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Final

**GEOLOGICAL AND PETROPHYSICAL
CHARACTERIZATION OF THE FERRON SANDSTONE
FOR 3-D SIMULATION
OF A FLUVIAL-DELTAIC RESERVOIR
(Contract No. DE-AC22-93BC14896)**

TECHNICAL PROGRESS REPORT

Submitted by

**Utah Geological Survey
Salt Lake City, Utah 84109
May 2, 1995**

**Contract Date: September 29, 1993
Anticipated Completion Date: September 29, 1996
Government Award (fiscal year): \$ 1,225,482
Program Manager: Thomas C. Chidsey, Jr.
Principal Investigator: M. Lee Allison**

Contracting Officer's Representative

**Robert Lemmon
U.S. Department of Energy
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005**

Reporting Period: January 1 - March 31, 1995

US/DOE Patent Clearance is not required prior to the publication of this document.

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OBJECTIVE

The objective of this project is to develop a comprehensive, interdisciplinary, and quantitative characterization of a fluvial-deltaic reservoir which will allow realistic inter-well and reservoir-scale modeling to be developed for improved oil-field development in similar reservoirs world-wide. The geological and petrophysical properties of the Cretaceous Ferron Sandstone in east-central Utah (figure 1) will be quantitatively determined. Both new and existing data will be integrated into a three-dimensional representation of spatial variations in porosity, storativity, and tensorial rock permeability at a scale appropriate for inter-well to regional-scale reservoir simulation. Results could improve reservoir management through proper infill and extension drilling strategies, reduction of economic risks, increased recovery from existing oil fields, and more reliable reserve calculations. Transfer of the project results to the petroleum industry is an integral component of the project.

SUMMARY OF TECHNICAL PROGRESS

The technical progress for this quarter is divided into sections for the Regional Stratigraphy and Case Studies tasks of the project. The primary objective of the Regional Stratigraphy Task is to provide a detailed description and interpretation of the stratigraphy of the Ferron Sandstone outcrop belt from Last Chance Creek to Ferron Creek (figure 1). Photomosaics and a database of existing surface and subsurface data are being used to determine the extent and depositional environment of each parasequence, and the nature of the contacts with adjacent rocks or flow units.

The primary objective of the Case Studies Task is to develop a detailed geological and petrophysical characterization, at well-sweep scale or larger, of the primary reservoir lithofacies typically found in a fluvial-dominated deltaic reservoir. Interpretations of lithofacies, bounding surfaces, and other geologic information are being combined with permeability measurements from closely spaced traverses and from drill-hole cores to develop a three-dimensional view of the reservoirs within three case-study areas (locations shown on figure 1).

Regional Stratigraphy

Surface Mapping/Interpretation of the Outcrop Belt

The Utah Geological Survey (UGS) continues to combine digitized land-based and aerial photographs of the Ferron Sandstone outcrop belt into reproducible photomosaics using image-editing software. A total of 1,823 photos depict 80 miles (130 km) of Ferron Sandstone outcrop. Interpretation of parasequence boundaries, lithofacies, and various field data (such as measured section and gamma-ray transect locations) are being plotted on the photomosaics as part of both the regional and case-study analyses. These interpretations will be checked later in the field.

Figure 1. Location map of the Ferron Sandstone study area (cross-hatched) showing detailed case-study sites (outlined by heavy dashed lines).

Collection and Interpretation of Existing Surface and Subsurface Data

The UGS has collected maps, measured sections, well logs, core descriptions, and other data which pertain to the study area. This information has been compiled into a project database. The drill-hole data contained in the database will allow others who are making detailed surface measurements of Ferron rock units in the area to correlate those surface rock units into the subsurface. In addition, the drill-hole data can be used by coal and petroleum companies evaluating the Emery coal field, an area of current coalbed methane drilling activity. The UGS just released this information (in both hard-copy and a computer-readable format) for benefit of all interested parties.

