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Improved Oil Recovery in Fluvial
Dominated Deltaic Reservoirs of Kansas - Near-Term

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Abstract

Common oil field problems exist in fluvial dominated deltaic reservoirs in Kansas. The problems are poor waterflood sweep and lack of reservoir management. The poor waterflood sweep efficiency is due to 1) reservoir heterogeneity, 2) channeling of injected water through high permeability zones or fractures, and 3) clogging of water injection wells with solids as a result of poor water quality. In many instances the lack of reservoir management is due to lack of 1) data collection and organization, 2) integrated analysis of existing data by geological and engineering personnel, and 3) identification of optimum recovery techniques.

Two demonstration sites operated by different independent oil operators are involved in the project. The Nelson Lease (an existing waterflood) is located in Allen County, Kansas in the N.E. Savonburg Field and is operated by James E. Russell Petroleum, Inc. The Stewart Field (on the latter stage of primary production) is located in Finney County, Kansas and is operated by Sharon Resources, Inc. The objective is to increase recovery efficiency and economics in these type of reservoirs. The technologies being applied to increase waterflood sweep efficiency are 1) in situ permeability modification treatments, 2) infill drilling, 3) pattern changes, and 4) air flotation to improve water quality. The technologies being applied to improve reservoir management are 1) database development, 2) reservoir simulation, 3) transient testing, 4) database management, and 5) integrated geological and engineering analysis.

The Savonburg Field project results include 1) installation of the air flotation device, 2) database development which includes injection and production data, and reservoir data, 3) development of a reservoir description, 4) completion of a pattern volumetric study to select high potential areas, and 5) completion of a streamtube waterflood simulation. The remainder of Phase 1 will include 1) optimizing the air flotation device for improvement of water quality, 2) pattern changes, 3) optimizing wellbore cleanups, and 4) in situ permeability modification treatments.

The Stewart Field project results include 1) database development, 2) completion of the simulation to history match the primary production, 2) simulation of waterflooding and polymer flooding, and 3) completion of laboratory analysis conducted on reservoir rock. The remainder of Phase 1 will include 1) fine tuning of the reservoir model, 2) conduct an economic analysis to assist in identifying the most economical waterflood pattern, and 3) complete the unitization process in order that a field-wide improved recovery process may be implemented.

Executive Summary

This project involves two demonstration projects, one in the Cherokee Group in eastern Kansas and the second in a Morrow reservoir located in the southwestern part of the state. The Cherokee Group has produced about 1 billion bbls of oil since the first commercial production began over a century ago. It is a billion barrel plus resource that is distributed over a large number of fields and small production units. Many of the reservoirs are operated close to the economic limit, although the small units and low production per well are offset by low costs associated with the shallow nature of the reservoirs (less than 1000 ft. deep). Morrow reservoirs of western Kansas are still actively being explored and constitute an importance resource in Kansas. Cumulative oil production from the Morrow in Kansas is over 174,308,000 bbls. Much of the production from the Morrow is still in the primary stage and has not reached the mature declining stage of that in the Cherokee.

Common problems in both reservoir types include poor waterflood sweep and lack of reservoir management. The poor waterflood sweep efficiency is due to 1) reservoir heterogeneity, 2) channeling of injected water through high permeability zones or fractures, and 3) clogging of water injection wells with solids as a result of poor water quality. In many instances the lack of reservoir management is due to lack of 1) data collection and organization, 2) integrated analysis of existing data by geological and engineering personnel, and 3) identification of optimum recovery techniques.

The technologies being applied to increase waterflood sweep efficiency are 1) in situ permeability modification treatments, 2) infill drilling, 3) pattern changes, and 4) air flotation to improve water quality. The technologies being applied to improve reservoir management are 1) database development, 2) reservoir simulation, 3) transient testing, 4) database management, and 5) integrated geological and engineering analysis.

In the Savonburg Project, the reservoir management portion involves performance evaluation. This work included 1) reservoir characterization and the development of a reservoir database, 2) identification of operational problems, 3) identification of near wellbore problems such as plugging caused from poor water quality, 4) identification of unrecovered mobile oil and estimation of recovery factors, and 5) preliminary identification of the most efficient and economical recovery process i.e., polymer augmented waterflooding or infill drilling (vertical or horizontal wells).

To accomplish these objectives the initial budget period was broken down into four major tasks. The tasks included 1) geological and engineering analysis, 2) waterplant optimization, 3) wellbore cleanup and pattern changes, and 4) field operations. To date the geological and engineering analysis is almost to completion which includes, 1) development of a database which includes injection and production data, and reservoir data, 2) development of a reservoir description, 3) completion of a pattern volumetric study to select high potential areas, and 4) completion of a streamtube waterflood simulation. The field work completed to date includes installation of the air flotation device. The remainder of Phase 1 will include 1) optimizing the air flotation device for improvement of water quality, 2) pattern changes, 3) optimizing wellbore cleanups, and 4) in situ permeability modification treatments.

In the Stewart Project, the reservoir management portion of the project involves performance evaluation. This includes 1) reservoir characterization and the development of a reservoir database, volumetric analysis to evaluate production performance, 3) reservoir modeling, 4) laboratory work, 5) identification of operational problems, 6) identification of unrecovered mobile oil and estimation of recovery factors, and 7) identification of the most efficient and economical recovery process.

To accomplish these objectives the initial budget period was broken down into three major tasks. The tasks are 1) geological and engineering analysis, 2) laboratory testing, and 3) unitization. Due to the presence of different operators within the field, it will be necessary to unitize the field in order to demonstrate a field-wide improved recovery process. The Stewart Field project results include 1) database development, 2) completion of the simulation to history match the primary production, 2) simulation of waterflooding and polymer flooding, and 3) completion of laboratory analysis conducted on reservoir rock. The remainder of Phase 1 will include 1) fine tuning of the reservoir model, 2) conduct an economic analysis to assist in identifying the most economical waterflood pattern, and 3) complete the unitization process in order that a field-wide improved recovery process may be implemented.

Stewart Field Project

OBJECTIVES

The objective of this project is to address waterflood problems in Morrow sandstone reservoirs in southwestern Kansas. The general topics addressed are 1) reservoir management and primary drive performance evaluation, and 2) the demonstration of a recovery process involving off-the-shelf technology which can be used to enhance waterflood recovery and increase reserves.

The reservoir management portion of this project involves performance evaluation and included such work as 1) reservoir characterization and the development of a reservoir database, 2) volumetric analysis to evaluate production performance, 3) reservoir modeling, 4) laboratory work, 5) identification of operational problems, 6) identification of unrecovered mobile oil, estimation of recovery factors, and identification of the most efficient and economical recovery process.

To accomplish these objectives the initial budget period was broken down into three major tasks. The tasks are 1) geological and engineering analysis, 2) laboratory testing, and 3) unitization. Due to the presence of different operators within the field, it will be necessary to unitize the field in order to demonstrate a field-wide improved recovery process.

BACKGROUND

History

The Stewart Field is located approximately 12 miles northeast of Garden City in Finney County, Kansas. The Field is about 1/4 - 1/2 mile wide, 4.5 miles long and is approximately 2400 acres. A location plat is shown in Figure 1.

In August of 1967, Davidor and Davidor drilled the Haag Estate #1 well in the NE NE of Section 12-T23W-R31W, attempting to extend Mississippian production found to the northeast in Section 6. This was the discovery well for the Stewart Field. The Haag Estate #1 well was completed from a basal Pennsylvanian Morrow sand from 4755-4767 ft. for 99 BOPD. Davidor and Davidor drilled two additional producers (Haag Estate #2 and Mackey #1) and one marginal well (Mackey #2) in Section 12 (refer to the well location plat in Figure 2).

In 1971, Beren Corporation acquired the lease and attempted to extend the field to the west with the Mackey #3 located in the NE NW of Section 12. The well was drilled in November, 1971 and temporarily abandoned in June, 1972 after minimal production.

In 1985, Sharon Resources, Inc. drilled the Sherman #1 located in C E/2 E/2 NE of Section 11 and penetrated 45 ft. of Morrow sand. This well was completed for 60 BOPD. This resulted in a more active development of the field. Sharon drilled four more producing wells in Section 11 through 1985 and early 1986, followed by two dry holes. Beren drilled two offset wells on the Mackey lease, both near the west line of Section 12. In 1986, Sharon extended the field north to Section 2 (four producers and two dry holes) on the Nelson and Carr leases. In 1987, Sharon continued a westward extension in Section 3

(four producers and two dry holes) and drilled the Bulger #7-1 east of the Haag lease in the C W/2 SW NW Section 7-T23S-R30W. Four producing wells were drilled on the Meyer lease in Section 10, around 1988, followed by wells on the Scott lease, in Section 4, in 1988 and 1989. Narco leased Section 9 and drilled a total of three producers and one dry hole in the north half of Section 9 during 1988. The eastern end of the field, the Bulger lease, was extended with two more Morrow producers, one St. Louis producer, and three dry holes in 1987.

Some locations were drilled during 1990 and 1991. Competitive forces resulted in development drilling with two additional wells in Section 12, one in Section 4 and three stepout wells in Sections 3 and 10. The Scott 4-8 was drilled in January 1992. During 1994, the final two wells, the Bulger 7-8 and 7-10, were drilled on the eastern end of the field.

The western extent of the field is currently defined by three tight Becker wells on the east edge of Section 5 and a wet Morrow test in Section 8. The eastern extent of the field is not as well defined with a suspected permeability barrier east of Bulger 7-10. Total field development resulted in 43 current producers and 14 dry or abandoned wells.

All wells were drilled through the Morrow, cased with 4.5 or 5.5 inch production casing, perforated through a majority of the net pay interval and stimulated. Most wells utilized approximately 450 ft. of 8-5/8 inch surface casing and a DV or stage collar around 2050 ft. with top stage cement to surface. Early completion practices included acid or diesel break-down jobs. Some wells were hydraulically fractured with gelled diesel. In 1990 and 1991, Sharon Resources implemented a field wide fracture program consisting of a water based gel with 3,000 to 43,500 lbs. of sand. All Morrow wells have currently been fracture stimulated, with the exception of Mackey #1. All wells are produced with pumping units and insert rod pumps.

Three wells within the Stewart Field were completed as St. Louis producers, namely Bulger #7-2, Sherman #5 and Nelson #2-3. The two latter wells have been recompleted into the Morrow, whereas the Bulger #7-2 remains a St. Louis producer with no Morrow sand present.

Pressure

The Stewart Field pressure history consists of drill stem tests (DST's) on 31 producers drilled from August 1987 to October 1991, and two field-wide shut-in surface buildup pressure tests in September 1989 and November 1991. The current average field pressure is estimated to be 100-150 psig.

The first well, the Haag Estate 1, was DST'd 8/14/67 with a final shut-in pressure of 1080 psig. The Haag Estate 2 was DST'd on 1/28/68 with a final recorded pressure of 1102 psig. No extrapolated pressures are available on these wells. Given the good permeability and no pressure depletion in the reservoir, the 1100 psig value is considered representative of an initial stabilized reservoir pressure. Subsequent extension wells proved the continuity of the reservoir over the 4.5 mile length of the field.

The initial two wells were drilled on the Mackey lease in 1968, on the west offset quarter section to the Haag wells. Only the Mackey 1 (SE NW Section 12) encountered productive Morrow sand. It tested with 1102 psig bottom-hole pressure(BHP). No further Morrow wells were drilled until the Sherman 1 was DST'd on 7/10/85. This well is near the east line of Section 11 and showed depleted pressures of 847 psig measured shut-in and 862 psig extrapolated. In the 18 years between 1968 and 1985 the two Haag wells and the Mackey well produced 323,196 bbls of oil. The field was extended west with

drilling from 1985 to 1992. In 1987 the initial wells were offset to the east with the Bulger 7-1 DST having a final shut-in pressure of 718 psig. The latest Morrow DST producer was the Scott #4-8 which had a static BHP of 300 psig in January 1992. Two additional wells were drilled on the Bulger lease in the latter part of 1993 and early 1994. Pressure data on these wells is not available.

In September 1989, surface measured bottom-hole pressure buildup tests were run on 12 wells after 2-6 days of shut-in (depending on the well) to obtain an average reservoir pressure. Bottom-hole pressure calculations and an isobar map resulted in an average reservoir pressure of 575 psig.

In November 1991, the field was shut-in for 4 days and surface measured bottom-hole pressure buildup tests (6 wells) and static fluid levels (31 wells) were used to calculate bottom-hole pressures. Eliminating wells with high fluid levels due to St. Louis water communication, the field-wide average pressure was planimetered to be approximately 215 psig.

Production

Initially most of the wells in the Stewart Field were completed in the Morrow formation. Three wells were completed in St. Louis and Ste. Genevieve initially. Therefore, production is mainly from the Morrow. Production increased approximately 8 fold due to the fracture stimulation work in 1990-1991. There was also substantial increase in water production which is believed to be due to communication with the underlying St. Louis formation.

The Morrow wells have produced approximately 3,365 Mbbl of oil and 1,143 Mbbl of water, through May, 1994. Using decline curve analysis, extrapolation of this production data indicates estimated primary recovery to be 3.88 million barrels of oil. May 1994 average daily production was 600 BOPD.

Gas production from the field has been used to power the pumping units and to fire the gun barrels and heater treaters. Gas volumes were insufficient to market and any excess gas not being used on the leases is vented. No gas volume measurements from the field are available.

Field Data Summary

General

State:	Kansas
County:	Finney
Location:	Section 7, T23S - R30W and Sections 2,3,4,9,10,11,12, T23S - R31W
Well Count:	43 Producers
Operators:	3

Reservoir Data

Formation	Morrow
Elevation (Field Average KB)	2884 ft.
Depth to Top of Morrow Sand	4764 ft.
Temperature	125° F
Original Pressure	1102 psig (estimated)

Average Initial Water Saturation	32.2%	
Area Within Zero Contour of Net Sand Map	1,356 Ac.	
Original Oil In Place (estimated)	22,653	MSTB
Cumulative Production (as of 6-1-94)	3,365.035	MSTB
Cumulative Recovery Factor	14.9%	
Estimated Ultimate Primary Reserves	3,881	MSTB
Primary Recovery Factor	17.1%	
Estimated Incremental Secondary Reserves	3,738	MSTB
Incremental Secondary Recovery Factor	16.5%	
Estimated Primary plus Secondary	7,619	MSTB
Primary plus Secondary Recovery Factor	33.6%	

Rock Properties

Lithology	Sandstone
Average Thickness	26 ft.
Average Porosity (11% cutoff)	16.5%
Arithmetic Average Permeability (from Cores)	138 md.
Compressibility	10×10^{-6}
Archie Equation Parameters:	$a = 1$
	$m = n = 2$

Fluid Properties

Crude Oil -

API Gravity	28
Viscosity at P_i and T_{res}	12.1 cp
Initial Solution Gas-Oil Ratio	37 SCF/STB
Gas Specific Gravity	1.234
FVF at P_i	1.038 RB/STB
Bubble Point Pressure (P_{BP})	180 psig
FVF at P_{BP}	1.045 RB/STB
Compressibility at P_i	$5.83 \times 10^{-6} \text{ psi}^{-1}$
Avg. Compressibility Above P_{BP}	$7.88 \times 10^{-6} \text{ psi}^{-1}$

Produced Water-

Resistivity at 125° F	0.04 ohm-m
Chlorides	55,500 mg/l
Total Dissolved Solids	91,300 mg/l
Compressibility at P_i	$3.07 \times 10^{-6} \text{ psi}^{-1}$

GEOLOGICAL AND ENGINEERING ANALYSIS

Geology Summary

The Stewart Field is situated on the northeastern edge of the Hugoton Embayment of the Anadarko Basin. Morrowan or Atokan aged sands filled an incised valley into the underlying Ste. Genevieve and St. Louis formation of the Mississippian age. This incision occurred from regressive sequences during the period of the Central Kansas Uplift. The incised valley is filled with at least three and as many as six stacked, partly eroded siliclastic sedimentary intervals. Each sequence represents a transgressive and

regressive succession reflecting flooding and then reemergence of the shelf and valley system. Local erosion and reworking of the sediments is common. The sands may be at least partially sourced from erosion of a local sandy Ste. Genevieve limestone. It is believed that marine reworking of the sands from the west contributed to cleaning up the sands. The Morrow reservoir is found at an average depth of 4780 ft. and average 26 ft. in thickness over 1,036 acres.

Log, core and dipmeter data indicate that the deposits prograded from east to west, landward to basinward. The channel thickens from around 20 ft. in the eastern end in Sec. 7-T23S-R30W to around 45 ft. in Sec. 9-T23S-R31W with a notable exception in the east half of Sec. 12-T23S-R31W, where a suspected karstic feature results in 61.5 ft. of gross sand. The lower half of this sand is poorly developed, possibly due to lack of marine reworking. The channel dips 3 to 5 degrees per mile until the paleogradient steepens in the western end of Sec. 3-T23S-R31W before emptying into a deltaic environment with shale and silty sandstones in Sec. 5-T23S-R31W. Deep fault planes or zones of weakness may have contributed to rapid directional changes of the center of the channel.

Sourcing of the reservoir is believed to have occurred along fault lines and porous reservoir rocks from the Woodford shale deep in the Anadarko Basin. A thick black oil stain is found in some of the core samples, possibly indicative of an earlier hydrocarbon migration. The Morrow reservoir is initially underpressured, but a higher pressure region was tested in the west end.

The lithology is described as glauconitic quartzarenite to quartzarenite with varying grain size distribution from very fine to medium sized grains. In some wells, a coarse grained conglomerate is reported at the base of the sand. Samples are typically subangular to subrounded, moderate to well sorted with intergranular to intercrystalline porosity development. Quartz overgrowths are abundant. X-ray diffraction indicates 0 - 6 % clay volume with a majority of smectite along with detrital chlorite and illite.

The fluvial influence of the channel is exemplified by the tributary channels and by the thickening and dipping sand strata towards the west. In addition, the cores show layers of coarse grains fining upwards with numerous instances of cross-bedding within the individual strata.

A strong marine influence is shown by numerous lime streaks. Even though individual lime streaks cannot be correlated across the whole length of the channel, the Pe curve identifies common no flow boundaries across 4-5 well distances. In actual core recovery, these lime streaks were tested impermeable with no oil saturation. An abundance of glauconite, pyrite, coals, shales, fossils, burrows and caleche zones are also found within the sand sequences.

Database Development

All the electric log data for the field were digitized into a computer database. The log data were analyzed by digitizing the Morrow interval of the printed logs using a commercial "Logdigi" computer program by "Logic Group". Existing core analyses and log data were analyzed to find a relationship between core porosity versus log porosity and porosity versus permeability. A cumulative porosity plot was used to determine a porosity cut-off as related to net pay. The porosity cut-off was determined to be 11%, which corresponds to about 8% of the total porosity feet. Net pay thicknesses for individual wells were completed using this porosity cut-off value. A net pay map was constructed for the purpose of the waterflood feasibility study. This map was planimetered to determine the reservoir volume of the Morrow and oil recovery factors.

Water saturation calculations from electric logs were done in order to be included in the database. The water saturations could not be calculated with sufficient accuracy to tabulate values for individual wells. Key problems identified were thin bed effects, thin conductive beds from pyrite cementation material, and conductive chloride clays. Capillary tests on cores were employed to estimate initial water saturation.

Production data for all wells in the Stewart Field was also entered into the computer database. Production data was tabulated by month since the discovery of the field. The wells have been grouped by tank battery so that allocations for each well can be monitored. The production was allocated to each well by monthly barrel tests. Water production was estimated by applying the percent of water as determined by a grind-out test and relating that to the oil volume produced. The sales numbers for each tank battery were also listed to compare with the production numbers supplied by the operators. Production was divided between Morrow and non-Morrow for the wells that had produced from other zones. Gas production from the field is minimal and is used to power the pumping units or vented.

The Stewart Field pressure history, including drill stem tests (DST) conducted on 31 wells, two field wide shut-in surface pressure tests, and individual well fluid level tests was also tabulated into the database. Pressure tests indicate the continuity of the reservoir over the 4.5 mile length of the field. Isobar maps were constructed for the field. Pressure history of all DST's, shut-in pressures, bottomhole pressure (BHP) from fluid levels, and BHP versus cumulative production plots were made for each well and the entire field.

A log stratification study was completed which indicated the Morrow formation can be divided into as many as eight different flow units. Three main flow units were identified as separate depositional sequences that appear to possess similar porosity and permeability characteristics. These three flow units correlate along the deepest parts of the channel, with some minor discrepancies within the thinner boundary wells. The three flow units were identified as the Red zone on top, Purple zone in the middle, and Yellow zone on the bottom. The depth and subsea elevation for the top and bottom of each zone was entered into the database for each well.

Porosity and resistivity log data (foot by foot) was cross plotted on log-log paper (Pickett plot) keeping track of depth trends. The three primary zones in the Morrow formed distinct clusters of points on these plots indicating that the zonation identified nicely groups the levels of heterogeneity. While most of the field is above the oil-water contact, several wells in the west half of the field indicate a transition zone and water leg.

Wettability tests, petrographic data, and standard core analysis was compared as series of plots with log analysis results to define correlations. In particular, relationships between bulk volume water (water saturation and porosity) and relative permeability data, grain size and sorting, and mineral composition (clays) were sought.

Permeability was estimated using different relationships utilizing porosity and water saturation. One method investigated was the Timor relationship. This empirical relationship provided only fair results when comparing measured core permeability versus estimated permeability.

The possibility of open fractures in the Morrow reservoir was evaluated through three potential sources of information:

1. 4-arm dipmeters from the reservoir to examine for borehole breakouts to establish minimum horizontal compressive stress direction.
2. Paleomagnetic measurements of core samples to orient the cores to define directions of any open fractures that might be present.
3. Examination of the oriented core from the Sherman #3.

The presence and characterization of fractures helped to define any anisotropy in the reservoir in addition to the influence of sedimentary structures on fluid flow.

Volumetric Analysis

Decline curve analysis from existing production data was completed for all the wells within the field. Utilizing a straight exponential decline analysis, calculated remaining primary reserves as of June 1, 1994 are 516,000 barrels of oil for an ultimate primary oil recovery of approximately 3,881,000 barrels. A plot of the field production is shown in Figure 3.

Over the last year a substantial flattening of the production decline has occurred for many leases, as more of the field is affected by gas expansion.

