Analysis and modeling of intermediate-scale reservoir heterogeneity based on a fluvial point-bar outcrop analog, Williams Fork Formation, Piceance Basin, Colorado

Matthew J. Pranter, Amanda I. Ellison, Rex D. Cole, and Penny E. Patterson

ABSTRACT

This study presents results of outcrop characterization and modeling of lithologic heterogeneity within a well-exposed point bar of the Williams Fork Formation in Coal Canyon, Piceance Basin, Colorado. This deposit represents an intermediate-scale depositional element that developed from a single meandering channel within a low net-to-gross ratio fluvial system. Williams Fork outcrops are analogs to petroleum reservoirs in the Piceance Basin and elsewhere. Analysis and modeling of the point bar involved outcrop measurements and ground-based high-resolution light detection and ranging data; thus, the stratigraphic frameworks accurately represent the channel-fill architecture.

Two- and three-dimensional (2-D and 3-D) outcrop models and streamline simulations compare scenarios based on different lithologies, shale drapes, observed grain-size trends, petrophysical properties, and modeling methods. For 2-D models, continuous and discontinuous shale drapes on lateral-accretion surfaces result in a 79% increase and 24% decrease in breakthrough time (BTT), respectively, compared to models without shale drapes. The discontinuous shale drapes in the 2-D and 3-D models cause a 30% and 107% decrease, respectively, in sweep efficiency because they focus fluid flow downward to the base of the point bar. For similar reasons, 2-D models based on grain size exhibit 67–267% shorter BTT and 44–57% lower sweep efficiency compared to other model scenarios. Unlike the 2-D models, the continuous shale drapes in the 3-D...
models cause the fluid front to spread out and contact more of the reservoir, resulting in 42–53% longer BTT and 41–52% higher sweep efficiency compared to the other models. These results provide additional insight into the significance of intermediate-scale heterogeneity of fluvial reservoirs.

INTRODUCTION

Characterization and modeling of fluvial reservoirs are challenging because of the various scales of heterogeneity that exist between and within fluvial deposits (Jackson, 1977; Miall, 1988; Willis, 1989; Sharp et al., 2003). Field-scale heterogeneity (e.g., heterogeneity levels 1 and 2 of Jordan and Pryor, 1992) of a fluvial reservoir is dependent on the hierarchy of architectural elements, sand body stacking patterns, and associated connectivity between reservoir sand bodies (Robinson and McCabe, 1997; Anderson, 2005). Intermediate-scale heterogeneity within individual fluvial sand bodies (e.g., heterogeneity levels 3 and 4 of Jordan and Pryor, 1992) also affects reservoir performance and is generally associated with facies distribution, grain size and sorting, and lithology variation (Richardson et al., 1978; Lasseter et al., 1986; Thomas et al., 1987; Tyler and Finley, 1991; Hartkamp-Bakker and Donselaar, 1993; Willis and White, 2000). The large-scale stratigraphic architecture and intermediate-scale internal heterolithic stratification of fluvial reservoirs are commonly difficult to characterize with subsurface data because of the relatively limited lateral extent of fluvial deposits, which are commonly less than the typical well spacing in developed fields (e.g., 10–40-ac [201–402-m; 660–1320-ft] spacing). In the case of isolated point-bar reservoirs of low net-to-gross (low sandstone-to-shale) ratio systems, common internal depositional features are lateral-accretion units and associated bedding that create intermediate-scale variability. These depositional units and associated shale drapes can influence reservoir behavior (Swanson, 1993) because they are potential baffles and barriers to fluid flow (Richardson et al., 1978; Hartkamp-Bakker and Donselaar, 1993). In addition, internal facies variations, such as the vertical change from trough cross-bedded to ripple-laminated sandstone, produce a fining-upward trend in grain size and a corresponding decrease in porosity and permeability.

To address these issues, outcrop analogs of well-exposed fluvial deposits of the Williams Fork Formation were evaluated and modeled. The outcrops are located in Coal Canyon near Palisade, Colorado, and are approximately 48 km (30 mi) southwest of natural-gas fields in the southern Piceance Basin that produce from the Williams Fork Formation (Figures 1, 2). In addition to its display of large-scale sand body heterogeneity (i.e., connectivity between sand bodies at a field scale), Coal Canyon is an excellent location to study intermediate-scale sand body heterogeneity (i.e., within a fluvial sand body) because vegetation is minimal, rocks are well exposed, structural complications are minimal (structural dips are generally <7°), and access is good.
Detailed two- and three-dimensional (2-D and 3-D) outcrop models of a well-exposed point-bar deposit (single reservoir element or sand body) in the lower Williams Fork Formation (Campanian) of the Mesaverde Group of western Colorado were constructed using high-resolution ground-based light detection and ranging (LIDAR) data (digital laser images), photomosaics, and field measurements. The point bar of this study is exposed through three primary outcrops that provide cross sectional views of the deposit in both depositional-dip and depositional-strike orientations. Several depositional scenarios and modeling methods are used to model lithology and petrophysical properties and evaluate the relative effects of internal heterogeneities on fluid-flow behavior. Although fluvial reservoirs are diverse and unique, there are common characteristics that link them, such as the origin of the depositional system and the general geometry of the reservoir bodies (Schumm, 1963; Miall, 1996). Therefore, we believe that the results of this study are applicable to a variety of point-bar reservoirs.

**GEOLOGIC AND STRATIGRAPHIC SETTING**

The Piceance Basin is an elongate northwest-southeast-trending downwarp created during the Laramide orogeny (Late Cretaceous–early Paleogene). During the Late Cretaceous, the Piceance Basin area was situated on the western foreland margin of the Western Interior seaway, which extended from the Gulf of Mexico to the
Arctic. During this time, sediment that formed the Williams Fork Formation was shed from the Sevier orogenic belt in Arizona, Utah, and Wyoming, transported eastward by fluvial depositional systems, and ultimately deposited in shoreline environments that bounded the epeiric seaway (see summaries in Johnson, 1989; Tyler et al., 1996; Johnson and Flores, 2003; Cole and Cumella, 2005).