Data were collected from wells that penetrate the Ferron Sandstone in the area from Last Chance Creek in the south to Ferron Creek in the north (figure 1). Well data from coal-company exploration wells; oil, gas, and stratigraphic test wells; and government test wells were entered into the database (table 1). First, a literature search was conducted and publicly available data were collected. Second, oil and gas geophysical well logs were copied from the Utah Geological Survey (UGS) geophysical log library. Finally, unpublished data were requested from companies known to have drilled in the area. Lithologic data were transcribed from published or company core and cutting descriptions onto standard data entry forms before entry into the database. When available, geophysical well logs were interpreted and the lithologies were transcribed onto the data entry forms.

The Ferron Sandstone drill-hole data were extracted from the larger, integrated UGS geoinformation digital database application developed under the working name of **INTEGRAL*gim**. **INTEGRAL*gim** was created at the UGS using a commercially available database manager. The database contains drill-hole data sorted by township, range, and section. It consists of header or well-location information and lithologic descriptions for each well. The header information includes county name, operator name, well name and number, API number, field or area name, cadastral location, meridian, surface elevation, and total depth or length of information recorded. Each record also includes latitude and longitude location (in decimal degrees) and quadrangle map names. The lithology data includes the depth below surface at which the top of each rock unit was penetrated by drilling, the unit name, and the unit description. Table 1 provides a list of the data sources and the number of data records from each information source in the database.

Case Studies

Reservoir Architecture

Parasequence designations in the stratigraphic sections have been standardized by combining facies descriptions and photomosaic interpretations. In Ferron deltaic deposits, parasequences may be considered as primary reservoir building blocks because marine and/or delta-plain shales act as laterally extensive permeability barriers and commonly separate parasequences. Fluid-flow communication may occur between parasequences where shales are absent due to erosion or non-deposition. Porosity and permeability values, dependent on lithofacies distribution, vary laterally and vertically within a parasequence. Mouth-bar and proximal-delta-front lithofacies are high quality reservoirs; these lithofacies distributions are related to spatial arrangement of parasequences making up the reservoir. Therefore, the initial

Table 1. Summary of drill-hole data entered into the Ferron Sandstone drill-hole database for the Ferron Sandstone reservoir characterization study.

Data Source	Number of wells with lithologic logs	Number of wells with geophysical logs
Coal Company		
Consolidation Coal Co.	348	62
Western States Minerals Corp.	14	0
Hidden Valley Coal Company	7	6
Rio Vista Oil LTD.	8	0
Marad Exploration	19	0
Government Agency		
Bureau of Land Management	7	2
University of Utah Research Institute	2	2
U.S. Geological Survey	35	15
Petroleum Company		
ARCO Exploration Company	7	7
Other	42	42
Total	489	136

stage in reservoir characterization must be an analysis of the architecture of parasequences and of lithofacies within parasequences.

In the Ivie Creek case-study area (figure 1), three parasequences are present within the Ferron No. 1 Sandstone parasequence set (Kf1). Delta-front sandstones of a modified Gilbert delta make up the sand-rich lithofacies of the basal parasequence, the Kf1a. Clinoforms in the delta front dip 10° - 15° and shale-out laterally within a mile (1.6 km) down depositional dip. This lateral change in composition occurs within the case-study area and will be incorporated into the reservoir modeling. The overlying sand-rich lithofacies of the Kf1b and Kf1c parasequences also vary in thickness within the case-study area. In contrast to the Kf1a, delta-front clinoforms of these parasequences dip less than 5° . Thinning of sand-rich lithofacies occurs in both up-depositional-dip and down-depositional-dip directions due to lateral lithofacies changes. Kf1b may be completely absent in some locations as a result of erosion and/or non-deposition. Modeling of Kf1 parasequences will aid understanding of reservoir production in fluvial-deltaic deposits that exhibit lateral changes over short distances.

The Ferron No. 2 Sandstone parasequence set (Kf2) contains three parasequences, the Kf2a, Kf2b, and Kf2c. These parasequences show less lateral variation in lithofacies than the Kf1 parasequences, possibly due to greater modification by wave processes. Within the case-study area, there is little lateral variation in thickness of sand-rich lithofacies, even when lateral change occurs from one depositional subfacies to another. Modeling of Kf2 parasequences will improve understanding of reservoir production in fluvial-deltaic deposits that exhibit gradual lateral changes over great distances.

