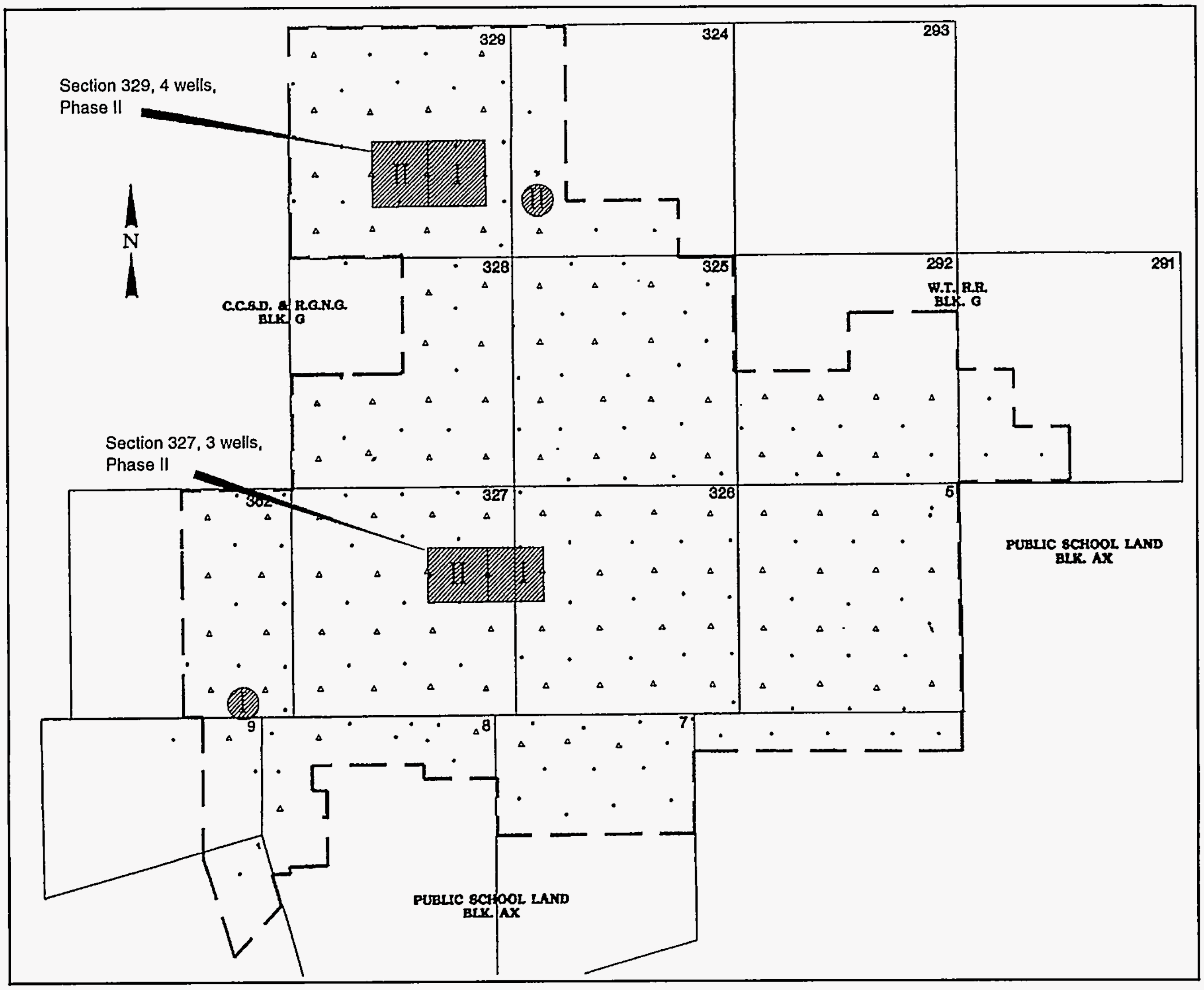


Fig. 2 Potential development areas for Phase I (11 wells) and Phase II (7 wells) drilling in North Robertson Unit, Gaines County, Tex.

intervals indicate that fracture half-lengths are ranging between 80 and 120 ft with average radial flow skin factors of approximately –5.0.

Oil fingerprinting. Surface oil samples were collected from each interval completion on all new wells for oil fingerprinting analysis. The samples have been sent to D. B. Robinson Fluid Properties, Inc., in Houston, Tex., for compositional analysis.

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

Work with D.B. Robinson will help determine if this cost-effective technology is a viable method for calculating each producing interval's contribution to total production. Information obtained from these tests and the interval pressure-transient tests currently performed will allow better targeting of productive intervals in future wells, a reduction in completion costs, and a more efficient completion.

Integration/Validation

Validation of Reservoir Characterization

Routine core analysis was performed on all newly acquired core. Porosity and permeability measurements were made over the entire cored interval on all the 1-in. by 1-in. quick plugs as well as on the 4-in. whole core across selected reservoir intervals. Numerous thin sections of the cored intervals also have been prepared.

Additional refinements were made to the depositional environment model on the basis of data from recently acquired core taken from the latest 10-acre infill wells. The planned coring program and a cursory description of these cores are complete. This represents 2730 ft of core in four wells.

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 sec. 327. Previous work suggested that a shelf edge existed to the east of sec. 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. 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 and upper Clearfork.

The second new piece of information concerns the MF3 layer (±6850 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 the presence of coal beds, abundant freshwater plant debris zones, erosion lag soils, and some root casts. Parts of the Unit were only partly 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.

Minipermeameter research. This reservoir characterization tool has the ability to take multiple permeability and porosity measurements in a very small grid across the surface of slabbed core. One hundred and fifty feet of slabbed core from the NRU 3533 well has been analyzed by Core Labs for minipermeameter and miniacoustic porosity measurements. On the basis of comparison with core-plug analyses, whole-core analyses, and thin sections, early indications are that the miniperm permeabilities and porosities are reliable for most of the rock.

Three vertical permeability traces, spaced 0.1 in. apart, were recorded. Vertical measurements of permeability along these traces were recorded every 0.1 in. One vertical trace of acoustic measured porosity was recorded. This trace was in the center of the core slab, and a measurement was taken every 0.1 in. It is hoped that this detailed information will provide a better understanding of small-scale vertical and lateral permeability changes, help refine porosity vs. permeability algorithms, improve the understanding of horizontal vs. vertical permeability ratios, clarify the understanding of the effects of diagenesis on permeability, and provide additional data for reservoir flow simulation.

Mud logging. Continuous reading of all mud gas components was captured while drilling, and the data were loaded into a computer database and depth corrected. Research into the applicability of using mud gas component ratios to estimate fluid content has begun. It is hoped that flushed zones will have uniquely different ratios than previously uncontacted oil zones.

The mud log is an excellent tool for locating the intervals that contribute most to production. In this particular shallow-shelf carbonate reservoir, it would appear that the pay intervals of interest could probably be cost-effectively defined simply by using the mud log and a base porosity and resistivity log.

Open-hole logging. The base logging suite for the 10-acre infill wells currently consists of a Dual Laterolog, Microlaterolog (MLL), or micro Spherically Focused Log (MSFL) (R_{xo} device), compensated neutron log, compensated spectral or litho-density log (includes PE), spectral gamma-ray log, and a sonic log. Several potentially useful modern open-hole log tools have been added to the normal logging suite in an attempt to more accurately characterize permeability, fluid content, and rock fabric. Some of these are summarized as follows:

High-frequency dielectric log. The high-frequency (200-MHz) dielectric log yields a salinity-independent measure of fluid distributions in the flushed zone. This is of paramount importance in such areas as the NRU which are currently under active waterfloods. The dielectric tool produces a much more accurate representation of pay intervals than can be obtained from the usual low-frequency flushed-zone resistivity devices, such as the MLL or MSFL, which do not always do a good job of differentiating between residual and movable hydrocarbons.

This device works extremely well in formations with mixed lithology and, if run in combination with a low-frequency flushed-zone resistivity device, yields a rock textural parameter that can be used to determine the type of porosity present (intergranular, vuggy, or fracture), which directly affects the producibility of any particular interval.

NMR log. Nuclear magnetic resonance (NMR) logs were recorded over selected sections of two cored wells to obtain permeability, lithology-independent porosity, pore-size distribution, and fluid saturation distribution from a single log. Most of the preliminary NMR work has been performed to differentiate between oil and water in low-resistivity clastics; however, several recent projects performed in the Permian Basin area are adding to the understanding of NMR responses in high-resistivity carbonate reservoirs.

The NMR log gave a reasonably good approximation of permeability, pore size, and location of free hydrocarbons; however, data turnaround was slow, costly, and initially needs to be closely calibrated with core. The distribution of free and bound fluids in the rock pores obtained from NMR analysis of selected core samples from the two wells indicated that the reservoir is oil wet. This fluid distribution was then used in the processing of the raw log data to yield a visual representation of the pore and fluid distribution in the reservoir. Permeability is estimated with the use of an empirical relationship involving the tool's porosity measurement and the T_2 time, or transverse relaxation time, required for a hydrogen molecule to reorient itself after being "tipped" by a magnetic pulse from the tool.

Given the fact that permeability and pore size change so rapidly in the Clearfork, the vertical resolution of the next generation of tools probably needs to be improved, and this is currently under way.

Borehole imaging log. An attempt was made to obtain log-based images of the borehole wall in two cored wells (NRU 1509 and NRU 3319) with both circumferential microresistivity imaging tools and acoustic-based imaging tools. The microresistivity imaging tool missed most of the small-scale features and many of the large-scale features, most probably caused by insufficient resistivity contrasts within the rock. Researchers were much more successful in identifying natural fractures, vugs, anhydrite nodules, and bedding planes with the use of the acoustic imaging tool.

Porosity vs. Permeability Relationships

Improving the understanding of the relationship between porosity and permeability has been one of the key efforts of this geologic work. The approach has been to integrate all geologic and engineering data in an attempt to refine existing porosity–permeability algorithms and to redefine flow unit boundaries. Now that the infill drilling program is complete and all new core and open-hole log data have been loaded into the database, porosity–permeability relationships and flow unit definitions can be updated.

Updating the Core-Log Model

Results from extensive work completed on improving the porosity vs. permeability algorithms used early on in this project indicate that several new lines of research hold promise:

- Generation of porosity vs. permeability plots for each shallowing upward carbonate cycle (previously called flow unit tops)
- Generation of porosity vs. permeability plots for each depositional environment.
- Use of neural-network programs to identify characteristic sequences on the basis of core and log responses.
- Improvement of the old core-log algorithms with new open-hole log data.
- Formulation of unique porosity vs. permeability relationships for small areas of the field related to the porosity vs. permeability relationships for the core in that area.

The geologists will work closely with David K. Davies & Associates, Inc., to combine these various techniques and formulate the best method(s) to obtain optimal permeability–porosity relationships.

Special Core Analysis (SCAL)

Approximately 120 preserved SCAL plugs were cut from the new whole core in 10-acre infill wells 1509, 3533, 1510, and 3319 to obtain a representative sampling of all pay rock types that were defined during Budget Period I. The SCAL plugs have been further screened with a computerized axial tomography (CT) scan machine at Texas A&M University to eliminate the plugs that possess major barriers to flow (which is almost always in the form of anhydrite nodules).

The images of 69 core plugs from NRU wells 1509 and 3533 were compared with the slabbed whole core and available thin sections. Of these 69 plugs, 26 were judged to be acceptable for future SCAL work. The results of CT scans for remaining core plugs from NRU wells 3533, 1510, and 3319 are being examined.

Validation of Reservoir Management Activities and Performance Analysis

Formation testing. The formation test tool has provided individual layer pressures that can be used to better understand the way in which the productive interval depletes and repressures across the Unit. This tool can be used not only as a formation evaluation tool but also as a reservoir conformance tool in an active waterflood. These results can be used to identify zones that are receiving insufficient or excess waterflood support. Also, oil–water contacts may be identified on the basis of differing fluid gradients, although this will be difficult in what is now a fairly mature waterflood.

Unfortunately, testing a low-permeability, heterogeneous formation such as the Clearfork is extremely difficult. Researchers here used a low-force snorkel, a slow-drawdown choke with a very small pretest chamber (5 cm^3), and a very soft packer pad (60 durometer) to possibly obtain valid formation pressures. Also, it is important to mud-up before reaching total depth to ensure the presence of a stable mud cake before logging because all of these wells are drilled with brine water. Even taking the preceding precautions, valid pressures were obtained only on about 15 to 20% of the tool sets. Data collected from three wells in the sec. 327 infill area are shown in Fig. 3.

Pressure-transient tests. Short-term pressure drawdown tests are being used to measure formation flow characteristics in the new producing wells. Drawdown tests rather than buildup tests are preferred to avoid the shut-in of recently completed wells. These tests are being recorded over individual completion intervals (i.e., lower, middle, or upper Clearfork) and are also being used to estimate the completion efficiency and the relative contribution of each zone to total production.

Both lower (NRU 3534) and middle (NRU 3532) Clearfork drawdown tests in the sec. 329 area and lower (NRU 1509) and middle (NRU 2705) Clearfork drawdown tests in the

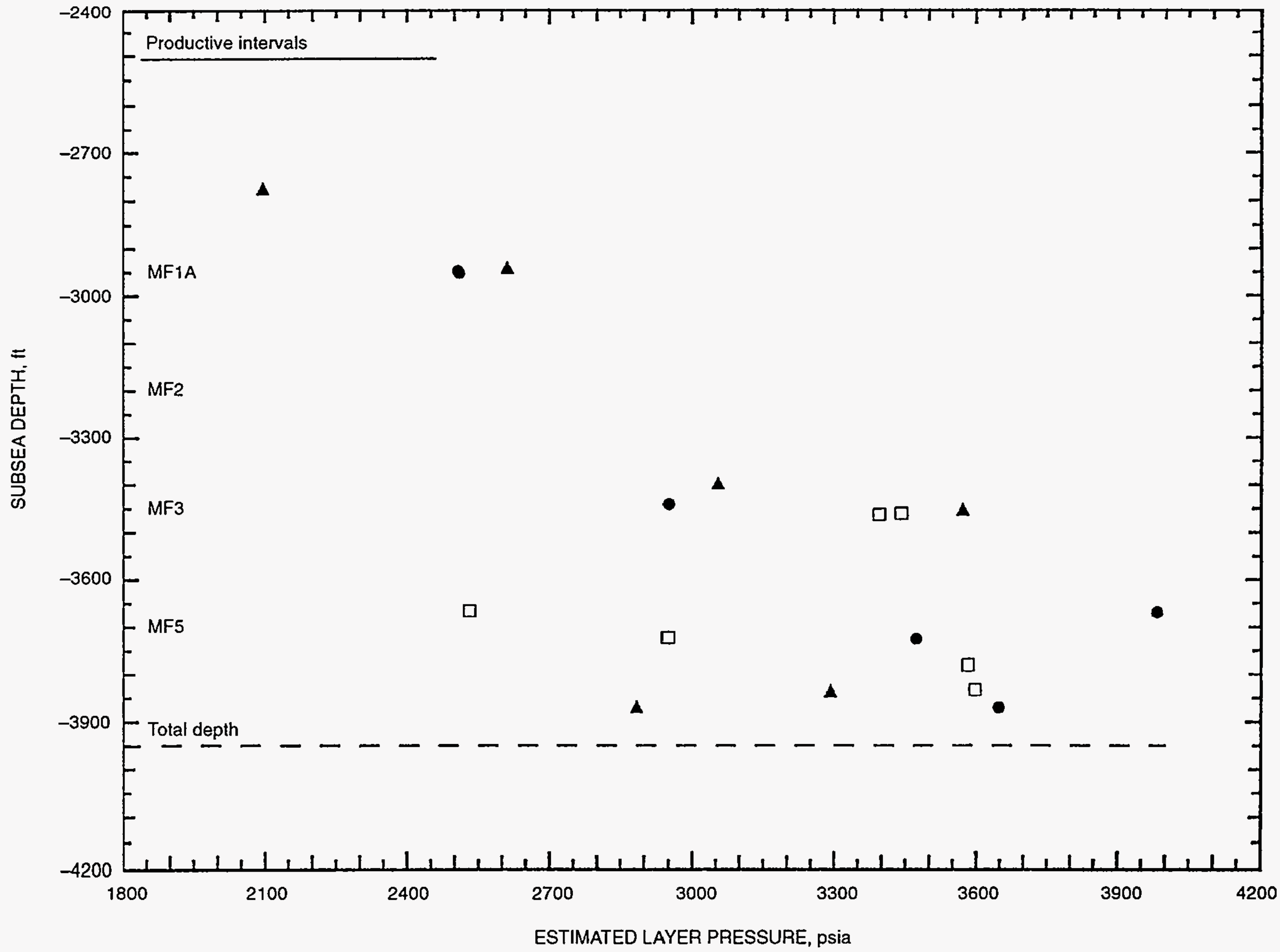


Fig. 3 Formation test layer pressures from three wells in sec. 327 10-acre infill area. □, NRU 505. ●, NRU 1509. ▲, NRU 2705.

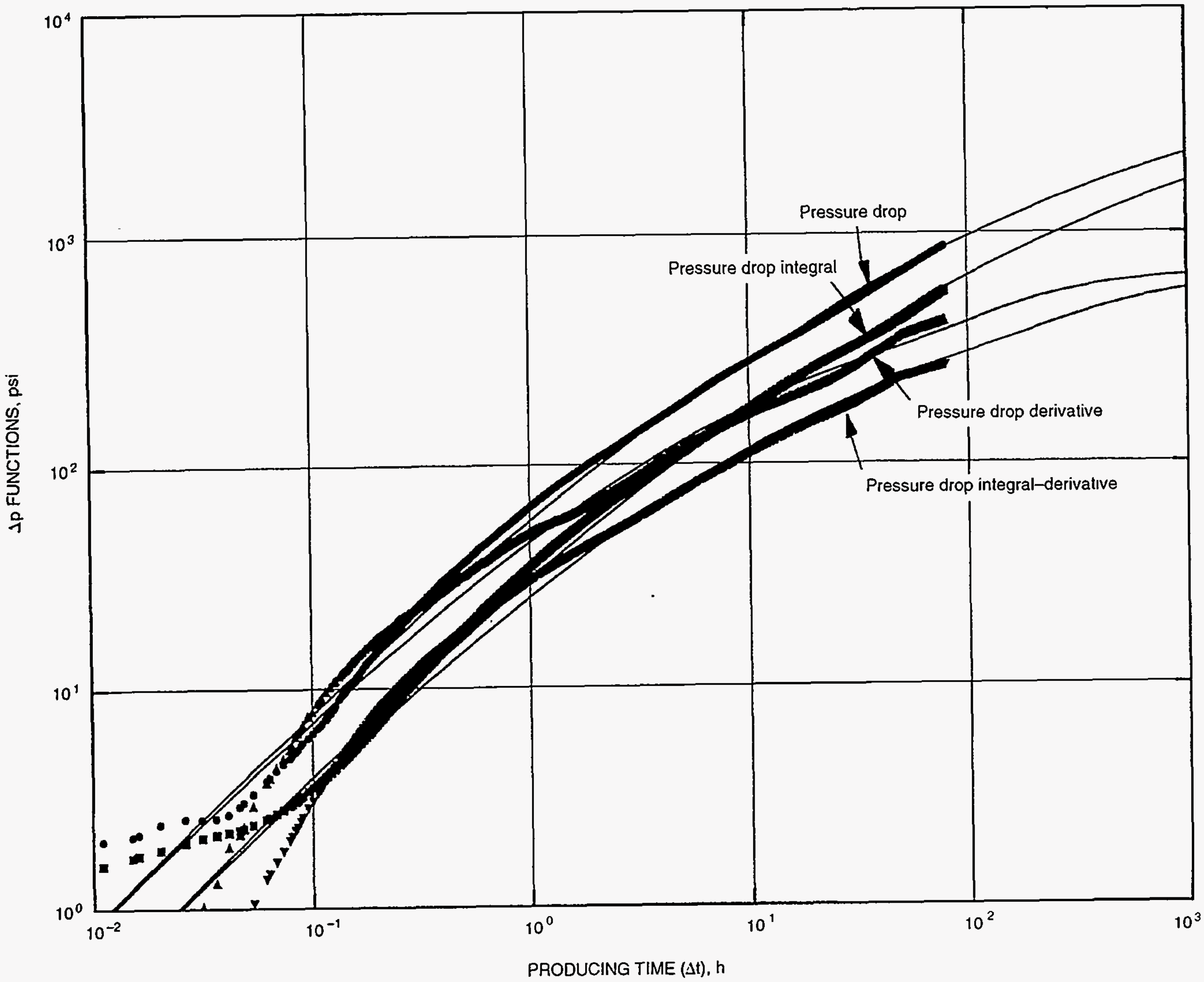
sec. 327 infill area have been recorded. The hydraulic fracture jobs have been successful and are producing fractures with half-lengths on the order of 100 ft (skin factor = –5.0). Figure 4 is a log–log plot summarizing the results for the analysis of the NRU 3532 middle Clearfork pressure drawdown test. Results also indicate that the middle Clearfork is a much more significant contributor to total production in both areas of the Unit than was previously thought. It also appears that the upper Clearfork and Glorieta sections contribute very little to total production in both areas of the Unit; this will be confirmed by future testing. At this point, each interval's approximate contribution to total production appears to be as follows:

	Section 327	Section 329
Upper Clearfork	5%	10%
Middle Clearfork	35%	65%
Lower Clearfork	60%	25%

This information, together with newly acquired corq qe and log data, has made the targeting of completion intervals much more effective.

Technology Transfer

A written report, "Integrated Reservoir Management and Characterization to Optimize Field Development," containing the results of current analyses, associated technical publications, and computer software generated as the result of the work performed on the project, was given to all attendees at two technical workshops (held April 25–26,1996, in Midland, Tex., for approximately 60 industry personnel and June 13–14, 1996, in Houston, Tex., for approximately 45 industry personnel).



Data for NRU 3532

(Drawdown test June 1996)

Oil Properties:

B_o = 1.2 RB/STB
μ_o = 2.0 cP

Reservoir Properties:

$c_t = 2.0 \times 10^{-5}$ psia^{-1}
r_w = 0.33 ft
h = 66 ft
ϕ = 0.06 (fraction)

Production Parameters:

q_o = 95 STBOPD
p_{wf} (Δt = 0) = 1724.0 psia

Results for NRU 3532

(Drawdown analysis—fractured well in a homogeneous reservoir)

k_o = 0.40 mD
x_f = 120.0 ft
C_{Df} = 0.0458
$C_{fD} = 1 \times 10^3$

Fig. 4 Data match on log–log plot for well NRU 3532 pressure drawdown test (June 1996). The match was made with the use of the model for a well with an infinite conductivity vertical fracture in an infinite-acting homogeneous reservoir. —, computed solutions. ●, pressure data. ▲, pressure derivative data. ■, pressure integral data. ▼, pressure integral–derivative data.

ECONOMIC RECOVERY OF OIL TRAPPED AT FAN MARGINS USING HIGH-ANGLE WELLS AND MULTIPLE HYDRAULIC FRACTURES

Contract No. DE-FC22-95BC14940

Atlantic Richfield Co.
Bakersfield, Calif.

Contract Date: Sept. 28, 1995
Anticipated Completion: Nov. 30, 1996
Government Award: $409,351
(Current year)

Principal Investigator:
Bruce L. Niemeyer

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The objective of this project is to demonstrate the effectiveness of exploiting thin-layered, low-energy deposits at the distal margin of a prograding turbidite complex through the use of hydraulically fractured, horizontal, or high-angle wells. The combination of a horizontal or high-angle well and hydraulic fracturing will allow greater pay exposure than can be achieved with conventional vertical wells while maintaining vertical communication between thin interbedded layers and the well bore.

A high-angle well will be drilled in the fan-margin portion of a slope-basin clastic reservoir and will be completed with multiple hydraulic fracture treatments. Geologic modeling, reservoir characterization, and fine-grid reservoir simulation will be used to select the well location and orientation. Design parameters for the hydraulic fracture treatments will be determined by fracturing an existing test well. Fracture azimuth will be predicted, in part, by passive seismic monitoring from an offset well during fracture stimulation of the test well.

Summary of Technical Progress

The fine-grid reservoir simulation of the northeast fan-margin region of the Yowlumne field was completed during this quarter. A variety of development alternatives were investigated to optimize project economics. Model forecasts compared slant well performance with more conventional development options and quantified rate impacts because of changes in well location, orientation, and completion technique. Project economics were then updated with the production forecasts from the simulation model.

Model Production Forecasts

The fine-grid, partial-field reservoir-simulation model of the northeast fan-margin region was used to test a variety of development alternatives aimed at optimizing project economics. Model forecasts compared slant well performance with more conventional development options and quantified rate impacts of changes in well location, orientation, and completion technique. Model results are reported in terms of incremental rates and reserves in order to eliminate interference effects.

All model forecasts were compared against a base prediction to determine incremental performance. The base prediction assumed water injection would replace reservoir voidage through year end 1999. Waterflood operations were then limited to reinjection of produced water only. Each producing well was placed on bottomhole pressure control for the entire predictive period and allowed to decline to an abandonment rate of 12 barrels of oil per day (BOPD). The model forecast was extended for the expected field life, which ends in 2005.

Results from the continued operations forecast demonstrated the effectiveness of the Yowlumne Unit B waterflood. Ultimate recovery from the model area, accounting for fluid flux, was 38.2 million barrels of oil (MMBO), or 48.5% original oil in place (OOIP).

North-South Fractured Slant Well

The model was initially used to predict the performance of a slant well drilled along the south-to-north well path. The well was expected to penetrate the reservoir interval at a 55° angle entering from an updip position (25° dip). This provided 1100 ft of pay exposure within approximately 180 ft of stratigraphic thickness. The well was also assumed to be fractured at three locations spaced 250 ft apart along the well path.

On the basis of results from the stimulation treatment in well 84-32, fractures were assumed to propagate along a northwest-southeast trend. Results from microseismic monitoring of the 84-32 treatment also indicated that fractures would probably not be confined by internal shales and would tend to be asymmetric with the longer fracture wing extending to the interior of the field.

For modeling purposes, fracture height was defined as equal to fracture length and was set at approximately 175 ft. Roughly 70% of total fracture length was allocated to the interior fracture wing, leaving 30% of total length to extend toward the sand margin. Within the model, each fracture was represented as a separate deviated well bore, which was defined to traverse the entire fracture plane numerous times. This treatment created an infinite conductivity pathway. Rates from each fracture were constrained on the basis of analogy to a successful frac in offset well 57X-34 and to predictions from commercial fracture-stimulation software.

Model results indicated that the well would initially produce 1252 BOPD if drawn down to a producing bottomhole pressure of 1200 pounds per square inch. Despite the high initial rate, incremental reserves attributed to the slant well were only 465 thousand barrels of oil (MBO).

