Reservoir Characterization and Improved Oil Recovery from Multiple Bar Sandstones, Cypress Formation, Tamaroa and Tamaroa South Fields, Perry County, Illinois

John P. Grube
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PLATES
1 Thin section photomicrograph showing void space and the development of secondary porosity by dissolution of feldspar grains 25
2 Thin section photomicrograph of heavy mineral lag along bedding planes 25

FIGURES
1 Generalized geologic column for southern Illinois 2
2 Tamaroa and Tamaroa South Fields and an outline of the Illinois Basin 3
3 Structure map contoured on top of the Beech Creek (Barlow) Limestone 4
4 Structure map contoured on the base of the Barlow limestone 5
5 Electric log of the total Cypress interval 9
6 Cypress thickness map 10
7 Type log of the Cypress Formation 11
8 Sandstone thickness map of the lower Cypress interval 12
9 Sandstone thickness map of the middle Cypress interval 14
10 Sandstone thickness map of the 50% clean, Y3 Cypress interval 15
11 Outline of the Y2 and Y3 sandstones greater than 4 feet thick superimposed on the Barlow structure 16
12 Structure map contoured on top of the Ridenhower limestone marker 17
13 Cross section A–A’ showing that Y2 and Y3 lenticular sandstones coalesce, forming abnormally thick upper Cypress sandstone 19
14 Cross section B–B’ showing that Y1 and the middle Cypress sandstones coalesce 20
15 Comparison of the SP curve and the plotted permeability data from the Stockton No. 1 Cypress core analysis 22
16 SEM photomicrograph of quartz overgrowth restricting a pore throat 23
17 SEM photomicrograph of partially dissolved feldspar grain 26
18 SEM photomicrograph of quartz grains coated by kaolinite booklets and iron chlorite 26
19 Thickness map of the Cypress sandstone 27
20 Thin section photomicrograph of euhedral quartz grain outlined by dust ring 28
21 Decline curve for the Tamaroa Field 30
22 Decline curve for the Tamaroa South Field 31
23 Decline curve for the Tamaroa South extension field 32
24 Waterflood design for Tamaroa Field 33
25 Combination map of the structure on top of the Y3 sandstone horizon and the thickness of the 50% clean, Y3 sandstone 38

TABLE
1 X-ray diffraction analyses of four Stockton No. 1 core plugs 29
ABSTRACT

Tamaroa and Tamaroa South Fields, discovered in 1942 and 1956, respectively, are located in northeastern Perry County, Illinois. The fields produce principally from lenticular sandstones located in the upper part of the Chesterian Cypress Formation at a depth of approximately 1,150 feet. These sandstone bodies, deposited as marine bars, are typically less than 10 feet thick, 1/4 to 1/2 mile wide, and less than 2 miles long. The bars trend northeast-southwest in an en echelon pattern and are vertically stacked. Spontaneous potential and gamma-ray log character, as well as core data, show shales that range from 10 feet to less than 1 foot thick separate the sandstones. The porous and permeable parts of closely spaced, en echelon bars and vertically stacked bars separated by shale create discrete reservoir compartments within these fields where the bars drape over the structural folds.

Diagenetic clay minerals such as iron chlorite and kaolinite found in the Tamaroa reservoirs can cause formation damage unless precautions are taken during drilling, completion, and stimulation procedures. Hydrochloric acid reacts with iron chlorite to form iron hydroxides that can reduce permeability by blocking pore throats. Permeability can also be reduced by the migration of kaolinite particles into pore throats. The particles are formed as loosely bound pore linings and are dislodged by high velocity fluid flow. Water shock, which is the introduction of water with low salinity into a reservoir containing brine with high salinity, can also dislodge kaolinite particles.

Understanding and modeling compartmentalized reservoirs and recognizing the potential for formation damage are essential for optimizing hydrocarbon recovery from the Tamaroa fields and other fields with similar characteristics. The range of recovery efficiencies for Tamaroa area pools appears to relate to the design and implementation of drilling and development programs, which in turn relate to the extent to which the geology of the reservoirs was previously understood. Reservoir volumetric calculations indicate that recovery efficiencies among the pools range from 5% to 43%. Cumulative production of 768,000 barrels of oil from all Cypress reservoirs in the Tamaroa area equals about 24% of the 3.2 million barrels of original oil in place. Given a recovery efficiency of 43%, recoverable reserves that may remain in the reservoirs are estimated to be 608,000 barrels.
Figure 1 Generalized geologic column for southern Illinois. Rocks that underlie the St. Peter are not shown. Formations or members that contain pay zones are shown in bold type. The names Alexandrian, Cayugan, Upper Devonian, Kinderhookian, Valmeyeran, and Virgilian are abbreviated as Alex., Cayu., Up., K., Val., and Virg. Variable vertical scale (after Howard and Whitaker 1990).
INTRODUCTION

The Mississippian Cypress Formation (fig. 1) ranks as one of the most prolific producing horizons in the Illinois Basin. An estimated 500 million barrels of oil has been produced from sandstone reservoirs in the Cypress. Many of these reservoirs were discovered 30 to 60 years ago and are now depleted. Primary and secondary development have drained a significant amount of the recoverable oil from these reservoirs. Unswept mobile oil (UMO) remains in these reservoirs, however, and it may be economically recoverable. A comprehensive geologic investigation integrated with engineering analysis of all production-related reservoir characteristics is necessary to evaluate and produce the remaining recoverable reserves. Drilling, completion, and stimulation methods, well spacing, pressure maintenance, and waterflood design are all highly dependent on characteristics of individual reservoirs. Tamaroa and Tamaroa South Fields, located in northeastern Perry County, south-central Illinois (fig. 2), contain four pools. Two pools are located in Tamaroa Field: one pool is in Sections 14 and 23, T4S, R1W; the other is in Section 22, T4S, R1W. The other two pools are located in Tamaroa South Field: one is in Sections 28, 32, and 33, T4S, R1W; the second is in Section 4, T5S, R1W (fig. 3). A part of the Tamaroa South Field, Sections 28, 32, and 33, lies directly under the town of Tamaroa. The fields form an arcuate pattern approximately 6 miles long, and the pools are separated by 0.5 to 1.5 miles. There appear to be no obvious, natural surface expressions of these pools.
Reservoir volumetric calculations indicate that recovery efficiencies of the four pools range from 5% to 43%. This study was conducted to evaluate the geologic characteristics of the Cypress reservoirs at Tamaroa and Tamaroa South Fields and to identify the problems that led to low recovery efficiencies and the techniques that produced the highest oil recoveries.

Figure 3 Structure map contoured on top of the Beech Creek (Barlow) Limestone. The three structures that control production in the Tamaroa Fields are shown. Contour interval is 10 feet.
Figure 4 Structure map contoured on the base of the Barlow limestone. The locations of Tamaroa and Tamaroa South Fields on the west flank of the present structural basin are shown (after Bristol 1967). Contour interval is 100 feet.

DISCOVERY AND PRODUCTION HISTORY

Geologic Setting

Figure 4, a structure map of the Beech Creek (Barlow) Limestone, shows the location of Tamaroa and Tamaroa South Fields on the west flank of the present structural basin. Regional dip varies from 20 to 40 feet per mile. The Du Quoin Monocline lies immediately east of the northeast pool in Sections 14 and 23, T4S, R1W. It is a major structural feature in the basin and strikes north-south over a distance of 50 miles. More than 1,000 feet of structural relief occurs in less than 1 mile on the Barlow limestone as the strata cross the monoclinal fold to the east of the field. The monocline defines the east edge of a structural terrace, the Sparta shelf, on which the Tamaroa oil pools are located. Subsidiary longitudinal folds on the east edge of the Sparta Shelf form the structural component of the hydrocarbon traps for these reservoirs (fig. 3). Changes in thickness of Cambrian and Pennsylvanian strata across the monocline indicate that recurrent movement along a system of basement faults has taken place (Nelson 1988, Hopkins and Simon 1975). If the folding that formed the traps in the Tamaroa area resulted from the tectonic events that created the Du Quoin Monocline, then deformation, and therefore, trap formation occurred during and possibly after the Pennsylvanian Period (Siever 1951).

Post-Pennsylvanian and probably post-Permian erosion removed all of the sedimentary rocks younger than the Pennsylvanian Modesto Formation that may have existed in the vicinity of Tamaroa Field (Willman and Frye 1975). In general, the basal Pennsylvanian sediments lie unconformably on the Mississippian
Menard Limestone at a depth of approximately 700 feet in northeastern Perry County (fig. 1).

A thickness map of the Cypress sandstone (Atherton et al. 1975) and a map showing the percentage of sand between the Downeys Bluff and the Barlow limestone (Potter et al. 1958) indicate that the Tamaroa area lies along the north edge of a concentration of sand that trends northeast-southwest. Sandstone thickness along this and several parallel sandstone fairways ranges from 80 to 160 feet. This sand appears to have been transported from the northeast. This interpretation is supported by regional outcrop measurements of foreset attitudes of cross strata (Potter et al. 1958) and by both general thinning of Cypress sandstones across the basin in a southwest direction and the presence of thick sandstone bodies oriented along northeast-southwest trends (Atherton et al. 1975).