Data input and editing of 1994 field data (measured stratigraphic sections and paleocurrent measurements) into the UGS database began last quarter and ended this quarter. Stratigraphic data were transferred from the database to software which drafted stratigraphic sections and core descriptions. This software generated graphic logs of stratigraphic sections at scales of 1 inch: 2.5 feet (2.5 cm: 0.8 m) and 1 inch: 10 feet (2.5 cm: 3 m) (figure 2). Logs at both scales contain attributes, such as lithologies, sedimentary structures, and parasequence designations. General comments, grain sorting, grain roundness, and degree of consolidation were also noted on the 1 inch: 2.5 feet (2.5 cm: 0.8 m) logs. All attributes will be used to define reservoir components in the statistical and reservoir-modeling parts of the project.

Paleocurrent measurements, grouped by parasequence and by lithologic units composing parasequences, were plotted as rose diagrams (figure 2). Measurements plotted according to parasequence give an overall indication of the direction of parasequence progradation. Measurements plotted according to units within a parasequence give direction of sediment transport of components of the parasequence (for example, distributary channels, mouth bars, or parts of the delta front). In addition, paleocurrent measurements from wave ripples were plotted separately from measurements taken from unidirectional current ripples and cross beds (figure 2). Wave-ripple measurements provide information on direction of waves impinging on and modifying the delta front. Unidirectional measurements provide information on depositional processes that delivered sediments to the deltaic parasequence and can be used in modeling fluid flow in reservoirs.

Most field-interpreted photomosaics in the Ivie Creek case-study area have been redrafted and acetate overlays added which show the interpretation of parasequences and deltaic subfacies (figure 3). The photomosaics will be the base for construction of scaled cross sections. In turn, the cross sections will form the base for construction of the three-dimensional model of the reservoir architecture.

Figure 2. On the left is a log of stratigraphic section IC-PBA-940504-MS2 from the Ivie Creek case-study area (originally at a scale of 1 inch: 2.5 feet) showing lithologies, sedimentary structures, and parasequence designations. The outcrop and orientation of the transect where this section was measured is shown on figure 3. On the right, paleocurrent rose diagrams for several parasequences are displayed: A) shows bidirectional data from Kf2c, B) shows bidirectional data from parasequence Kf2b, C) shows bidirectional data from parasequence Kf1c, and D) shows unidirectional data from parasequence Kf1c.

Figure 3. Part of an east-west oriented photomosaic from the Ivie Creek case-study area, north view, SW1/4NE1/4 section 16, T. 23 S., R. 6 E. The heavy, white horizontal line is a parasequence set boundary and is underlain by parasequence set Kf1 and overlain by parasequence set Kf2. The thin, white horizontal lines are parasequence boundaries. Parasequence Kf1b, normally present between parasequences Kf1a and Kf1c, is not present due to either post-depositional erosion or non-deposition. The marine sandstone of Kf2c is overlain by nonmarine sandstone and shale. The thin, white vertical and steeply inclined lines mark the location of two measured stratigraphic sections. Section IC-PBA-940504-MS1 describes Kf1a and section IC-PBA-940504-MS2 describes Kf1c through Kf2c.

Preliminary Mini-permeameter Results and Interpretations

During the first quarter of calendar year 1995 we completed the first phase of mini-permeability testing and compiled and documented the test results. We also developed and tested a method for generating stochastic permeability fields and modeling subsurface fluid flow. During this quarter the project team chose the part of the study area to be used for the reservoir simulation.

Approximately 110 feet (34 m) of slabbed core obtained from Ivie Creek Nos. 3, 5a, and 9a core holes (figure 4) were tested with an automated mini-permeameter provided by the Mobil Exploration and Production Technical Center. The distance between measurement points on the core ranged from 0.03 to 0.05 feet (0.9-1.5 cm) yielding 1,939 measurements. Core was selected for slabbing and testing after a series of reconnaissance mini-permeability tests were performed on segments of whole core. The reconnaissance results are shown with the corresponding gamma-ray profiles in figure 5. Each hole is approximately "hung" on the gamma-ray peak that represents the approximate interface between the Kf1 and Kf2 parasequences. The plots are arranged in a proximal-to-distal pattern when viewed from left to right (figure 5). Sections of core with higher reconnaissance permeability values were submitted for detailed testing because they provided a reasonable probability that we could obtain a detailed sequence of permeability variation with values above the resolution of the instrument (above 1-2 millidarcies).

