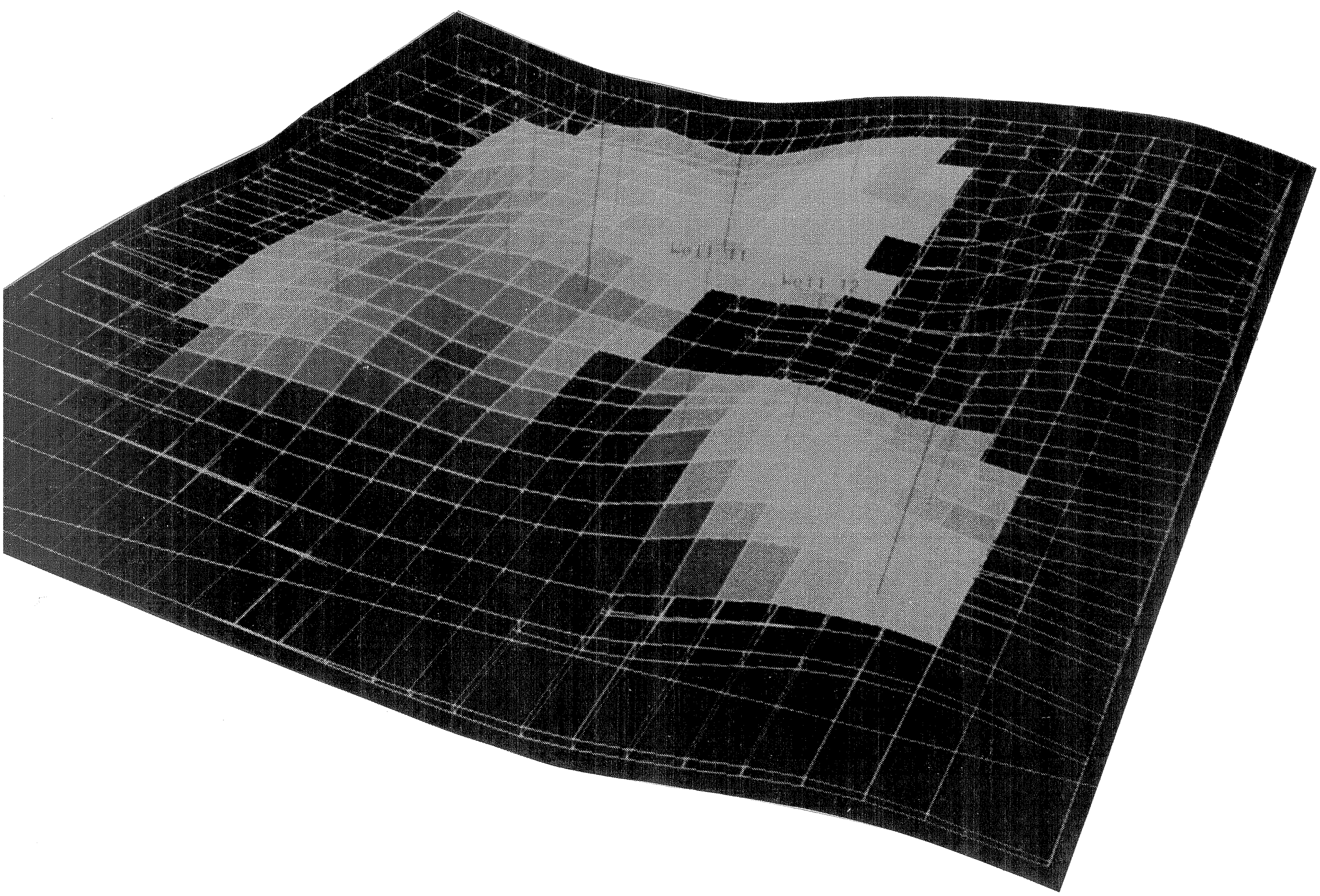
143

Strategies for Improved Oil Recovery from Aux Vases Reservoirs in McCreery and McCullum Waterflood Units, Dale Consolidated Field, Franklin County, Illinois

Emmanuel O. Udegbunam, D. Scott Beaty, and Joseph P. Fagan, Jr.



ILLINOIS STATE GEOLOGICAL SURVEY
Department of Energy and Natural Resources

Illinois Petroleum 143
1993

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ILLINOIS STATE GEOLOGICAL SURVEY
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Champaign, Illinois 61820-6964

Cover

Three-dimensional presentation of oil saturation distribution in the McCreery and McCullum Waterflood Units, as generated by the VIP 3DVIEW^{TM}.

Disclaimer

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CONTENTS

TABLES

ABSTRACT

The McCreery and McCullum Units in southwestern Dale Consolidated Field in Franklin County, Illinois, have produced more than 400,000 barrels of oil from two reservoirs in the Mississippian Aux Vases Formation. The marine sandstones that constitute the reservoirs were deposited as bars in a mixed siliciclastic–carbonate environment, in which they formed by shoaling against paleotopographic highs in the underlying limestone. Studies of petrographic thin sections, X-ray diffraction (XRD) analyses, and petrophysical analyses of Aux Vases sandstone cores taken from the McCreery Unit show that all producing sandstone was deposited within the bar facies. Calcite content increases with depth, and thereby reduces the porosity and permeability. The vertical reduction in permeability limits the influence of bottom-water drive on oil production.

The original oil in place (OOIP), estimated using the model developed in this study, was 1,798 and 652 MSTBO (thousand stock tank barrels of oil) for the McCreery and McCullum Units, respectively. The pre-waterflood oil recovery factors were 14.6% and 30.5% of the OOIP, respectively.

Analyses of monthly waterflood data from the McCreery Unit reveal a poor waterflood oil recovery response; the additional incremental oil production is only 0.56% of the OOIP. This waterflood program has not been profitable to date. As this study suggests, an oil price above $35 per barrel will be required for economic recovery, if there are no improvements in field development strategies.

Field production evidence suggests that hydraulic fracturing adversely affected oil secondary production from these bars by creating high permeability fracture channels oriented in an east–west direction. A three-dimensional (3-D), black oil, full-field simulation model was developed, based on the assumption that hydraulic fracturing techniques created preferential fracture orientations. These fractures align themselves subparallel to the maximum horizontal compressive stress direction oriented from N76°E to N90°E. Simulated water–oil ratio versus cumulative water injection results from an idealized reservoir model with higher permeability values along the line of wells in an east–west direction compared favorably with the observed field data. The results indicate that the fractures induced by hydraulic fracturing are responsible for the low sweep efficiencies and poor waterflood oil recovery.

The following strategies are suggested for improving oil recovery from the McCreery and McCullum Units:

- perform fieldwide reservoir tests, such as tracer and pressure transient tests, which will assist in further definition of the highly permeable flow channels and their directions in the reservoir;
- squeeze existing perforations in all water injectors and reperforate in the lower zone;
- place water injection wells in a repeated, staggered line drive pattern oriented in an east–west direction so that all producers are either north or south of water injectors;
- use selective plugging techniques (e.g. polymers or microbes) to reduce bypassing of oil by injected water.

Infill drilling for waterflood locations north or south of existing well locations may be more effective for incremental oil recovery than implementing the above strategies

alone, but it is also more costly. If infill drilling was combined with these strategies, the existing wells could serve as oil producers while the new infill wells serve as water injectors.

KEYWORDS

Petroleum geology, computer modeling, reservoir simulation, improved oil recovery, reservoir heterogeneity, cost analysis, water injection well pattern, induced fracture orientations.

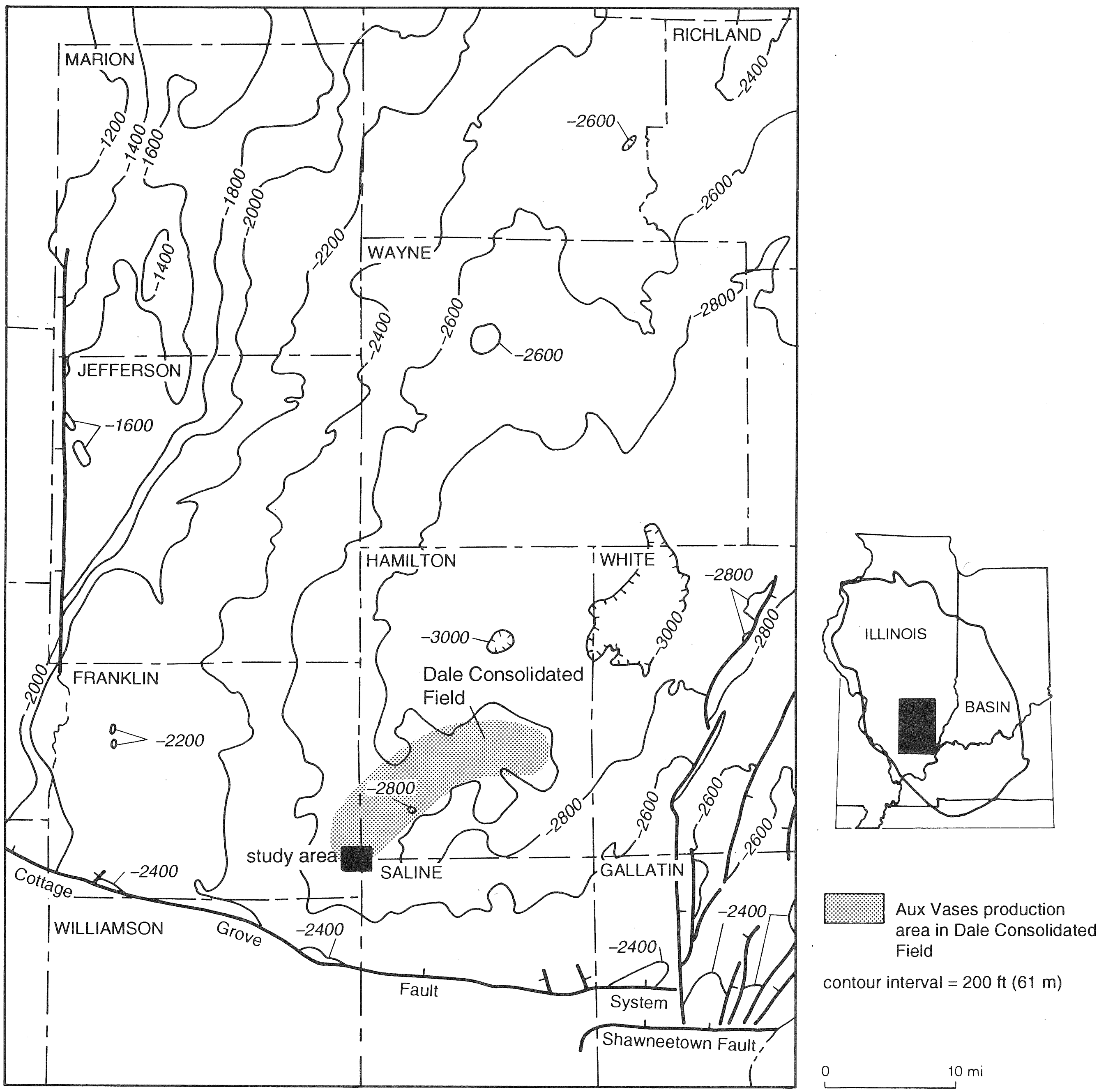


Figure 1 Structure map on top of the middle Mississippian Ste. Genevieve Formation, which underlies the Aux Vases Sandstone in the south-central part of the Illinois Basin (modified from Bristol and Howard 1973).

INTRODUCTION

The McCreery and McCullum Units of Dale Consolidated oil field lie in Sections 13 and 24, T7S and R4E, in Franklin County, Illinois (figs. 1 and 2). The two units, which have produced more than 470,000 barrels of oil from two Aux Vases Sandstone (Mississippian) reservoirs, contain 16 active oil wells on 10-acre spacing, encompass more than 400 surface acres, and underlie eight productive leases unitized by Farrar Oil Company (fig. 2). The reservoirs range from 3,175 to 3,210 feet deep, and oil production comes from a pay zone with an average thickness of 15 feet.

The discovery well, the F. L. Strickland McCullum Community No. 1 (Section 24, T7S and R4E), was completed in June 1955 (fig. 3, point A) with an initial production of 80 barrels of oil per day (BOPD) and 8 barrels of water per day (BWPD). It had produced a total of about 109,000 barrels of oil from 5.5 feet of sandstone until 1986 when it was shut in. Development wells were drilled in the McCullum Unit in 1985. The McCullum Unit had produced about 200 MBSTO (table 1) from four wells by mid-1992.

Production in the McCreery Unit was established in 1969 when the C.E. Brehm Drilling and Producing Company completed the Brehm McCreery No. 1 and the Brehm Potter Community No. 1 (fig. 3, point B). These wells produced 63 MSTBO and 66 MSTBO, respectively, in the 15 years before other McCreery Unit wells were drilled. Ten additional producing wells in the McCreery Unit were developed during field extension and put on production in 1984 and 1985 (fig. 3, point C). By mid-1992, about 263 MSTBO had been produced from the McCreery Unit.

Study Objective and Recent Production Problems

When this study began in mid-June 1991, the primary objective was to integrate geological descriptions, petrophysical data, and production data to develop reservoir simulation models of the Aux Vases producing intervals in the McCreery and McCullum Units. These models were then to be used to explore the potential of waterflooding as a strategy for improving oil recovery.

At the end of June 1991, however, a waterflood was initiated in the McCreery Unit, and the oil production increase from the project was disappointing. While water injection averaged 750 BWPD in three wells (Triple "B" Eaton No. 3, Brehm Potter Community No. 1, and Farrar Pansy Summers No. 2), oil production only increased for a short period (fig. 3, point E) and declined rapidly thereafter (fig. 3, point F). The first significant "kick" in oil production occurred after 170,000 barrels of water were injected into the McCreery Unit. The slow response in oil production during this time provided initial evidence that the injected water was channeling away from the intended zone. The poor results of the waterflood program strengthened the hypothesis that directional, high-permeability fracture channels and/or thief zones existed in the reservoir.

As a consequence of these events, the study objectives were modified to include the consideration of probable in situ fracture conditions that might explain the strong, directional waterflood effects, the poor oil recovery performance, and the very high water to oil ratios in the reservoirs.