Although Cypress reservoir rock and trapping mechanisms appear to be abundant on the west flank of the basin, relatively few Cypress oil fields have been discovered there. Hydrocarbons in the fields that have been found are mostly in the stratigraphically highest Cypress sandstone, even though structural closure may exist throughout the Cypress section.

**Discovery History**

The Tamaroa Field discovery well, the James N. Harsh No. 1 Newborn, was drilled in SE SE NW, Section 22, T4S, R1W, in January 1942 (fig. 3). The well was drilled on the west flank of a small dome to a depth of 1,530 feet, penetrating 94 feet of the St. Genevieve Limestone. Initial production was established at 16 barrels of oil (BOPD) and 10 barrels of water per day (BWPD) from the upper Cypress at a depth of 1,127 to 1,150 feet. Following the discovery, only three successful development wells were completed in the Cypress in Section 22.

In 1952, the Ted Glass No. 1 Zmudzinski Well, was drilled and completed as a Cypress producer in NW SW SE, Section 14, T4S, R1W. This well defined a separate structure, offsetting that of the No. 1 Newborn discovery (fig. 3). Initial production was 38 BOPD with no reported water from the interval at 1,131 to 1,136 feet (total depth). Seven more wells, drilled on a standard 10-acre spacing pattern in Section 14, were completed as producers on the Zmudzinski lease in 1952. One additional marginal producer was completed in Section 14 in 1983 for a total of nine producers in Section 14. Initial production rates for these wells ranged from 2 to 105 BOPD and little water. The pool extends to the south into Section 23, where six Cypress wells have been completed as oil or gas producers. Commingled Cypress and Galena/Trenton (Ordovician) production was established from the No. 1 V.A. George NCT-1 in the NW SE, Section 23, T4S, R1W, as Texaco developed a Trenton pool discovered in 1964.

Tamaroa South Field was discovered in 1956, and its southern extension in T5S was discovered in 1970. These pools lie on separate structures, neither of which is connected to the Tamaroa Field structures (fig. 3). Eighteen wells were completed as producers in Sections 28, 32, and 33, T4S, R1W, on 10-acre spacing. Four wells were completed in the south extension, in Section 4, T5S, R1W. Initial production for both pools ranged from 2 to 30 BOPD from a depth of approximately 1,150 feet.

**Production History**

Cumulative production from the Cypress reservoirs at Tamaroa and Tamaroa South Fields through the end of 1989 was 768,000 barrels of oil (BO). This figure includes
only the production from the 32 wells for which cumulative production data are available, although 46 completed Cypress wells are recorded. A documented waterflood program and a pressure maintenance program assisted in this production. The cumulative production from the six Trenton wells in Tamaroa Field is 118,000 BO. (Other data on the Trenton appear in Bristol and Buschbach, 1973.) The multiple Cypress reservoirs that make up Tamaroa Field, Tamaroa South Field, and the south extension field result from the combination of stacked, lenticular sandstones, which are each less than 10 feet thick and cross three separate folds (fig. 3). The north fold includes two separate closed structures. Production data, although commonly incomplete, are available for each structural feature.

Records show that Section 22, containing the initial field discovery, has seven Cypress wells completed on a 10-acre spacing pattern. Production records exist for only the four wells drilled in the north half of the section in the 1940s. Inconsistencies in these records indicate that more than the reported 35,000 BO was produced from these four wells. Correlation of the producing intervals in these wells shows two separate sandstones contributed to this production.

A significant part of the hydrocarbon column on this structure appears to have been occupied by gas. The Majewski No. 4 Well, NW SE NE, Section, T4S, R1W, was drilled in 1975 and completed for 1 BO and 2.1 million cubic feet of gas per day. Although no production records exist for this well, its completion, combined with the significant show of gas from the Majewski No. 4-A, SW SE NE (one location south), indicates the presence of a large gas cap on this structure.

More than 352,000 BO has been produced from the Cypress from the structure that makes up the eastern extension of Tamaroa Field in Sections 14 and 23. Production data are available for eight of the ten completed wells on the Zmudzinski lease in Section 14. The Section 14 wells were drilled on 10-acre spacing. Primary recovery for the eight wells, reported collectively, is 200,000 BO. Secondary recovery through 1989 added 134,000 BO for a total of 334,000 BO. Section 23 records show additional recovery of 18,000 BO from three of the seven wells completed in the Cypress. Again, inconsistencies and a lack of data indicate that this is a minimum production figure.

The eastern structure also contains a gas cap within the upper 10 feet of closure. Four wells that define the crest of the structure were completed with initial production values ranging from 95 thousand cubic feet of gas and 10 BO per day to 4.68 million cubic feet of gas per day.

Combined cumulative production for the Tamaroa South Field and the southern extension is about 381,000 BO through 1989. Production data that make up this figure are available for only 12 of the 18 reported completed producers in Tamaroa South in Sections 28, 32, and 33, T4S, R1W, and all four producers in the southern extension, Section 4, T5S, R1W. Drill spacing for these wells is commonly 10 acres. Although gas is not prevalent in the upper reaches of these reservoirs, it did flow to the surface on some drill stem tests, according to scout ticket records.

Tamaroa South Field has a cumulative production of 310,000 BO. The production has been concentrated in the southwest quarter of Section 28, and the northwest quarter of Section 33. This prolific area includes four wells that have produced from 40,000 to more than 60,000 BO per well. The uneven distribution of production in this and the extension field reflect the uneven distribution of the en echelon, vertically stacked, lenticular, reservoir-forming sandstones.
A pressure maintenance program was initiated in Section 28 in 1963. Four wells in the southwest quarter of Section 28, and the northwest quarter of Section 33, are documented as production wells in the pressure maintenance program. Produced water was injected into the No. 2 Stockton Well, NE SW SW, Section 28. Records show that only two wells presently produce from this field.

The extension field in Section 4, T5S, R1W, produced 71,000 BO through 1989. No gas cap was indicated for this field. Oil is presently being produced from two wells. A waterflood has been established at this site through one injection well using water produced from the two offset producers.

Production records (Huff 1987) show that at least 33 fields have established production from Cypress sandstones on the west flank of the basin. Most of these fields produce from more than one horizon, and 10 of the 33 Cypress pools have each produced from 1 million to more than 4 million barrels of oil (MMBO).

**RESERVOIR CHARACTERIZATION**

**Stratigraphy**

Stratigraphic units used to map and interpret the Cypress Formation for this study include the Tar Springs Sandstone, Glen Dean Limestone, Beech Creek (Barlow) Limestone, Ridenhower Formation, Downeys Bluff Limestone, and multiple Cypress sandstones (fig. 1). In the study area, the Glen Dean, Barlow, Ridenhower, and Downeys Bluff all appear to be laterally continuous or nearly continuous limestones that are useful interval boundaries for isopach mapping. If the upper bounding surfaces of these limestones are depositional surfaces of low relief, then paleostucture, compensating deposition, and differential compaction can be determined by comparing the thickness of the various intervals.

The Cypress Formation represents a major pulse of siliciclastic sedimentation that occurred in the Illinois Basin during the early part of the Chesterian (fig. 1). In the vicinity of Tamaroa and Tamaroa South Fields, the Cypress consists predominantly of sandstones and shales. The Cypress Formation, together with approximately the upper 10 feet of the Ridenhower, ranges from 65 to 127 feet thick. In this study, all beds from the base of the Barlow to the top of the Ridenhower limestone marker are included in the thickness of the Cypress Formation (fig. 5). The shale that commonly marks the base of this interval is approximately 10 feet thick and belongs genetically to the Ridenhower Formation. It is included here, however, as part of the Cypress. The base of the Cypress Formation is commonly placed at the base of the lowest sandstone above the Ridenhower limestone marker, but this sandstone varies in thickness and is also discontinuous. A regionally consistent and practical mappable unit that does not rely on this variable basal sandstone was established by mapping the interval bounded by the base of the Barlow and the top of the Ridenhower limestone marker, which includes all sediments between the basal Cypress sandstone and the Ridenhower marker.

A thickness map (fig. 6) of the Cypress Formation, as defined here, shows significant thickening coincident with and enhancing the present Barlow structural highs. A well defined, thin interval trends north-south and occupies the western part of the area. This thin interval correlates closely with a Barlow structural depression that forms the structural rollover on the west side of the Tamaroa South Field and part of the south extension field (fig. 3).

For the purpose of mapping reservoir facies and interpreting depositional facies, the Cypress Formation in the study area was informally divided into lower, middle, and
upper intervals (fig. 7). The three primary criteria for defining these divisions were (1) similarity of log character, (2) stratigraphic position of sandstones in the Cypress Formation, and (3) stratigraphic position of shale breaks in the Cypress Formation.

Hydrocarbon reservoirs in the Tamaroa area are limited to the sandstones within the upper interval; therefore, further subdivision of this interval into four units was necessary to establish relationships among the individual sandstones and to determine geometries of individual sandstone bodies. In ascending order, these
sandstones were labeled Y1, Y2, Y3, and Y4. Separate sandstones within the lower and middle Cypress intervals were grouped and mapped as net sandstones within their respective intervals.