Results of the detailed permeability testing and corresponding gamma-ray profiles are shown for Ivie Creek Nos. 9a, 5a, and 3 in figure 6. Visual inspection indicates that the gamma-ray profiles fail to capture variations that correspond to the detailed permeability variations. Additional work is required to more fully explore relationships between the permeability and gamma-ray results. The detailed mini-permeameter measurements capture characteristic patterns of permeability associated with internal elements of the Kf1 and Kf2 parasequence sets.

Core plugs (379 plugs) collected during the 1994 field season have been tested using Mobil's portable mini-permeameter. A subset of these core plugs (220 plugs) was tested using Mobil's Hassler cell equipment. All test results are compiled in a spreadsheet and plotted in graphical form.

Twenty core plugs were collected during the latter part of 1994 from blocks on talus slopes that appear to have fallen from the Kf1a facies in the eastern part of the study area. Permeability measurements taken from these core plugs should aid understanding of permeability variations in what is inferred to be the most proximal exposure of the Kf1a delta-front sandstones.

Mini-permeameter tests on the talus slope cores performed using Mobil's portable equipment, yielded the results shown in table 2. Samples were tested two ways. First, the samples were tested after only brushing off the drill cuttings (unprepared). Second, each sample was washed then dried in an oven for two days in an effort to ensure that all moisture was removed from the samples prior to testing. Apparently, for the samples tested, sample preparation method has little impact on permeability test results.

Permeability (k) test results shown in table 2 are consistent with results obtained for transects T4 and T3 located at progressively more distal positions in the Kf1a lithofacies (see figure 7 for transect locations). Although the T3 and T4 test results did yield k values in excess of 40 millidarcies (md), the higher k values typically fall in the range 10 to 20 md.

Figure 4. Location map for the Ivie Creek Nos. 3, 5A, and 9A core holes. The 2-mile by 2-mile (3.2 km by 3.2 km) detailed case-study site at Ivie Creek is outlined by dark lines.

Figure 5. Reconnaissance permeability data and corresponding gamma-ray measurements, in API units, obtained for the Ivie Creek Nos. 9A, 5A, and 3 core holes. Plots are arranged to present changes in permeability (k, in millidarcies [md]) and gamma-ray profiles that occur when moving from proximal to distal positions within the Kfla.

Ivie Creek 9a

Ivie Creek 5a

Ivie Creek 3

Figure 6. Gamma-ray profile, in API units, and results of both reconnaissance k tests, in md, on whole core (center graph) and automated k tests (right graph) on slabbled core for Kf1 and Kf2 for the Ivie Creek Nos. 9A, 5A, and 3 core holes.

Table 2. Results of permeability tests (k, in millidarcies [md]) for cores from talus slope blocks of Kf1a at Ivie Creek.

Core No.	Unprepared k (md)	Rinsed and Dried k (md)
1	22.55	21.69
2	13.41	10.16
3	2.78	2.17
4	22.85	23.77
5	27.15	31.54
6	6.12	4.93
7	22.07	22.35
8	6.35	5.11
9	10.9	16.9
10	19.62	18.47
11	3.66	3.79
12	0.82	0.8
13	0.83	0.79
14	6.47	11.78
15	1.87	2.05
16	14.42	13.23
17	2.99	3.76
18	2.21	2.26
19	35.53	34.59
20	2.93	2.26

Figure 7. Location of seven permeability transects (vertical and parallel to bedding) in the Ivie Creek case-study area, section 16, T. 23 S., R. 6 E., Emery County, Utah. Base map modified from U.S. Geological Survey Mesa Butte and Walker Flat 7 1/2' topographic maps; contour interval is 40 feet.