East-West Fractured Slant Well

Saturation and pressure distributions estimated for the partial-field model of the fan margin differed from results generated by the full-field model. Better representation of reservoir heterogeneity and a change in flow unit correlations resulted in a significant portion of the original bypassed oil target being swept. Fine-grid modeling suggested that an alternate east-to-west well path would be superior to the south-to-north orientation. An area of higher oil saturations appeared to be trapped between two east-west rows of producers immediately adjacent to the original slant well location.

A second slant well location was therefore tested with an approximate 1000 ft east-to-west well path. The well is expected to penetrate the formation approximately along strike at a 75° angle from vertical. The well was assumed to be fractured at three points 250 ft apart. The approach used to represent each fracture plane was identical to the methodology described for the north-south well. This required that the nested grid be reoriented to accommodate the east-west well path.

Model results indicated that the well could initially produce 2180 BOPD and provide 724 MBO of incremental reserves. Improved well performance for the east-west orientation was attributed to higher oil saturations and better reservoir quality. The well also produces an incremental 8% of OOIP from the distal fan margin. The east-to-west slant well orientation was selected for this project.

Vertical Wells

The model was next used to predict performance of three vertical wells placed equidistant along the east-west slant well path. The wells were assumed to be unstimulated with 0.25-ft wellbore radii and skin factors of 3.

On a development cost basis, the three wells were virtually identical to the east-west slant well. Model projections, however, indicated that rates and reserves were much lower for vertical wells. The forecast estimated the combined initial rate of all three wells to be 679 BOPD, whereas incremental reserves were projected to be only 223 MBO.

Increased pay exposure along the deviated well path and fracture planes accounted for most of the variance in rates between the slant well and vertical wells; however, operational differences in the two sets of forecasts also contributed to the rate difference. The slant well was assumed to be equipped with an electric submersible pump (ESP) to minimize producing bottomhole pressure. The vertical wells were assumed to be lifted with hydraulic jet pumps operating at 500 psi higher bottomhole pressure. The reason for the difference in lift equipment was that the incremental rate from any one of the vertical wells as the result of greater drawdown could not justify the higher operating cost associated with the ESP.

Horizontal Well

The east-west slant well was also compared with a horizontal well. The horizontal well was assumed to be drilled and completed entirely within sands E1 and E2 (model layers 8 and 9), which appeared to be relatively unswept. The well would follow the same lateral east-west path as the slant well.

The model forecast suggested that the horizontal well would initially produce 404 BOPD and provide only 74 MBO of incremental reserves. These results confirmed the obvious need to establish communication between the wellbore and each productive flow unit.

Number of Fractures

A sensitivity study was conducted to examine the impact of reducing the number of fracture treatments pumped in the slant well. Model results are summarized in Table 1.

TABLE 1

Model Results of Fracture Treatments Pumped in the Slant Well

	Number of fracs			
	0	1	2	3
Incremental rate, BOPD	684	1267	1638	1980
Incremental recovery, MBO	296	527	622	734
Total well recovery, MBO	691	1215	1388	1547

Analytical Estimates of Reserves and Initial Rates

Analytical methods were used to confirm model predictions of reserves and initial rates. Although there are many uncertainties, particularly with reserve estimates, model results appeared to be reasonable. Because of the detailed geology and reservoir characterization in the fine-grid model and the difficulty with analytical methods of accounting for fluid flux in a small volumetric region, the results from the reservoir simulation model are believed to be much more reliable.

Conclusions

Results from the fine-grid model confirm the use of the east-to-west slant well with multiple vertical fractures to develop the fan-margin region. The well clearly outperforms other development options in thinning highly stratified intervals (Figs. 1 and 2). The detailed description used in the fine-grid, partial-field model also provided a much improved representation of static and dynamic reservoir conditions.

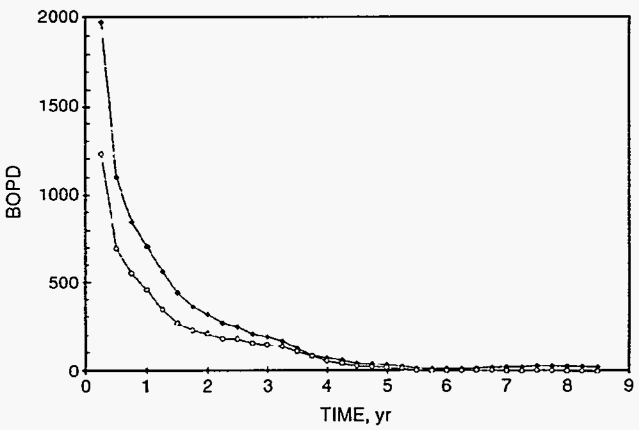


Fig. 1 Comparison of model production forecasts for east-west slant well with 3 fracs (♦) and north-south slant well with 3 facs (O).

Project Economics

Risk and Costs Analyses

A discounted cash flow model was used to update the original economics of drilling the slant well and completing with as many as three hydraulic fracture treatments.

Decision tree analysis was applied to production and costs in the economic evaluation to account for the many possible outcomes (Fig. 3). There is mechanical risk involved in drilling the well and successfully pumping up to three fracs. Also, successfully pumping three fracs does not guarantee desired frac results, such as height, length, width, conductivity, and azimuth. There is also geologic risk pertaining to rock quality and reservoir risk regarding saturations.

The estimated investment outlays to drill, complete, and equip the slant well are shown in Table 2. Several activities associated with the proposed slant well add to the costs to drill, complete, and equip a "typical" vertical well in the Yowlumne field:

- Directional work
- Cut and analyze whole core
- Drillpipe-conveyed logging
- Process formation microimager log data
- Perforate long intervals
- Three large hydraulic fracture treatments
- Microseismic logging in an offset well for each of the three fracs
- Production testing, pressure-transient testing, and production logging of each fractured interval
- ESP lift

Expected operating expenses for the slant well are also higher than the cost to produce a typical well in the field. Table 3 lists the annual operating expenses used in the

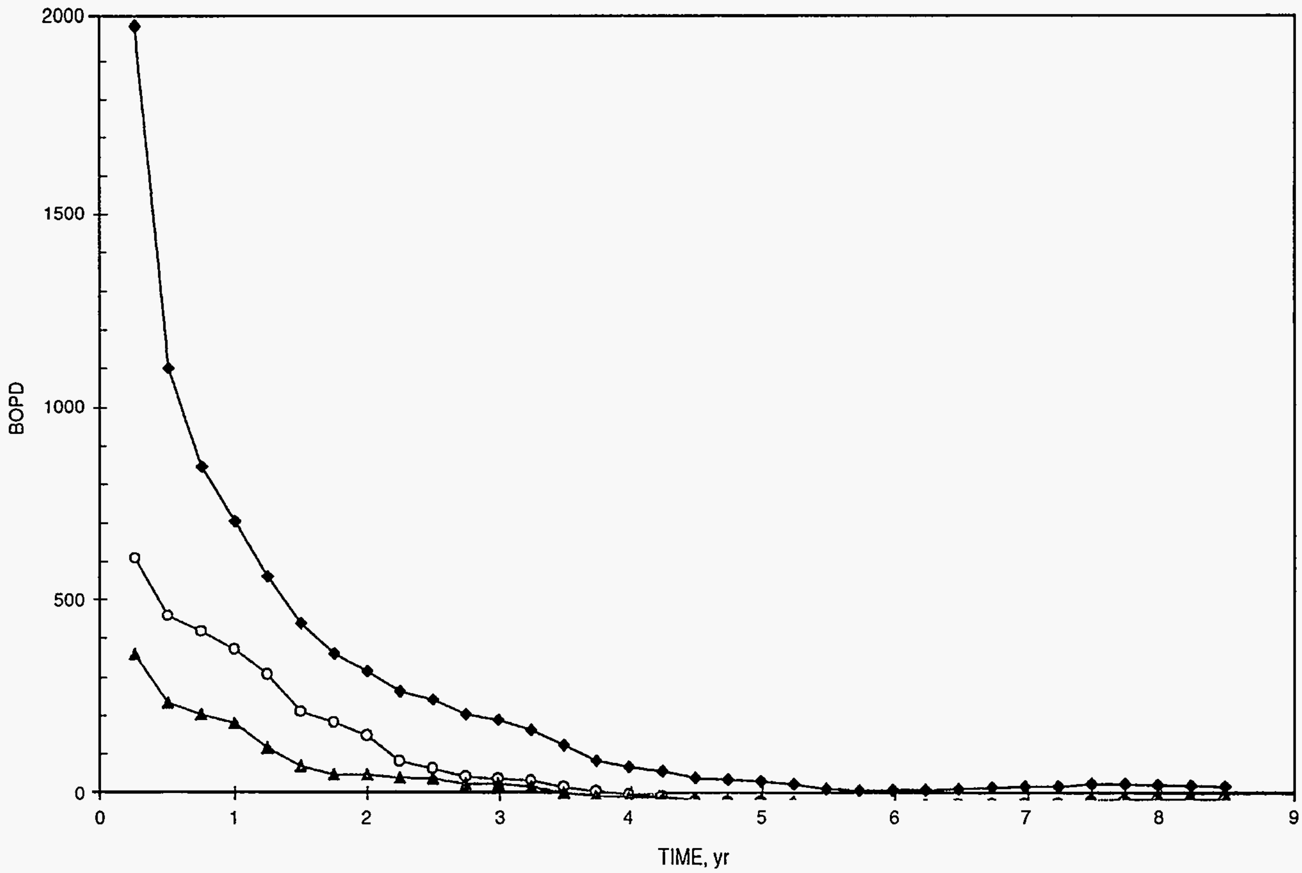


Fig. 2 Comparison of model production forecasts for east-west slant well with 3 fracs (♦), 3 vertical wells (O), and east-west horizontal well (▲).

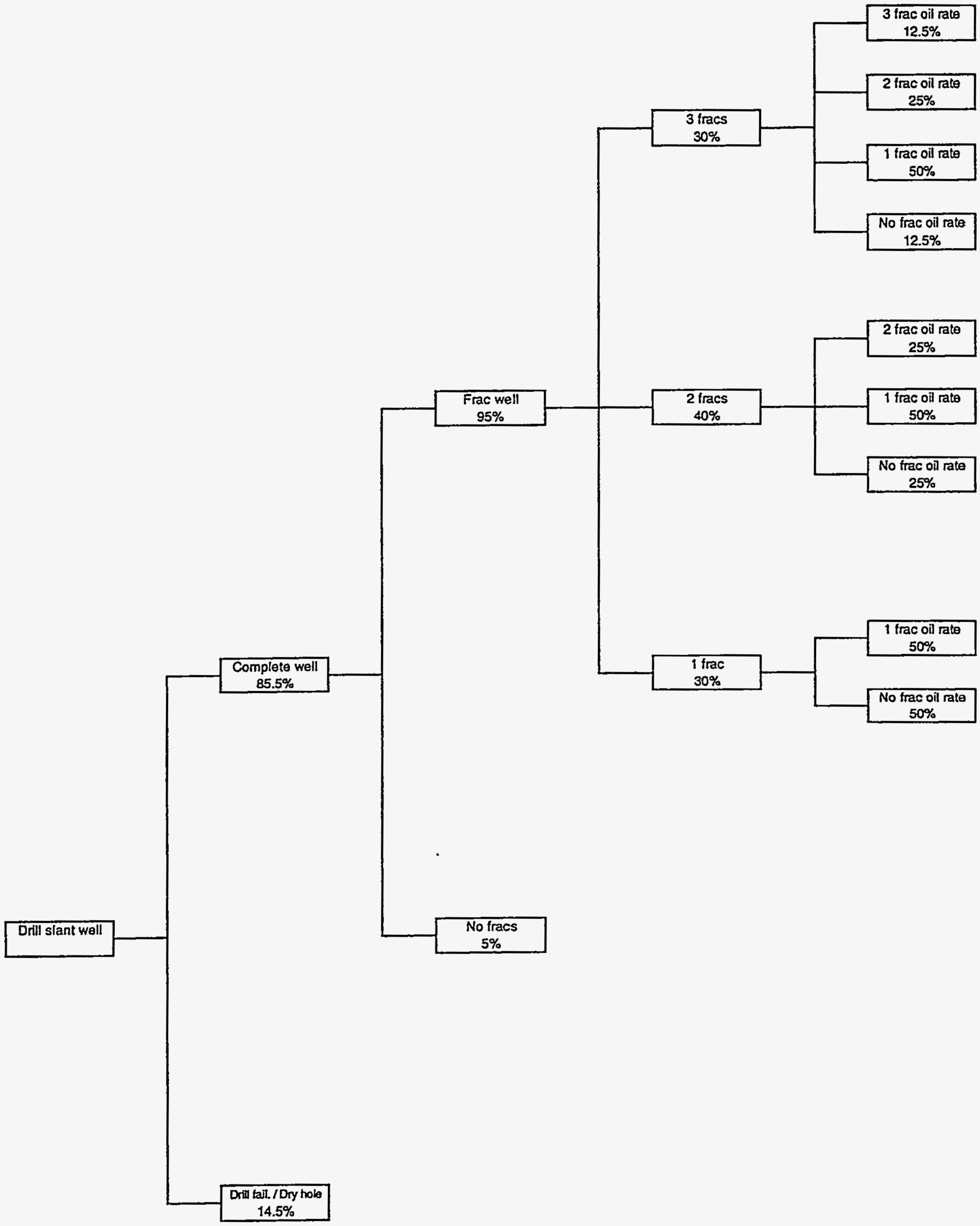


Fig. 3 Decision tree for determining expected value production and costs.

economic evaluations for the 8.5-yr life of the well. All expenses are inflated 5% annually.

Operations surveillance costs represent lifting costs for a well equipped with an ESP sized for 3000 to 3500 bbl/d, including provisions for one ESP replacement each year. The production string will be equipped with a "Y" offset tool to permit production logging and pressure-transient testing while the well is producing. Also, costs are included for remedial water shutoff workovers. The economics also include contract and company labor costs for frac and microseismic logging design, 5 yr of technology transfer, overhead, and burden.

TABLE 2

Outlays to Drill, Complete, and Equip Slant Well (in thousands of dollars)

	Number of fracs				Mechanical failure
	3	2	1	0	
Drill	2193	2193	2193	2193	2078
Complete	1085	776	309	157	35
Equip	291	291	291	291	0
Microseismic logging	196	130	65	0	0
Total outlays	3765	3390	2858	2641	2113

TABLE 3

Slant Well Operating Expenses (in thousands of dollars)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Total
Operations surveillance	269	471	480	429	423	439	456	478	335	3780
3rd-party consulting and technology transfer	177	104	29	64	25	0	0	0	0	399
Company labor, burden, and overhead	263	167	163	124	172	180	189	199	104	1561
Total project costs	709	742	672	617	620	619	645	677	439	5740

Production, Prices, and Taxes

The production streams for each scenario consisting of a slant well with no fracs up to a slant well with three fracs were input into the economic evaluation (Fig. 4). Each stream was factored on the basis of a decision-tree analysis. The expected-value incremental production stream (Fig. 5) consists of a starting rate of 967 BOPD and reserves of 407 MBO. Expected-value reserves are 55% of the three-frac success case reserves.

Gas and natural gas liquid sales were also included in the economics and were based on a gas/oil ratio of 489 standard cubic feet/stock tank barrel, gas shrinkage of 22%, and 5.1 gal/min yield.

Pricing is based on 1996 postings for the Yowlumne field (31 °API). The starting prices were $18.00 per barrel of oil, $18.15 per barrel of natural gas liquid, and $1.45 per thousand cubic feet. Prices were escalated at 5% per year, consistent with escalation of operating expenses.

Income tax rates used in the economics were 35% for federal and 5.4% for California state. Severance tax rates were 2.2% for oil and 0.22% for gas. The ad valorem tax rate was 1.61%.

With the use of commercial economic analysis software, expected-value, incremental economics were calculated for the project on the basis of working and revenue interests of 100%. Table 4 lists the present worth figures for a range of discount rates.

The economics are less favorable at lower discount rates because of rate acceleration effects. Although the well has full incremental operating expenses for 8.5 yr, there is virtually no incremental production after 5 yr. Higher discount rates increase the present values of the negative cash flows after year 5, thereby improving project economics.

TABLE 4

Present Worth for a Range of Discount Rates (before and after federal income taxes)

Discount rate, %	Present worth before federal income tax, thousand dollars	Present worth after federal income tax, thousand dollars
0	629	387
5	865	471
10	969	487
15	992	463
20	967	416

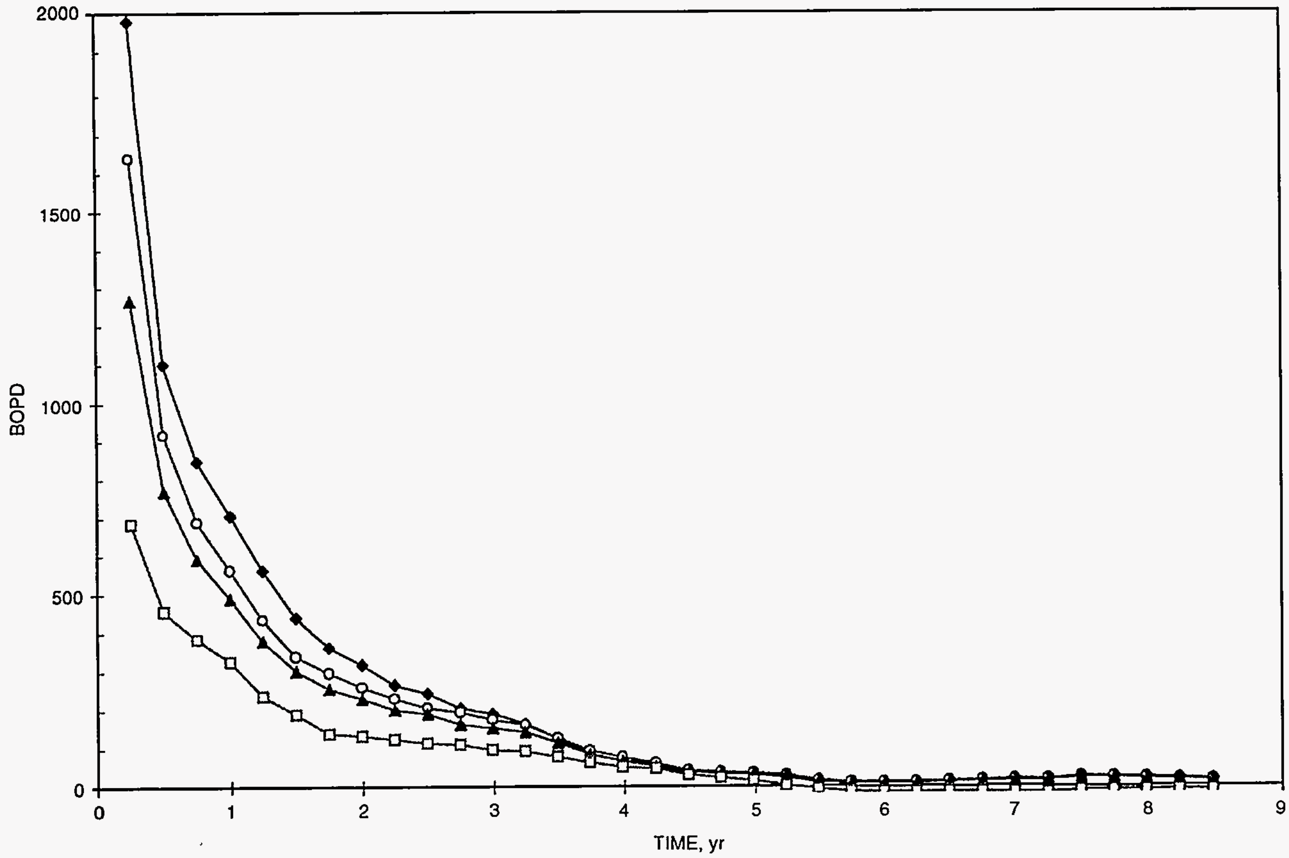


Fig. 4 **Sensitivities of east-west slant well model production forecasts to number of fracs. ♦, 3 fracs. ○, 2 fracs. ▲, 1 frac. □, no fracs.**

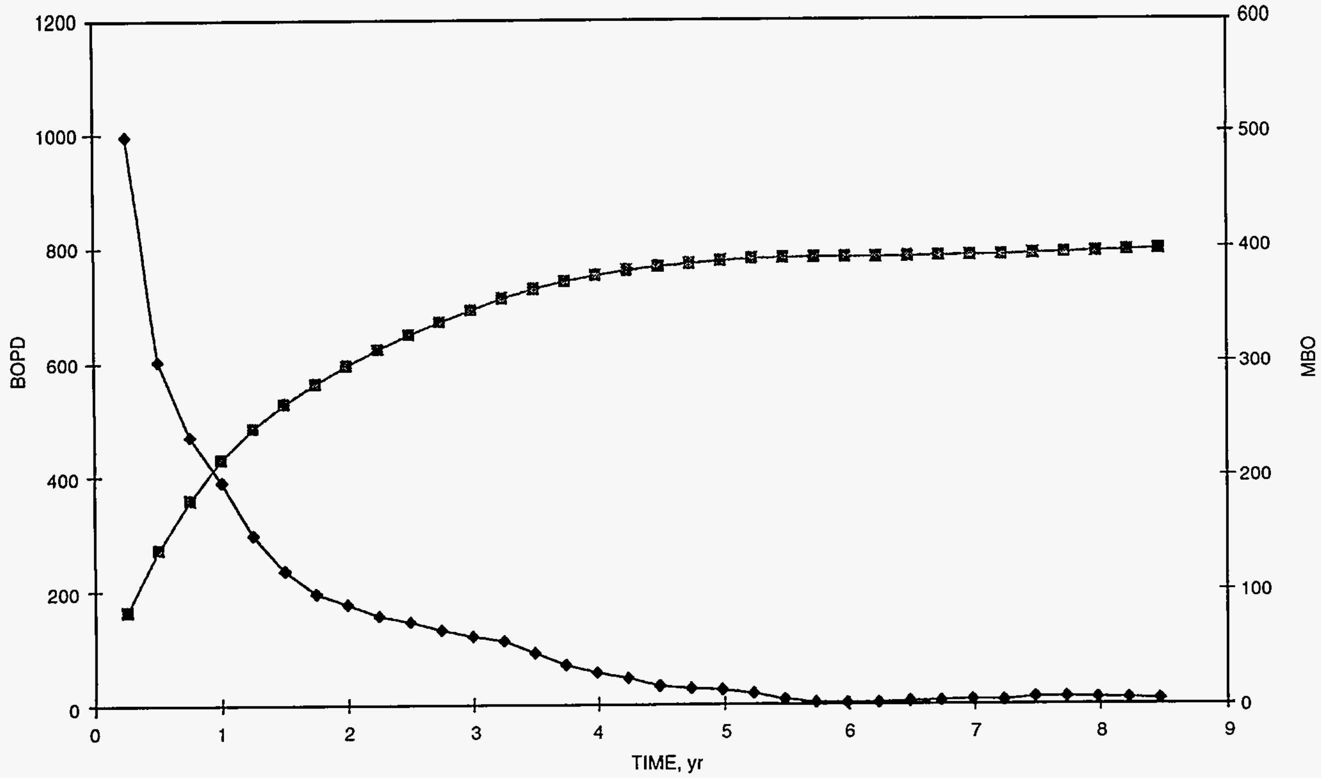


Fig. 5 **Expected value rate and reserves for east-west slant well on the basis of decision tree analysis of model production forecasts. ♦, rate. ■, recovery.**

INTEGRATED APPROACH TOWARD THE APPLICATION OF HORIZONTAL WELLS TO IMPROVE WATERFLOODING PERFORMANCE

Contract No. DE-FC22-93BC14951

University of Tulsa
Tulsa, Okla.

Contract Date: Jan. 1, 1993
Anticipated Completion: Dec. 31, 1996
Government Award: $250,973

Principal Investigator:
Balmohan G. Kelkar

Project Manager:
Rhonda Lindsey
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The overall objective of this project is to improve secondary recovery performance of a marginal oil field through the use of an appropriate reservoir management plan. An integrated approach will be used for the selection of a plan based on a detailed reservoir description. With the use of this method, a 2 to 5% recovery of the original oil in place is expected. This should extend the life of the reservoir by at least 10 yr.

In Stage I of the project, a detailed, state-of-the-art reservoir description was developed for Glenn Pool Field, Tulsa County, Okla. Evaluation of alternate reservoir management strategies resulted in the selection completion of many wells, followed by an increase in the injection rate. This management plan is being implemented and performance is being monitored.

Stage II involves selection of the Berryhill Unit Tract 7 of the same reservoir, development of reservoir description with only conventional data, and simulation of flow performance with developed reservoir description. By comparing the results of the two stages, the use of collecting additional data with state-of-the-art technology will be evaluated. Also, the use of optimum reservoir management planning to improve secondary performance of marginal fields will be evaluated.

Summary of Technical Progress

Monitoring of the reservoir management plan in the Self Unit continued. During the quarter, the production from the unit has remained steady up to 50 bbl/d (over 200% increase in the production). The scope of the project for Stage II is being expanded. Instead of concentrating only on Tract 7, all the areas currently operated by Uplands Resources are being evaluated to find the best location for either a multilateral or a horizontal well. The geological mapping is complete, and an indexing procedure is being established to rank the areas by potential. The geostatistical description and the flow simulation should begin soon. Although not part of this project, a 3-D seismic survey is being conducted on the Glenn Pool field to better evaluate the channel sand structure.

Stage I Project Monitoring

Last quarter, after evaluating each individual well, electrical submersible pumps were installed to produce three wells. Three other wells required rod pumps. After the pumps were installed, production improved significantly. Over the last 3 months, average daily production has been approximately 50 bbl/d, compared with a baseline production of 13 bbl/d before installation. On the basis of an estimation of flow simulation results, production from the unit should reach between 100 and 120 bbl/d once the implementation is complete.

To increase the water injection rate as planned, an injection pump and the piping to bring the water from the Arkansas river have been installed.

Geological Description

In the third quarter of 1996, geology activities of the Glenn Pool project focused on workshop preparation, facies map modification for Tract 7 area, completion of field-scale cross sections, facies architecture evaluation for Tracts 9 and 16, and Chevron Polymer Flooding acreage.

Six additional cased-hole gamma-ray logs were acquired. Five of them are in Tract 7 unit (well numbers 7-97, 7-99, 7-100, 7-103, and 7-107), and one (11-82) is in Tract 11 unit. As a result of these additional well logs, the net sand isopach and facies maps developed earlier were checked and modified as necessary. Only very minor changes were needed. Also, interpretation of these additional logs indicates that the actual reservoir sandstone volume is a little higher than that shown in the original maps. For discrete genetic intervals (DGIs) E, F, and G, only net sand contours need minor modification. For DGIs A, B, C, and D, both facies boundaries and net sand contours need minor modification.

