Reservoir characterization of a Permian deep-water sandstone, East Ford field, Delaware basin, Texas

Shirley P. Dutton, William A. Flanders, and Mark D. Barton

ABSTRACT

Deep-water sandstones of the Delaware Mountain Group in west Texas and southeast New Mexico contained an estimated 1.8 billion bbl of original oil in place, but primary recovery from these fields is commonly less than 20%. East Ford field in Reeves County, Texas, which produces from the Ramsey sandstone in the upper Bell Canyon Formation, went directly from primary production to tertiary recovery by CO₂ flooding. Field production has increased from 30 to more than 185 BOPD. Oil recovery has been improved by the CO₂ flood, but not as much as expected. Geologic heterogeneities such as interbedded siltstones are apparently influencing reservoir displacement operations in the East Ford unit.

A depositional model of the East Ford unit was developed using data from Bell Canyon outcrops and subsurface data. The Ramsey sandstones were deposited by turbidity currents in a basin-floor setting. The sandstones are interpreted as having been deposited in a channel-levee system that terminated in broad lobes; overbank splays filled topographically low interchannel areas. Injection wells located in splay sandstones apparently have poor communication with wells in channel sandstones, perhaps because communication is restricted through levee and channel-margin deposits. The south part of the unit is responding well to the flood because the injection and production wells are in the same interconnected lobe depositional environment.

INTRODUCTION

Reservoirs in deep-water sandstones of the Delaware Mountain Group in the Delaware basin (Figures 1, 2) contained more than 1.8 billion bbl of original oil in place (Holtz, 1995). Recovery efficiencies of these reservoirs have averaged less than 20% since production began.

Copyright © 2003. The American Association of Petroleum Geologists. All rights reserved.
Manuscript received February 19, 2002; provisional acceptance July 8, 2002; revised manuscript received September 23, 2002; final acceptance October 10, 2002.

mostly in the 1950s and 1960s, and only 340 million bbl of oil had been produced through 1998. Many of these mature fields are nearing the end of primary or secondary production and are in danger of abandonment unless effective, economic methods of enhanced oil recovery (EOR) can be implemented.

Because of their historically low recovery, reservoirs in the Bell Canyon Formation of the Delaware Mountain Group were the target of a reservoir-characterization and demonstration project funded by the U.S. Department of Energy as part of the Class III (Slope and Basin Clastic Reservoirs) Field Demonstration Program (Dutton and Flanders, 2001a). Our study was focused on East Ford field in Reeves County, Texas (Figures 1, 3), which produces from the Ramsey sandstone, the youngest sandstone in the Bell Canyon Formation. Primary recovery efficiency at East Ford field was only 16%, and enhanced oil recovery by CO₂ flooding is now being conducted in the East Ford unit in an effort to increase recovery.

A depositional model of Bell Canyon sandstones was developed from well-exposed outcrops (Barton and Dutton, 1999; Dutton et al., 1999b). The outcrop model was used to guide interpretation of the subsurface data and develop a geologic model of East Ford field. The geologic model explains much of the production response to the fluid-displacement operation and provides a framework for modifying the flood to increase recovery.

More than 375 reservoirs have been discovered in the Delaware basin submarine-fan sandstone play in west Texas and New Mexico (Galloway et al., 1983; Dutton et al., 2000). Because the reservoirs in this play have similar depositional, diagenetic, and production histories, knowledge gained from study of the East Ford field can be extrapolated to other fields in the play. Lessons learned from the production history of this mature reservoir in west Texas may also have application to development of newly discovered turbidite reservoirs throughout the world.

**Geologic Setting**

Upper Permian (Guadalupian) Delaware Mountain Group strata compose a 4500-ft-thick (1400-m) succession of slope and basin deposits in the Delaware basin (Gardner, 1997b). The Delaware Mountain Group is divided, from oldest to youngest, into the Brushy Canyon, Cherry Canyon, and Bell Canyon Formations (Figure 2). Shelf-to-basin-floor correlations of time-equivalent strata indicate water depths were between 1000 and 2000 ft (300 and 600 m) during deposition of the Bell Canyon Formation (Kerans et al., 1992). The cyclic interbedding of sandstones with organic-rich siltstones in the Delaware Mountain Group has been interpreted to record frequent changes in relative sea level (Meissner, 1972; Fischer and Saranthein, 1988; Gardner, 1992, 1997a,b). During highstands in relative sea level, sands were trapped behind a broad, flooded shelf and were prevented from entering the basin. Thin, widespread, organic-rich siltstones accumulated on the basin floor by the slow settling of marine algal material and airborne silt. During
subsequent lowstands in relative sea level, the carbonate shelf was exposed and sands bypassed to the basin floor. Many workers have interpreted the Delaware Mountain Group sandstones as having been deposited by turbidity currents (Newell et al., 1953; Payne, 1976; Berg, 1979; Jacka, 1979; Gardner, 1992; Zelt and Rossen, 1995; Bouma, 1996; Barton and Dutton, 1999; Beaubouef et al., 1999; Gardner and Borer, 2000). Textural characteristics of the sands, such as the absence of detrital clay-sized material and the lack of channels on the shelf, suggest that wind was an important agent in transporting the sands to the shelf margin (Fischer and Sarnthein, 1988). According to this model, dunes prograded to the shelf break during sea level lowstands, and eolian sands were then carried into the basin by turbidity currents (Fisher and Sarnthein, 1988; Gardner, 1992). Paleocurrent indicators show that the sands entered the basin from the Northwest shelf and Central Basin platform (Williamson, 1978) (Figure 1).