Some of the earliest evidence suggesting the existence of directional, high-permeability fracture channels was provided by the injection responses of the Eaton No. 5 and the Triple "B" Eaton No. 3 wells in 1985 (fig. 2). The Eaton No. 5 was a dry hole with the top of sandstone below the oil–water contact, but the Eaton No. 3, an offset to the east, was an oil well with 23 feet of producing sandstone above the oil–water contact (at initial conditions). The Eaton No. 5 was completed as a disposal well for salt water produced from Triple "B" wells in the area. At the time of completion

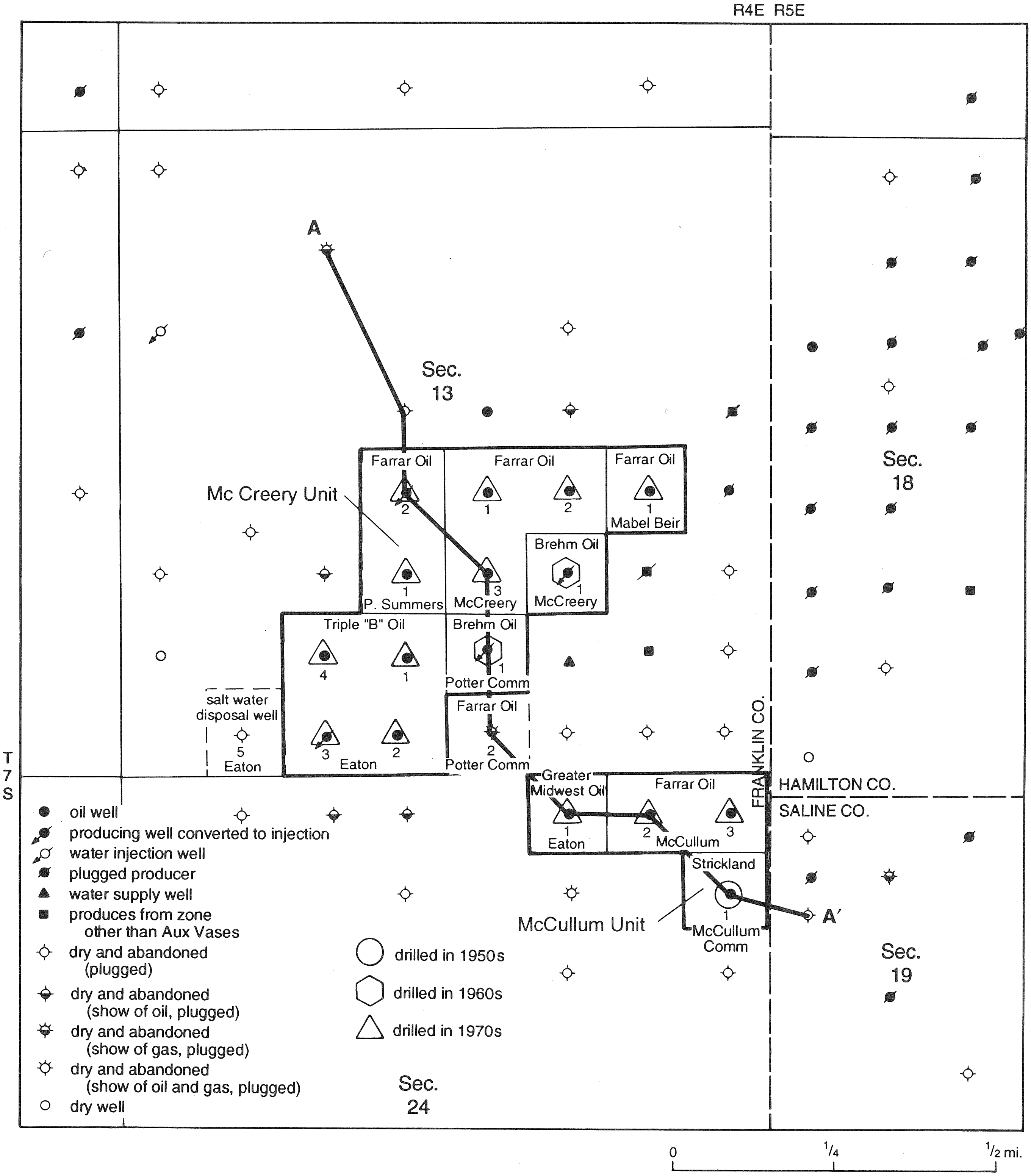


Figure 2 McCreery and McCullum Waterflood Units in Dale Consolidated Field (outlined) and location of cross section A–A′ (fig. 9). Waterflood units are leases controlled by an operator, treated as a single entity, and given the same treatments during waterflooding.

of the disposal well, the Eaton No. 3 was producing oil with a fairly low water cut. Walker (1989) reported that the water cut of the Triple “B” Eaton No. 3 increased to unity (100%) within 2 weeks after beginning daily injection of 100 BWPD into the Eaton No. 5. By contrast, water production from the Eaton No. 3 well decreased significantly when water was injected into the Eaton No. 5 only every other day.

The possibility that poor waterflood oil recovery was caused by strong, directional permeability created in response to in situ stresses and hydraulic-fracture directions has been investigated for oil fields in other basins (Dyes et al. 1958, Donohue et al. 1968, Nolen-Hoeksema et al. 1992). There is scant literature on the effects of in situ stresses on hydraulic fracture directions and the creation of induced fracture networks during oil production in the Illinois Basin. An early study of Benton Field in Franklin County, Illinois, alluded to the possible effect of fractures on oil production (Parkinson 1957). Discussions with Illinois Basin operators indicate that waterflood production problems are common in Illinois fields. Consequently, significant attention has been devoted to the possibility of fracture-associated problems in this report.

Table 1 Nomenclature used in the report

A =	area of the reservoir (acres)
B_o (or FVF) =	oil formation volume factor (bbls/STBO)
h =	reservoir pay thickness (feet)
K =	absolute permeability of rock (md)
K_{ro} =	relative permeability to oil at a given water saturation
K_{rw} =	relative permeability to water at given water saturation
L =	characteristic length (feet)
L_f =	fracture half-length (feet)
MSTBO =	thousand stock tank barrels of oil
NRI =	net royalty interest (19.333%)
nugget =	term used in variogram analysis to indicate lack of data (information) at small scales. In this study, the nugget is 0, implying that permeability data were available at all scales considered.
psig =	pounds per square inch guage (pressure measurement)
Q_t =	cumulative waterflood oil production at time, n years
r =	coefficient of determination
R_s (or GOR) =	gas to oil ratio (scf/bbl)
range =	the distance at which the variogram model reaches its maximum value or sill (feet)
s =	skin factor, dimensionless
sill =	upper limit of the variogram model—the point at which the semivariogram curve levels off
S_o =	oil saturation (fraction or percentage)
S_w =	water saturation (fraction or percentage)
V_{DP} =	Dykstra–Parson coefficient defined in equation 2
WOR =	water to oil ratio (fraction)
Φ =	porosity (fraction or %)
(d) =	semivariogram function
d =	distance (feet)

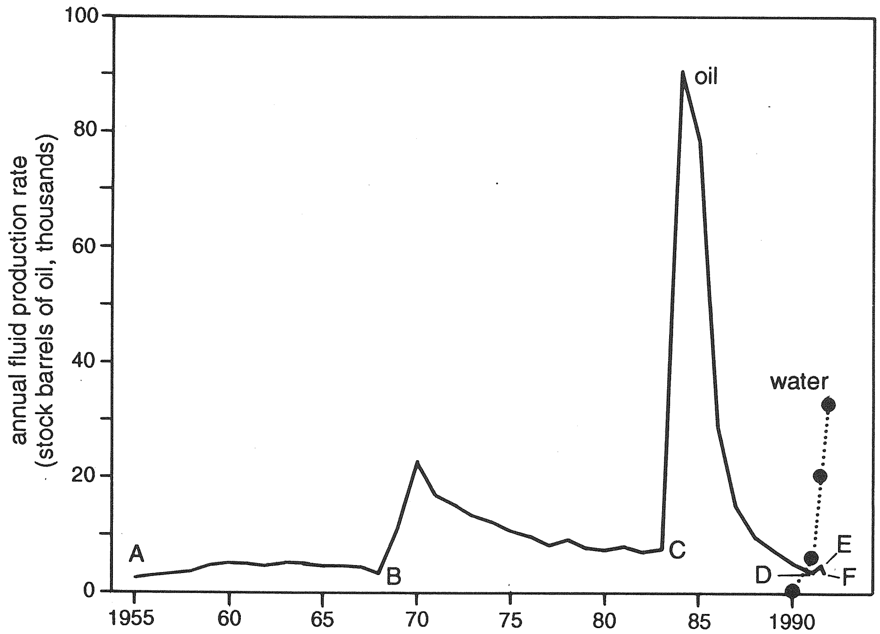


Figure 3 Production curve for the McCreery and McCullum Waterflood Units:

A start of production in the McCullum Waterflood Unit from the McCullum Community No. 1,
B drilling of two wells in the McCreery Unit (Brehm McCreery No. 1 and Potter Community No. 1),
C drilling of 13 new wells in both the McCreery and McCullum Waterflood Units,
D beginning of a waterflood in the McCreery Unit,
E, F oil production peaked at E but began to decline thereafter (E–F). Water production continues to increase.

RESERVOIR DESCRIPTION

Geological and Reservoir Characteristics

Sandstone Geometry The McCreery and McCullum Waterflood Units produce from two sandstone bars that overlap and are connected (Beaty and Fagan, in prep.). The two bars are thus treated as a single structure: the McCreery–McCullum sandstone bar. The bars were part of an offshore marine bar complex deposited in a mixed siliciclastic–carbonate environment; they were formed by shoaling against paleotopographic highs in the underlying limestone. The bars in the complex generally are shingled and isolated from one another by shaley sandstone and shale intervals that form lateral barriers to fluid and pressure migration. Because of this shingling, the McCreery–McCullum sandstone bar is isolated from other surrounding bars and, for purposes of reservoir simulation, treated as a closed system.

In the study area, the producing sandstone bar facies of the Aux Vases Formation averages 15 feet in thickness, but may attain as much as 26 feet in thickness (fig. 4). Bar intervals become increasingly calcareous at their margins because of the proximity of limestone beds; these stratigraphic influences on oil production are evident in wells along the periphery of the bar facies. Although wells immediately

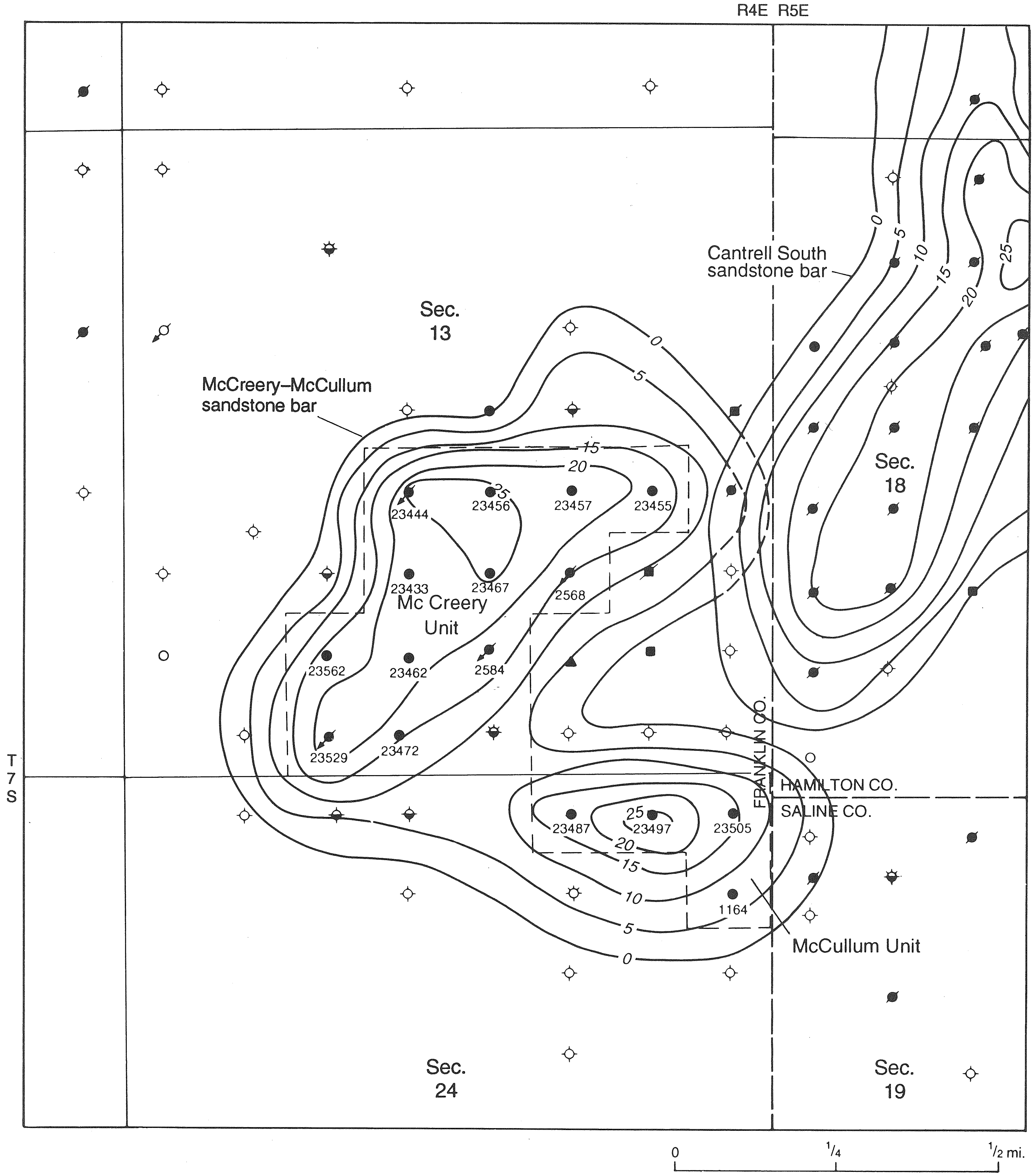


Figure 4 Isopach map of productive sandstone above the original oil–water contact (–2,715 feet). The McCreery–McCullum sandstone bar lies underneath the Cantrell South sandstone bar developed northeast of the study area. The two bars are separated from each other by sandy shale and shale (Beaty and Fagan, in prep.). Contour interval is 5 feet; see table 5 for well names.

east of the McCreery Unit and north of the McCullum Unit are structurally higher (fig. 5), stratigraphic pinchouts or lateral facies changes from productive sandstone to nonproductive interbar shale result in the absence of reservoir quality sandstone.

Structure The McCreery and McCullum Waterflood Units lie at the southwestern end of Dale Consolidated Field, a prolific, multiple pay oil field on a nose along a regionally developed anticline (fig. 1). Although the anticline strongly influences oil production from traps developed along this trend, production within the study area is from a relative structural low. The Downeys Bluff Limestone lies approximately 50 feet above the Aux Vases. It is a limestone horizon easily distinguished on electric logs and was used to construct the structure map shown in figure 5. Contoured on the base of the Downeys Bluff, this map indicates the absence of structural closure in the study area. A structural low extends from Section 24 north–northeast into Section 13 through all of the McCreery Unit and the western part of the McCullum Unit. A structure map on top of the producing sandstone from the Aux Vases bar facies (fig. 6) shows, however, more pronounced closures in the McCreery and McCullum Units due to the convex-upward, lenticular geometry of the bar and to the differential compaction of shale and shaley sandstone in interbar areas.

Depositional Environments The Aux Vases Sandstone was assigned by Swann (1963) to the uppermost part of the Valmeyeran Series of the Mississippian System (fig. 7). A typical electric log for the Aux Vases Sandstone in the study area is shown in figure 8.

Fine grained sandstone was deposited in offshore bars (fig. 9) that overlap and are connected (as in the case of the McCreery–McCullum sandstone bar) or are shingled and separated from adjacent bars by discontinuous beds of shale and shaley sandstone that form barriers to hydrocarbon migration. Carbonate deposition, which was apparently syndepositional with Aux Vases sand deposition, may have been locally dominant in areas where the influx of siliciclastic material was not sufficient to inhibit carbonate development (Beaty and Fagan, in prep.). As discussed in Beaty and Fagan, sandstone beds in sandstone bars are sometimes laterally transitional to sandy limestone, thus making the recognition of an upper contact of the Aux Vases Formation difficult. Because of this difficulty, the cross section (fig. 9) denotes this interval as the Aux Vases–Renault.

After deposition of the siliciclastic Aux Vases Formation, a marine transgression inundated the area, depositing the fossiliferous limestones of the Renault Formation and marine shales of the Yankeetown Formation. Together these units form the seal that prevents vertical hydrocarbon migration from the Aux Vases.

Petrography and Diagenesis Sixteen thin sections from the Farrar McCreery No. 1 well were examined using a petrographic microscope to determine grain size and interpret intergranular relationships and diagenetic phases. Analyses were also performed using X-ray diffraction (XRD) and a scanning electron microscope equipped with an energy dispersive X-ray analyzer (SEM/EDX). Sandstone from the reservoir is composed primarily of very fine to fine grained quartz and feldspar framework grains with coatings of clay minerals. Partially dissolved fossil fragments are also present in the matrix of framework grains (fig. 10a).

The clay minerals identified by XRD are chlorite, illite, and mixed layered illite/smectite (fig. 10b). Because the clay coatings contain a large amount of bound water, wireline logs of these sandstones commonly exhibit abnormally low resistivities (fig. 8) that lead to erroneously high values of calculated water saturation (Seyler 1988, Asquith 1990).