Figures 1 and 2 compare the facies maps of the original and modified versions, respectively, for DGI C. Only small variations exist in the original and the modified maps.

Perforation and initial production information were added to the six field-scale cross sections constructed earlier this year. The cross sections include an interval from the Pink Lime marker to the Brown Lime marker. A copy of these completed cross sections was submitted to Uplands Resources, Inc.

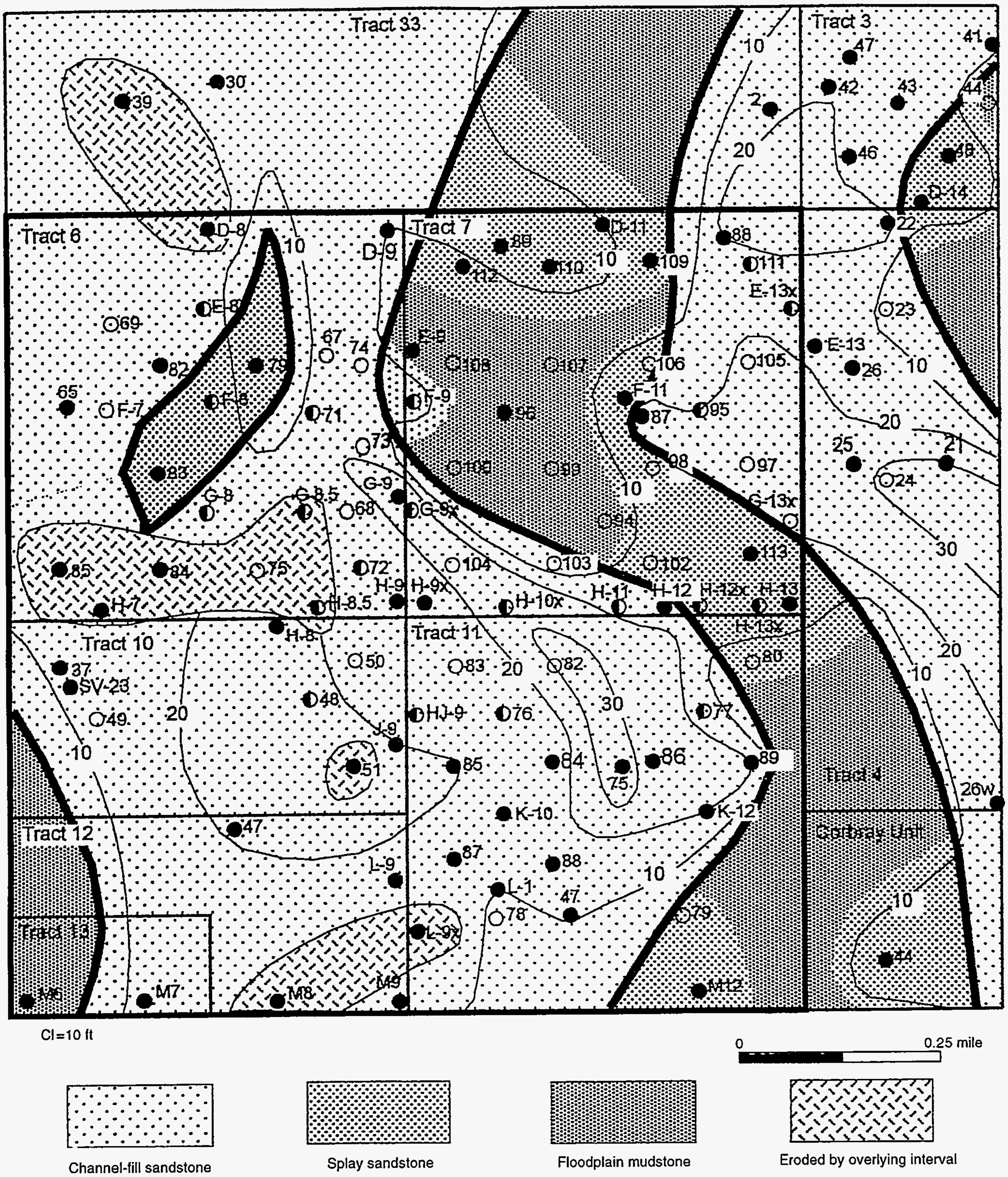


Fig. 1 Net sand isopach and facies map, DGI C (Tract 7 and adjacent area, original version).

Facies architecture reconstruction is being undertaken for Tracts 16 and 9 and Chevron Polymer Flooding acreage to generate a uniform picture, in terms of facies distribution, for the entire area that has potential for drilling a horizontal well. With completion of this task, the area mapped for detailed facies architecture over the course of the project will be about 1500 acres.

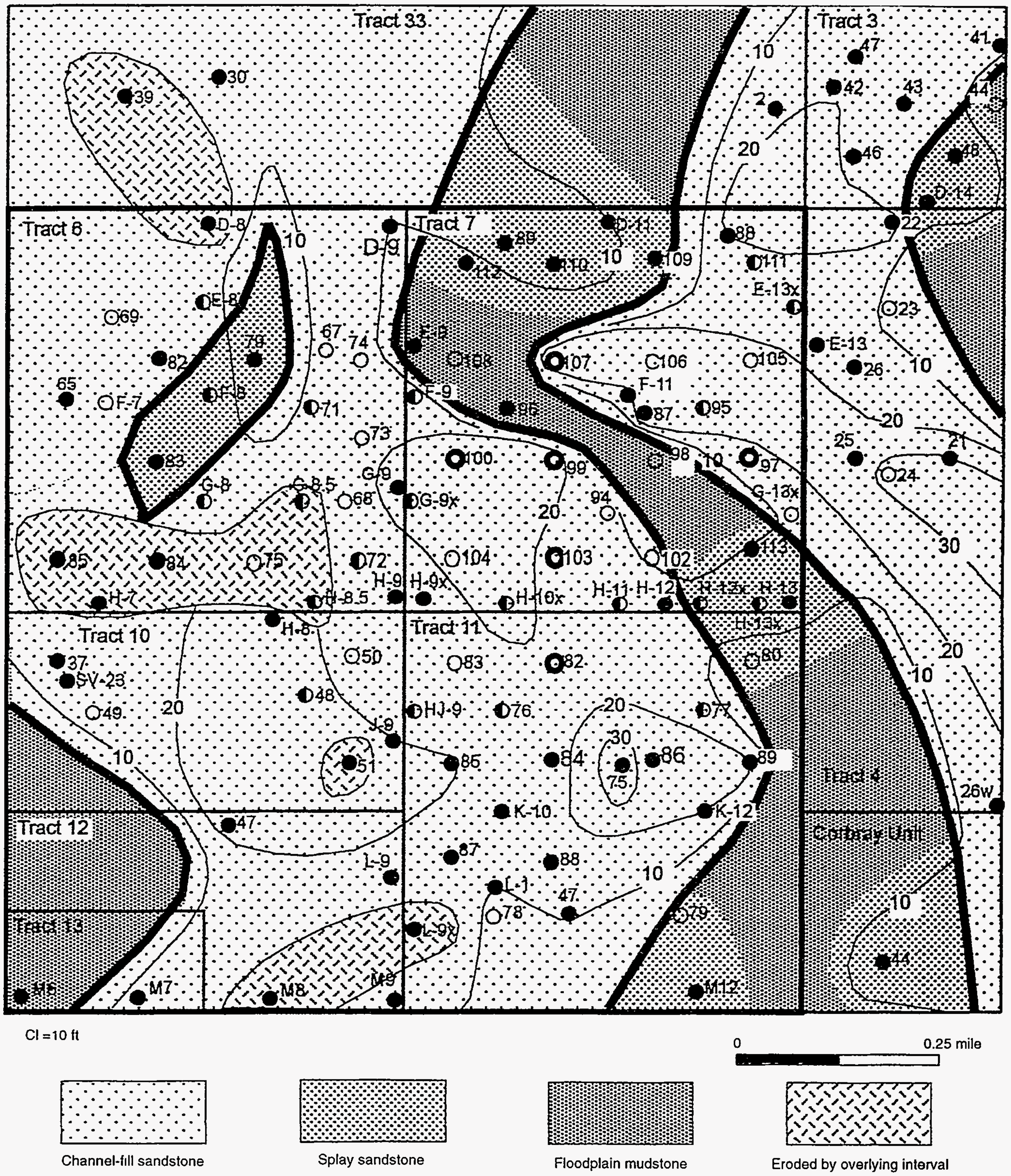


Fig. 2 Net sand isopach and facies map, DGI C (Tract 7 and adjacent area, modified version).

Engineering Evaluation

On the basis of the old as well as newly collected logs, researchers here have concluded that the gas cap does not exist in Tract 7 or the surrounding areas. Also, on the basis of the evaluation of the adjacent area operated by Chevron, researchers believe that significant potential exists for additional oil recovery in the upper DGIs and have developed a simple procedure to grade the areas of high and low potential.

Perforation Maps

The DGI interpretation for Tract 7 and adjacent areas was used to observe how the field was completed over its life. The DGI interpretation gives the depth of each DGI (A through G) at each well location where the log data are available.

A kriging procedure was used to estimate DGI depths at locations where no logs are available. The area of interest, which is approximately 5280 × 5280 ft, was divided into 10 × 10 ft grid blocks. The depth of each DGI was then estimated for each of those 10 × 10 ft grid blocks. After the nearest grid block location was known, the DGI depths at all the wells were estimated. Because the depths of the individual DGIs do not vary widely, the kriging procedure was deemed adequate for such estimation purposes.

Perforation maps are then generated for each DGI displaying only the wells that have been completed in that DGI with an estimate of the interval that has been completed out of the thickness of the DGI under consideration. The density of completed wells decreases dramatically from lower to upper DGIs. The reason for this completion strategy is the fear that upper DGIs are occupied by a gas cap. The existing density neutron logs show no evidence of gas cap. Further, additional cased-hole pulsed neutron logs at three wells confirm the nonexistence of gas cap.

Perforation Maps for the Chevron Acreage

The Chevron acreage adjacent to the area under investigation was studied to further confirm the nonexistence of the gas cap. Chevron conducted a successful micellar–polymer flood project in the early 1980s in the William Berryhill Unit, which is located northwest of the study area. The perforated intervals before and after 1980 were plotted to investigate the completion practices in that unit. Data used for this comparison are not complete, and the records on most of the wells completed before 1942 are unavailable. By comparing the data with other parts of the Berryhill Unit, however, it is reasonable to assume that before 1942 the wells were completed in the lower DGIs, namely, in F and G.

During the implementation of the micellar flood, no additional wells in DGI G were completed by Chevron. Instead, they concentrated on the upper DGIs. Several more wells were completed in the upper intervals. It is not known whether the success of Chevron's project was due to better chemical flooding or improved infill drilling practices. In any case, the production improvement was remarkable. Compared with Chevron's acreage, Tract 7 and its adjacent areas are on a structural high. As evidenced by the logs, if the gas cap is not present in those tracts, the potential for additional oil recovery is significant.

Mapping of Petrophysical Properties

Porosity. Logs were collected and digitized wherein the combination of logs for a particular well is sufficient to make a reasonable estimation of porosity and saturation. The number of such wells is extremely small. Typically, a combination of spontaneous potential, gamma-ray, density, and neutron logs is used to compute porosity. The computation validity is then established by comparing it with the core porosity data for the lower intervals because the upper intervals are predominantly uncored. The porosity values at the well locations are averaged for each DGI. These average values are kriged to estimate porosity values at all other grid blocks for a particular DGI. The result is seven areal slices (DGIs A to G); each slice represents a particular DGI.

Permeability. Log permeability vs. porosity relationships are established for each DGI individually by combining all available core data. Permeabilities are evaluated on the basis of the preceding relationships for all wells where porosity is computed. The permeability values at the well locations are averaged for each DGI. Precautions are taken to strip any unreasonable permeability value. These average values are kriged to estimate permeability values at all other grid blocks for a particular DGI.

Saturation. Typically, a combination of porosity, induction, and resistivity logs is used to compute saturation. The saturation values at the well locations are averaged for each DGI. The computation validity is then established by comparing the log-derived profile with the core profile and comparing water saturation averaged for each DGI with thermal decay time saturations with the use of compatible water resistivity and water porosity values.

The average values are kriged to estimate saturation values at all other grid blocks for a particular DGI.

Potential Index (PI) Estimation

The potential for a particular location is a cumulative effect of the production capacity, storage capacity, and access to the existing wells. The potential should be directly related to the production and storage capacities and inversely proportional to the access by other wells.

Conductivity index (CI). This index quantifies the production capacity and is related to the product of permeability (k) and thickness (h) ($k \times h$). Because k and h are defined at all grid blocks in all the seven DGI slices (A to G), the productivity can be estimated at each grid block. Because F and G have been drained considerably, further indexing is done only from DGIs A to E. The productivity data for the DGIs A to E are then combined to establish quartiles X_{25}, X_{50}, and X_{75}. Ranks are then assigned from 1 to 4 by comparing data points at each grid block with the quartiles (for instance, if the productivity for a particular grid block is less than X_{25}, then it is assigned a rank 1; if it is between X_{25} and X_{50}, then the grid block is assigned a rank 2 and so on).

Storativity index (SI). This index quantifies the storage capacity and is related to the product of porosity (ϕ), oil saturation (S_o), and thickness (h) ($\phi \times S_o \times h$). Since porosity, saturation, and thickness are defined at all grid blocks in all the five DGI slices (A to E), the storativity can be estimated at each grid block. The storativity data for the DGIs A to E are then combined to establish quartiles X_{25}, X_{50}, and X_{75}. Ranks are then assigned from 1 to 4 by comparing data points at each grid block with the quartiles, as was done for the conductivity index.

Accessibility index (AI). This index defines the access by drilled wells. It is assumed that a fully penetrated well in a particular DGI contacts 10 acres. If partially penetrated, the area is proportionately reduced. If a grid block is contacted, the AI is assigned 0; if a grid block is not contacted, the AI is assigned 1.

Potential index. The productivity and storativity data are combined by summing up their individual ranks at all grid blocks. The maximum value of the sum is 8, denoting that the area has the highest potential both in terms of its productivity and storativity. Conversely, the least value of the sum is 0, denoting low potential. Because the essence of the procedure is to identify areas of high potential, the decision was made to use a combined sum of 4 as the index of demarcation between high and low potential areas. Hence, if the sum is greater than 4, the grid block is categorized as 1 (high potential); if the sum is less than 4, the grid block is categorized as 0 (low potential). The category value is then multiplied by the AI to calculate the final PI as PI = (CI + SI) × AI.

Irrespective of a grid block with a high or low potential, if the area being contacted by a well has an accessibility of 0, this also reduces the PI value to 0. By including the accessibility, all the regions that are being drained are essentially masked and treated as being equivalent to areas with zero potential.

Cumulative index is estimated by adding the PI values at corresponding grid blocks for all DGIs (A to E). For each areal location, 5 indexes are added corresponding to each DGI. By collapsing all the DGIs into one unit, areas that have the highest potential both areally and vertically can be examined. Figure 3 is a map of the cumulative potential index for DGIs A to E. The areas of high potential and low potential are delineated. These need to be validated with additional geostatistical and simulation work.

Technology Transfer

Workshops regarding this DOE Glenn Pool project are being offered in Tulsa, Denver, and Houston. Workshop material will include a notebook containing a brief summary of all the presentations as well as copies of the overheads and a copy of the software used to generate reservoir description.

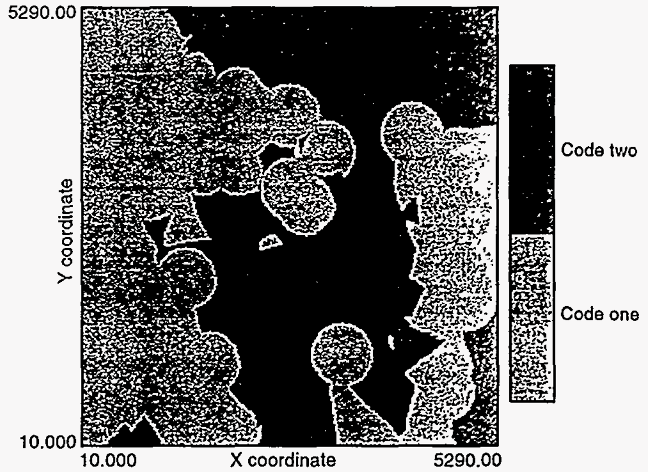


Fig. 3 Cumulative potential index map for DGIs A to E.

WEST HACKBERRY TERTIARY PROJECT

Contract No. DE-FC22-93BC14963

Amoco Production Company
Houston, Tex.

Contract Date: Sept. 3, 1993
Anticipated Completion: Apr. 2, 1997
Government Award: $6,017,500

Principal Investigators:
Travis Gillham
Bruce Cerveny
Ed Turek

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The objective of this project is to demonstrate the technical and economic feasibility of combining air injection with the Double Displacement Process (DDP) for tertiary oil recovery. The DDP is the gas displacement of a water-invaded oil column for the recovery of oil through gravity drainage. The novel aspect of this project is the use of air as the injection fluid. The target reservoirs for the project are the Camerina sands located on the west and north flanks of West Hackberry field in Cameron Parish, La. If successful, this project will demonstrate that the use of air injection in the DDP can economically recover oil in reservoirs where tertiary oil recovery is uneconomic.

Summary of Technical Progress

During this quarter, air injection continued on the west flank and was initiated on the north flank. Also, the first oil production from air injection occurred, and the air injection flow line to the north flank neared completion.

West Flank Activities

On the west flank, air is injected into fault blocks II and IV. Fault block II has had limited air injection because of premature nitrogen breakthrough and no production response. No production response has been noted in fault block IV, even though fault block IV has had the vast majority of the air injected to date. Reservoir pressure has increased in fault block IV by 350 pounds per square inch (psi) since the start of air injection. Production response is expected in fault block IV after sufficient air has been injected to expand the gas cap and thereby push the oil rim down to the location of the highest producing well on structure, the Gulf Land D (GLD) No. 44.

The GLD No. 51 serves as the air injector for fault block IV on the west flank of West Hackberry field. In July 1996, the GLD No. 51 became plugged with iron oxide and sand fill when the air injection compressors went down. In August, a workover was initiated to wash fill out of the wellbore. Several pieces of casing were recovered during the workover. Drilling mud was used during the workover to keep the formation sand from sloughing in while tripping in and out of the wellbore. The well will be gravel packed to prevent sand fill in the future. After cleaning the fill out of the wellbore, the workover was discontinued while a gravel pack screen was being manufactured. Completing the GLD No. 51 with a gravel pack was deferred in order to gain operating experience with air injection through the gravel packs in the other two air injectors. To date, the only problem experienced with air injection through a gravel pack has been some iron oxide fill inside the screen. The GLD No. 51 will be gravel packed and returned to injection in mid-October.

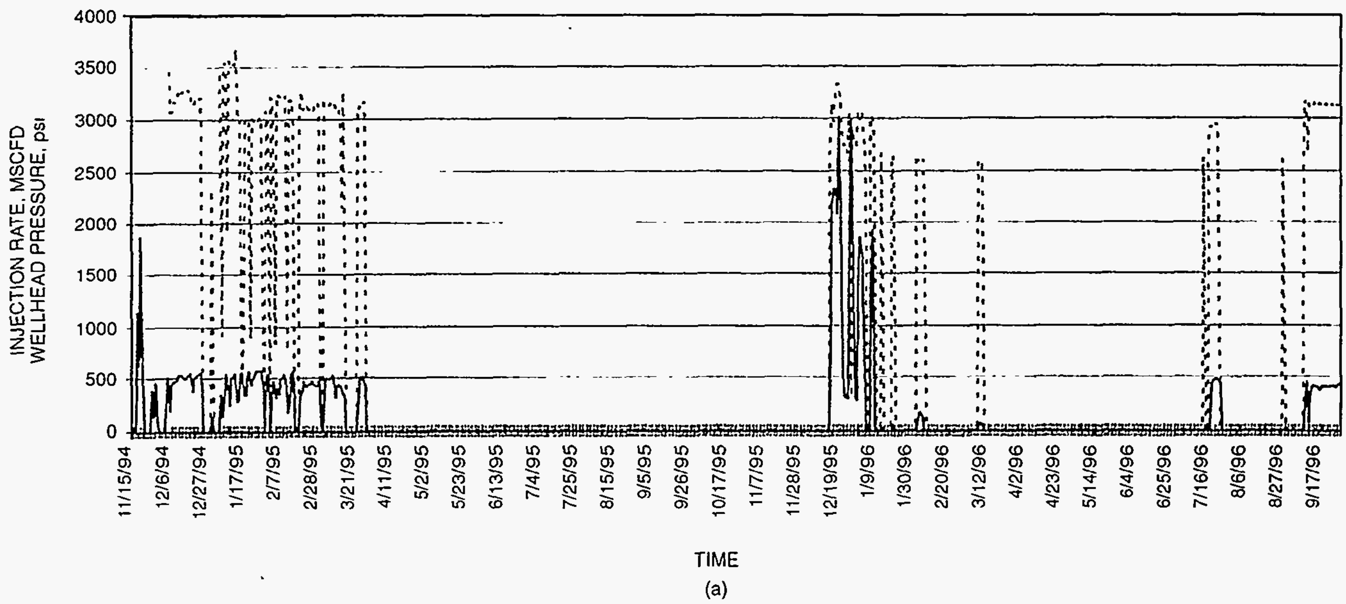
During the workover on the GLD No. 51, air injection was discontinued throughout the field because of safety concerns relating to the proximity of the high-pressure air injection line to the workover operations. While the GLD No. 51 has been shut in awaiting the gravel pack, injection has been initiated on the north flank in the SL 42 No. 155 and restarted on the west flank in fault block II in the Watkins No. 18.

Approximately 0.4 million standard cubic feet per day (MMSCFD) of air is currently being injected into the Watkins No. 18. Once the GLD No. 51 is gravel packed, air injection will be split between the GLD No. 51 on the west flank and the SL 42 No. 155 on the north flank. Figure 1 is a plot of west flank air injection rates and air injection wellhead pressures vs. time. Figure 2 is a plot of cumulative air injected vs. time.

First Oil Production Occurs on the North Flank

Air injection began on the north flank in a low-pressure Cam C-1,2,3 oil reservoir, the WH Cam C RB SU, during July 1996. This north flank reservoir had previously undergone gas injection, which improved the rate for the nearest downstructure producing well, the SL 42 No. 220, from 21 bbl of oil per day (BOPD) and 89 bbl of water per day (BWPD) in December 1991 to 43 BOPD and 88 BWPD in April 1993. The production rate achieved in April 1993 remained at about that level for the next 3 yr. After air injection began in the WH Cam C RB SU in July 1996, the SL 42 No. 220 was tested on Aug. 11, 1996, producing at a rate of 177 BOPD and 145 BWPD. This is the first increase in oil production as a result of air injection in the West Hackberry Tertiary Project.

The air injector for the WH Cam C RB SU is the SL 42 No. 155. Figure 3 is a structure map depicting the location of the various wells in the WH Cam C RB SU. Although the SL 42 No. 98 was originally the gas injector for this reservoir,



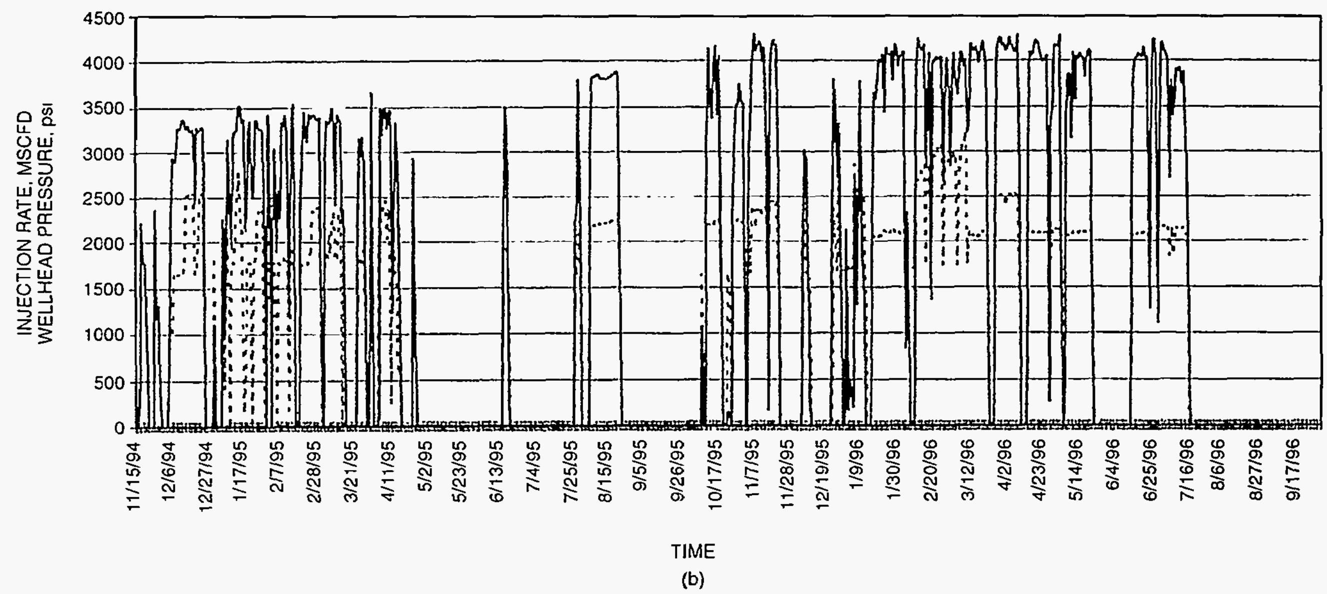


Fig. 1 Plot of air injection rates (——) and wellhead pressures (- - - -) for (a) Watkins No. 16 (11/94 to 3/95) and No. 18 (12/95 to present) wells (fault block II, west flank) and (b) Gulf Land D No. 51 well (fault block IV, west flank).

an attempt to convert the well to air injection was unsuccessful because of collapsed casing. After the failure of the SL 42 No. 98, the SL 42 No. 155 was converted into an air injector and continues to serve as the air injector for the WH Cam C RB SU. Currently, 3.3 to 3.4 MMSCFD is injected into the SL 42 No. 155. Figure 4 is a plot of air injection rates and wellhead pressures vs. time for the SL 42 No. 155.

The area depicted on the north flank structure map in Fig. 3 is highly faulted with low-pressure fault blocks that typically exhibit reservoir pressures in the range of 330 to 500 psi. Many of the faults in the structure map were included to explain differences in gas–oil and oil–water contacts between wells. Although the SL 42 No. 220 was the first well to exhibit increased production, as many as four additional wells in several fault blocks in the immediate area have had some increase in production (and/or nitrogen production) since the start of north flank air injection. Figure 5 is a composite production plot for all five wells.