Material Balance

Material balance calculations were performed from initial pressure to the 1989 and 1991 field wide tests. Assuming no water influx and pressure above the bubble point, the fluid produced should be due to fluid and rock expansion over the given pressure drop. These calculations give original reserves in excess of 100 million barrels of oil in place. Volumetric mapping of the net sand indicates only 22 million barrels in place.

It was determined that uncertainties in fluid and rock properties would not resolve the difference in determining the original oil in place between volumetric mapping of the net sand and material balance calculations. Either a large volume of the reservoir has yet to be defined or a limited water influx (pressure support) exists within the field.

Development drilling and seismic data indicate that the reservoir boundaries are defined with reasonable certainty. Therefore, potential pressure support sources were investigated and identified. This was accomplished through the geological examination of well logs and drill stem test data from locations adjacent to the field. A complete collection of well logs from adjoining areas to the field was assembled.

Three potential sources of pressure support were identified. A water aquifer associated with the Morrow formation is present at the west end of the field. Underlying formations, the Ste. Genevieve and St. Louis, appear to be in communication with the Morrow reservoir in certain areas of the field.

Polymer Flood Analysis

Relative permeability tests were conducted on cores taken from the Stewart Field. Using the endpoints from the relative permeability curves, mobility ratios were calculated. All the mobility ratios calculated based on the average saturation behind the flood front were less than 1.0, which is highly favorable.

Analysis was conducted utilizing the Polymer Flood Predictive Model developed by Scientific Software-Intercomp for the National Petroleum Council's (NPC) 1984 survey of U.S. enhanced oil recovery potential (NPC, 1984). Using average reservoir properties the model did not predict significant incremental amounts of oil recovery for polymer flooding versus waterflooding. Figure 4 is a plot illustrating the results of this analysis.

Based on these findings there is no justification for considering a polymer flood in this project.

Reservoir Modeling

Independent reservoir simulation studies were undertaken by Sharon Resources and the University of Kansas. Sharon Resources, located in Englewood, Colorado, was connected via Internet to the workstation at the University of Kansas. The studies are being performed using a Silicon Graphics workstation with Western Atlas VIP Executive simulation software. The VIP simulator is a conventional black oil simulator, equipped with graphics interface. A major portion of the technology transfer associated with this budget period pertains to University personnel assisting Sharon Resources in their simulation efforts.

The objectives of each study consisted of: (1) the characterization and distribution of the various reservoir parameters, (2) a material balance model to establish a history match with the primary production, and (3) a waterflood predictive model to select the optimum waterflooding pattern for maximum economic oil recovery. The independent studies resulted in different models, however, the two models provide similar results.

Overview of Reservoir Simulation

A. Introduction

Reservoir simulation is a tool to increase profitability of a reservoir through proper reservoir management. Simulation can be a tool to determine optimum well pattern and spacing, design of a facility, optimum recovery method, optimum well completion, etc. Simulators can also be used to match the history of the reservoir with updated seismic and geological data. It can serve as a tool to judge the actual performance of the reservoir and also predict the future performance. Based on the predictions, proper reservoir management can be applied to reduce operating costs and thereby increasing profitability.

B. Data Requirements

The approach for reservoir description entirely depends on the available reservoir database. Data required for a reservoir description can be classified as follows:

1. Rock property data at initial static conditions.
 - a. Formation structure: Tops and bottoms of the formation.
 - b. Net pay thickness.
 - c. Porosity at initial pressure.
 - d. Drainage and capillary pressure data.
2. Fluid properties at static conditions.
 - a. Oil, gas and water formation volume factors.
 - b. Oil, gas and water densities at standard conditions.
3. Rock and fluid data for oil/gas displacement
 - a. Absolute permeability of rock.
 - b. Gas and oil relative permeability curves.
 - c. Formation, oil and water compressibility.
 - d. Oil and gas formation volume factor as a function of pressure.
 - e. Gas in solution as a function of pressure.
 - f. Oil and gas viscosity as a function of pressure.
4. Rock and fluid data for water/oil displacement
 - a. Oil and water relative permeability curves.
 - b. Water formation volume factor as a function of pressure.
 - c. Water viscosity as a function of pressure.

Porosity and permeability distributions are normally derived from core analysis, well-log, and well test data. The most difficult reservoir property to define is the permeability distribution areally and vertically between wells. Adequate knowledge of permeability distribution is more important than the porosity to understand the flow of reservoir fluids. Porosity can be measured by logging, but permeability cannot be measured reliably by logging. Thus, it is necessary to estimate the permeability from permeability/porosity correlations developed from core analysis data. Correlations will be most reliable if they are developed for each major rock type present in the reservoir.

After developing the reservoir description, it is necessary to test the description. This is carried out by matching the available history of the reservoir. Simulation of the past history can identify the weaknesses in the reservoir description and modifications to the description can then be implemented. In some cases the reservoir description is changed to match the history, considering that the changes should be rational and consistent. History matching can also be used to study the current status of the reservoir, to identify the depletion mechanism, and to determine the fluid distribution in the reservoir.

Simulation Conducted at the University of Kansas

A. Data Availability

Necessary data required for simulation was provided by Sharon Resources. The most important data for reservoir description is the porosity /permeability correlations for the three major zones within the Morrow. These correlations were derived by Sharon Resources and the results of the correlations were used in the simulation for distribution of properties in the reservoir. Relative permeability data representative of the field was also required. This data was also supplied by Sharon Resources.

B. Reservoir Description

The Stewart Field model was developed in stages. Sharon Resources initially identified the three major pay zones in the reservoir. Based on core/log and permeability/porosity correlations they assigned porosity and permeability values to the zones present in all the producing wells. Digitized logs were also provided to get the tops and bottoms of each zone. Initially it was decided to divide the field in four different sections (Figure 5), which were assumed to be isolated from each other. The first section of the field consisted of the Sherman, Nelson, Carr and Mackey leases. These leases comprise 912,000 barrels of oil production from the Morrow, which is approximately 35% of the total field production from the year 1985. The assumptions used to match the production history of this section were also used in the subsequent sections.

Initially it was necessary to assign X and Y coordinates to each well from a zero reference point. The NE corner of section 10 was chosen as the zero reference point. Refer to Figure 6.

To identify the distributions in the regions between the wells, it was necessary to contour the tops, bottoms, porosity, permeability and water saturations of each zone. Data files were created and CPS Radian software was used for contouring. Due to the absence of control points, other than the wells, CPS Radian mathematically extrapolated the reservoir boundaries. In order to get a more accurate reservoir description, about 100 Dry holes were introduced around the reservoir to force a NO FLOW boundary in the desired locations. The necessary files were converted to a format which was acceptable to the VIP black oil simulator's GRIDGENR, a preprocessor program to generate grids graphically for simulation purposes.

C. Reservoir Simulation using VIP Simulator

The VIP black oil simulator was developed by Western Atlas Inc.. It is one of the most powerful commercial software packages available for reservoir simulation. Its graphic interface enables the user to import geological and other data from various engineering and geological software. GRIDGENR is a utility of VIP which allows the user to import reservoir parameters in the form of contours. Based on the grid system selected, it calculates and assigns values to each grid block.

Using the VIP PRCORE utility, all rock and fluid parameters were input and the necessary data files relating to the formation structure, porosity and permeability distribution were imported into GRIDGENR. The initial simulation grid of 150x20x3 blocks was created and the values were calculated using the program. This allowed creation of the VIP-CORE initialization module file.

Once the initialization file was created, the next step was to create the VIP-EXEC file. This file consists of the history of all the wells which includes location, date of completion, perforation intervals, wellbore radius, skin factor, stimulation history, production history, pressure constraints, and any other information related to the wells. All relevant information was provided by Sharon Resources. Using the VIP PREXEC utility, all data was imported and a recurrent run file was created. The field consists of 44 producing wells. The locations of the wells in the simulation grid system are shown in Figure 7.

D. History Matching of Primary Production

The model had the following initial assumptions:

1. Initial reservoir pressure was assumed to be 950-1000 psi (depending on the first date of production in the four sections). No external pressure support was provided.
2. The reservoir was under natural depletion drive.
3. There was no initial skin damage on the wells.
4. Based on the pressure buildup tests an average skin factor of -3 was assigned to each well after the fracture stimulation work.

Several cases were run to get an optimum history match of each section. The details of the simulation results for section "C" consisting of Sherman, Nelson, Carr and Mackey leases are enclosed in Appendix A. Similar assumptions were used for all the other three sections. The following is a summary of the assumptions used and changes implemented to the field description in order to obtain a history match of the primary production of the four sections.

1. Permeability of the reservoir was increased by a factor of 2. Justifications for this could be that there was uncertainty in the porosity permeability correlations developed using the core/log data or damage to the cores during the drilling process.
2. Reservoir volume was added to the northern portion of the Nelson and Carr leases. This led us to question whether the reservoir boundaries have been properly defined in this area.
3. Outside pressure support was included. It appears most logical that this support is coming from the underlying Ste. Genevieve/St. Louis formations. This would result in the primary drive mechanism being a combination of depletion drive and water influx.
4. The initial skin had to be changed to +1 and the average skin after fracture stimulation remained at -3 for all wells. This post fracture skin used in the simulator is in agreement with the pressure transient analysis where the post fracture stimulation skin is within the range of -2.8 to -3.6.
5. The initial reservoir pressure was 1200 psi and the pressure of the underlying formation was assumed to be 1500 psi. Initially it was assumed that the underlying formation was in pressure communication with the entire field, but based on the geological analysis and production history it was observed that the direct communication of the permeable underlying formation is in the area of the Mackey and Scott leases. This assumption was built into the model in order to describe the reservoir more realistically.

Based on the above assumptions the model was developed. An external aquifer, as described above in assumption 5, was included as the fourth layer in the model. None of the wells were perforated in the fourth layer.

A model of the entire field was developed. The model was built using a grid of 150x20x4. Each gridblock had average dimensions of 190 x 250 ft. The resulting model had about 2-3 gridblocks between each well. The model contained a total of 12000 gridblocks. The OOIP for this model was 25256 MSTB. This figure does not match with the estimated OOIP based on the net sand map provided by Sharon Resources. One reason for this discrepancy could be the uncertainties associated with the reservoir boundaries. The following parameters were added to the reservoir description to obtain a history match.

1. Water saturations in the four layers:

Layer 1 : 31 %

Layer 2 : 31 %

Layer 3 : 31 %

Layer 4 : 99 %

2. Vertical permeability distribution within and between the layers.

Layer 1 : $K_z = 0.05$

Layer 2 : $K_z = 0.01$

Layer 3 : $K_z = 0.05$ Only at the west end and in section 12.

Layer 4 : $K_z = 0.05$ Only at the west end and in section 12.

The vertical permeability in the rest of the field in layers 3 & 4 was zero.

3. Initial pressure for the layers:

Layer 1 : 1200 psi

Layer 2 : 1200 psi

Layer 3 : 1200 psi

Layer 4 : 1500 psi

These values provided a primary history match in which the simulated production was 95.74% of the actual production. The actual and simulated results are plotted in Figure 8.

This was assumed to be a representative model of the field. This model looks different from the actual field in certain aspects, but it behaves similar to the actual reservoir in terms of the production and pressure history. One of the reasons for possible discrepancies could be the description of the reservoir properties within the interwell region. Many different models are capable of producing a history match for the same field.

E. Waterflood Simulation

Reservoir simulators have served as an effective tool to predict and design the optimum recovery processes. The VIP simulator has the capability to simulate many of the enhanced oil recovery processes, including waterflooding. During the initial stages of this study it was observed that the mobility ratio was favorable for waterflooding. Thus, there was minimal incremental increase in oil production due to polymer flooding. Polymer flooding was analyzed using the DOE streamtube waterflood/polymerflood predictive model. Based on the results of the predictive model, it was decided to design an optimal waterflood recovery pattern.

F. Waterflood Patterns Investigated

Six different patterns were proposed by Working Interest Owners (WIO) and University personnel. The injection rate was restricted by the water availability of about 6000 BWPD (as informed by Sharon Resources). Thus, in each case the total water of 6000 BWPD was distributed equally between each injection well within the waterflood pattern. The following are the different waterflood patterns. Each table includes the proposed wells to be converted to injection and/or to be drilled, the maximum injection rate in BWPD and the maximum bottom-hole pressure for the well.

1. 3 Line Drive (illustrated in Figure 9)

Name of Injection well	Max.Injection rate	BHP of Injection well
Haag 4	1000	3000
Mackey 1	1000	3000
Nelson 2-2	1000	3000
Nelson 2-3	1000	3000
Sherman 3-5	1000	3000
Meyer 10-3	1000	3000

2. 5 Line Drive (illustrated in Figure 10)

Name of Injection well	Max.Injection rate	BHP of Injection well
Bulger 7-11 **	667	3000
Mackey 1	667	3000
Mackey 6	667	3000
Nelson 2-1	667	3000
Carr 2-1	667	3000
Meyer 10-1	667	3000
Meyer 10-5	667	3000
Scott 4-1	667	3000
Pauls 9-2	667	3000

** This well is to be drilled in the west end of the section 7.

3. 7 Line Drive (illustrated in Figure 11)

Name of Injection well	Max.Injection rate	BHP of Injection well
Bulger 7-11 **	545	3000
Haag 4	545	3000
Sherman 1	545	3000
Nelson 2-1	545	3000
Carr 2-1	545	3000
Sherman 3-2	545	3000
Sherman 3-5	545	3000
Meyer 10-3	545	3000
Meyer 10-4	545	3000
Scott 4-4	545	3000
Scott 4-7	545	3000

** This well is to be drilled in the west end of the section 7.

4. Beren's Pattern (illustrated in Figure 12)

Name of Injection well	Max.Injection rate	BHP of Injection well
Bulger 7-1	667	3000
Mackey 6	667	3000
Sherman 2	667	3000
Nelson 2-1	667	3000
Sherman 3-1	667	3000
Meyer 10-5	667	3000
Sherman 3-5	667	3000
Scott 4-7	667	3000
Pauls 9-2	667	3000

5. Narco's Pattern (illustrated in Figure 13)

Name of Injection well	Max.Injection rate	BHP of Injection well
Bulger 7-4	1000	3000
Haag 4	1000	3000
Sherman 2	1000	3000
Sherman 3-1	1000	3000
Meyer 10-2	1000	3000
Scott 4-2	1000	3000

6. TORP's Pattern (illustrated in Figure 14)

Name of Injection well	Max.Injection rate	BHP of Injection well
Haag 4	1000	3000
Haag 2	1000	3000
Carr 2-1	1000	3000
Sherman 3	1000	3000
Meyer 10-1	1000	3000
Meyer 10-5	1000	3000

All the above patterns were run for a waterflood period of ten years. The production wells were set to a watercut limit of 90%. During the waterflood predictive runs convergence failures were observed. To avoid excessive failures, timestep control was implemented in the simulation. Timestep control restricts the maximum change in the saturation profiles, pressure, etc, in order to avoid convergence failures by solving the fluid flow equations at small time intervals. This has no significant effect on the calculated results.

G. Analysis of Waterflood Results

Each of the six proposed patterns were simulated for waterflood prediction, using the above referenced criteria. This simulation is currently in progress and the final results have not been obtained. Results reported here are based on preliminary analyzes.

H. Conclusions of the Waterflood Simulation

The Stewart Field shows favorable results for waterflood. Simulation results are based on assumptions and accuracy of the field results cannot be achieved. The following conclusion can be derived for waterflood prediction based on the simulation results.

1. Based on the simulations, the cumulative oil production and the WOR for all the patterns would vary by less than 10%.
2. Simulation results suggest that the total oil recovery is a function of the volume injected, but not a strong function of the injection pattern.

Simulation Conducted by Sharon Resources

The simulation conducted by Sharon Resources was designed in two phases. A two-dimensional (2D) study was done with radial and linear models using a range of reservoir characteristics and sensitivities. Also a three dimensional (3D) study was conducted to history match the Morrow production history and predict the optimum waterflooding pattern.

A. Two-Dimensional Study

The objectives of the 2D simulation were to study oil recovery changes as reservoir characteristics varied within a range of known field data. This would acquaint Sharon Resources personnel with the simulator, assist in the understanding of the reservoir, and would also help simplify history matching in the 3D simulation. The following objectives were stated:

1. In a radial model, history match a typical fracture stimulation response.
2.
 - a. In a linear model, study the effect of layering and cross-flow between layers. Study oil recovery as a function of permeability variation and permeability ordering.
 - b. Study the impact of wells with St. Louis communication. Study the effect of shutting in first line producing wells at various water cuts and converting them to injectors.
 - c. Vary relative permeabilities and capillary pressures within known field parameters to ascertain their effect on oil recoveries.

1. Radial Model

Sherman #3 was selected as the well to model via radial simulation. The well has good logs with clearly identified flow units, core analysis, pre- and post-stimulation pressure transient analysis and is an excellent example of the increased production rates obtained from hydraulic fracture treatments. The purpose of the radial model was to history match the fracture results.

Core porosities and permeabilities were used to represent eight layers identified from the logs. Production declined from a peak rate of 47 BOPD in January, 1986 to 3 BOPD in October, 1990. The well was fractured in November, 1990 with 11,000 gallons of 40 lb. Boragel with 1,300 lbs. 100 mesh sand and 18,200 lbs. 20/40 sand. Production reached a stable rate of around 120 BOPD before declining to 13 BOPD in December, 1993. This production response cannot be explained by changing from a +1 pre-frac skin to a -2 post-frac skin factor, but must be augmented by additional thickness opened at the wellbore. An eight layer radial model with 20 concentric cylinders with increasing radii away from the wellbore was used to match production from a 32 acre drainage area. The production could not be matched by depletion drive alone without substantial pressure support. This support is likely water influx, possibly from hydraulic fractures communicating with the St. Louis. It was also necessary to double the core permeabilities to match the actual flow rates.

The after-frac peak production rate was best modelled by adding a large outer cylinder of water reservoir, surrounding the drainage area, to represent an external pressure source. A no-flow boundary was needed to isolate half of the reservoir at original pressure. Half of the thickness was initially perforated, with the pressure support, and allowed to produce down to the pre-frac rate. The fracture was then responsible for opening up the other half of the thickness, releasing oil that was still at original pressure, matching the production increase. This is a plausible explanation as several shale and limestone streaks are evident in the core and pressure support could be seen from different sources.

The external pressure source and isolation of part of the reservoir accomplished the goal of approximating the well's performance. The model did not sustain the peak rate for as long as the actual production, but this can be accomplished by increasing the drainage area. Figure 15 shows the model performance. The model requires a pressure constraint at the producing well. The well was allowed to produce at the actual rate if the BHP stayed above 50 psi. If the actual rate was too great and required a lower pressure than 50 psi, the pressure limit was invoked thereby reducing the rate at which the well could produce. The model performance shows that the well is able to produce at the actual rates while keeping the well essentially pumped off as evidenced by the pressure staying above 50 psi but not exceeding 200 psi. The only portion of the plot where the well is unable to keep up with the actual production is the extended peak rate after the frac.

2. Linear Model

a. Layering, Cross-Flow, Permeability Variation and Ordering

The linear model was built using $25 \times 5 \times 8$ gridblocks in the X, Y and Z directions, respectively. Each gridblock is 55 feet in the X and Y direction and 5 feet in the Z direction. One well at each end of the model approximates the 40 acre spacing seen across most of the field. (this is referred to as a 2D model since the purpose of including the Y-direction was to judge the directionality of the solution algorithm and not to describe the width of the channel.) The flow units were described by eight layers, two in the Red (top) and Purple (middle) and four in the Yellow (bottom). Eight layers represent the maximum amount of flow units identified in any well and was felt necessary to adequately describe the reservoir with a proper permeability variation. Since the permeability-porosity transforms are based on log analysis that averages data over several feet, the permeabilities calculated from the logs are too uniform. As an example, Sherman #3 plotted a permeability variation (V) = 0.7 from point specific lab measurements, but $V=0.3$ based on the log transforms. The linear model was run at $V=0.3$, 0.5 and 0.7 to quantify how much the log derived permeability transforms over-estimate waterflood performance. The results are shown in Figure 16. The recovery of reserves in a 2D model is very high as each layer will flood out eventually and areal sweep is complete for each case. Therefore, comparing ultimate recovery is not an indication of waterflood performance. The method chosen to compare waterflood performance in the 2D study is the number of months to recover 72,000 barrels of oil. The more efficient floods will have later water breakthrough, thereby recovering more reserves sooner and without the added operational cost of produced water. The $V=0.7$, 0.5 and 0.3 cases recovered 72,000 BO in 47, 28 and 24 months respectively. The 0.3 permeability variation case recovers the oil in almost half the time of the case with $V=0.7$.

The different permeability variation cases were all run with 1 md. of cross-flow between layers. The effect of cross-flow on a reservoir with $V=0.7$ was studied at 0, 1 and 100 md. The model uses the vertical permeability as the permeability to flow between the gridblocks. Figure 17 show the 0, 1 and 100 md. cases recovered 72,000 BO in 48, 47 and 27 months, respectively. The no-flow barriers isolate

the layers creating different pressure profiles in each layer. Cross-flow between layers allows the pressure to equalize so that a uniform pressure drop from the injector to the producer exists across all the layers. Based on these results, wells with low stratification would make better injection wells.

The impact of permeability ordering was seen to be negligible in the case of wells with no-flow boundaries. This was expected since cross-flow is not occurring and the pressure transients move through each zone individually with no effect of gravity. What was more surprising, however, was the small effect of permeability ordering in the presence of vertical permeability.

Sensitivity to number of layers was tested by comparing a three layer model with the eight layer model to see the validity of representing a $V=0.7$ with only three layers. Figure 18 show that three layers recover 72,000 BO in 37, 31 and 24 months for the 0, 1 and 100 md cases, respectively. This is an improvement of 23%, 34% and 11% over the eight layer model with the same vertical permeability. The difference is caused not from the difficulty of representing a $V=0.7$ with three or eight data points, but from the vertical permeability. Seven no-flow barriers exist in an eight layer system as opposed to only two in a three layer. At low vertical permeability this causes considerable differences. Increasing vertical permeability reduces the contribution of the barriers and puts more priority on the permeability variations. At high vertical permeability a three layer system only differs from an eight layer model by 11%.