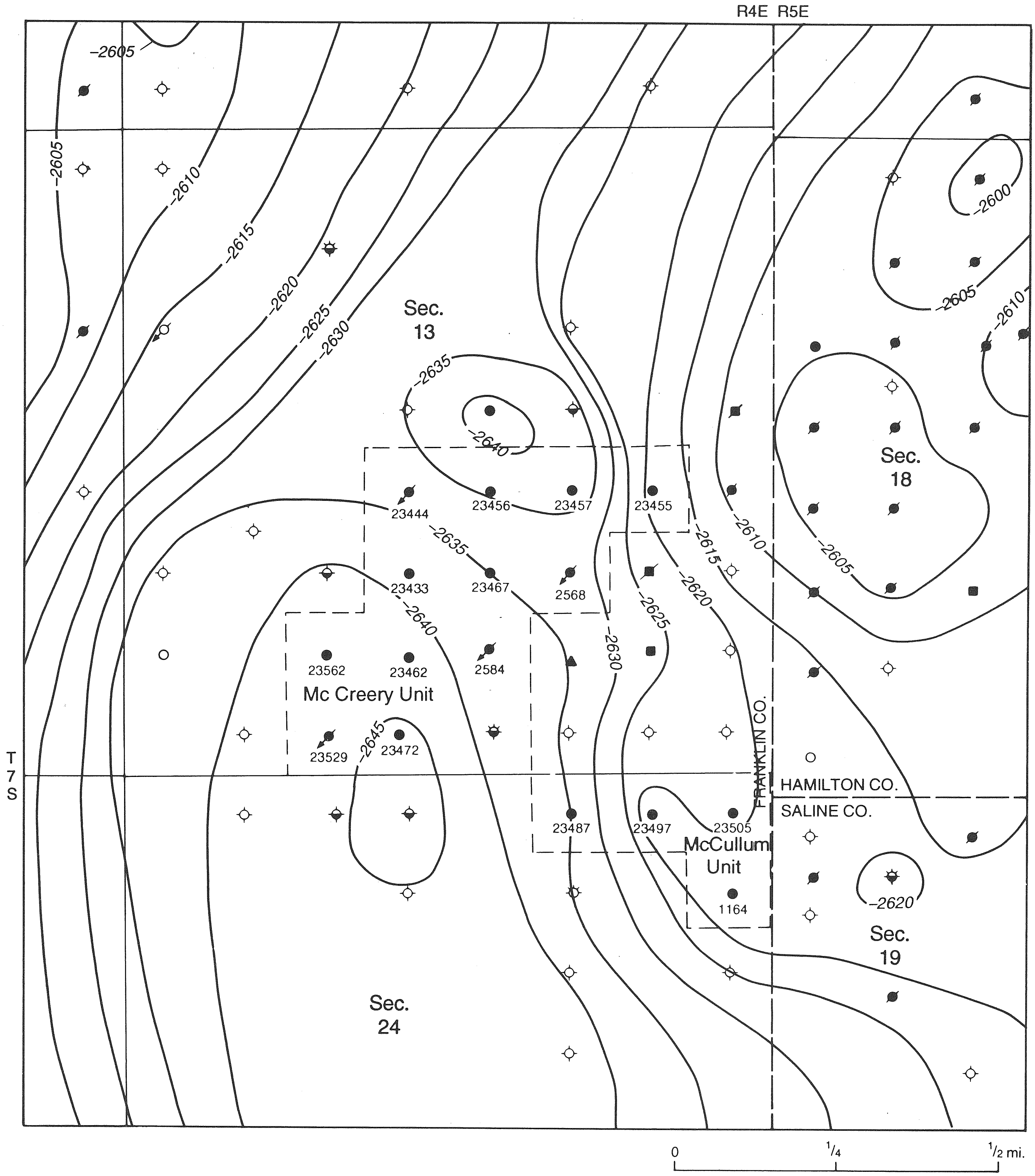


Figure 5 Structure on the base of Downeys Bluff Limestone in the area of the McCreery and McCullum Waterflood Units. A distinct structural low is developed throughout the study area. Contour interval is 5 feet; see table 5 for well names.

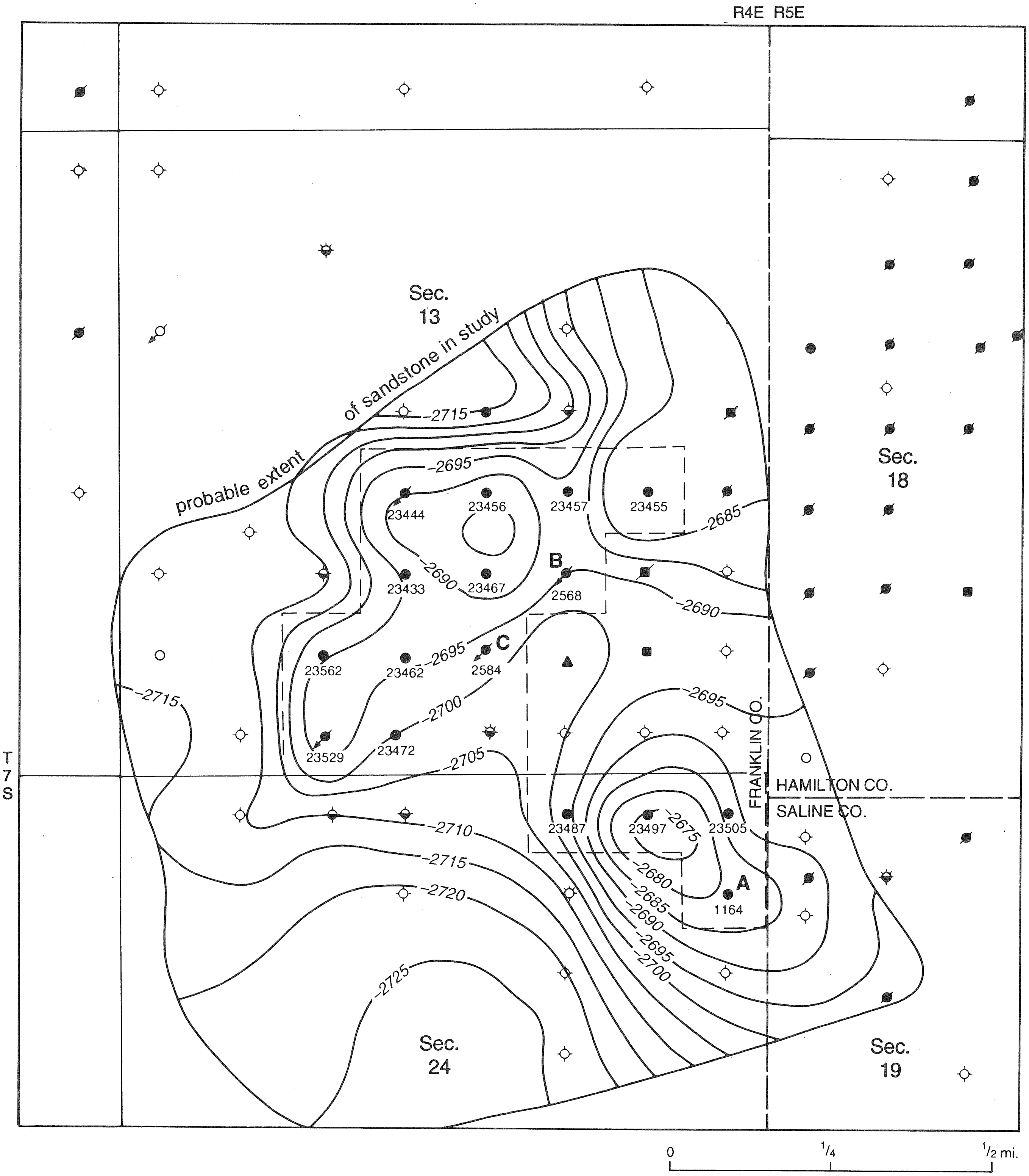


Figure 6 Structure on the top of producing sandstone in the McCreery–McCullum bar complex. Well A is the F. L. Strickland McCullum Community No. 1; well B is the Brehm McCreery No. 1; and well C is the Brehm Potter Community No. 1. Contour interval is 5 feet; see table 5 for well names.

For the sandstone of the reservoir interval (sampled from 3190.5 to 3205.5 feet), XRD and thin section analyses reveal a general increase in calcite content with depth, a condition that results in lower permeability (fig. 11). As demonstrated in the next section, this change in reservoir quality results in zonation of the Aux Vases interval into two broad flow units and forms the basis for selection of the reservoir simulation layers. A more detailed discussion of diagenetic changes within the McCreery and McCullum reservoirs and general reservoir geology is given in Beaty and Fagan (in prep.).

Measurement of Reservoir Heterogeneity Vertical heterogeneities have a pronounced effect on the sweep efficiency within a reservoir during incremental recovery processes. The Dykstra–Parson equation is commonly used in reservoir engineering to quantify the vertical variation in permeability and to predict displacement performance (Lake 1989).

The Dykstra–Parson coefficient, V_{DP} can be calculated from the log-permeability cumulative distribution function (CDF) as follows:

$$V_{DP} = \frac{K_{50} - K_{84.1}}{K_{50}} \; ; (0 < V_{DP} < 1.0) \qquad [1]$$

where K_{50} = absolute permeability corresponding to the 50th percentile (table 1),
$K_{84.1}$ = absolute permeability corresponding to the 84.1 percentile.

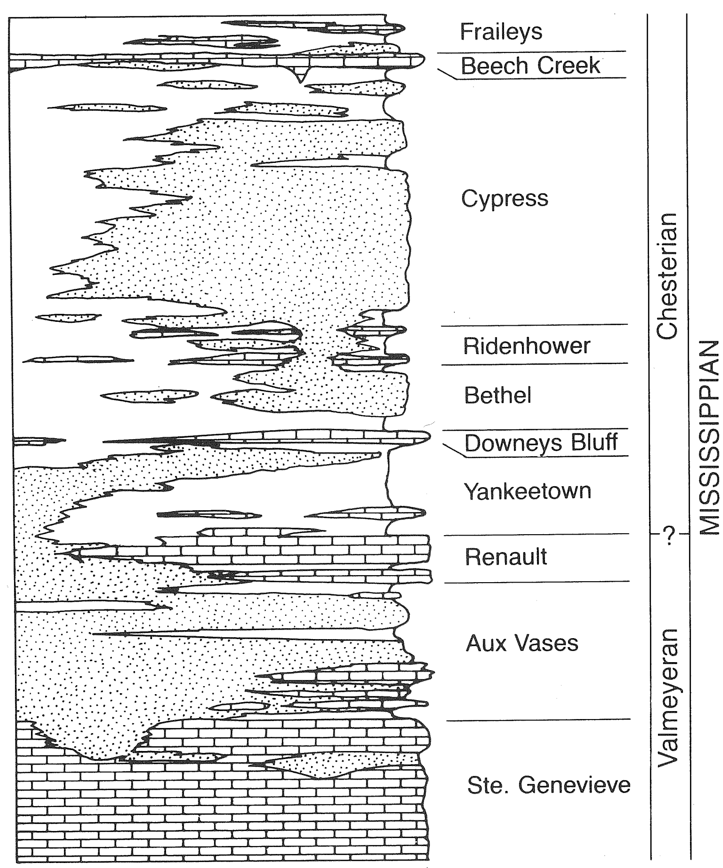


Figure 7 Generalized stratigraphic column of southern Illinois (after Whitaker and Finley 1992).

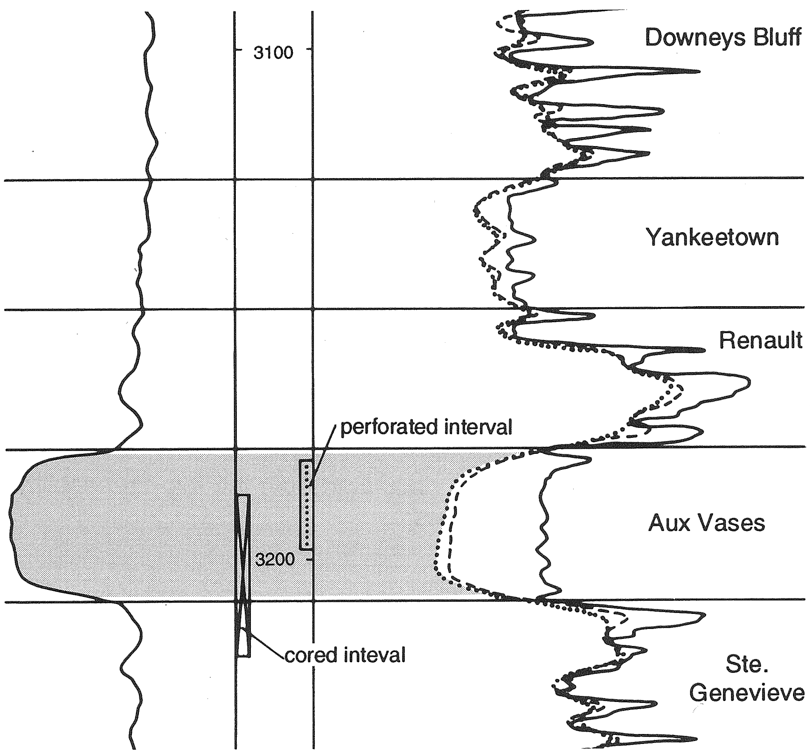


Figure 8 Type log for the McCreery–McCullum reservoir interval (orange) in the Farrar McCreery No. 1 well. Cored and perforated intervals are also indicated.

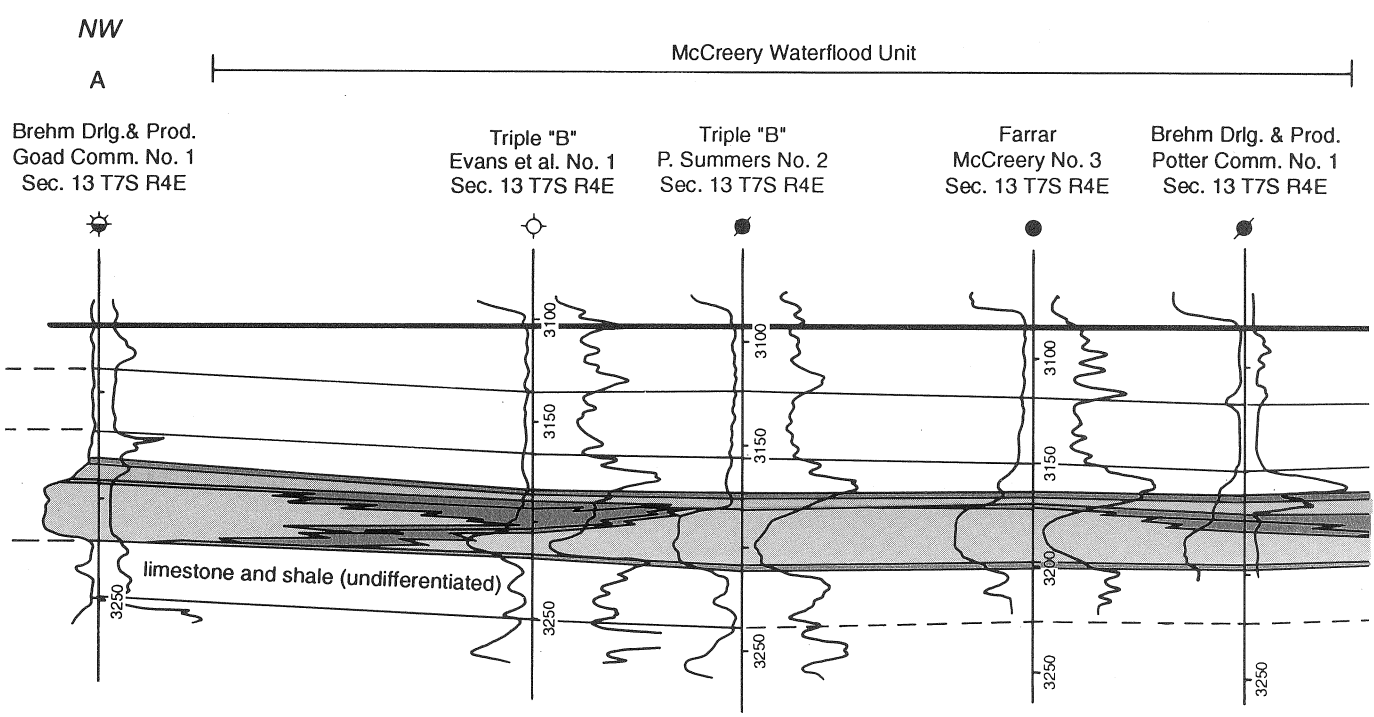


Figure 9 Cross section A–A′ (fig. 2) through the McCreery–McCullum bar. It was constructed using long normal resistivity logs (64-inch spacing) to illustrate the typically low resistivities of the reservoir sandstone; all available logs were used to make well to well, lithologic correlations. Aux Vases sandstone is interbedded with shale and shaley sandstone at the edges of the bar.