Several of the five wells that have had an increase in production have also had an increase in nitrogen content in the produced gas. The presence of increased nitrogen in the produced gas of several wells in several fault blocks has proven that air injection is influencing more than the single fault block in which the air injector is located. Table 1 shows the composition of samples of recently collected produced gas from nearby wells and the field overall.

Although a basic gas compositional analysis measures nitrogen, the oxygen portion is hidden in the nitrogen content.

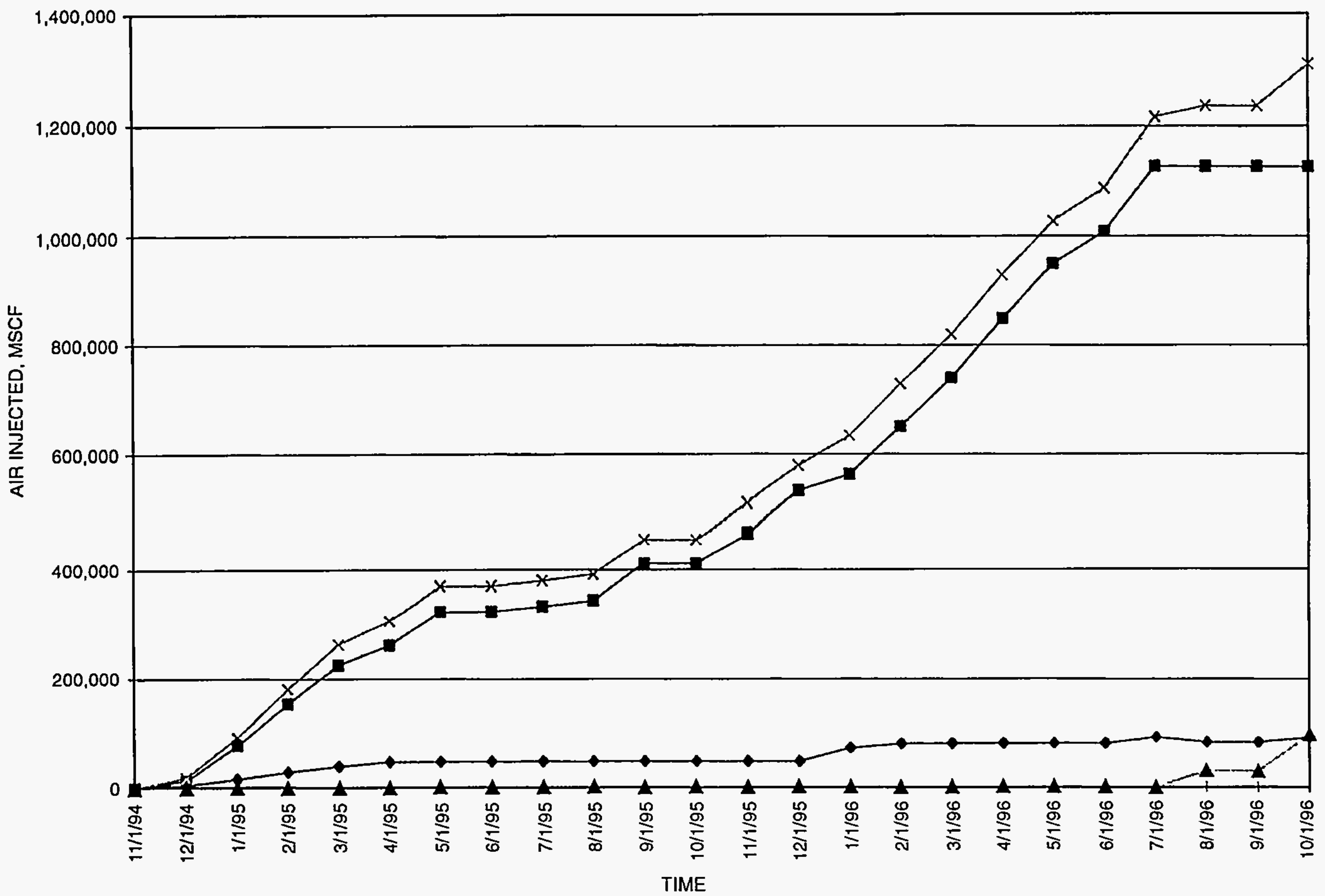


Fig. 2 Plot of cumulative air injected vs. time (north and west flanks), West Hackberry Tertiary Project. ●, Watkins 16 and 18 cumulative injection. ■, Gulf Land D No. 51 well cumulative injection. ▲, SL 155 cumulative injection. ×, total cumulative injection.

Running a gas sample through a second gas chromatograph column is necessary to determine the amount of oxygen in a sample of produced gas. The current operating practice in West Hackberry is to measure a gas sample for oxygen content if the sample exhibits more than 5 mol % nitrogen content. As noted in Table 1, the gas sample with the highest nitrogen content showed almost no oxygen content. The oxygen monitors at the production facilities have also measured almost no oxygen content in the produced gas. The lack of oxygen content in the produced gas proves that the oxygen is being consumed through combustion with the oil in the reservoir. The lack of combustion-generated carbon dioxide in the produced gas is caused by the carbon dioxide dissolving into the reservoir oil.

Injecting air into low-pressure oil reservoirs can increase oil recovery by pushing the oil rim downstructure to the structural location of existing wellbores, repressurizing the reservoir, and obtaining tertiary oil recovery through the DDP. Although nitrogen, carbon dioxide, and natural gas have been used to increase oil recovery in Gulf Coast reservoirs in the past, this project is unique in the use of air as the injection gas. For Gulf Coast projects such as the West Hackberry Tertiary Project, air injection combines the benefits of low cost with universal accessibility.

Operation and Maintenance of Air Injection System

Relatively little downtime occurred last quarter as the result of mechanical failures of the surface equipment. In July, broken drive belts on the reciprocating compressor auxiliary water pump did cause approximately 12 hr of downtime. The remainder of the downtime was caused by injection well repairs as discussed under West Flank Activities. While the injection well repairs were being performed, the downtime was used to perform preventive maintenance on the compressors and a screw compressor repair. A problem with screw compressor lubricant contaminating the coolant was being monitored before the injection well problems. This problem was thought to be caused by communication in the oil cooler; however, replacing the oil cooler did not solve the problem. Atlas–Copco diagnosed the oil–coolant communication to be most likely occurring across a leaking plug in a machined port in either the low- or high-pressure compressor assembly. Both the low- and high-pressure screw compressor assemblies were removed, disassembled, and inspected. The high-pressure assembly had the leaking plugs. Atlas–Copco installed a new high-pressure screw compressor assembly under warranty, and no oil contamination has been noted to date.

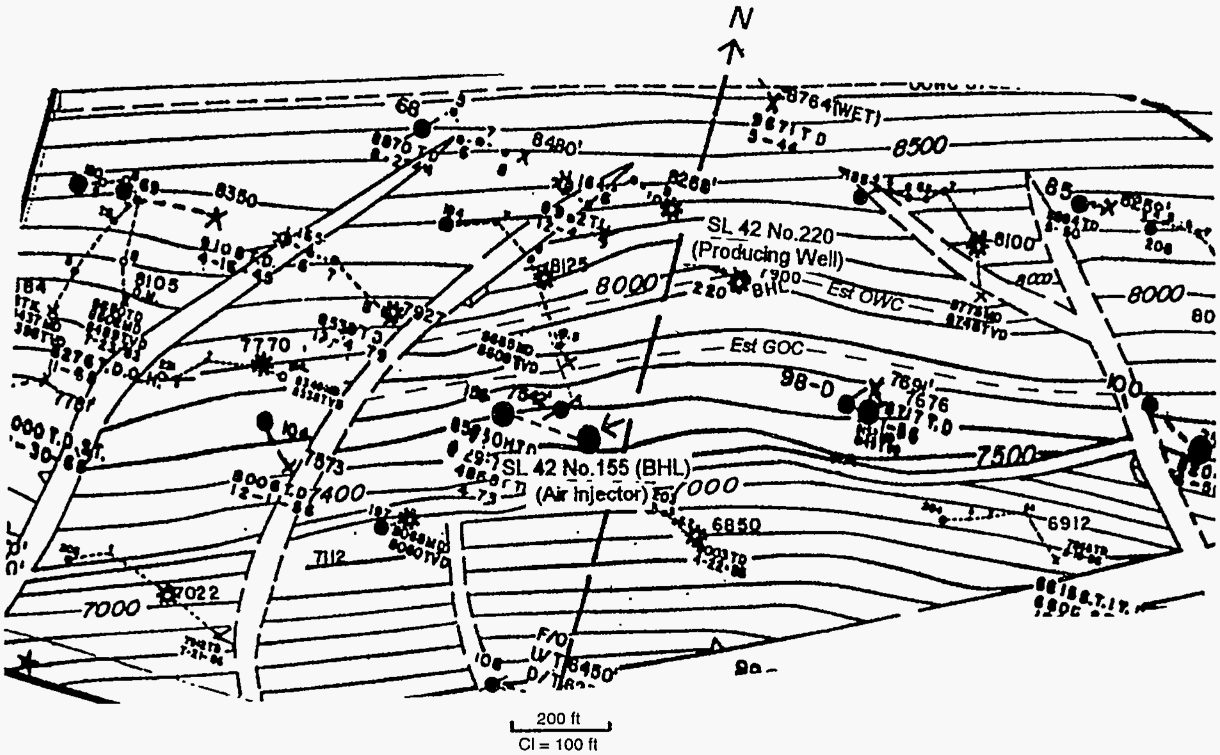


Fig. 3 Structure map for the top of Cam C-1 sand, West Hackberry Tertiary Project, West Hackberry field (north flank), Cameron Parish, La.

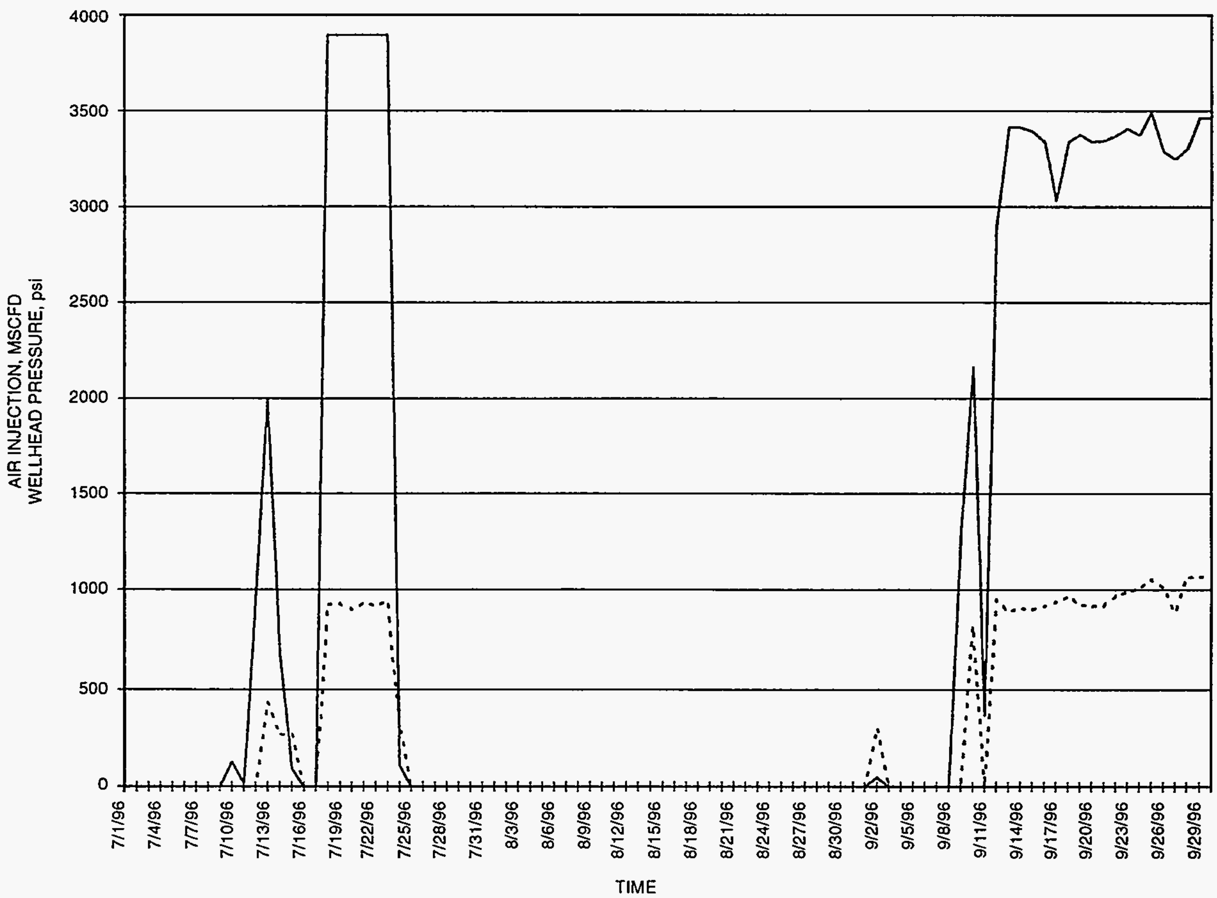


Fig. 4 Plot of SL 42, No. 155 (WH Cam C RB SU, north flank) air injection rate and wellhead pressure vs. time. ——, SL 155 injection rate. - - - -, SL 155 wellhead pressure.

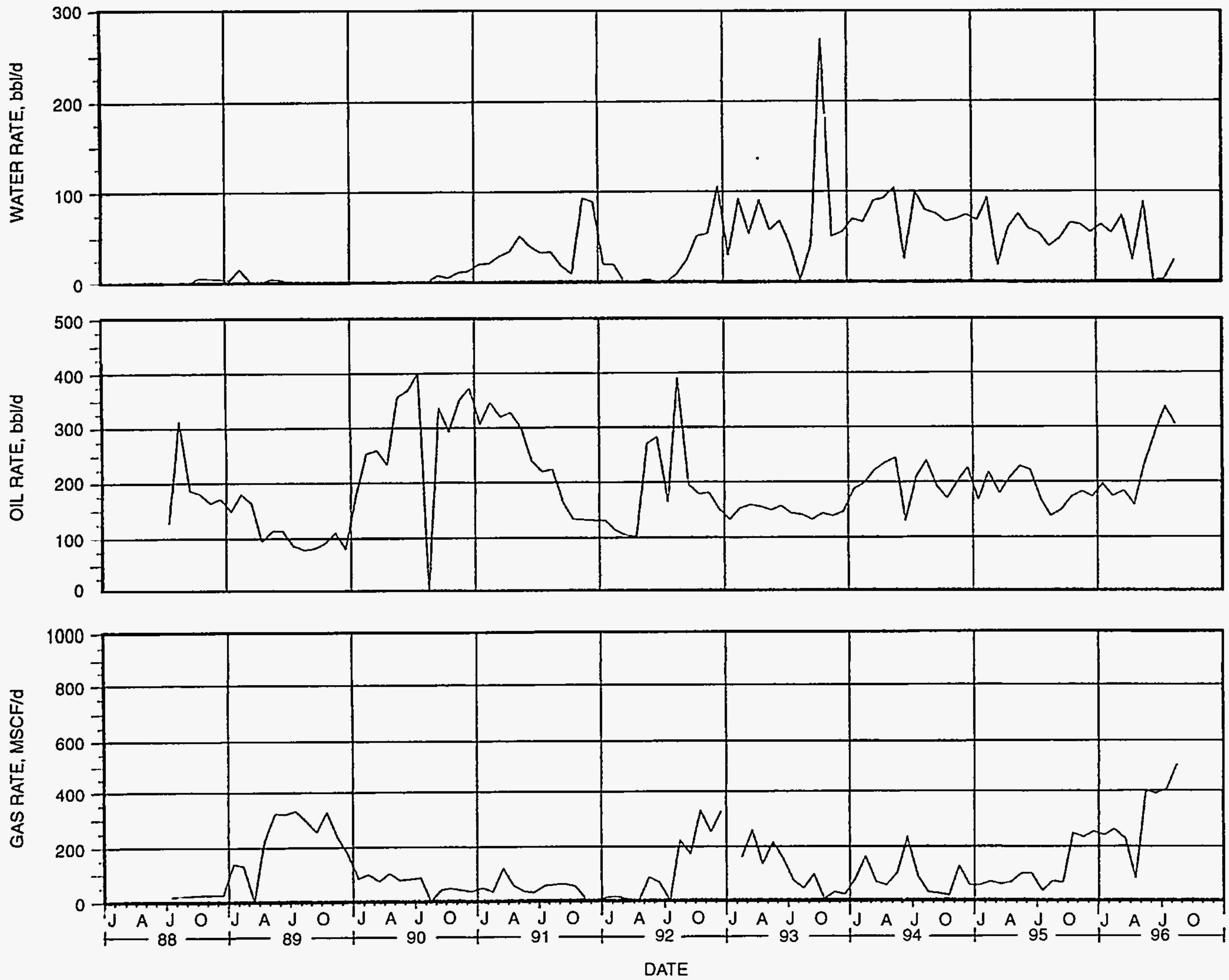


Fig. 5 Wells influenced by north flank air injection. [Combined plot for SL 42 Nos. 197, 205, 220, 221, and 222 (north flank), West Hackberry Field, Cameron Parish, La.]

TABLE 1

Recent Gas Compositional Analyses (West Hackberry Field)

	Field gas sales, %		Gas from SL-42 wells, %		
	4/7/94	9/27/96	9/25/96	9/27/96	10/2/96
N_2	0.29	3.61	4.16	46.46	0.44
O_2	N/A*	N/A*	N/A*	0.55	N/A*
CO_2	0.41	0.62	0.42	2.96	0.47
Methane	92.71	86.83	86.60	44.73	89.71
Ethane	3.88	5.07	5.22	3.16	5.81
Propane	1.44	2.03	1.89	1.23	2.02
C4+	1.27	1.84	1.71	0.91	1.55

*N/A, oxygen not measured in this sample.

Last quarter, most of the north flank injection equipment was completed. The air injection line across Black Lake to serve the other north flank injection wells is approximately 90% complete and will be completed in the upcoming quarter. Also, oxygen monitors were installed in the producing well equipment serving the north flank to monitor the produced gas for oxygen levels, which could create an explosive mixture.

RECOVERY OF BYPASSED OIL IN THE DUNDEE FORMATION USING HORIZONTAL DRAINS

Contract No. DE-FC22-94BC14983

Michigan Technological University
Houghton, Mich.

Contract Date: Apr. 28, 1994
Anticipated Completion: Apr. 27, 1997
Government Award: $800,000
(Current year)

Principal Investigator:
James R. Wood

Project Manager:
Chandra Nautiyal
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The principal objective of this project is to demonstrate the feasibility and economic success of producing oil from abandoned or nearly abandoned fields in the Dundee formation of central Michigan with the use of horizontal drilling technology.

Summary of Technical Progress

Reservoir Characterization

Daily production of the TOW No. 1-3 well in Crystal field has varied from about 75 to 120 bbl of oil per day (BOPD) since its completion in 1995. Currently, the well is producing at the 100-BOPD level. The water cut remains at 0%, and pressure has been maintained at 1445 psi by an active water drive.

Cronus Development Co. now plans to drill 9 to 12 additional horizontal wells in the Dundee in Crystal field during the coming year. Plans are to drill 1900-ft laterals (horizontal legs) in each well, similar to that originally planned for the TOW No. 1-3 well; however, special drilling technology will be required to prevent lost circulation and blowout in the fractured and vuggy Dundee reservoir, as occurred while drilling the 1-3 well. Underbalanced drilling, in which the formation is allowed to flow during drilling, will probably be used. Coiled-tubing technology, which minimizes time-consuming trips in and out of the hole, is being considered. The 90-ft lateral in the TOW No. 1-3 well is producing 120 BOPD with no water cut. It is expected that 1900-ft laterals will be capable of much higher water-free production. The Department of Energy (DOE) has awarded a $20,000 supplementary grant to perform additional technical evaluation work on one of these upcoming wells.

Apollo Oil and Gas recently drilled a horizontal well in the Dundee formation in another central Michigan field. The well came in structurally low. As a result, the horizontal wellbore encountered the Dundee at a low oblique angle and followed the soft Bell Shale along the top of the cap limestone for some distance before penetration of the Dundee was achieved. This incident shows that careful attention must be given to the drilling technique in order to bring in successful horizontal wells.

Core and Log Analysis

A 59.3-ft core was recovered from the top of the Dundee in the TOW No. 1-3 well. Petrographic, X-ray-diffraction, and fluid inclusion analyses are being performed on the samples. The wellbore diagram and core description log were placed on the Western Michigan University (WMU) Internet Home Page and can be downloaded by anyone with interest in the project. X-ray-diffraction analyses were performed on samples from the TOW 1-3 core collected on a foot-by-foot basis during this quarter. Selected core samples of dolomitized Dundee reservoir recovered from other fields in central Michigan were also X-rayed.

Haliburton ran three consecutive log suites on the TOW No. 1-3 well, which included (1) a gamma-ray log and a Dual Laterolog with microresistivity, (2) a lithodensity log (compensated formation density plus photoelectric factor), and (3) a compensated neutron log. The logs were then correlated with a high degree of confidence and combined. The digital log traces were loaded into MTU's GeoGraphix Exploration System's QLA2 log-evaluation software module, and evaluation of the logs for porosity and fluid saturations began.

Data Measurement and Analysis

GeoGraphix Exploration System's QLA2 log-evaluation module was used to evaluate the log suite in the TOW No. 1-3 well, but to date saturations calculated from logs do not match those measured in core.

Production data for the 30 project fields were reviewed, reorganized, and replotted in ways that will provide useful insights into reservoir heterogeneity and past production practices. The first effort concentrated on Isabella field, where production data are available for individual leases. Production was plotted for 20-acre boxes in the field and color-coded according to production volume. Production maps constructed at individual time increments reveal changes in the production pattern with time, whereas the map of total production pinpoints reservoir heterogeneities and "sweet spots" in the field.

During the past quarter, mass balance calculations were performed and original oil in place and recovery factors were estimated for Crystal field.

The inductively coupled plasma spectrograph was used to complete elemental analyses. More problems were experienced in the calibration of Fourier transform infrared spectroscopy standards. Current efforts concentrate on obtaining better standards.

Database Management

Design and implementation of the Multimedia Database Management System (MDMS) are now essentially complete. All data and information are accessible through drop-down menus and hotlinks in a table of contents. A tutorial is presented up front to guide users through the MDMS and instruct them on the various ways in which data can be viewed and retrieved. The MDMS will be written to CD-ROM at the end of the project. Copies of the CD-ROM will be pressed and made available to the public. The CD-ROM, which will contain project maps, cross sections, core and production data, interpretations, and nonproprietary log and seismic data, will be the principal project deliverable.

The following information was entered into the MDMS during the last quarter:

- All quarterly and annual reports to DOE.
- Well activity and production decline curves for all 30 study fields.
- Basin-wide maps of Dundee structure, Bougier gravity anomaly, and oil-well locations .
- An east-west Devonian cross section through the basin.
- Autocad maps for Crystal field.
- Autocad cross sections for Crystal field.

Now that a front end has been developed for inputting Autocad files to the MDMS, maps and cross sections for the 29 other fields will be added during the coming quarter. Core data and core photos will soon be added as well.

A search engine developed in Microsoft Access can now be used to retrieve logs from the CD-ROM. Any desired log curve can be located using queries and then exported from the CD-ROM to temporary Access tables created on the computer's hard drive. Once in the Access tables, log curves can be manipulated or transferred to log-evaluation packages such as GeoGraphix's QLA2 or Crocker's Petrolog program for analysis and plotting.

Log digitization software, produced by Neurolog, Inc., was purchased along with a 36-in. scanner for reading logs into the program. Hundreds of paper copies of Michigan Basin well logs are available from the WMU Core Repository and from such companies as Angstrom Precision Corporation and Maness Petroleum Co. With this new software, project staff can digitize their own well logs and input them to QLA2 or Terrastation for quantitative analysis. This eliminates the prohibitive expense of having well logs digitized commercially and will be important to the modeling effort, which will require hundreds of digitized well logs in order to be successful. Neurolog also provided a map-digitization software module.

Dundee Atlas

The creation of an *Atlas of Michigan Dundee Reservoirs* is planned. As envisioned, this Atlas will include a regional overview of Dundee stratigraphy and reservoir variability; development history of the trend, including comparisons between different fields; production history, including a discussion of engineering and completion techniques; and a table of important reservoir parameters for use in characterizing the Dundee reservoir in other old fields for which little data are available. Maps and cross sections already prepared during the first phase of this project will serve as the cornerstone of the Atlas. The main body of the Atlas will consist of individual discussions of reservoir geology, engineering practices, and tables of reservoir parameters for each Dundee field. Discussion of the importance of fracturing, fracture density, and irregularity of the dolomitized surface will aid in the design of the optimal strategy for horizontal drilling. This Atlas will undoubtedly enhance the capability of the small operators in the state to independently explore and develop this neglected resource. The Atlas will represent a major project deliverable.

Pseudoseismic Visualization

MatLab, a statistics and visualization software package, is being used to produce pseudoseismic sections from spontaneous potential and gamma-ray logs. During this quarter, efforts focused on basic program development. The pseudoseismic program was originally developed to analyze the Maness well-log data set. The front end to the program is being rewritten to take in log ASCII standard (LAS) and well-location data so that log data in any form from any area can be input to the program. A front end that will enable the input of any logs, not just gamma-ray logs, to MatLab is also being written.

Geochemical Modeling

During this quarter, a PC-based FORTRAN program was written to convert lithologic sample descriptions on drillers' logs to LAS format, in which form they can be input to GeoGraphix's QLA2 log-evaluation module. Once in QLA2, they are converted to log binary standard (LBS) and can then be handled and displayed as graphic lithology logs. Since QLA2 is used as both a log-evaluation and a cross-section construction tool, facies cross sections can now be constructed in GeoGraphix. All 10,000 drillers' logs in the working database are now convertible to lithology logs.

GeoGraphix's management is quite interested in this work because at present the GeoGraphix Exploration System does not have the capability of handling facies data. Once the Neurolog software is operating, plans are to digitize the paper copies of wireline logs already in possession and overlay log traces on the facies cross sections.

Subsurface mapping and stratigraphic interpretation are greatly facilitated by the use of digital data that can be used to generate graphic displays. Graphic displays of lithologic sample descriptions obtained from drillers' logs constitute a source of information that can be used for several purposes. Among these are the rapid identification of potential inaccuracies in commercially available subsurface databases, identification of subsurface facies changes, and facilitation of sequence stratigraphic interpretations. Generation of pseudologs that contain depth vs. lithology information in LAS or LBS format allows the use of log analysis software to display information and correlate wells.