**Delaware Sandstone Play**

Fields in the Delaware sandstone play produce oil and gas from slope and basin sandstone deposits that form long linear trends (Figure 1). The reservoir sandstones in much of the basin dip to the east and northeast, almost directly opposite original depositional dip, because Late Cretaceous movement associated with the Laramide orogeny tilted the Delaware basin eastward (Hills, 1984). Production from the East Ford unit and other upper Bell Canyon fields in the central Delaware basin occurs from the distal (southwest) ends of east-dipping, northeast-oriented linear trends of thick Ramsey sandstone deposits. Most hydrocarbons in these fields are trapped by up-structure facies changes from higher permeability reservoir sandstones to low-permeability siltstones (Williamson, 1979; Ruggiero, 1985, 1993).

Approximately 379 fields produce from sandstones of the Delaware Mountain Group in west Texas and southeast New Mexico (Dutton et al., 2000), including 182 large fields that have produced more than 100,000 bbl of oil each. The Bell Canyon Formation has produced more oil than the Cherry Canyon or Brushy Canyon Formations. The 79 large fields in the Bell Canyon Formation (Figure 1) had produced 209 million bbl of oil and gas from slope and basin sandstone deposits that form long linear trends (Figure 1). The reservoir sandstones in much of the basin dip to the east and northeast, almost directly opposite original depositional dip, because Late Cretaceous movement associated with the Laramide orogeny tilted the Delaware basin eastward (Hills, 1984). Production from the East Ford unit and other upper Bell Canyon fields in the central Delaware basin occurs from the distal (southwest) ends of east-dipping, northeast-oriented linear trends of thick Ramsey sandstone deposits. Most hydrocarbons in these fields are trapped by up-structure facies changes from higher permeability reservoir sandstones to low-permeability siltstones (Williamson, 1979; Ruggiero, 1985, 1993).

![Figure 1. Location of the largest fields (cumulative production >100,000 bbl) producing from the Bell Canyon Formation, Delaware Mountain Group (modified from Dutton et al., 2000). Field outlines and locations are based on information from Grant and Foster (1989), Kosters et al. (1989), Basham (1996), Lewis et al. (1996), and the Railroad Commission of Texas (unpublished data). Field names and other information are given in Dutton et al. (2000). Basin axis interpreted from Ewing (1990).](image-url)

![Figure 2. Stratigraphic nomenclature and relative hydrocarbon production of the Delaware Mountain Group and time-equivalent formations on the surrounding shelves. Modified from Galloway et al. (1983), Ross and Ross (1987), Kerans and Fitchen (1995), and S. C. Ruppel (personal communication, 2000).](image-url)

Dutton et al., 611
Through 1998 (Dutton et al., 2000). Through 1998, 62 large fields in the Cherry Canyon Formation had produced 75 million bbl of oil, and 41 large Brushy Canyon fields had produced 45 million bbl of oil (Dutton et al., 2000). Previous papers have summarized information about Brushy Canyon and Cherry Canyon reservoirs in the Delaware sandstone play (Montgomery et al., 1999, 2000). This paper focuses on the youngest and most productive interval in the Delaware Mountain Group, the Bell Canyon Formation.

Outcrop Characterization of Bell Canyon Sandstone

Interpretation of the Ramsey sandstone reservoir at the East Ford unit was based largely on the depositional model developed by investigation of Bell Canyon sandstones exposed in outcrop 25 mi (40 km) to the west (Barton and Dutton, 1999; Dutton et al., 1999b) (Figure 1). The outcrop work focused on the first sandstone below the McCombs limestone (Figure 2), a sandstone that is environmentally analogous to, but older than, the Ramsey sandstone. The older sandstone was investigated because it is interpreted to be a better analog to the reservoirs at East Ford field, being from a similar position in the facies tract. The Ramsey sandstone exposed in outcrop represents a more distal depositional environment than the Ramsey sandstone deposited at East Ford field. The results of the outcrop study are summarized below; more detailed descriptions of the lithofacies, sandstone thickness and geometry, and interpreted depositional processes are published in Barton and Dutton (1999) and Dutton et al. (1999b).

Six lithofacies were identified in outcrop: lithofacies 1 is a massive, organic-rich siltstone; lithofacies 2 is an organic-rich, laminated siltstone; lithofacies 3 is a laminated sandstone having water escape and load structures; lithofacies 4 is composed of thin-bedded sandstones and siltstones that are graded or display partial Bouma sequences (Bouma, 1962); lithofacies 5 is a massive sandstone having water escape and load structures; lithofacies 6 is a large-scale, cross-laminated sandstone (Barton and Dutton, 1999). The sandstones and massive siltstones are interpreted as having been deposited by sandy high- and low-density turbidity currents that carried a narrow range of sediment size, mostly very fine sand to coarse silt. Laminated siltstones are interpreted to have been deposited by fine material settling out of suspension.

Depositional elements recognized in the Bell Canyon deposits exposed in outcrop include (1) channels, (2) levees, (3) lobes, (4) overbank splays, and (5) sheets of laminated siltstones (Barton and Dutton, 1999; Dutton et al., 1999b). Stratigraphic relationships of the depositional elements indicate that the sandstones were deposited on the floor of the Delaware basin by a system of leveed channels having attached lobes and overbank splays (Barton and Dutton, 1999; Dutton et al., 1999b) (Figure 4). Individual channel-levee and lobe complexes stack in a compensatory fashion and are separated by laterally continuous, laminated siltstones. Paleocurrent measurements indicate that the sandstone bodies in the outcrop area trend north-south, which is nearly perpendicular to the shelf margin on the northwest side of the basin.