Thickness maps of 25% and 50% clean sandstone were constructed for each of the above-mentioned Cypress sandstones. Thickness data were acquired from normalized spontaneous-potential (SP) and gamma-ray logs. The shale baseline, or 0% clean sandstone, for normalizing the SP logs was established by using the consistently flat-line response of the Fraileys Shale (figs. 5 and 7). The 100% clean sandstone SP response was calibrated using the overlying Tar Springs sandstone with the greatest amount of SP deflection. The clean middle Cypress sandstone was also used, where present. When the 0% and 100% endpoints are used to
Figure 7 Type log of the Cypress Formation with divisions used for mapping in this study. The principal reservoirs in the Tamaroa area are the Y2 and Y3 sandstones. Although no Y4 sandstone is present at the No. 1 Newborn location, the Y4 sandstone elsewhere forms a horizon that begins at or within a few feet of the base of the Barlow limestone.

calibrate the SP curve, the 25% clean sandstone can be established as that part of the SP curve that deflects to the left of the shale baseline one-fourth or more of the distance between the 0% and 100% endpoints. Sandstones that deflect to the left of the shale baseline one-half or more of the 0% to 100% distance are 50% clean sandstones. The inability of the SP-logging tool to record total deflection of thin, clean sandstone beds causes the thickness values of these beds to be underestimated.

In the lower Cypress interval (fig. 7), the sandstones are poorly developed and do not contain rock of reservoir quality through most of the study area. The lower
Figure 8 Map showing net thickness of sandstone greater than 50% clean in the lower Cypress interval. Thicker sandstone in the southeastern to southern part of the study area indicates proximity to the source. The lower Cypress interval is interpreted to have been deposited in a distal delta front setting by a delta lobe prograding in a northwest direction. Electric logs indicate that only in the northern part of T5S, R1W, is there a potential for reservoir development in the lower Cypress. Contour interval is 5 feet.

Cypress interval consists of shales, siltstones, and poorly to moderately well sorted, very fine to fine grained sandstones. The sandstones and siltstones are thinly bedded to laminated and are commonly interlaminated with shale. Bioclastic limestone beds grading to very calcareous sandstone beds less than 1 foot thick are also observed.

A net thickness map of clean sandstones in the lower Cypress interval (fig. 8) shows a broad band of sandstone, 10 to 30 feet thick, that trends northeast-southwest in the southeastern part of the area. Sandstone in the northwestern part of the area is thin to absent. The greater concentration of sandstone in the south to southeast
indicates a proximity to the source. Electric logs indicate that there is potential for reservoir development in this interval only in the northern part of T5S, R1W.

Although the middle Cypress sandstones are commonly of reservoir quality, oil shows have been noted only in the upper part, and drill stem tests and completion attempts have yielded only water with traces of oil. Microscopic study of drill cuttings shows that middle Cypress sandstones are moderately well to well sorted and fine to very fine grained. The abundant, flat, reflective, crystal faces and subangular to angular shape of sand grains observed in drill cuttings indicate that quartz overgrowths are abundant. Silica cementation also is indicated by the tendency of the sandstones to fracture across the grains rather than along grain boundaries.

A high negative deflection and blocky character of the SP response is common for the middle Cypress sandstones in areas where the thickness of particular sandstones exceeds approximately 20 feet. This implies that the sandstone is very clean and probably porous and permeable. The magnitude of the middle sandstone SP deflection commonly is as great as that of any of the Chesterian sandstones. Figure 5 shows a blocky, clean SP response for the middle Cypress sandstones. The shale break at a depth of 1,139 feet is one of several that commonly occur in this sandstone. This break is slightly more pronounced than those observed in other wells. Subtle breaks such as the one at a depth of 1,151 feet shown in figure 5 are very common to the middle Cypress sandstones. They probably signify changes in depositional settings or possibly lithologic-diagenetic changes. Careful petrographic analysis, facies correlation, and mapping of individual genetic units of the middle Cypress could significantly improve recovery efficiency in fields that produce from this interval. The high resistivity response of the middle interval sandstones on this log (fig. 5) indicates that extensive invasion of drilling fluids occurred during drilling, although the Tar Springs and Aux Vases sandstones do not show this SP response.

The middle Cypress interval was not subdivided for this study primarily because no hydrocarbon reservoir exists within this interval in the area studied. Because the sandstones within this interval may represent deposits from more than one environmental setting, geometries related to particular depositional environments may have been masked by lumping the sandstones into one interval. Specific environments may thus be difficult to interpret.

The net thickness of middle Cypress sandstones greater than 50% clean ranges from 0 to 46 feet. Figure 9 shows a bifurcating pattern of elongate, interconnected bodies of thick sandstone that surround and separate three pods of thinner sandstone several square miles or less in size. The elongate sandstone bodies are generally 30 to more than 40 feet thick, whereas the thinner pods include areas containing no 50% clean sandstone and only a few feet of 25% clean sandstone. As observed in the underlying lower Cypress interval, the thickest middle Cypress sandstones are concentrated in the eastern and southern parts of the study area. This concentration provides further support for their having been derived from a northwestern-prograding delta lobe.

The upper Cypress interval was divided into four units. Similar characteristics of the sandstones in each of these units indicate that cyclical depositional conditions stacked four separate lenticular sandstones at some locations. Each of these sandstones is separated by shale (fig. 7), although coalescing or shingling of two sandstone units appears to occur. The type log in figure 7 shows the Y1, Y2, and Y3 sandstones of the upper Cypress interval. The Y4 sandstone, which forms at the base to several feet below the base of the Barlow limestone, is not present at this
Figure 9 Map showing net thickness of sandstone greater than 50% clean in the middle Cypress interval. (Contour interval is 10 feet.) Arrows highlight a bifurcating pattern of thick sandstone that appears to trend in a northwest to north direction. A northwestward-prograding delta lobe is indicated by this pattern.

location. The Y4 sandstone develops less frequently than the Y1, Y2, and Y3 sandstones, and it is generally too tight to be an effective reservoir rock. The Y3 and, to a lesser degree, the Y2 are the primary reservoir sandstones. A detailed discussion of the lithology of these sandstones is in the section, Reservoir Lithofacies and Petrology.

The Y3 sandstones are typically less than 10 feet thick, 1/4 to 1/2 mile wide, and less than 2 miles long (fig. 10). The northeast-southwest trend and en echelon pattern of these sandstones is very apparent. Figure 11 superimposes the parts of the Y2 and Y3 sandstones greater than 4 feet thick. The trend and geometries of both units are quite similar.
Figure 10  Thickness map of the 50% clean, Y3 Cypress sandstone. The northeast-southwest trend and en echelon pattern of these sandstones are shown. Contour interval is 4 feet.

Structure
A comparison of structure maps constructed on the top of the Barlow limestone (fig. 3) and the Ridenhower marker limestone bed (fig. 12) indicates that both tectonics and thickness variations in the Cypress Formation are responsible for the structural relief of the Barlow limestone in the study area. Mapping the top of the Barlow limestone, as opposed to mapping the base, avoids structural misinterpretation due to "false Barlow" thickness variations associated with the base of the Barlow (Cluff and Lasemi 1980). The structure map of the Ridenhower limestone marker shows that the structural grain of this horizon is similar to that of the overlying Barlow limestone. However, an offset of the structural crests in the Tamaroa South extension field and, to a lesser extent, in Tamaroa Field is apparent. This offset indicates that the axial planes of the folds are not vertical, possibly as a result of
tectonic deformation related to drape folding of the sedimentary section over tilted basement fault blocks.

Structural relief of the Barlow folds is enhanced in the Tamaroa area, particularly over Tamaroa and Tamaroa South Fields, because the Barlow drapes over underlying Cypress thick areas and into thin areas (fig. 6). Thinning of the Cypress Formation is a function of the sandstone thinning and changing facies to shales. Thinning of the shales by differential compaction has increased the divergence between sandstone thicks and shale-dominated thins, and thereby increased the structural relief of the Barlow.
A comparison of the Ridenhower and Barlow structure maps for Tamaroa Field shows structural closure of approximately 40 feet on both horizons. Similar to the Tamaroa South Field and its extension, the Cypress Formation at Tamaroa Field is thicker within the field and becomes thinner adjacent to the field, particularly to the immediate southwest. Although stratigraphic thickening of the Cypress contributed to the presence of this structure, it appears that a pre-Cypress element of structure has propagated through the stratigraphic section to dominate the structure at this field. The source of that element of structure is most likely tectonics associated with the formation of the Du Quoin Monocline. Pre-Cypress local thickening, such as that observed at Bartelso Field, may also have created this structure. The Bartelso Field structure is attributed to drape over a Silurian reef (Whitaker and Finley 1992).
Paleostructure and Compensating Deposition

Minor to significant thinning, coincident with the crests of three Barlow structures, is apparent in three intervals: (1) the Ridenhower to the Downeys Bluff, (2) the Barlow limestone, and (3) the Glen Dean to the top of the Barlow. Thickening can be observed off the structures. This relationship typically indicates a paleostructural influence on sedimentation. Alternatively, Cypress sandstone thickening could have created paleotopographic highs. Subsequently, the sediments overlying the thick Cypress section tend to be thinner than sediments overlying the adjacent, compacted shales. Although both the Barlow and the interval from the Glen Dean to the Barlow may be thinner because of compensating deposition over the thicker Cypress zones, the thinning in the interval from the Ridenhower to Downeys Bluff coincident with the crests of structures visible in the Barlow cannot be attributed to thickening of the Cypress. Therefore, it is probably caused by the presence of structural, paleotopographic highs.