The LSD data used in this study are from Angstrom Precision Corporation's Michigan Basin Oil and Gas Well database. The database contains information on 51,275 wells; 11,472 of those include LSD data. Before use, the LSD data must be converted to digital form. This was accomplished with the use of a FORTRAN program written to extract the depth and dominant lithology from the database and to then output an LAS file containing the well header information and depth vs. lithology data. The program assigns a value of one to the dominant lithology for each depth interval and zero to the other possible lithologies. The current version of the program recognizes 10 different lithologies: those most frequently occurring in the basin. GeoGraphix–Schlumberger's QLA2 Log Interpretation program is used to convert the LAS file to an LBS file. QLA2 is also used to create a template to display the lithology data. Other templates were made to display the lithology data in association with standard well logs (e.g., gamma ray and neutron density). The log display templates are used in conjunction with GeoGraphix's *Cross Section* and *WellBase* modules to create the *PseudoLog* lithologic cross sections. The inclusion of the formation top subsea picks from the database provides a simple, graphic display of the data. Examples from the Michigan Basin demonstrate that the display of data in a graphical fashion provides the user with a visual method to compare top subsea picks with log and lithology data. Potentially incorrect top picks can be easily identified with this method, and the database information can be corrected. Regional cross sections made with the use of these data define large-scale sediment patterns and permit identification of stratigraphic sequences with a greater degree of confidence.

The facies-plotting capability achieved in GeoGraphix will enable sequence stratigraphic analyses of the Michigan Basin on any scale. During the last quarter, all significant penetrations of the Glenwood–Prairie du Chien (Cambrian) interval were plotted on a map of the Michigan Basin, and three cross sections (one north-south and two east-west) were constructed through the basin using 38 wells. The current work focuses on customizing the Angstrom database for use in sequence stratigraphic and other types of regional stratigraphic analyses.

Technology Transfer

The Dundee Project has its own Home page on the Internet. It can be reached at **http://www.wmich.edu/geology/corelab/coreres.htm.**

WMU has set up a server for the Michigan DOE Project as a file transfer protocol (FTP) site. At present, it contains zipped files of 27 map sets, which include all Autocad maps generated by the project.

A paper comparing various Michigan Dundee exploration plays and describing the history of the TOW 1-3 demonstration well, its drilling program, core and log data, and production results to date was published in the *Oil and Gas Journal* on October 21 and October 28, 1996, as a two-part Exploration feature article. Part 1 was entitled "Horizontal Well Taps Bypassed Dundee Oil in Crystal Field, Michigan," and Part 2 was entitled "Horizontal Well Success Spurs More Devonian Work in Michigan." The editorial staff of the *Oil and Gas Journal* chose to publish the long article unabridged because the staff considered it to be an important contribution to horizontal drilling strategy and Michigan oil and gas development.

INCREASING WATERFLOOD RESERVES IN THE WILMINGTON OIL FIELD THROUGH IMPROVED RESERVOIR CHARACTERIZATION AND RESERVOIR MANAGEMENT

Contract No. DE-FC22-95BC14934

City of Long Beach
Long Beach, Calif.

Contract Date: Mar. 21, 1995
Anticipated Completion: Mar. 20, 2000
Government Award: $147,166
(Current year)

Principal Investigators:
Dennis Sullivan
Don Clarke
Scott Walker
Chris Phillips
John Nguyen
Dan Moos
Kwasi Tagbor

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objectives

The main objective of this project is the transfer of technologies, methodologies, and findings developed and applied in this project to other operators of slope and basin clastic reservoirs. Methods to identify sands with high remaining oil saturation and to recomplete existing wells with the use of advanced completion technology will be studied.

A deterministic three-dimensional (3-D) geologic model will be developed and state-of-the-art reservoir management computer software will be used to identify sands with high remaining oil saturation. The wells identified by the geologic and reservoir engineering work as having the best potential will be logged with a pulsed acoustic cased-hole logging tool. The application of the logging tools will be optimized in the lab by developing a rock–log model, which will allow the conversion of shear-wave velocity measured through casing into effective porosity and hydrocarbon saturation.

Wells that have the best oil production potential will be recompleted. The recompletions will be optimized by evaluating short-radius and ultrashort-radius lateral recompletions as well as other techniques.

Summary of Technical Progress

Reservoir Characterization

Continued progress was made on developing rock–log and fluid–log models needed to calibrate, interpret, and understand acoustic log data. Data from earlier tests of Wilmington cores were further analyzed to determine porosity and to refine pulse transmission velocity determinations. Additional cores of Ottawa sand were also tested to verify the source of anelasticity in the Wilmington samples.

Modeling code was developed and run to determine from the laboratory data the velocity dispersion caused by frame elasticity. A Cole–Cole distribution of relaxation times was used to parameterize the frequency dependence of velocity. The transition from low- to high-frequency behavior predicted by this new model remains well below the frequency band excited by sonic logs. Researchers also continued to develop velocity–porosity transforms for high-porosity rocks where cementation patterns vary from noncontact to contact cement. These transforms will assist in the development of porosity from cased-hole sonic logs.

Reservoir Engineering

Fault block IV production data for the Union Pacific zone, Ford zone, and "237" zone have been quality controlled. All fault block IV zones except upper Terminal need to be converted into an official database and then exported to Production Analyst software. Quality control on injection data input is approximately 50% complete.

Fault block V production data from the Tar zone, Ranger zone, upper Terminal zone, lower Terminal zone, Union Pacific zone, and Ford zone have been quality controlled. These data need to be converted into an official database and then exported to Production Analyst software. Quality control on injection data input is approximately 50% complete.

Fault block VI production data from the Tar zone, Ranger zone, upper Terminal zone, lower Terminal zone, Union Pacific zone, and Ford zone have been quality controlled. These data need to be converted into an official database and then exported to Production Analyst software. Quality control on injection data input is approximately 50% complete.

Deterministic 3-D Geologic Modeling

The deterministic 3-D geologic model continues to be updated and refined. Figures 1 and 2 represent the latest 3-D model. The model area was expanded so that the horizon surfaces on the east side of the Daisy Avenue fault could be represented more accurately. Figure 3 shows a contour map of the top of the Hx_0 horizon. The grid for this map was pulled directly from the 3-D model. The structural highs were determined from the grid and are noted by the arrows. Also, structural control points were added in areas of little or no data.

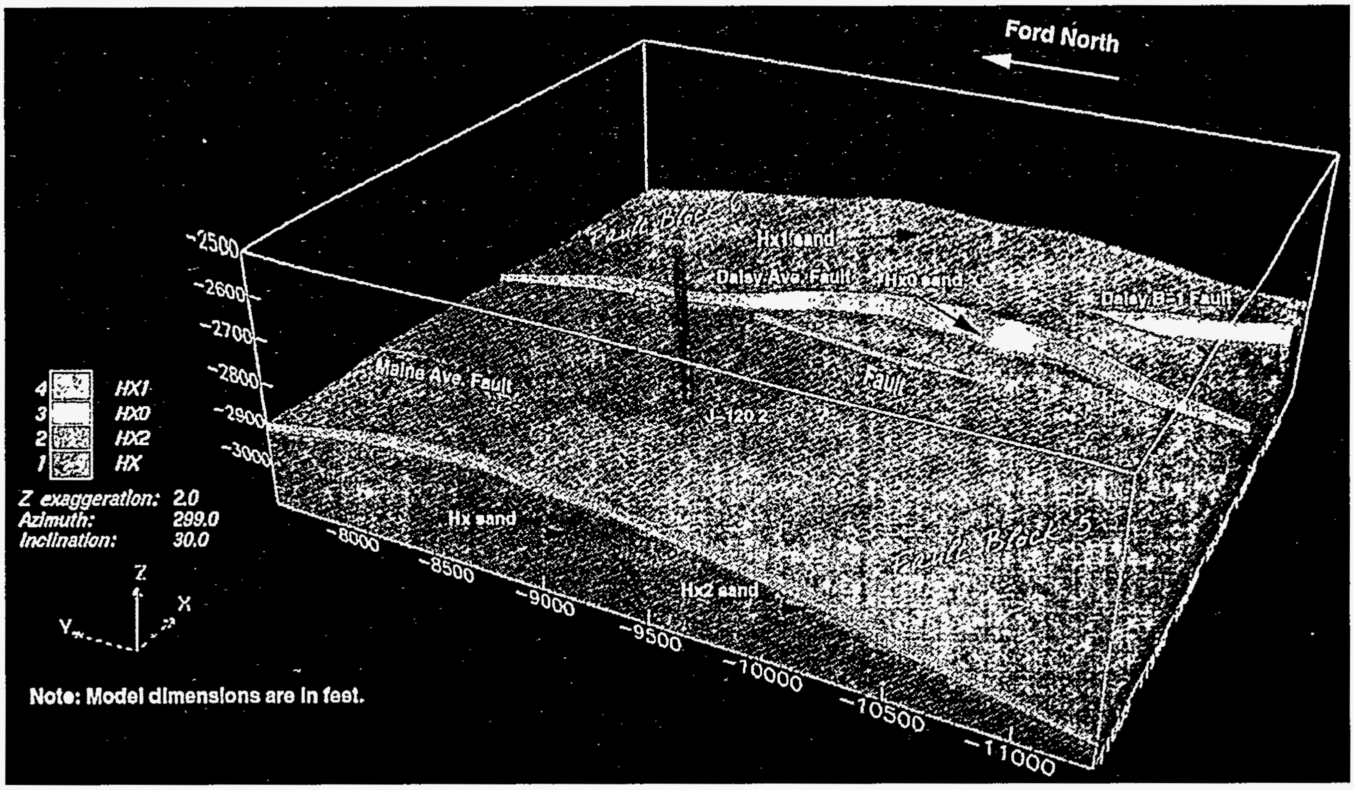


Fig. 1 Deterministic 3-D geological model (selected volume of fault blocks V and VI). (Art reproduced from best available copy.)

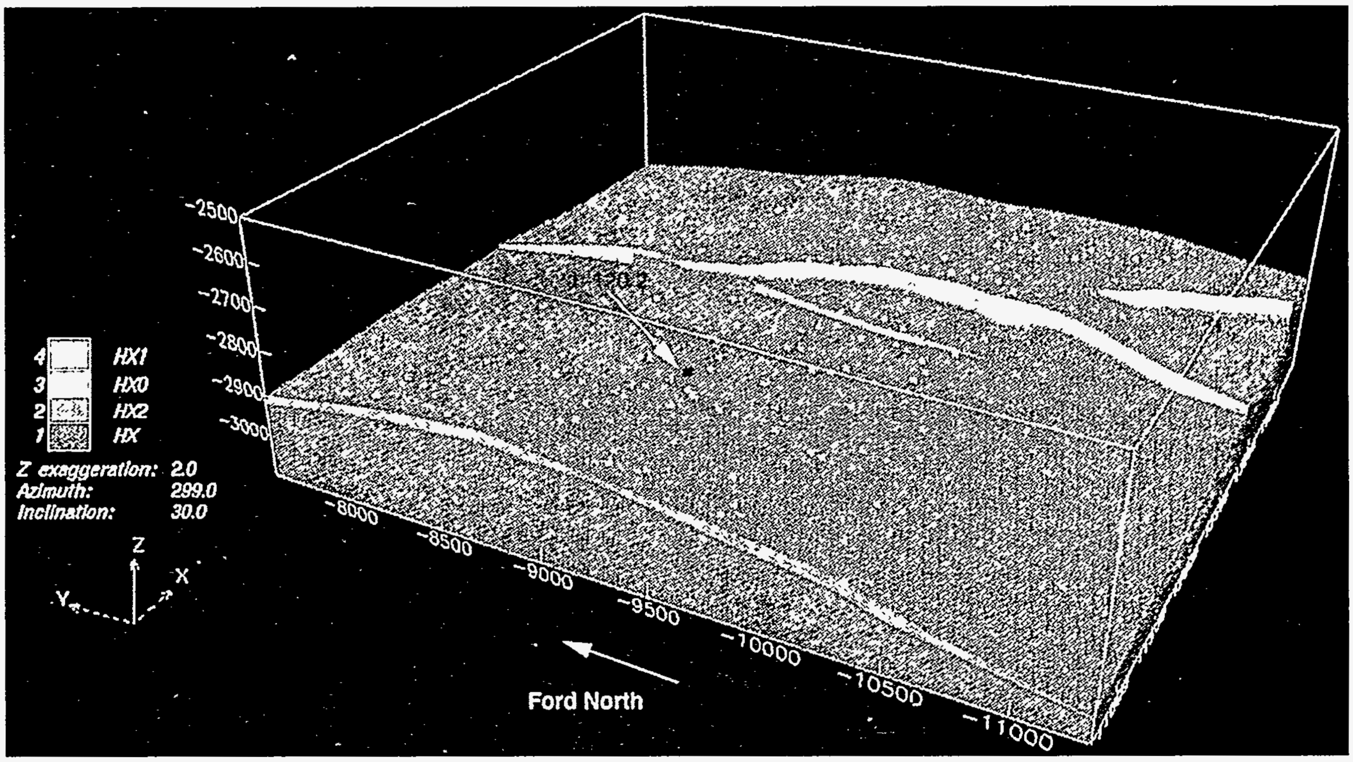


Fig. 2 Deterministic 3-D geological model (the Hx_1 layer is removed and the data for the Hx_0 layer are posted). (Art reproduced from best available copy.)

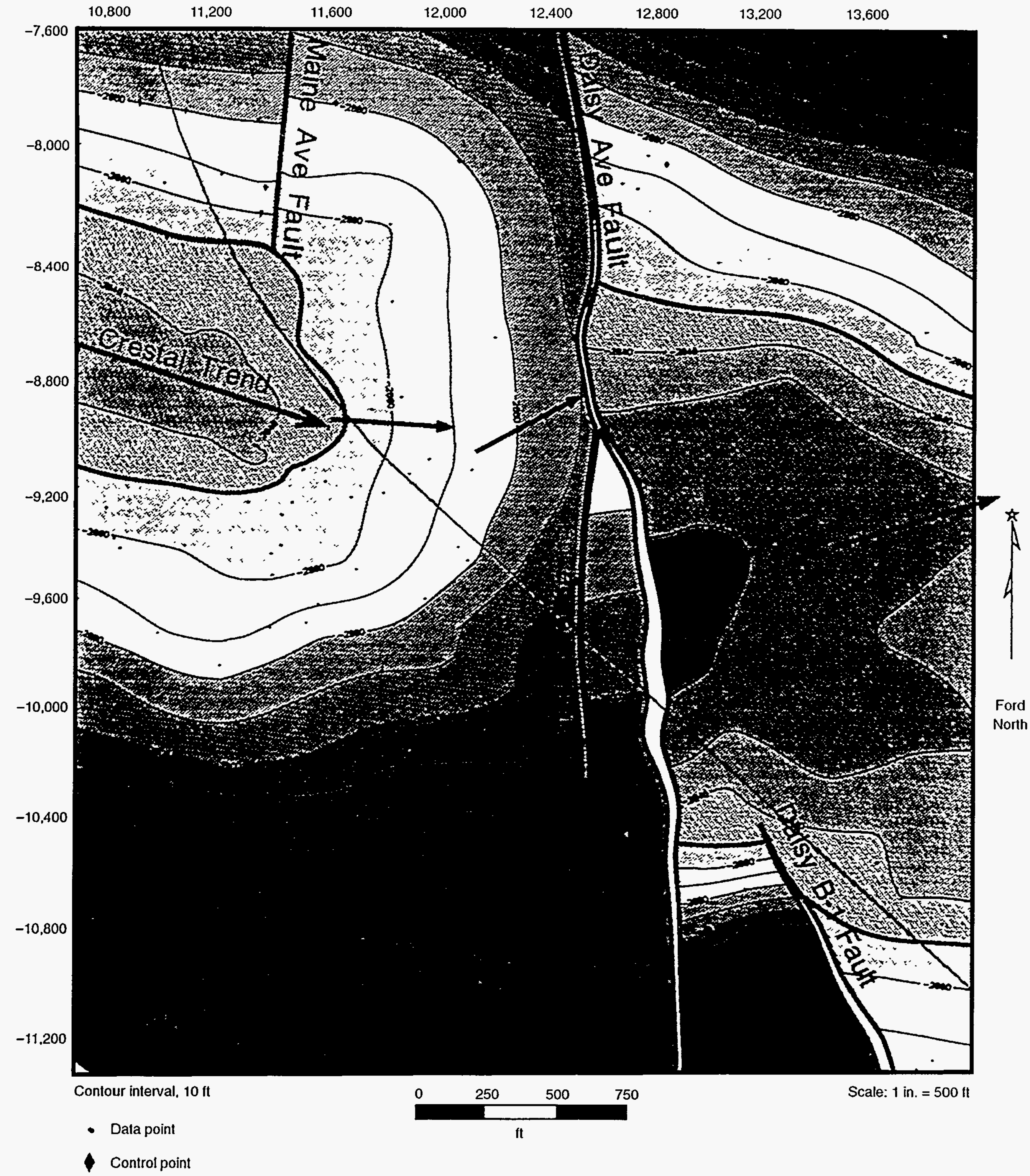


Fig. 3 Structure map on top of Hx_0 sand.

The geologic 3-D model uncovered a flawed interpretation to the west of the Daisy Avenue fault. An en echelon fault is the newer interpretation and is supported by the distribution of the scattered data of the four modeled horizons. The en echelon fault interpretation is structurally consistent with other parts of the Wilmington oil field. The fault interpretation is included in the model and provides good consistency for all the modeled layers.

The deterministic geologic 3-D model for the upper Terminal zone fault block IV prospect continues to be updated and refined. The 3-D model suggests that there is a structural trap for oil against the Harbor Entrance fault which can be exploited by the Y-63 recompletion candidate.

Pulsed Acoustic Logging

Log data from recompletion candidates Z-223 and Z-27 were further analyzed for usable acoustic data. Shear-wave logs are in satisfactory agreement with new analysis results, but compressional data are unusable. Shear velocity determined from the waveforms is stable in some sections, but in other sections the final results depend on how the data were filtered. This result is consistent with the frequency dependence of the shear mode velocity but is a problem for consistent estimation of physical properties.

Formation signals with the Magnetic Pulse Inc. acoustic tool have been greatly hampered by the strong presence of Stoneley (tube) waves arriving at the same time as formation signals, especially where poor cement-to-casing bond is suspected. The acoustic tool's analog-to-digital converter is being upgraded from 12 to 16 bits. This should enhance the signal-to-noise ratio of the data acquired and hopefully improve the chances of obtaining formation shear and compressional data.

Researchers also found, when modeling wave propagation in cased wells, that good cement-to-casing bond can actually *degrade* low-frequency waveforms in certain situations. Trapped energy is propagated more efficiently when cement-to-casing thickness is large and the formation is soft. This effect was exhibited in Wilmington field logging runs where the old logging tool yielded better results because of its lack of energy output below 1 kHz. The modified newer logging tool has a very energetic low-frequency energy band around 600 Hz. This was the tool used to log the most recent recompletion candidates.

Recompletions

Recompletion candidate wells J-15 and J-120 have been successfully extreme overbalanced perforated and have been steam consolidated. Both wells have been shut in for soaking. Well J-15 is the fault block V Tar Zone recompletion candidate that was perforated across the "F_I" and "F_0" sands. This well took 92,800 bbl of cold-water equivalent (BCWE) of steam injection. Well J-15 was shut in for soaking in late August 1996 and will be returned to production in late October 1996.

Well J-120, the fault block V upper Terminal zone recompletion candidate, was perforated across the "Hx_I" sand. This well took 18,800 BCWE of steam injection. Well J-120 was shut in for soaking in late August 1996 and will be returned to production in late October 1996.

Technology Transfer

Researchers planned the Stanford Rock and Borehole Geophysics Project Annual Meeting on June 19–21, 1996. Papers written and presented included "Viscoelasticity and Dispersion in Unconsolidated Reservoir Rocks from the Wilmington Field, California," "A Comparison of Dynamic and Static Moduli in Unconsolidated Reservoir Rocks from the Wilmington Field, California," "Hydrocarbon Saturation Determination from Sonic Log Data," "Identifying Patchy Saturation from Well Logs," and "Application of Rock Physics Relationships to Wireline Log Data."

A paper titled "Application of Theoretically Derived Rock Physics Relationships for Clastic Rocks to Log Data from the Wilmington Field, CA," was revised and has been accepted by *Geophysical Research Letters*.

Researchers participated in the Ocean Drilling Program Downhole Measurements Panel Meeting in Salt Lake City, Utah. Results were disseminated to other attendees.

A presentation on the status of the Waterflood Project was made in September 1996 to the Department of Energy, California Department of Oil and Gas, and California State Lands Commission along with representatives from state and federal government in Long Beach, Calif.

The project's World Wide Web Home Page at **http://pangea.stanford.edu/~moos/DOE_home.html** has been updated.

INCREASED OIL PRODUCTION AND RESERVES UTILIZING SECONDARY/ TERTIARY RECOVERY TECHNIQUES ON SMALL RESERVOIRS IN THE PARADOX BASIN, UTAH

Contract No. DE-FC22-95BC14988

Utah Geological Survey
Salt Lake City, Utah

Contract Date: Feb. 9, 1995
Anticipated Completion: Feb. 8, 2000
Government Award: $448,800
(Current year)

Principal Investigator:
M. Lee Allison

Project Manager:
Rhonda Lindsey
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objectives

The primary objective of this project is to enhance domestic petroleum production by demonstration and technology transfer of an advanced oil-recovery technology in the Paradox Basin in southeastern Utah. If this project can demonstrate technical and economic feasibility, the technique can be applied to approximately 100 additional small fields in the Paradox Basin alone and result in increased recovery of 150 to 200 million bbl of oil. This project is designed to characterize five shallow-shelf carbonate reservoirs in the Pennsylvanian (Desmoinesian) Paradox formation and choose the best candidate for a pilot demonstration project for either a waterflood or carbon dioxide (CO_2)-flood project. The field demonstration, monitoring of field performance, and associated validation activities will take place in the Paradox Basin within the Navajo Nation. The results of this project will be transferred to industry and other researchers through a petroleum extension service, creation of digital databases for distribution, technical workshops and seminars, field trips, technical presentations at national and regional professional meetings, and publication in newsletters and various technical or trade journals.

Summary of Technical Progress

Interpretation of Outcrop Analogs

Outcrops of the Paradox formation evaluated in the Wild Horse Canyon area along the San Juan River of southeastern Utah provide small-scale analogs of reservoir heterogeneity, flow barriers and baffles, depositional facies, and geometry. These characteristics can be used in reservoir-simulation models for secondary–tertiary recovery of oil from small fields in the basin.

Morphologically, algal buildups within the Ismay zone of the Paradox formation consist of large, northwest-trending algal banks separated by interbank troughs or channels. Smaller, secondary algal mounds and intermounds define the upper surfaces of the algal banks. Cyclic sedimentation is recorded by four dominant facies recognized in a single, shoaling-upward sequence: (1) substrate carbonate, (2) phylloid algal, (3) intermound, and (4) skeletal capping. An outcrop in the Wild Horse Canyon area displaying these and additional facies was selected for detailed study.

The Wild Horse Canyon study site is interpreted as consisting of three principal features: (1) a phylloid algal mound with grainstone buildups deposited at or near sea level; (2) a "reef wall" that formed in a higher energy, more marginal setting than the mound; and (3) a carbonate detrital wedge and fan consisting of shelf debris (Fig. 1).[1] This interpretation is not only based on observations made at the outcrop but also incorporates subsurface core data that are documented and discussed.[2]

Bafflestone and *Chaetetes*- and rugose-coral-bearing grainstone and packstone textures observed in the northern part of the Wild Horse Canyon complex represent the main phylloid algal mound. A texturally and compositionally similar algal buildup constitutes the primary reservoir facies in oil and gas fields east of the study site. A flooding surface recognized on top of the buildup in outcrop and probable low-permeability lithotypes (packstone and cement stone) within the buildup might act as barriers or baffles to fluid flow in the subsurface. The Wild Horse Canyon outcrop appears to be only a portion of a larger algal-bank complex or one of a series observed in the San Juan Canyon. Although not documented at this outcrop locality, observations from core in similar areas in the subsurface suggest that an interior-lagoon and other associated facies likely formed west of the study area as part of this complex.[2] Hypothetical facies relationships are illustrated in the schematic block diagram (Fig. 1).

The rudstone, cement stone, and lumpstone depositional textures represent deposits that were part of, or near, what might be interpreted as a reef wall (Fig. 1). The presence of internal sediments in these rocks indicates an influx of mud during storms or mud routinely distributed by stronger currents. The reef wall records deposition and intense sea-floor cementation as a result of reflux of large pore volumes of water through sediments occupying a high-energy marginal setting between shallow-shelf and deeper, open-marine conditions. The reef wall may have served as a barrier behind which algal buildups could develop and thrive in a more protected setting that facilitated preservation of primary shelter porosity. The presence of reef-wall facies in a well core might serve as a proximity indicator for a more prospective drilling target. Examples of this relationship have been

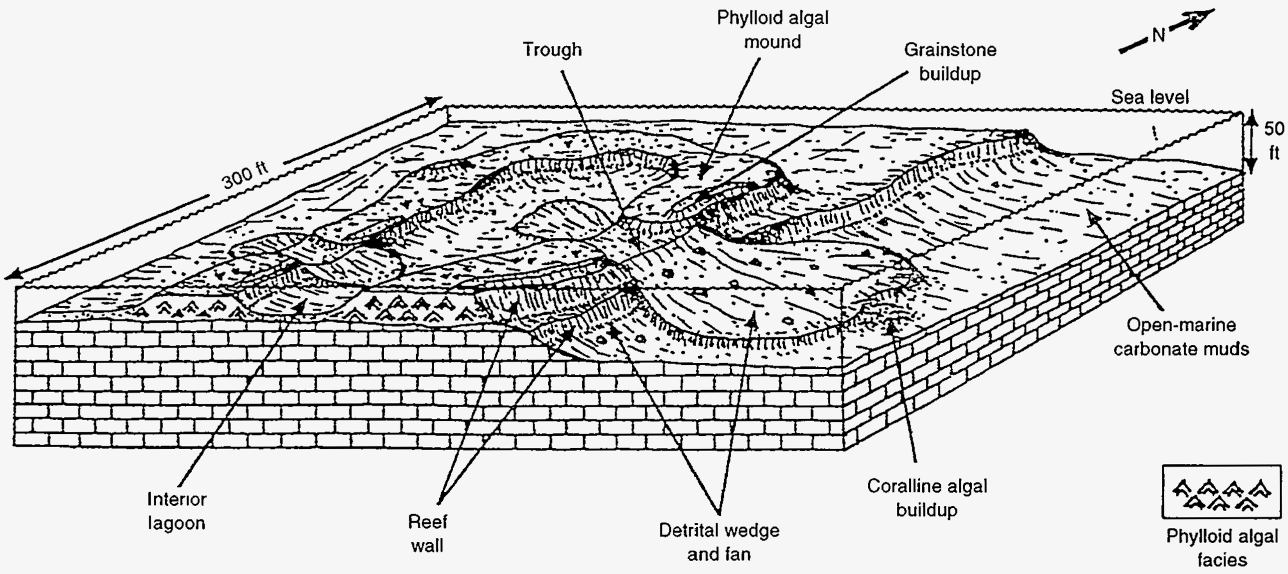


Fig. 1 Block diagram displaying depositional interpretation of the Wild Horse Canyon mound complex and associated features. This interpretation is a composite of inferences made from outcrop and subsurface data.[1]

observed in the Blue Hogan and Brown Hogan fields southwest of the Greater Aneth field.[2]

An intermound trough in the center of the mound could represent a tidal channel flowing across the reef wall (Fig. 1). Material shed from the mound and reef wall and subsequently carried through the tidal channel might have been deposited as a detrital wedge or fan on open-marine carbonate muds. These features are recorded by the grainstone and transported material observed in outcrop on the east side of the complex. Coralline algal buildups may have also developed near the carbonate detrital fan but were not observed at this locality in the canyon. Reservoir-quality porosity may have developed in troughs, detrital wedges, and fans identified from core and facies mapping. If these types of deposits are in communication with mound-reservoir facies in the subsurface, they could serve as conduits facilitating sweep efficiency in secondary–tertiary recovery projects; however, the relatively small sizes and the abundance of intermound troughs over short distances, as observed along the river, suggest caution should be used when correlating these facies between development wells. Facies that appear correlative and connected from one well to another may actually be separated by low-permeability facies that inhibit flow and decrease production potential.