Stochastic Modeling and Fluid-flow Simulation

A 2-mile by 2-mile (3.2-km by 3.2-km) region (figures 4 and 8) has been selected as the site where detailed, three-dimensional geological and petrophysical models will be developed as input to a series of reservoir simulations. Data needed for these models will be obtained by geological mapping, outcrop gamma-ray logging, petrophysical measurements on core plugs, and mini-permeameter testing of slabbed core from the Ivie Creek Nos. 3, 5A, and 9A. The simulation study area encompasses both river-dominated and wave-modified sedimentary facies (Kf1 and Kf2) with thickness less than 200 feet (61 m). In addition, a well-defined distributary channel cuts through the upper Kf2 parasequence set.

We anticipate simulating fluid flow through at least three rock volumes at two different scales. We will begin at the interwell scale with a very detailed model of the Kf1a clinoform features found in the vicinity of core holes 5A and 9A. At the larger, reservoir scale we will simulate the dynamic interaction between Kf1, Kf2, and an associated distributary channel. A scaling-up procedure will be used to homogenize and transfer petrophysical information from the very detailed interwell-scale models to the reservoir scale.

A combination of methods will be used to develop the three-dimensional geological models needed to define permeability and porosity distributions in the reservoir simulator. A deterministic approach will be used to build geological models for each of the three model volumes. This effort involves manual determination of facies architecture within the three-dimensional volumes. Once the architecture is determined, values of permeability and porosity are stochastically distributed according to "rules" derived from outcrop observations.

A first step in the process needed to develop stochastic rules is shown in figures 9a and 9b. The interpretations of three characteristic inclined bedforms observed at the Ivie Creek case-study area have been digitized and stored for analysis (dotted lines shown in figure 9a). The solid lines shown in figure 9a indicate that mathematical functions could be derived to recreate similar inclined bedforms in a synthetic two-dimensional model. Although fitting a sixth order polynomial to the digitized curves represents none of the physical processes involved in creating the bedform, a simple fitting process like this could provide a satisfactory basis for generating a set of similar bedforms.

Information contained in figure 9b indicates general trends in factors, that reflect the origin of the bedforms, which control permeability distributions within the inclined bedforms. We anticipate that further study will show that these preliminary inferences will lead to workable rules for generating synthetic permeability distributions within specific facies elements.

The following section outlines the modeling procedure and illustrates a test of the methodology using a two-dimensional data set collected by Barton (1994) at the Cedar Ridge II location approximately 5 miles (8 km) northeast of Ivie Creek. When completed, our modeling study will include a significant three-dimensional modeling component at the Ivie Creek case-study site. The modeling methodology was developed and tested at Mobil's Exploration and Producing Center in Dallas, Texas. Modeling steps include the following:

1. Construct a two-dimensional, deterministic, geologic model.
2. Use outcrop-based petrophysical data to select flow units and construct a two-dimensional model of flow unit architecture that corresponds to the deterministic geologic architecture.
3. Assign permeability values within each architectural element using a stochastic modeling approach.

Figure 8. Perspective view of the Ivie Creek detailed case-study site.

A

B

Figure 9. Developing rules for representing clinoform features within the Ivie Creek Kfla parasequence set involves: A) digitizing typical bounding surfaces to derive geometric rules and B) identifying geological and petrophysical factors that vary in characteristic ways within individual bedforms and bedform sets.

4. Perform fluid-flow simulations that illustrate the influence of reservoir architecture and permeability structure on oil production.
5. Use a homogenization approach to average and upscale the detailed permeability structures.

Steps 1 and 2 - Construct two-dimensional geological and flow-unit models. In developing and testing our modeling procedures we used permeability and architectural data from the Cedar Ridge II location presented by Barton (1994) (figure 10). This data set was selected because architectural data collected at the Ivie Creek case-study site by the project team during the 1994 field season were not yet available. Barton's Cedar Ridge II data were particularly attractive because the field site is located within the Ferron No. 5 Sandstone parasequence set (Kf5) that, at one time, was considered as a possible target for detailed study during the UGS Ferron project. Because the project team has since determined that the Ivie Creek case-study site will provide sufficient insight into the reservoir characteristics of several parasequence sets, the Cedar Ridge II location will not receive focused geological study during the UGS Ferron project.