Trap Type

The trapping mechanism for the reservoirs in the Tamaroa area is a combination of structure and stratigraphy. As previously discussed, the upper Cypress reservoirs are in lenticular, stacked sandstones separated by shales. The oil trapped in these sandstones occurs in the part of a sandstone that drapes across the crest of a structural fold. Sandstone lenses that lie along the flanks of folds and do not cross the crest are not productive. The shales, or possibly the Barlow limestone, that overlie the reservoirs provide the ultimate permeability seal. Although correlation of these sandstones is subject to several possible interpretations, the lenticular sandstones appear to coalesce vertically in some locations, possibly in a shingle-like manner (fig. 13). The middle Cypress sandstones coalesce with the upper Cypress Y1 sandstone in the northern field area (fig. 14), as determined from electric log interpretations. Interconnection of these sandstones without development of a vertical permeability barrier would create a conduit for hydrocarbon migration from the middle Cypress sandstones to the upper Cypress reservoirs.

Reservoir Lithology and Petrology

Drill cuttings from several wells in the Tamaroa and Tamaroa South Fields were available for lithologic analysis. Small diameter plugs taken from a 15-foot core cut through most of the Y2 and Y3 reservoirs of the Stockton No. 1 Well, NW SW SW, Section 28, were available for analysis of reservoir properties. The 14 core plugs taken at 1-foot intervals from this core covered most of the coalesced Y2 and Y3 sandstones of the upper Cypress in the Tamaroa South Field. Although the Stockton No. 1 was completed for only 24 BOPD and 40 BWPD, cumulative production from 1957 through 1989 was approximately 55,000 BO. The well is one of the larger cumulative producers in the Tamaroa area.

The porosity of the core plugs from the Stockton No. 1 ranges from 18% to 23% and averages 20% for sandstone of reservoir quality. Permeability ranges from 88 to 183 millidarcys and averages about 146 millidarcys. Figure 15 shows the close correspondence between the electric log SP curve and the graphic representation of the plug permeabilities. The porosity graph does not mimic the SP log or the permeability graph. Instead, the porosity data show a straight-line tendency throughout the more permeable, clean-responding portion of the SP log. The maximum SP deflection of this sandstone is about 95% of the 100% clean Tar Springs Sandstone.

The core plugs and drill cuttings are composed of very light gray to oil-stained light brown, moderately well sorted, mostly fine to very fine grained sandstone. Minor components include scattered medium gray, flat clay clasts, generally less than
Figure 13 Cross section A–A′ showing that log signatures of the Y2 and Y3 lenticular sandstones coalesce, forming an abnormally thick sandstone in the upper Cypress interval.
Figure 14  Cross section B–B’ showing that Y1 and the middle Cypress sandstones coalesce, and possibly assist in the migration of oil through the widespread middle Cypress sandstones into the lenticular, upper Cypress sandstones.
Figure 15 Comparison of the SP curve and the plotted permeability data from the Stockton No. 1 Cypress core analysis, showing similar character. Multiple shingling events during deposition of the Y2 and Y3 sandstones have created permeability barriers at 1,163.5 feet and possibly at 1,159 feet. Samples were examined in thin section and by scanning electron microscope and X-ray diffraction, as indicated in the column on method: T = thin section; S = SEM; and X = X-ray diffraction.
1 mm thick by less than 1 cm in diameter, and wispy clay laminations. The reservoir sandstones appear to be very clean, and silica is the dominant cement. Four plugs from the Stockton No. 1 were thin sectioned and analyzed by X-ray diffraction. Three additional plugs were analyzed by scanning electron microscope (SEM) (fig. 15). Thin sections of drill cuttings of reservoir rock from the Newborn No. 1, SE SE NW, Section 22, and the Zmudzinski No. 1, NW SW SE, Section 14, also were examined. The petrographic characteristics of these samples were all generally similar. Visual examination, supported by results from X-ray diffraction analysis, showed that quartz constitutes an estimated 90% of the samples; feldspar, clay minerals, chert, calcite, mica, and a minor amount of heavy minerals make up the remaining 10%.

Fine, subangular quartz grains that show pervasive quartz overgrowths dominate these samples. The angularity of the grains appears to be a result of the overgrowths. Visible infilling by quartz overgrowths along grain contacts has decreased the pore space and pore throat size, thereby decreasing porosity and permeability (fig. 16). Quartz overgrowths may also have increased the tortuosity of flow paths within the sandstones, and thus restricted hydrocarbon flow rates through the reservoir.

Secondary porosity, approximately 3%, has been created by the dissolution of feldspar grains. Partial to complete dissolution of fine feldspar grains is clearly visible in both thin sections (plate 1) and SEM images (fig. 17). A part of the residual oil observed in thin sections is attached to these remnant feldspar grains (plate 1). The oil appears to have an affinity for these grains, possibly because of capillary attraction to the micropores.

Three separate methods were used to analyze the reservoir clay minerals; (1) thin section, (2) X-ray diffraction bulk pack, and (3) SEM with an energy dispersive X-ray analyzer (EDX). Although the quantity of clay minerals in the clean portion of these reservoirs is less than 2% of the sample, knowledge of the types and locations of
clay minerals present in the reservoirs is crucial for the optimal development of the reservoirs. X-ray diffraction and SEM-EDX analysis confirmed that kaolinite and iron-rich chlorite are the principal clay mineral constituents in the Tamaroa samples (fig. 18). Thin section analysis revealed relatively few clay-filled pores in the clean part of the reservoir. Patchy, clay-filled areas and thinly laminated, bedded clays, both probably detrital in origin, were observed as minor constituents within the reservoir sandstones. SEM analysis showed a patchy scattering of authigenic clay minerals on the overgrowth surfaces of many quartz grains. These clay minerals present a large surface area to passing fluids and thus create a potential for reservoir damage.

Clay mineral abundance is greatest in the 1,163.5-foot plug from the Stockton No. 1 Well. Irregular, patchy porosity and clay-filled zones are apparent in the thin section of this plug. A mottled, disturbed bedding appearance on the sample block of this thin section indicates that burrowing organisms reworked and intermixed a low energy, mud-rich sand with an interlaminated, nearly mud-free, porous sand. The core plug analysis showed a corresponding decrease in the porosity and a sharp decrease in the permeability of this sandstone. The SP log trace verifies the decreased reservoir quality of this thin bed (fig. 15).

Calcite, mica, and other heavy minerals are minor constituents of the reservoir rock. Calcite occurs as scattered to rare, patchy, fine grained crystals, and it appears to be of little consequence to oil production. Very fine, rounded, heavy mineral grains are scattered to rare, except in a few locations where lag concentrations occur along bedding planes (plate 2).

**Depositional Environments**

As the Cypress Formation in the Tamaroa Field area shows, siliclastic materials flooded into the Ridenhower sea. The classical interpretation of a southwestward-prograding delta set forth by Swann (1963) for deposition of the Chesterian Series can be applied to the lower and middle Cypress intervals.

The lower Cypress interval was deposited in the distal delta to prodelta part of a westward- to northwestward-prograding delta lobe. Evidence supporting this interpretation includes electric log character; drill cuttings of sandstone, shale, and limestone; and the sandstone distribution pattern shown on the lower Cypress interval thickness map (fig. 8). This delta lobe, shown in figure 19 to project into the Tamaroa area, could have branched off of the main southwestward-prograding delta, as postulated by Swann (1963).

The middle Cypress sandstones, particularly the thicker sandstones, probably represent more than one depositional environment. A northwest to north trend of thick sandstones forms a broadly linear, bifurcating to high angle, conjugate pattern (fig. 9). One possible interpretation for deposition of the middle Cypress sandstones entails separation of the sandstones into a lower progradational sequence and an upper transgressive sequence. The lower sequence represents the generally westward-prograding delta front–distributary mouth complex. The upper sequence represents the reworked, winnowed remnant of the delta plain after abandonment of the delta lobe and transgression of the Barlow sea.

Lenticular sandstone geometry, shale encasement, burrowing, heavy mineral lags, and SP log character are all consistent with deposition of the upper interval reservoir sandstones in a marine setting, possibly as tidal shoals or offshore bars. The northeast-southwest trend of these sandstone bars generally parallels the regional alignment of the thick deltaic sandstones in the middle and lower Cypress intervals.
Plate 1 Thin section photomicrograph showing void space and the development of secondary porosity by dissolution of feldspar grains. Residual oil appears to be attached to partially dissolved feldspar grains. The sample is from the Y3 reservoir of the Stockton No. 1 (depth 1,160.5 feet).

Plate 2 Thin section photomicrograph of heavy mineral lag along bedding planes. The sample is from the Stockton No. 1 (depth 1,160.5 feet).
**Figure 17** SEM photomicrograph of partially dissolved feldspar grain displaying secondary microporosity. The sample is from the Y3 reservoir of the Stockton No. 1 (depth 1,156 feet).

**Figure 18** SEM photomicrograph of quartz grains coated by kaolinite booklets (upper center) and iron chlorite (lower left). The sample is from the Y3 reservoir of the Stockton No. 1 (depth 1,156).
Tidal bars of the upper Cypress interval apparently were oriented shore-normal, if the shoreline or delta front trended northwest-southeast. Alternatively, the Cypress thickness patterns indicate that distributaries in the Tamaroa area may have directed sediments toward the northwest, thereby creating an embayment with a local northeast-southwest-trending shoreline. In this case, the northeast-trending upper Cypress marine bar system would have been oriented parallel to the shore of the embayment.