Reservoir Mapping

Structure contour maps on the top of the Desert Creek zone of the Paradox formation and gross Desert Creek interval isopach maps were constructed for the Anasazi, Blue Hogan, Heron North, Mule, and Runway project fields, San Juan County, Utah.[3–7] These maps were combined to show carbonate buildup trends, define limits of field potential, and indicate possible combination structural and stratigraphic traps (Fig. 2). Well names and total depths are given for project field wells. The maps indicate Desert Creek completions, completion attempts, and drill stem tests and display the Desert Creek subsea top and gross thickness for each well. These maps incorporated correlations from all geophysical well logs in the areas and regional Chimney Rock shale structure maps and gross Desert Creek isopach maps generated from closely spaced seismic lines.

Reservoir Engineering Analysis of the Five Project Fields

Basic reservoir parameters for the Anasazi, Blue Hogan, Heron North, Mule, and Runway fields were compiled from the following sources: (1) geophysical well logs, (2) core analyses, (3) compressibility tests on carbonates from the Anasazi Nos. 1 and 6H-1 wells, (4) pressure–volume–temperature tests, (5) oil and gas analyses, (6) reservoir mapping, and (7) monthly production reports.[8] The results are summarized in Tables 1 to 3. Production histories, including monthly oil, gas, and water production and number of producing wells, were also plotted for each field (Fig. 3).

The information and plots compiled during this quarter have been merged with geological characterization data and incorporated into reservoir statistical models and simulations. The results will be used to estimate sweep efficiencies for various secondary–tertiary recovery methods and the ultimate enhanced recovery for all five fields.

Technology Transfer

Project material was displayed at the Utah Geological Survey (UGS) booth, and a paper describing the outcrop reservoir analogs along the San Juan River[9] was presented

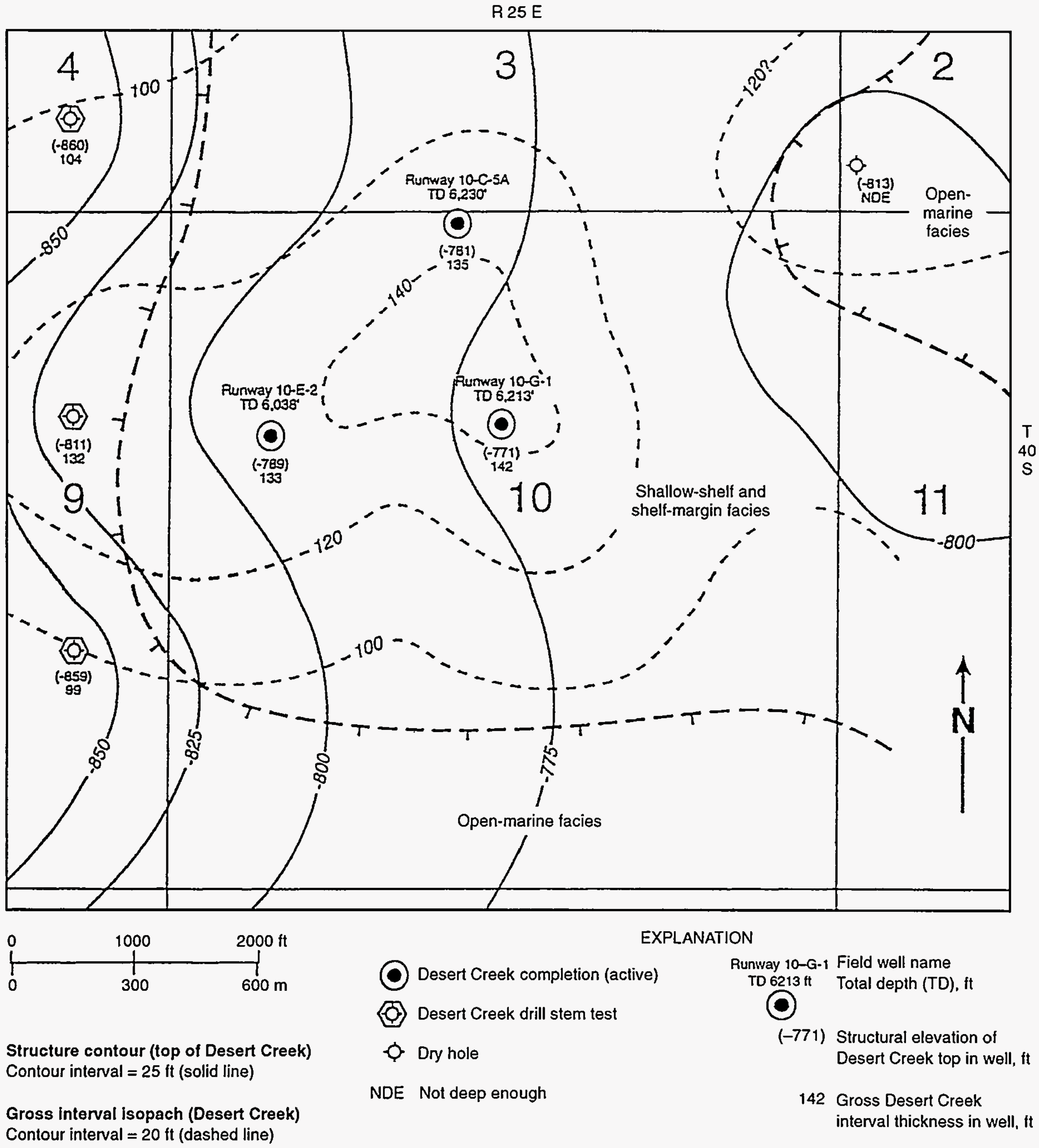


Fig. 2 Combined Desert Creek zone structure contour and gross interval isopach map, Runway field, San Juan County, Utah, Navajo Nation.[7] Hachured lines separate carbonate depositional facies.

during the American Association of Petroleum Geologists (AAPG) Rocky Mountain Section meeting held in Billings, Mont., July 28–31, 1996.

The UGS cosponsored a symposium entitled the Geology and Resources of the Paradox Basin held in Durango, Colo., September 20–21, 1996. A UGS workshop presenting the results of phase 1 (Budget Period 1) of the Paradox Basin project included the following poster displays: (1) project field summaries, (2) regional facies belts and analysis, (3) outcrop studies, (4) statistical models and reservoir simulations, and (5) technology transfer. The workshop also included a computer demonstration of the UGS-developed project database. A representative conventional core from the Anasazi No. 1 well was displayed. The UGS and its industry partners published the results of reservoir characterization and outcrop work in the symposium guidebook.[1,2]

A field trip through the Paradox Basin with 50 participants was also conducted September 17–19 as part of the symposium with visits to outcrops in Wild Horse Canyon along the San Juan River and the production facilities at the Mule field.[10]

TABLE 1

Petrophysical Properties and Pressure Data for Project Fields

Field	Average porosity, %	Average permeability, mD	Pore volume compressibility (C_p), 10^{-6}/psi		Reservoir pressure		Water saturation, %	Initial gas/oil ratio, scf/STB	Initial formation volume factor, reservoir bbl/STB	Bubble-point pressure, psig	Type of drive
			Limestone	Dolomite	Initial, psig	Present, psi					
Anasazi	14.1	≈190 for mound core ≈2 for supramound	2.3329	3.1849	1945	200 to 300	15	364:1	1.199	1023	Gas expansion
Blue Hogan	9.1	≈190 for mound core ≈2 for supramound	2.3329	3.1849	1800	200 to 300	15	487:1	1.260	1590	Gas expansion
Heron North	15	17.7	ND*	ND	1934	200 to 300	15	644:1	1.328	1922	Gas expansion
Mule	13	≈190 for mound core ≈2 for supramound	2.3339	3.1849	2050	200 to 300	15	478:1	1.240	1478	Gas expansion
Runway	11.9	17.3	ND	ND	2162	200 to 300	15	967:1	1.511	2141	Gas expansion

*ND, No data.

TABLE 2

Cumulative Production and Estimated Primary Recovery

Field	Carbonate buildup facies type	Spacing, acres	Productive area, acres	Net pay, ft	Cumulative production*		Water, bbl	Approximate recovery factor, %	Estimated primary recovery	
					Oil, bbl	Gas, Mcf			Oil, bbl	Gas, Bcf
Anasazi	Phylloid algal	80	165	46	1,692,117	1,339,281	25,922	20	2,069,392	1.89
Blue Hogan	Phylloid algal	80	89	82	286,161	262,620	1,699	20	645,000	0.968
Heron North	Platform-margin calcarenite	40	110	60	202,776	316,289	25,124	20	990,000	2.65
Mule	Phylloid algal	80	48	47	352,919	212,794	19,408	20	430,603	0.288
Runway†	Phylloid algal–bryozoan	40	193	50	760,726	2,344,321	3,420	20	720,000	2.83

*Utah Division of Oil, Gas, and Mining, *Oil and Gas Production Report*, May 1996.
†Runway field includes commingled Desert Creek and Ismay zones.

TABLE 3

Oil, Gas, and Water Properties

Field	Bottom-hole temperature, °F	Resistivity of water, ohm-m @ bottom-hole temperature	Oil gravity, °API	Oil viscosity, cP @ initial reservoir conditions	Gas heating value, Btu/ft^3	Gas specific gravity, decimal fraction
Anasazi	138° @ 5777 ft	0.035	41	0.951	1400.3	0.8080
Blue Hogan	128° @ 5613 ft	0.035	40.6	0.811	1497.0	0.8992
Heron North	126° @ 5752 ft	0.035	44.0	0.475	1321.0	0.8335
Mule	128° @ 5804 ft	0.035	44.0	ND*	1539.0	0.8890
Runway	126° @ 6203 ft	0.070	40.5	0.314	1356.5	0.7790

*ND, No data.

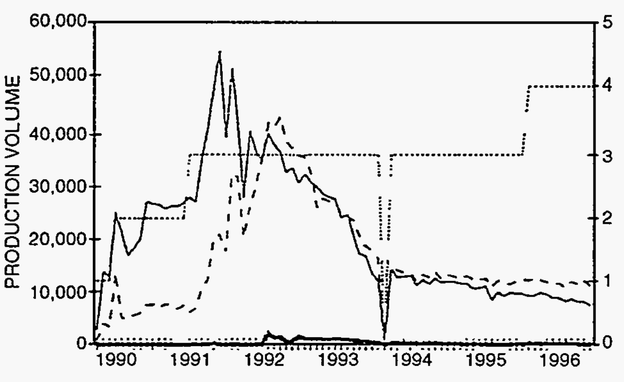


Fig. 3 Annual production for the Anasazi field, San Juan County, Utah, Navajo Nation. —, oil (bbl). – – –, gas (Mcf). —, water (bbl). - - - -, number of wells.

Field summaries for the five project fields were also published in the second edition of the Utah Geological Association guidebook entitled *Oil and Gas Fields of Utah.*[3–7]

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ADVANCED OIL RECOVERY TECHNOLOGIES FOR IMPROVED RECOVERY FROM SLOPE BASIN CLASTIC RESERVOIRS, NASH DRAW BRUSHY CANYON POOL, EDDY COUNTY, NEW MEXICO

Contract No. DE-FC22-95BC14941

Strata Production Company
Roswell, N. Mex.

Contract Date: Sept. 25, 1995
Anticipated Completion: Sept. 25, 2000
Government Award: $1,786,163
(Current year)

Principal Investigator:
Mark B. Murphy

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The overall objective of this project is to demonstrate that a development program based on advanced reservoir management methods can significantly improve oil recovery. The demonstration plan includes the development of a control area with standard reservoir management techniques and comparison of the performance of the control area with an area developed with advanced reservoir management methods. Specific goals are to (1) demonstrate that a development drilling program and pressure maintenance program, based on advanced reservoir management methods, can significantly improve oil recovery compared with existing technology applications and (2) transfer the advanced methodologies to oil and gas producers in the Permian Basin and elsewhere in the U.S. oil and gas industry.

Summary of Technical Progress

Management and Project Planning

Geological, engineering, geophysical, and simulation teams continue compiling and analyzing data. The combination of E-mail, the Internet, and high-capacity data transfer is used successfully to exchange data and conclusions among team members located in diverse geographical areas.

Geology

The initial stratigraphic framework geological model was developed, and maps were put into the Landmark's Stratamodel program. The top and bottom of each of the primary reservoir sands, the K, K-2, and L sands, the top of the underlying Bone Spring formation, and the layers for the uppermost sand, the J interval, were added to the model. The process was complicated because the maps were based on only 23 data points in the area. As layers were added to the model, correcting problems was an ongoing requirement. The most persistent problem encountered dealt with intersections between the horizons in between the data points. In some cases, significant portions of the maps needed to be recontoured in order to eliminate the problem. After much revision, the final result was a three-dimensional (3-D) model that satisfied the needs of the reservoir simulation group as well as conformed to the geological model interpretation.

After the stratigraphic framework was developed, the subunit isopach layers for the K, K-2, and L sands were added. Like the other maps integrated into the model, these maps were modified where needed and put into the 3-D framework without violating the constraints of the model.

Refinement of the geological model will be affected by the results of the 3-D seismic survey that has been shot over the unit. Initial results indicate a reasonable correlation between porosity development and seismic attributes. Work is continuing on the data volume, and the interpretation will greatly enhance the accuracy of the geological model.

The drilling of the Nash Draw No. 12 well has added an important data point to the model. The structural and stratigraphic mapping data from well No. 12 as well as the other reservoir maps have been integrated into the stratigraphic model.

Engineering

One data well, the Nash Draw No. 12, has been drilled at a location 918 ft from the south line and 2153 ft from the east line of sec. 12, T. 23 S., R. 29 E. This well exhibited good L zone development and fair K zone development. Of interest was the correlation of porosity in the K and L sands with the high-intensity seismic reflection amplitudes for the respective intervals in the 3-D seismic data volume. This correlation presents positive information that seismic attributes may be used to determine the distribution of the best quality reservoir rocks in the Nash Draw Unit. The well is being completed and tested.

Instead of obtaining a second full core as planned, additional reservoir fluid swelling tests were performed to determine possible injectant parameters. Lean gas, carbon dioxide, and nitrogen were studied as possible injection fluids for a possible pressure-maintenance project. Of the fluids tested, carbon dioxide exhibits the most favorable characteristics and separator gas exhibits satisfactory results. Nitrogen exhibited limited solubility in the Nash Draw crude oil and provided only about half the oil viscosity reduction as CO_2 and separator gas.

With the use of data from the bottom-hole pressure analysis, the frac-treatment design was evaluated, and the presently used design parameters were confirmed. The design used to frac-treat the Brushy Canyon uses a fracture half-length of 400 ft and a frac height of approximately 200 ft, which includes K, K-2, and L zones. With the use of the Delaware Model to predict the ultimate recovery from the wells and an average recovery factor of 12%, the drainage area is estimated to be 50 to 60 acres. This represents an area approximately 600 ft surrounding the indicated fracture geometry. The drainage area is described as a rectangle approximately 1200 ft wide and 2000 ft long. The reservoir simulation model will be used to further verify these assumptions. Larger designs are being considered to extend the frac length, but the concern over frac-height growth has curtailed these plans until a quantitative model can be found to predict frac heights with frac lengths of 600 to 800 ft.

Historical production data have been updated through August 1996. The decline curves have been compared with the Delaware Model to evaluate production trends.

The pilot area has been proposed around well No. 1. The spacing in this part of the field is very close, and interference has been observed between well Nos. 1, 6, 14, 5, 9, and 10. Preliminary calculations indicate that the water injection rates would be 150 to 200 bbl of water per day, which would be too low to obtain response in a reasonable length of time.

Detailed flow-unit maps have been prepared. Each of the subunits of the three main sands has been mapped individually. Maps prepared for each subunit are isopach maps for log-derived net pay and isopach maps for gross subunits. These maps have been put into the initial geologic model for the simulation study in the pilot area.

The logs on the 16 wells in sec. 14, T. 23 S., R. 28 E., selected as an analogy to the Nash Draw Unit, have been digitized. These digitized logs will be used to determine the productive zones and to arrive at an original-oil-in-place number for the entire section (640 acres).

With the use of core and log data, each well has been calibrated to match production, net pay, and transmissibility. By calculating a transmissibility value for each interval, production rates and cumulative production were allocated to each interval. The transmissibility for each layer, along with saturation data, will be used as input into the reservoir simulation model to determine the producing characteristics of each layer.

3-D Seismic

The 3-D seismic volume data were acquired and processed during this quarter. Because of the extensive presurvey testing and planning, high-quality data were obtained. The rigorous processing sequence applied to the 3-D field records produced a valuable image volume of the heterogeneous turbidite reservoirs that are the focus of the Nash Draw study.

The interpretation of the 3-D seismic image began late in the quarter, and preliminary structure, isochron, and seismic attribute maps were produced. Seismic amplitude attributes appear to be valuable for identifying productive reservoir facies with high-reflection amplitudes occurring at the better producing wells and low-reflection amplitudes at the poorer producers.

Reservoir Characterization/Reservoir Simulation

Activities this quarter focused on the completion of the geological model based on log and core measurements. Although seismic data were acquired, processed, and partially interpreted during the quarter, the data are not represented directly in the present model.

During the quarter, the Engineering and Geology Teams developed a new interpretation of the Nash Draw on the basis of the logs and well test data. In this interpretation, the Nash Draw Brushy Canyon Unit is divided into three noncommunicating "lobes." The central lobe supports production in the pilot area. This segment of the reservoir was reinterpreted and redigitized. The resulting files were imported into a Stratigraphic Geocellular Model (SGM) to build a new 3-D representation of the lobe. Figure 1 illustrates the structure of the top of the uppermost horizon, the J sand (displayed only for the eastern half of the reservoir), and locates the proposed pilot area (the boundaries are slightly different from before). Figure 2 outlines the lobe that supports the pilot. Figure 3 illustrates the relationship between the five major producing horizons in this new interpretation. In this model the well picks in each zone and subzone (of the K and L sands) were enforced.

The Well Attribute Model developed last quarter was used to import the following attributes into the stratigraphic framework model for the pilot lobe:

- Interpreted porosity and interpreted permeability
- Perforated interval and fractured interval
- Net pay
- Water saturation

In some instances these attributes were available on a foot-by-foot basis for one or more of the producing zones. Not all of the attributes were available for each well. The distribution of reservoir attributes such as conductivity and storage capacity within the producing zones of the Nash Draw Brushy Canyon Unit will be based on the well attribute model. Within SGM, these distributions are interpolated deterministically (i.e., weighted by the reciprocal of the square of the distance between the location of interest and nearby wells within the reservoir model).

The model is adequate to represent the geological characterization of the Nash Draw Brushy Canyon Pilot for reservoir simulation.

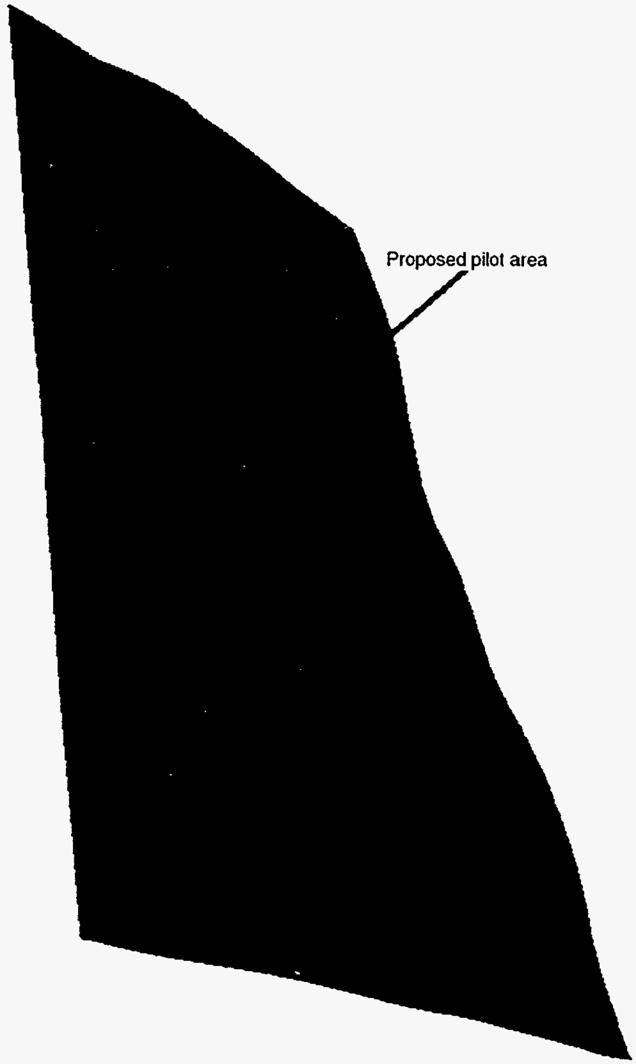

Fig. 1 Proposed pilot area of Nash Draw project top of J sand. (Art reproduced from best available copy.)

Technology Transfer

Strata has participated in several meetings and workshops to promote the dissemination of information generated during this quarter.

- *Liaison and Technical Committee Meeting.* A liaison and technical committee meeting was held on August 16, 1996. Fourteen participants heard a discussion on the status of the project and findings to date.
- *Characterization Workshop.* A workshop sponsored by the Petroleum Recovery Research Center at New Mexico Tech, "Integration of Advanced Reservoir Characterization Techniques," was held in Roswell, N. Mex., on August 22–23, 1996. Strata Production Company presented an update of the status and findings at the Nash Draw Project.
- *DOE Outreach Program Meeting.* A poster was presented at the DOE Outreach Program meeting in Roswell on July 25–26, 1996. Several area producers attended the

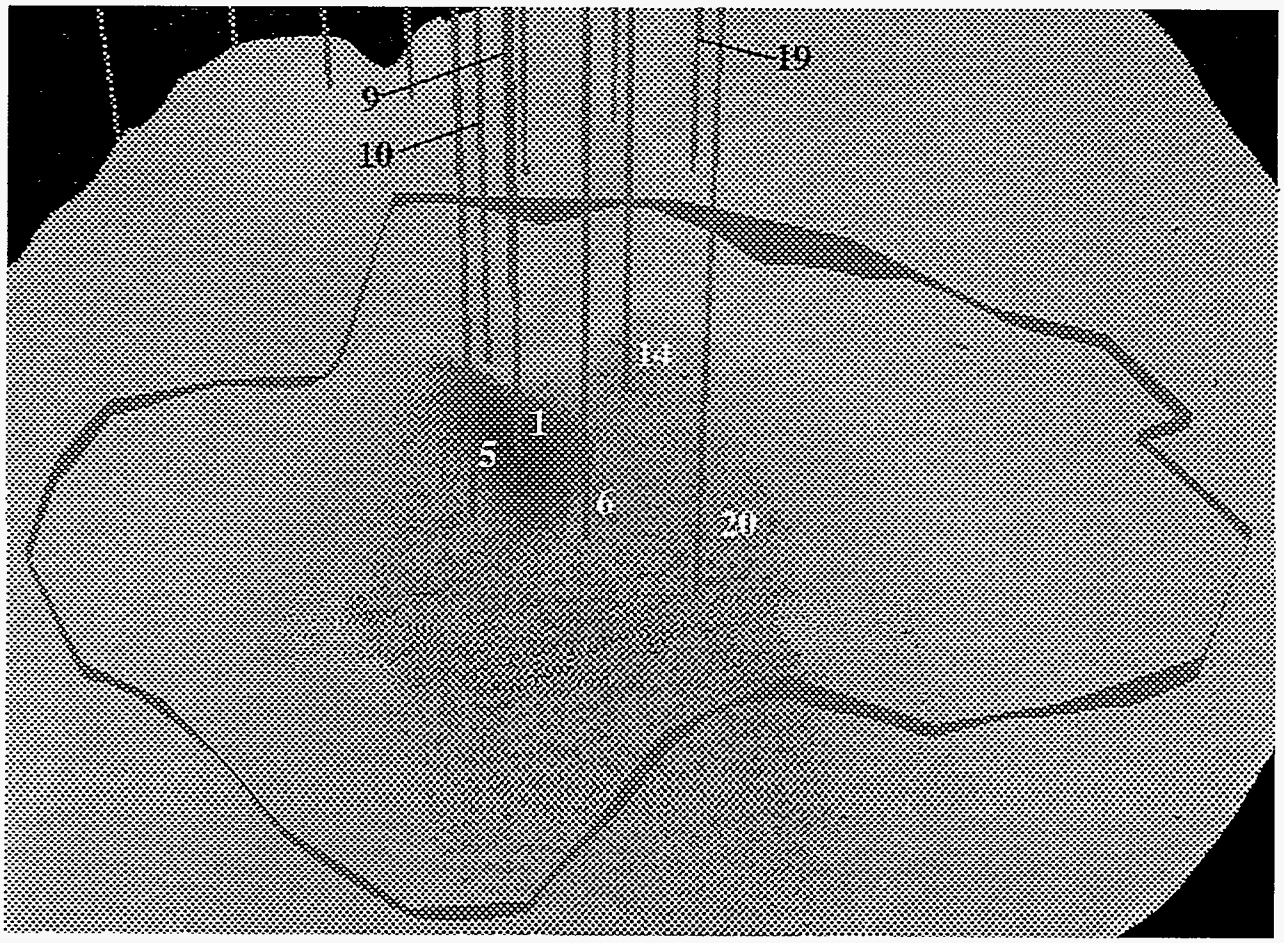

Fig. 2 Outline of net pay lobe "Kb" interval.

meeting, and there was considerable interest in the activities being conducted at the Nash Draw Unit.