Lobe deposits are broadly lenticular sandstone bodies that generally lack an erosive base (Figure 4c). They are as much as 25 ft (8 m) thick and 2 mi (3.2 km)
Figure 4. (a) Depositional model proposed for the Bell Canyon sandstone, showing deposition in submarine channels with levees, overbank splays, and attached lobes. Modified from Galloway and Hobday (1996) and Barton (1997). (b) Photograph of channel-levee deposits; the two channels are vertically stacked in an offset fashion (from Dutton et al., 1999b). (c) Photograph of lobe sandstones and interbedded laminated siltstones. (d) Strike-oriented cross section AA' from Willow Mountain outcrop showing distribution of facies and traces of key surfaces in a single high-order cycle, Bell Canyon Formation (modified from Dutton et al., 1999b). See Figure 1 for location.
wide (Barton and Dutton, 1999; Dutton et al., 1999b). Lobes are composed mostly of medium- to thick-bedded massive sandstones having dewatering features such as dish and flame structures and are commonly interbedded with sheets of laminated siltstone. Lobe sandstones are interpreted as having been deposited at the mouths of channels by unconfined, highly decelerating sediment-gravity flows. In a prograding system, lobe facies would have been deposited first and then overlain and partly eroded by the channel levee overbank system (Figure 4d).

Channels are bound at the base by an erosion surface and are largely filled with massive and cross-stratified sandstones (Barton and Dutton, 1999; Dutton et al., 1999b). Channels mapped in outcrop range from 10 to 60 ft (3 to 18 m) in thickness; most are 20–40 ft (6–12 m) thick. Channel widths are 300–3000 ft (90–900 m). Aspect ratios (width/thickness) range from 15 to 40. The channels bifurcate and widen downdip.

Flanking the channels on both sides are wedge-shaped “wings” composed of thinly bedded sandstone and siltstone (Figure 4b, d) and interpreted to be levee deposits (Barton and Dutton, 1999; Dutton et al., 1999b). In some cases, sandstone beds in the levees can be traced into the adjacent channel (Figure 4b), and the bedding relationships indicate that the margins of the channels were maintained by elevated levee deposits. In other cases, the levee and channel deposits display a disconformable contact. Paleocurrents in the levee deposits deviate by about 15–45° away from the axis of the channel. Levees are interpreted as having been deposited by unconfined turbidity currents that spilled over the margin of the channel. The width of levee deposits mapped in outcrop range from about 500 to 3000 ft (150 m to 1 km) wide. The levees thin abruptly away from the channel, decreasing in thickness from 20 to 1 ft (6 to 0.3 m).

Overbank splays are composed of massive sandstones and display a broad, tabular to irregular geometry. They onlap the levee deposits (Barton and Dutton, 1999; Dutton et al., 1999b) (Figure 4d). Convoluted bedding and dewatering structures such as dish and pillar structures are common in these beds. The splay sandstones are 3–25 ft (1–8 m) thick. Splays on the flanks of the channel system were at least 3000 ft (900 m) wide and possibly much greater, as they extended beyond the limits of the mappable outcrop. Overbank splays increase in thickness away from the channel margins in a compensatory fashion with the levees, indicating that the splays filled topographically low interchannel areas. The locally irregular geometry of the splay deposits is related to the underlying topography. Stratigraphic relationships suggest that the splays formed during the final stages of channel filling (Barton and Dutton, 1999). Volumetrically, they contain much of the sandstone in the system (Figure 4d). It is not possible to distinguish overbank-splay deposits from lobe deposits by lithofacies alone. The location, shape, and stratigraphic position of the massive sandstones are needed to distinguish these two depositional elements.

This depositional model is similar in many respects to the “build, cut, fill, and spill model” proposed for the older Brushy Canyon Formation by Gardner and Borer (2000). The lobe deposits, which represent the “build” stage, are cut and overlain by the channel levee deposits that represent the “cut and fill” stage. Splay sandstones represent the “spill” phase of overbank deposition. A difference between our Bell Canyon model and the Brushy Canyon models of Beaubouef et al. (1999) and Gardner and Borer (2000) is our interpretation that levees maintained the Bell Canyon channel margins.

The depositional model developed from study of well-exposed outcrops in the Bell Canyon Formation guided our interpretation of the reservoirs at East Ford field. This depositional model should be widely applicable to other Bell Canyon reservoirs. The results of the outcrop study can thus be transferred by operators to Bell Canyon fields throughout the play and used to guide reservoir characterization.

**RESERVOIR CHARACTERIZATION OF EAST FORD FIELD**

The Ramsey sandstone, the main reservoir in East Ford field, is the youngest sandstone in the Bell Canyon Formation. It is divided into two sandstones (Ramsey 1 and 2) that are separated by a 1- to 3-ft-thick (0.3- to 1-m) laminated siltstone (SH1) (Figure 5). The geologic model of East Ford field was developed on the basis of (1) subsurface data, including one core, from the East Ford field, (2) an earlier study of the Geraldine Ford field (Figure 1), for which abundant data, including 70 cores, were available (Dutton et al., 1999b), and (3) the Bell Canyon outcrop study. Eleven other cores that were taken in East Ford field had been discarded many years ago, and only core-analysis data were available (Figure 3).

It is difficult to interpret detailed facies relationships, such as those observed in the Bell Canyon outcrops, from widely spaced well data alone. This difficulty is compounded in Bell Canyon reservoirs by the
absence of detrital clay in the sandstones; as a result, log responses are muted, and log patterns are not always reliable for facies identification. Interpretation of the sandstone-thickness and log-facies data in the East Ford field was strongly influenced by the depositional model developed from the outcrop study.

**Sandstone Distribution and Facies**

The Ramsey 1 sandstone is thickest on the east side of East Ford field (Figure 6a). It pinches out along the west and south margins and reaches a maximum thickness of more than 25 ft (7.6 m) along an elongate, north-south trend that widens at the south end. The east side of the Ramsey 1 sandstone is not defined because few wells were drilled where the Ramsey sandstone dips toward the water. Typical of Ramsey sandstone reservoirs, significant production is from within the oil-water transition zone. Productive oil has not been

---

**Figure 5.** Typical log from East Ford field; well location is shown in Figure 3. Lithology is interpreted on the basis of log response because core was not available from this well. Modified from Dutton and Flanders (2001b).