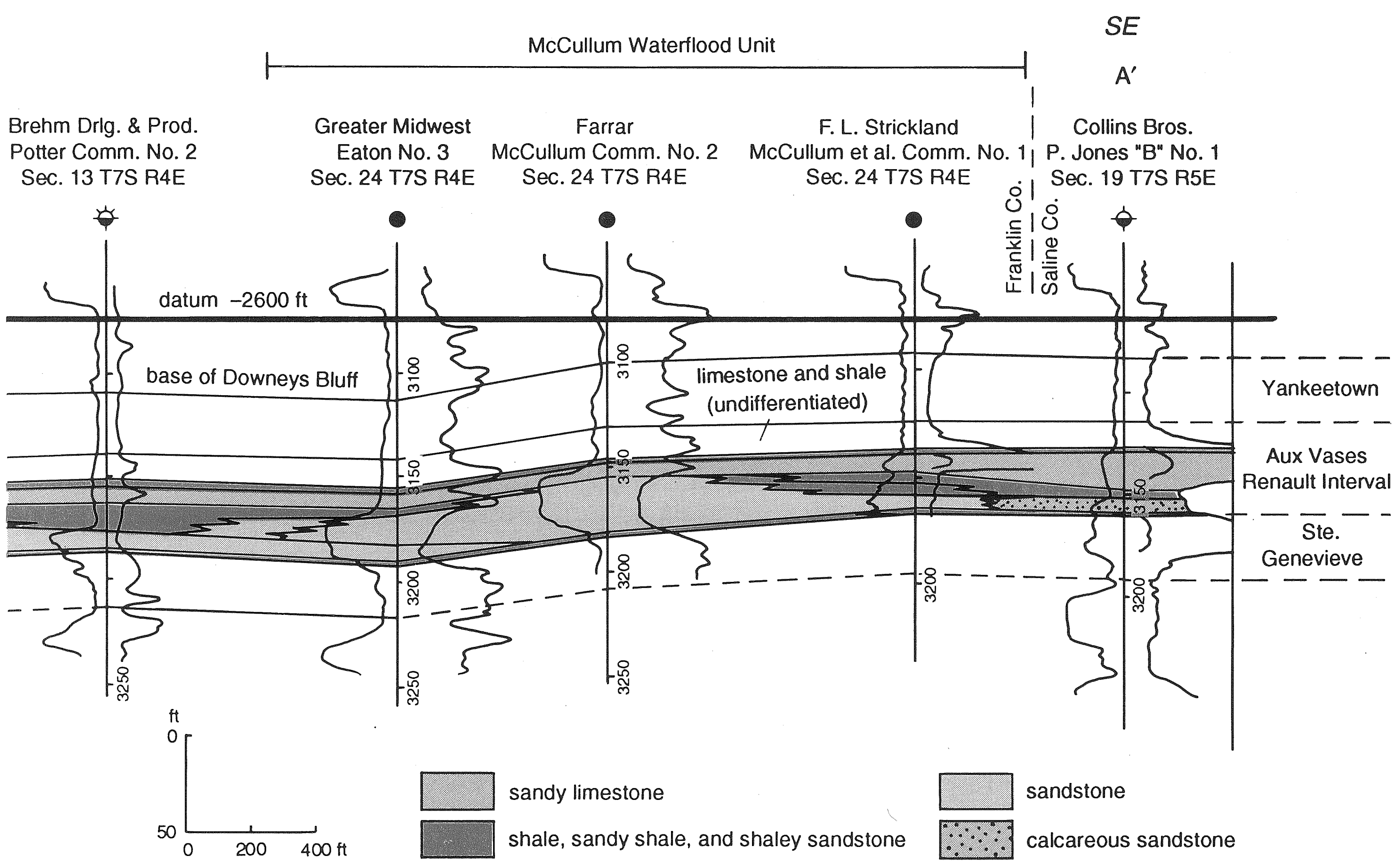
The Dykstra–Parson coefficient varies from 0 (homogeneous porous medium) to 1 (very heterogeneous porous medium). Figure 12 is the log-permeability cumulative distribution function of core-derived permeability from the Farrar Oil McCreery No. 1 well. The Dykstra–Parson coefficient determined from the data depicted in figure 12 is 0.63. This value is considered moderately heterogeneous.

The variability of permeability in the Farrar Oil McCreery No. 1 well can be determined by means of a semivariogram model, which uses core analysis data to illustrate that there is more than one flow unit in the reservoir interval at the McCreery Unit. A semivariogram model for the data constructed using GEO-EAS™ software (1991) is given by

$$\gamma(d) = 1500\,[1 - e^{-(3d^2/132)}];\ d > 0 \qquad [2]$$

where $\gamma(d)$ = a semivariogram model of absolute permeability,
d = distance from a reference point (bottom of the sandstone in this case).

The relationship shown in figure 13 reveals at least two sandstone flow units within the Aux Vases reservoir interval (from 3190.5 to 3206 feet) at the McCreery Unit. Figure 13 (or equation 2) only correlates the lower, less permeable 10 feet of sandstone that corresponds to simulation layer 2 (fig. 11) (i.e. below 3,196 feet). This finding is consistent with the Farrar McCreery No. 1 core analysis (see Appendix A), which suggests that two distinct sandstone layers are present: an upper, relatively more permeable layer about 15.5 feet thick (8 feet of which was analyzed), and a lower, relatively less permeable layer 10 feet thick.



Regional Stress Orientations and Fracturing Conditions The orientations of axes of principal compressive stress in southern Illinois are shown in figure 14. In situ stress measurements in an underground coal mine near McLeansboro, Illinois (15 miles northeast of the study area), indicated a maximum horizontal compressive stress (σ_H) axis trending N86.5°E (Nelson and Lumm 1984). The effects of the present stress regime on small-scale structures throughout the Illinois Basin were discussed by Nelson and Bauer (1987). In their work, several diagrams that show the trend of these small-scale structures provide additional evidence for the orientation of the maximum regional stress in the vicinity of the McCreery and McCullum Units and also throughout the southern portion of the Illinois Basin.

Lorenz et al. (1991) discuss mechanisms that lead to the formation of regionally extensive fracture systems. They also discuss the pore pressure conditions necessary for the development of hydraulic fractures. The conditions that result in formation of both natural and artificially induced fractures are affected by external compressive stresses as well as hydrostatic stresses within the reservoir. Thus, regional stress orientations and their effect on internal stress conditions are important considerations.

Fractures induced by hydraulic fracturing field experiments have been observed to propagate subparallel to the maximum horizontal compressive stress, σ_H (Haimson 1983). Because induced fractures are known to develop along preexisting natural fractures, it is important in field development projects to document the existence and orientation of natural fractures as well as to establish the orientation of the axis of maximum stress. Natural and induced fractures may develop in reservoir rocks in response to compressive stresses, as demonstrated by loading experiments in the laboratory (Cleary 1958). When subjected to prolonged unidirectional stress, failure will occur in the rock with fractures developing subparallel to σ_H.

The optimal methods for obtaining fracture orientations are selective oriented coring and/or fracture identification logging. In the absence of such data, other interpretive data may provide regional in situ stress conditions and fracture orientations (such as strain guage measurements in mines, underground joint-set measurements in shale beds above coal seams, analysis of earthquake focal plane mechanism, and measurements of borehole elongation).

Core from the Farrar McCreery No. 1 well contained a large oil-stained vertical fracture in the Ste. Genevieve Limestone below the reservoir interval; a core description from the Brehm McCreery No. 1 well also reported vertical fractures in the Ste. Genevieve. A large vertical fracture was developed in shaley sandstone above the reservoir interval in a core from the Triple "B" Evans et al. No. 1. Inspection of samples from the reservoir interval in the Farrar McCreery No. 1 well yielded some evidence of natural vertical fracturing, and the core description from the Brehm McCreery No. 1 well also reported some vertical fracturing in the reservoir. Minor vertical fractures were also observed in core from nonreservoir sandstone within the reservoir interval of the Triple "B" Evans et al. No. 1. Although the natural fractures are not as readily apparent in reservoir intervals as in nonreservoir intervals, the presence of natural fractures above and below the reservoir supports the interpretation that natural fractures exist within the reservoir interval, possibly at a microscopic scale. Because cores were not oriented, it was not possible to determine the trend of the present maximum, horizontal, compressive stress axis.

Implication(s) of Reservoir Heterogeneity on Oil Production All wells in the McCreery and McCullum Units were perforated within the upper 4 to 8 feet of the more permeable interval. The less permeable lower sandstone interval was not perforated in an attempt to retard incursion of bottom water into producing wells.

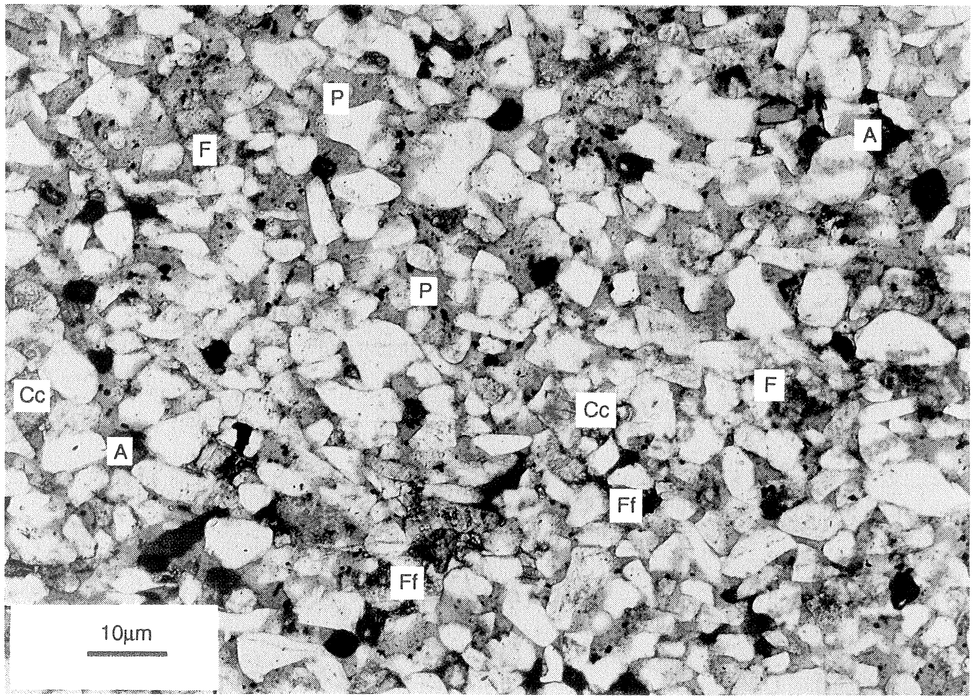


Figure 10a Thin section photomicrograph showing typical reservoir sandstone from the Farrar McCreery No. 1 well (depth 3,192.7 feet). Many of the framework grains are composed of calcium carbonate in the form of fossil fragments (Ff) and allochems (A). Other features highlighted in this sample are partially dissolved feldspar (F), patchy remnant calcite cement (Cc), and porosity (P), which has been dyed blue. Carbonate framework grains are present in all of the reservoir sandstone.

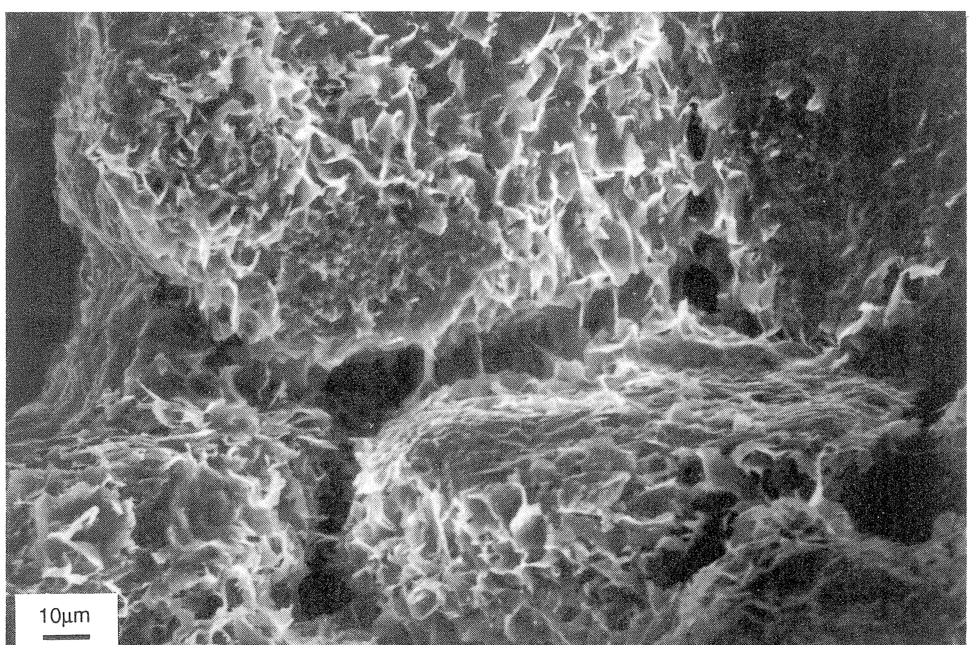


Figure 10b SEM photomicrograph showing typical clay coatings around quartz sand grains from the reservoir interval in the Farrar McCreery No. 1 well (depth 3,189 feet). The clays consist of illite, mixed layered illite/smectite, and chlorite.

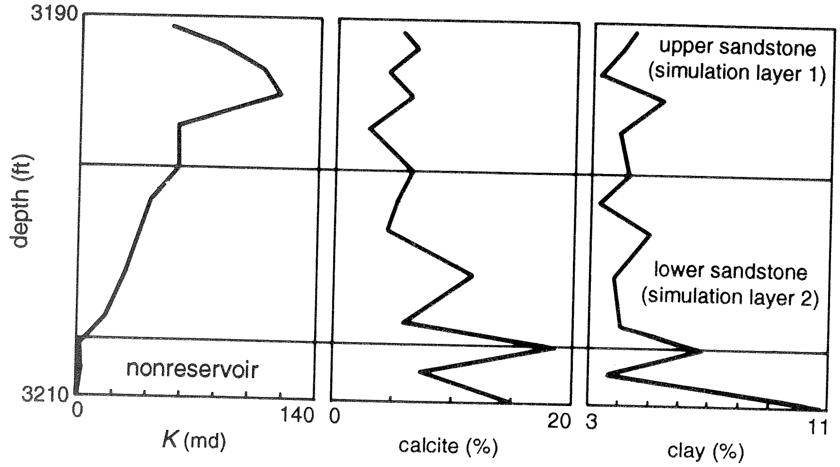


Figure 11 Variation of absolute permeability, calcite content, and clay content with depth for sandstone in the highlighted reservoir interval (fig. 8) of the Farrar McCreery No. 1 well. Porosity has been factored into these percentages to obtain volumetric percent from bulk mineral percent, as determined by X-ray diffraction.

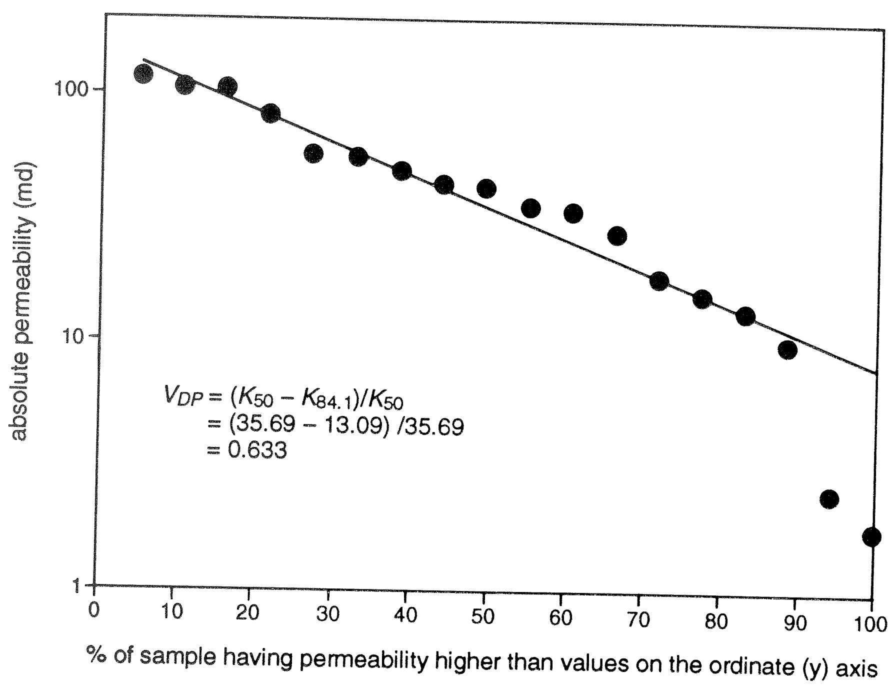


Figure 12 Cumulative permeability distribution function and the Dykstra–Parson coefficient (V_{DP}) at the Farrar McCreery No. 1 well. A calculated V_{DP} of 0.633 suggests that the reservoir rock is moderately heterogeneous.