In this article, we follow the stratigraphic terminology of Hettinger and Kirschbaum (2002, 2003) for the Mesaverde Group in the southwestern Piceance Basin (Figure 3). The middle to upper Campanian Williams Fork Formation of the Mesaverde Group conformably overlies the Iles Formation and is overlain disconformably by the Paleocene Wasatch Formation. The Williams Fork Formation thins from approximately 1525 m (5003 ft) on the eastern side of the Piceance Basin to about 370 m (1213 ft) at the Colorado–Utah border (Hettinger and Kirschbaum, 2002, 2003). In the southwestern Piceance Basin, the Williams Fork is subdivided...
into two intervals based on lithofacies. The lower 150–200 m (492–656 ft) of the Williams Fork Formation consists mostly of mudrock (approximately 40–70%), with subordinate lenticular channel-form sandstone and coal, whereas the upper 250–300 m (820–984 ft) is mostly sandstone (50–80%), with subordinate mudrock and almost no coal. The upper sand-rich interval was deposited in an alluvial-plain setting, and the lower sand-poor interval of the Williams Fork Formation was deposited in a coastal-plain setting with meandering streams, swamps, and flood plains (Cole and Cumella, 2005). The sand-poor deposits include relatively isolated but internally heterolithic sandstones (e.g., isolated point-bar sand bodies) encased in flood-plain mudstones and coals. Connectivity between the point-bar sand bodies is generally low; however, connectivity is greater in the sand-rich intervals (high net-to-gross ratio), where amalgamated sand bodies are more common.

A composite section (Cole and Cumella, 2005) of the lower 600 ft (182 m) of the Williams Fork Formation in Coal Canyon is illustrated in Figure 4. The Cameo-Wheeler coal zone (Figures 3, 4) at the base of the Williams Fork Formation is about 73 m (240 ft) thick in Coal Canyon and consists of interstratified coal, carbonaceous to very carbonaceous mudrock, ironstone (siderite) concretions, sandstone, and mud-chip conglomerate (rare). Four locally mappable coal seams occur in this zone: Cameo, Highwall, Ash, and Upper (Cole and Cumella, 2005). The point-bar sand body of this investigation is located near the middle of the Cameo-Wheeler interval between the Ash and Upper coal seams (Figure 4). The focus of this study is on the intermediate-scale internal lithologic heterogeneity within this single fluvial point-bar sand body (analogous to a single isolated reservoir element).

**POINT-BAR SEDIMENTOLOGY**

Detailed sedimentologic observations and measurements were collected from three outcrops of a single point-bar and associated deposits within Coal Canyon (Figures 2, 5). Six main lithofacies based on thirteen stratigraphic sections include trough cross-bedded sandstone, current-rippled sandstone, nodular siltstone, laminated siltstone, conglomeratic mud-chip sandstone, and coal and bentonite beds (Figure 6; Table 1). The point-bar deposit exhibits a fining-upward succession of facies from medium-
Figure 4. Comparison of a composite section in Coal Canyon with the Dyco Petroleum 1 Sommerville well (data are modified from Hettinger and Kirschbaum, 2002, 2003; see Figure 1 for the well location). The correlation line at the top of the composite section is based on thickness equivalence. Data for the composite section are based on measured sections of Cole and Cumella (2003). The study interval for the point-bar sand body of this investigation is shown on the composite log.
upper fine-grained trough cross-beds to fine-grained ripple-laminated sandstone. The succession is attributed to a gradual decrease in flow velocity during deposition. Based on lateral-accretion bedding, the long dimension and paleoflow direction of the main point-bar sand body is oriented to the southeast (azimuth of $\sim$94–102°) (Cole and Cumella, 2003; Ellison, 2004). In some sections, the main sand body is dominated by channel-form sets of trough cross-stratification, whereas in other sections, it is nearly all ripple stratified or mainly massive. Scour surfaces with mud-chip lags are locally common. For reference, in previous work (Cole et al., 2002; Cole and Cumella, 2003; Ellison, 2004), this sand body was informally named the “6-50” sand body.

The main point-bar sand body (Figures 5, 7) partially overlies an older point-bar deposit and is overlain by a thin mudstone interval (abandonment shale) and a fine-grained, ripple-laminated sandstone (thin levee or crevasse-splay sand body) (Cole et al., 2002; Cole and Cumella, 2003; Ellison, 2004) (Figure 7). The crevasse-splay deposit has a sheetlike geometry with a sharp planar base, ranges in thickness from 1.5 to 3 m (5 to 10 ft), and lacks large-scale internal bedding. The main point-bar deposit is a lens-shaped body with a sharp base and has an average thickness of 8.0 m (26 ft). The two amalgamated point-bar sand bodies are separated by an erosional surface. Distinct high-angle, lateral-accretion surfaces and lateral-accretion sandstone beds within the point-bar deposits have average dips between 10 and 12°. The accretion surfaces dip to the south in the younger (main) point bar and to the north in the older point bar, indicating that they accreted in opposite directions. The sandstone beds are separated by lateral-accretion surfaces and mudrock interbeds and are typically cross-stratified.
Figure 6. Major fluvial facies of the Williams Fork Formation. (A) Trough cross-bedded sandstone, (B) current-rippled sandstone, (C) nodular siltstone, (D) laminated siltstone, (E) conglomeratic mud-chip sandstone, and (F) coal (c) and bentonite (b) beds. See Table 1 for more detailed facies descriptions.
Table 1. Fluvial Facies Recognized in the Coal Canyon Outcrops and Their Characteristics

<table>
<thead>
<tr>
<th>Facies</th>
<th>Lithology</th>
<th>Modal Grain Size</th>
<th>Grain Shape and Sorting</th>
<th>Dominant Features</th>
<th>Depositional Process</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trough cross-bedded sandstone</td>
<td>Lithic sandstone</td>
<td>Lower medium to upper fine</td>
<td>Subangular to subrounded; moderately sorted</td>
<td>Trough cross-bedding, also planar cross-bedding, soft sediment defined, scoured surfaces</td>
<td>Unidirectional tractive flow deposit, dune height indicates water depths between 1.2 and 3 m (3.9 and 10 ft)</td>
</tr>
<tr>
<td>Current rippled sandstone</td>
<td>Lithic sandstone</td>
<td>Upper to lower fine</td>
<td>Subrounded; moderately sorted</td>
<td>Current ripple laminations, climbing ripples</td>
<td>Tractive flow deposit; climbing ripples indicate fluctuations in aggradation rate; mud drapes indicate periods of little to no ripple migration</td>
</tr>
<tr>
<td>Nodular sandstone</td>
<td>Mudstone</td>
<td>Silt dominated</td>
<td>NA*</td>
<td>Nodular texture, siderite concretions, rooting</td>
<td>Vertical accretion; suspension fallout and pedogenesis</td>
</tr>
<tr>
<td>Laminated siltstone</td>
<td>Mudstone</td>
<td>Silt rich</td>
<td>NA</td>
<td>Millimeter-scale laminations, bioturbation, rooting</td>
<td>Vertical accretion; suspension fallout and pedogenesis</td>
</tr>
<tr>
<td>Conglomeratic mud-chip sandstone</td>
<td>Conglomeratic lithic sandstone</td>
<td>Upper to lower medium NA</td>
<td>Subangular; poorly sorted</td>
<td>Mud-chip lag, woody plant debris, scoured surfaces</td>
<td>Scour and fill generated by flow separation indicates disequilibrium in flow conditions</td>
</tr>
<tr>
<td>Coal and bentonite</td>
<td>Coal and bentonite</td>
<td>NA</td>
<td>NA</td>
<td>Regularly spaced cleats in coal (2–7 cm; 0.8–2.75 in.)</td>
<td>Vertical accretion processes such as suspension fallout; continuity of coals indicates low channel activity</td>
</tr>
</tbody>
</table>