**Figure 6.** (a) Isopach map of the Ramsey 1 sandstone. (b) Isopach map of percentage of net/gross sandstone in the Ramsey 1 interval. Net sandstone was determined from sonic and gamma-ray logs as the number of feet of sandstone having volume of clay less than or equal to 15% and porosity greater than or equal to 17.5%. Sandstone thickness and ratio of net/gross sandstone were used to interpret facies distribution.
defined below 88 ft (27 m) above sea level. Because log control to the east is poor, the orientation of the Ramsey 1 sandstone is uncertain, and it may be oriented more northeast-southwest than is shown in Figure 6a.

The younger sandstone in the Ramsey cycle, the Ramsey 2 (Figure 7a), is thickest along a north-south trend that is shifted to the west of the underlying Ramsey 1 sandstone. The offset of the Ramsey 2 sandstone trend suggests that the younger sandstone was deposited in the adjacent topographic depression created by deposition of the preceding Ramsey 1 sandstone, indicating compensational stacking. The Ramsey 2 sandstone is thinner than the Ramsey 1, having a maximum thickness of 24 ft (7.3 m) at the north end and 10 ft (3.0 m) at the south end.

Net/gross sandstone maps of the Ramsey 1 and 2 intervals provide an indication of heterogeneity in the Ramsey sandstones. Because the goal of the maps was to show the ratio of clean sandstone to total interval thickness, net sandstone was mapped as sandstone having porosity greater than or equal to 17.5% and volume of clay ($V_{cl}$) less than or equal to 15%, no matter what the water saturation (the choice of porosity and $V_{cl}$ cutoffs is discussed in Reservoir Properties). Clean sandstones on the east side of the field have high water saturation because they are in a structurally low position, not because of poorer reservoir quality. Well control for the maps is limited to wells having both sonic and gamma-ray logs through the entire interval.

The map of net/gross sandstone for the Ramsey 1 interval (Figure 6b) shows that the highest values (>90%) are along the east side of the field. Net/gross sandstone values decline toward the west and at the south end of the field. The Ramsey 2 sandstone has net/gross sandstone values (Figure 7b) that are somewhat lower, although few wells have sonic logs where the Ramsey 2 sandstone is thickest and might be expected to have the highest net/gross values. Net/gross sandstone decreases both to the east and west, as well as at the south end of the field (Figure 7b).

A 54-ft (16.5-m) core was taken in the Orla Petco 41R East Ford Unit well; the cored interval extends

![Figure 7](image-url)

Figure 7. (a) Isopach map of the Ramsey 2 sandstone. (b) Isopach map of percentage of net/gross sandstone in the Ramsey 2 interval. Net sandstone was determined from sonic and gamma-ray logs as the number of feet of sandstone having volume of clay less than or equal to 15% and porosity greater than or equal to 17.5%. Sandstone thickness and ratio of net/gross sandstone were used to interpret facies distribution.
from the bottom few feet of the Trap siltstone, through the Ramsey sandstone, and into the upper few feet of the Ford siltstone (Figure 8). Several lithofacies identified in outcrop were observed in the core: (1) organic-rich siltstone; (2) laminated siltstone; and (3) structureless or massive sandstones having few laminations but containing floating siltstone clasts, dewatering features, and load structures. Two lithofacies that were observed in outcrop and in cores from Geraldine Ford field (Dutton and Barton, 1999), but not in the Orla Petco 41R East Ford Unit core, are cross-stratified sandstone and rippled sandstone. The Ramsey 1 and 2 intervals in the core are mostly massive, very fine grained sandstones. The most common sedimentary structures are features related to dewatering: dish structures, flame structures, and convolute bedding.

Depositional Model

Ramsey sandstones in East Ford field are interpreted as having been deposited in a channel-levee system with attached lobes and overbank splays (Figures 9, 10). The Ramsey deposits at East Ford are about 2500–4000 ft (760–1220 m) wide, dimensions similar to those of the system studied in outcrop. Channel deposits in East Ford field are interpreted to occur along the trend of thickest Ramsey 1 and 2 sandstones (Figure 10), where net/gross sandstone is greater than 90%. Channels in the Ramsey 1 sandstone are about 25 ft (7.6 m) thick and 950 ft (290 m) to perhaps as much as 2000 ft (610 m) wide (Figure 10a). Ramsey 2 channels are interpreted to be about 15 ft (4.5 m) thick and about 1300 ft (400 m) wide (Figure 10b). In outcrop, many channels were seen to be nested and laterally offset from each other (Figure 4b). Similar nesting of multiple channels may occur in East Ford field, but the well control is not sufficiently close to distinguish separate channels. Assuming the channels at East Ford field are single channels, the aspect ratio (width/thickness) of Ramsey 1 channel deposits is 40:1 to as much as 80:1. Ramsey 2 channel deposits have aspect ratios of about 85:1.

The sandstones that flank each side of the channel deposits are interpreted to be levee and overbank-splay deposits (Figures 9, 10). On the basis of the outcrop study, we infer that levee deposits are continuous with the Ramsey 1 and 2 channel sandstones and separate them from splay deposits. The sandstones that border each side of the levee deposits are interpreted to be overbank splays. Volumetrically, the splays contain much of the sandstone outside of the channels (Figure 10). Good-quality reservoir sandstone occurs in the levee and overbank deposits, but these facies also contain interbedded siltstones and silty sandstones and thus have lower values of net/gross sandstone (30 to 90%) (Figures 6b, 7b).