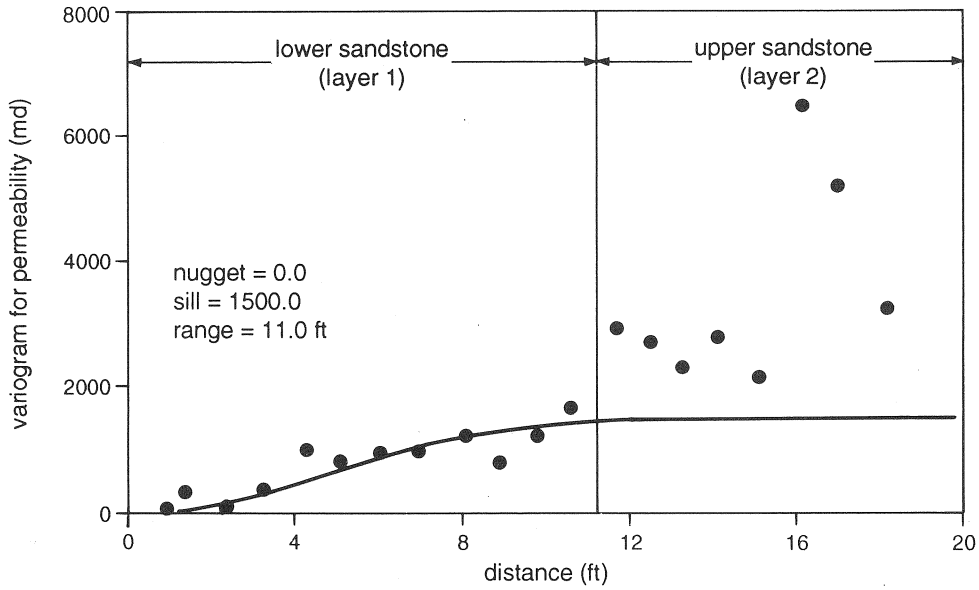


Figure 13 A semivariogram model based on core analysis data is used to detect trends in permeability of the Aux Vases sandstone at Farrar McCreery No. 1 well. The model helps to illustrate that there is more than one flow unit in the reservoir interval at the McCreery Unit. The permeability of the basal 10 feet of sandstone is correlatable by this model and corresponds to simulation layer 2 in figure 11, the lower flow unit. The next 15 feet of producing sandstone form the upper flow unit (simulation layer 1, fig. 11), although only 8 feet were cored and analyzed. (See table 1.)

Access to oil beyond the vicinity of the wellbore was increased, however, by using gelled salt water, lease or diesel oil, and sand proppant to hydraulically fracture the wells.

Although the hydraulic fracturing improved primary oil production, the production history and other evidence suggest that some induced fractures in these pays may have extended into the underlying aquifer. This would increase the conduction of bottom water to the producing wells. Such a system could have been responsible both for the delayed oil production response (because injected water was initially being diverted from the oil bank) and for the very high water–oil ratios at the producing wells. Furthermore, because there were no recompletions for the waterflooding project, the injected water may have been partly diverted into the permeable upper sandstone as well as into the induced fractures. If so, the oil sweep quite possibly occurred only through the induced fractures and through highly permeable streaks in the sandstone, thus resulting in a low sweep efficiency.

Geological Framework for the Reservoir Simulation Model

The reservoir simulation model of the McCreery and McCullum Units integrates geologic maps, reservoir rock and fluid data, field test results, and completion–production data. Isopach maps of the producing sandstone at the McCreery and McCullum Units and structure maps contoured on the elevation of the top of the producing sandstone (figs. 4 and 6) were digitized for input into a VIP^{TM} reservoir simulator and served as the geologic foundation for the reservoir simulation model. Interpretations of other data such as porosity and permeability distributions, water saturation distributions, relative permeability, oil–water contact, and pressure–volume–temperature (PVT) data necessary for reservoir simulation are discussed in the following sections.

Porosity and Absolute Permeability Distributions The Farrar McCreery No. 1 is the only cored well in the reservoir interval and therefore provides the only core

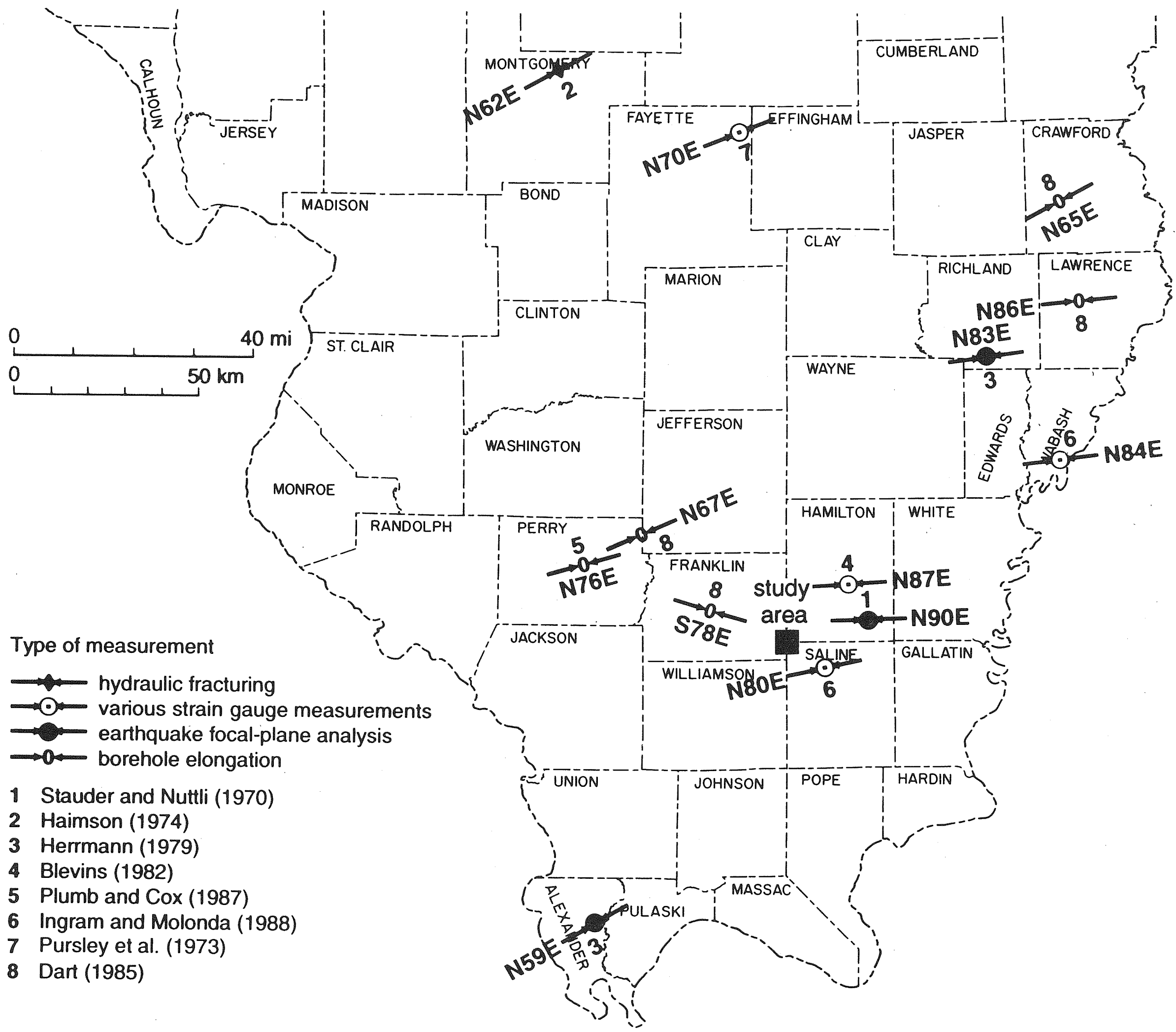


Figure 14 Orientations of maximum horizontal compressive stress (σ_H) in southern Illinois, as determined by various methods. (Modified from Nelson and Bauer 1987)

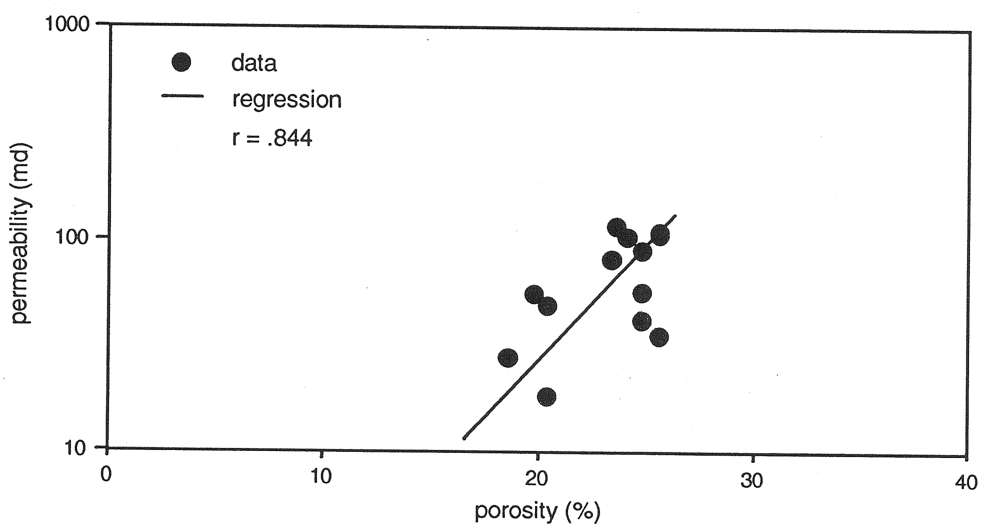


Figure 15 Porosity–absolute permeability cross plot based on core data from the Farrar McCreery No. 1 well is used to determine permeability values at uncored wells.

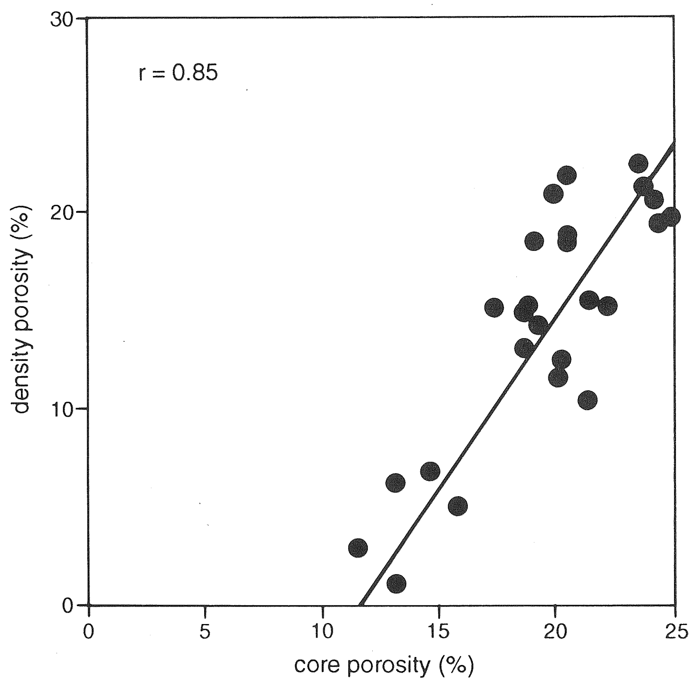


Figure 16 Cross plot of log-derived porosity versus measurements of core porosity.

analysis report for the entire productive portion of the McCreery Unit. In this well, the upper 8 feet of the productive interval is highly permeable, whereas the lower 11 feet of the interval is less permeable. A crossplot of porosity versus absolute permeability for the well is shown in figure 15 and is approximated by the relationship (r = .844):

$$K\,(\text{md}) = 0.192564e^{(0.24771\Phi)} \qquad [3]$$

where Φ = porosity in %.

Because of the sparseness of core data, porosity logs from a number of wells have been used to extend porosity data to other parts of the field. Figure 16 shows the correlation of log-derived porosity values to core-derived porosity values. Estimating permeabilities in uncored wells required using figure 16 to determine the core-derived equivalence of the log-derived porosities, and then figure 15 to determine corresponding permeability values for the uncored wells.

Permeability values determined in this way (equation 3 or fig. 15) cannot be considered exact because the variations of porosity are small even for permeability changes exceeding one order of magnitude. Therefore, in situ permeabilities derived from production data or pressure surveillance tests are necessary to quantify heterogeneities that may affect waterflooding and other improved oil recovery programs. Such data are, however, not available from the McCreery and McCullum reservoirs.

Initial Oil–Water Contact and Reservoir Pressure The initial elevation of the oil–water contact determined from the Farrar McCreery No. 1 core analysis report and from wireline logs was –2,715 feet (subsea level). The presence of low permeability calcite streaks has impeded the encroachment of bottom water, and the source of reservoir energy has primarily been solution gas. Water production in the McCullum Unit has been negligible except in the Greater Midwest Eaton No. 3 (fig. 2), which had an average water cut of 20%. Many wells at the flanks of the

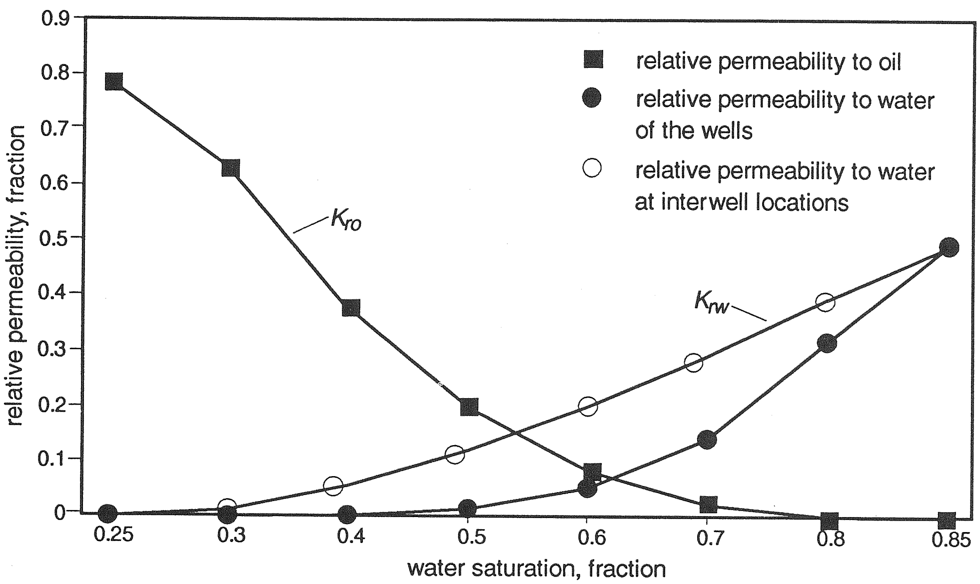


Figure 17 Relative permeability of oil and water saturation in samples from the Farrar McCreery No. 1 well. The end-point relative permeability values (K_{ro} and K_{rw}) were experimentally determined. The relative permeability values of water and oil at other water saturations were determined by use of a simulation program, PEP™.

McCreery Unit, including the Greater Midwest Eaton No. 3 in the McCullum Unit, contain a significant column of permeable and porous sandstone below the present oil–water contact. Therefore, primary fluids produced from these wells had medium to high water cuts, seemingly because of water coning at the wellbore and water conducted through vertical fractures. Furthermore, it is postulated that during waterflooding, most of the injected water went down into and filled up the fractures, and also entered the partially depleted aquifer. Continuing water injection caused water to channel into producing wells, choking off most of the oil production.

Initial reservoir pressures in these units are unknown. The earliest drill stem test, conducted on the Strickland McCullum Community No. 1 well in 1955, gave an unrealistic bottom-hole value of 255 psig. The "rule of thumb" used by several Illinois basin operators to determine original reservoir pressures is the hydrostatic pressure at a datum depth less 100 psig (Brad Aman, Farrar Oil, personal communication 1991). On this basis, the original pressure in the McCreery and McCullum Units is assumed to be about 1272 psig at a reservoir depth of 3,190 feet.

Relative Permeability and Capillary Pressure Data The end point, oil–water, relative permeability values (K_{ro} and K_{rw}), as well as the irreducible water and residual oil saturations, were derived from ISGS laboratory measurements on the Farrar McCreery No. 1 core. The relative permeability values of water and oil at water saturations other than the end point values were determined by use of a simulation program, PEP™, which calculates approximate, effective relative permeabilities at the well and in the interwell region of the reservoir model. These relative permeability values were then used to perform the full-field simulation of the reservoir. The oil–water, relative permeability–saturation curves used in this study are shown in figure 17.