*NA = not applicable.
The lithologies present along the accretion surfaces vary laterally. Updip, thin mudstones are common along the accretion surfaces and change downdip to silty sandstones with siderite concretions. The upper bounding surface of the point-bar deposit is sharp and planar, with little to no relief.

Figure 7. Key fluvial architectural elements exposed in the northwest outcrop. The main point bar is a lens-shaped sand body defined by sharp basal-scour and top-truncated surfaces. The main point bar is separated from an older point bar by an erosional surface. Both point bars have well-defined lateral-accretion surfaces. The overlying levee-splay has a sheetlike geometry with a sharp base. A cross section based on the measured sections, photomosaic, and outcrop data of the fluvial deposits is shown in the lower panel. The depth scales on the measured sections are in feet.
POINT-BAR (RESERVOIR) DIMENSIONS

Outcrop analogs are commonly used to obtain dimensional statistics of fluvial sandstone or shale bodies for 3-D modeling of similar petroleum reservoirs. In most cases, outcrops provide 2-D data (e.g., thickness and/or widths) for sandstone and shale bodies. Therefore, the plan-view geometry of the body must be inferred from modern analogs, or the dimensions and morphology of the paleochannel can be reconstructed or estimated from empirical data and relationships that are commonly based on modern systems (Ethridge and Schumm, 1977; Bridge and Mackey, 1993a, b). For 3-D modeling purposes (to be discussed), the plan-view dimensions and morphology of the point-bar sand body were estimated using empirical data and spatial relationships.

Bankfull Channel Depth and Width

The maximum lateral extent of a point-bar sand body or reservoir element relates to the meander-belt width (meander amplitude) and meander wavelength, both of which can be estimated from channel size (Collinson, 1978). Previously developed empirical relationships based on modern streams relate channel width, channel depth, meander-belt width, and meander wavelength (e.g., Leopold and Wolman, 1960; Carlston, 1965; Schumm, 1972; Leeder, 1973; Ethridge and Schumm, 1977; Collinson, 1978; Lorenz et al., 1985). These empirical relationships and measurements of the main point-bar deposit in outcrop were used to estimate the paleochannel size (bankfull channel depth and width). Because the subject point bar represents a relatively isolated and complete deposit, potential sources of error associated with amalgamation and truncation are limited.

Bankfull channel depth and width are defined as the maximum depth and width that a stream channel can attain before the discharge of floodwater into areas outside of the channel (Leeder, 1973). Bankfull channel depth (D) is estimated from the average thickness of the sand body (D*) and corrected for the curvature of the meander bend and compaction (Figure 8). Because bankfull channel depth in straight reaches of a channel is less than in the meander bends, a correction factor is applied to values of point-bar thickness from outcrop or core. Based on experimental studies (Ethridge and Schumm, 1977), an average value of 0.585 for the ratio between bankfull channel depth in a straight reach versus a meander bend of a channel is used. Ethridge and Schumm (1977) suggest that a 10% reduction in thickness for the conversion of sand to sandstone as a result of compaction is conservative. Therefore, the point-bar thickness is also divided by 0.9 to convert sand body thickness measurements to original bankfull channel depth:

\[ D = D^* \times 0.585 / 0.9 \]

The average thickness (D*) of the main point bar studied herein (Figure 5) is approximately 8.0 m (26 ft), which yields a bankfull channel depth of 5.2 m (17 ft).

As an approximation, Allen (1965) showed that point bars commonly extend two-thirds of the distance across a channel (or two-thirds of the bankfull channel width). Based on this, bankfull channel width (W) is estimated by measuring the average horizontal width of the lateral-accretion surfaces as exposed in outcrop (W*) (Figure 8) such that

\[ W = W^* \times 1.5 \]

For the well-exposed outcrops of this study, the horizontal widths of lateral accretion surfaces can be measured. The average horizontal width of an accretion surface (W*) in the main point-bar sand body is 29.6 m (97 ft), which yields a bankfull channel width of 44.4 m (146 ft).

For comparison, in high-sinuosity rivers (i.e., sinuosity > 1.7), Leeder (1973) presents an empirical relationship between bankfull channel depth and width that can be used in situations where the outcrop exposure is not adequate to measure lateral-accretion surfaces. In this situation, the following empirical equation is used, with an estimate of bankfull channel depth as

\[ W = 6.8 \times D^{1.54} \]

Based on this relationship and using the corrected bankfull channel depth from outcrop (5.2 m; 17 ft), the estimated bankfull channel width is 86.1 m (283 ft). A range in the estimated bankfull channel width estimates (44.4–86.1 m; 146–283 ft) is not uncommon and is expected given the different sources of data for the empirical relationships and the resulting estimates.