Figure 10 shows a strike-oriented cross section of laterally continuous Kf5 delta-front deposits with lower to upper shoreface facies associations. A strong, layered appearance is exhibited in this strike-oriented section. Detailed permeability measurements made by Barton (1994) on the vertical outcrop face indicate an increasing upward trend that is very consistent across the entire section (figure 10). Maximum permeability values range up to 450 md and are found in the upper, swaley cross-stratified unit.

The first step in characterizing the permeability structure of a lithofacies map or section is to plot permeability values in both histograms and variograms to get quantitative variations of permeability in each facies. Permeability values associated with each of the more permeable facies types shown in figure 10 are plotted as histograms in figure 11. It is important to note that the histogram plotted for samples obtained from all facies has a log-normal character. This result is consistent with the common observation that permeability histograms developed from reservoir data can often be fitted to a log-normal distribution. The individual histograms plotted for facies 1, 3, and 4; however, each appear to deviate from the log-normal distribution and may be better fitted by a normal distribution. This result, obtained because a large number of permeability values are available within each facies, suggests that the log-normal character typical of reservoir permeability values may reflect the mixing of different permeability distributions associated with each of the different facies.

Both vertical and horizontal variograms are calculated for facies 1, 3, and 4. Sample variograms for facies 1 are shown in figure 12. Experimental variograms constructed for the vertical permeability transects were each fitted using a spherical variogram model. The horizontal variogram shown in figure 12 exhibits a poorly defined sill and range because only eight horizontal locations are available for calculating the variogram. The horizontal variogram model shown in figure 12 is empirically defined assuming a high level of correlation in permeability values separated by distances up to 200 feet (61 m). The high degree of lateral correlation is assumed to result from the apparent lateral continuity of the lithofacies units observed in outcrop.

Step 3 - Assign permeability values using a stochastic approach. Three methods of assigning permeability and porosity in two dimensions to each facies model are used to explore how each step might influence oil production when applied to lithofacies with the particular characteristics of those shown in figure 10. Figure 13.1 shows a digitized version of the facies architecture

Figure 10. Facies architecture and permeability distribution at the Cedar Ridge II location (after Barton, 1994).

Permeability Histograms by Facies

Histograms for Facies 2 ($k = .5$ md) and Facies 5 ($k = 10$ md) are not shown. This is why the count for all facies of the permeability intervals $[0,10)$ and $[10,20)$ is greater than indicated by the individual histograms.

Figure 11. Permeability histograms plotted for the entire set of permeability values and for individual facies 1, 3, and 4 at the Cedar Ridge II location.

Figure 12. Experimental variograms (both vertical and horizontal) with corresponding variogram models computed for facies 1 at the Cedar Ridge II location.

Figure 13. Three different permeability models constructed for the Cedar Ridge II data set by: 1) assigning a facies-specific geometric mean k to each of facies 1, 3, and 4, 2) generating a stochastic, facies-specific k distribution within each facies using sequential gaussian simulation, and 3) generating a stochastic, non-facies-specific k distribution using sequential gaussian simulation. In the facies-specific models the laminated siltstone/mudstone (facies 2) is assigned a uniform k of 0.5 md and the burrowed sandstone (facies 5) is assigned a uniform k of 10 md.

illustrated in figure 10. A two-step procedure is used to construct the permeability models shown in figure 13. First, either the facies-specific bounding surfaces derived from the mapped architecture of figure 10 are explicitly included in the model (for example, the facies-specific models of figure 13.1 and 13.2) or permeability values are assigned without reference to the facies architecture (for example, the non-facies-specific permeability model of figure 13.3). Second, permeability distributions are computed and assigned to mimic the distribution of values shown in figure 10.

Two methods are adopted to distribute permeability values within each model domain. In the first facies-specific case (figure 13.1) the geometric mean k of measured k values is computed and assigned for each of facies 1, 3, and 4. Computed mean k values are 165, 120, and 45 md for facies 1, 3, and 4, respectively. The laminated siltstone/mudstone (facies 2) is assigned a uniform k of 0.5 md and the burrowed sandstone (facies 5) is assigned a uniform k of 10 md. Facies 2 forms the thin, low-permeability layers that separate the other more permeable layers shown in figure 10.