The continuity of layers must be considered. The low vertical permeability in the Stewart Field would suggest that more layers are required, but if the eight layers are of limited extent it may not be necessary to model that many layers. The following cases are defined as follows:

- Case 8 > 3: Eight layer model with seven no-flow barriers in the injector and two no-flow barriers in the producer.
- Case 3 > 8: Same as above, inject from the other direction.
- Case 8: Eight layer model, vertical permeability = 100 md. with two no-flow barriers.
- Case 3-0: Three layer model with two no-flow barriers.
- Case 8F: Eight layers, vertical permeability = 100 md., communication in all layers near well-bore, two no-flow barriers.
- Case 3F: Three layers, vertical communication near well-bore (100 md.), two no-flow barriers.

Again, comparisons are based on time to breakthrough and time to recover 72,000 BO. Case 8 > 3, with the more stratified well used as the injector, showed water breakthrough in 12.6 months, two months sooner than Case 3 > 8. A well with more uniform stratigraphy makes a slightly better injector, but the two cases were not much different. Case 8 had slightly later breakthrough (15.7 months) and recovered the reserves in the same amount of time as Case 3 > 8. Therefore, it is not necessary to model eight layers if the no-flow barriers are discontinuous.

Case 8 was compared to Case 3-0 to see if a vertical permeability variation of 0.7 is better described with eight layers as opposed to three layers if only three continuous flow units exist in each well. The three layer case has water breakthrough in 15.2 months as compared to 15.7 months for the eight layer, but it recovers the reserves much faster than the eight layer model (35 months vs. 43.8 months). In comparing results with $V=0.7$, with three vs. eight layers, breakthrough occurs in the high permeability layer at about the same time. The three layer model is more efficient and results in more optimistic results regarding reserve acceleration.

Cases 8F and 3F were designed to study the same effects as above where fractures result in communication around the wellbores. Note, both cases have only two no-flow barriers. The results were similar to the comparison of Case 8 and 3-0 in the preceding paragraph. The eight layer model showed no difference between the fractured and non fractured cases. The three layer model has a three month delay in breakthrough and recovers reserves three months sooner than the non-fractured. Figure 19 compares the 3F, 8, 8F and 8>3 cases. The three layer results are slightly optimistic as compared to the eight layer. Therefore, the configuration used in the 3F case will be used in the 3D simulation.

b. St. Louis Communication

The effect of communication with the St. Louis in a linear model was duplicated by a thick, water aquifer underlying the Morrow. A third well was inserted between the two previous wells in the center block (20 acre spacing). No vertical flow was present between the Morrow and St. Louis except in the one gridblock containing the center well. A vertical permeability of 1.0 md was allowed in the 55 foot by 55 foot block containing the well to simulate the conductivity of a hydraulic fracture into the St. Louis. The pressures in the Morrow and St. Louis were 200 psia and 800 psia, respectively. The cases were run on a $V=0.7$ and $kz=1$ md in the Morrow. The center well was shut-in at different watercuts to determine the optimum time to shut-in the well and to observe any cross-flow into the St. Louis.

The first model had a fixed injection rate of 110 BWPD (approx. 1 ft/day advance rate in the reservoir). The center well was shut-in at 0 (not producing), 50, 80 and 98 percent watercut. Figure 20 shows that the center well accelerates recovery of reserves. The cumulative production after one year is 36,000 BO, 36,667 BO, 42,000 BO and 42,000 BO for the 0, 50, 80 and 98 case, respectively. Although producing the first well at high watercuts (80% and 98%) recovers more oil in the first year, producing the injection water is not cost effective as compared to keeping it in the ground. Shutting in the first line producer as soon as it begins to cut water allows the flood front to advance to the next well.

The model allows for injection to be controlled by a constant rate or constant injection pressure. The bottom-hole pressure in the 110 BWPD case remains low enough that no cross-flow into the St. Louis occurred. Another case was run with the bottom-hole pressure in the injection well held constant at 3000 psia. The rate was allowed to vary to accommodate the pressure. Again, the recoveries were accelerated by producing the center well with the added cost of handling more produced water. A producing well pressure limit of 400 psia on the 40 acre producer was able to keep the pressure low enough at the center well to prevent cross-flow. Therefore, it appears that a communicated well may be shut in without the reservoir pressure building high enough to cross-flow into the St. Louis. This would need to be verified in the field with BHP tests in the communicated wells. Initial water influx from the St. Louis into the base of the Morrow was seen in both cases.

B. Three Dimensional Study

The 3D study was divided into a material balance (MB) study and a reservoir description study. The objective of the MB portion of the simulation study was to utilize the simulator as a volumetric tool to establish a history match with the primary production. More attention was paid to reservoir volumes and areas of influx than to detailed reservoir description.

The results show that reservoir volume of the Morrow channel is insufficient to match produced volumes from depletion drive alone. The study identified three possible sources of influx that may contribute to the reservoir performance. These sources are 1) a Morrow or St. Louis reservoir

communicated at the west end of the channel, 2) a juxtaposed productive Ste. Genevieve found in the E/2 of Section 11, Section 12 and the W/2 of Section 7 and 3) Mackey #3 (a temporarily abandoned well with fracture stimulation into the St. Louis, isolated behind a bridge plug).

The MB simulation was done with a two layer model to reduce computer run time associated with multiple layer models. The Morrow channel for the Stewart Field is represented by a single layer of varying thickness and average reservoir characteristics. The second layer serves as the source for "other" zones that may provide pressure support.

A net sand map shown in Figure 21 was digitized using GridGenerator software included in the VIP Program package. The Morrow interval was mapped on screen and included some dry holes within the area mapped. However, the volume of the map calculated a satisfactory 26,468 MSTB OOIP. The field was mapped to include the production from the Chief operated wells found in Section 8, T23S-R30W. These wells were drilled beginning in July of 1990 and had a discovery pressure around 700 psig. The less than original pressure found in this section may have been an indication of pressure communication with the Stewart Field, but this was later found to be questionable. The final match did not include the estimated 86,000 barrels of oil produced from the Chief wells as part of the MB. The volume mapped for the Chief wells was left in the model to compensate for additional Morrow reservoir beyond the Bulger 7-10 or in the N/2 of Section 7.

A thick (up to 100 feet) aquifer was modelled underlying the Morrow that represents multiple geologic intervals. This "influx" zone was divided into four sections, as shown in Figure 22, using zero permeability barriers around each section. This was done to prevent pressure communication between the influx zones and to reduce the number of gridblocks required to study three or four layers. The GridGenerator puts an overlying grid on the maps and assigns reservoir parameters to each gridblock including: structure top, gross and net thickness, porosity, water saturation and permeability in the X, Y and Z directions. The grid orientation chosen for this run had 100 blocks along the channel (east - west) and 15 blocks across the channel (north - south) approximately 320 by 320 feet. With 1,500 blocks for the Morrow and the influx zone, the entire model required 3,000 gridblocks.

The Stewart Field was divided by sections with reservoir parameters assigned to each as follows:

<u>Section</u>	<u>kx-ky-kz</u>	<u>porosity</u>
4 and 9	150 md	18%
3 and 10	120 md	17%
2 and 11	90 md	15%
12	80 md	16%
7	65 md	16%

These values are based on average log calculated data that show an increasing trend in permeability toward the west. The initial pressure of the Morrow was set at 1200 psig and an initial water saturation of 31% was used across the field.

The initial run had no aquifer influx and represented a total depletion drive system in the Morrow. The field recovered 2.11 MMBO (including Chief) as compared to 3.23 MMBO actual production through 7/1/93 (including Chief), or a 65% match.

Due to an increase in water production in the Scott 4-4, 4-5 and on the Pauls lease along with the presence of a permeable, high pressured zone DST'd in the Scott 4-3, the west end was chosen as the first area to introduce water influx. The influx support is represented by a 100% water saturated zone with 5 md. permeability in the X and Y directions with a pressure of 1400 psig. Communication between the Morrow and the aquifer was modelled with vertical permeability between the layers of 0.07 md. over an area of approximately 40 acres on the west end of the field, south of the Scott 4-4 and 4-5 and west of the Pauls 9-3. After trying varying values of vertical permeability, 0.07 md. was selected as the value providing the most pressure support without excessive water production.

The influx from the aquifer supports the early production from 1967 to 1985. In this time period only 3 wells in Section 12 are producing and the withdrawal from the Morrow is small compared to the size of the reservoir. From 1985 and forward, production increases sharply due to the drilling activity. As the production increases, the water influx becomes less adequate in supporting the producing wells.

Modelling wells fractured into the St. Louis was initially attempted, but water production from these wells caused the pressure in the aquifer to be drawn down too quickly. The influx from the west end was assumed to be from a different source than the St. Louis "C" zone in the fracture communicated wells. The water production from the St. Louis is from an independent zone and contributes little pressure support to the Morrow if the communicated wells remain on production or are only shut-in for short periods of time. Since only the Mackey #5 was shut-in for some of the recent months, modelling the water production from the St. Louis is unnecessary.

The west end influx increased the model recovery from 2.11 MMBO to 2.23 MMBO or 69% of actual. The model was still having trouble keeping up with the post 1985 drilling program. The pre-frac skin was then reduced from +3.0 to +1.5 and the producing BHP was reduced from 50 to 15 psi. The skin was lowered to reduce the severity of the pressure drop from the grid block to the wellbore. Since the wells have historically been "pumped off", the BHP could be lowered to allow for lower fluid levels. These changes increased the model production to 2.49 MMBO, a 77% match.

Having obtained the maximum benefit from the west end influx, the Ste. Genevieve was identified as another source of influx. Many well logs calculate a productive Ste. Genevieve interval underlying the Morrow channel, especially in an area extending from the east half of Section 11 to the west half of Section 7. A study map of the Ste. Genevieve result in 1.5 MMBO in place. One section of the influx layer was allocated to represent the Ste. Genevieve. An area extending from the Sherman #1 to the Bulger 7-1 on the south side of the channel was used as the Ste. Genevieve source in the model. It was necessary to use a porosity of 1% and 40% water saturation to obtain an oil volume approximating that of the study map. The low porosity is only a means of adjusting the storage volume in the model and does not affect the flow capacity of the reservoir. The saturation value means both oil and water will flow from the Ste. Genevieve. These values increase the oil volume of the model by 1,703 MSTB for an OOIP of 28,171 MSTB. The Ste. Genevieve was given 0.07 md. communication with the Morrow channel. The Ste. Genevieve influx increased the model history match to 2.53 MMBO or 78% of actual.

In December 1971, the Mackey #3 was drilled and encountered 1 foot of Morrow sand. A fracture attempt communicated with the St. Louis, and the well tested 160 BWPD and was temporarily abandoned. In 1986, holes in the casing were repaired. Fluid levels after swab tests showed pressures to be 900-1100 psig. The well was again temporarily abandoned. Wells have been producing from Section 12 since 1967. In 1985, an offset well in Section 11 (Sherman #1) DST'd an extrapolated pressure (p*) of 862 psig, less than the original pressure. From 1972 to 1986 (and forward) the fracture

in the Mackey #3 has potentially allowed water influx from the St. Louis to cross-flow into the Morrow as the Morrow was being depleted. This represents the third source of pressure support used in the simulation.

Multiple runs showed that a high conductivity fracture between the Morrow and St. Louis in the Mackey #3 could be simulated by allowing 1 md. of vertical permeability in the gridblock containing the well without watering out offset wells. Fluids were allowed to move between the zones due to the pressure differential. No fluids were produced from the well. The simulation of the Morrow channel with these three sources of influx produced 2.57 MMBO through 7/1/93 as compared to an actual 3.23 MMBO (including Chief), an 80% match. Even though oil production only increased 40 MBO, the pressure history match was improved. See Figure 23.

Core work performed by TORP on extracted cores from the Sherman #3 and Scott 4-4 indicate sensitivity to water resulting in a reduction in permeability. Meyer 10-4 and Mackey #1 have exhibited lower production rates subsequent to being exposed to water from casing leaks. The coring procedure itself is likely to reduce the permeability found in the routine core analysis due to water and mud filtrate. For these reasons and the need to increase transmissibility along the length of the channel, the permeability in the Morrow was doubled. This brought the model results up to 2.98 MMBO produced, a 92% match.

The fine tuning of the MB simulation case included removing the Chief production from the match and updating the production data to 1/1/94. Adjustments were made to the skin of individual wells to improve each well's match. The final case had a 98% match with 3.19 MMBO (without Chief) compared to the actual production of 3.27 MMBO as of 1/1/94.

Figure 24 shows the cumulative production for each case as compared to the actual. The pressure was also evaluated visually in the 3-D graphical display. Particular attention was paid to reservoir pressure as wells were drilled westward. Although the model pressure of the Sherman #1 was higher than actual (1000+ vs. 862 psig), the majority of the wells in the model were drilled with reservoir pressure around 800 psig. The simulation also showed a reservoir pressure of approximately 800 psig at the time of drilling the western-most wells on the Scott lease. This coincides with the p^* of 775 psig exhibited by the DST of Scott 4-4 in January, 1989.

The final MB history match utilized the following parameters:

1. Three sources of water influx
 - a. West end, $k_z=0.07$ md, k_x and $k_y = 5$ md, Porosity = 12%, $S_w = 100\%$, area of influx approximately 43 acres, pressure = 1400 psig.
 - b. Ste. Genevieve, 1.7 MMB OOIP, $k_z = 0.07$ md, k_x and $k_y = 5$ md, Porosity = 1%, $S_w = 40\%$, pressure = 1400 psig.
 - c. Mackey #3 cross-flow, one grid block with $k_z = 1.0$ md, k_x and $k_y = 5$ md, Porosity = 12%, $S_w = 100\%$.
2. A producing BHP of 15 psig.
3. A pre-frac skin = 1.5 and post-frac skin = -3.0 with the following exceptions:
Bulger 7-4, 7-5 and Sherman 3-5 have post-frac skin = -4.5
Sherman #5, Pauls 9-1 and Haag #4 have pre/post-frac skin = 0.0/-4.5

4. Permeability and porosity values of:

<u>Section</u>	<u>kx-ky</u>	<u>kz</u>	<u>porosity</u>
4 and 9	300 md	150 md	18%
3 and 10	240 md	120 md	17%
2 and 11	180 md	90 md	15%
12	160 md	80 md	16%
7	130 md	65 md	16%

5. Morrow pressure = 1200 psig.

6. OOIP Morrow = 26,468 MSTB, Morrow and Ste. Genevieve = 28,171 MSTB

C. Waterflood Study

The 3D reservoir description study was used in a predictive mode to quantify secondary reserves and to select the best pattern for waterflood operations. The objective of the predictive portion of the simulation study was to create a model with the reservoir characteristics that would affect waterflood performance, yet simple enough to maintain the history match found in the material balance portion of the simulation study.

A net sand map for each flow unit (Red, Purple and Yellow) was drawn using GridGenerator. Each zone was mapped honoring all data, including dry holes surrounding the field. The Red and Purple intervals were mapped with a maximum thickness of 10 feet. The Yellow zone was mapped with a maximum net thickness of 30 feet with a 15 foot contour being carried the entire length of the field. At an initial water saturation of 31%, the field was calculated to contain 27.8 MMSTB OOIP. The OOIP includes approximately 1.7 MMSTBO from the Ste. Genevieve leaving 26.1 MMSTB of Morrow oil.

No vertical permeability was allowed for the three Morrow layers except at the wellbore. A vertical permeability of 1 md. was assigned to each gridblock (approximately 300-320 feet square) containing a fracture stimulated well. Permeability was assigned to each zone so as to establish a 0.70 permeability variation. Utilizing the permeability-porosity transform derived from the core-log relationship, the most frequently occurring permeability ordering is the Yellow (bottom) zone with the highest permeability, the Purple (middle) zone with the lowest permeability and the Red (top) zone with the median permeability. The permeability distribution across the field was described as follows:

	<u>Sec 4&9</u>	<u>Sec 3&10</u>	<u>Sec 2&11</u>	<u>Sec 12</u>	<u>Sec 7</u>
Red (Top)	300	240	180	160	130
Purple (Middle)	130	105	79	70	58
Yellow (Bottom)	680	550	400	350	285

Vertical permeability allows cross-flow from the three sources of influx into the Yellow zone. The bottom-hole pressure in each producer was reduced to 10 psig and all fractured wells were given a post-frac skin of -4.5. Increasing the post-frac skins on all wells in reality affected only a few wells, since most were limited by their actual producing rate. The pre-frac skins were retained from the material balance simulation study.

This predictive model was first run to compare the history match by using the same three sources of influx described in the material balance study. Ninety six percent of the historical production was matched with the new and more detailed model.

Several injection patterns were modelled. Each pattern was modelled with 6,000 and 10,000 barrels of water injected per day (BWIPD) for the field. The two injection rates were chosen to see the effect of injection rate and to bracket the range of available source water which is unknown until the waterflood is implemented. The injection volume was equally distributed among the number of injection wells with a maximum allowable BHP of 3000 psig. A favorable mobility ratio allows oil to move more easily than the water. As the reservoir fills with water, the injectivity goes down. The field injection curves show that the maximum rate (6,000 or 10,000 BWIPD) is sustained for 2 to 4 years until injection wells become pressure limited. The three line drive pattern was not modelled with 10,000 BWIPD because of insufficient number of injection wells to allow such a large volume. The majority of the net present value of the waterflood occurs in the first five years. The predictive model was designed for a ten year life with all producing wells being shut in at an 80% watercut. Reserves are recoverable at a higher watercut, but would be recovered late in the life of the project having a small effect on the NPV. The 3, 5 and 7 line drive patterns were chosen in order to select the optimum number of line drives. An additional run was made on the 5 line drive pattern where the producing wells are shut in at a 20% watercut and then returned to production on 7/1/97 and produced to a 97% watercut (labeled 5 L-D 20/97). Each pattern is associated with a different oil and water production curve, capital requirement and operating expense. Once the optimum number of line drives has been established, the results of the 2D and the reservoir characteristics can be used in selecting individual wells in the final pattern.

The injection patterns are shown in Figures 25 - 29. The 5 and 7 line drive cases utilize a lease line injection well between the Haag and Bulger leases that was selected due to a lack of a suitable well for injection on the Haag lease. The location was selected to increase the well density in the thick of the channel.

Plots for the 6,000 BWIPD are shown in Figures 30 - 32. The figures show the oil production rate, water production rate and water injection rate vs. time for each pattern. The same data is plotted in Figures 33 - 35 for the 10,000 BWIPD cases. It should be noted that late in the simulation run only a few wells remain on production as the other wells have been shut in due to the 80% watercut limit. No provision has been made for shutting in injectors so all wells are still injecting in areas with no producing wells. The model allows the injection water to repressurize the aquifer zones. This explains the difference in injection and withdrawal volumes late in the simulation run.

The cases run with the high injection rate exhibit higher peak oil rates and earlier water breakthrough. The low injection rate cases break through later and recover more reserves. The ten year reserves and the recovery factors for the different cases are as follows:

	Waterflood Recovery	Recovery Factor
3 L-D	2,986,000	11.4%
5 L-D Lo	2,776,000	10.6%
5 L-D Hi	2,764,000	10.6%
7 L-D Lo	2,796,000	10.7%
7 L-D Hi	2,713,000	10.4%
Beren Hi	2,710,000	10.4%
5 L-D 20/97	3,622,000	13.9%

LABORATORY TESTING

Commercial Laboratories

Cores were recovered on the following six producing wells: Meyer 10-1, Scott 4-4, Scott 4-8, Sherman #3, Sherman #5 and Pauls 9-2, with a directional whole core routine analysis performed on Sherman #3. The other five wells were analyzed with plug analysis.

A special core analysis was run by Core Laboratories on the Meyer 10-1 with steady state relative permeability tests on four extracted samples. The cores represent a slight water-wet condition. Connate water saturations ranged between 18 and 29%, whereas residual oil saturations varied between 33 and 42%. Formation compressibilities were measured over a range from 2400 to 800 psig to be 10×10^{-6} psi⁻¹. No apparent water sensitivity was experienced.

Laboratory tests were also conducted on preserved cores taken from the Stewart Field. These tests were conducted by Surtek, Inc. located in Golden, Colorado. The tests consisted of a fluid-rock linear core study to determine the relative permeability characteristics using reservoir fluids. Capillary pressure was determined by mercury injection method. The linear corefloods also define the initial and residual oil saturation, effective and absolute permeability, fractional flow, wettability of the reservoir rocks and the mobility ratio between water and oil. The capillary pressure test results were used to calculate the pore size distribution and saturation data.

The average initial oil saturation from three linear corefloods using Scott 4-8 core was 71% and the average waterflood residual oil saturation was 44%. The average oil recovery was 38% OOIP.

The average initial saturation in the laboratory for two relative permeability determinations was at 0.67 PV, and the waterflood residual oil saturation was 0.48 PV for a recovery of 35% OOIP.

The mobility ratio averaged 1.0 using endpoint permeability and saturation values for water displacing crude oil. This indicates that water is a good fluid for displacing crude oil.

Fractional flow data from the two relative permeability tests indicates the producing water-oil ratio will be approximately 3.5 after water breakthrough. The average oil saturation at water breakthrough would be 0.62 for 7.5% OOIP recovery at breakthrough. Assuming an economic limit of 99% water, the average residual oil saturation would be 0.509 or a total of 24% OOIP recovered economically by waterflooding.

Total waterflood recovery in coreflood 2 was 40.6% OOIP, and in coreflood 3 was 30.1% OOIP for an average recovery of 35.4% OOIP. This indicates that approximately 11.4% of this waterflood oil cannot be recovered economically.

Mercury injection capillary pressure curves generated on the Meyer 10-1 and Sherman #3 cores suggest that the average initial non-wetting phase saturation would be 76% of the pore volume. Using the imbibition curve, the change in oil saturation by both primary production and waterflooding processes will be about 31%.

University of Kansas Laboratory

The objective of the laboratory testing conducted at the University of Kansas was to analyze the water sensitivity of Stewart Field cores. Initially the testing was to be done to determine the reservoir sensitivity to the proposed injection water. However, in the early stages of the testing, it was determined that the reservoir rock displayed sensitivity to formation brine. The following summarizes the results of these experiments.

Introduction

Water sensitivity analysis of Stewart Field cores was conducted through permeability measurements of the cores. Core plugs of known dimensions were cut, evacuated and saturated. Permeability measurements were made on these cores using different solutions at room temperature ($\approx 68^{\circ}\text{F}$) and reservoir temperature (125°F). Experiments were performed on the core plugs from the following wells:

- (i) Scott 4-4 (depth 4796 ft.)
- (ii) Sherman 3 (depth 4781 ft.)
- (iii) Meyer 10-1 (depth 4800 ft.)