Stacking of the Cypress sandstones would occur, if the shoreline remained approximately stationary while coastal processes and sediment influx remained constant during the period of bar deposition. Stacking also requires that the rate of sedimentation equals the rate of subsidence.

**Diagenesis**

Petrologic analyses of the reservoir samples indicate that the presence of quartz overgrowths, the presence and composition of clay minerals, and the alteration of feldspar are the three diagenetic factors most influential in the development of reservoirs in the Tamaroa fields.
Quartz overgrowth and cementation occurred early in the sequence of diagenetic events recorded in the upper Cypress sandstones. Quartz precipitation was widespread and unimpeded by clay coatings on the original quartz grains, a conclusion based on the observation that dust rings outlining original grains are rare. The lack of clay coatings early in the diagenetic process implies that these sands were deposited in a mud-free environment or one with strong winnowing and sorting capacity. More than one overgrowth event is indicated by the presence of some grains that have dust rings outlining euhedral grains (fig. 20). The euhedral form of the grains probably resulted from the growth of quartz crystal faces that formed during the earliest silica cementation event. Figure 16 shows a quartz grain with a chlorite-filled channel. This channel may have resulted from formation of chlorite on a quartz grain after an early stage of quartz overgrowth. During the second stage of quartz growth, the chlorite impeded overgrowth.

Feldspar dissolution not only created secondary porosity, but may have also enriched the brine waters with the aluminum and silica necessary for the formation of kaolinite, chlorite, and quartz overgrowths. Various stages of feldspar alteration can be observed in the upper Cypress sandstones. Total and partial dissolution are pervasive in the clean reservoir sandstones. Complete voids and cavities containing partially dissolved feldspars are common. The remaining feldspar is mostly sodium-rich plagioclase. A trace of potassium feldspar also is present. All evidence indicates that the less stable calcium-type plagioclase was more extensively altered and dissolved than other types of feldspar. Figure 17 shows a twinned plagioclase feldspar in which the calcium-rich laths have dissolved. This dissolution results in the creation of microporosity. The remaining undissolved portion of the grain displays secondary crystal growth (albitization), which reduces porosity.

Authigenic chlorite and kaolinite are common throughout the clean reservoir sandstone samples, although the total quantity of all clay in the cleaner samples is
approximately 1% to 2% of the sample. This quantity is determined by bulk X-ray diffraction analysis and includes both detrital and authigenic clay minerals. The authigenic clay minerals observed by SEM form only a delicate, thin, spoty veneer on the surface of many quartz grains. Rarely is a grain entirely coated. SEM-EDX analyses indicate that chlorite, largely the iron-rich variety, is more prevalent than kaolinite. Bulk X-ray diffraction analysis indicates, however, that the quantity of kaolinite is probably twice that of chlorite (table 1). This discrepancy may result from the presence of detrital kaolinitic clasts and thin clay laminations within the X-ray sample. The detrital clay may affect the reservoir by decreasing vertical permeability and adding possible pore-throat-plugging fines; however, the dispersed, authigenic clay minerals that veneer quartz grains present a greater potential for reservoir damage.

Table 1  X-ray diffraction analyses of four Stockton No. 1 core plugs showing weight percentages of mineral constituents taken from bulk pack (total mineral) analyses.

<table>
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<th>depth (ft)</th>
<th>clay</th>
<th>illite</th>
<th>illite/smectite</th>
<th>kaolinite</th>
<th>chlorite</th>
<th>quartz</th>
<th>K-feldspar</th>
<th>(Na-Ca) feldspar</th>
<th>calcite</th>
<th>dolomite</th>
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<td>1155.5</td>
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<td>0.3</td>
<td>0.8</td>
<td>0.6</td>
<td>0.2</td>
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<td>0.5</td>
<td>0.4</td>
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<td>0.2</td>
<td>0.2</td>
<td>3.5</td>
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Summary: Petrophysical Characteristics that Influence Reservoir Quality

Upon deposition, the lenticular sands of the upper Cypress interval were apparently very clean and probably had a porosity of at least 35% and permeability of more than 1 darcy (Almon and Davies 1981). Postdepositional processes have reduced the porosity to an average value of 20% and the permeability to between 100 and 200 millidarcys. A porosity of 20% is generally considered acceptable and, provided the pores are well connected, a permeability greater than 100 millidarcys is sufficient to drain those pores. Permeability, which is a function of the size of pore throats, has been significantly reduced by quartz overgrowths. Also, pore throat restriction has increased flow path tortuosity, which may explain the low production rates and longevity of some of these wells.

Reservoir quality is also affected by reservoir compartmentalization caused by depositional processes. Although these sandstones generally stack and appear to coalesce, they are commonly separated by vertical, permeability barriers such as the one indicated by the log and core data from the Stockton No. 1 Well. Migration of these marine bars, a common process, can create a "shingling" effect where one bar laps onto or over another bar. The presence of a shale at this contact causes a permeability barrier to develop along the onlap, transitional contact. This barrier results in a reservoir that consists of separate compartments. The SP resistivity log commonly used in the Illinois Basin may not discern the presence of thin, intervening shale beds or impermeable zones that separate the shingled bars; but core observations, gamma-ray logs, and neutron-density logs confirm their presence. Although not common, the shingled bars may also form a single interconnected compartment.
Although porosity has been decreased by quartz overgrowths, secondary porosity has increased as a result of partial to total feldspar dissolution. The microporosity created by the selective dissolution of the calcium-rich laths of plagioclase feldspars may not be effective porosity, and the microporosity appears to be a residual oil trap.

The authigenic clays in the reservoir are inactive and stable under natural, unaltered reservoir conditions. In their natural state, grain-coating chlorite and kaolinite tend to generally reduce reservoir porosity and permeability. Further serious reservoir damage may result from improper treatment of these clay minerals by procedures that affect the reservoir during drilling, completion, stimulation, and production. This subject is discussed in the section, Development, Production Strategy, and Recommendations.

IDENTIFICATION OF PLAY

The upper Cypress interval sandstone reservoirs that constitute the Tamaroa fields appear to be nearshore, marine bars. The bars resulted from the reworking of a prograding delta that was terminated by a marine transgression. Up to four lenticular sandstone bars can be stacked, but the middle two sandstones commonly form the productive reservoirs.

These bar-type reservoirs appear to require a structural component to trap hydrocarbons. In no instances have hydrocarbons accumulated solely by stratigraphic trapping. Structural rollover associated with a physical flexure of the reservoir is characteristic of all the Tamaroa pools. Vertical migration of hydrocarbons into the lenticular sandstones may have been accommodated by a flexure-induced, fracture system. The fact that the Trenton produces from a fractured reservoir at Tamaroa Field supports the concept that fracturing, most likely flexure-induced, has assisted migration. The juxtaposition of the Du Quoin Monocline may also be a component of this play through the possible creation of a fault-fracture, hydrocarbon migration conduit.
PRODUCTION CHARACTERISTICS

Production and Completion Procedure

Records indicate that rotary drive rigs were used to drill the wells in the Tamaroa area. Mud systems used freshwater with gel additive for particle suspension.

Several completion and stimulation techniques were used. The more productive wells were drilled to the top of the sandstone and cased. Cable tools were then used to chip through the reservoir to approximately the oil-water contact, and the wells were thereby completed open hole. Other wells were rotary-drilled into the reservoir, cased to the top of the reservoir, and completed open hole. This type of completion was commonly followed by a 10-quart-nitroglycerin, fracture treatment to stimulate production. Wells were also drilled through the reservoir, and in some instances, to deeper horizons. These wells were cased and perforated, usually with two shots per foot through the reservoir interval. A few of the cased wells were hydraulically fractured using 900- to 2,000-pound water-sand combinations. As the records indicate, very few acid treatments that penetrated deep into the formation were performed. Almost all wells were pump-produced from initial completion.

Production and Waterflood Data

Decline curves were constructed for Tamaroa, Tamaroa South, and the Tamaroa South extension fields. The Tamaroa Field decline curve (fig. 21) includes recorded production from wells draining both structural closures in the field. Clearly shown on the graph are the initial production from the discovery pool in Section 22, T4S, R1W, from 1942 to 1952; the discovery and rapid development of the pool in Sections 14 and 23, T4S, R1W, in 1952; and the initiation of the Tamaroa waterflood in 1961. The fairly constant slope of the decline curve from 1962 to 1989 reflects the stable oil production that was induced by waterflooding.

Figure 22 shows the Tamaroa South Field decline curve. The south extension part of the Tamaroa South Field in Section 4, T5S, R1W, is excluded from the decline curve shown in figure 22. The field was rapidly developed in 1957 and several marginal producers were added in 1962, only one of which has recorded production.
data. Reinjection of produced water was initiated in 1963. The combination of the additional well and the injection well can be seen on the curve for 1963 and 1964.

Figure 23 shows the Tamaroa South extension pool decline curve. Production from three good wells and two marginal wells is recorded on this curve. The curve shows an unusually flat decline from 1973 through 1985. Production may have been restricted to maintain reservoir pressure and hold down water cut.