A stochastic approach is used to assign permeability values for the second facies-specific case (figure 13.2) and for the non-facies-specific case (figure 13.3). In both cases a sequential gaussian simulation (SGS) method is used to compute the spatial variation in permeability between the measured values. In the facies-specific case the SGS method is applied within each facies using the appropriate, facies-specific variogram model. As in the previous facies-specific case, facies 2 is assigned a uniform k of 0.5 md and facies 5 is assigned a uniform k of 10 md. The non-facies-specific k distribution shown in figure 13.3 is computed using horizontal and vertical variograms derived for the entire data set. Although facies-specific bounding surfaces are not preserved in constructing figure 13.3, the general trend of increasing permeability with increasing elevation is preserved by applying a vertical variogram model in the SGS method.

Step 4 - Perform fluid-flow simulations. The permeability models shown in figure 13 are input into a numerical simulator to explore the way that each model might influence the production of oil in a waterflood scenario. The characteristics of the model are shown in figure 14. A relatively simple model is used in this test of our methodology. For example, a uniform porosity of 15 percent is applied and a simple injection-withdrawal regime is imposed. The finite difference code TETRADv10 is used to compute the evolution of oil and water saturations through time as water is injected on the lefthand side and oil is extracted on the right hand side of the model domain (figure 14).

Figure 15 illustrates the computed migration of a waterflood through the non-facies-specific permeability model of figure 13.3 at times of 60, 180, and 360 days. The permeability structure clearly influences the effectiveness of the waterflood with the upper-level, higher permeability facies providing a preferred pathway for migration.

Figure 16 provides a comparison of the oil and water saturations obtained for each permeability model after 360 days of injection and production. Although each result shown in figure 16 is similar, the facies-specific models (figure 16.1 and 16.2) clearly show the localized influence of the laterally continuous, low permeability facies on oil and water saturations. The summary results shown in figure 17 confirm that there is little effective difference between each simulation result. For example, cumulative oil production computed for the facies-specific cases is only slightly less than that computed for the non-facies-specific permeability model (figure 17). The similarity between model results suggests that, for strongly layered permeability structures where a long horizontal correlation length relative to the length of the model domain is assigned,

RESERVOIR ROCK AND FLUID PROPERTIES

Initial Pressure	5000 psia
Oil gravity	45 °API
Residual water saturation	0.3
Porosity	0.15
Formation compressibility	2×10^{-6} psi ⁻¹
Oil compressibility	9×10^{-5} psi ⁻¹
Water compressibility	2×10^{-5} psi ⁻¹
μ_{oil}	2.5 cp
μ_{water}	1 cp
Well flowing pressure	3500 psia
Water injection rate	10 STB H ₂ O/day
Isotropic Permeability Tensor ($k_x = k_z$)	
Dead oil, no free gas	
TETRAD v10

Figure 14. Initial value problem used to numerically explore the way that each permeability distribution influences waterflood-assisted oil production from the model domain. The lefthand injection well and right hand production well are each perforated over the entire model section.

Figure 15. Computed evolution of a waterflood at three times after the start of water injection (60, 180, and 360 days) for the non-facies-specific permeability model of figure 13.1.

Figure 16. Computed distribution of oil and water at 360 days for each of the three permeability models shown in figure 13.

Figure 17. Comparison of computed cumulative oil production and cumulative water cut for each of the three permeability models shown in figure 13.

a stochastic approach may be unnecessary if specific bounding surfaces and facies-based permeabilities can be included in the model. In the absence of a realistic architectural model; however, it may be necessary to use the stochastic, non-facies-specific approach in an effort to preserve the obvious vertical variation in permeability illustrated in figure 10. Additional simulations, including the equivalent homogeneous case, will be run to more fully explore this issue.