The following solutions were used for performing permeability measurements:

- (a) 2.0% sodium chloride
- (b) synthetic formation brine (composition given in Table 1)
- (c) injection water (proposed)
- (d) filtered produced water from Scott 4-5
- (e) 3.0% potassium chloride
- (f) 500 ppm aluminum (aluminum citrate)

Table 1: Composition of Synthetic Formation Brine

Salt	Concentration (mg/l)
NaCl	76,470
NaHCO ₃	430
Na ₂ SO ₄	1,700
CaCl ₂ ·2H ₂ O	15,010
MgCl ₂ ·6H ₂ O	9,930
pH adjusted to 6.5	

Experimental Procedure

The core plugs were cut having approximate dimensions of 1" length and 1" diameter. The plugs were cut using fresh water unless specified otherwise. The core plugs were then evacuated and saturated with the desired solution. The experimental set-up consisted of placing the core plugs in a rubber sleeve within a metal casing. The rubber sleeve was subjected to a pressure of approximately 200 psi, which resulted in an air-tight seal around the plug. This was done in order to ensure no bypassing of the plug by the injected fluid.

The injection fluid was pumped into the core and the flow rate was measured by collecting the fluid from the effluent line. The pressure drop across the core was measured using two pressure ports situated upstream and downstream of the core, which were connected to a transducer to measure the pressure differential. Experiments were performed at room temperature and reservoir temperature by placing the apparatus in a water bath maintained at 125°F. The procedure for calculating the permeability from these measurements is outlined in Appendix B.

Results of Permeability Measurements

This section gives a brief summary of the results obtained from the permeability measurements of the core plugs from the three wells. Preliminary experiments were performed on Berea core plugs to validate the measurements by the apparatus being used.

The experiments performed on core plugs from the wells are summarized in Tables C-1 through C-4 in Appendix C. Data for all the measurements are also shown in Appendix C.

- (i) Scott 4-4: Table C-1
- (ii) Sherman 3: Table C-2
- (iii) Meyer 10-1 Core #1: Table C-3
- (iv) Meyer 10-1 Core #2: Table C-4

Figure 36 shows the results of the experiment performed on a core plug from Scott 4-4. The core was injected with synthetic formation brine at 125°F. The results show the relative permeability as a function of the pore volumes injected. A continuous decrease in the permeability was observed for the entire injection period. Figure 37 shows similar results for a core plug from Sherman 3 injected with

Figure 36: Relative permeability versus pore volumes injected for synthetic formation brine.

Figure 37: Relative permeability versus pore volumes injected for filtered produced water.

Figure 38: Relative permeability versus pore volumes injected for 3.0% potassium chloride solution.

filtered produced water from Scott 4-5 at 125°F. The plug was continuously injected with produced water for a period of four days and a continuous decrease in permeability was observed. Figure 38 shows the results of the experiment performed on a core plug from Meyer 10-1. The core was injected with 3.0% potassium chloride solution at 125°F and for the entire injection period a continuous decrease in permeability was observed.

From the results obtained it was observed that there is a reduction in permeability for all the field cores. This behavior was observed with all the injection fluids at reservoir temperature, indicating a high sensitivity of the cores to the injection fluids.

Conclusions

Permeability reduction of at least 50% will occur in the immediate vicinity of the wellbore where large volumes of water flow through the porous rock. Consequently, there will be an increase in the skin factor and decrease in the injection rates with time in water injection wells.

UNITIZATION

A critical task associated with the initial budget period of this project is the unitization of the field. Unitization needs to occur in order to implement a field-wide improved oil recovery process. There are three operators and multiple working and royalty interest owners currently owning production interests within the field. A minimum of 75% of all interest owners will have to be in agreement on equity issues in order for the field to be unitized.

The Kansas Corporation Commission is the governing body concerning unitization in the State of Kansas. If 100% of the working and royalty interest owners agree to a unit operating agreement, then formal unitization by the Kansas Corporation Commission for waterflooding operations is not required. If 100% agreement cannot be reached, then a minimum of 75% of both working and royalty interest owners would have to be in agreement prior to initiating forced unitization proceedings with the Kansas Corporation Commission.

A technical committee was formed in order to help resolve some of the equity issues. Regular meetings and correspondence has taken place between the technical committee members and the working interest owners throughout the duration of this project. To date many equity issues necessary for unitization are yet to be resolved and continue to be debated. One major issue yet to be resolved is the selection of the unit operator.

Savonburg Field Project

OBJECTIVES

The objective of this project is to address waterflood problems in Cherokee Group sandstone reservoirs in eastern Kansas. The general topics addressed are 1) reservoir management and performance evaluation, 2) water optimization, and 3) demonstration of off-the-shelf technologies in optimizing current or existing waterfloods with poor waterflood sweep efficiency. It is hopeful that if these off-the-shelf technologies are implemented the abandonment rate of these reservoir types will be reduced.

The reservoir management portion of this project involves performance evaluation and included such work as 1) reservoir characterization and the development of a reservoir database, 2) identification of operational problems, 3) identification of near wellbore problems such as plugging caused from poor water quality, 4) identification of unrecovered mobile oil and estimation of recovery factors, and 5) preliminary identification of the most efficient and economical recovery process i.e., polymer augmented waterflooding or infill drilling (vertical or horizontal wells).

To accomplish these objectives the initial budget period was broken down into four major tasks. The tasks included 1) geological and engineering analysis, 2) waterplant optimization, 3) wellbore cleanup and pattern changes, and 4) field operations.

BACKGROUND

History

The Nelson Lease is located in Allen County, Kansas in the N.E. Savonburg Field about 15 miles northeast of the town of Chanute and one mile northeast of Savonburg. The project is comprised of three 160-acre leases totaling 480 acres in Sections 21, 28, and 29, Township 26 South, Range 21 East.

The first well drilled in the location of this project was in 1962. Fifty-nine production wells and forty-nine injection wells have been drilled and completed since 1970. A pilot waterflood was initiated in March 1981 and expanded in 1983. Full development occurred in 1985.

Production of oil in the Nelson Lease in the Savonburg NE Oil Field is from a valley-fill sand in the Chelsea Sandstone member of the Cabaniss Formation of the Cherokee Group (Fig. 39, 40). This lease is similar to a large number of small oil fields in eastern Kansas that produce from long, narrow sandstones, "shoestring sandstones" (Bass, 1934), at shallow depth.

The most productive part of the reservoir sand in the lease lies in the eastern half of the SW/4 of Section 21 and is a narrow valley cut to a depth of up to 40 feet (12 m) through the Tebo and Weir-Pittsburg horizons into the Bluejacket A coal (Harris, 1984). The deepest part of the valley is less than 300 m wide. Wells that encountered the most sandstone in the valley are the most productive.

In 1986, eleven gel polymer treatments were implemented successfully on the Nelson Lease. Overall incremental oil recovery was 3.5 barrels per pound of polymer placed which totaled 12,500 barrels. The production increase was not sustained due to wellbore plugging as a result of poor water quality.

Cumulative production through June 1994 has been 344,755 barrels. Of this production, 131,530 barrels were produced by primary depletion. Water injection began in March 1981 and 213,225 barrels have been produced under waterflood operations. The most current graph of waterflood production data is presented in Figure 39. A map presenting oil production by well since waterflood startup is included as Figure 40.

WATERPLANT DEVELOPMENT

The waterflood has been plagued with poor water quality. Bag filters have not been adequate in improving water quality to a level it can be injected without plugging injection wells. As a result, the injection wells have had to be cleaned regularly and injection pressures have been extremely high.

Air flotation was selected as the process to improve water quality. The air flotation unit has been installed along with additional tanks and lines needed for proper installation. Steady-state operation is expected in August 1994. A flocculation chemical was selected to aid in the performance of the air flotation unit.

GEOLOGICAL AND ENGINEERING ANALYSIS

Database Development

Due to the abundance of data on the field, a computer database was set up to make data easily accessible. Spreadsheets were utilized to in the development of the database. The computer database included, 1) reservoir properties from core analysis on a well basis, 2) production and injection data on a well basis since waterflood start up, and 3) lithology picks on a well basis.

This study used materials provided by J.E. Russell Petroleum Inc., including cores, unscaled g-ray--neutron logs and core data. While cores collected before 1983 were discarded after description and analysis, cores were available for 23 wells drilled since Russell became operator of the field. Russell cores are simply designated by their well number, either RW-n (n=1 through 19) or O-n (n=1 through 4). The Russell cores were described and were the basis for much of the depositional interpretation of the reservoir rocks and associated strata. Core data provided was collected by Oil Field Research in Chanute Kansas, except for two descriptions carried out by CoreLab. Core data included a verbal and graphic description, measurements of porosity, permeability, and fluid saturation for nearly all wells, and, for the Russell cores, recoverable oil and effective permeability at residual oil saturation.

Zone Description and Mapping Methods

Sandstone was mapped and identified utilizing two methods, 1) utilizing core reports to determine net floodable sand for volumetric analysis, and 2) utilizing g-ray logs to determine sand thicknesses and differences in lithologies for geological analysis. Both methods proved valuable.

In the volumetric study, net pay was determined from core analysis utilizing a porosity cut-off of 13% and effective water permeability cut-off of 1 md.

In the geological study, a shale line and a sand line were drawn on the g-ray log. The shale line was drawn at a deflection which was consistently reached by beds which did not appear to be anomalously radioactive. The sand line was drawn at the g-ray reading in the Cherokee Group. Rocks with a

deflection greater than 1/2 of the difference between the sand and shale lines were considered to be shale and those with a smaller deflection were considered to be sandstone.

Reservoir Parameters

The reservoir characteristics were defined from log and core analyses. Average porosity and permeability are 18.4% and 27 md respectively. Average residual oil saturation, based on laboratory flood pot tests was 34.9 percent. Connate water saturation of 24 percent was estimated from core data and by applying an empirical relationship using permeability data. The gravity of the crude oil is 31.2 degrees API at 60° F. The viscosity of the reservoir crude oil at reservoir temperature is 15.4 cp.

Volumetric Analysis

A pattern volumetric analysis was conducted to determine waterflood sweep efficiencies for given portions of the field. Net pays were determined from flood pot data. Within each net pay, average porosity, and water saturations were calculated and placed in a database. From the database three grids and maps were developed; 1) net pay, 2) porosity, and 3) water saturation. The net pay grid was multiplied with the porosity grid to develop a porosity-foot grid for the field. Each pattern was then integrated to determine acre-ft. The patterns are presented in Figure 41. The net pay isopach map is presented in Figure 42.

Initial-oil-in-place at waterflood start up was determined by multiplying the porosity-ft grid with the (1-%water sat.) grid. Each pattern was then integrated a second time to determine IOIP per pattern. A formation volume factor (FVF) of 1.06 was included in the calculations. Waterflood recovery was then determined by the following equation.

$$\text{Waterflood Recovery per pattern} = \frac{\text{Pattern Production}}{\text{IOIP}}$$

This recovery factor was used as a measure of waterflood efficiency per pattern. This measure could then be used in investigating the high potential areas of the field.

Table 2: Pattern Volumetric Analysis

Pattern Well Name	IOIP(cu.ft) f(Sw,por,net)	IOIP/FVF (cu.ft.)	IOIP (STB)	Produced (Barrels)	Waterflood Recovery.
H-1	198,277	187,054	33,313	6,417	19.3%
H-11	181,948	171,649	30,570	2,740	9.0%
H-14	365,284	344,608	61,373	15,973	26.0%
H-15	154,240	145,509	25,914	2,568	9.9%
H-16	229,709	216,707	38,594	10,805	28.0%
H-17	396,673	374,220	66,646	6,942	10.4%
H-22	187,297	176,695	31,468	6,245	19.8%
H-26	260,555	245,807	43,777	4,856	11.1%
H-27	234,958	221,658	39,476	188	0.5%
H-28	226,623	213,795	38,076	2,655	7.0%
H-3	646,993	610,371	108,704	7,036	6.5%
H-30	912,038	860,413	153,235	32,855	21.4%
H-9	246,819	232,848	41,469	3,941	9.5%
K-36	217,030	204,745	36,464	641	1.8%
K-39	601,435	567,392	101,049	22,026	21.8%
K-40	144,354	136,183	24,253	0	0.0%
K-41	189,292	178,577	31,804	2,748	8.6%
K-42	241,749	228,065	40,617	1,442	3.6%
K-43	239,614	226,051	40,258	3,868	9.6%
K-44	424,853	400,805	71,381	9,678	13.6%
K-45	369,859	348,924	62,141	5,222	8.4%
K-47	354,986	334,892	59,642	834	1.4%
K-49	35,344	33,343	5,938	660	11.1%
K-54	59,025	55,684	9,917	1,825	18.4%

Total IOIP in patterns studied- 1,196,081 STB

Simulation Study

To determine the potential recovery from waterflooding in the Savonburg Field, a streamtube simulator was utilized. The following input parameters were used in the simulation:

Table 3: Input Parameters for Streamtube Simulator

FORMATION PROPERTIES AND PATTERN VOLUMES

FORMATION DEPTH	620.0	FT
FORMATION TEMPERATURE	70.0	DEG.F
FORMATION AVE. PERMEABILITY	27.0	MD
FORMATION POROSITY	0.2	
TOTAL NET THICKNESS	17.2	FT
TOTAL PORE VOLUME	61.4	MBBL
ORIGINAL OIL IN PLACE	45.8	MSTB
OIL IN PLACE AT START OF FLOOD.....	42.2	MSTB
DYKSTRA-PARSONS COEFFICIENT	0.63	VDP
PATTERN AREA	2.50	ACRE
WELLBORE RADIUS.....	0.50	FT
INJECTIVITY COEFFICIENT	1.00	PSI/FT
INJECTION RATE OVERRIDE	40.0	RB/D
WATER-OIL MOBILITY RATIO	4.92	
POLYMER-OIL MOBILITY RATIO	0.00	

FLUID PROPERTIES

OIL FORMATION VOLUME FACTOR	1.019	RB/STB
WATER FORMATION VOLUME FACTOR	1.001	RB/STB
API OIL GRAVITY	31.5	DEGREES
OIL VISCOSITY	15.400	CP
WATER VISCOSITY	1.067	CP

Simulation results are the following:

WATERFLOOD REPORT

PATTERN PRODUCTION SUMMARY

PATTERN LIFE RATIO	11.47	
PATTERN AREA	2.50	ACRE
PATTERN PORE VOLUME	61.4	MBBL
ORIGINAL OIL IN PLACE	45.8	MSTB
OIL IN PLACE AT START OF FLOOD	42.2	MSTB
TOTAL OIL PRODUCTION	14.0	MSTB
OIL RECOVERY - FR. ORIG. OIP	0.3057	
OIL REC - FR. OIP AT START OF FLOOD..	0.3319	
TOTAL POLYMER INJECTED	0.0	MLB
OIL/POLYMER RATIO	0.00	STB/LB

The simulation run indicates that the average recovery factor of the IOIP is 33.19%. This recovery factor is larger than most of the recovery factors in the volumetric pattern study. This would indicate that many of the patterns have a high potential for incremental oil if the waterflood was optimized.

Geological Analysis

A detailed geological report is included in Appendix D. The following are conclusions from the geologic evaluation. Geological cross sections of the field are presented in Appendix E.

The primary zone of oil production is a sandstone that is part of the Chelsea Sandstone of the Cabaniss Formation, Cherokee Group. The sandstone, with associated mixed lithology (rippled sandstone, wavy and linsen bedded sandstone, siltstone and shale) and shale, fills a valley that was cut during a low

stand of sea level. The low stand occurred after deposition of the Tebo Coal and some overlying strata but before deposition of the Scammon Coal. The most productive reservoir is structureless, fine-grained sandstone associated with the first stage of filling this valley, called the B₃ zone in this report. Rippled sandstones of the overlying interval, the B₂ zone, are potentially productive in the NW part of the lease, but are generally either saturated with dead oil, have low initial oil saturations, or are thin and discontinuous, making poor reservoirs.

Geological understanding of this reservoir results from two factors. One is the availability of good data. The operators, J.E. Russell Petroleum, Inc. provided cores, core descriptions and analyses, and logs. The other factor was the application of sedimentologic and stratigraphic principles that have emerged in the past few years, especially sequence stratigraphy and the understanding of the features of sediments deposited by tidal currents.

The stratigraphic framework of the Cherokee Group in the field area is a series of regional marker intervals that consist (ideally) of an underclay, a coal, a caprock of marine sandstone or limestone, and a dark gray or black shale. In terms of sequence stratigraphy, the boundary of the underclay and coal represents a sequence boundary, a surface of sub aerial exposure. The boundary between the coal and the caprock represents the initial surface of marine transgression, with the caprock representing a lag deposit on a ravinement surface cut during transgression. The surface of maximum transgression lies in the overlying dark gray or black shale or in the medium gray shale that gradationally overlies it. These strata thus reflect the effects of rise and fall of sea level relative to the area of deposition of these sediments. Regional marker intervals extend across the Cherokee basin of southeastern Kansas and into the Forest City and Sedgwick basins (northeastern and south-central Kansas, respectively). They may continue into Iowa and southwestern Kansas.

Locally, the regional marker intervals are missing, notably in the vicinity of the Nelson Lease. The pattern of their absence in the field area suggests a valley eroded into underlying deposits; this is the valley referred to above. The sediments that fill this valley appear to carry indications of deposition by tidal currents. The sediments show gradational changes from shale to wavy- and linsen-bedded sandstone and mudrocks to rippled sandstone on a dm scale. The gradational nature of these changes suggests no little erosion between depositional events. The changes of grain size suggest frequent changes of current intensity, from essentially no current, when mudstone and macerated plant material accumulated in wavy- or linsen-bedded successions to times of current when ripples or sand or silt accumulated. This may correspond to currents during individual tidal cycles. The dm-scale gradation of shale to mudrocks to sand may reflect changes in intensity of ripple-forming episodes of the kind that would result from the neap-spring cycles of tidal activity. Because the mixed lithologies of the B₂ and B₃ zones suggest tidal activity, the sandstones and shales of these zones may also have formed in tidal environments. Tidal sandstones occur in mounded masses, convex upward, rather than in the convex-downward patterns of fluvial channels.

Planning for further development of this field should take into account the linear nature of the primary reservoir, the lower (or B₃) sandstone, and the sheet-like nature of the upper sand (B₂) in the northwestern part of the field, if that area is developed further. Additional drilling for improved waterflood recovery may be warranted in the central part of the deep valley and in the northwestern part of the lease. Several wells are completed in sandstones where petrophysics, saturations, and continuity of beds are unfavorable for either injection or production. Each well should be evaluated in view of current subsurface information, and those that are not likely to be productive should be abandoned. The field contains substantial amounts of dead oil, which not only cannot be produced but which act as a barrier to flow of

fluids thought the reservoir. Wells drilled during further development the wells logged at least with g-ray-neutron logs. The wells should be cored and the cores analyzed for normal petrophysics, fluid saturations, recoverable oil and effective permeability. Cores should be described geologically and their character used to improve knowledge of the distribution of rocks in the field.

The geological study identified two sandstones, B₂ and B₃, which have potential for additional oil recovery. The study utilized regional marker horizons to form the basis for correlation of Cherokee Group rocks over the Cherokee Basin and to adjacent basins. East-West cross sections were developed on nearly all the wells identifying the continuity of the B₂ and B₃ pay zones. The cross sections are presented in Appendix E. Isopach maps were developed for the B₂ and B₃ sandstones.

It was concluded that the sandstones of the B₃ zone of the Chelsea valley fill in the eastern 1/2 of section 21 may not be completely drained by the current arrangement of wells. Specifically, injection wells may be needed between wells H-14 and H-16, between H-16 and K-44, between H-20 and H-21, and between H-30 and H-27. These locations lie along the trend of thickest sandstone in the axis of the Chelsea valley fill and adjacent injection wells are on the margins of the sandstone. While these steps would reduce spacing substantially, very high original oil saturations along the valley (as high as 5000 bbls/acre recoverable oil) and the potential for improved recovery may justify the step.

Cores of the B₂ zone in the northwest part of the Nelson Lease indicate recoverable oil averaging 2000 Bbls/acre, but production from that area has been low. Recompletion, additional development drilling, or some expansion of the field in this direction may be desirable, under the right economic conditions.

Discussion of Field Recommendations

As part of the Phase 1 work, selected field testing of the waterflood must be completed. Based on the volumetric pattern study and geological evaluation, several recommendations have been made. Field recommendations include well cleanups and pattern changes. Recommendations were based on zone potential. From examining the geological report, Zone B-3 is of better quality and of higher potential than Zone B-2. As a result, it is suggested that initial work be conducted on Zone B-3 in phase 1. Once these recommendations are implemented, areas of high potential will be identified in Zone B-2 and work will be continued.

The following work will be attempted in the remainder of Phase 1. A map showing the location of these wells is presented in Figure 43.

- 1) Convert the following producers to injectors and clean wellbores. From examination, the B-3 zone has been poorly swept due to lack of water injection in the Zone B-3. The following injection wells should increase injectivity into Zone B-3. Conduct temperature surveys pre and post cleanup.
 - a) Well H-5 - The producing wells which should respond are H-3 and H-20.
 - b) Well O-1 - The producing wells which should respond are H-30 and H-21.

- 2) Clean the following injection wells and conduct injection profiles pre and post cleanup.
 - a) Well KW-51
 - b) Well RW-8
 - c) Well RW-3
 - d) Well KW-6
 - e) Well KCW-1

CONCLUSIONS AND SUMMARY

An engineering and geological study is being conducted on the Savonburg Field with many conclusions and findings to date. Also a water cleanup process has been selected to cleanup the low quality injection water in the field.

Air flotation was selected as the process to improve water quality. The air flotation unit has been installed along with additional tanks and lines needed for proper installation. Steady-state operation is expected in August 1994. A flocculation chemical was selected to aid in the performance of the air flotation unit.