Meander Amplitude and Wavelength: Reservoir Lateral Dimensions

The lateral dimension of the point-bar reservoir perpendicular to the paleoflow direction (reservoir width) approximately corresponds to the meander-belt width (meander amplitude) of the channel that deposited the main point bar (Collinson, 1978; Lorenz et al., 1985). The meander-belt width is estimated to be 300 m (980 ft),
based on the lateral extent of the point-bar sandstone in outcrop (i.e., based on the observed sandstone body pinch-out). The lateral dimension of the point-bar reservoir parallel to the paleoflow direction (reservoir length) relates to the meander wavelength (Collinson, 1978) of a channel. The meander wavelength cannot be directly measured from outcrop as with the meander-belt width. The meander wavelength ($\lambda_m$) was thus calculated using empirical relationships to estimate the lateral dimension of the point-bar reservoir parallel to the paleoflow direction. Meander wavelength (Figure 8) is estimated using the methods of Leopold and Wolman (1960) and Schumm (1972), which relate meander wavelength to bankfull channel width ($W$) and bankfull channel width-to-depth ratio ($F = W/D$). The following empirical relationships were used to estimate meander wavelength:

$$\lambda_m = 10.9 \ W^{1.01} \text{ (units = m)}$$

(Leopold and Wolman, 1960) or

$$\lambda_m = 18(F^{0.53}W^{0.69}) \ (F = W/D; \text{ units = m})$$

(Schumm, 1972)

Using the estimate of bankfull channel depth ($D = 5.2 \text{ m [17 ft]}$) and bankfull channel width ($W = 86.1 \text{ m [283 ft]}$) based on the relationships of Leeder (1973), the above equations yield meander wavelengths for the main point-bar deposit of 982 and 1725 m (3222 and 5660 ft). Meander wavelength estimates based on the lower value of bankfull channel width ($W = 44.4 \text{ m [146 ft]}$) yield wavelengths of 503 and 768 m (1650 and 2520 ft). Fluvial systems are complex, and point-bar sand body dimensions parallel to the paleoflow direction exhibit a range of values relative to the meander wavelength (e.g., Collinson, 1978). For simplicity and given the relatively high sinuosity of the channels of the lower Williams Fork Formation (sinuosity = 1.7–1.9; Ellison, 2004), the average of meander wavelength estimates was used herein. Given the relatively narrow range of the lowest three meander wavelength estimates, an average value of 750 m (2460 ft) for the meander wavelength was subsequently used as the lateral dimension of the point-bar reservoir (reservoir length parallel to the paleoflow direction) for 3-D outcrop modeling. The actual point-bar lateral dimension is not exactly 750 m (2460 ft) (this is an estimate); however, based on
how the 3-D reservoir models were constructed (dis-
cussed below), the overall impact of the model size is
less important than the degree of internal heterogeneity
that is modeled.

OUTCROP RESERVOIR MODELING

High-resolution geologic modeling of outcrops is use-
ful to identify the types and scales of lithologic and petro-
physical heterogeneity that affect fluid-flow behavior
and rock and pore-volume estimates (Joseph et al., 2000;
Sullivan et al., 2000; Willis and White, 2000; Dalrymple,
2001; Stephen et al., 2001). There have been numerous
studies and methods that explore geologic modeling of
various scales of heterogeneities within fluvial reser-
voirs, including process-based (Allen, 1978; Leeder,
1979; Bridge and Mackey, 1993a; Mackey and Bridge, 1995),
stochastic (Hirst et al., 1993; MacDonald and Halland, 1993; Tyler et al., 1994; Jones et al., 1995; Eschard et al., 1998; MacDonald et al., 1998; Dalrymple, 2001), deterministic (Stephen and Dal-
rymple, 2003), and combination stochastic-deterministic
models (Novakovic et al., 2002; Patterson et al., 2002).
Many of these studies investigate stratigraphic architec-
ture (i.e., sand or shale body dimensions and distribu-
tion) and reservoir connectivity on a field scale (e.g.,
Richardson et al., 1978; Robinson and McCabe, 1997).
Others address the potential effect of internal shale or
sand body heterogeneity (lithological or petrophysical)
on fluid flow (e.g., Weber, 1982; Hartkamp-Bakker and
Donselaar, 1993).

Two- and three-dimensional modeling of the main
point-bar deposit in Coal Canyon (Figure 5) was con-
ducted to quantify and evaluate intermediate-scale lith-
ological and petrophysical heterogeneity within the
fluvial point-bar deposit using deterministic and sto-
castic techniques. Sedimentologic data collected from
outcrop were used to build deterministic lithology and
grain-size models, which served as constraints for petro-
physical modeling. Four methods of modeling petro-
physical properties were investigated (two deterministic
and two stochastic). Porosity and permeability models
were used to calculate rock and pore volumes and con-
duct single-phase streamline flow simulations. The
streamline simulations compare the relative effects of
lithology, grain size, and petrophysical heterogeneity
on breakthrough time (BTT), reservoir volume swept
at BTT, and sweep efficiency. For this study, the reser-
voir volume swept at BTT and sweep efficiency refer to
the reservoir area (or volume for 3-D models) and per-
centage of the total reservoir area (or volume), respec-
tively, that are contacted by injected water as determined
at the time of first water breakthrough in the producing
well of the model.

2-D and 3-D Stratigraphic Frameworks

The 2-D and 3-D outcrop model frameworks were
defined and built using high-resolution LIDAR data
(Figure 9), detailed (centimeter-scale) measured sec-
sections (Figure 7), and interpretations of the outcrops in
Coal Canyon. LIDAR uses a low-energy laser and sen-
sitive receiver to acquire detailed digital-elevation mod-
els of the outcrop (Jennette et al., 2003). Light-ranging
and light-intensity data are combined to generate 3-D
doutcrop images with near-zero spatial distortion and
centimeter-scale vertical and meter-scale horizontal res-
olution. In this study, LIDAR data were used to interpret
key stratigraphic surfaces and constrain the 2-D and 3-D out-
crop models and for 3-D visualization of the outcrops.

For the 2-D models, the outcrop framework is based
on the northwest exposure of the point-bar deposit. The
model framework was built using an xy-regular grid format that maintained a constant cell width and length.
The model is divided into 13 distinct zones to reflect
the stratigraphic architecture of the point-bar deposit
(Figure 10). Each zone is further subdivided using fine-
scale layering to represent the stratigraphic patterns of
the accretionary bedding observed in outcrop. Cell layering
was truncated at the top of each architectural element
(i.e., zone). Cell dimensions of 1.13 × 1.5 m (3.7 × 4.9 ft)
with a thickness 5 cm (2 in.) were used to capture the
observed lateral and vertical heterogeneity. As a result,
the 2-D outcrop model framework consists of 75,900
model cells.