Summary. We have established and tested a methodology for using a numerical modeling approach to explore the influence of reservoir architecture and permeability structure on oil production. Detailed architectural and permeability models will be based on high-resolution field work performed in our outcrop-based studies of the Ferron Sandstone. Permeability and architectural data to be collected in the 1995 field season will be combined with our 1994 data as a basis for developing a series of three-dimensional flow-unit models using the methods discussed in this report. Although our methodology is tested in a two-dimensional mode, this approach is readily extended to a three-dimension mode.

TECHNOLOGY TRANSFER

The following technical presentations were made during the quarter as part of the Ferron Sandstone project technology transfer activities:

"The Ferron Reservoir Characterization Project: Using Outcrop Analogues to Characterize Fluvial-Deltaic Reservoirs at the Interwell Scale," by S.H. Snelgrove, Guest Lecturer; Los Alamos National Laboratory, Los Alamos, New Mexico, February, 1995.

"Exciting New Oil and Gas Activities in Utah and Overview of Utah Geological Survey Reservoir Characterization Projects," by M.L. Allison; Utah Association of Petroleum & Mining Landmen, Salt Lake City, Utah, March, 1995.

"Integrated Multidisciplinary Reservoir Characterization of a Deltaic System-1: Architecture and Lithofacies of the Cretaceous-age Ferron Sandstone, East-Central Utah," by R.D. Adams, T.C. Chidsey, Jr., and M.D. Laine; American Association of Petroleum Geologists Annual Convention, Houston, Texas, March, 1995.

"Integrated Multidisciplinary Reservoir Characterization of a Deltaic System-2: Developing a Petrophysical Model for Reservoir Simulation Using Data from the Ferron Sandstone, Utah," by S.H. Snelgrove, C.B. Forster, and J.V. Koebbe; American Association of Petroleum Geologists Annual Convention, Houston, Texas, March, 1995.

"Depositional Environments, Sequence Stratigraphy, and Reservoir Quality of a Portion of the Ferron Sandstone, East-Central Utah," by J.A. Dewey, Jr., Spring Research Conference, College of Physical and Mathematical Sciences, Brigham Young University, and the American Chemical Society, Provo, Utah, March, 1995.

Project materials were displayed at the UGS booth during the 1995 annual convention of

the American Association of Petroleum Geologists, Houston, Texas, and at the 1995 regional convention of the Society of Petroleum Engineers, Denver, Colorado.

REFERENCES

Barton, M.D., 1994, Outcrop characterization of architecture and permeability structure in fluvial-deltaic sandstones, Cretaceous Ferron Sandstone, Utah: Ph.D. Dissertation, The University of Texas at Austin, 255 p.

NEXT QUARTER PLANNED ACTIVITIES

Activities planned for the next quarter include:

1. Open-file database of published measured sections, well logs, core descriptions, and available mini-permeameter values. Complete preparation of strip logs generated from the database.
2. Complete plotting locations of measured sections, paleocurrent sites, and gamma-ray and mini-permeameter transects on base maps. Complete production of columnar presentations of measured-section data and rose diagrams of paleocurrents using computer software designed for the display of stratigraphic data. Post paleocurrent rose diagrams on the digital base maps.
3. Complete graphical log displays of gamma-ray measurements taken from outcrops in the Ivie Creek case-study area.
4. Complete cataloging and printing of digitized ground-based and aerial photographs, and construction of photomosaics for regional stratigraphic and case-study analysis.
5. Continue regional outcrop mapping and interpretation. Determine which data locations are to be surveyed in the Ivie Creek case-study area and conduct geographical survey using an electronic distance measuring theodolite. Produce scaled cross sections in the Ivie Creek case-study area based on photomosaic interpretations, measured sections, and the surveyed data locations.
6. Describe the sedimentology and stratigraphy of the three cores drilled by the UGS. Enter the data into the database and draft columnar logs.
7. Begin 1995 mini-permeameter transects in the Ivie Creek case-study area. Document results in spreadsheet and graphic format.
8. Digitize versions of geologic trace maps with a grid. Produce gridded cross sections as a basis for constructing digital fence diagrams. Simulate two-dimensional cross sections mapped by the project field team.
9. Continue quantifying sedimentary and petrophysical data to develop statistical models.