Results from the engineering study include, 1) a volumetric study of selected patterns throughout the field, and 2) a waterflood simulation study of a five-spot with average properties of the Nelson Lease. The volumetric study provided waterflood efficiencies on a pattern basis to determine patterns of highest potential for additional recovery. The simulations indicated that the average recovery factor of the IOIP is 33.19%. This recovery factor is larger than most of the recovery factors in the volumetric pattern study. This would indicate that many of the patterns have a high potential for incremental oil if the waterflood were optimized.

To confirm the potential of the waterflood in the Savonburg Field, the following pattern changes and well workovers will be attempted in the remainder of Phase 1. A map showing the location of these wells is presented in Figure 43. Well H-5 and Well O-1 will be converted to injectors and the wellbores will be worked over. The following injection wells will have injection profiles conducted and the wellbores will be cleaned with appropriate workovers: a) Well KW-51, b) Well RW-8, c) Well RW-3, d) Well KW-6, and e) Well KCW-1.

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FIGURES

Location Plat

Figure 1

Stewart Field Well Location Plat

Figure 2

Field Production Curve

Figure 3

POLYMER FLOODING VERSUS WATERFLOODING

STEWART FIELD

80 Acre 5-Spot Sherman #3 Data

Figure 4

STEWART FIELD, FINNEY COUNTY, KS.

Figure 5

Plot showing different sections simulated separately.

Plot showing location of well with respect to zero reference point.

Figure 7

Location of wells in the simulation grid system of 150x20.

Stewart Field Simulation Results Actual vs Simulated Production

Figure 8

Figure 9 - 3 Line Drive.

Figure 10 — 5 Line Drive.

Figure 11 - 7 Line Drive.

Figure 12 ~ Beren's Pattern.

Figure 13 -- Narco's Pattern.

Figure 14 - TORP's Pattern.

2D Simulation - Radial Model

Figure 15

2D Simulation - Permeability Variation

Figure 16

Figure 17

Figure 18

Figure 19

Figure 20

3D MB Simulation
Morrow Net Sand Map

Bottom of Structure - Zone 01

4750.0 4812.5

CONTOUR INTERVAL = 5 FT.

Figure 21

3D MB Simulation - Influx Zone

X Permeability for plane Z 2

Figure 22

3D Simulation Results Mat'l Balance
Stewart Field, 1 Layer Morrow, 1 Layer Aquifer

Figure 23

3D Simulation - Production History Match

3D Simulation Results Mat'l Balance Stewart Field, 1 Layer Morrow, 1 Layer Aquifer

Figure 24

3 Line Drive

Figure 25

5 Line Drive

Figure 26

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23
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T
23
S

Figure 27

3D Simulation - Beren Proposed Injection Pattern

Beren Pattern

Figure 28

3D Simulation - NARCo Proposed Injection Pattern

Narco Pattern

Figure 29

3D Simulation - Oil Rate vs. Time - 6,000 BWPD

3D Simulation Waterflood Prediction

Producing Watercut Limit 80%

Maximum Field Injection Rate 6,000 BWIPD

Figure 30

3D Simulation - Water Rate vs. Time - 6,000 BWPD

3D Simulation Waterflood Prediction

Producing Watercut Limit 80%

Maximum Field Injection Rate 6,000 BWIPD

Figure 31

3D Simulation - Injection Rate vs. Time - 6,000 BWPD

3D Simulation Waterflood Prediction

Producing Watercut Limit 80%

Maximum Field Injection Rate 6,000 BWPD

Figure 32

3D Simulation - Oil Rate vs. Time - 10,000 BWPD

3D Simulation Waterflood Prediction

Producing Watercut Limit 80%

Maximum Field Injection Rate 10,000 BWIPD

Figure 33

3D Simulation - Water Rate vs. Time - 10,000 BWPD

3D Simulation Waterflood Prediction

Producing Watercut Limit 80%

Maximum Field Injection Rate 10,000 BWPD

Figure 34

3D Simulation - Injection Rate vs. Time - 10,000 BWPD

3D Simulation Waterflood Prediction

Producing Watercut Limit 80%

Maximum Field Injection Rate 10,000 BWIPD

Figure 35

Savonburg Field

Figure 39

Figure 40

NELSON LEASE STUDY PATTERNS

Figure 41

NELSON LEASE NET ISOPACH MAP

Figure 42

PROPOSED STEPS TO IMPROVE RECOVERY
NELSON LEASE
SAVONBURG NE OIL FIELD

Figure 43

Appendices

APPENDIX A

Details of the Simulation Conducted at the University of Kansas of Section "C" of the Stewart Field

The model had the following initial assumptions:

1. Initial reservoir pressure was assumed to be 950 psi and there was no external pressure support for the reservoir.
2. The reservoir was under natural depletion drive.
3. There was no skin damage on the wells.
4. Based on the pressure buildup tests an average skin factor of -3 was assigned to each well after the fracture stimulation work.

Several cases were run to get an optimum history match. Tables and plots of all cases are included. During the initial run it was observed that the simulated production was much less than the actual production, especially during the period from 1989-1992 (Case 1). This was the period when Sharon Resources had conducted the field wide fracture stimulation program. The actual peak rate of production in this period was about 850 BOPD. The simulated results showed a peak rate of production of about 250 BOPD. During the analysis of the results it was observed that most of the wells became pressure limiting and were unable to produce the rates due to low pressures. These results lead to a hypothesis that there is a source of external pressure support. One possible scenario for providing pressure support was from the underlying St. Louis formation acting as an active aquifer. Based on various data available, the St. Louis formation was implemented into the model as a layer which was 95% water saturated and had a slightly higher pressure compared to that of the Morrow formation. The simulated results after the introduction of the St. Louis formation (at 1250 psi) increased, but were still below actual production (Case 2).

The St. Louis formation pressure was then increased to 1550 psi with a very low vertical permeability (Case 3). There was some increase in the production, but simulated results were still off in the post fracture production by a factor of 3.

In the next two runs, a skin factor of +1 was introduced during the pre-frac period and -3 in the post-frac period. Low vertical permeability of 0.002md and 0.0015 were introduced in all the layers (Case 4 and 5). In both the runs, there was substantial increase in post-frac production, but the pre-frac production was reduced by a factor of 3 due to the skin factor.

Vertical permeability was then increased by a factor of 10, i.e to 0.015 md (Case 6). It was observed that the initial simulated peak production during the pre-frac period was approximately 150 BOPD less than actual and the post-frac production was about half the actual production.

At this point the perforations were changed in the wells. It was assumed initially, all the wells were perforated in all the zones present in the wells. To maintain the reservoir pressure during the post-frac period and achieve the peak production rate, it was decided to have perforations only in the top two layers during the pre-frac period and have perforations in all the zones including the St Louis formation during the post-frac period (Case 7). Also, a -2 skin factor was implemented during the pre-frac period and a skin factor of -4 during the post-frac period (Case 8). The St. Louis formation pressure was also increased to 1750 psi. Simulated results were still much below the actual until the permeability of the system was increased by a factor of 2. In this model the initial peak production rate during the pre-frac period was off by about 30-40 BOPD and the post-frac rate was off by about 250 BOPD.

Analysis of each well's simulated production compared with the actual production history revealed that some of the edge wells did not have enough reservoir volume to produce properly. It was decided to extend the NO FLOW boundary and give these wells additional reservoir volume. This increased the original-oil-in-place(OOIP) in the model by about 35%. The results of this model were 96.013% of the actual production from the wells in the section (Case 9). The match from this model was considered adequate for the reservoir section in question.

Conclusions

The following changes to the original description enabled the model to have a history match of the reservoir section chosen for simulation:

1. Permeability of the reservoir was increased by a factor of 2.
2. Reservoir volume had to be added to the northern portion of the simulated area. This leads us to question whether the reservoir boundaries have been properly defined in this area.
3. Outside pressure support had to be included. It appears most logical that this support is coming from the underlying St. Louis formation. this would result in the primary drive mechanism being a combination of depletion drive and water influx.

Results and Cases

Case 1

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.002	31	950
2	Yes	0.002	31	950
3	Yes	0.002	31	950
4	No	0.0015	99	950

Pre-frac Skin = 0

Post-frac Skin = -3

Simulation results are plotted in Figure A-1.

Red: Oil Production
Yellow: Water production
Green: Average Pressure

Analysis: The prefrac results are about 100 BOPD less than the peak production and Post frac results are about 1/4th of the actual production.

Case 2

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.002	31	950
2	Yes	0.002	31	950
3	Yes	0.002	31	950
4	No	0.002	95	1250

Pre-frac Skin = 0

Post-frac Skin = -3

Simulation results are plotted in Figure A-2.

Red: Oil Production
Yellow: Water production
Green: Average Pressure

Analysis: There was not much difference from the case one.

Case 3

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.001	31	950
2	Yes	0.001	31	950
3	Yes	0.001	31	950
4	No	0.001	95	1550

Pre-frac Skin = 0

Post-frac Skin = -3

Simulation results are plotted in Figure A-3.

Red: Oil Production

Yellow: Water production
Green: Average Pressure

Analysis: The prefrac results are about 80 BOPD less than the peak production and Post frac results are about 1/4th of the actual production. Not much Increase in cumulative production.

Case 4

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.002	31	950
2	Yes	0.002	31	950
3	Yes	0.002	31	950
4	No	0.002	95	1550

Pre-frac Skin = +1

Post-frac Skin = -3

Simulation results are plotted in Figure A-4.

Red: Oil Production
Yellow: Water production
Green: Average Pressure

Analysis: There was decrease in pre-fracture production by a factor of three but increase in post fracture production by a factor of 2.

After this the permeability in x and Y direction were increased by a factor of 2, resulting in some major changes which are discussed in the cases below.

Case 5

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.0015	31	950
2	Yes	0.0015	31	950
3	Yes	0.0015	31	950
4	No	0.0015	95	1550

Pre-frac Skin = +1

Post-frac Skin = -3

Simulation results are plotted in Figure A-5.

Red: Oil Production
Yellow: Water production
Green: Average Pressure

Analysis: Due to the low vertical permeability there was some pressure support but was not substantial to increase the cumulative production by factor of 2 to match the actual production.

Case 6

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.015	31	950
2	Yes	0.015	31	950
3	Yes	0.015	31	950
4	Yes	0.015	95	1550

Pre-frac Skin = +1

Post-frac Skin = -3

Simulation results are plotted in Figure A-6.

Red: Oil Production
Yellow: Water production
Green: Average Pressure

Analysis: The vertical permeability was increased by a factor of 10, resulting in increase of the total production substantially. post fracture production by a factor of 2.

It was then decided to produce from Zone 1 & 2 to match the pre-fracture production and then open all the zones after the fracture job.

Case 7

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.0	31	1000
2	Yes	0.09	31	1000
3	Yes	0.002	31	1000
4	Yes	0.002	60	1700

Pre-frac Skin = +1

Post-frac Skin = -3

Simulation results are plotted in Figure A-7.

Red: Oil Production

Yellow: Water production

Green: Average Pressure

Analysis: No substantial changes in production observed.

Case 8

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.025	31	950
2	Yes	0.025	31	950
3	Yes	0.025	31	950
4	Yes	0.0095	95	1750

Pre-frac Skin = -2

Post-frac Skin = -4

Simulation results are plotted in Figure A-8.

Red: Oil Production

Yellow: Water production

Green: Average Pressure

Analysis: Initial peak production was about 30-40 BOPD less than the actual production, but the post fracture peak production was about 250 BOPD less than the actual production.

Reservoir Model OOIP: 7523.140 MSTB
 Total production: 817757 STB
 Actual production: 912540 STB
 % of Actual Production: 88.846 %

It was found that the edge wells namely Nelson #2-2, Nelson #2-3, Sherman #4 and Carr #2-1 were not producing at the rate they should have been producing. Looking into the maps and contours, it was found that there was not enough reservoir volume in that area for the wells to produce. In order to increase the reservoir volume the no flow boundary was moved further outside. this increased the total reservoir OOIP by about 35%.

Case 9

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.002	31	950
2	Yes	0.09	31	950
3	Yes	0.095	31	950
4	Yes	0.09	99	1650

Pre-frac Skin = -2

Post-frac Skin = -4

Simulation results are plotted in Figure A-9.

Red: Oil Production
 Yellow: Water production
 Green: Average Pressure

Analysis: Substantial changes in production observed. The final results gave us history match of about 99.013 %

Reservoir Model OOIP: 100288 MSTB
 Total production: 876153.9 STB
 Actual production: 912540 STB
 % of Actual Production: 96.013 %

Conclusions: 1. Permeability increased by factor of 2.
 2. Increased reservoir volume at the edges.
 3. Pressure support from the aquifer.

Case to prove aquifer support:

Case 10 : No vertical permeability in either layers.

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.0	31	950
2	Yes	0.0	31	950
3	Yes	0.0	31	950
4	Yes	0.0	95	1750

Pre-frac Skin = -2

Post-frac Skin = -4

Simulation results are plotted in Figure A-10.

Red: Oil Production

Yellow: Water production

Green: Average Pressure

Analysis: Initial peak production was about 60-80 BOPD less than the actual production, but the post fracture peak production was about 250 BOPD less than the actual production.

Reservoir Model OOIP: 10288 MSTB

Total production: 730160.2 STB

Actual production: 912540 STB

% of Actual Production: 80.01%

Case 11 : No aquifer present in the model.

Layer #	Perf	KZ md	Sw %	P psi
1	Yes	0.002	31	950
2	Yes	0.09	31	950
3	Yes	0.0095	31	950

Pre-frac Skin = -2

Post-frac Skin = -4

Simulation results are plotted in Figure A-11.

Red: Oil Production

Yellow: Water production

Green: Average Pressure

Analysis: Initial peak production was about 60-80 BOPD less than the actual production, but the post fracture peak production was about 250 BOPD less than the actual production.

Reservoir Model OOIP:	10007 MSTB
Total production:	762144.7 STB
Actual production:	912540 STB
% of Actual Production:	83.51%

Figure A-1: Case 1

Figure A-2: Case 2

Figure A-3: Case 3

Figure A-4: Case 4

Figure A-5: Case 5

Figure A-6: Case 6

Figure A-7: Case 7

Figure A-8: Case 8

Figure A-9: Case 9

Figure A-10: Case 10

Figure A-11: Case 11

APPENDIX B

Calculations for Permeability Measurements Conducted at the University of Kansas

$$K = Q\mu L / (A\Delta P)$$

where: K = permeability, darcys
 Q = flow rate, cc/sec
 μ = liquid viscosity, cP
 L = core length, cm
 A = cross-sectional area of core, cm²
 ΔP = pressure drop across the core, atmospheres

Core Dimensions:

Core	Average length (cm)	Average diameter (cm)
Berea	2.478	2.506
Scott	2.616	2.506
Sherman	2.908	2.504
Meyer #1	2.682	2.508
Meyer #2	2.533	2.505

Viscosity:

2.0% Sodium Chloride Solution: Viscosity assumed to be same as water

For distilled water,

$$\mu = \exp(1.003 - 1.479 \cdot 10^{-2}T + 1.987 \cdot 10^{-5}T^2), \text{ viscosity in cP}$$

where: T is the temperature in degrees Fahrenheit

Synthetic Formation Brine:

Viscosity at 125°F = 0.67 cP

Viscosity at 77°F = 1.07 cP

Viscosity at 68°F $\approx$ 1.20 cP

Injection Water:

Viscosity assumed to be same as water

3.0% Potassium Chloride Solution:

Viscosity at 125°F = 0.66 cP

Viscosity at 77°F = 0.98 cP

Viscosity at 68°F ≈ 1.10 cP

Filtered Produced Water:

Viscosity assumed to be same as synthetic formation brine

500 ppm Aluminum (Aluminum Citrate) Solution:

Viscosity assumed to be same as water

Porosity:

Berea core: porosity = 20.0 %

Field cores: porosity assumed to be 16.0 %

APPENDIX C

Description of Experiments Conducted at the University of Kansas

Berea core: Experiments were performed on berea core using synthetic formation brine solution at room temperature ($\approx 68^\circ\text{F}$) and reservoir temperature (125°F). Normally the injection was done at three different flow rates. The flow rate was measured from the effluent line and typical values of these were around 1.2 ml/min, 2.4 ml/min and 3.6 ml/min.

Figure C-1: Permeability measurements for the plug with synthetic formation brine at room temperature and reservoir temperature. The permeabilities were found to be around 150 md for all flow rates at both temperatures. Figure (a) shows the measurement of pressure drop versus time. Figure (b) shows the relative permeability (instant permeability divided by the initial permeability) as a function of the pore volumes injected for the same experiment.

Scott 4-4: The core plug was cut from the rock sample using fresh water. The plug was then evacuated and saturated with synthetic formation brine. Injection was typically done at measured flow rates of about 1.2 ml/min, 2.4 ml/min and 3.6 ml/min.

Figure C-2: Permeability measurements for injection with synthetic formation brine at room temperature on day 1. The permeability values were calculated to be between 187 and 189 md. The core plug was left in contact with synthetic formation brine overnight. This procedure was followed for the entire length of the experiment, where the core was left shut-in in contact with the injection fluid at room temperature.

Figure C-3: Permeability measurements for synthetic formation brine at room temperature and reservoir temperature on day 2. Initial injection was done at room temperature and the permeability calculated was around 184 md indicating good reproducibility of measurements. The apparatus was then allowed to sit in a water bath maintained at 125°F for about an hour and injection at high temperature was started. The initial permeability was calculated to be about 180 md. As the injection rate was increased, the pressure drop showed a constant increase indicating a reduction in permeability. This behavior continued to persist and after about 3 hours of injection, the permeability had dropped to 140 md.

Figure C-4: The injection was started at room temperature and constant permeability values were obtained. The permeability values were calculated to be around 139 md. Once the injection was started at high temperature, a further drop in permeability was observed. At the end of the run, the permeability was calculated to be 107 md.

Figure C-5: Permeability measurements for day 4. For this experiment, after an initial brine injection, the direction of flow was reversed. The results shown here depict the measurements only for the reversed direction of flow. The three different flow rates used for this experiment were 0.57 ml/min, 1.2 ml/min and 2.4 ml/min. Similar behavior was observed in these experiments also, where the injection at high temperature was found to decrease the permeability of the core. The initial permeability measured for this experiment, without flow reversal, was 90 md and the same value was

calculated after the direction of flow was reversed. However, the permeability continued to decrease after injection was started at 125°F.

Figure C-6: For this experiment the direction of flow was reversed again. The injection rates for this experiment were 1.2 ml/min and 2.4 ml/min. The initial permeability was calculated to be 75 md and it continued to drop until the injection was stopped. At the end of the run, the permeability was calculated to be 59 md.

Figure C-7: Permeability measurements for injection water from the field on day 11. Initial injection was done at room temperature and constant permeability values were measured around 65 md. Injection at high temperature resulted in a further reduction in permeability and at the end of the run the permeability had dropped to 40 md. The core was left in contact with the injection water at room temperature overnight.

Figure C-8: Injection on day 12 was started with 3.0% potassium chloride solution at room temperature. The initial flow rate for injection was around 2.4 ml/min and after shutting the pump for an hour, the solution was injected at rates of about 1.2 ml/min, 2.4 ml/min, 3.6 ml/min respectively. During this experiment, the injection with potassium chloride solution resulted in an increase in permeability. The initial permeability at the beginning of the run was 43 md and at the end of the run the permeability had increased to 94 md. The core was left in contact with the salt solution overnight at room temperature.

Figure C-9: Injection with potassium chloride solution on the following day resulted in a decrease in permeability. The initial permeability measured was around 80 md and at the end of the run the permeability was calculated to be 55 md. The injection rates for this run were 1.2 ml/min and 2.4 ml/min.

Figure C-10: Measurements on day 14 were performed at reservoir temperature with potassium chloride solution. The flow rates were 1.2 ml/min, 2.4 ml/min and 3.6 ml/min. The run was stopped for a couple of hours and then injection was continued with the same flow rates. The permeability was calculated to be around 48 md initially, and at the end of the run the value was found to be around 30 md.

Figure C-11: Injection at reservoir temperature with potassium chloride solution was started at a flow rate of 2.4 ml/min. Injection was continued for about 6 hours until the permeability reached a constant of around 25 md. The run was stopped for a while and then injection was started at the rate of 1.2 ml/min. Injection was continued overnight at reservoir temperature. Due to a pump malfunction, no data could be obtained for a period of 5 hours. However, the permeability values remained constant on restarting the injection at the same flow rates. The final permeability values were calculated to be around 20-25 md.

The core plug was removed from the apparatus and on visual inspection no damage could be observed. The plug was stored in a bottle containing 3.0% potassium chloride solution. The history of the series of experiments performed on the core plug is summarized in chronological order in Table C-1.

Sherman 3: The core plug was cut using fresh water. It was then evacuated and saturated with filtered produced water from the Scott 4-5. The produced water obtained from the field was filtered at atmospheric conditions and then used for saturation and injection.

Figure C-12: Injection was started at a flow rate of about 1.2 ml/min at 125°F. Injection was continued for a period of three days. The initial permeability value was 7.0 md and at the end of three days the value reduced to 2.4 md. The flow rate at the end of three days had to be reduced in order to prevent damage to the transducer. The transducer had a rating of 50 psi and the pressure drop at the initial rate was approaching 50 psi. The injection rate was reduced to about 0.6 ml/min and injection continued for another day. At the end of four days, the permeability had gone down to 1.7 md.

The core plug was removed from the apparatus and no anomalies could be observed on visual inspection. The plug was stored in a bottle containing filtered produced water. The history of the series of experiments performed on the core plug is summarized in chronological order in Table C-2.

Meyer 10-1 Core #1: The core plug was cut using 3.0% potassium chloride solution. It was then evacuated and saturated with the same solution. Injection was typically done at the flow rates of 1.2 ml/min, 2.4 ml/min and 3.6 ml/min at reservoir temperature.

Figure C-13: This figure shows the results for the injection at three typical flow rates at 125°F. The permeability values were found to decrease continually. The initial permeability was calculated to be 30 md and by the end 6 hours, the permeability had dropped down to 16 md. Injection was continued overnight at the rate of 1.2 ml/min. Unfortunately, due to a power failure no data could be collected overnight.

Figure C-14: Injection was continued with potassium chloride solution at the flow rates of 1.2 ml/min, 2.4 ml/min and 4.8 ml/min. The permeability appears to have reached a constant value in the range of 9-12 md. Overnight the plug was left in contact with the potassium chloride solution at 125°F.