Figure 8. Description of core from Orla Petco 41R East Ford Unit well (modified from Dutton and Flanders, 2001b). Well location is shown in Figure 3.
Figure 9. (a) Strike cross section BB’ of the central part of the East Ford unit. (b) Strike cross section CC’ of the south part of the unit. Location of cross sections is shown in Figure 3.
Deposits that widen out at the south end of the field are interpreted to be lobe sandstones in both Ramsey 1 and 2 intervals (Figure 10). Lobe facies, deposited by unconfined, high-density turbidity currents at high suspended-load fallout rates, occur in broad sheets at the mouths of channels. The presence of massive sandstones having abundant fluid-escape structures in the Orla Petco 41R East Ford Unit core is consistent with the interpretation that they are lobe deposits. Because deposition of lobe sandstones was episodic, laminated siltstones are interbedded with the lobe sandstone sheets. Net/gross sandstone values are highest in the center of the lobe deposits (70 to >90%) and decrease to 30% toward the margins of the lobes (Figures 6b, 7b).

Channel, levee, splay, and lobe facies in the East Ford unit could not be distinguished by log patterns in many cases. The interpretation of depositional facies shown in Figures 9 and 10 was made on the basis of (1) sandstone thickness and net/gross sandstone trends in the unit, (2) the depositional model developed from outcrop, and (3) production response to the CO₂ flood, which is discussed in CO₂ Flood of East Ford Unit.

**Reservoir Properties**

Ramsey sandstones in the Orla Petco 41R East Ford Unit well are well-sorted, very fine grained arkoses having an average composition of Q₆₇F₂₆R₇. Primary porosity estimated from thin-section point counts of 25 sandstone samples averages 19%, and secondary porosity averages 2%. Cements constitute between 1 and 31% of the sandstone volume, with calcite and chlorite being the most abundant. Calcite cement has an average volume of 7% and ranges from 0 to 30%. Chlorite (average = 1%) forms rims around detrital grains, extending into pores and pore throats.

Porosity and permeability of Ramsey sandstones and siltstones were determined by core analyses of 368 samples from 12 cored wells (Figure 11). Porosity in Ramsey sandstones averages 22% and ranges from 4.5 to 30.6%. Sandstone permeability ranges from 0.01 to

---

**Figure 10.** (a) Interpreted facies distribution of the Ramsey 1 sandstone in the East Ford unit, superimposed on Ramsey 1 isopach map. (b) Interpreted facies distribution of the Ramsey 2 sandstone, superimposed on Ramsey 2 isopach map. See text for discussion of facies interpretation. Heterogeneities at facies boundaries apparently disrupt fluid-displacement operations in the East Ford unit.
The average permeability is 40 md, and geometric mean permeability is 22 md. Ramsey 1 sandstones have higher average permeability than do Ramsey 2 sandstones, 44 versus 34 md, respectively. Volume of calcite cement is the dominant control on porosity and permeability (Dutton and Flanders, 2001b). In samples having less than 10% calcite cement, average porosity is 22.5%, and average permeability is 46 md. Sandstones having more than 10% calcite cement have an average porosity of 11.5% and average permeability of 3 md.

On the basis of the Dykstra-Parsons heterogeneity coefficient ($V$), a measure of permeability heterogeneity (Dykstra and Parsons, 1950), the Ramsey sandstone in the East Ford unit was found to be moderately homogeneous ($V = 0.52$).

The Ramsey sandstone at the East Ford unit had high initial water saturation ($S_w$), and many wells produced some water at discovery. Log-calculated values of $S_w$ ranged from 44 to 55% across most of the field and averaged 48% (Dutton et al., 1999a). The cementation exponent ($m$) of 1.83 and saturation exponent ($n$) of 1.90 used in these calculations were determined in the Ford Geraldine unit (Asquith et al., 1997). Average $S_w$ measured in core analyses of Ramsey sandstones was 47%. Water saturation increases to the east and northeast in the field, which is to be expected because that direction is down structural dip. The Ford Geraldine unit averaged 48% $S_w$ at discovery, well above the irreducible water saturation of 35% (Pittaway and Rosato, 1991).

Average net-pay thickness in East Ford field is 20 ft (6 m). The highest values (>30 ft [9 m]) follow a north-south trend down the center of the field. Net pay decreases to the west, where the Ramsey sandstone pinches out into siltstone, and to the east, where the sandstone dips toward the oil-water contact.

**EAST FORD PRODUCTION HISTORY**

**Primary Development**

Primary recovery in East Ford field began in October 1960 and continued until June 1995. Several wells were initially completed in the Olds sandstone (Figure 5), and production from the Olds and Ramsey sandstones was commingled. Production peaked at 965 BOPD in May 1966, and cumulative production during primary recovery was 3,209,655 bbl. The estimated 2.9 million bbl produced from the Ramsey sandstone represents 16% of the 18.4 million bbl of original oil in place (OOIP) (Dutton et al., 1999c) (Table 1). East Ford field, like other Delaware sandstone reservoirs, was characterized by relatively high amounts of mobile water at the time of discovery. Among the reasons for the low primary production are (1) the solution gas/oil ratio of only 400–600 scf/bbl, which resulted in limited natural drive energy; (2) the expenditure of considerable solution-gas drive energy in the recovery of water from the reservoir; (3) the lack of pressure support from the aquifer because of the limited water influx.

Production during 1994, the last full year of primary production, was 9734 bbl, and daily production
had declined to 30 bbl. The decline rate, calculated using an exponential least-squares fit of the production data from April 1991 through September 1994, was 10.1%. At that rate of decline, the economic limit of the field would have been reached soon if the CO₂ flood had not started.