• *FRAC Design Workshop.* A conference, "Stimulation Design and Monitoring—Delaware Mountain Group Formations," was held on September 19, 1996, at the New Mexico Junior College in Hobbs, N. Mex. Strata presented the findings of the fracture stimulation design and evaluation scenario used to determine the effectiveness of the stimulation program.

• *Internet Home Page.* An Internet home page went on line in September 1996 at http://baervan.nmt.edu/prrc/homepage.html. At this URL, go to "Research Divisions," then "Reservoir Evaluation and Advanced Computational Technologies (REACT)," then "REACT PROJECTS," and then to "DOE CLASS III PON Slope Basin Reservoir Characterization: Nash Draw Field." Finally, click on "NASH DRAW" to view project and field data.

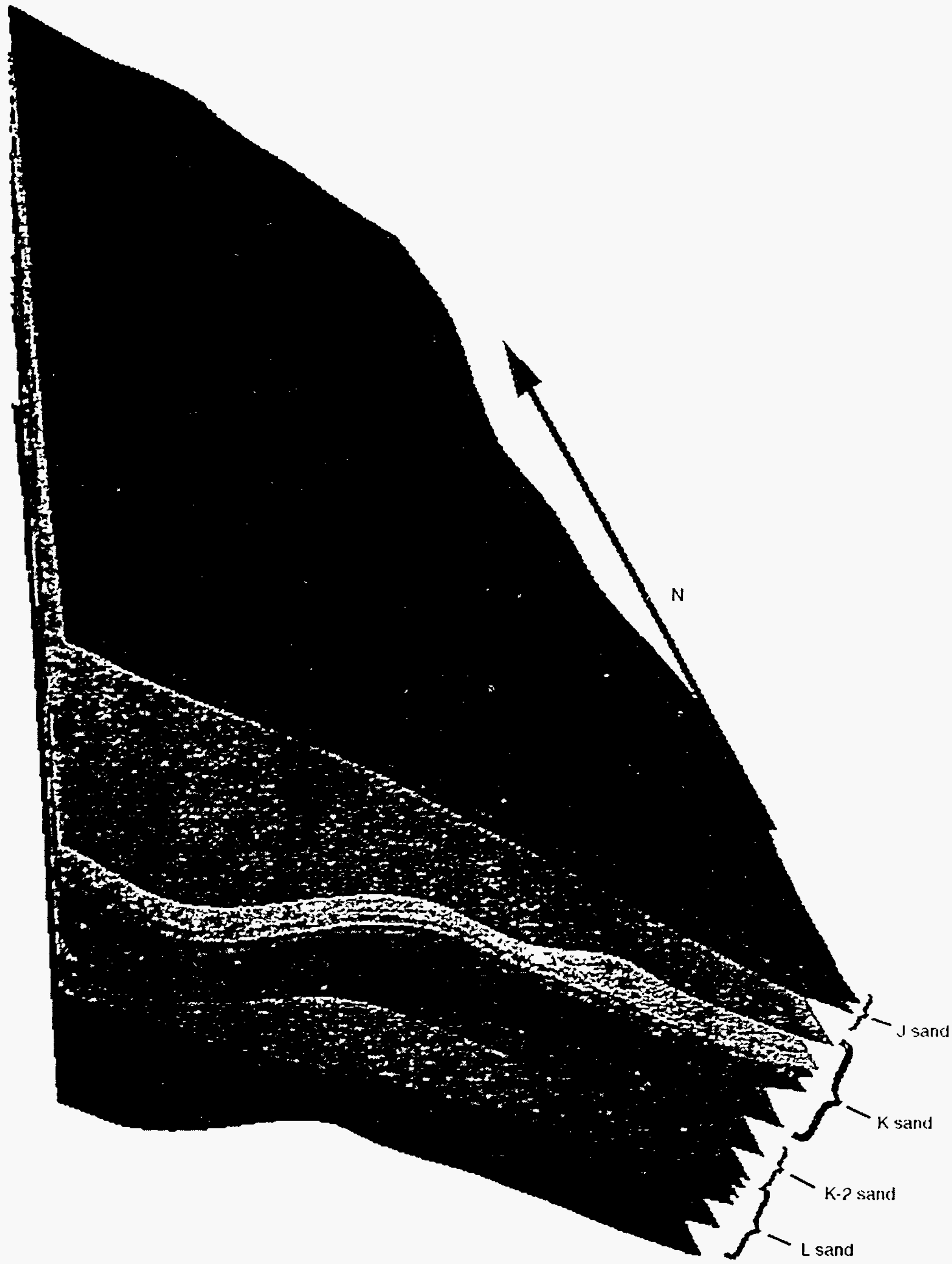

Fig. 3 Nash Draw project stratigraphic framework model.

POSTWATERFLOOD CO_2 MISCIBLE FLOOD IN LIGHT OIL FLUVIAL-DOMINATED DELTAIC RESERVOIRS

Contract No. DE-FC22-93BC14960

Texaco Exploration and Production, Inc.
New Orleans, La.

Contract Date: June 1, 1993
Anticipated Completion: Dec. 31, 1997
Government Award: $995,000
(Current year)

Principal Investigator:
Sami Bou-Mikael

Project Manager:
Chandra Nautiyal
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objectives

The overall objective of this project is to integrate research on petroleum reservoir characterization and process monitoring funded by the U.S. Department of Energy (DOE). Specific objectives for this quarter included:

- Monitor reservoir performance.
- Evaluate the feasibility of three workovers in wells Kuhn No. 14, Stark No. 8, and Kuhn No. 38.

Summary of Technical Progress

During this quarter CO_2 recycling continued in the Port Neches project with three wells (Kuhn No. 14, Kuhn No. 15R, and Kuhn No. 38) producing an average of 48 bbl of oil per day (BOPD). During this period well Kuhn No. 15R sanded up because of corrosion problems in the screen and the tubing. Wells Kuhn No. 14 and No. 38 were placed on production in an attempt to maintain production to recover any CO_2 displaced oil remaining in the reservoir. Injection of the produced CO_2 and water continued in wells Kuhn No. 42, Stark No. 10, and Kuhn No. 17.

After well Kuhn No. 15R went off production, researchers evaluated performing workovers on three wells: Kuhn No. 14, Stark No. 8, and Kuhn No. 38, but the decision was made to not perform workovers on the wells because of the project economics and the low reservoir yield from current production. Production was successfully initiated from wells Kuhn No. 14 and Kuhn No. 38, however, which are currently producing about 60 BOPD.

Table 1 lists the most recent well tests taken during the month of September 1996 for the producing and injection wells. Figure 1 shows the monthly production of oil.

TABLE 1

Well Test Results, September 1996*

Well No.	BOPD	MCFGD	BWPD	Basic sediment and water, %	Pressure, psi	Choke
Producing wells						
Kuhn No. 14	37			97	250	36
Kuhn No. 38	54			46	1100	11
Injection wells						
Kuhn No. 42		613			1294	
Stark No. 10		1691			1295	
Kuhn No. 17			375		1550	
Margulina Area No. 1H			389		1400	

*BOPD, barrels of oil per day; MCFGD, thousand cubic feet of gas per day; BWPD, barrels of water per day.

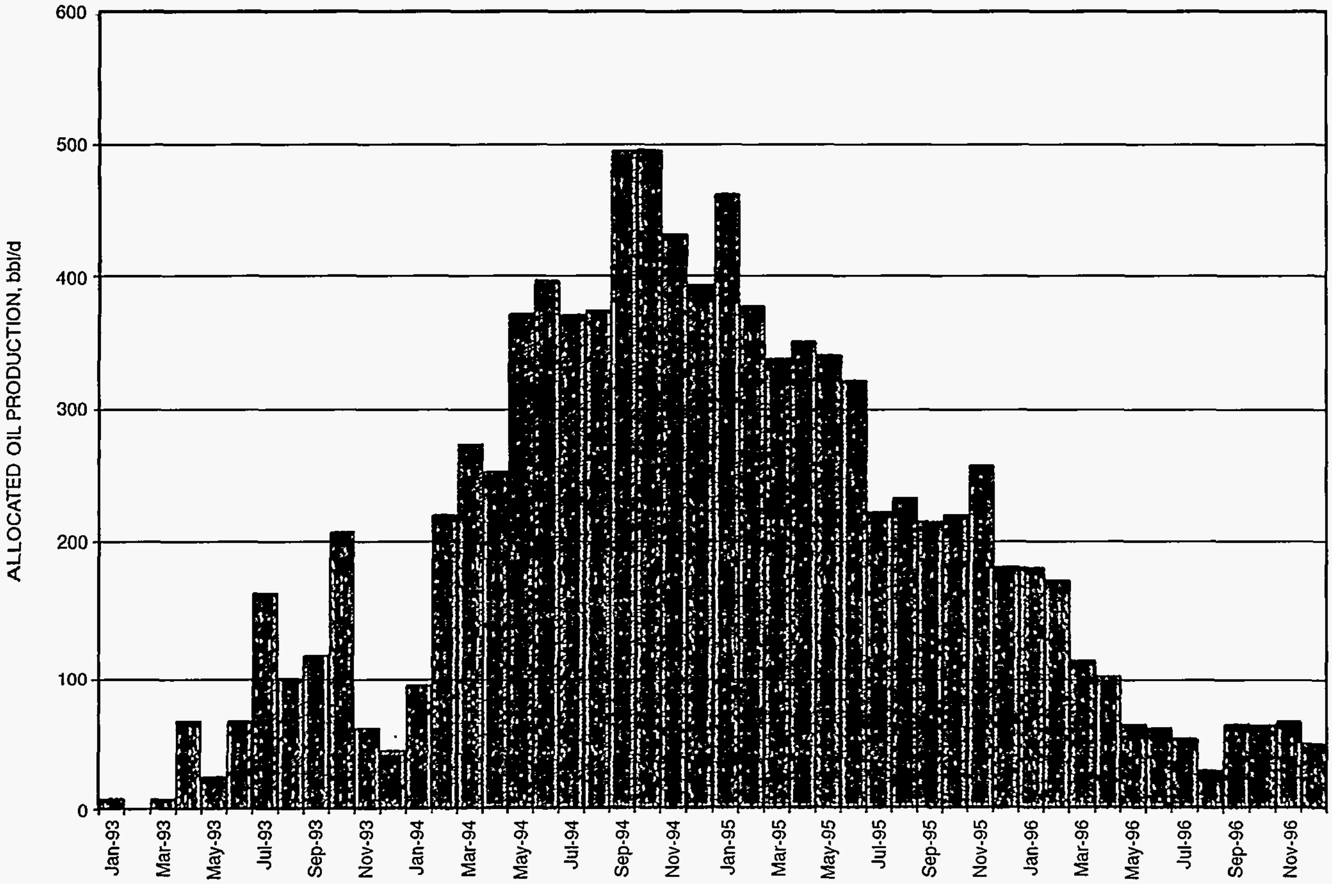

Fig. 1 Port Neches CO_2 project allocated oil production.

AN INTEGRATED STUDY OF THE GRAYBURG/SAN ANDRES RESERVOIR, FOSTER AND SOUTH COWDEN FIELDS, ECTOR COUNTY, TEXAS

Contract No. DE-FC22-93BC14982

Laguna Petroleum Corporation
Midland, Texas

Contract Date: Aug. 2, 1994
Anticipated Completion: Feb. 2, 1998
Government Award: $649,100

Principal Investigators:
Robert C. Trentham
Richard Weinbrandt
William Robertson

Project Manager:
Chandra M. Nautiyal
National Petroleum Technology Office

Reporting Period: July 1–Sept. 30, 1996

Objective

The principal objective of this research is to demonstrate in the field that three-dimensional (3-D) seismic data can be used to help identify porosity zones, permeability barriers, and thief zones and thereby improve waterflood design. Geologic and engineering data will be integrated with the geophysical data to result in a detailed reservoir characterization. Reservoir simulation will then be used to determine infill drilling potential and the optimum waterflood design for the project area. This design will be implemented and the success of the waterflood evaluated.

Summary of Technical Progress

Engineering

During this quarter the Foster No. 11 well was drilled to test the simulation and contact additional reserves in the San Andres and the lower Grayburg. The well was located in the southwest quarter of section 36 to take advantage of the lack of producing wells in the west half of the southwest quarter of the section (Fig. 1). The well is 690 ft northwest of the No. 4 Foster and 690 ft southwest of the No. 3 Foster, 40-acre wells drilled in 1941. The No. 4 was plugged in 1984 and the No. 3 plugged in 1986. The No. 3 Foster was successfully reentered this year and placed back on production in the A1 Zone.

The Foster No. 11 total depth'd (TD'd) at 4403 ft in the San Andres. A full suite of logs (Compensated Neutron, Three Detector Density, Long Spacing Sonic, Dual Laterolog, micro-Centrally Focused, Spectral Gamma-Ray, and Mud) were run. Additionally, a Repeat Formation Tester was used in an effort to obtain reservoir pressure data. Eighteen tests were attempted with six good tests and two formation fluid samples recovered (Table 1). The results indicate that the San Andres and the lower Grayburg are in different pressure regimes and the A1 Zone is depleted. Core was cut in the lower Grayburg and San Andres to provide rock property information for these two intervals.

On the basis of the log calculations (Fig. 2) and core recovery (Fig. 3), the initial No. 11 Foster completion was attempted in the San Andres. The interval from 4238 ft (–1290) to 4323 ft(–1375) was perfed and acidized. Rates of 3 to 4 bbl of oil per day (BOPD) and 6 to 8 bbl of water per day (BWPD) were established. Because water zones were indicated both above and below the completed interval, the fracture completion had to be designed to minimize fracturing into these zones. A "Mini Frac" was attempted with 3500 gal of cross-link gel and 6000 lb of 100-mesh sand followed by 2000 gal of nitrified gel and 6000 lb of sand. At the end of the quarter, the well was on test.

During this quarter the first deepening of an existing well was completed. The Witcher No. 2 (Fig. 1) is one of the original 40-acre wells; drilled in 1940, it was completed open hole and shot with nitro in the upper Grayburg with TD 20 ft above the top of lower Grayburg. The well was deepened from 4055 to 4450 ft in the San Andres. No cores were taken during the deepening of this well but a full suite of logs (Compensated Neutron, Three Detector Density, Long Spacing Sonic, Dual Laterolog, micro-Centrally Focused, Spectral Gamma-Ray, and Mud) were run (Fig. 4). Located in the northwest quarter of section 36, the well was proposed to test the lower Grayburg and determine if the San Andres was below the oil–water contact. The simulation results indicated untapped reserves in the lower Grayburg at this location.

The "historic" oil–water contact of –1340 vss in the San Andres is coincident with the top of San Andres (–1334 vss) at this location. Production in other wells has been deeper than –1340 vss, and this location was chosen to test the paradigm. Perforations from 4388 ft(–1461 vss) to 4398 ft (–1471 vss) were acidized, flowed 100% water, then CIBP set. Perforations from 4291 ft(–1364 vss) to 4325 ft(–1398 vss) were acidized, and the well flowed 10 to 12 bbl of oil (BO) and 100 to 120 bbl of water (BW). At the end of the quarter, the well was on pump, producing 33 BO, 124 BW, 8 thousand cubic ft per day, having produced a total of 1380 BO and 6452 BW. This proves that the historic oil–water contact needs revision. It is now believed that the San Andres has multiple oil–water contacts. This will be tested in future new drills and deepenings.

Plans were made to reenter the No. 4 Foster–Pegues (Fig. 1) and convert it to injection. This well, originally directionally drilled under the interstate, had been shut in for lack of production. The simulation indicated that this location would provide lower Grayburg pressure support for the recently

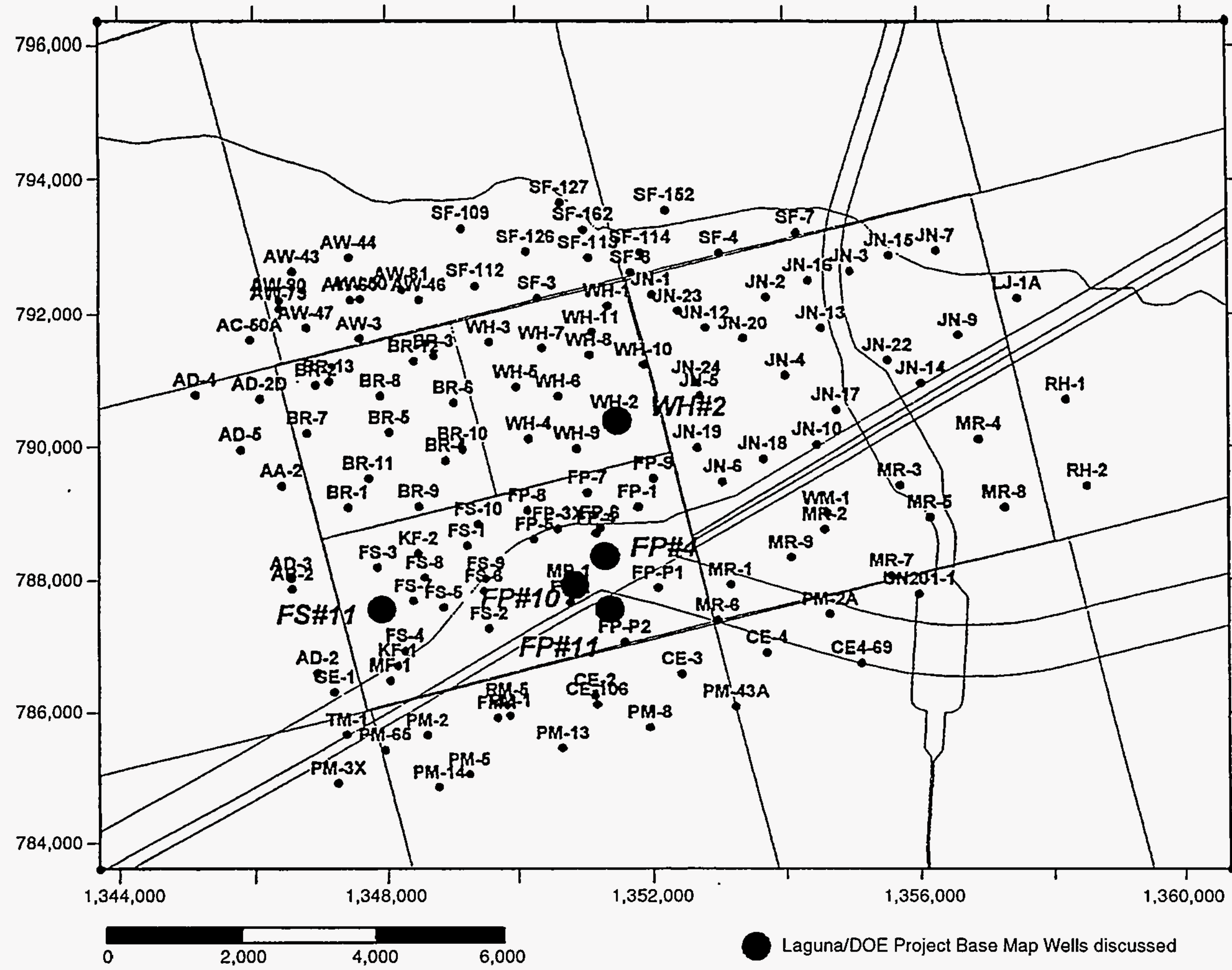

Fig. 1 Location map for wells discussed this quarter.

TABLE 1

Repeat Formation Tester Pressures

Depth, ft	Zone	Formation pressure	Hydrostatic pressure
3577.1	A-1	124.5	2087.9
4038.0	D	2070.0	2246.0
4081.0	F	2142.0	2271.1
4301.0	SADR	2161.3	2394.5
4339.0	SADR	2191.2	2415.5

completed Foster–Pegues No. 11 and the Foster–Pegues No. 10, a Grayburg plug back completed in November 1995.

Well testing continues, which reinforces the preliminary conclusion that the waterflood, as designed and implemented, is ineffective.

The Produced Water Suspended Solids Survey, completed this quarter, found that (a) 89% of the suspended solids are between 0.45 and 0.5 μm, (b) an injectivity enhancement chemical decreased overall suspended solids at the injection pump by 62% primarily by removing hydrocarbons from the solids, (c) the Brock and Henderson (makeup water) leases contributed higher suspended solids waters to the unit, (d) a 30% increase in suspended solids occurs when incompatible waters are mixed, (e) a 65% suspended solids decrease occurs between the gunbarrel inlet and gunbarrel outlet, and (f) a further 8% suspended solids decrease occurs between the gunbarrel outlet and the injection pump suction. The water system is, therefore, removing the majority of dissolved solids, and only the Brock and Henderson leases need to be tested to see what corrective measures need to be taken. No other changes to the waterflood system surface facilities are planned at this time.

Geology

Foster No. 11 Core

The Foster No. 11 was cored in the lower Grayburg from 4045 to 4148 ft and the San Andres cored from 4149 to 4220 ft. Note: because of a driller's error, the core depths were 45 ft off from the electric log depths. Thus 4200 ft in the core equals 4155 ft in the electric log. Core depths referred to in this report are adjusted. The core analyses report (Fig. 3), however, reflects the depths as recorded at the well site. The

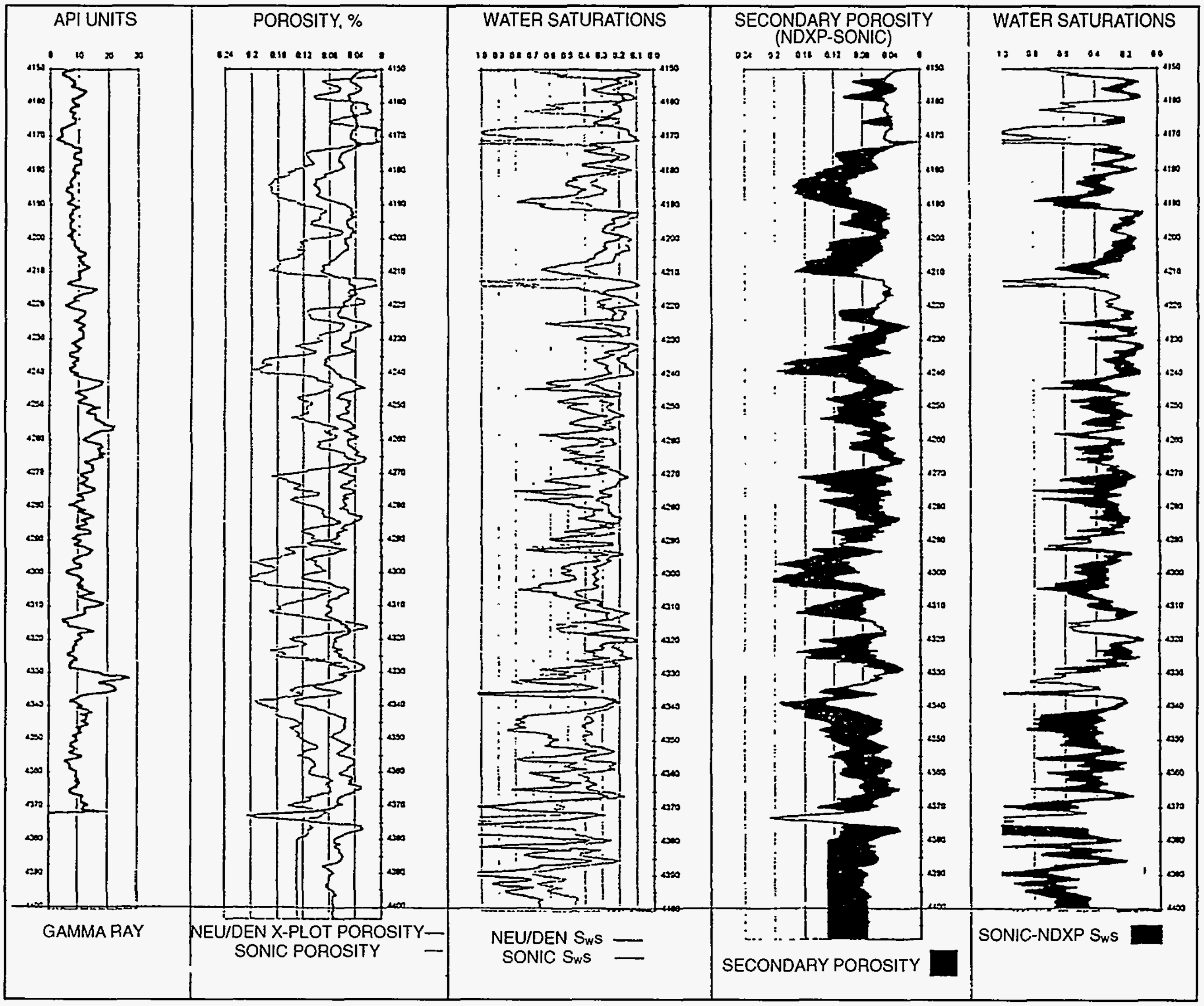

Fig. 2 Log calculations for San Andres section of Foster No. 11 showing gamma-ray; neutron density (NEU/DEN) cross-plot porosity and sonic porosity; water saturation calculated using cross-plot and sonic porosity and difference between cross-plot and sonic-derived porosity and water saturations. (Art reproduced from best available copy.)

core has been analyzed and thin sections cut. The core and thin sections are being described. The core analysis indicates that the lowermost Grayburg, unlike Foster–Pegues No. 11, is relatively tight. The San Andres core analyses from the Foster No. 11 are consistent with the two San Andres cores (Witcher No. 6 and Brock No. 10) taken before the study.

The lower Grayburg is a series of shallowing upward cycles composed primarily of shallow subtidal to intertidal supratidal facies. The visible porosity is primarily fenestral with little if any secondary porosity. There are some small, 2 to 4 ft long, vertical fractures with oil staining. The deepest water facies (maximum flooding surface), a fusulinacean wackestone, are found within 30 ft of the transgressive base of the Grayburg. There are no reworked siliciclastics at the base of the Grayburg. A number of exposure surfaces with associated minor karstification are seen in this section.