Figure C-15: This figure shows the results of injection at the three typical flow rates and 125°F. It can be observed from the figure that the permeability values are nearly constant and were found to be in the range of 9-12 md. Overnight the plug was left in contact with the potassium chloride solution at 125°F.

Figure C-16: Results of the similar injection are shown here and the permeability values were calculated to be between 10-12 md for the three typical flow rates.

The core plug was left in contact with the salt solution at room temperature. The history of the series of experiments performed on the core plug is summarized in chronological order in Table C-3.

Meyer 10-1 Core #2: The core plug was cut using 3.0% potassium chloride solution. It was then and evacuated and saturated with 500 ppm aluminum (aluminum citrate) solution. Injection was done at different flow rates for permeability measurements.

Figure C-17: Injection was performed at 125°F at three different flow rates which were measured to be approximately 1.1 ml/min, 2.3 ml/min and 3.4 ml/min respectively. The initial permeability was calculated to be 29 md and at the end of the run, the permeability value had dropped to 16 md. The injection fluid was changed to synthetic formation brine. Injection was continued for a short period and then the core was left in contact with the synthetic formation brine at the reservoir temperature. Unfortunately, due to a malfunction no data was collected for the pressure drop for synthetic formation brine.

Figure C-18: Injection was started with synthetic formation brine at 125°F. The noise observed in the initial measurements was caused to a pump malfunction which was corrected in the latter half of the measurements. The different flow rates observed in these measurements are approximately 0.75 ml/min, 1.5 ml/min, 1.2 ml/min, 2.1 ml/min and 3.0 ml/min respectively. The permeability values were observed to be constant between 5 to 6 md.

The core plug was left in contact with synthetic formation brine at room temperature. The history of the experiments performed on the core plug is summarized in a chronological order in Table C-4.

Table C-1: History of experiments performed on Scott 4-4 core plug

Time	Experimental Process	Permeability (md)
Day 1	Core plug cut using fresh water. Core evacuated and saturated with synthetic formation brine (SFB). Permeability measurements performed using SFB at room temperature ($\approx 68^\circ\text{F}$). Overnight the core was left in contact with SFB at room temperature.	189-187
Day 2	Injection started with SFB at room temperature and good reproducibility was obtained. Injection started with SFB at reservoir temperature (125°F). A decrease in permeability was observed and the behavior continued during the entire injection period of about 3 hours. Overnight the core was left in contact with SFB at room temperature.	184-140
Day 3	Permeability measurements performed with SFB at room temperature giving a value of about 139 md. Measurements were then performed at 125°F and further decrease in permeability was observed for the entire injection period of about 2 hours. Overnight the core was left in contact with SFB at room temperature.	139-107
Day 4	After an initial permeability measurement with SFB at room temperature (90 md), the direction of flow was reversed. No change in permeability was observed. Injection at 125°F yielded further reduction in permeability. Overnight the core was left in contact with SFB at room temperature.	90-70

Time	Experimental Process	Permeability (md)
Day 5	The direction of flow was reversed again and SFB was injected at 125°F. The decrease in permeability was observed for the entire injection period of about 2 hours. The core was left in contact with SFB overnight at room temperature.	70-59
Day 6-10	The core was left in contact with SFB at room temperature.	-
Day 11	The core was injected with injection water from the field. Permeability measurements at room temperature remained constant but injection at high temperature resulted in a further reduction in permeability. Overnight the core was left in contact with the injection water at room temperature.	65-40
Day 12	The core was injected with 3.0% KCl solution at room temperature. An increase in permeability was observed with KCl injection at various flow rates. The core was left in contact with KCl solution overnight.	43-94
Day 13	Further injection with KCl solution resulted in a decrease in permeability. Overnight the solution was left in contact with KCl solution at room temperature.	82-55
Day 14	Permeability measurements performed with 3.0% KCl solution at 125°F. A continuous decrease in permeability was observed for the injection period of about 6 hours. The core was left in contact with the KCl solution overnight at room temperature.	48-30
Day 15	Injection was started with KCl solution at 125°F. A further drop in permeability was observed. Injection was continued at a fixed flow rate for about 6 hours until the permeability reached a constant value. The flow rate was changed and the injection was continued overnight at 125°F.	30-21
Day 16	No further change in permeability was observed. Changing the flow rates did not show any significant change in the permeability values. The core plug was removed from the apparatus and on visual inspection, no damage could be observed. The core plug was stored in a bottle containing 3.0% KCl solution.	20-25

Table C-2: History of experiments performed on Sherman 3 core plug

Time	Experimental Process	Permeability (md)
Day 1-4	Core cut using fresh water. Evacuated and saturated with filtered produced water from Scott 4-5. Injection started with produced water at 125°F and was continued for a period of three days. A constant decrease in permeability was observed. At the end of three days, the flow rate was reduced by 50% and injection continued for another day. Decrease in permeability was still observed. The core plug was stored in a bottle containing filtered produced water.	7-2

Table C-3: History of experiments performed on Meyer 10-1 core plug #1

Time	Experimental Process	Permeability (md)
Day 1	Core cut using 3.0% KCl solution, evacuated and saturated with the same solution. Injection started with 3.0% KCl solution at 125°F. Solution was injected at three different flow rates and a continuous decrease in permeability was observed. Overnight the injection was continued at the reservoir temperature.	30-16
Day 2	Injection was done at three different flow rates and the permeability values appear to have reached a constant value. Overnight the core was left in contact with the 3.0% KCl solution at 125°F.	9-12
Day 3	Injection was done at different flow rates and the permeability values did not show any change. Overnight the core was left in contact with the 3.0% KCl solution at 125°F.	9-12
Day 4	Injection was continued with the same solution and no change in permeability was observed. The core was left in contact with 3.0% KCl solution at room temperature.	10-12

Table C-4: History of experiments performed on Meyer 10-1 core plug #2

Time	Experimental Process	Permeability (md)
Day 1	Core cut using 3.0% KCl solution. It was evacuated and saturated with 500 ppm aluminum (aluminum citrate) solution. Injection started with 500 ppm aluminum solution at 125°F. Solution was injected at three different flow rates and a continuous decrease in permeability was observed. After approximately 6 hours of injection the injection fluid was changed to synthetic formation brine. Overnight the core plug was left in contact with the synthetic formation brine at the reservoir temperature.	29-16
Day 2	Injection was done at different flow rates. For all the different injection rates the permeability values appear to have reached a constant value. The core was left in contact with synthetic formation brine at room temperature.	6-5

Figure C-1(a): Pressure drop for Berea core injected with synthetic formation brine at room temperature and reservoir temperature.

Figure C-1(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-2(a): Pressure drop for field core injected with synthetic formation brine at room temperature.

Figure C-2(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-3(a): Pressure drop for field core injected with synthetic formation brine at room temperature and reservoir temperature.

Figure C-3(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-4(a): Pressure drop for field core injected with synthetic formation brine at room temperature and reservoir temperature.

Figure C-4(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-5(a): Pressure drop for field core injected with synthetic formation brine at room temperature and reservoir temperature.

Figure C-5(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-6(a): Pressure drop for field core injected with synthetic formation brine at reservoir temperature.

Figure C-6(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-7(a): Pressure drop for field core injected with proposed injection water at reservoir temperature.

Figure C-7(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-8(a): Pressure drop for field core injected with 3.0% potassium chloride solution at room temperature.

Figure C-8(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-9(a): Pressure drop for field core injected with 3.0% potassium chloride solution at room temperature.

Figure C-9(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-10(a): Pressure drop for field core injected with 3.0% potassium chloride solution at reservoir temperature.

Figure C-10(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-11(a): Pressure drop for field core injected with 3.0% potassium chloride solution at reservoir temperature.

Figure C-11(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-12(a): Pressure drop for field core injected with filtered produced water from Scott 4-5 at reservoir temperature.

Figure C-12(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-13(a): Pressure drop for field core injected with 3.0% potassium chloride solution at reservoir temperature.

Figure C-13(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-14(a): Pressure drop for field core injected with 3.0% potassium chloride solution at reservoir temperature.

Figure C-14(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-15(a): Pressure drop for field core injected with 3.0% potassium chloride solution at reservoir temperature.

Figure C-15(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-16(a): Pressure drop for field core injected with 3.0% potassium chloride solution at reservoir temperature.

Figure C-16(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-17(a): Pressure drop for field core injected with 500 ppm aluminum (aluminum citrate) solution at reservoir temperature.

Figure C-17(b): Relative permeability versus pore volumes injected for the same experiment.

Figure C-18(a): Pressure drop for field core injected with synthetic formation brine at reservoir temperature.

Figure C-18(b): Relative permeability versus pore volumes injected for the same experiment.

APPENDIX D

Geological Description of the Savonburg Field

Correlation of the well logs provided the stratigraphic framework of the field and the basis for interpreting lithology in wells or parts of wells where no core description was available. Stratigraphic markers, either regional or local, were traced through the field area to provide detailed correlation on a scale of 10 to 40 feet. Some of the markers, which are designated "marker intervals" can be tied into the regional stratigraphic correlation previously developed by Harris (1984) and applied by Staton (1987) and Huffman (1991). Where such correlations could be made, the marker intervals were referred to by the name of the associated coals, either those that have been formally recognized (Weir-Pittsburg, Tebo, Scammon, etc.) or those that Harris (1984) informally named (Fig. D-2). A few markers, especially those that are only of local significance, are still designated by the color of the press-on dots that were used to identify them on logs during the phase of the study when the internal stratigraphy of the field was being worked out (red, brown, dark blue, silver, etc.). Others, below the silver marker, were referred to by the letters A, B, C, and D because no additional colors were available to differentiate them. Traces of this usage remain in this report. Names of sandstones are based upon Jewett et al. (1968), as modified by Hulse (1978), Ebanks (1979), Staton, and Huffman.

Nomenclature of Mudrocks

The geological study uses *shale* in an informal sense that is common both in the oil industry and among professional geologists. Usage here does not differentiate between fissile or laminated rocks, which are strictly called clay- or mud shales, and non-fissile, non-laminated rocks which are given the suffix -stone. Clay and mud differ in particle size. Claystones and clay shales consist dominantly of clay (particles less than 4mm), whereas mudstones and mud shales consist of sub equal mixtures of clay particles and silt particles (4 to 62mm).

Contouring

Isopach maps of good quality reservoir sandstone, especially that in the B₃ and B₂ zone, were contoured to represent the geological interpretation of them as the result of deposition in a tidal estuary. These map are presented in Figure D-6 and D-7, respectively.

Regional Geology

The valley-fill deposit that is productive on the Nelson Lease is in the Chelsea Sandstone member of the Cabaniss Formation (Jewett, et al., 1968), the lower part of the Skinner interval (younger than the Tebo Coal and older than the Scammon Coal; Staton, 1987), or the informal Cattlemans interval (Hulse, 1978). Rocks of the Cabaniss Formation are assigned to the Desmoinesian stage of the Middle Pennsylvanian Series. The Nelson Lease includes the SW/4 of Section 21, and the NW/4 of Section 28, Township 26 South, Range 21 East (Fig. D-1, D-2) and lies on the SW flank of the Bourbon Arch, a subtle structure that separates the Cherokee basin to the south from the Forest City basin to the north.

Both of these shallow basins lie in the marginal part of the craton of North America, on the shelf north of the Arkoma Basin, a foreland basin that, in turn, lies north of the Ouachita Tectonic Belt. The Ouachita belt was most active in the early and middle Pennsylvanian, with orogeny climaxing in Desmoinesian time, simultaneous with deposition of the Cherokee Group. Deposition in the Arkoma basin began in early Middle Pennsylvanian time (Atokan). Despite intense contemporary tectonic activity a few hundred km to the south, sediments for the Cherokee Group appear to have come from sources that lay to the north and east.

The Cabaniss Formation consists mostly of shale, but includes beds of sandstone, coal, and limestone. In the area of the Nelson Lease, only the sandstones reach large thickness, with single sandstone lenses making up to 10 to 25 percent of the entire thickness of the Cabaniss Formation in many wells. Shale intervals are broken up by marker intervals, which are described below, into sequences 10 to 40 feet thick.

Previous descriptions

Operators of this field have divided the reservoir into informal A, B and C sandstone intervals (named from top to bottom). These intervals were defined primarily upon their depth, and the boundaries were drawn between them on the basis of shale interbeds that were approximately at the same elevation in adjacent wells. The A sand was not present in all parts of the field and was not productive of where it was found. The B sandstone was traced throughout the field and is perforated in most, if not all, productive wells. The C sandstone, as defined by the operators, is best developed in the eastern part of the northern 1/4 section lease, but was correlated over the entire field area. The operator's C sand is the major productive sands in the most productive wells, and intervals that appeared to have C sand in them were perforated in many wells throughout the field.

Results of restudy of the field

The analysis presented below has used the same designations for the intervals containing sandstone in the reservoir (A, B, and C), but has defined them according to their age with respect to regional stratigraphic marker intervals, described below, which are more continuous than the shale breaks used by the earlier analysis. The C sandstone, as used in this study, is older than the Tebo marker interval and younger than the Weir-Pittsburg marker interval, although it locally is deposited in a valley that was eroded through the Weir-Pittsburg marker interval. The B interval post-dates the Tebo marker interval and predates the Scammon marker interval, but includes a valley-filling succession that is lower in elevation than the projected position of older markers down as far as the Abj coal (Harris, 1984). The most productive sandstones in the field, which were designated C by the operators, have been reassigned to the B interval, based upon their situation as part of the fill of that valley. The B interval has been subdivided into B₃, B₂, and B₁ zones (listed from bottom to top) to differentiate sandstones that formed during different parts of the history of valley filling. All of the oil production in the field comes from beds designated as part of the B₂ and B₃ zones, according to revised correlations. Sandstones of the A interval are younger than the Scammon marker interval and older than the Mineral marker interval. Locally A sandstone beds are deposited in a shallow valley that cuts through the Scammon marker interval.

Regional marker intervals of the Cherokee Group

Regional marker intervals are characteristic of the Cherokee Group and other dominantly siliciclastic Pennsylvanian strata of eastern Kansas. Where these marker intervals are completely developed, they include, in ascending order, an underclay or paleosol, a coal bed, an argillaceous limestone or shelly sandstone, and a dark gray to black shale (Fig. D-3). Commonly small concretions of siderite, called "birdshot siderite" are found in the strata just below the underclay. The strata containing siderite may be very light gray claystone or siltstone that has a bleached appearance and is tightly cemented.

Marker intervals can be correlated for distances of hundreds of kilometers, and from basin to basin on the shelf of the US interior. Some of those in the Cherokee can be correlated into Iowa and, across the Mississippi River Arch, into the Illinois Basin (Brenner, 1989; Coveney et al., 1987). Regional marker intervals may also correlate with markers that divide the Atokan and Desmoinesian succession in southwestern Kansas (Youle, 1993). Marker intervals have been successfully used to subdivide the Cherokee Group of Kansas, especially the Cabaniss Formation, and traced over southeastern and south-central Kansas (Killen, 1986; Staton 1987; Huffman, 1991) and into the Kansas City area. They are generally the stratigraphically equivalent to the coal beds used by Hulse (1978), Ebanks (1979), and Harris (1984), but are easier to correlate because they consist of a suite of lithologies, not all of which need to be present to establish the position of the marker interval. In characterizing reservoirs, as well as in other geological activities in the Cherokee section, these markers make possible a detailed stratigraphy and fine subdivision of the section into temporally distinct units (Fig. D-2, D-4). Marker intervals are 10 to 40 feet apart, for the most part, they are thus the most precise basis for correlation of Cherokee successions.

Marker intervals are remarkably recognizable in g-neutron logs. The underclay commonly washes out, which can be reflected in the caliper log. Underclays may also be depleted of potassium, compared to other shales, and resemble shaley sandstone on the g log, while the neutron log shows a "high porosity" response (leftward deviation) to bound water in the clay. Underclays are almost invariably present beneath Pennsylvanian coals in Kansas, and commonly beneath dark shales where no coal is present. A g low and a neutron deflection toward the right (low apparent porosity) is common just below the underclay. This corresponds to the tightly cemented, apparently bleached shales or siltstones that contain birdshot siderite.

Coal beds by themselves have strong leftward neutron responses because they contain abundant water and hydrogen. Coal has low g intensities, but the g response is commonly masked by overlying highly radioactive dark gray or black shales, which are actually more common and continuous than the coals.

Argillaceous limestone and sandstone beds are not common in the Savonburg NE Field area, and are generally very thin, so that their log response is masked. They are common in other parts of the Cherokee elsewhere in SE Kansas. Harris (1984) reports that about 50% of coal occurrences have overlying limestones in the Krebs Formation (lower Cherokee Group) in cores and in natural and artificial outcrops in Cherokee, Crawford, and Bourbon counties.

Dark shales, either dark gray or black and either massive or fissile, are the fourth member of the complete marker interval. They contain a concentration of uranium and organic matter, which makes their response strong on both the g and neutron sides, although the g response is the most marked. Dark shales of one type or the other are almost invariably present above thin limestones or sandstones, above coal where the limestones are not present, or above underclay, where both coal and thin limestones and sandstones are missing. In the Nelson lease, such shales were the most recognizable unit of marker intervals.

Sequence Stratigraphy

The paleosols and underclays of the marker successions represent sub aerial exposure of the succession during periods of low relative sea level. They thus meet the definition of boundaries of stratigraphic *sequences* (Van Wagoner et al., 1990). The overlying part of the marker successions (coal, limestone or sandstone, if present, and dark gray or black shale; Fig. D-3) are probably the result of deposition during a rise in relative sea level with accompanying landward shift of adjacent depositional environments. The successive environments would be sub aerial coal swamp, erosional region (associated with passage of the shoreline and shoreface across the area, which may leave residual deposits), and deposition in a shelf environment in a stratified water column, respectively. Between the coal (or underclay if no coal is present) and the next overlying bed is a surface of initial transgression, marking the passage from non-marine to marine deposition. The dark gray shale or a gradationally overlying medium gray shale would represent the surface of maximum transgression for each sequence.

Strata in the interval between marker successions reflect filling of available accommodation space (space beneath local base level that is not already filled with sediment) during conditions of rising, steady, or falling sea level. All of the sediment above a particular marker interval is younger than all of the sediment beneath that marker interval, e.g. all of the sediments between the Tebo and Scammon marker intervals are older than all beds between the Scammon and Mineral markers, so that temporal ordering of inter marker intervals is unequivocal.

In the valley region in the eastern part of the NW/4 of Section 21, T26S R21E (filled by Chelsea Sandstone; Fig. D-2, D-4), and elsewhere wherever erosion has removed the sequence boundary, the boundary lies at the base of the erosive cut, commonly just below a sandstone or a conglomerate. The depth of incision of the Chelsea valley is sufficient to indicate that sea level fell below a shelf edge during its incision (van Wagoner et al., 1990).

Marker intervals in the Nelson Lease

In the lower and middle Cabaniss of the Nelson Lease, six regional marker intervals are present, correlated (from top to bottom) to "V" Shale -Croweburg Coal, the Mineral Coal, the Scammon Coal, the Tebo Coal, Weir-Pittsburg Coal, and the Bluejacket "A" coal (Fig. D-2, D-4). In addition, several characteristic kicks of the gamma-neutron logs carry across the field, or parts of it, and are useful as additional stratigraphic markers (Fig. D-4). The following section of the report describes the individual marker intervals present close to the reservoir sandstones in the Savonburg Field and correlates them into a regional framework developed by Harris (1984). The correlation is based upon a study of the Cherokee Group in the Bourbon Arch region by Huffman (1991). While this report uses a nomenclature for the marker intervals based upon existing correlations, it does point out a few places where correlations are questionable and possibly subject to revision. This section also

describes other stratigraphic markers in the field, the stratigraphic position of sand bodies, including the reservoir sand body in the Chelsea Sandstone, and non-reservoir rocks between markers in the Nelson Lease.

Stratigraphic Succession in the Nelson Lease - Bluejacket A marker interval

The Bluejacket A marker interval consists of the Bluejacket A coal bed ("A" coal bed on logs used in this study) and overlying dark shale. The coal bed itself was penetrated in the core from well RW-8, where it was 0.8' thick. The presence of this coal bed is inferred from a spike of low ρ intensity and high neutron porosity occurs in all other wells that penetrate deeply enough. The designation of the Bluejacket A coal bed was introduced informally by Harris (1984) to distinguish one of several previously unrecognized coal beds between the Weir-Pittsburg and Dry Wood coals. Staton (1987) and Huffman (1991) did not find the Bluejacket A coal easy to correlate across the Cherokee basin and Bourbon arch areas.

The coal of the Bluejacket A marker is underlain by a poorly developed underclay that is the lowest 3.1' of core RW-8. The underclay grades from laminated mudrock at the base, with vertical fractures filled with siderite and some slickensides, to mottled claystone with slickensides at the top. Above the Bluejacket A coal is less than 0.1' of very fine sandstone with pebbles of shale, siderite, and carbonaceous material, and medium gray streaked, burrowed shale that forms a small gamma peak. This shale bed was penetrated by the core of well O-1 (Fig D-5C), where it consisted of 3' of dark gray laminated shale. This dark gray shale is overlain directly by the silver marker.

Silver marker

The silver marker is a distinct rightward kick on the neutron log and moderate kick toward lower ρ values, compared to shales above and below. The top of this marker is 6 feet above the top of the Bluejacket A coal. The silver marker is present in the core RW-15, and its lower part is present in core O-1 (Fig. D-5C). In RW-15, it consists of 3.7' of near white, light gray and dark gray mudstone that is firmly cemented. Siderite concretions of mm-scale ("birdshot siderite") are common in it. It was originally wavy bedded or laminated, but has since been disturbed by the action of organisms. Its boundaries with dark gray clay beneath (part of the Bluejacket A marker interval) and medium gray claystone above are sharp.

In core RW-12, light gray shales of the silver marker are overlain by just over 1' of siltstone and very fine sandstone with disturbed bedding. This bed grades into 1.1' of poorly stratified, dark gray silty shale. In RW-15, the silver marker is again overlain by light to medium gray shale, here 0.5' of laminated clayey mudstone below and 0.8' of blocky, slickensided clay above. The upper contact of the slickensided clay is gradational with laminated olive medium gray claystone that becomes light gray at the top.

The succession from the silver marker to the dark gray or olive clay above it appears to be a marker interval that lacks a coal at this locality. It differs from the normal marker interval in that its dark gray clay overlies the underclay or paleosol component gradationally, rather than sharply. Correlation of this horizon, referred to below as the Silver marker interval, is problematical and is discussed further below.