The East Ford unit did not undergo secondary recovery by water flooding, because water flooding has not been very successful in other Ramsey sandstone reservoirs. Water flooding added about 4% of the OOIP to the total recovery from the Ford Geraldine unit (Pittaway and Rosato, 1991) and from Twofreds (West Side) field in Loving County, Texas (Kirkpatrick et al., 1985; Flanders and DePauw, 1993). Waterflood recoveries in Ramsey sandstones have been low because of poor sweep efficiency caused by (1) abundant mobile water present when the waterflood was started, (2) water injection above the formation parting pressure, (3) lack of proper water filtration, and (4) patterns not arranged to exploit depositional characteristics.

**CO₂ Flood of East Ford Unit**

Two Bell Canyon reservoirs have already undergone CO₂ floods, Twofreds Delaware unit and Ford Geraldine unit (Figure 1). Tertiary recovery began in 1974 in the Twofreds unit (Kirkpatrick et al., 1985; Flanders and DePauw, 1993) and in 1981 in the Ford Geraldine unit (Pittaway and Rosato, 1991). In the Twofreds unit, 12% of OOIP was recovered by the CO₂ flood (Table 1) (Dutton and Flanders, 2001a). Approximately 7% of OOIP in the flooded area of the Ford Geraldine unit was recovered by the CO₂ flood (Table 1). Tertiary recovery from the Ford Geraldine unit may be lower because a higher percentage of OOIP (23%) was recovered during primary and secondary production than in the Twofreds unit (16%) (Table 1) because of a stronger solution-gas drive at Ford Geraldine.

East Ford field was unitized, and CO₂ injection in the East Ford unit began in July 1995 with 8 injectors and 11 producers; the unit currently has 7 injectors and 15 producers (Figure 3). The number of active wells in the unit was kept low to reduce costs. In the north part of the unit, the injectors are positioned on the west side, but to the south, the injectors are located centrally (Figure 3).

The first response to the flood was observed in April 1996, and major production response in the unit began in December 1997 (Figure 12). Average bottom-hole pressure in the unit at the start of the project was 723 psi (4.98×10⁶ Pa), whereas minimum miscibility pressure is 900 psi (6.21×10⁶ Pa). Somewhat higher pressure occurred around wells 7, 12, 36, and 37 (Figure 13a), where produced water was reinjected into the formation. The low pressure in the East Ford unit at the start of the CO₂ flood, combined with the low reservoir temperature of 83°F (23°C), meant that CO₂ would exist as both vapor and liquid phases under these conditions.

---

**Table 1. Summary Production History of Three Fields Producing from Bell Canyon Sandstones**

<table>
<thead>
<tr>
<th>Field</th>
<th>OOIP Inception</th>
<th>Primary + Secondary Production to Start of CO₂ Injection</th>
<th>Production After Start of CO₂ Injection to January 1, 2002</th>
<th>Cumulative Production to January 1, 2002</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(MMbbl)</td>
<td>(MMbbl) (%) OOIP</td>
<td>(MMbbl) (%) OOIP</td>
<td>(MMbbl) (%) OOIP</td>
</tr>
<tr>
<td>Ford Geraldine</td>
<td>99</td>
<td>22.3 23</td>
<td>6.6 7</td>
<td>28.9 29</td>
</tr>
<tr>
<td>Twofreds</td>
<td>51</td>
<td>8.4 16</td>
<td>6.1 12</td>
<td>14.5 28</td>
</tr>
<tr>
<td>East Ford</td>
<td>18.4</td>
<td>2.9** 16</td>
<td>0.22 1</td>
<td>3.1 17</td>
</tr>
</tbody>
</table>

*MMbbl = Million stock-tank barrels; OOIP = Original oil in place.
**Estimated primary production from Ramsey sandstone only.

---

**Figure 12.** Plot of monthly oil production from the East Ford unit since the field was discovered in 1960. The field was on primary production until a CO₂ flood was begun in July 1995.
conditions. Response to CO₂ injection in the field may have been delayed as a result. At these low temperatures and pressures, liquid CO₂ can occur on both the injection side and the production side.

By May 2001, the production rate had increased to 185 BOPD, along with 345 BWPD and 1.7 mmcf/day (hydrocarbon gases and CO₂) (Figure 14a). Most of the produced gas and water are reinjected, and to repres- sure the reservoir, additional water for injection is being taken from a nearby operator. Cumulative production through May 2001 was 180,097 stock-tank bbl of oil, 518,000 bbl of water, and 1344 mmcf of gas. Essentially all the oil production since the start of the CO₂ flood can be attributed to the EOR project. Injection rates in May 2001 were 3100 mcf/day of purchased CO₂, 1425 mcf of recycled CO₂, and 375 BWPD (Figure 14b). Cumulative injection through May 2001 was 9057 mmcf of purchased CO₂, 1075 mmcf of recycled CO₂, and 670,000 bbl of water.

The CO₂ flood has increased production from the East Ford unit substantially (Figure 14), but several production abnormalities have been observed: (1) low pressure in the center of the field, (2) low production rates, (3) severe reduction in transmissibility indicated by a bottom-hole pressure-buildup test, and (4) low gas production rates in key wells. Some of these abnormalities may be caused by mechanical problems, but others may result from the effect of geologic heterogeneity in the field.

Although pressure at the north and south ends of the field has increased during CO₂ injection, low pressure has persisted in the center of the field (Figure 13b). The pressure data were collected in wells used as observation wells; injection wells were shut in for 48 hr, and the decline in pressure was observed. The pressure distribution suggests that communication is poor between wells in the center of the field and the nearest injectors (Figure 13b).