Data are available for one waterflood and one pressure maintenance, saltwater disposal project in the Tamaroa Cypress pools. Another unrecorded pressure maintenance, saltwater disposal program with one injector well and two production wells was established in the south extension field. The Tamaroa waterflood in Sections 14 and 23 was initially designed as a peripheral injection project with six injectors partially encircling five production wells (fig. 24). Water was injected into the reservoir (1) at the structurally lowest part of the field, (2) at the midstructure, and (3) in the structurally highest well within the gas cap. In effect, this procedure concentrates the oil into a central area of production. Water was injected at 700 to 750 psi. It consisted of 90% produced water and 10% pond water. The project was initiated in December 1961, after primary production had yielded 200,000 BO. Through 1985, the last year with consistent records, an additional 139,000 BO had been produced by means of this secondary recovery program. By 1985, 3,244,000 barrels of water had been injected; 2,490,000 barrels of water had been produced.

The Bagwell pressure maintenance, saltwater disposal project was initiated in Tamaroa South Field in December 1962. One injection well, the Bagwell No. 2 in SE NW SW, Section 28, T4S, R1W, was used as a brine disposal and pressure maintenance well for the four producing wells to the west and south. From 1962 to 1985, 57,000 BO was recovered from the four producers. Approximately 870,000 barrels of produced Cypress brine was reinjected and 1,070,000 barrels of brine was produced during this period.

**Reservoir Temperature and Pressure**

Drill stem tests and electric logs are the only sources of pressure and temperature data. Drill stem test data show that the highest shut-in pressures are in the range of 435 psi at an approximate depth of 1,130 feet. The standard hydrostatic pressure
gradient of 0.43 psi/foot is slightly greater than the 0.38 psi/foot calculated from the drill stem test data, and thus indicates that these reservoirs are underpressured. Bottomhole temperatures of up to 100°F were measured during logging operations. Finally, the primary drive mechanism appears to be gas solution.

**Oil Characteristics**

Oil samples were collected for analysis in 1990 from one well in Tamaroa South and from two wells in the south extension pool. Analyses, including chromatograms, are presented in the appendixes. Oil gravity (API) and viscosity values reported from samples taken from the Tamaroa waterflood in Sections 14 and 23 were 31.5° and 9.01 cp at formation temperature. The gravity at the Bagwell project in Section 28 was 27.6° and the viscosity was 26 cp at 42°F.

The 1990 sample taken from the Hampleman No. 1 Well in the south extension pool yielded a gravity of 27.4° and a viscosity of 11.2 cp at 95°F.

**Water Characteristics**

Reservoir brine samples were collected along with the oil samples in 1990. The same wells that were sampled for oil were also sampled for brine. An additional sample was collected from the Hampleman No. 2, the injection well in the extension to Tamaroa South Field. Although reinjection of Cypress reservoir brines occurred in the vicinity of the sampled wells, the analytical data shown in appendix A should closely represent the composition of the brine from the two reservoirs sampled. The water resistivities of the brine samples are between 0.088 and 0.095 ohms and may be useful for calculations requiring an R_w value.

**Volumetrics**

Original oil in place (OOIP), stock tank original oil in place (STOOIP), and recovery factors were determined for both the Y2 and Y3 sandstones in each of the four structurally separate Tamaroa area pools. Values were calculated using the standard volumetric formula:

\[
\text{OOIP} = \text{porosity} \times (1 - \text{water saturation}) \times \text{reservoir acre-feet} \times 7758 \, \text{BO/acre-foot.}
\]
A 20% porosity value, as determined from the average of measured porosities from the Stockton No. 1 core, was used. A conservative value of 40% water saturation was assigned. Water saturations calculated from logs were inaccurate, mostly because of thin-bed effects and some invasion complications. Reservoir volumes were estimated using the 50% clean sandstone maps of the reservoir intervals.

Stock tank original oil in place represents the conversion and reduction of oil volume at original reservoir pressure to oil volume at atmospheric conditions. The reduction in oil volume is caused by a release of solution gas from oil at reservoir pressure greater than bubble-point as the confining pressure on the oil approaches atmospheric pressure. The assumption that solution gas is the driving mechanism for these reservoirs requires this conversion.

The conversion factor or formation volume factor (B₀) commonly used in the Illinois Basin for oils with API gravity similar to that of the Tamaroa oil is 1.15. This value was used for Tamaroa South Field and its extension. Because of the presence of a gas cap on the two pools in Tamaroa Field, a formation volume factor of 1.20 was used to calculate the STOOIP for these pools. This larger B₀ value maintains a conservative estimate for STOOIP in this pool.

Also calculated for Tamaroa Field was the volume of oil displaced by the gas cap on the two pools. The removal of this volume yields a more accurate estimation of OOIP and recovery factors. The volumetric results using the factors described above are as follows:

Tamaroa Field Sections 14 and 23 (eastern pool)

\[
\text{OOIP} = 982,000 \text{ BO} \\
\text{STOOIP} = 818,000 \text{ BO} \\
\text{Primary recovery} = 218,000 \text{ BO (26.7%)}
\]

\[
\text{Secondary recovery} = 134,000 \text{ BO (16.4%)} \\
\text{Total recovery} = 352,000 \text{ BO (43%)}
\]

Tamaroa Field Sections 22 and 23 (western pool)

\[
\text{OOIP} = 1,157,000 \text{ BO} \\
\text{STOOIP} = 964,000 \text{ BO} \\
\text{Total recovery (estimate)} = 50,000 \text{ BO (5%)}
\]

Tamaroa South Field Sections 28, 32, and 33

\[
\text{OOIP} = 1,404,000 \text{ BO} \\
\text{STOOIP} = 1,221,000 \text{ BO} \\
\text{Total recovery} = 310,000 \text{ BO (25%)}
\]

Tamaroa South extension field Section 4

\[
\text{OOIP} = 253,000 \text{ BO} \\
\text{STOOIP} = 220,000 \text{ BO} \\
\text{Total recovery} = 71,000 \text{ BO (32%)}
\]

Volumetric calculations determined from residual water and residual oil saturation data from the Stockton No. 1 core analysis were also prepared. Assuming that the average of the residual water saturation values from the Stockton No. 1 core analysis approximates the original water saturation (Sₖ) for Tamaroa South Field (Y3 Sₖ = 45.6%, Y2 Sₖ = 31.1%), then the recovery factor for the field is 22.7%. This figure supports the above calculations. Also, if the average of the residual oil values from the Stockton No. 1 core analysis approximates the residual oil saturation (Sₖ) for
the entire field \((Y3 \text{ S}_{or}= 26.6\%, Y2 \text{ S}_{or}= 31.1\%)\), then 395,000 barrels of movable oil remain in the Tamaroa South Field.

**DEVELOPMENT, PRODUCTION STRATEGY, AND RECOMMENDATIONS**

A comparison of the separate pools of the Tamaroa Field area shows similarities in lithology as well as in size and geometry of sandstone bodies. Depositional processes and settings for these lenticular sandstones were most likely similar as well. Consequently, similar recovery efficiencies might be expected. The differences between the fields with respect to cumulative production and particularly field recovery efficiency are thus a function of drilling, completion, stimulation, or development programs, or a combination of these programs. A strategy that can optimize production should be employed at each stage, from the drilling of the discovery well to the final abandonment of a reservoir.

Some recommendations to achieve optimum production can be derived from this study of the Tamaroa fields. Waterflood and pressure maintenance programs show the most positive effects on increasing cumulative production. Drilling and completion techniques, especially with regard to preventing formation damage caused by the alteration of indigenous clay minerals, may also influence the amount of recoverable reserves. Enhanced oil recovery (EOR) methods (e.g., carbon dioxide treatment) are gaining technical and economical merit. As Fisher and Galloway (1983) discovered in Texas, however, intensive development and infill drilling are the most effective means of extending and increasing production from an oil field. Their conclusions are based on the amount of oil recovered by EOR techniques, 90% of which are miscible gas flood programs.

Waterflood and pressure maintenance records show that production in Tamaroa Field in Sections 14 and 23 has benefited significantly from the peripheral design waterflood program. Sections 14 and 23 have produced 352,000 BO, as compared with 35,000 BO from Section 22. Because of inconsistent and incomplete production records, the actual production figure for Section 22 could be twice that amount.

Three factors may contribute to the difference between these two volumetrically and lithologically similar pools:

1. No secondary pressure maintenance or waterflood program was established in the western pool (Section 22). Unlike the eastern pool (Sections 14 and 23), in which the gas cap and reservoir energy were maintained, the drive energy was probably depleted in the western pool. Retaining reservoir energy is crucial to maximizing recovery efficiency, particularly in a reservoir of limited extent and a correspondingly limited drive.