The San Andres is composed of very porous and permeable cross-bedded ooid and skeletal packstones and grainstones separated by intervals of massive anhydrite with collapsed mudstone and wackestone rubble. These anhydritic intervals are interpreted to be cavern fill sediments because they are featureless and lack the classic "chicken wire texture" of sabkha anhydrite. The terminal event of the San Andres is a major subaerial exposure surface with an associated drop in the water table of at least 60 ft at the Foster No. 11 location (Fig. 2) and 50 ft at the Witcher No. 2 location (the Witcher No. 2 is structurally lower and basinward of the No. 11 Foster). During subaerial exposure, a sequence of

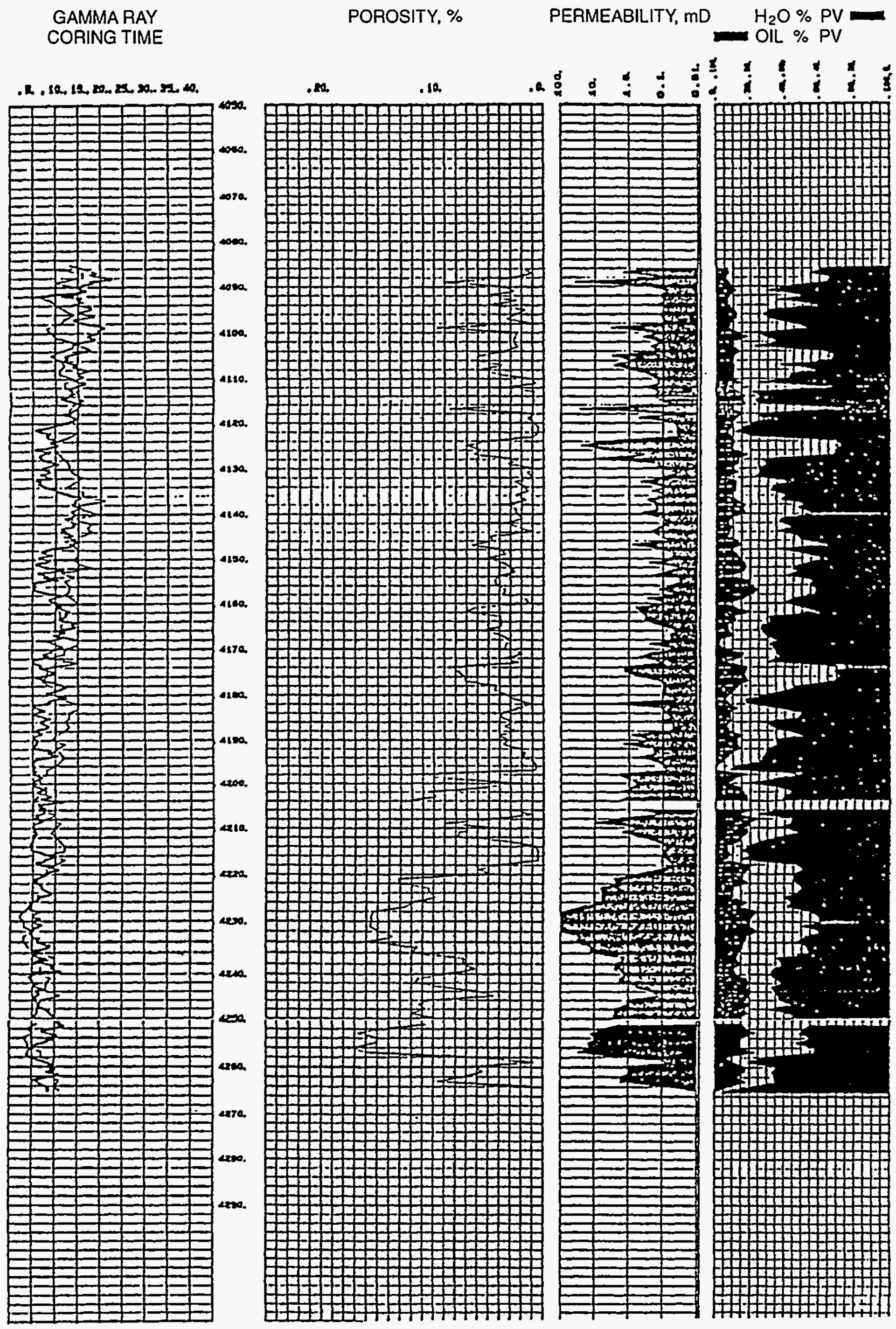

Fig. 3 Core report for Foster No. 11. (Art reproduced from best available copy.)

mudstones and wackestones, originally interbedded with the grainstones and packstones, underwent intense dissolution. The aragonitic mudstones and wackestones were prone to dissolution by fresh water in the vadose environment, whereas the calcite-rich grainstones and packstones were resistant and acted as cave roofs and floors. There is crackle breccia, indicative of incipient cave roof collapse, in the core near the base of the grainstone at 4198 ft (4153 on logs) above one of the anhydrite infill intervals.

Foster No. 11 Logs

It is very difficult to make log correlations within the San Andres. There is no area-wide correlation in the upper 50 ft of the San Andres. From the core–log relationships, the interval ranges from 100% anhydrite to 50% wackestone–mudstone or anhydrite and 50% grainstone–packstone to almost 100% grainstone–packstone (Fig. 5). Beginning 50 to 75 ft below the top of the San Andres and extending down at

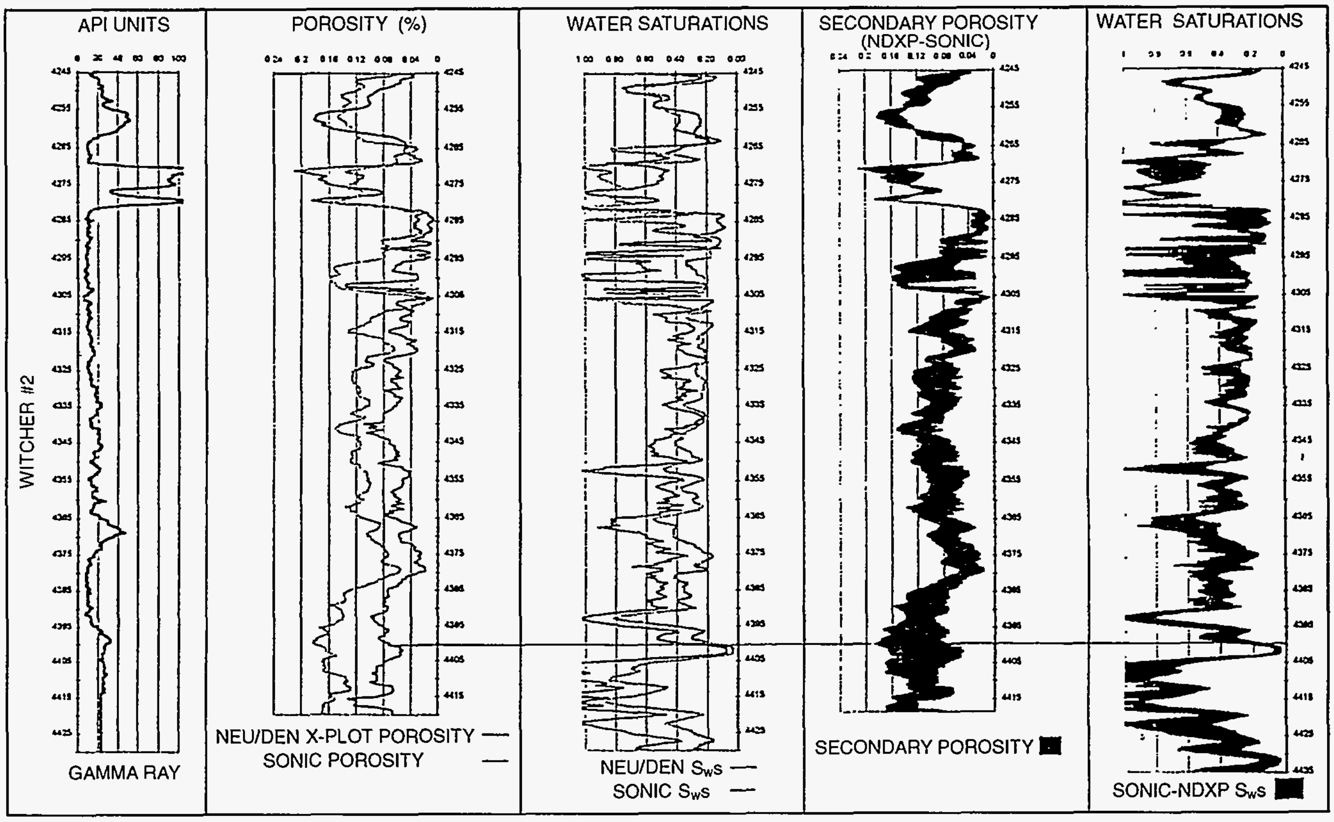

Fig. 4 Log calculations for San Andres section of Witcher No. 2 showing gamma-ray; neutron density (NEU/DEN) cross-plot porosity and sonic porosity; water saturation calculated using cross-plot and sonic porosity and difference between cross-plot and sonic-derived porosity and water saturations. (Art reproduced from best available copy.)

least 150 ft, there appears to be a series of 30- to 70-ft-thick shallowing upward sequences which shallow into thick, highly porous units (interpreted to be grainstone shoals) capped by less porous units (interpreted to be lower energy packstone–wackestone). These units are identified by porosity log signature because there is little gamma log character. When these facies were plotted on a map of seismic reflection amplitudes at the top of the San Andres, a good correlation was seen. Anhydrite-rich log character is correlated with low reflection amplitude and grainstone–packstone (>8% porosity) log character with high reflection amplitude.

Witcher No. 2

The Witcher No. 2 was completed flowing from acidized perfs in the upper 60 ft of the San Andres in an area with high reflection amplitude. On the basis of log character (Fig. 4), the upper 21 ft of the San Andres is composed of a 2-ft-thick massive anhydrite, an 11-ft-thick shale-rich cave infill, and a 7-ft-thick massive anhydrite above a porous (16% cross-plot porosity) interval with possible fractures (crackle breccia?). At the base of the porous unit and just above the interpreted water table is another anhydrite interval. As in the Foster No. 11, the porous interval is believed to be calcite-rich grainstone–packstone. This diagenetic overprint on the uppermost San Andres has a major impact on reservoir distribution and behavior. Without a proper understanding of this diagenetic history, successful completions in the San Andres are "hit or miss."

Water Saturations

Water saturations (S_w's) for the San Andres, in the Foster No. 11 (Fig. 2), calculated using neutron density cross-plot porosity appear to be too optimistic (9 to 20% S_w) when compared with visual inspection of the core and the production history of other wells in the area. When water saturations for the same interval are calculated with the use of sonic porosity, some zones calculate to have higher, and more realistic, saturations (34 to 46% S_w), whereas other zones calculate "wet" (50 to 100% S_w). When two zones with cross-plot porosities of 14 to 18% and low S_w's (calculated by both methods) were perforated and acidized, pumping production rates of only 4 to 5 BOPD and 6 to 8 (BWPD were obtained.

A possible explanation for this is found in the porosity–permeability cross-plots of the core data. Although many analyzed intervals have permeabilities of >1 mD for porosities of 14 to 18%, other highly porous zones have permeabilities of <<1 mD. A comparison of the cross-plot neutron density porosity (which matches well with the core analyses) with the sonic porosity is revealing. There appears

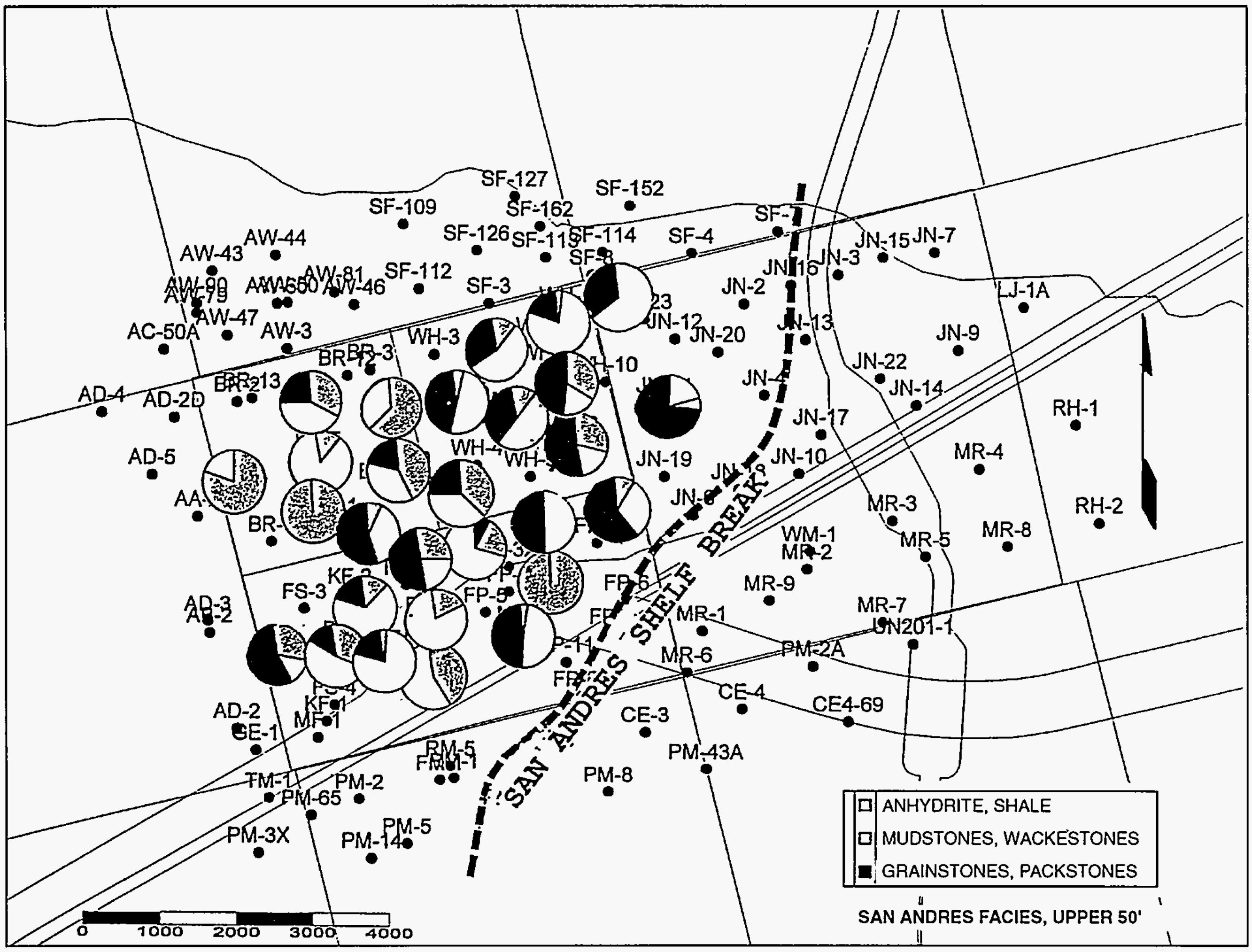

Fig. 5 Facies distribution for upper 50 ft of San Andres.

to be 8 to 10% secondary porosity above the sonic porosity (Fig. 2). Zones with up to 18% total porosity may have only 5 to 7% sonic porosity and low permeabilities (<1 mD). This observation, coupled with the production test results, indicates that there is a dual porosity system in the San Andres. One system is porous but not very permeable (vuggy) and the other is permeable and porous (interparticle connected). At the end of the quarter, the San Andres had been fractured and was being tested.

The Witcher No. 2 was deepened from the upper Grayburg through the lower Grayburg and the San Andres to contact reservoir not previously productive at this area. Again, as in the Foster No. 11, S_w calculations with the use of neutron density cross-plot porosities are overly optimistic (Fig. 4). Water saturations calculated with the use of sonic porosities were more variable and more realistic. A lower zone, 4388 to 4398 ft, was perfed and acidized on the basis of fair mud log shows and marginal cross-plot water saturations (16 to 45%). This zone flowed 100% water, confirming that the sonic-derived water saturations (55 to 100%) were correct. The zone from 4290 to 4315 ft had cross-plot porosities of 9 to 13% and sonic-derived water saturations of 12 to 45%. To date, it has produced 1380 BO and 6452 BW. The dual-porosity system appears to be present in this interval because the water production initially dropped at a faster rate than the oil production. More recently, the oil production has begun to decline at a more rapid rate than the water. Testing of this well will continue in the 4th quarter.

Mapping

Base map construction was accomplished by editing existing CAD-type digital files for use in SURFER. A spreadsheet, recording surveyed well locations and well top data, was printed. This base map will serve as a common base for all subsequent maps of geology and geophysics and can be updated easily by modifying the well data spreadsheet and by adding or removing map layers. It can also be imported into the SSI Workbench for integration into the reservoir model.

The first series of maps included subsurface and seismic reflection maps of main correlation horizons. All Grayburg internal correlations (log calls) will be mapped along with isopach intervals both for quality control and for their

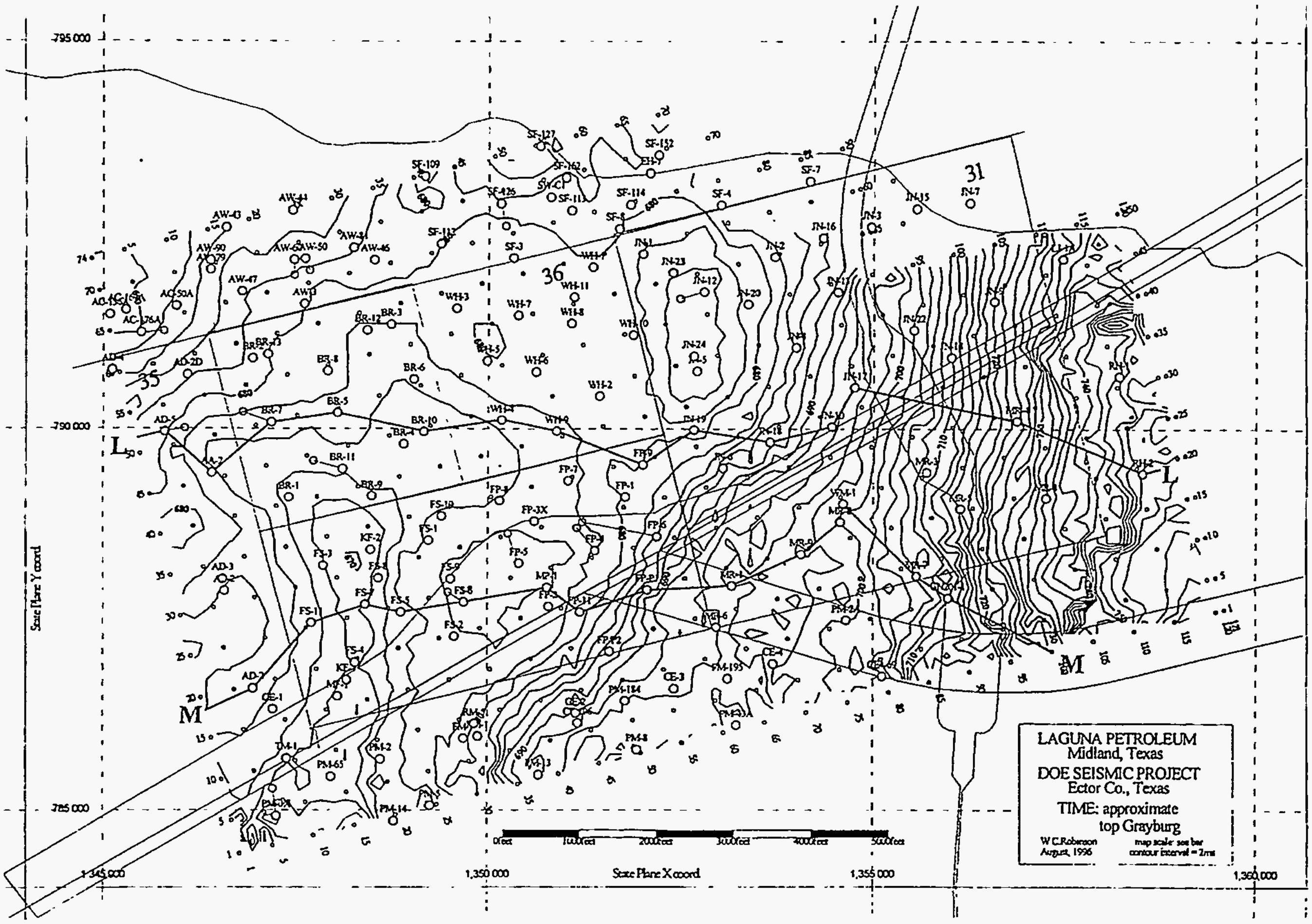

Fig. 6 Grayburg seismic time structure map.

information value. Seismic reflections from near the tops of Grayburg (Fig. 6) and San Andres (Fig. 7) are mapped, showing the features of the relatively flat shelf area in the west and the structural break to the outer shelf in the east. The position of cross section L-L[1] is shown on the maps.

Reflections from below the San Andres (Pennsylvanian and Devonian) were tracked to relate buried structure and (perhaps) faulting to structural boundaries observed in the Grayburg sequence. Seismic faults were tracked, but rigorous relationships could not be easily demonstrated; the horizon interpretations are ready to be evaluated.

Near-Term Objectives

Resolution of the seismic data is being studied to further relate the seismic scale to the geologic (log) scale for the Grayburg and the San Andres formations. Additional simplified forward models will be built to demonstrate the effects on seismic response of porosity changes within several levels of the Grayburg sequence. Thought has been given to the maximum economically achievable seismic resolution, for the sake of some future three-dimensional or specific-task two-dimensional seismic acquisition, and has been included in model studies.

Quantities of subsurface maps will be made, and revisions will be made to some of the preliminary seismic correlations which will require remapping. Inversion modeling will be moved forward. Interval averaging and slicing methods will be used to make new maps of seismic intervals.

Geophysical Conclusions

The most interesting observation so far is the strong relationship of San Andres stronger amplitude with good porosity in some wells and of weaker amplitude with nonporous, anhydrite-rich San Andres in other wells. The observation has immediate economic interest because deepening of certain Grayburg wells to the San Andres would be justified and encouraged, whereas others might be postponed or dropped from the program. Forward models made so far support seismic interpretations of observations and define the vertical scale of seismic resolution (lateral resolution will

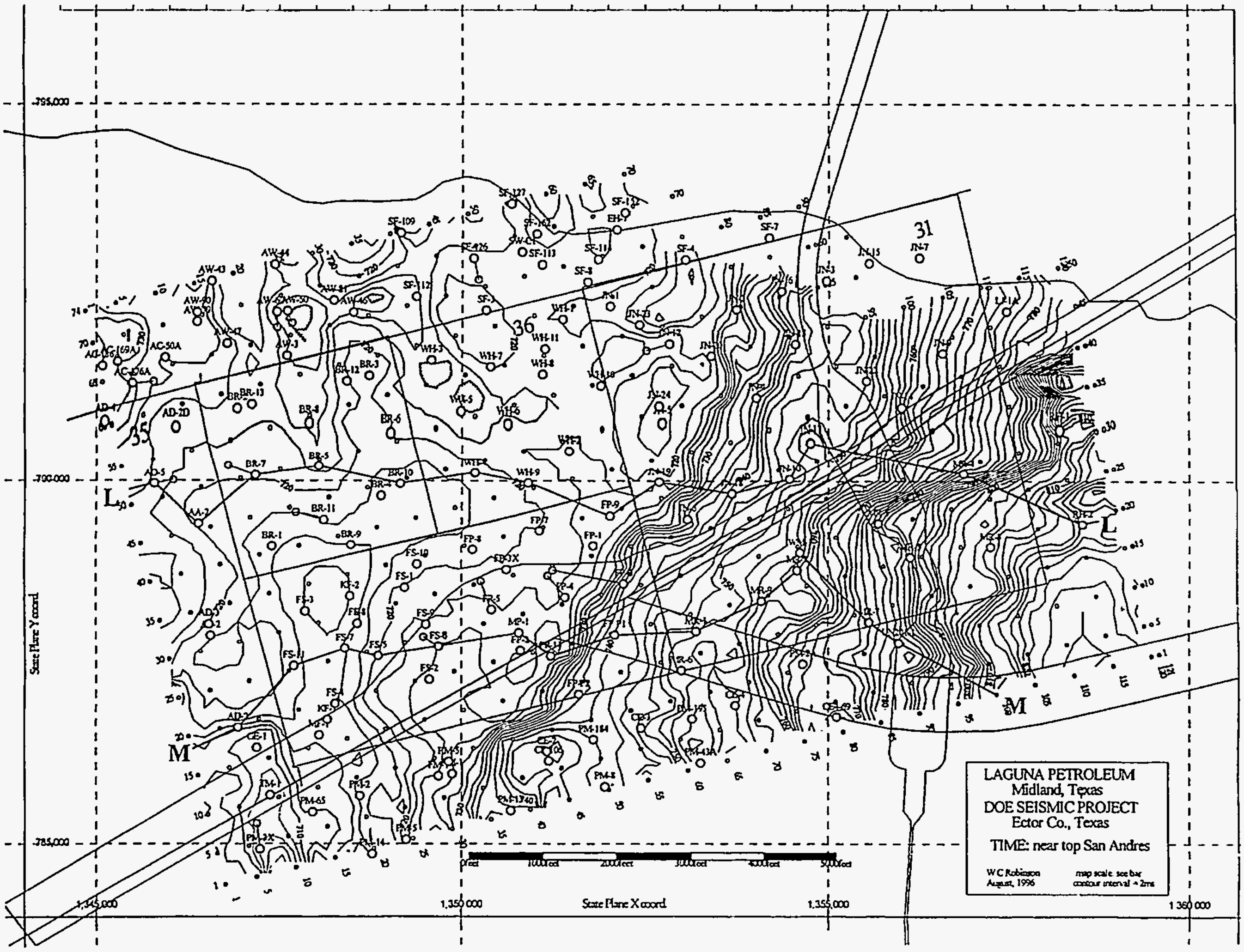

Fig. 7 San Andres seismic time structure map.

also be addressed). The continuous reflection labeled Grayburg actually crosses time-stratigraphic lines, as do other reflections.

Technology Transfer

A statistical comparison of well-log-defined geologic characteristics with observable seismic attributes included in the three-part article "Seismic-Guided Estimation of Log Properties" was published in the May–July 1994 issue of *SEG The Leading Edge.*

The University Lands/Bureau of Economic Geology (BEG) group seminar (11/6/96) provided a methodology for relating fine cycle sedimentation packages as described in the South Cowden field to the seismic sequence and tied to the right position by log points.

An abstract for the poster session at the Fourth International Reservoir Characterization Technical Conference March 2–4, 1997, was submitted.

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