Because 2-D geologic modeling and flow simulation
can commonly be overly pessimistic in predicting reser-
voir behavior and performance (Li and White, 2003),
3-D models of the point-bar deposit were also constructed
that represent similar scenarios of stratigraphic and
petrophysical heterogeneity as in the 2-D models. The
3-D point-bar model framework consists of surfaces that
represent the top and base of the point bar and internal
lateral-accretion surfaces constrained to observations and
data from all three outcrops and their respective LIDAR
data. For the general 3-D point-bar shape, data on mod-
er and exhumed ancient point bars were used (Puigde-
fabregas, 1973; Jackson, 1976; Nanson, 1980; Edwards
et al., 1983). The point bar was modeled assuming the
entire point-bar sand body was preserved (Figure 11)
Figure 9. Paired ground-based LIDAR (upper) and photomosaic (lower) images of the (A) southwest, (B) northwest, and (C) east outcrops within the Coal Canyon study area.
and with lateral dimensions discussed above (300 × 750 m; 980 × 2460 ft). Surface topography of the point bar was based on published experimental data (Willis, 1989) that show that the maximum variation in point-bar topography and the thickest part of the deposit occur at the bend apex. The geometry and character of the lateral-accretion surfaces were interpreted from the LIDAR data and represent what is observed in outcrop.

An xy-regular (constant cell width and length) 3-D model grid with 810,000 cells was built with 100 rows, 100 columns, and 81 layers. Cell dimensions are 7.8 × 4.1 m (25.6 × 13.5 ft) aerially. Nine zones were generated using the defined stratigraphic surfaces. Those zones that define shale drapes on lateral-accretion surfaces have cells that are only 5 cm (2 in.) thick, so that the thickness of the shale as observed in outcrop is accurately represented. All other zones have cell thicknesses of 0.5 m (20 in.). All zones within the model were top truncated to represent the erosional character of the upper part of the accretionary units.

Figure 10. Two-dimensional stratigraphic framework of the point bar exposed in the northwest outcrop. Thirteen subgrids or zones, each indicated by different gray shading, subdivide the point-bar reservoir. Those zones are further subdivided into thin layers that are each 5 cm (2 in.) thick. Each 5-cm (2-in.) layer is divided into 1.5 × 1.13-m (4.9 × 3.7 ft) cells.

Figure 11. Perspective view of the LIDAR outcrop elevation model (contoured surfaces) and the 3-D point-bar model (3-D grid) relative to the LIDAR data. The view is looking northward. Cell dimensions are 7.8 × 4.1 m (25.6 × 13.5 ft) with variable thickness. Contour interval is 2.5 m (8.2 ft).
Lithology and Grain-Size Models

Using the 2-D and 3-D modeling frameworks, three different lithology models were constructed of the northwest outcrop for 2-D modeling (Figure 12A–C), and three lithology models of the entire point bar were generated for 3-D modeling. Deterministic methods were used to model the distribution of sandstone and shale by simply assigning values of lithology to the layers or zones of the corresponding stratigraphic framework. The different 2-D and 3-D lithology models thus represent the internal heterogeneity of the point-bar deposit of this study as well as other point-bar deposits observed within Coal Canyon. The surrounding units (i.e., crevasse splay and flood-plain mudstones) were modeled as homogeneous sandstone or shale layers.

The most simplistic lithology scenario (lithology model 1; Figure 12A) consists of 100% sandstone within the point bar. This scenario assumes that there is no internal lithologic variability within the point bar. Shale drapes on lateral-accretion surfaces represent the most significant stratigraphic features that could act as flow baffles or barriers. The other lithology scenarios and corresponding models were built using either continuous shale drapes on lateral-accretion surfaces that could potentially compartmentalize the reservoir into separate hydraulic flow units (lithology model 2; Figure 12B) or discontinuous shale drapes that could create tortuous paths for fluid movement (lithology model 3; Figure 12C). For scenario 3, the drapes are restricted to the topographically higher parts of the accretion surfaces, and sand-on-sand contacts exist near the toe of the accretion surfaces. Lithology scenario 3 is the closest approximation of the actual lithologies or bounding layers present in the point-bar deposit of this study (Figures 5B, 7); however, the other scenarios have been observed in other point-bar deposits within Coal Canyon.

Because grain size has a significant control on petrophysical properties (Beard and Weyl, 1973), the grain-size distribution within the point-bar deposit was also modeled as an additional scenario for comparison to lithology model scenarios. The measured sections show two scales of fining upward in grain size: the first at the scale of the overall point-bar deposit and the second within each lateral-accretion unit. These trends were modeled (Figures 7, 12D) using linear interpolation and assuming isotropic conditions. In general, variability in grain size within the point-bar models correlates to facies transitions observed in outcrop. The grain-size models most likely provide more realistic distributions of internal heterogeneity when compared to the previously described lithology models because grain size is commonly inherently linked to petrophysical properties.

Petrophysical Models

Deterministic and stochastic methods were used to model porosity and permeability using the lithology and grain-size models as constraints. These common modeling methods were used to produce different levels of detail (different petrophysical scenarios). Four methods were used to distribute petrophysical properties for the 2-D models: (1) uniform distribution (deterministic), (2) stochastic simulation, (3) stochastic simulation with an imposed vertical trend, and (4) a method related to grain size (deterministic). For the 3-D porosity and permeability models of the entire point-bar deposit, the properties were modeled using (1) uniform distribution, (2) stochastic simulation, and (3) a method related to grain size.

Porosity Modeling

Average porosity for productive sandstone reservoirs within the Williams Fork Formation ranges from 6 to 12% (Cumella and Ostby, 2003). This porosity range for sandstone was honored in the porosity models except for the cases based on a uniform distribution in which sandstone porosity was set to 9% (the median value of productive sandstones within the Williams Fork Formation). Because of its negligible effective pore volume (nonreservoir rock) compared to the sandstone, shale was assigned porosity values that ranged from 0.1 to 1%.

The algorithm used to generate the stochastic porosity models is a fast Fourier transform, which performs the convolution of a white noise field with a filter to create the correct correlation structure (Ripley, 1987). The procedure involves unconditional simulation of the spatial variable (e.g., porosity or permeability) and then performs kriging on the unconditional simulated field (Ripley, 1987). For the porosity models generated using stochastic simulation with an imposed vertical trend, a linear function in stratigraphic depth was used to impose a decreasing-upward porosity trend within the point-bar model.