2. Correlation of separate, vertically stacked reservoir sandstones is not obvious in this area. It is possible that miscorrelation and consequent misunderstanding of the character of these discontinuous and coalescing sandstones has inhibited development, particularly of the western pool. The fact that only gas was found in the upper reach of this pool may also have inhibited development. It is recommended that reservoir continuity and flow unit correlation be evaluated with the use of field pressure analyses, including pulse, interference, build-up, drawdown, and tracer tests (Lee 1982). Pressure maintenance and other reservoir management requirements can also be evaluated through the use of field tests and accurate, per-well production histories that include water and, if possible, gas production.
(3) Development of the eastern pool appears to have been a coordinated effort, incorporating all operators from separate leases into the waterflood program. The western pool does not show a similar record of coordinated development. It appears likely that moveable hydrocarbons remain in this reservoir, although a detailed engineering evaluation of present reservoir conditions is necessary to confirm the presence and volume of remaining mobile oil. Also, a coordinated development program, similar to that used in the eastern pool, incorporating the whole reservoir and including multiple sandstone lenses, may be the most feasible and economically sound approach.

Though less obvious, Tamaroa South and the extension pool also have benefited from water injection. Tamaroa South has experienced very little secondary development. This field more than likely has secondary recoverable reserves remaining in place. Records indicate that only one water injector well has operated in this field, and there is a low recovery efficiency, as calculated from volumetrics. Several factors must be considered, however, before undertaking extensive development activities in Tamaroa South Field. There is a lack of production data for six wells and a possibility of unrecorded waterfloods. Also, most wells appear to be plugged.

Another significant factor, with respect to waterflooding, is illustrated by the geologic model of Tamaroa South Field (fig. 11). The compartmentalization caused by the shingled character of the marine bars must be thoroughly assessed. Although the sandstone encountered in one well may appear to correlate with sandstone in an adjacent well, the sandstones may represent two separate bars, and therefore, two separate, noncommunicating reservoirs. Figure 11 shows that some wells in Sections 28 and 32 intersect only the Y3 sandstone. An attempt to waterflood into a Y2 sandstone from a well that intersects only the Y3 sandstone will probably fail.

Although their effects on cumulative production are not as obvious as waterflooding, drilling and completion techniques may be significant factors in terms of both short term, initial production and overall, cumulative production. As previously mentioned, wells that had open hole completions and were not drilled deeper than the reservoir, and particularly wells that were completed using standard tools (cable) to penetrate the reservoir, generally showed the greatest cumulative production and higher initial production rates. By contrast, wells drilled deeper than the reservoir and completed with casing through the reservoir tend to show lower initial production rates and lower cumulative production.

The Cypress sandstones may thus be susceptible to formation damage, either by drilling fluids or completion procedures. Drilling fluids, both the filtrate and the fines, can reduce permeability during invasion. They do this either by dislodging clay-sized fines, usually kaolinite, that migrate and catch in pore throats or by clogging pore throats near the well bore with drilling fines.

During drilling, completion, and other development procedures, fluids introduced into the reservoir can interact with the authigenic chlorite and kaolinite and significantly reduce the permeability of the reservoir. Although clay minerals are minor constituents in these sandstones, their presence as pore and pore throat linings causes them to be in total contact with drilling, completion, and development fluids.

Because clay minerals also possess a high ratio of surface area to volume, they are very susceptible to alteration and consequent formation damage. The high-iron chlorite prevalent throughout these sandstones is extremely sensitive to acid and oxygenated waters (Almon and Davies 1981). Chlorite dissolves readily in dilute HCl, and the liberated iron reprecipitates as an iron hydroxide as the acid is spent.
This iron hydroxide clogs pore throats, effectively blocking the production flow paths. This problem can be avoided if an oxygen scavenger and an iron chelating agent are added to the acid, and if all the treatment fluid introduced into the reservoir is recovered. Because of the minor amount of calcite observed in the Tamaroa reservoirs, the only practical use of acid is for mud clean-up during completion. Even then, it is recommended that an oxygen scavenger and an iron chelating agent be used and that all acid be removed from the hole rapidly. Almon and Davies (1981) further recommend that if iron hydroxide has been precipitated in the reservoir, as the result of an inadequately designed acid job, it can be removed by treatment with weak (5%) HCl combined with appropriate iron chelating agents and an oxygen scavenger. It is strongly recommended that all acid be recovered before it is spent.

Kaolinite, the other dominant clay mineral in the Tamaroa reservoirs, is chemically stable in the presence of the commonly introduced drilling, completion, and development fluids, as long as the salinity of the introduced fluids does not greatly differ from the original brines. Kaolinite is very loosely attached to the surface of host grains, however, and it can be easily dislodged and moved by fluids. The kaolinite particles can then migrate into pore throats where they lodge. Permeability is thereby decreased and production flow is reduced. This occurs, particularly in the area close to the well bore, where fluid flow rates reach velocities capable of moving these particles. Clay stabilization systems are available to easily resolve this problem, as long as treatment is applied early in the history of the well (Almon and Davies 1981).

Damage from kaolinite migration also occurs as a result of the mixing of incompatible brines (Vaidya and Fogler 1990). Water shock, a term applied to an abrupt change in salinity in a reservoir, leads to a rapid and drastic decline in permeability. The shock is caused by introducing fresh or low salinity water into a reservoir containing normal to high salinity brine. Vaidya and Fogler (1990) show that this problem can be avoided by gradually lowering the salinity of an injection fluid during waterflood, or by using brine compatible with the reservoir during drilling.

Almon and Davies (1981) further recommend that any program that introduces fluids into a reservoir be designed for the specific variety of clay mineral(s) in that reservoir. Therefore, a mineralogical analysis of the reservoir, particularly of the clay mineral(s), is required prior to introducing fluids into the system. Brine analysis, although not mentioned by Almon and Davies (1981), should be included. The composition of the introduced fluids must also be known to evaluate chemical reactions that may occur between the components of the reservoir, particularly reservoir fluids, and the introduced chemicals. Iron materials used in oil well installations should be considered as reactive materials that can affect the reservoir.

An optimum drilling and development program that avoids formation damage can then be designed using the results from the previously mentioned tests. The suggested clay mineral analysis includes four steps: (1) SEM-EDX analysis, (2) X-ray diffraction analysis of the fine fraction (reservoir clays alone), (3) petrographic analysis by thin section, and (4) bulk X-ray diffraction analysis. At the very minimum, analysis by SEM-EDX will reveal the locations of clay minerals and indicate the types of clay minerals and their relative iron contents.

Infill drilling of the Tamaroa area fields may prove to be economically feasible. Whitaker and Finley (1992) found that for Bartelso Field in Clinton County, Illinois, drill spacing of 5 acres or less, combined with waterflooding, yielded an estimated recovery efficiency of greater than 49% for all the Cypress reservoirs and possibly 60% (Steven T. Whitaker, personal communication 1992) for the marine bar reservoirs within the field. Considering the similarity of the reservoir characteristics...
at Bartelso and Tamaroa and Tamaroa South Fields, even the most effectively drained, eastern part of Tamaroa Field may warrant infill drilling to increase the recovery efficiency from 43% to 60%. Ten-acre spacing, even when combined with a waterflood program, may not be adequate to effectively drain the bar-type reservoirs. Assessing the effective drainage spacing for these reservoirs requires the use of pressure and production data that are not available.

Infill drilling may also be required to assess the degree of reservoir compartmentalization that exists throughout the Tamaroa area. The coalesced and stacked nature of these reservoirs may conceal bypassed reservoirs or entirely separate reservoirs. Most of the wells in Section 14 of Tamaroa Field and many of the wells in Tamaroa South Field were never drilled below the first oil-producing horizon encountered.

Figure 25 Combination map of the structure on top of the Y3 sandstone horizon and the thickness of the 50% clean, Y3 sandstone in the Tamaroa area. (Contour interval of the thickness map is 2 feet, and of the structure map, 5 feet.)
Development drilling in the Tamaroa area shows good potential. The combined thickness-structure map of figure 25 shows an undeveloped eastern extension of the Section 22 pool. The Texaco John Majewski No. 2, SW NW, Section 23, T4S, R1W, penetrated Cypress Y2 and Y3 coalesced reservoir rock, although production records indicate that this well produced only from the Trenton. Even if the well was recompleted in the Cypress, standard offset drill spacings still exist. As mentioned previously, an engineering assessment and a thorough geologic evaluation of this pool is recommended to confirm these preliminary observations. Pressure depletion and complications caused by coalescing and splitting of these lenticular sandstone reservoirs should be considered in developing this field.