The production rate in some wells, including Orla Petco 3 East Ford Unit and Orla Petco 4 East Ford Unit (Figure 13), is lower than would be expected from their initial potential. For example, well 4 made 106 bbl of liquids (oil + water) per day (BLPD) during initial-potential tests, so the current production of about 20 BLPD is surprisingly low. In addition, gas production from Orla Petco 4 East Ford Unit has leveled off. Well Orla Petco 3 East Ford Unit has a similarly low production rate of 10 BLPD (whereas it flowed 110 BLPD during the initial-potential test), and pressure in the well now is greater than 1200 psi (8.27 × 10⁶ Pa). Gas
production from Orla Petco 3 East Ford Unit is also low, although the well is close to the injector Orla Petco 2 East Ford Unit.

**Influence of Geologic Heterogeneity on East Ford Production**

Oil recovery has been improved by the CO₂ flood, but not as much as had been expected. Production abnormalities may indicate that geologic heterogeneities are affecting reservoir displacement operations. In many cases, these heterogeneities do not have a major influence on primary recovery, but they can have a significant impact on EOR processes, including water-floods and CO₂ floods.

Interbedded siltstones are probably the most important cause of heterogeneity in the Ramsey reservoirs. Because of the low permeability of siltstones (average 4 md), limited cross-flow of fluids occurs between sandstones separated by siltstones. Siltstones occur as (1) widespread sheets that bound high-order depositional cycles, (2) a concentration of rounded siltstone clasts and, rarely, a drape of massive, organic-rich siltstone along the base of channels, and (3) beds interbedded with thin sandstones in the levee deposits (Dutton et al., 2000). All of these siltstone beds have the potential to disrupt displacement operations in Delaware sandstone reservoirs. For example, cross-flow of fluids may be limited between a well in an overbank-splay deposit and a well in a channel deposit, not only

---

**Figure 14.** Plot of oil production, water/oil ratio, and gas/oil ratio in the East Ford unit since 1990. (b) Plot of gas and water injection since 1995. STB is stock-tank barrels.
because of interbedded siltstones in the levee, but also because of a siltstone-pebble lag or thin siltstone drape along the base of the channel (Dutton et al., 2000). Wells in the same interconnected depositional facies should have good displacement communication.

In the East Ford unit, a major geologic heterogeneity is caused by the 1- to 3-ft-thick (0.3- to 1-m) laminated siltstone (Figure 5) that divides the Ramsey reservoir into the Ramsey 1 and Ramsey 2 sandstones throughout the field. The siltstone represents a pause in sand deposition in the Ramsey interval, when laminated silt and organic matter were deposited over a widespread area. Cross-flow of fluids between the Ramsey 1 and 2 sandstones is limited because of the siltstone. Because CO₂ that is injected only into the Ramsey 2 sandstone interval probably will not penetrate the Ramsey 1 sandstone, both injector and producer wells should be perforated above and below the siltstone.

Another source of heterogeneity in the East Ford unit is variation in reservoir quality between wells. Net/gross maps indicate that channel- and central-lobe deposits are the most homogeneous, consisting mostly of clean, porous sandstone (net/gross sandstone >90%), whereas the levee, overbank, and lobe-margin deposits are more heterogeneous (net/gross sandstone 30–90%). In general, better communication would be expected between wells in the areas of high net/gross sandstone and poorer communication in areas of low net/gross sandstone or between areas of high and low net/gross sandstone.

Finally, 2- to 16-in.-thick (5- to 40-cm) layers of tightly calcite-cemented sandstone also increase reservoir heterogeneity (Figure 8). Well response and geophysical log correlations suggest that some calcite-cemented layers are laterally continuous over a distance of 1000 ft (300 m) and cause vertical compartmentalization in the reservoir.

The East Ford unit appears to be divided into three areas of better interwell communication that correspond to the areas of higher pressure at the north and south ends of the field and the low-pressure area in the middle (Figure 13b). Communication between wells in different areas is restricted. The areas may result from facies changes, subtle structural or bathymetric controls on deposition, or variations in sediment transport direction.

North Part of East Ford Unit
The area of higher pressure at the north end of the unit (Figure 13b) contains three injector wells located along the west side of the area (wells 2, 7, and 14) and seven producers (1, 3, 4, 9, 10, 13, and 17) (Figure 10). In this part of the field, the Ramsey 2 sandstone is the main target (Figure 10b). Orla Petco 1 East Ford Unit has responded well to the flood and is one of the better wells in the field, producing about 26 BOPD in March 2000. Production from Orla Petco 4 East Ford Unit is lower, about 15 BOPD. One possible explanation for the lower production is that a barrier may restrict communication between this producing well and the injector, Orla Petco 2 East Ford Unit. Geologic interpretations suggest the presence of a channel-levee boundary between wells 2 and 4 in the Ramsey 2 sandstone (Figure 10b).

Orla Petco 10 East Ford Unit, which is interpreted to be in the same overbank-splay sandstone as injector Orla Petco 7 East Ford Unit (Figure 10b), is a moderately good well, producing about 19 BOPD in March 2000. Orla Petco 9 East Ford Unit is a poor well, although it is located in the thickest part of the Ramsey 2 sandstone. The presence of a levee between injector well 7 and producer well 9 may explain the poor response of well 9 (Figure 10b).

Locating a new injector in a north-south orientation with the existing producers, following the channel trend, might improve recovery from the thick Ramsey 2 channel sandstones in the north area. Orla Petco 6 East Ford Unit could be converted into an injector to increase the response of Orla Petco 9 East Ford Unit. Both of these wells are in the thickest part of the Ramsey 2 sandstone, in an area of high net/gross sandstone (Figures 7, 10) that is interpreted to be in the channel facies.