In the absence of porosity data linked to grain size for the Williams Fork Formation outcrops of this study, a basic linear transform was used to relate measured sandstone grain size from outcrop to average porosity.
of productive sandstone reservoirs within the Williams Fork Formation:

\[ \phi = 0.4167 \times \text{grain size in millimeters} - 0.0037 \]

where \( \phi \) is porosity expressed as a fraction. This function was used to convert the grain-size models to porosity.

Detailed lateral sampling of the outcrop (e.g., foot-to-foot samples) to obtain petrophysical measurements was not conducted because of limited accessibility of the outcrop and for safety reasons. Nonetheless, this type of information is essential to quantify lateral variability of properties at the scale of interest and is an important input to reservoir modeling. Based on information from the measured sections and field samples, accordingly, the lateral correlation length or range for porosity was estimated to be 20 m (66 ft). This length corresponds to approximately one-fourth of the horizontal dimension of the dominant lateral-accretion bedding of the point-bar deposit (perpendicular to the paleoflow direction). This lateral range was consistently used with a spherical function and zero nugget effect in all stochastic petrophysical modeling. The vertical correlation length is generally a fraction of the lateral or
horizontal correlation length in most sedimentary formations. Based on measured-section data, a vertical correlation length of 1 m (3.3 ft) was consistently used in all stochastic petrophysical modeling.

Ten 2-D porosity models were generated based on the four petrophysical distributions and conditioned to the three lithology models and the grain-size model (Figure 13). Three 2-D porosity models with a uniform distribution are designated 2D-LM1-U, 2D-LM2-U, and 2D-LM3-U (2D = two-dimensional; LM = lithology model number; U = uniform distribution) and are constrained to lithology models 1 to 3 (2D-LM1, 2D-LM2, and 2D-LM3; Figure 12), respectively. These models represent the simplest spatial distribution of porosity of all model scenarios that were evaluated. Three 2-D porosity models based on stochastic simulation are designated as 2D-LM1-S, 2D-LM2-S, and 2D-LM3-S (where model 2D-LM1-S is constrained to lithology model 1 and so forth, and S = stochastic). These models, in comparison to the other three scenarios, have the most random distribution of porosity. Three 2-D porosity models based on stochastic simulation with a decreasing-upward porosity trend are designated as 2D-LM1-ST, 2D-LM2-ST, and 2D-LM3-ST (where model 2D-LM1-ST is constrained to lithology model 1 and so forth, and ST = stochastic simulation with a trend). The decreasing-upward trend in porosity follows the grid-cell layering, causing the stratigraphically lower parts of the point bar to have the highest porosities. The 2-D grain-size model was transformed to create a porosity model based on grain size as discussed previously (2D-GS-TR; GS = grain size and TR = transform; Figure 13D). In general, the models based on stochastic simulation with a linear trend have the highest average values of porosity, and the lowest average porosity is associated with the grain-size model.

Similarly, seven 3-D porosity models were generated: three based on a uniform distribution (3D-LM1-U, 3D-LM2-U, 3D-LM3-U), three based on stochastic simulation (3D-LM1-S, 3D-LM2-S, 3D-LM3-S), and one based on grain size (3D-GS-TR).

Permeability Modeling
This study addresses intermediate-scale fluvial reservoir heterogeneity based on the Williams Fork Formation because its stratigraphic architecture and internal lithologic heterogeneity is characteristic of fluvial reservoirs in various basins and settings. However, the Williams Fork Formation produces mainly from fracture-related permeability in the subsurface caused by the very low matrix permeability, which is on the order of 0.1–2 µd (Cumella and Ostby, 2003). The permeability values of Williams Fork Formation reservoirs are therefore unique because they are associated with tight-gas sandstone reservoirs. In addition, outcrop-based permeability values for the Williams Fork Formation are also anomalous because they are affected by different burial histories compared to equivalent subsurface reservoirs and by meteoric diagenesis (German, 2006). Because the focus of this study is not the petrophysical properties of tight-gas reservoirs, to make the outcrop modeling results useful and applicable to more conventional fluvial reservoirs and to efficiently run single-phase streamline flow simulations using the lithology and petrophysical modeling results, permeability data from a conventional (non–tight-gas sandstone) fluvial reservoir analog were used to model permeability. Permeability data from a Middle Jurassic fluvial reservoir of the Brent Group (Ness Formation) in the northern North Sea were used. Similar to the Williams Fork Formation, the Ness Formation was deposited as a complex of coastal sediments, including isolated, fining-upward fluvial channels, coal seams, and lagoonal mudstones (Richards, 1992). These permeability data are used because they are characteristic and representative of many conventional fluvial reservoirs. Core plugs from productive sandstones and shales of the Brent Group were analyzed for porosity and permeability by Stiles and Hutfilz (1992) and later compiled by Nelson and Kibler (2003). Based on these data (Figure 14), the following transforms were used to convert porosity (φ) to permeability (κ) for the 2-D and 3-D models:

\[ \kappa = 10.811 \ e^{0.3199\phi} \] (for sandstone)

\[ \kappa = 0.05 \ e^{0.3199\phi} \] (for shale)

From the single porosity model based on grain size, three different permeability models were produced with values that correspond to the distributions of shale drapes as in the three lithology models (i.e., without shale drapes and continuous and discontinuous shale drapes).

Streamline Simulations
To assess the relative effect of lithologic and petrophysical heterogeneity on fluid flow within the point-bar reservoir, single-phase streamline simulations were conducted using the 2-D and 3-D outcrop models. Explanations of the streamline simulation methods that were used are provided by Pollock (1988), Datta-Gupta

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and King (1995), and Ponting (1998). In general, a streamline approximates the trajectory of a moving fluid particle through the reservoir (Pollock, 1988). All 2-D streamline simulations involved an injection well on the south (left) side of the model and producing well on the north (right) side. Both wells penetrated the entire thickness of the model; however, only the main point-bar sandstone was open to flow in the injection and production wells. Twelve 2-D streamline simulations were run using the porosity and permeability models conditioned by the different lithology models. The simulations were compared in regard to BTT, pore volume swept at BTT, and sweep efficiency (Figures 15, 16).