Silver marker to light blue marker

Dark clays at the top of the silver marker interval grade into a succession characterized by decreasing g intensity and rightward-shifting neutron values upwards, followed by sharper shifts of the g and neutron curves toward values characteristic of shales. The succession is about 14' thick. In part this sequence reflects a coarsening- then fining-upward succession of dark gray to light gray, weakly laminated shale, light gray streaked and linsen-bedded shale, and light gray linsen- to wavy-bedded silty shale. The shaley part of the succession may contain a few fossils of fragmented plants, especially 1/4 of the way up.

Some of the log deflections may be related to tight cementation and presence of siderite, like those of the silver marker. Several parts of the upper 6.5' of this interval have beds with moderate to high concentrations of birdshot siderite. In such beds, disruption of bedding by root marks or brecciation is common, especially in the upper part of the bed, where it grades into the underclay beneath the overlying Weir-Pittsburg marker. Maximum deflection of g and neutron curves corresponds to a light gray or light olive gray, cemented layer with red, birdshot siderite concretions in cores O-2, RW-7, RW-9 (Fig. D-5B), RW-10, RW-12, RW-15, and RW-16. The peak of this apparently upward coarsening upward succession lies about 16 feet above the top of the silver marker and was correlated as the dark blue marker. The topmost part of this sequence decreases in grain size to shale and changes from linsen-bedded to streaked with thin laminae of silt. It has higher g values and leftward deflection of the neutron curves.

Weir-Pittsburg marker interval

The Weir Pittsburg marker appears in logs as a prominent gamma-ray peak and the immediately underlying peak of a leftward neutron deflection; both have a sharp deflection below and a gradational one above, unless the overlying succession has been removed by erosion and the marker is overlain by a valley-filling succession. This marker is partially or completely present in cores from wells O-3, RW-3, RW-6, RW-7, RW-9 (Fig. D-5B), RW-10, RW-12, and RW-16. This marker is very persistent, Harris (1984), Staton (1987) and Huffman (1991) were able to trace it across southeastern Kansas. It is absent in part of the Nelson Lease where it is apparently truncated by erosion before deposition of the B or C sandstones. The Weir-Pittsburg marker generally lies a few feet above the dark blue marker and is 21 feet above the silver marker.

Generally, the Weir-Pittsburg marker consists of an underclay overlain by a dark gray shale. Coal, limestone, and sandstone are not present in any of the cores from this field, but bleached, sideritic, cemented light gray shale and siltstone is present in the dark blue marker beneath. The correlation with the Weir-Pittsburg Coal is based upon the work of Huffman (1991). Reasons why this correlation is only tentative are discussed below.

The underclay of the Weir-Pittsburg marker interval grades from the light gray, cemented, sideritic mudrocks of the underlying dark blue marker. No bedding is preserved in the underclay, but it is friable and breaks into chunks that are slickensided and show root marks. The clay has a waxy appearance. Fractures are filled with brecciated fragments of the bed itself. This bed is 3.3' thick where completely preserved in core RW-7. The dark gray to black shale (actually claystone) bed in the Weir-Pittsburg marker is 0.75' to 2' thick and is laminated. It includes some phosphatic concretions and, at least in one well, a bed of fossil shells and shell fragments. Dark gray to black

shale grades into overlying beds of medium gray or olive medium gray shale of the Weir-Pittsburg--Tebo interval.

Weir-Pittsburg--Tebo interval and C Sandstone

Dark gray, fissile, phosphatic shales of the Weir-Pittsburg marker interval grade into medium gray shales then into an upwards-coarsening mudrock sequence that has birdshot siderite and disturbed bedding as widespread features. This sequence is remarkably like the silver and dark blue markers and like the development between the Tebo marker interval and the brown marker outside the channel area, as described below. It is present in cores O-3, RW-6, RW-7, RW-10, RW-11, RW-16, and RW-17. Core descriptions from Oil Field Research commonly describe the top of this succession as "light gray sandstone". The total CU succession is about 6 feet thick. The shale bed is about two feet thick and is generally of an olive medium gray color. It is laminated and fissile. The coarser beds are shale and siltstone, apparently structureless, well indurated, and of light gray or perhaps olive light gray to very light gray color. They have disturbed bedding, root marks, and birdshot siderite in their upper part. Calcite cements may also be present. The top of this siltstone interval grades into the underclay at the base of the Tebo interval.

In the southeast corner of the southwest corner of section 21, T26S R21E, the interval between the base of the Tebo marker and the top of the Weir-Pittsburg marker includes a sandstone bed up to 11 feet thick. It has an erosional base and cuts through the Weir-Pittsburg marker interval into the dark blue marker below. According to the usage in this report, this sandstone is the C sandstone. The C sandstone has a upward-fining log pattern on the g -ray--neutron log. This sandstone was encountered in only a few wells and no cores are available. Some sandstone assigned to the Chelsea valley fill that postdates the Tebo marker interval might actually be older than the Tebo marker interval and actually part of the C sandstone. Only where the Tebo marker is present is it possible to differentiate the B and C sandstones unequivocally. Sandstone in deep part of the valley fill (wells H-27, H-30, KW-51, H-21, RW-8, K-44, H-16, KW-6, H-13) was mapped as part of the B₃ zone, rather than being incorporated into the laterally adjacent C sandstone because the trend of the valley, as defined by the truncations of markers was at right angles to that apparent trend of the C-sandstone.

Tebo Marker Interval

In cores RW-16 and RW-17, the Tebo marker interval is a coal bed about six inches thick that overlies a poorly developed underclay. This marker was also encountered in cores RW-4, RW-5, and RW-11. In all of these cores, the coal was overlain by sandstone or conglomerate, rather than black shale. Despite the lack of a dark shale in those wells, the Tebo marker interval is marked on their logs by a distinct kicks, with the neutron peak just above the g-ray peak. In wells on the east bank of the Chelsea erosional valley, the Tebo appears to be overlain by a black shale that grades up into a upward-coarsening succession, because logs of those wells display a sharper g-ray peak than the Tebo marker interval does in other wells on the Nelson lease.

The underclay is at least 1.3' thick in the cores of the Tebo marker interval, and is a mottled, medium to very light gray, very friable claystone that gradationally overlies the sideritic upward-coarsening succession described above. The coal is less than one foot thick. In one well, the coal is split by layer of sandstone 0.3' thick, in another, by a shale bed. In the core from RW-16, the Tebo coal is overlain by a thin (0.4") limy sandstone interval with rip ups and other intraclasts that passes

up into medium gray laminated mudstone. The mudstone passes, over a thickness of a foot, to medium gray siltstone and then into wavy-bedded mudrock or very fine sandstone. The log from this well shows a stronger g-ray peak than other occurrences of the Tebo marker interval.

Bluejacket A Coal through Tebo Marker Interval

Correlation . The Weir-Pittsburg and Tebo marker intervals, as defined above, correlate exactly to markers Huffman (1991) identified in the Yemon #54 Dotson well in the NW SW of Section 26, T26S R21E, about 2 miles east of the Nelson Lease in the Savonburg NE Oil Field. Huffman (1991) and Staton (1987) had correlated their nets of wells back to the Pittsburg and Midway #20 core (SE NE NE Section 8, T32S R22E in Cherokee County, Kansas), which includes all of the Cherokee except the few feet above the Breezy Hill Limestone (Fig. D-2). Harris (1984) described this core and identified several key beds in it. Because Huffman's and Staton's correlations appear consistent and are already available, they are used in this report.

However, it is suspected that the correlation is incorrect with regard to the Tebo and Weir-Pittsburg coals. The marker called Weir-Pittsburg in this study normally has a phosphatic dark gray to black shale, similar to the shale assigned to the Tebo marker interval elsewhere, but no coal, whereas the Weir-Pittsburg is dependably a mineable coal with no black shale just 30 miles to the east, near the outcrop in Crawford County. It is suspected that the marker called "Weir-Pittsburg" in this study is actually includes the horizon of the Tebo Coal Bed.

If this is true, the identity of the marker called Tebo (i.e. the green marker) in this study then becomes a problem. However, Harris (oral comm., 1983) found that the Tebo coal is commonly split into two beds. For an example of this, see Harris's (1984, p. A-45) description of the P&M #21 core. It is possible that both markers (Weir-Pittsburg and Tebo, as referred to in this study) should be correlated with the Tebo. Unfortunately, where the Tebo is split into two beds elsewhere, the beds are generally not separated by as much section, 13 feet, as they are here.

Making the light blue marker part of the Tebo requires that another bed be the Weir-Pittsburg. It is possible that the silver marker is actually the Weir-Pittsburg horizon, with a well-developed paleosol and underclay, but no coal and little black shale. Final judgment on exact identity of beds awaits re-evaluation of Huffman's (1991) and Staton's (1987) correlations with the P&M 20 core. For the meantime, I have used their nomenclature.

Spacing between the Marker Intervals

Generally the spacing between the markers, especially the upper markers in the succession, vary from well to well. That is not true of the spacing between the Tebo marker interval, the Weir-Pittsburg marker interval, and silver marker and the Bluejacket A coal bed. Wherever the Bluejacket A coal bed and the silver markers are both present in a well, it is six feet from the top of the A bed to the top of the silver marker. The Weir-Pittsburg marker (defined as the cross-over from high neutron values (leftward deflection) to high gamma values) lies 21 feet above the top of the silver marker. Thirteen feet separates the Weir-Pittsburg marker from the Tebo marker, again defined as the crossover from high neutron to high gamma values. These distances serve as very reliable guides in reconstructing the depth of erosion of the valley now filled by the B₂ and B₃ sands and to projecting the depth of an underlying marker not penetrated by the drill.

The Reservoir Interval, the B₂ B₃ Interval

The reservoir interval is younger than the Tebo marker interval and older than the brown marker. It appears to be part of the fill of a valley cut through the Tebo and Weir-Pittsburg marker intervals, the dark blue marker, and, in places, the silver marker into the top of the Bluejacket A coal bed (Fig. D-2, D-4). Lithology of the valley-filling succession is complex. It consists of three basic lithologies: sandstones; interbedded sandstones, siltstones, and shales; and shales. It can be divided into two separate units, referred to here as the B₂ and B₃ zones. Stratigraphy and lithology of the reservoir interval are described below.

At places along the eastern side of the Nelson lease, the wall of the valley is preserved. Beds that predate cutting of the valley, but post-date the Tebo marker interval, are encountered in wells K-34, K-35, K-36, and K-37 (Fig. D-2, D-4). The succession in these wells has a log character like that of the coarsening upward successions between the Silver and Weir-Pittsburg markers and the Weir-Pittsburg and Tebo markers. No cores penetrate these rocks, but they are believed to be similar to the other successions with the same log character. If so, they would consist of medium gray shale and streaked shale grading into medium to light gray shale and siltstone, with linsen-, wavy- and ripple bedding. Their log character suggests that they have the same kind of siderite cement as the upper parts of the similar successions. While these beds lie between the Tebo marker interval and the brown marker, it may be interpreted as being slightly older than the valley-filling succession that lies between the same markers and is the main reservoir interval in the field. The western edge of their distribution marks the eastern margin of the valley succession.

East - West cross sections were developed presenting the B₂ and B₃ zones and their continuity. These cross sections are presented in Appendix D.

Brown Marker

The brown marker overlies the reservoir interval. Of the markers recognized in this field, this is the most difficult to identify and trace. It was recognized as a distinct, but neither sharp nor very high, g-ray maximum that occurs below the Scammon marker interval and above reservoir sandstones and interbedded sandstones, siltstones and shales of the B₂ and B₃ intervals. However, this marker is not identifiable on logs from all wells and is well developed in only a few. In many wells, the brown marker was placed at the top of a sequence of interbedded sandstones, siltstones, and shales, and below a sequence of shale several feet thick. The brown marker was identified in cores O-1 (Fig. D-5C), RW-6 and RW-7. In those cores, it consists an interval of gray shale, which may contain pyrite concretions or plant fragments and is distinctly darker than overlying or underlying shales, although not very dark gray or black. It lacked any hint of development of coal, underclay, limestone, dark gray to black shale, or siderite-cemented, upward-coarsening sequence, which are all parts of the regional marker intervals as described in this report, and it is not known to extend beyond the boundaries of this field. It does, however, extend into wells along the east side of the Nelson lease where the valley-fill succession is not present and the interval above the Tebo marker interval has upward-coarsening character. This provides precise age control on the valley fill.

Brown Marker to Scammon Marker Interval, the B₁ Zone

The interval between the brown and Scammon markers contains light gray to medium gray shale at most places with moderate to extensive development of birdshot siderite and an underclay beneath

the Scammon Coal Bed. The interval is 5 to 20' thick and is especially well developed above the deepest part of the Chelsea valley in the eastern part of the SW/4 of section 21. In RW-6, shales in this interval are at least 9.9 feet thick and consist of an upward-coarsening succession of clayshale and mudshale, with intense mottling and slickensides at the top. Shales contain pyritized plant remains and birdshot siderite. Siderite commonly is associated with near-vertical features that may be rhizocretions or expansion-contraction cracks related to drying during exposure at the earth's surface and soil formation. In RW-8, 20 feet of shale are present above the top of interbedded sandstone, siltstone, and shale of the B₂ zone, including a well developed underclay that probably is part of the Scammon marker interval. All of this shale has been assigned to the B₁ zone. The remarkable feature of this zone in RW-8 is the vertical fracture lined with birdshot siderite that reaches 20 feet down from the pre-Scammon underclay.

There is little development of sandstone between the brown marker and the Scammon marker interval, except in the southwestern part of the field. In the northwest corner of section 28, T26S R21E, sandstone reaches a thickness of over 10' between these markers. No preserved cores contain this sandstone. It does not appear to be productive.

Scammon Marker Interval

The Scammon marker interval includes the Scammon coal, an underlying underclay and an overlying dark shale. Birdshot siderite is common in the shales beneath the underclay, but the underlying succession does not display the nicely defined decrease in natural g-radiation and rightward deflection of the neutron log. However, a sharp, but low, rightward neutron kick in logs of some wells between the coal and overlying dark gray shale probably indicates a limestone. Many of Harris's (1984) descriptions of cores from the upper Cherokee in Crawford and Cherokee counties, Kansas, show a limestone above the Scammon Coal.

The Scammon marker interval is present in cores O-1 (Fig. D-5C), RW-4, and RW-8. The Scammon Coal Bed is the among the thickest cored in the Nelson leases, reaching 1.5' in core RW-4. The Scammon marker interval is present in most wells, but has been partly to completely removed by erosion preceding deposition of the overlying "A" sandstone in one well, H-17, in the center of the E 1/2 of the SW 1/4 of section 21, and the coal has been removed in both RW-4 and RW-8, where underclay is overlain by sandstone. Dark shale of the Scammon marker interval is rather thin and not highly radioactive. It is commonly a foot or less thick.

The Overlying Section - Scammon-Mineral Interval

Between the Scammon marker interval and the overlying Mineral marker interval is a sequence of shale, with some sandstone. This interval was designated as the "A" sandstone by the operators of the field. It contains sand along the eastern margin and in the center of the field, both in the SW 1/4 of section 21. This sand shows a distinct upward-fining pattern where it is thick enough that the g curve can be interpreted to show a pattern. In this interval, core RW-8 encountered 3.7' of light olive tan, fine, structureless sandstone, with a few inches of very fine to fine sandstone at the base. No other cores sampled this interval. This sandstone fills a shallow valley eroded through the Scammon marker in well H-17, and sandstone overlies the sub-Scammon underclay in several wells in the valley region in the east or southeast center of the SW/4 of section 21, T26S, R21E.

Mineral Marker Interval

The Mineral marker interval includes the Mineral Coal and an overlying dark shale. In many wells the dark shale is not present, so the Mineral coal is marked by a leftward kick on both the neutron and gamma logs. In other wells, it has a thin dark shale immediately above it. The dark shale may have additional spikes of high gamma count, making a gamma kick up to about five feet thick. This marker lies 15 to 30 feet below the "V" shale marker and is present in nearly all wells in the Nelson Lease. In core RW-6, the Mineral marker interval included 2.3' of coal overlain by 2' of fissile, very dark gray claystone with streaks of silt in places and 0.5' of light gray, laminated shale.

Red marker

The red marker is a sharp rightward neutron kick and lower gamma kick about 10 to 20 feet below the "V"-shale marker. In some wells, the red marker appears to be similar to, but not as well developed as, the dark blue marker, which is an upward-coarsening succession with siderite cement in the upper part. In some wells, one or more sharp kicks on gamma-ray or neutron are present above and below the red marker. The red marker is a persistent, but is not attributable to any horizon previously identified regional marker, although Jewett et al. (1968) and Harris (1984) have identified the Flemming and Robinson Branch coals between the Mineral Coal and the "V" shale.

"V" Shale marker interval

The most persistent and easily identified marker in the upper Cherokee is the "V" shale marker, which includes the associated beds of the Croweburg Coal, with its underclay and a very persistent black shale. This succession is overlain by the Verdigris (or Ardmore) Limestone, which occupies the position of a regressive limestone in limestone-shale cyclothems of the later Desmoinesian, Missourian, or lower Virgillian. Brenner (1989) referred the interval between the Croweburg Coal and the top of the Verdigris (Ardmore) Limestone to the Verdigris Formation. This marker succession is easily correlated into Iowa, where the black shale is called the Oakley Shale and the coal is called the Whitebreast Coal (Brenner, 1989). Schlinsog and Angino (1983) called this dark shale the "V" shale in southeastern Kansas.

Extent of Marker Intervals in the Nelson Lease

The Tebo and Weir-Pittsburg marker intervals and the dark blue and silver markers do not extend all the way across the Nelson Lease (Fig. D-2, D-4). Because some of these markers are regional in their extent, their local absence must be explained. The absences of marker beds form a pattern in which the lowest one, the silver marker, has a small area from which it is absent and subsequent overlying markers have progressively greater areas of absence. The most consistent interpretation of this pattern is that an erosional valley that developed after deposition of the Tebo marker interval, and cut through to the level of the silver marker or below (in places).

As pointed out above, the brown marker extends on to the bank of the valley, as defined by the presence of the Tebo marker and an upward-coarsening succession above it, which implies that the cutting took place before deposition of the brown marker. Sand and mud filled the valley before accumulation of the brown and younger markers, although a depression may have been left or developed by differential compaction after deposition of the brown marker.

Valley-fill Succession and Reservoir Sandstones

Reservoir sandstones of the Nelson Lease are part of a lithologically complex interval that lies stratigraphically between the Tebo marker interval and the brown marker (Fig. D-4). It includes a valley fill that is set into the underlying beds as far down as the Bluejacket A coal, but not the upward-coarsening succession of slightly older (but still post-Tebo) age found in wells K-34-37, in the bank of the valley. In addition to sandstones ranging from a few cm to over 10 m thick, this succession includes interbeds (called mixed lithologies or interbedded lithologies) of shale, siltstone, and sandstone on a scale of mm to dm, and beds of shale that are up to a few meters thick.

This interval can be divided fairly unequivocally into B₂ and B₃ zones, because a discontinuous horizon of conglomerate or a sharp increase of grainsize can be correlated from well to well across the lease, marking the base of the upper, or B₂ zone (Fig. D-4, D-5). In most wells, an interval of shale or mixed lithology lies at the top of the B₃ zone. This change is noted in preserved cores, and can be inferred in several of the core descriptions prepared by Oil Field Research. The B₃ zone fills the deepest part of the erosional valley in the eastern 1/2 of the SW/4 of section 21 and extends westward and southwestward across much of the lease. The B₃ zone includes the thickest and most productive sandstones in the study area. Thickness of the entire B₃ interval ranges up to 54 feet. The B₂ zone is more sheet-like and sandstone bodies in it are also thinner and more laterally extensive. However, they have distinctly less productive capability than the B₃ sandstones, although a small area in the NW part of the field in section 21 has recoverable oil results suggesting possible future development may be warranted.

Component Lithologies - Sandstone

Two types of sandstone that may have good reservoir properties are present in the Chelsea Sandstone, reservoir interval in the Nelson leases. Generally, structureless sandstones, with some rippled or laminated intervals, are present in the B₃ zone and B₂ sandstones are structured with ripples and some laminated intervals. Some B₂ sandstones do contain structureless intervals. Not all such sandstones are good reservoir, however, because some contain dead oil with initial saturations of greater than 50%, but no recoverable oil and zero effective permeability at residual oil saturation.

It is possible to recognize sandstone with good reservoir properties in the B₃ and B₂ intervals from the g pattern developed on logs, even on the unscaled logs available for this study (Fig. D-4). Good reservoir quality sandstones had sharp deflections and did not appear to be broken into thinner intervals by shale, because the g-ray curve was consistently below the 50% deflection line that differentiated sandstone and shale. Mixed lithologies, such as those described below, have higher and more irregular g readings than the good reservoir sandstone. This difference permitted differentiation of good reservoir sandstones in logs of wells for which cores are no longer available.

Both structureless and structured sandstone commonly have conglomerates or conglomeratic sandstone at their base and may have one or more conglomeratic horizons above the base. Thickness of conglomeratic beds ranges from a few inches to several feet. Pebbles, cobbles and boulders are intraclasts of siltstone and concretions, with coalified fossil wood also present.

Structureless Sandstone

Structureless sandstones are especially common in the B₃ interval, in the paleovalley in the eastern part of the SW/4 of section 21. These sandstones are displayed in cores O-1 (Fig. D-5C), RW-1, and RW-8. Good quality B₃ sandstone is up to 35 feet thick in the core from well RW-8, which is in the valley center. Thickness decreases rapidly to the east and west of the axis of the valley and varies somewhat along the valley trend. The rock is heavily oil stained. For the most part, bedding is absent or so subtle that it is not detectable during description of core that has not been slabbed. Broken surfaces of the core are irregular or hackly with no tendency to have smooth, angled, or undulating surfaces, as beds with sedimentary structures would. Mica flakes show neither strongly preferred orientation nor concentration into zones. A few intervals of this sandstone, a few feet thick at most, do display ripples and lamination. The sandstone contains a few plant fossils.