Middle Part of East Ford Unit
Ramsey 1 and 2 sandstones are both targets in the center of the unit. The pressure response here has been slow during the CO₂ flood (Figure 13b), suggesting that this area is in poor communication with injectors Orla Petco 14 East Ford Unit (and Orla Petco 17 East Ford Unit before it was converted from an injector to a producer) to the north and Orla Petco 25 East Ford Unit to the south. No injectors are located in this area, and well 19 is the only producer (Figure 13b). Orla Petco 19 East Ford Unit is not responding to injection in Orla Petco 14 East Ford Unit or Orla Petco 25 East Ford Unit; production during March 2000 was only 4 BOPD.

Communication between Orla Petco 25 East Ford Unit and Orla Petco 19 East Ford Unit may be limited in the Ramsey 1 sandstone because the channel apparently makes a large bend to the east in this part of the

Middle Part of East Ford Unit
Ramsey 1 and 2 sandstones are both targets in the center of the unit. The pressure response here has been slow during the CO₂ flood (Figure 13b), suggesting that this area is in poor communication with injectors Orla Petco 14 East Ford Unit (and Orla Petco 17 East Ford Unit before it was converted from an injector to a producer) to the north and Orla Petco 25 East Ford Unit to the south. No injectors are located in this area, and well 19 is the only producer (Figure 13b). Orla Petco 19 East Ford Unit is not responding to injection in Orla Petco 14 East Ford Unit or Orla Petco 25 East Ford Unit; production during March 2000 was only 4 BOPD.

Communication between Orla Petco 25 East Ford Unit and Orla Petco 19 East Ford Unit may be limited in the Ramsey 1 sandstone because the channel apparently makes a large bend to the east in this part of the
field (Figure 10a). The Ramsey 1 sandstone is thinner in Orla Petco 19 East Ford Unit (Figure 6a), net/gross sandstone is lower than in the wells to the north and south (Figure 6b), and the percentage of calcite-cemented sandstone is higher. All these factors may restrict communication between Orla Petco 19 East Ford Unit and Orla Petco 25 East Ford Unit. By adding an injector well to this area, such as Orla Petco 20 East Ford Unit and making Orla Petco 18 East Ford Unit, Orla Petco 21 East Ford Unit, and Orla Petco 22 East Ford Unit producers may improve production from this apparently isolated area.

South Part of East Ford Unit
The south area of the unit is mostly in the lobe facies of the Ramsey 1 sandstone (Figure 10a), but lobe deposits of the Ramsey 2 sandstone (Figure 10b) probably also contribute to production. This area is responding well to the existing north-south line of injectors. Wells Orla Petco 27 East Ford Unit, Orla Petco 28 East Ford Unit, and Orla Petco 31 East Ford Unit are among the best wells in the field. Recovery in this area is interpreted to be good because the injection and production wells are all in a laterally continuous lobe sandstone. Recovery might be improved by bringing on additional producers.

CONCLUSIONS
The Ramsey sandstone interval of the Bell Canyon Formation in East Ford field was characterized using subsurface log and core data, but the interpretation was guided by the depositional model developed from study of well-exposed outcrop analogs in the Bell Canyon Formation. The Ramsey sandstones are interpreted as having been deposited in a basin-floor setting by a system of leveed channels having attached lobes and overbank splays. Individual channel-levee and lobe complexes stack in a compensatory fashion and are separated by laterally continuous, laminated siltstones. Reservoir sandstones consist of (1) broadly lenticular lobe deposits, (2) elongate channel deposits, and (3) irregular splay deposits. The depositional model developed from outcrop can be widely applied by operators to other reservoirs that produce from Bell Canyon sandstones.

Enhanced oil recovery by CO2 flood has increased production from these deep-water sandstone reservoirs. As a result of the CO2 flood, production from the East Ford unit increased from 30 bbl/day at the end of primary production to more than 185 bbl/day in 2001. The unit produced 216,6297 bbl of oil from the start of tertiary recovery through December 2001, and essentially all this production can be attributed to the EOR project.

Geologic heterogeneities appear to influence response to the CO2 flood in the East Ford unit. The most important causes of heterogeneity in the Ramsey sandstone reservoirs are the presence of siltstone beds, variations in net/gross sandstone, and calcite-cemented sandstone layers. All these heterogeneities have the potential to disrupt displacement operations in Delaware sandstone reservoirs by limiting cross-flow of fluids between injector and producer wells. Locating an adequate number of injectors and producers in the same depositional facies, whether channels, splays, or lobes, will maximize the reservoir volume contacted and the production rate and minimize the displacement across restrictive depositional barriers and the time to produce the reservoir. EOR projects undertaken without integrated geologic and engineering reservoir characterization will not realize maximum potential production.

REFERENCES CITED
Barton, M. D., 1997, Facies architecture of submarine channel-levee and lobe sandstones: Permian Bell Canyon Formation, Delaware Mountains, west Texas: University of Texas at Austin, Bureau of Economic Geology Field Trip Guidebook, 40 p.
Berg, R. R., 1979, Reservoir sandstones of the Delaware Mountain Group, southeast New Mexico, in N. M. Sullivan, ed., Guadalupian Delaware Mountain Group of west Texas and southeast New Mexico, Symposium and Field Trip Conference Guidebook: SEPM (Permian Basin Section) Publication 79-18, p. 75–95.
Bouma, A. H., 1996, Initial comparison between fine- and coarse-grained submarine fans and the Brushy Canyon Formation


Ewing, T. E., 1990, Tectonic map of Texas: University of Texas at Austin, Bureau of Economic Geology, scale 1:750,000, 4 sheets.


Lewis, P., S. Cross, and G. Hoose, 1996, Delaware Mountain Group production map, in W. D. DeMis and A. G. Cole, eds., The Brushy Canyon play in outcrop and subsurface: Concepts
and examples: SEPM (Permian Basin Section) Publication 96-38, separate map in back pocket.