The results of the 2-D flow-simulation runs and analysis of variance statistical tests that compare BTT, pore volume swept at BTT, and sweep efficiency reveal that lithologic heterogeneity has a greater effect on recovery efficiency than petrophysical heterogeneities (disregarding the 2-D grain-size–based model, which is discussed below). As an example, for the models based on stochastic simulation, the continuous (2D-LM2-S)
and discontinuous (2D-LM3-S) shale drapes on lateral-accretion surfaces within the point bar cause a 79.3% increase and 24.1% decrease in BTT, respectively, compared to the models without shale drapes (Figure 15A). However, for the continuous-shale-drape model (2D-LM2-S), only a 5.5 and 2.9% decrease is observed in the pore volume swept at BTT and sweep efficiency, respectively, compared to the models without shale drapes (Figure 15B, C). For the discontinuous-shale-drape model (2D-LM3-S), a 31.7 and 30.3% decrease in the pore volume swept at BTT and sweep efficiency, respectively, is observed (Figure 15B, C). The continuous shales act as baffles to flow, causing an increase in BTT compared to the homogeneous case. Because these baffles are continuous, no preferential paths of fluid flow are established (Figure 16A, B). Although the BTT values are different between models based on lithology models 1 and 2, the sweep efficiency values are greater than 80% (Figure 15A, C). The discontinuous shales act mainly as permeability baffles where they are present and force the flow downward toward the base of the point bar where shale drapes are not present, thus reducing both the BTT and sweep efficiency as compared to the other cases (Figures 15A, C; 16C). This lithologic heterogeneity associated with the discontinuous shales (Figure 12C) is representative of the heterogeneity that is present in many point-bar deposits because shale drapes are commonly only preserved on topographic high areas of the lateral-accretion surfaces (Miall, 1996).

The 2-D streamline simulations of the models based on grain size exhibit 67–267% shorter BTT (Figure 15A) and 44–57% lower sweep efficiency (Figure 15C) than the other models. The various 2-D models based on grain size were all produced in a similar way. Therefore, the petrophysical variability among just the grain-size models is similar, and as expected, the resulting BTT, pore volume swept at BTT, and sweep efficiency of the different grain-size models are also similar (Figure 15A–C).

For the 3-D streamline simulations, two well patterns were used to compare the relative effect of fluid flow with respect to the orientation of the architectural framework within the point bar (e.g., perpendicular and parallel to the paleoflow direction). Well pattern 1 is oriented so that the injected fluid flows from east to west, parallel to the paleoflow direction (Figure 17A–C). Well pattern 2 is oriented so that the injected fluid flows from south to north, perpendicular to paleoflow (Figure 17D–F). Well pattern 2 is comparable to the well positions used in the 2-D outcrop modeling. The 3-D streamline simulations were also evaluated in terms of BTT, pore volume swept at BTT, and sweep efficiency (Figure 15D–I).

Given the greater distance between wells for well pattern 1, absolute BTT for well pattern 1 was significantly
longer for all cases than for well pattern 2 (Figure 15D, G). For well pattern 1 (parallel to paleoflow), the magnitude of the differences in the measured parameters among the different scenarios (excluding the models based on grain size) is negligible (Figure 15D–F). The shale barriers present on the topographic highs of the accretion surfaces in lithology model 3 (3D-LM3) do not focus or confine the fluid flow in the direction parallel to paleoflow. In general, for a given lithology constraint, BTT was shortest, and sweep efficiency was lowest for the models based on the grain-size distribution (Figure 15D–I). The fining-upward trends in grain size produce the most distinct and focused fluid-flow pathways and result in shorter BTT and lower sweep efficiency (Figure 15D–F).

For well pattern 2 (perpendicular to paleoflow), the lithologic distribution has a more significant control on the resulting streamline parameters compared to the petrophysical distribution. This is especially true for the models with continuous shale drapes (3-D lithology model 2, 3D-LM2). Simulations based on lithology model 2 have 42–53% longer BTT and 41–52% higher sweep efficiency compared to the other models (Figure 15G, I). In the case of 3D-LM2, shale drapes act as lateral permeability baffles, uniformly inhibit fluid flow, and result in relatively longer BTT compared to 3D-LM1 or 3D-LM3. In contrast to the 2-D models, for the 3-D models, the continuous shale drapes of lithology model 2 actually cause the fluid front to spread out laterally and contact more of the reservoir (Figure 17E). However, as in the 2-D models, the discontinuous shale drapes of lithology model 3 act as baffles, focus fluid flow downward to the base of the point bar, and lead to similar BTT and sweep efficiency compared to the uniform

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**Figure 15.** Histograms of streamline simulation results for 2-D (A–C) and 3-D (D–F) models. Model results are coded as follows: LM1 = lithology model 1 (black bars); LM2 = lithology model 2 (gray bars); LM3 = lithology model 3 (light-gray bars). U = uniform distribution; S = stochastic simulation; ST = stochastic simulation with a vertical trend; GS = distribution based on grain size; BTT = breakthrough time.
case, but relatively shorter BTT and lower sweep efficiency compared to models with continuous shale drapes (Figures 15G, I; 17D–F).

**IMPLICATIONS FOR RESERVOIR MODELING AND DEVELOPMENT**

For fluvial reservoirs, especially those associated with low net-to-gross meandering streams, point-bar deposits (and other related sand bodies) are commonly disconnected or in limited fluid-flow communication and, thus, form isolated reservoir compartments. Within these types of reservoir elements, internal lithological and petrophysical heterogeneities commonly compartmentalize the reservoir, control fluid movement, and affect recovery efficiency under different development scenarios. The results of this outcrop analog study show how lithologic heterogeneities (e.g., laterally discontinuous shale drapes on accretion surfaces, grain-size variability) within a point-bar deposit of a fluvial reservoir can act as baffles or barriers to fluid flow to compartmentalize a reservoir. The spatial distribution of petrophysical properties, fluid-flow behavior, and reservoir

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**Figure 16.** Streamline simulation results for select 2-D model examples. Time from injector (TFI) is displayed at BTT for each model. The TFI is the amount of time it takes a particle of water to move from the injector well to that location in the model given the boundary conditions. For comparison, the input models for the streamline simulations correspond to the same models as shown in Figures 12 and 13.

LM1–3 = lithology models 1–3; U = uniform distribution; S = stochastic simulation; ST = stochastic simulation with a vertical trend; GS-TR = transform based on grain size; BTT = breakthrough time.