The base of the good, structureless sandstone, although sharp and apparently erosive, is not necessarily the base of the erosional valley. In cores from both RW-8 and O-1 (Fig. D-5C), which are the best ones from the deep valley fill, the base of such sandstone lies several feet above the base of the valley fill, above a conglomerate bed and an interval of mixed lithology. The top of the good structureless sandstone of the B₃ interval in the valley fill grades into overlying successions of mixed lithology.

In the NE/4 of the NW/4 of section 28, the deep channel of the eastern part of the SW/4 of section 21 broadens, becomes less deeply incised, and contains thinner, less productive sandstones. Cores RW-13, RW-14, and RW-17 are from this area. B₃ sandstone reaches 16 feet thick in this area, and is mostly not structured, although beds do contain intervals of rippled, laminated, or cross-bedded sandstone. The base of sand beds and intervals within them contain mud intraclasts, in some places these are common enough to make the rock a conglomerate. Beds of structureless B₃ sandstone in this area have sharp, possibly erosive bases and gradational tops. They are overlain by interbeds of sandstone, siltstone, and shale.

West of the deepest part of the valley, in the center and south center of the SW/4 of section 21 and extending into the NW/4 NW/4 of section 28, B₃ sandstones are thinner, more laterally extensive, and not as productive. Cores are available from wells O-2, RW-7, and RW-15. Sandstone beds in this region is up to 15 feet thick and generally very fine grained and structureless. Sand beds may have coarser intervals with sharp bases at the base and within them, dividing the overall succession into units 5 to 10 feet thick. Coarser intervals at the base of units of the succession may be coarser sand (fine or on the border of fine and medium) or they may be conglomerates containing intraclasts of granule to boulder size. Conglomerates are up to 2.5 feet thick and may contain siderite cement. Coalified wood fragments are common in conglomerates and in parts of the section immediately overlying conglomerates but are scattered throughout sandstone beds. Some relatively thin intervals of the sandstone are laminated or rippled. Calcite cement is present in a few places.

Rippled Sandstone

Sandstones of the B₂ zone, in contrast, generally display clear ripple cross-lamination, plane lamination, small-scale to medium-scale cross-bedding, or other sedimentary structures. They have sharp bases and their lower few feet are commonly conglomeratic or slightly coarser grained—fine to very fine sandstone as opposed to the very fine sandstone above. Conglomerate clasts are intraclasts of mudrock. Internally, structured sandstones of the B₂ zone are very fine micaceous sandstones. B₂

sandstones grade upward into interbeds of sandstone, siltstone, and clay. Beds of sand range up to nearly 17 feet thick, but generally are thinner, commonly less than 10 feet thick. Layers of wavy-bedded sandstone and mudrock may break them into packages a few feet thick. Coalified wood fragments are present and may be common in B₂ sandstones; macerated plant debris commonly defines bedding in ripple marked or plane laminated intervals. Birdshot siderite is present in bands and layers in many occurrences of B₂ sandstone.

Structured sandstones of the B₂ zone are thickest, up to nearly 17 feet, in the valley region in the eastern part of the SW/4 of section 21. Cores O-1 (Fig. D-5C), RW-1, RW-3, RW-6, and RW-8 are all that part of the field. Several of the sandstones in the B₂ interval in the valley region are partially to completely saturated with "dead" oil. These beds have no recoverable oil, despite measured saturations of over 50%, and no permeability to water at residual oil saturation. Not only are they not reservoir, but they are barriers to movement of fluids through the sand.

In the NW/4 SW/4 of section 21, west of the main valley trend and in the northwest corner of the Nelson Lease, several wells encountered thick, potentially productive sandstone in the B₂ interval. Average recoverable oil saturations reach 2000 bbls per acre in wells RW-4, RW-5, RW-7, and RW-11, for which cores are available. Sandstones in this region may exceed 15 feet in thickness, but are commonly less than 10 feet thick. They are rippled very fine sandstones with a few silty partings. Macerated organic debris and mica fragments mark bedding surfaces. Some intervals, up to a few feet thick, are actually wavy-bedded intercalations of sandstone and mudrocks. Intervals of parallel-laminated intercalations of macerated plant debris and sandstone and intervals of wavy bedded sandstone and shale divide thicker sand-rich successions into intervals a few feet to several feet thick. Such intercalations have gradational bases and tops.

Sandstones are also found in the B₂ zone in the center of the SW/4 of section 21 and in the northern part of the NW/4 of section 28. Cores RW-9 (Fig. D-5B) and RW-12 represent the center of the SW/4 of section 21 while cores from wells O-2, O-3, RW-13, RW-14, RW-15, and RW-17 are from the northern part of the NW/4 of section 28. Cores RW-16 and RW-18 represent accumulation of the B₂ zone in a erosional remnant left between arms of the Chelsea valley.

In the RW-8 core, B₂ sandstone had recoverable oil of a few hundred barrels per acre-foot and total recoverable oil of 5500 bbls per acre, according to core analyses conducted by Oil Field Research in Chanute, Kansas. Wells developed in this sand where it lies in the paleovalley of the E 1/2 of the SW 1/4 of Section 21 have produced 10,000 to over 20,000 bbls of oil during water flood operations and may have produced for long periods before the water flood was installed in the area.

Interbedded sandstone, siltstone, and shale (mixed lithologies)

A characteristic suite of lithologies in the B₂ and B₃ zones of the Chelsea valley fill of the Nelson Lease comprises rippled very fine sandstones and siltstones, linsen- and wavy-bedded sandstones and mudrocks, and shale, including structureless mudrock, laminated shale, and streaked shale. In such sequences, the predominant lithology is wavy-bedded sandstone, siltstone, and shale, with linsen-bedded shale and siltstone second in importance. Burrowing is common but by no means sufficient to destroy the primary lamination of the sediment. Sandstone beds in most such successions are subordinate in abundance, but they are a plurality or a majority of the beds in some wells. They can be described as very fine grained, rippled, and tan, although some sandstone beds are apparently structureless or contain parallel lamination. Some sandstones contain a few shaley intraclasts or mud

flasers. Sandstones commonly contain carbonaceous debris on lamina surfaces and may be sparsely burrowed.

In this suite, lithologies are interstratified at two scales. At the larger scale, the sequence is thin to medium bedded, with beds a several cm to a few dm thick. Rippled very fine sandstone and siltstone in beds several cm to a few tens of cm thick alternate with similarly thick beds of either interbedded shale and wavy- or linsen-bedded siltstone or beds of shale alone. At the smaller scale of interstratification, in wavy or linsen-bedded sequences, laminae of silt, sand, or shale are less than one mm to one cm thick and form coarse-fine alternations.

Characteristic of these rocks are gradational boundaries between beds in which rocks of different grain size prevail. This describes the beds at the several cm to a few dm scale, not the mm to cm laminations within wavy-bedded successions or streaked shales. Examples of such changes are from a bed where sandstone or siltstone predominates to one where linsen or wavy bedding is common or from a linsen- and wavy-bedded interval to shale. It is important to note that sharp-based sequences, progressively grading from coarse lithology (fine sand or conglomerate) to finer grained lithology (very fine sandstone to siltstone to mudrocks) are not common in interbedded intervals, although they are present.

Interbeds of sandstone, siltstone, and shale are found in both the B₂ and B₃ zones. Wells O-1 (Fig. D-5C), RW-3 and RW-8 represent the B₃ zone in the valley fill of the eastern part of the SW/4 of section 21. Commonly, a zone of interbeds overlies a thin sandstone or conglomeratic bed at the base of the valley fill. Such intervals are a few feet thick. In well RW-8 for example, the interbedded succession, 9 feet thick, at the base of the valley fill is overlain by structureless reservoir sandstone of excellent quality. Elsewhere, notably in wells KW-10, KW-11, RW-9 (Fig. D-5B), and RW-12, the entire B₃ zone is composed of such interbeds. The B₃ zone is 28 and 21 feet thick, respectively, in KW-10 and KW-11 which lie in the Chelsea valley. Logs of wells containing mixed lithologies show an irregular pattern, indicating interbedding at about the scale of resolution or finer. Cores from RW-9 (Fig. D-5B) and RW-12 confirm the lack of good quality sand in the B₃ interval, but they lie on an erosional remnant between the eastern valley and the western patch of B₃ sand. A similar set of thin to medium interbeds of sandstone, siltstone, and shale occurs in core RW-14 from along the western side of the eastern branch of the Chelsea valley in the NE/4 of the NW/4 of section 28 and in the core from well O-2 in the NW/4 of the NW/4 of section 28. Log patterns indicate that the upper 5 to 15 feet of the B₃ zone throughout its extent is composed of interbeds of sandstone, siltstone, and shale.

Interbedded successions of sandstone, siltstone, and clay are common in the B₂ zone as well, but they are generally absent from the bottom of that succession, because the base of the B₂ zone was generally placed at a sharp increase in grain size from the underlying B₃ zone. Some B₂ successions, however, consist of a thin conglomerate and a few feet (1 or 2 feet) of fine to very fine sandstone above it with and then interbedded successions above that range to over 20 feet thick. Elsewhere, the bulk of the B₂ succession is rippled sandstone, as described above, and only the upper few to several feet is interbedded lithologies. Contacts between thick beds of rippled sandstone and overlying interbedded successions are gradational in all occurrences.

Cores from wells RW-3, RW-6, and RW-8 contain interbedded lithologies in the B₂ zone from the region where the Chelsea valley is best developed, in the eastern half of the SW/4 of section 21. Interbedded sequences in the B₂ zone range from 4 to 18.9 feet thick in these wells, and are divided

into beds 0.1 to 2.6 feet thick. Some of the thicker sandstone beds have scoured bases.

RW-2, RW-4, RW-10, and RW-19 display interbedded lithologies from the west part of the productive area in the SW/4 of section 21. Interbedded successions range from 9.5 to 16 feet. Sandstone occurs in beds from a few tenths of a foot to 6 feet thick, with thickest beds at the base of the B₂ zone. The thicker of these sandstone beds, over about 2-3 feet thick, might be separated from the mixed lithology successions and considered as individual sandstones. Sandstone is very fine grained, except at the base of the B₂ zone, where conglomeratic sandstone or conglomerate up to 0.9 feet thick may be present. Sandstone layers are rippled, inter laminated with mica and macerated organic matter, or structureless. Shale strata range from laminae to over 1 foot thick. They are streaked with sand or silt and may be burrowed. Large plant fragments are present in some beds.

The main Chelsea valley occupies two branches in the northern part of the NW/4 of section 28. Cores from wells O-2, O-3, and RW-15 contain interbedded lithologies in the B₂ zone above western branch, while O-4, RW-13, and RW-14 sample that zone overlying the eastern branch. In this area, interbedded lithologies may reach a total thickness of 8 to 21 feet, including beds of shale up to 1.8 feet thick and wavy- or linsen-bedded sandstone and siltstone up to 5.7 feet thick. Wavy- or linsen-bedded successions display variation in the proportion of sandstone or siltstone ripples to intervening mudstone drapes on a scale of several inches to a foot. Shale beds are commonly laminated, or contain streaks or lenses of sand or silt. Interbedded sequences in this part of the field contain sparse burrows, large plant fossils, and macerated plant debris, which is common on bedding surfaces. A series of upward fining beds of siltstone and shale, including linsen-bedded and streaked shale is present in RW-15. In O-2, an associated bed four feet thick consists of inter laminations of fine sandstone and macerated organic matter with mica.

RW-16 represents deposition of interbedded lithologies on the divide between the two branches of the Chelsea valley in the NW/4 of section 28. The B₂ zone is 17 feet thick and contains at least 5 feet of good sand at the top. The basal foot is pebbly sandstone, and the overlying 9 feet is interbedded sandstone, sandstone, siltstone and shale. Wavy-bedded sandstone is in beds some 2 feet thick, streaked shales are in beds 0.6 to 1.5 feet thick, laminated shales in beds 0.5 to 0.8 feet thick, and rippled sandstones in beds some 0.5 feet thick. Siderite is present in some beds.

Parallel-Bedded Sandstone and Organic Matter

Several cores from the B₂ zone (O-2, RW-6, and RW-8) contain distinctive successions of parallel stratified inter laminations of fine to very fine sand and organic matter, with mica. Laminae are on the mm scale. Sand laminae either display little in the way of sedimentary structures or the inter laminations may be wavy-bedded. Parallel-bedded sandstone and organic matter may be interbedded with rippled successions. Interlaminated successions range up to 6.7 feet thick.

Shale

Shale is a common component of the fill of the Chelsea valley in both the B₂ and B₃ zones. Much of it occurs intimately interstratified with silt and sandstone or as flasers or other inclusions in coarser rocks, as described above. In addition there are beds of shale about 2 feet to 11 feet thick in the succession. Such beds are most common in the upper part of either of the two zones, where they represent the culmination of gradational sequences from conglomerate or sandstone through interstratified lithologies. Shale beds are thickest in the area of the deep part of the Chelsea valley fill

in the eastern part of the SW/4 of section 21.

Shale ranges over the gamut from mudstone and mudshale, which have subequal amounts of silt and clay, through claystone and clayshale. Shales in the B₂ and B₃ zones range from very light gray to dark gray, in places with an olive cast to the color. The range of shale lithologies includes laminated or bedded shales, structureless shales, streaked shales, with laminae of silt or sand as thin as a grain or two thick, and linsen-bedded shales, with scattered lenses of silt or sand. Generally, shale intervals at the top of both the B₂ or B₃ zones of the valley fill grade finer upwards, from linsen-bedded to streaked to laminated or structureless. Some cores of apparently structureless shale break easily along planar surfaces that parallel bedding in nearby rocks and indicate that the shale is stratified, although layering may not be visible because of fine grain size and little or no contrast between adjacent beds.

Shales contain fossilized plant material, either macerated or as pieces that may be larger than the diameter of NX core. Shale beds are commonly bioturbated normally in particular zones. Rarely are primary bedding structures in them completely destroyed by burrowing. Shale commonly contains pyrite, especially in the form of pyritized plant remains, and birdshot siderite, which may be in beds or may follow vertical structures that appear to be related to soil formation in overlying strata.

Tidal Features

Intervals of interbedded sandstone, siltstone, and shale display several features indicative of deposition by tidal currents. The most prominent is gradational alternations of thickness of sand laminae in wavy- and linsen-bedded intervals. These variations occur over intervals of several centimeters. Detailed counting of beds has not been attempted, and none of the intervals of wavy- and linsen-bedded siltstone and shale that have been examined had obvious periodicity of bed thickness of 14 or 28, which may form from diurnal or semi-diurnal tidal frequencies. Despite the lack of the compelling periodicity in thickness variation, the interval shows repeated rapid variations of current intensity, both fine-coarse alternations at the scale of mm to one cm and bed thickness variations at the scale of several cm to a few dm. Such variations are characteristic of tidal environments.

The sequences of varying thickness of bedding are also unlike wave-rippled sequences because they do not have scoured basal surfaces and thin dm-scale fining-upward sequences that are produced by storms. Individual thin laminae in linsen-bedded intervals can be traced across the entire width of the core, which is also a common feature of tidal deposition during the neap part of the tidal cycle, when deposition takes place from suspension and each successive current from the rising and falling tide does lead to accumulation without erosion of previous deposits. Boundaries between laminae are commonly thin, continuous layers of mica and carbonaceous trash, which imply cessation of current activity between depositional events. Current ripples from river deposits or other sites of activity of unidirectional currents, on the other hand, have macerated plant debris in troughs and part way up the foresets, where they are trapped in eddies rather than deposited during pauses of current activity.

Interbeds of wavy- and linsen-bedded sandstone, siltstone, and shale with shale, of possible tidal origin, are common in the B₂ zone. As a result, the B₂ zone is interpreted as a series of tidal sand bars with intervening tidal flat or mud bank deposits. Tidal indicators are also present in the mixed lithologies of the B₃ zone.

Another characteristic lithology in the Nelson Lease is best understood if it is assigned to formation by tidal activity. Sandstone interlaminated with organic matter and mica, which may make up units a few m thick, are unlikely to be the result of accumulation in flow-regime bed forms, because the rapid fluctuation from conditions where plant debris and mica would accumulate to those where plane beds of very fine sand are deposited seems unlikely, especially with no evidence of erosion between depositional events. Tidal ebb and flood cycles, with periods of slack water, seem to be a more likely explanation. Again, no obvious 14- or 28-bed cyclicity was noted during core description. Tidal deposits of interlaminated sandstone and organic matter, like tidal deposits of very fine sandstone, siltstone, and shale, are not rocks of reservoir quality.

Shapes of Sand Bodies

In drawing cross sections of the B_1 and B_2 intervals, it was necessary to depict the shape of the sandstone bodies. They could be either channels, which are convex downward with a broad, relatively flat top, or bars, with a convex upward top and a bottom conforming to the pre-existing surface. Which configuration one chooses has considerable significance in terms of the continuity of the reservoir. In this report, sandbodies in the B_2 interval are depicted as bars for several reasons. First, the B_2 interval commonly overlies a rather flat, apparently erosional surface, and the sand accumulations are of smaller scale than the width of the valley (Fig. D-4, D-7). Above this apparent erosion surface, even where thick sandstones were absent, thin layers of conglomerate and sandstone are present at the base of the interval. Tidal features, listed above, in the mixed lithology intervals suggest tides were important processes in depositing these sediments. The shape of the sediment accumulation in the B_2 zone is similar to an estuary, which is a common environment where tidal processes are important today. Tidal estuaries often contain convex upward sand bars, which form elongate, irregular mounds. Choosing to make the accumulations of sand in the B_2 interval convex-upward bars avoided the necessity of inferring large quantities of sand in areas between wells, where no available evidence bore on the shape of sand bodies.

Diagenesis

Ten thin sections were cut from several different layers of the B sandstone interval. These have been only cursorily examined. They show development of three minerals that are of significance for recovery efforts in the Nelson Lease. Two of these are iron carbonates, siderite (FeCO_3) and ankerite $\text{Ca}(\text{Mg,Fe})(\text{CO}_3)_2$. Iron may be released from these minerals during acidification of wells or other recovery operations, and be oxidized to form iron hydroxide, an insoluble precipitate. Particles of iron hydroxide may migrate to pore throats, where the plates of iron hydroxide can be trapped, blocking the pore.

The other mineral is kaolin, $\text{Al}_2\text{Si}_2\text{O}_{10}(\text{OH})_8$. Kaolin is a clay mineral that forms accumulations of flaky particles in pores. During recovery operations, the clay particles may be moved to pore throats, blocking them. The sandstone also contains pyrite, which may oxidize during recovery operations and provide an important source of iron.

Figure D-1

COMPOSITE STRATIGRAPHY OF THE CHEROKEE GROUP
 (DESMOINESIAN, UPPER MIDDLE PENNSYLVANIAN)
 CHEROKEE BASIN, SOUTHEASTERN KANSAS
 (INCLUDES INFORMAL UNITS)

Figure D-2

COARSENING UPWARDS SEQUENCES AND MARKER INTERVALS, CHEROKEE GROUP, SOUTHEASTERN KANSAS

Figure D-3

CROSS SECTION OF THE
CABINASS FORMATION, CHEROKEE GROUP,
NELSON LEASE, SAVONBURG NE OIL FIELD

Figure D-4

A

EXPLANATION OF CORE DESCRIPTIONS

B

NELSON LEASE, SAVONBURG NE OIL FIELD
ALLEN COUNTY, KANSAS
SE/4 NE/4 SW/4 SW/4 SECT 21 T26S R21E
WELL RW-9

Figure D-5

B, Cont.

NELSON LEASE, SAVONBURG NE OIL FIELD
ALLEN COUNTY, KANSAS
SE/4 NE/4 SW/4 SW/4 SECT 21 T26S R21E
WELL RW-9

Figure D-5, Continued

C.

NELSON LEASE, SAVONBURG NE OIL FIELD
ALLEN COUNTY, KANSAS; C S/2 SW/4 SECTION 21, T26S R21E

WELL O-1

DEPTH, FEET
LITHO- UNN
MAO LOGY
SC SED. STRUCT.
DDG

DEPTH, FEET
LITHO- UNN
MAO LOGY
SC SED. STRUCT.
DDG

Figure D-5, Continued

C., CONT.

NELSON LEASE, SAVONBURG NE OIL FIELD
ALLEN COUNTY, KANSAS C S/2 SE/4 SW/4 SECTION 21, T26S R21E
WELL O-1

D-26

Figure D-5, Continued

C, CONT.

NELSON LEASE, SAVONBURG NE OIL FIELD
 ALLEN COUNTY, KANSAS S/2 SE/4 SW/4 SECTION 21, T26S R21E
 WELL O-1

Figure D-5, Continued

Figure D-6

Figure D-7

APPENDIX E

Cross-Sections for Savonburg Field

Attribute: STAT PERMEABILITY

Title: Cross section 11, from RW-10 to K-59

Filename: sevenberg00010041.gpr

Color

Cross section 11 (from RW-10 to K-59)

Azimuth 306.9 Inclination 90.8

SGM

100.0000
50.0000
25.0000
10.0000
3.0000
NULL

snapshot

Cross section 22 (from nel-7 to K-32)

100,0000
50,0000
25,0000
10,0000
3,0000
MULL
snapshot

Azimuth 39.9 Inclination 89.9

S G M

Attribute STAT PERMEABILITY Title: Cross section 29, from H-25 to K-59 Filename: savinberg00010059.gtt

Cross section 29 (from H-25 to K-59)

H-25 RW-17 K-59

S.G.M

Azimuth 21.3 Inclination 89.9

Color

100.0000

75.0000

50.0000

25.0000

10.0000

3.0000

NULL

snapshot

Cross section of B3 valley

Color

Attribute: STAT PRIMWEARBY The: cross section from KCW-3 to HW-18 Filename: sgm0000000002.grf

Azimuth 270.0 Inclination 89.9

SGM

Color

Attribute : STAT PERMEABILITY

Title : Cross section 5, from RW-5 to K-33

Filename : savonberg00010033.grf

Cross section 5 (from RW-5 to K-33)

100.0000

50.0000

25.0000

10.0000

3.0000

NULL

snapshot

Azimuth 317.7 Inclination 88.4

SGM

Color

100.0000

75.0000

50.0000

25.0000

10.0000

3.0000

NULL

snapshot

Attribute STAT PERMEABILITY

Title Cross section 6, from RW-11 to K-34

Filename savonberg00010038.grf

Cross section 6 (from RW-11 to K-34)

RW-6

H-17

KV

K

RW-11

RW

Azimuth 333.3 Inclination 89.9

SGM