Capillary pressure–water saturation relationships (fig. 18) were derived from analyses of depth relative to water saturation, as provided in the core analysis report for the Farrar McCreery No. 1 well. It is, at best, approximate because in situ fluid

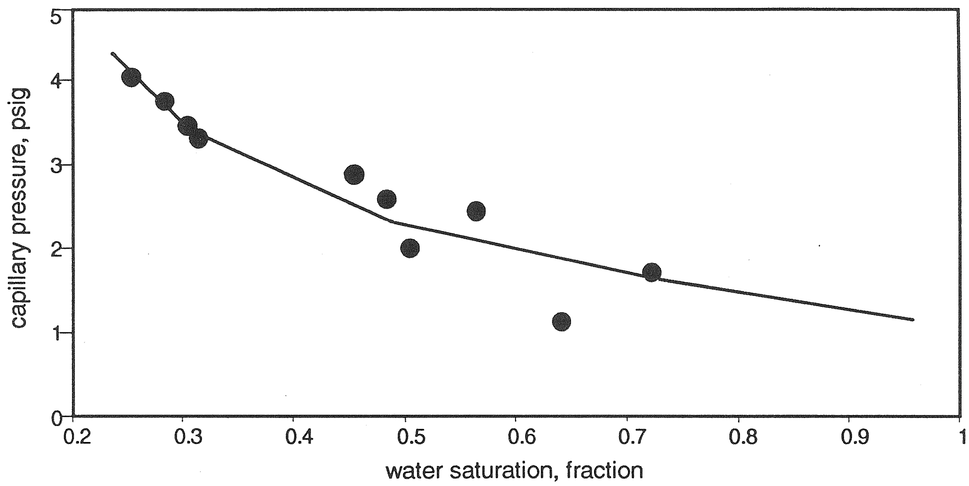


Figure 18 Capillary pressure–water saturation curve derived from core analysis of Aux Vases samples from the Farrar McCreery No. 1 well.

content may have been altered by differential pressure exerted by drilling mud and fluid expansion as the core is retrieved (Bass 1987). The initial equilibrium saturation distribution in the simulation model was established using this curve. Capillary pressure–saturation data, which show the water and oil saturation at various depths of the productive sand, can be used to determine the initial equilibrium saturation distribution in the simulation model. In this study, the reserve estimates were determined by the simulator using this capillary pressure data.

PVT Analyses of Hydrocarbon Fluids There is no previous report of the PVT properties of reservoir fluids for either unit. Oil and gas were sampled by the ISGS from the wellhead of the Farrar McCullum No. 2, then were recombined and analyzed in the ISGS PVT laboratory to obtain solution gas to oil ratios, formation volume factors and viscosities of oil at various saturation pressures, and a reservoir temperature of 98°F (Sim 1993). Because the oil and gas samples do not represent the original compositions at field discovery, the PVT properties were measured at various mixing ratios to permit a sensitivity analysis of the effects of various ratios on reservoir performance. As shown by Sim (1993), a plot of saturation pressure against oil formation volume factor (B_o) is linear.

The PVT properties of the samples at saturation (bubble-point) pressures of 150, 350, and 610 psig were used in a two-dimensional, cross sectional, reservoir simulation model to investigate how reservoir performance would vary after 10 years of production. A solution drive type of reservoir, in which water-drive energy was negligible, was simulated. Table 2 shows the range of values (level of uncertainty) to be expected in the results of reservoir simulations due to the uncertainty regarding the bubble-point pressure of the original fluid in the reservoir.

A bubble-point pressure differential of 460 psi, for example, results in only a 2.7% change in the simulated 10-year oil recovery factor and a difference of 7.5 psig in average reservoir pressure.

A bubble-point pressure of 350 psig was arbitrarily selected for subsequent full-field simulations because the bubble-point pressures of Illinois oils from the Aux Vases reservoirs are historically low and in the range of 300 to 600 psig (G.A. Payne, petroleum engineering consultant, personal communication 1992). Data on PVT properties, experimentally determined at a saturation pressure of 350 psi and

Table 2 Effects of variations in PVT properties on reservoir performance

Bubble-point pressure (psig)	150	350	610
After 10 years of production			
Oil recovery factor (%)	34.4	32.9	31.7
Reservoir pressure (psig)	50.0	45.7	42.5
Cumulative producing GOR (scf/bbl)	322.7	667.9	894.3
Original oil in place (MSTBO)	1,079.0	894.0	831.0

Table 3 Data from differential vaporization of McCullum No. 2 crude oil

Pressure (psig)	B_o (bbl/STBO)	Rs (scf/STBO)	Oil viscosity (cp)	Gas viscosity (cp)
2000	1.197			
1000	1.205			
350	1.213	319.4	1.39	0.014
250	1.19	292.0	2.00	0.013
150	1.13	245.1	2.33	0.012
65	1.07	164.5	2.44	0.011
15	1.03	82.9	2.69	0.0105
0	1.02	0.0	2.75	0.01

Reservoir temperature = 98°F
Oil °API = 37
Gas gravity = 1.4
Bubble-point pressure = 350 psig

a temperature of 98°F, are given in table 3. In practice, knowledge of the bubble-point pressure (the reservoir pressure at which gas begins to bubble out of the oil) is very important because it can be used by the operator to plan strategies and timing for pressure maintenance activities required to maintain the reservoir pressure at or above the bubble-point pressure.

Estimation of Oil Reserves and Pre-Waterflood Recovery Factors Original oil in place (OOIP) was determined by the volumetric method. Data for this determination are given in table 4. The OOIP is given by the following (Garb and Smith 1987):

$$\text{OOIP} = 7758\,\frac{\Phi A h S_o}{B_o} \qquad [4]$$

where OOIP = original oil in place in stock tank barrels (STB),
Ah = reservoir volume in acre-feet,
Φ = average porosity (fraction),
S_o = average initial oil saturation (fraction),
B_o = oil formation volume factor (FVF), reservoir barrels/STB.

The initial oil in place for the McCreery Unit was 1,798 MSTBO and for the McCullum Unit, 652 MSTBO. Reservoir volumes were estimated by planimetry of the productive sandstone isopach map (fig. 4). The estimated initial oil saturation value of

43.3% was based on the entire reservoir sandstone interval. Table 4 contains a summary of estimates of the OOIP, primary recovery factors, and the waterflood reserves before the initiation of the McCreery waterflood program. Primary recovery factors of 14.6% and 30.5% were calculated for the McCreery and McCullum Units, respectively. The McCullum Unit oil recovery factor is twice that of the McCreery Unit because the McCullum Unit had been producing for 15 years before the start of oil production in the McCreery Unit. The average primary recovery factor from both units is 18.9%. Waterflooding was initiated in the McCreery Unit on June 28, 1991.

RESERVOIR SIMULATION

The exact magnitude and distribution of rock heterogeneities within the reservoirs are unknown. The reservoir description provided above is based on initial conditions in the reservoir. It does not include the effects of induced heterogeneities because the actual spatial distribution of these heterogeneities in the reservoir is also largely unknown.

The two layer, full-field simulation model used for this study was based on contour maps of structure on the top of productive sandstone, productive sandstone thickness, and geologic interpretations derived from a 3-D model of stratigraphic framework. Because the core analysis data and the semivariogram model showed two flow units within the reservoir interval, a two-layer grid system was created to more accurately model this obvious difference in petrophysical properties. The grid dimension is $23 \times 20 \times 2$ (920 blocks), and the interwell distance is 660 feet (i.e. 10-acre spacing). In the grid block model, adjacent wells have one or more grid blocks between them, as recommended by Mattax et al. (1990). Sixteen producing oil wells were involved in this simulation (table 5).

The reservoir simulator used is the Western Atlas Integrated Technologies Vector Implicit Program (VIP) CORE™ (black oil) simulator implemented on a Silicon-Graphics IRIS 4D/310GTX workstation. VIP's BLITZ solution technique was employed for solving the algebraic equations (Western Atlas Software 1991). This reservoir simulator software can be used to compare and/or match simulated results to historical data. The simulation model can also be used to predict future performance of the field under various recovery strategies.

Table 4 Summary of reserve estimates by volumetric method

	McCreery Unit	McCullum Unit	Total
Estimated volume (acre-feet)	3,152	1,143.4	4,295.4
Average porosity (fraction)	0.206	0.206	0.206
Average oil saturation (fraction)	0.433	0.433	0.433
Oil formation volume factor (FVF, bbls/STBO)	1.213	1.213	1.213
Estimated OOIP (MSTBO)	1,798	652	2450
Residual oil (15%)	623	226	849
Pre-waterflood production (MSTBO)	263	199	462
Waterflood reserves (UMO)	912	227	1139
Primary recovery factor (% of OOIP)	14.6	30.5	18.9
Waterflood reserves (% of OOIP)	50.7	34.8	46.5

Table 5 Well names, API short numbers, and sandstone thicknesses*

Well (company, name, no.)	Short API no.	Simulation no.	Completion date	Gross sand thickness (ft)
Farrar McCullum No. 1	1164	1	08/09/55	5.5
Brehm McCreery No. 1	2584	2	08/09/69	15
Brehm Potter Community No. 1	2568	3	12/05/69	17
Farrar Pansy Summers No. 1	23433	4	12/23/83	21
Farrar Pansy Summers No. 2	23444	5	02/16/84	26
Farrar McCreery No. 1	23456	6	03/27/84	26
Farrar McCreery No. 2	23457	7	04/03/84	22
Farrar Mabel Berry No. 1	23455	8	04/12/84	19
Farrar McCreery No. 3	23467	9	05/02/84	25
Triple "B" Eaton No. 1	23462	10	05/01/84	21
Greater Midwest Eaton No. 3	23487	11	07/26/84	19
Farrar McCullum No. 2	23497	12	09/25/84	25
Farrar McCullum No. 3	23505	13	10/24/84	16
Triple "B" Eaton No. 2	23472	14	10/03/84	15
Triple "B" Eaton No. 3	23529	15	04/07/85	23
Triple "B" Eaton No. 4	23562	16	06/14/85	19
Triple "B" Evans et al. No. 1	—	—	04/04/84	(dry)

* The prefix of all API numbers is 12055.

Results of Reservoir Sensitivity Studies

Flow continuity between McCreery and McCullum Units Sensitivity analyses showed that communication between the McCreery and McCullum Units (fig. 19, point A) is necessary to sustain the historical oil production from the F.L. Strickland McCullum Community No. 1 (fig. 2) well for 30 years and to match the water cut in the Greater Midwest Eaton No. 3 (fig. 2), a well at the west edge of the McCullum Unit. Reservoir models that prevented communication at point A (fig. 19) resulted in insufficient water production at the Greater Midwest Eaton No. 3 and insufficient energy to match the historical oil production data in the McCullum Unit, even when permeability values were unrealistically altered. Although the degree of communication is reflected by the amount of current water production at the Greater Midwest

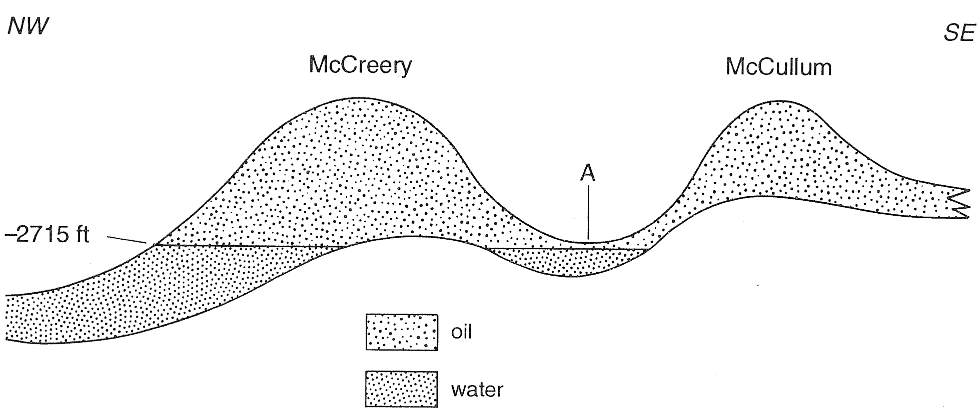


Figure 19 The conceptual model of the McCreery and McCullum Waterflood Units showing the trough between the McCreery and McCullum portions of the sandstone bar. At point A (arbitrarily placed between the two units), there is thought to be a small column of oil-saturated sandstone.

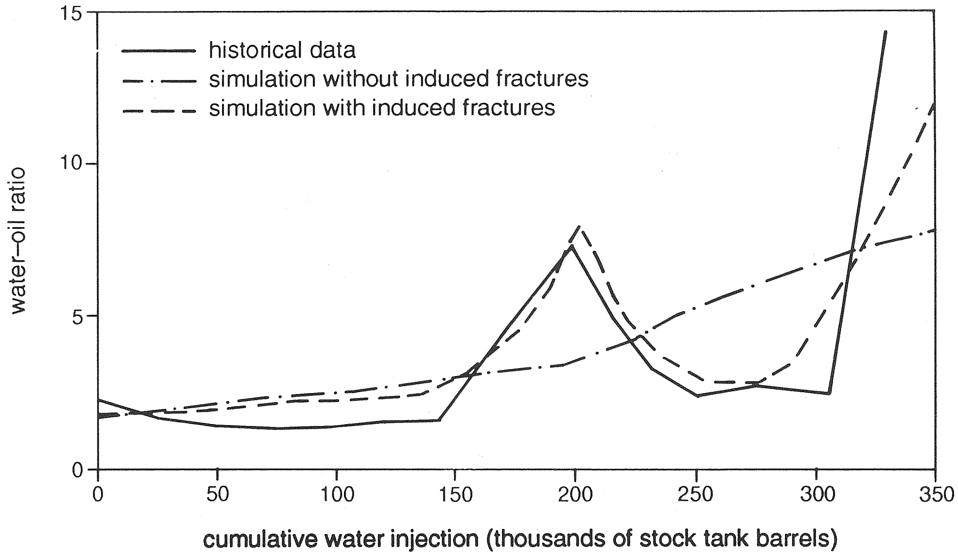


Figure 20 Water–oil ratio versus cumulative water injection curves compare simulated to observed data for fractured and nonfractured models. The shape of the curve for the fractured model is very similar to the actual production (historical) data.

Eaton No. 3 (about 15% to 20% of total liquid production), interwell tests should be performed to substantiate this hypothesis.

Effects of induced fractures on simulated reservoir performance Simulation of the effects of induced directional fractures on the distribution of oil saturation during production and on oil recovery efficiency required that absolute permeability values in all rows of grid cells containing wells be increased by 1.5 to 2 times in the x-direction (east–west) and the z-direction (vertical) because a dual porosity simulator, which is better suited for this analysis, was not available. The increased permeability values in the x and z directions in the rows containing wells should cause the model to simulate the effective permeabilities of the fractured rocks.

Figure 20 compares the simulated and observed water–oil ratios for induced fracture and nonfracture scenarios. The simulated profile for the fractured reservoir model closely matches the historical data for the McCreery Unit, thus suggesting that actual reservoir performance during waterflooding in the McCreery Unit was adversely affected by directional permeability from induced fractures.

As expected, the predicted waterflood performance is lower in the fractured case than in the nonfractured case. Simulation results show that at least 15% more oil may be recovered if there are no induced fractures. Early water production and a poor sweep efficiency are responsible for the lower oil production response in the fractured case.

Evaluation of the McCreery Unit Waterflood Project

Water injection into the McCreery Unit began on June 28, 1991, with three previously oil-producing wells used as injectors: the Farrar Pansy Summers No. 1, Triple "B" Eaton No. 3, and Brehm Potter Community No. 2 (fig. 2). These wells were also used in the simulation modeling. Although water injection into the unit averaged 750 BWPD, a production kick was not noticed until about 9 months later. Since the inception of water injection, the water–oil ratio has increased from less than 1 to more than 14 barrels of produced water per barrel of oil.

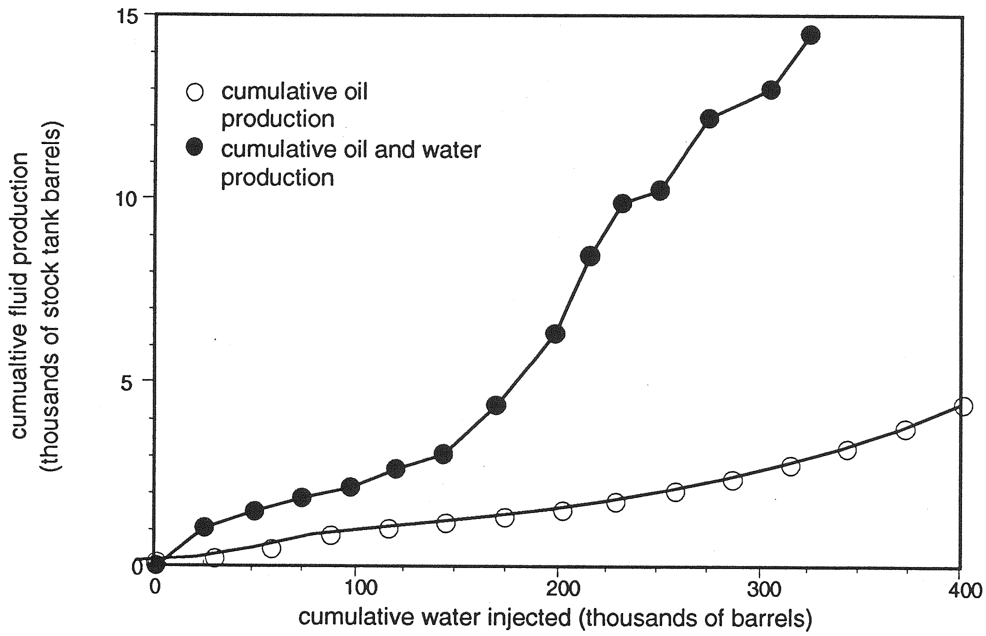


Figure 21 Cumulative fluid production versus cumulative water injection curves for the McCreery Unit illustrate the early water breakthrough and the widening gap between the amount of oil produced and the total amount of fluid. This profile suggests that the waterflood program is not optimal.