ACKNOWLEDGMENTS

Technical assistance, analytical services, and data interpretations were provided by several colleagues at the Illinois State Geological Survey: D. Scott Beaty, Todd Black, Ilham Demir, Dennis J. Haggerty, Randall E. Hughes, Duane M. Moore, Gary Salmon, Beverly Seyler, Emmanuel O. Udegbunam, and Stephen T. Whitaker. Their work is much appreciated. This research was funded by the U. S. Department of Energy under grant DE-FG2289BC14250 and the Illinois Department of Energy and Natural Resources under grant AE-45. Support for the research in this strategic program is gratefully acknowledged.
REFERENCES


APPENDIX A  CYPRESS RESERVOIR FLUID ANALYSIS

API Number  1214502946
Operator  Bixby
Well Name  Hampleman No. 1
Location  SW SE SE, Sec. 4, T5S-R1W
Perforations Depth (ft)  1160-1166 (24 shots) Cypress Y3
Surface Elevation (ft)  483 (Kelly bushing)
Waterflooded  yes, offsets saltwater disposal well

Brine Analysis
Brine sample number  EOR-B20
Resistivity  0.095 OHM-M @25° C
Eh (mV)  -100
pH  6.76
TDS  83457 mg/L

Anion chemistry (mg/L)
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<thead>
<tr>
<th>Anion</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
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<tr>
<td>Cl</td>
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<td>I</td>
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<td>NO₃</td>
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<td>SO₄</td>
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Cation chemistry (mg/L)
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<td>Ti</td>
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<tr>
<td>V</td>
<td>NA</td>
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<td>Zr</td>
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Oil Analysis
Oil sample number  EOR-018

Hydrocarbon fraction (%)
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<td>Saturated hydrocarbons</td>
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<td>Aromatic hydrocarbons</td>
<td>29.91</td>
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<td>Resins</td>
<td>14.85</td>
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<td>Asphaltenes</td>
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Selected hydrocarbon ratios
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<td>C₁₈/Phytane</td>
<td>2.10</td>
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</table>
APPENDIX A  continued

API Number  1214503023
Operator  Baldridge
Well Name  Zielinski No. 1-A
Location  NE SW SE, Sec. 4, T5S-R1W
Perforations Depth (ft)  1148?-1152 Cypress Y3?
Surface Elevation (ft)  473 (ground level)
Waterflooded  yes, offsets saltwater disposal well

Brine analysis
Brine sample number  EOR-B21
Resistivity  0.091 OHM-M @25°C
EH (mV)  -81
pH  6.70
TDS  84255 mg/L

Anion chemistry (mg/L)
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Oil Analysis
Oil sample number  EOR-019

Hydrocarbon fraction (%)
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APPENDIX A  continued

API Number 1214502950
Operator Bixby
Well Name Hampleman No. 2
Location SE SE SE, Sec. 4, T5S-R1W
Perforations Depth (ft) 1148-1182 open hole Cypress
Surface Elevation (ft) 474 (ground level)
Waterflooded saltwater disposal well

Brine Analysis
Brine sample number EOR-B23
Resistivity 0.088 OHM-M @25°C
EH (mV) -73
pH 6.68
TDS 85236 mg/L

Anion chemistry (mg/L)
Br  NA  I  NA
Cl 51276  NO3  NA
CO3 <1  SO4  NA
HCO3 156

Cation chemistry (mg/L)
Al NA  Co <0.07  Mn 0.72  Se  NA
As NA  Cr  NA  Mo <0.08  Si 3.2
B 2.79  Cu <0.06  Na 30220  Sr 195
Ba 7.10  Fe 18.0  NH4 NA  Ti 0.12
Be 0.014  K 134  Ni <0.15  V  NA
Ca 2058  Li  NA  Pb <0.4  Zn <0.02
Cd <0.05  Mg 1164  Sb 0.7  Zr 0.07

Oil Analysis
Oil sample number saltwater disposal well
**APPENDIX A continued**

API Number 1214502273  
Operator Pouch  
Well Name Stockton No. 1  
Location NE NW NW, Sec. 33, T4S-R1W  
Perforations Depth (ft) NA  
Surface Elevation (ft) 497 (Kelly bushing)  
Waterflooded no

**Oil Analysis**

<table>
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<td>I</td>
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**Oil Analysis**

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<tr>
<th>Oil sample number EOR-O20</th>
<th>Hydrocarbon fraction (%)</th>
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<th>55.72</th>
<th>Aromatic hydrocarbons</th>
<th>27.13</th>
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<th>Asphaltenes</th>
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APPENDIX B  GAS CHROMATOGRAMS OF SATURATED HYDROCARBONS

sample EOR-18  $n{\text{C}}_{17}$

sample EOR-19  $n{\text{C}}_{17}$

sample EOR-20  $n{\text{C}}_{17}$

relative abundance

retention time
APPENDIX C  RESERVOIR SUMMARY

Field  Tamaroa, Tamaroa South, Tamaroa South extension

Location  Perry County, Illinois: Tamaroa, Sections 14, 22, and 23, and Tamaroa South, Sections 28, 32, and 33; Tamaroa South extension, Section 4, T5S, R1W.

Tectonic/Regional Setting  intracratonic basin

Geologic Structure  anticline

Trap Type  structural/stratigraphic

Reservoir Drive  gas dissolution

Original Reservoir Pressure  NA; DST shut-in pressures range up to 435 psi

Reservoir Rocks
Age  Mississippian (Chesterian)
Stratigraphic Unit  Cypress
Lithology  quartz arenite
Wetting Characteristics  NA
Depositional Environments  marine bars, vertically stacked
Productive Facies  sandstones of the active, central bar
Petrophysics  ($\phi$ and $k$ from unstressed conventional core)

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<th>Porosity Type</th>
<th>Average</th>
<th>Range</th>
<th>Cutoff</th>
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<td>$\phi$</td>
<td>20%</td>
<td>16–23%</td>
<td>16%</td>
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<td>$k$ air (md)</td>
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<td>4–183</td>
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<td>$k$ liquid</td>
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<td>NA</td>
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<td>$S_{or}$</td>
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<td>$S_{gr}$</td>
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<tr>
<td>Cementation factor</td>
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</table>

Source Rocks
Lithology and stratigraphic unit  NA
Time of hydrocarbon maturation  NA
Time of trap formation  Chesterian (stratigraphic); Penn./Perm. (structural)

Cypress Reservoir Dimensions
Depth  1095–1170 ft
Areal dimensions  Tamaroa, 340 acres; Tamaroa South, 180 acres; Tamaroa South extension, 52 acres
Productive area  as above
Number of pay zones  2
Hydrocarbon column  Tamaroa, 30 ft; Tamaroa South, 14 ft; Tamaroa South extension, 10 ft
Initial fluid contacts  Tamaroa: gas/oil, -638 ft, oil/water = -665 ft; Tamaroa South Oil/Water = -668 ft; Tamaroa South extension, oil/water = -661 ft
Avg. net sand thickness  Tamaroa, Y3 = 4.6 ft, Y2 = 3.4 ft; Tamaroa South Y3 = 4.7 ft, Y2 = 3.8 ft; Tamaroa South extension, Y2 only = 4.9 ft
APPENDIX C  continued

Avg. gross sand thickness  Tamaroa: Y3 = 6 ft, Y2 = 5 ft; Tamaroa South: 
Y3 = 6 ft, Y2 = 5 ft; Tamaroa South extension: Y2 only = 6 ft 
Net/gross  Tamaroa: Y3 = 3.8/6, Y2 = 3.4/5; Tamaroa South: Y3 = 4.7/6, Y2 
= 3.8/5; Tamaroa South extension: Y2 only = 4.9/6 
Initial reservoir temperature  100°F (estimated from logs) 
Fractured  natural, NA; artificial, nitroglycerin induced or sand-water

Wells
Spacing  10-acre primary 
Pattern  normal primary and secondary 
Total 
Tamaroa producers  23 (water source 0, observation 0; suspended na, injection 6, disposal 0, abandoned 12 recorded, dry holes 12) 
Tamaroa South producers  18 (water source 0, observation 0, suspended 0, injection 0, disposal 1, abandoned 7 recorded, dry holes 14) 
Tamaroa South extension producers  4 (water source 0, observation 0, suspended 0, injection 0, disposal 1, abandoned 2, dry holes 8)

Reservoir Fluid Properties
Hydrocarbons
Type  oil and gas 
GOR  NA 
API Gravity  Tamaroa, 31.5°; Tamaroa South, 27.6°; Tamaroa South extension, 27.4° 
FVF  Tamaroa, 1.20; Tamaroa South and Tamaroa South extension, 1.15 
Viscosity  Tamaroa, 9.01 cp @ Formation temp.; Tamaroa South = 26 cp @ 
42°F; Tamaroa South extension, 11.2 cp @ 95°F 
Bubble point pressure  NA 
Formation Water
Resistivity  0.09 @ 77°F 
Total dissolved solids  84,000 ppm

Volumetrics
In-place  3,223,000 BBLs STOIP; 1,782,000 Tamaroa, 1,221,000 Tama-
roa South, 220,000 Tamaroa South extension 
Cumulative production  768,000 BO; Tamaroa, 387,000; Tamaroa South, 
310,000; Tamaroa South extension, 71,000 
Ultimate recovery
Primary  Tamaroa Section 14 and N1/2 23, 200,000 ; Tamaroa South, NA; 
Tamaroa South extension, NA 
Secondary  Tamaroa Section 14 and N1/2 23, 134,000; Tamaroa South, 
NA; Tamaroa South extension, NA 
Tertiary  none 
Recovery efficiency
Primary  Tamaroa Section 14 and N1/2 23, 26.7%; Tamaroa South, NA; 
Tamaroa South extension, NA 
Secondary  Tamaroa Section 14 and N1/2 23, 16.2%; Tamaroa South, NA; 
Tamaroa South extension, NA 
Tertiary  none
APPENDIX C continued

Typical Drilling/Completion/Production Practices
  Completions open hole or cased
  Drilling fluid freshwater mud with gel additive
  Fracture treatment 10 quarts of nitroglycerin or 900- to 2000- pound water-sand combination
  Acidization one
  Producing mechanism
    primary pump
    secondary pump

Typical Well Production (to date)
  Average daily IP 17 BOPD; range = to 105 BOPD
  Cumulative production 22,000 BO (primary and secondary); range =,000 to 65,000 BO
  Water/oil ratio (initial) NA