A 2D-LM1-U
BTT = 32 days; Sweep Efficiency = 90.5%

B 2D-LM2-S
BTT = 52 days; Sweep Efficiency = 83.2%

C 2D-LM3-ST
BTT = 20 days; Sweep Efficiency = 57.3%

D 2D-GS-TR
BTT = 12 days; Sweep Efficiency = 46.2%
Figure 17. Maps of streamline simulation results for select 3-D model examples. Time from injector (TFI) is displayed at BTT for the petrophysical models based on stochastic simulation. The TFI is the amount of time it takes a particle of water to move from the injector well to a location in the model given the boundary conditions. Models in (A) and (D) were conditioned using lithology model 1, models in (B) and (E) were conditioned using lithology model 2, and models in (C) and (F) were conditioned using lithology model 3. Models in (A–C) were run using well pattern 1, where fluid flow is oriented parallel to the paleoflow direction within the point bar. Models in (D–F) were run using well pattern 2, where fluid flow is oriented perpendicular to the paleoflow direction within the point bar.
performance differ between models based on lithology, observed grain-size trends, average-property values (deterministic methods), and distributions based on stochastic simulation. Therefore, the reproduction of internal lithologic variability, depositional trends, and associated petrophysical properties within modeled point-bar deposits (reservoir-model objects) are important depending on the character and degree of internal heterogeneity that exist (e.g., Jackson, 1976; Richardson et al., 1978; Lasseter et al., 1986; Thomas et al., 1987; Tyler and Finley, 1991; Jordan and Pryor, 1992; Hartkamp-Bakker and Donselaar, 1993; Willis and White, 2000).

Given the geometry and dimensions of the point-bar sand bodies of the lower Williams Fork Formation and similar low net-to-gross ratio systems, a relatively high well density (e.g., 10–40-ac [201–402-m; 660–1320-ft] spacing or less) is necessary to intersect these individual reservoirs. Within each point-bar sand body (reservoir compartment), lithologic heterogeneity and directional permeability (petrophysical anisotropy) of varying magnitudes associated with cross-stratified sandstone, rippled and laminated sandstone, and other facies influence fluid movement (Jones et al., 1987; Hartkamp-Bakker and Donselaar, 1993; Anderson 2005). Jones et al. (1987) and Anderson (2005) also suggest that maximum permeability in trough cross-bedded sandstone is parallel to the trough axis and, therefore, parallel to the paleocurrent direction. Therefore, for a given well spacing, shorter BTT parallel to paleoflow is expected.

The results suggest that when producing a fluvial reservoir with discontinuous shale drapes, it would be favorable to align production-injection well pairs such that the displaced fluid flows parallel to the paleoflow direction. If shale drapes on lateral accretion surfaces exist (either continuous or discontinuous), horizontal wells drilled perpendicular to the paleoflow direction would allow multiple reservoir compartments to be contacted (in the case of continuous shale drapes) and more uniform sweep and higher sweep efficiency to be achieved (in the case of discontinuous shale drapes) relative to a vertical well. This is especially true if the shale drapes are essentially impermeable. Because fining-upward grain-size trends can partially compartmentalize the reservoir vertically and reduce sweep efficiency, horizontal or deviated wells might be preferred depending on the magnitude of grain-size variability. However, if lithological variability exists and vertical wells are used, producer-injector well pairs should be aligned parallel to the paleoflow direction to maximize sweep efficiency.

CONCLUSIONS

The Williams Fork Formation of the western Piceance Basin consists of interbedded sandstone, shale, and coal that were deposited in alluvial- and coastal-plain settings. The lower Williams Fork Formation is a relatively low net-to-gross ratio interval. These deposits include relatively isolated but internally heterolithic sandstones (e.g., isolated point-bar sand bodies) encased in flood-plain mudstones and coals. Reservoir connectivity between the point-bar sand bodies is generally low; therefore, each point-bar deposit acts as a separate reservoir element.

The point-bar deposit of this study exhibits a vertical succession of facies from medium- to upper fine-grained, trough cross-bedded sandstone to fine-grained ripple-laminated sandstone, and it has an associated fining-upward grain-size profile. Grain size decreases vertically at the scale of individual accretionary units and for the entire point bar. Distinct lateral-accretion surfaces within the point-bar deposit commonly have thin shale drapes present on the updip part of these surfaces.

Two- and three-dimensional modeling results indicate that the effect of internal lithologic heterogeneity on fluid flow varies, depending on the type and extent of the heterogeneity and the point-bar orientation relative to development wells. Continuous and discontinuous shale drapes on the lateral-accretion surfaces within the point bar cause significant differences in BTT, but only moderate differences in the pore volume swept at BTT and sweep efficiency. The continuous shales inhibit flow along their entire length and cause an increase in BTT compared to the homogeneous case. The discontinuous shales act mainly as permeability baffles where they are present and force the flow downward toward the base of the point bar, thus reducing both the BTT and sweep efficiency as compared to the other cases. This is also the case for the models based on grain size, which exhibit shorter BTT and lower sweep efficiency compared to the other models because of the fining upward in grain size.

For the 3-D models with producer-injector well pairs aligned parallel to the paleoflow direction, the magnitude of the differences in BTT and sweep efficiency among the models without shale drapes, with continuous shale drapes, and with discontinuous shale drapes is negligible, excluding the models based on grain size. The shale drapes do not focus or confine the fluid flow in the direction parallel to paleoflow. Similar to the 2-D models, for the models based on grain
size, the fining-upward trends produce the most distinct and focused fluid-flow pathways and result in shorter BTT and lower sweep efficiency.

For a well pattern oriented perpendicular to paleoflow, the lithologic distribution has a more significant effect on BTT and sweep efficiency as compared to the petrophysical distribution. Simulations based on the continuous shale drapes have the longest BTT and highest sweep efficiencies because they act as lateral permeability baffles and uniformly inhibit fluid flow. Unlike the 2-D model cases, the continuous shale drapes also cause the fluid front to spread out laterally and contact more of the reservoir. As a result, the pore volume swept at BTT and sweep efficiency are greater. Similar to the 2-D models, the discontinuous shale drapes act as baffles, focus fluid flow downward to the base of the point bar, and lead to relatively shorter BTT and lower sweep efficiency compared to the other models.

These results suggest that when developing a fluvial point-bar reservoir with internal discontinuous shale drapes, if vertical wells are used, it would be favorable to align production-injection well pairs such that the displaced fluid flows parallel to the paleoflow direction. If continuous or discontinuous shale drapes exist, a single horizontal well drilled perpendicular to the paleoflow direction would allow multiple reservoir compartments to be contacted and more uniform sweep and higher sweep efficiency to be achieved relative to a vertical well.

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