Figure 21 shows the cumulative fluid and oil production as a function of the cumulative water injected. In this profile, the cumulative oil production curve deviates from the cumulative fluid production near the inception of the waterflood. This indicates an early water breakthrough and the probability of a poor waterflood recovery performance.

Figure 22 shows oil production rates beginning in 1990 and throughout the secondary phase from the inception of the waterflood to August 1992. As the figure shows, the production incline period was quite short and the subsequent production decline phase precipitous.

Economic limit and field abandonment time The economic life of the present waterflood can be evaluated from figure 23. Data for the evaluation were provided by the operator (appendix B). These calculations assume a net royalty interest (NRI) of 19.333%. The cumulative oil produced is determined from the production decline curve (fig. 22). The results shown in figure 23 suggest that the present McCreery Unit waterflood plan can produce a profit (positive cash) only if the price of oil is between $35 and $40 dollars per barrel from the inception of the waterflood project. If the price of oil falls below $35 per barrel, the present waterflood recovery project will not be profitable unless further improvements in waterflood recovery strategies can be successfully and economically initiated.

Improving Oil Recovery of the McCreery and McCullum Unit Waterflood

Diagnostic tests The poor oil production response in the McCreery and McCullum Unit waterflood has prompted a somewhat aggressive surveillance program by the operator. Figures 24 and 25 show some of the test results.

Figure 24 is a typical Hall plot developed in this study for analysis of the performance of the Farrar Pansy Summers No. 1. It clearly shows an inflection in the slope of the curve after cumulative injection of 90,000 barrels of water. This change of slope is

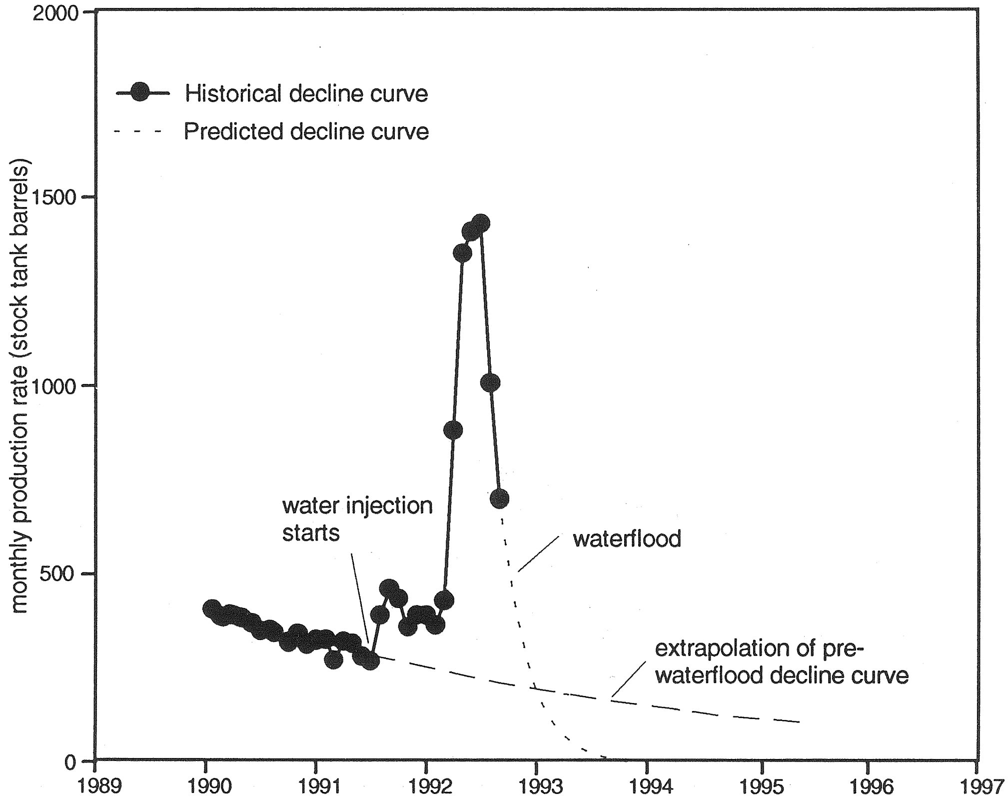


Figure 22 Monthly oil production curve for the McCreery Unit. The oil production decline curve due to waterflooding is steeper than the pre-waterflood decline curve because injected water is channeling through the fractures and into the wells, thus effectively choking off oil production.

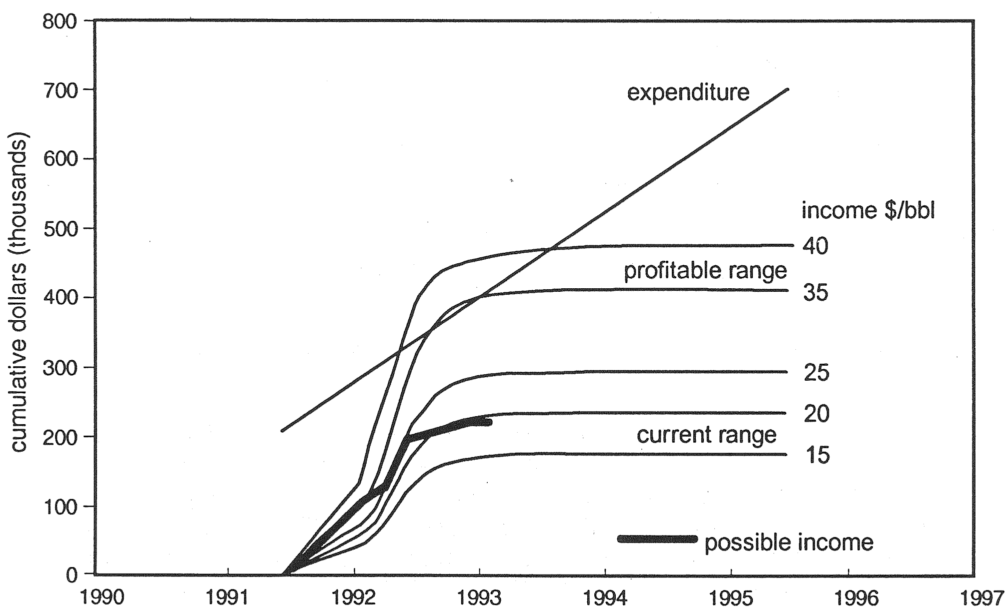


Figure 23 Cost analysis of the McCreery Unit waterflood suggests that the project would be uneconomic, unless oil prices reach at least $35 per barrel.

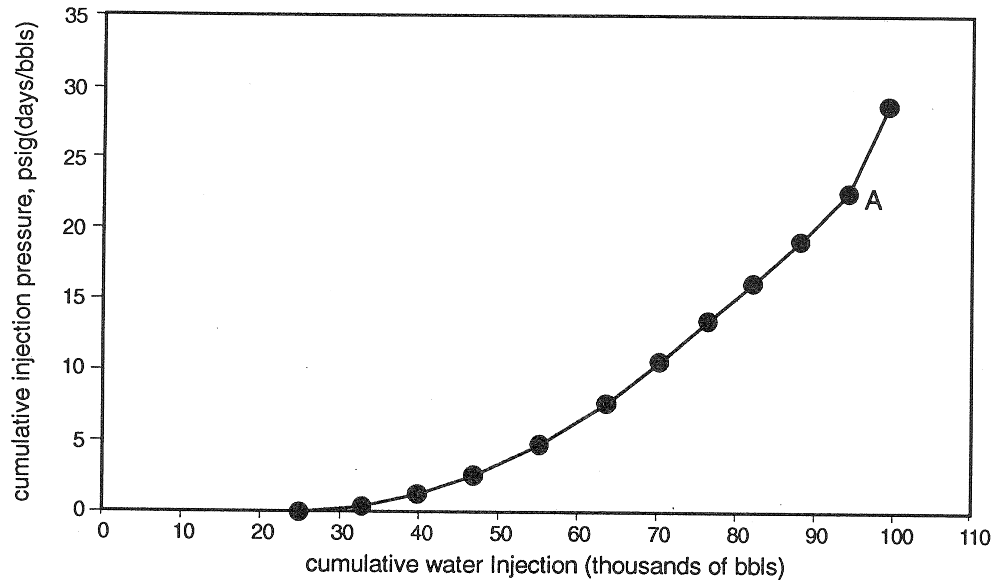


Figure 24 Hall plot for the Farrar Pansy Summers No. 2 water injection well. Increase in slope at A suggests increasing positive skin (formation damage), possibly due to poor water quality.

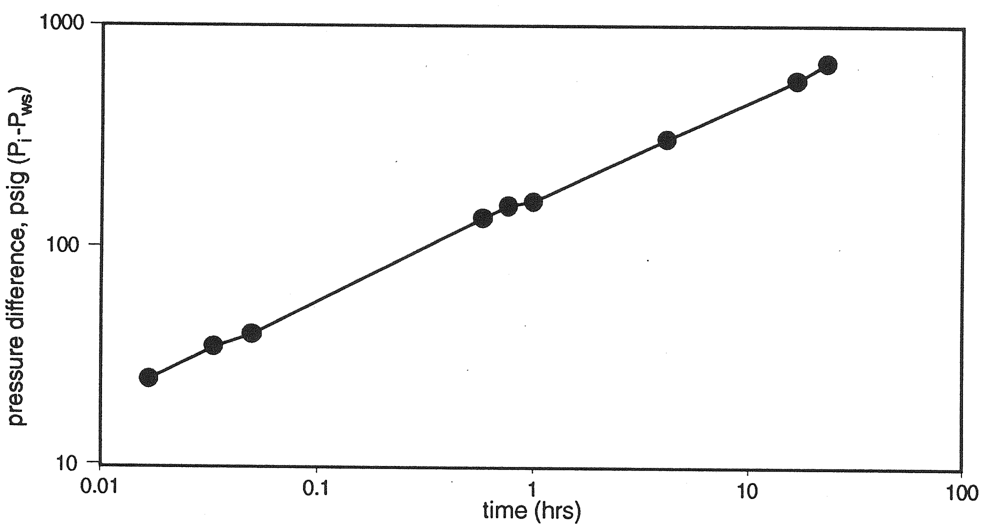


Figure 25 Typical pressure fall-off test plot (Triple "B" Eaton No. 3 well).

indicative of formation damage at the wellbore region, possibly due to poor water quality.

Pressure fall-off tests were conducted by the operator at the injection wells, and build-up tests were conducted by taking fluid levels at shut in producing wells over a period of 24 hours. Lee (1982) presented a methodology using the type-curve approach of Gringarten et al. (1972) to estimate permeability values and half-lengths of vertical fractures from pressure transient test data. In this study, test data such as those from the Triple "B" Eaton No. 3 well (fig. 25) were used to calculate permeability values and half-lengths of vertical fractures in the vicinity of the injection wells, the Triple "B" Eaton No. 3, Brehm Potter Community No. 1, and Farrar Pansy Summers No. 2 (table 6).

Table 6 Results from pressure fall-off test data

Injection well	Pay, *h* (ft)	Permeability, *K* (md)	Half-length, L_f (ft)
Brehm Potter Community No. 1	17	264	260
Farrar Pansy Summers No. 2	26	9.5	50
Triple "B" Eaton No. 3	23	28	72

The fracture half-length (L_f) values in table 6 suggest that the induced fractures extend into the water-bearing interval (below –2,715 feet subsea) and have varying lengths from well to well. For example, the values suggest that the induced fractures extended the farthest from the Potter Community No. 1 well and the least from the Summers No. 2 well. The effective in situ permeability value of the reservoir around the Potter No. 1 well is also more than five times greater than that around the Summers No. 2 well. Although the vertical fractures may not extend from well to well in some areas of the unit, they apparently created highly conductive channels oriented in an east–west direction in every case.

Results from a recent tracer test using fluorescein dye in the Triple "B" Eaton No. 3 well show that there is communication in both the north–south and east–west directions. Possible explanations for these results are given in the following section.

Possible reasons for reservoir inefficiency Three causes for the poor reservoir performance can be postulated, based on the studies of the reservoir geology, the completion and production history, and the diagnostic tests conducted in the McCreery Unit.

Reservoir geology As shown by the schematic diagram of the reservoir interval in the McCreery Unit (fig. 26), only a few feet of the upper sandstone interval was perforated in each well—a good strategy that, during the primary production, may have helped to retard arrival of bottom water. No attempt was made, however, to reperforate the existing producing wells before converting them to injectors. Con-

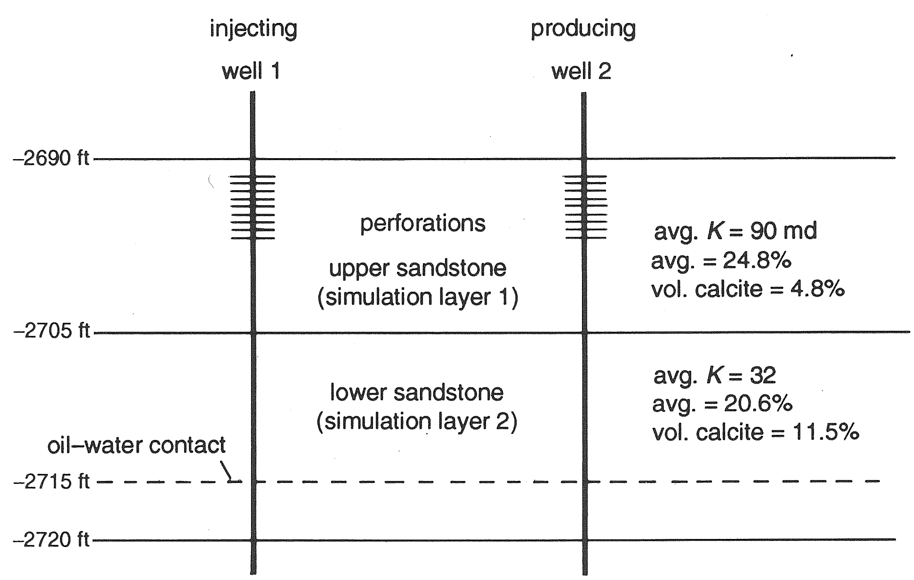


Figure 26 Diagram showing reservoir zonation, sandstone quality, and perforated intervals in the McCreery Unit.

sequently, water was injected only into the more permeable upper sandstone layer. The rationale was that the entire pay interval was open to oil production because each well was heavily fractured during the initial completion phase. Because the induced fractures are oriented east to west, the injected water could not efficiently sweep the reservoir north or south of the wells and in the rock matrix east or west of the wells. Furthermore, oil production would be drowned before any appreciable amount of oil in the lower zone could be produced. The recent tracer test shows that fluid flow is also controlled by the highly permeable upper sandstone interval; the fluorescein dye tracer was also detected in the Triple "B" Eaton No. 4 north of the injection test well, the Triple "B" Eaton No. 3.

Induced fractures As shown by the historical production record, the water–oil ratios increased dramatically only in the wells immediately east or west of the water injectors after 170,000 barrels of water had been injected. There was no significant change in the water–oil ratios of the oil producers due north or south of the water injectors.

In the Triple "B" Eaton No. 2, which is immediately east of the water injection well, Triple "B" Eaton No. 3, the water–oil ratio increased from 14.6 in January 1992 to 50.5 a month later. It also increased fivefold at the same time (from 4 to 20) in the Triple "B" Eaton No. 1, which is due west of the Potter No. 2. During injection, the water–oil ratio remained essentially the same (0.3) in the Triple "B" Eaton No. 4, which is directly north of the water injection well, Triple "B" Eaton No. 3. These observations are a further indication of the presence of highly conductive, induced fractures oriented in an east–west direction (fig. 27).

Water injection well pattern The available evidence suggests that the use of existing wells as injectors may not be effective without remediation and well rearrangement to minimize interference. Injection of water through existing wells without squeezing the existing perforations and reperforation of the lower layer would almost certainly lead to a poor recovery response; the injected water would migrate to the producers through the highly permeable interval in the upper zone

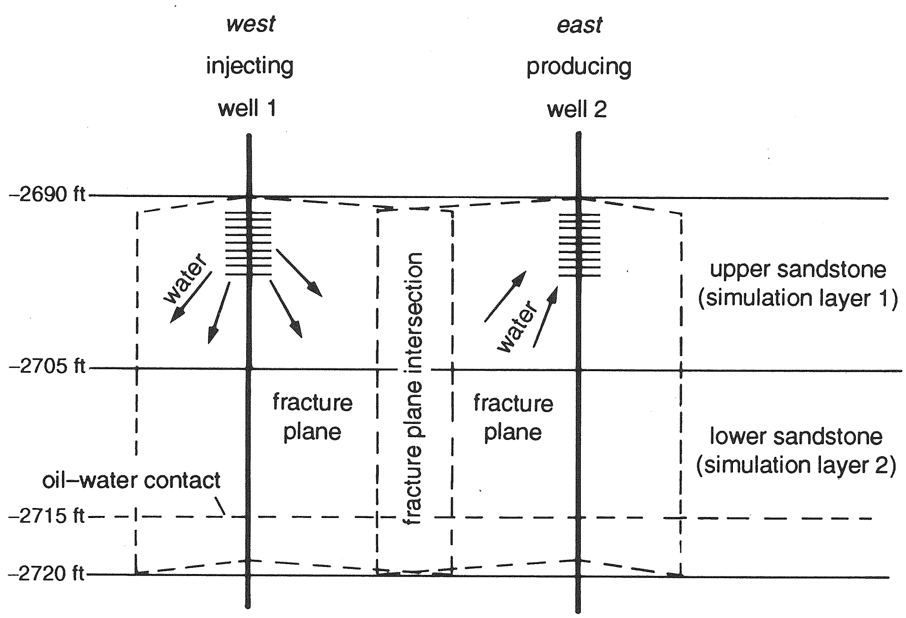


Figure 27 Diagram showing the presumed orientation of induced fracture planes, how they extend into the aquifer, and their effect on the injected water. The intersection of these fracture planes is highlighted in the center of the diagram.

and through the induced fractures. Recommendations for a stepped testing and recompletion program to overcome this obstacle and to improve oil recovery from this unit are provided in the following section.

IMPROVED OIL RECOVERY POTENTIAL

Pre-waterflood oil recovery from the McCreery Unit was 14.6% of the OOIP. After 14 months of waterflooding (June 1991 to August 1992), incremental oil recovery from the unit was only 0.56% of the OOIP. Estimated unproduced mobile oil (UMO) in the unit exceeds 48% of the OOIP. Considering that waterflood oil production responses from other Aux Vases reservoirs have been an additional 15% to 20% of the OOIP, it seems reasonable to attempt other strategies for improved recovery from the McCreery–McCullum bar.

Selection of the improved and enhanced oil recovery techniques to be applied depends on the causes of the recovery inefficiency. Examination of the field data and the results of the reservoir simulations in the preceding sections suggest that much oil has been bypassed in the productive interval because of lateral and vertical heterogeneities, probably caused by hydraulically induced fractures.

Mobile Oil Recovery

The more permeable upper sandstone interval will be better swept than the less permeable, more calcareous lower sand. The current waterflood practice, in which water is injected into the permeable upper sand, increases oil bypassing by floodwater. The following measures are recommended as the first steps towards improving recovery:

Perform fieldwide, cost effective reservoir tests Tracer tests and pulse tests, for example, assist in detecting highly permeable or conductive fracture channels and their orientations.

Recomplete all water injection wells The existing perforations in all water injection wells should be squeezed; the wells should be reperforated in the lower sand. Oil production wells need not be reperforated to reduce water-coning effects or incidences of high water–oil ratios.

Plan a line-drive pattern of water injection wells oriented east–west Wells that communicate through induced fractures should either be all water injectors or all oil producers. For example, the Triple "B" Eaton Nos. 2 and 3 wells could be used as water injectors, while the Triple "B" wells directly north of them and the Potter No. 1 could be used for oil production.

Plan a selective plugging program A need for selective plugging with polymers, crosslinked polymers, or microorgansims may arise during the improved waterflood program. A selective plugging program may be necessary to mitigate the bypassing of oil by water moving through streaks of highly conductive sandstone. Polymers and gels may be affected by reservoir properties or high brine concentration of Aux Vases reservoirs, and laboratory tests may be necessary to check the efficacy of polymer/gel applications. Whether chemical polymers and gels are used, however, usually depends on economic considerations. Because of the high costs associated with chemical floods and the low oil throughput from the McCreery Unit, a microbially enhanced waterflood may be perferable.

Microbial applications are very cost effective and suitable for stripper well production. Microorganisms produce copious amounts of biomass. Some species also produce biopolymers. Biomass and biopolymers can reduce fluid flow through propped fractures and porous media significantly (Udegbunam et al. 1993). Because of their mobility in the aqueous phase and their ability to multiply rapidly, microbes may plug the fracture channels more completely than chemical gels and polymers. Furthermore, microbial action in the reservoir can be suspended at any time by application of a biocide.

Many commercial companies and research groups offer the public services in application of microbial technologies. Microbially enhanced oil recovery (MEOR) processes have been based on the injection of one or many microbial species into the reservoir or stimulation of the native microbial species. Tanner et al. (1992) argued that reservoirs contain various microbial species and that the addition of suitable nutrients into the reservoir can stimulate a specific microbial activity.

Drill infill wells north and/or south of existing wells Figure 28 shows four suggested infill wells located in a five-spot pattern with the existing active wells. If this option is chosen, it is suggested that the infill well(s) be used as injectors and the existing wells be used as producers. The infill wells should be lightly fractured, enough to carry fluids past the vicinity of the well bore where there is formation damage due to drilling and completion. This arrangement may be the most effective solution to the present inefficiency of waterflood oil recovery because water injected through the infill wells could chase the bypassed oil toward induced fractures and ultimately into producing wells. The economic feasibility of this approach has not been considered in this study.

Immobile Oil Recovery

The average residual oil saturation, as determined from the core analysis report of Farrar Oil McCreery No. 1, is low. If this value (15% of the reservoir pore volume) holds true throughout the reservoir, any enhanced oil recovery technique may be difficult to justify economically, unless oil prices increase. In any event, MEOR will be cheaper than chemical flooding methods. Use of acid-, surfactant-, and CO_2-producing microbes may not only mobilize oil, but also improve reservoir rock properties because of the calcareous content of the lower Aux Vases. Furthermore, carbonates buffer the environment for the microbes against the acids they produce.

CONCLUSIONS

- Comparison of field production data from the reservoir simulation model with historical production indicates that the McCreery and McCullum Units are hydraulically connected.

- Core data and a semivariogram model both show the existence of two flow units within the reservoir interval. A two-layer simulation model was created to correspond to the observed flow units.

- Calcite cement increases with depth and occludes much of the permeability and porosity in the lower reservoir interval.

- Hydraulic fracturing in the McCreery and McCullum Units may have created an east–west network of fractures that may possibly intersect between some wells. In the future, operators should consider regional compressive stress orientations when designing hydraulic fracturing programs.

- Simulated results of water–oil ratio versus cumulative water injection and water–oil ratio versus time for the reservoir simulation model with an intersecting fracture network trending in an east–west direction compared well with observed

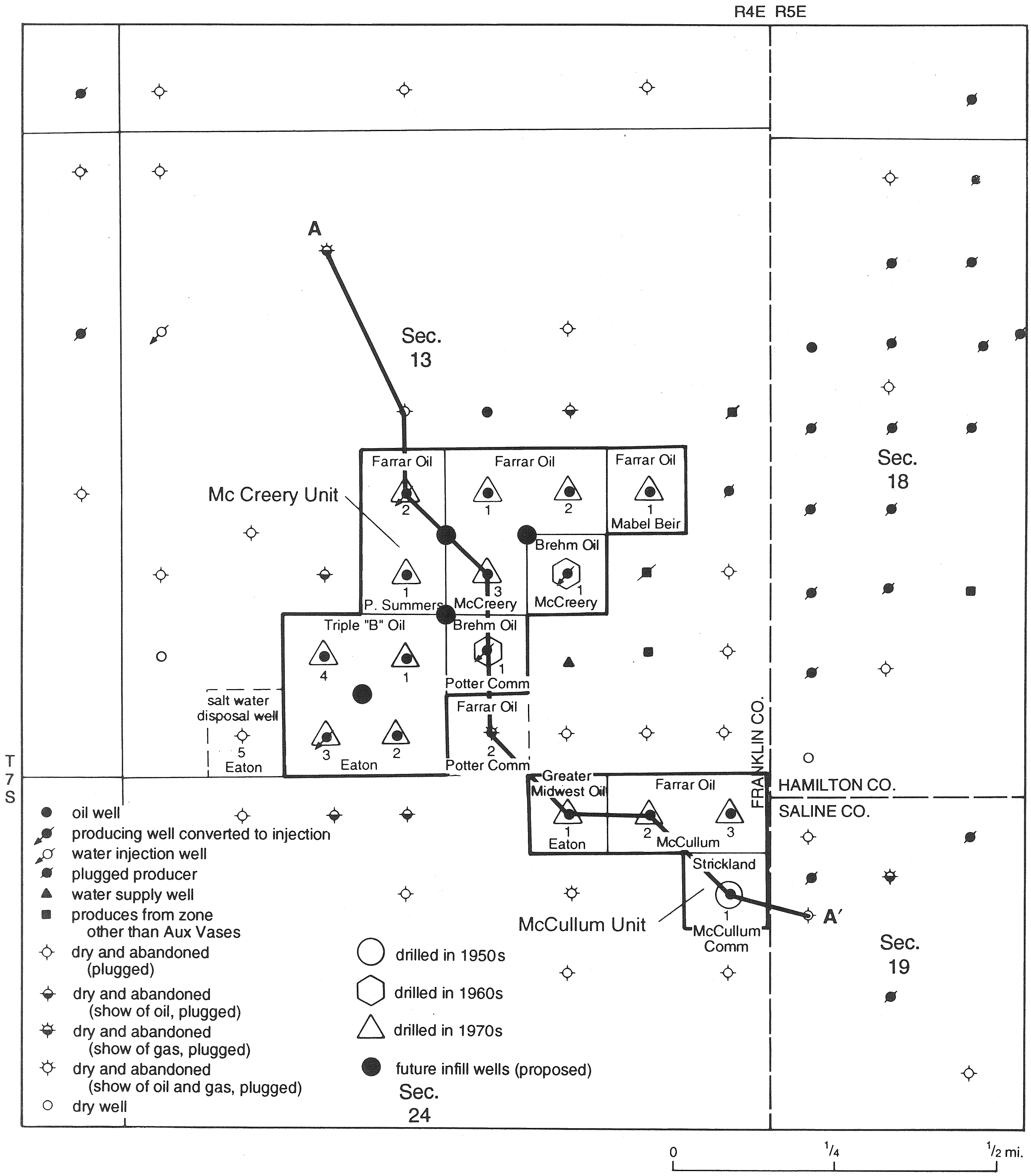


Figure 28 The proposed infill wells (filled circles) in the McCreery and McCullum Waterflood Units would form a five-spot pattern with the existing wells.

field data. This suggests that fractures induced by hydraulic fracturing may be partly responsible for the historical low sweep efficiencies and poor waterflood oil recovery.

■ Analysis of 15 months of actual waterflood performance data show poor oil recovery response, which is thought to result from an inefficient reservoir sweep due to several causes including the following:

- injectors and producers are open only in the upper more permeable sandstone;
- induced fractures conduct water to the producers, thereby bypassing the oil banks;
- injection well arrangement is not optimal. Existing injection wells should be reperforated to increase their efficiency as injectors.

■ Suggested strategies for improved oil recovery from the McCreery and McCullum Units include the following:

- perform reservoir tests to define flow units and directions;
- recomplete wells;
- place water injection wells in a repeated line-drive pattern oriented in an east–west direction;
- plan a selective plugging program to mitigate the bypassing of oil by the injected water;
- drill infill well(s) for water injection in a five-spot pattern or line-pattern arrangement.

The most efficient and economic well pattern may involve placement of infill wells halfway between wells north and south of the existing line of wells.

ACKNOWLEDGMENTS

We are grateful to Brad Aman of Farrar Oil Company, Mount Vernon, Illinois, for his contribution of data, manuscript review, and helpful suggestions. Donald F. Oltz, Jonathan H. Goodwin, Joan E. Crockett, Beverly J. Seyler, Steve Sim, and several other colleages at the Illinois State Geological Survey also contributed significantly to the review and production of this report.

This report is part of a major research project for reservoir classification and improved and enhanced oil recovery, cofunded by the U.S. Department of Energy (Grant DE-FG22-89BC14250) and the Illinois Department of Energy and Natural Resources (Grant AE-45). Their funding and dedication to the goals of this research are gratefully acknowledged.

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APPENDIX A CORE ANALYSIS REPORT FOR FARRAR McCREERY NO. 1 WELL

Company	Farrar Oil Company
Lease	McCreery No. 1
Field	Dale Consolidated
Location	Section 13, T7S, R4E, Franklin County
KB elevation	491 feet

Sample	Depth (ft)	Permeability (md) Vertical	Permeability (md) Horizontal	Porosity (%)	Residual saturation (%) Oil	Residual saturation (%) Water
1	3190.5 – 91.2	5.5	49.0	20.4	4.3	31.0
2	3191.5 – 92.1	0.8	81.5	23.4	7.4	47.9
3	3192.5 – 92.9	8.6	106.0	25.6	10.9	56.0
4	3193.1 – 93.8	9.7	104.0	24.1	9.0	53.8
5	3194.0 – 94.4	8.8	116.0	23.6	10.1	53.4
6	3195.5 – 96.0	2.0	55.8	19.8	10.3	57.0
7	3196.4 – 96.8	3.2	18.4	20.4	3.3	58.0
8	3197.3 – 97.9	12.3	56.8	24.8	8.6	49.9
9	3198.5 – 99.0	6.0	34.3	20.4	11.1	71.4
10	3199.4 – 99.7	8.7	41.9	24.3	7.9	48.4
11	3200.3 – 00.9	1.6	43.6	19.0	4.8	68.5
12	3201.0 – 01.5	3.0	35.5	21.4	7.2	54.8
13	3202.4 – 03.2	1.0	13.5	18.6	trace	63.7
14	3203.3 – 04.1	1.4	27.9	18.6	8.6	60.1
15	3204.9 – 05.8	1.5	10.0	17.3	8.1	74.1
16	3205.8 – 06.3	2.8	15.8	21.4	2.1	51.3
17	3206.9 – 07.9	0.4	1.8	14.6	0.0	96.4
18	3208.3 – 09.0	0.2	2.5	13.1	0.0	94.0
19	3209.4 – 10.0	(.1–)	0.7	11.5	0.0	96.1
20	3210.3 – 11.1	(.1–)	(.1–)	7.3	0.0	96.2
21	3211.4 – 12.1	(.1–)	(.1–)	3.6	0.0	97.1

APPENDIX B ESTIMATED COST ANALYSES FOR McCREERY UNIT WATERFLOOD PROJECT

Installation Costs

Land and legal
Engineering
Injection well conversions
Water supply well
Saltwater disposal
Plant and tank battery consolidation
Miscellaneous flowline work
Road work
Miscellaneous labor
Electrification (two producers & labor)
Land damages

Total estimated costs: $208,000

Estimated Monthly Operating Expenses

Average estimated monthly operating expenses: $10,000

Net Waterflood Income

The procedure for computing net waterflood income is as follows:

1. Total waterflood expenses = $208,000.00 + 120,000 × ($n$ −1991.491)
   where n = time in years (e.g. October 31, 1992, is equivalent to 1992.833).
2. Oil income, using oil price of $20.00/STB, for example:
   = $20/STB × Q_t STB × 0.80667 (NRI)
   = $16.13 × Q_t

   where

$$Q_t = \int_{t_o}^{t_n} Q_o dt = 1444.56 \int_{t_o}^{t_n} e^{[-4.37342\,(t-1992.581)]} dt$$

and Q_o = waterflood oil production rate, BOPM
t = year (e.g. October 31, 1992, is 1992.833)
t_o = start of waterflood, year
t_n = present time, year