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An Integrated Approach to Characterization and Modeling of Deep-water Reservoirs, Diana Field, Western Gulf of Mexico

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ABSTRACT

The situation presented at the Diana field in the western Gulf of Mexico is a common one in exploration and early development: a hydrocarbon reservoir expressed by a single-cycle seismic event and limited appraisal wells spaced thousands of feet apart. There is excellent core coverage that enables close calibration of seismic and well data. Integration and analysis of the data suggest a relatively channelized reservoir in an updip position, becoming more sheetlike and layered downdip. This subsurface data, however, does not have the resolution to provide the dimensional and architectural information required to populate an object-based three-dimensional geologic model for more accurate flow simulation and well-performance prediction. To solve these uncertainties, deep-water outcrop analog data from the Lower Permian Skoorsteenberg Formation in the Tanqua Karoo Basin, South Africa, and the Upper Carboniferous Ross Formation in the Clare Basin, western Ireland, were integrated with the seismic and well data from the Diana field. Bed-scale reservoir architectures were quantified with photomosaics and by correlation of closely spaced measured sections.

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Bed continuity and connectivity data, along with vertical and lateral facies variability information, also were collected, as these factors ultimately control the reservoir behavior. From these measurements, a spectrum of channel dimensions and shapes were compiled to condition the modeled objects. These dimensions were compared to Diana specific seismic and well data and adjusted accordingly. The advantage of the resulting Diana geologic model is that it incorporates geologic interpretation, honors all available information, and models the reservoir as discrete objects with specific dimensions, facies juxtaposition, and connectivity. This study provides the framework for optimal placement of wells to maximize the architectural and facies controls on reservoir performance.

INTRODUCTION

The Diana field is situated in the western Gulf of Mexico 260 km (160 mi) south of Galveston in approximately 1430 m (4700 ft) of water (Figure 1). ExxonMobil is the operator with 66% interest, whereas British Petroleum (BP) holds a 33% interest. Diana is the second largest of several discoveries recently made in the Diana Subbasin and has in excess of 100 MMBOE of recoverable hydrocarbons from the upper Pliocene A-50 reservoir. The turbiditic sandstones and mudstones that comprise the A-50 reservoir at the Diana field were deposited as a lowstand fan in an intraslope basin setting. The field is located on the east flank of a north-south–trending salt-cored ridge. Hydrocarbons are trapped by a combination of structure and stratigraphic onlap, with a large gas cap (>305 m [1000 ft] column height) and a relatively thin oil column (approximately 75 m [240 ft] column height). The Diana Subbasin is relatively large, consisting of two narrow feeder corridors to the north, which open into a large low-relief basin approximately 32 km (20 mi) wide by 32 km (20 mi) long. It is about three to four times the size of the next largest updip intraslope basin.

The challenge at the Diana field was to predict the production performance of a channelized deep-water reservoir with a relatively thin oil rim and a large gas cap (Figure 1). Associated development costs are high, requiring an optimization program to ensure a successful project. These predictions were challenged further by variable-quality seismic data, a reservoir thickness expressed by a single-cycle seismic event, only limited appraisal wells, and the likelihood for subseismic reservoir variability that could control the economic viability of the project. To assist with reserve assessments and optimization of depletion strategies, deep-water outcrop analog data were integrated with seismic and well data to produce a detailed object-based model for more accurate reservoir characterization.

In the Diana study, two outcrop analogs were found to be most applicable to the penetrated subsurface reservoirs based on similarities in grain size, facies associations, and interpreted sand-body architecture. These were the Lower Permian Skoorsteenberg Formation in the Tanqua Karoo Basin, South Africa, and the Upper Carboniferous Ross Formation in the Clare Basin, western Ireland. These deep-water turbidite successions have been studied widely in recent years by Collinson et al. (1991), Bouma and Wickens (1994), Chapin et al. (1994), Sullivan et al. (1998), Bouma (2000), Elliot (2000), Martinsen et al. (2000), Morris et al. (2000), and Sullivan et al. (2000a, b). The main purpose of this current outcrop study was to provide the data necessary to help assess future prospects and newly discovered fields with analogous reservoir characteristics.

To better understand and apply the observations and learnings from this outcrop analog study, normal-incidence forward seismic models were constructed for both the Skoorsteenberg and Ross Formations. These models illustrate both the seismic facies of the individual outcrops using Diana subsurface rock properties (density and velocity) and the resolution limits of typical seismic data.

By combining dimensional and architectural data from outcrops with seismic, well-log, and core data from the subsurface, it is possible to construct more accurate reservoir models for deep-water turbidite sandstones for Diana and other fields. Such studies are important because they greatly reduce the uncertainties associated with reservoir assessment parameters for economically important deep-water turbidite sandstones.

DEEP-WATER OUTCROP ANALOGS

Outcrop analogs span a critical gap in both scale and resolution between seismic and wellbore data. The integration of appropriate outcrop analogs, core, well-log, and seismic data can provide the detailed geometric properties required for interpreting the reservoir architecture at a subseismic or flow-unit scale. The Lower Permian Skoorsteenberg Formation in Tanqua Karoo Basin, South Africa, and the Upper Carboniferous Ross Formation in the Clare Basin, western Ireland, are both

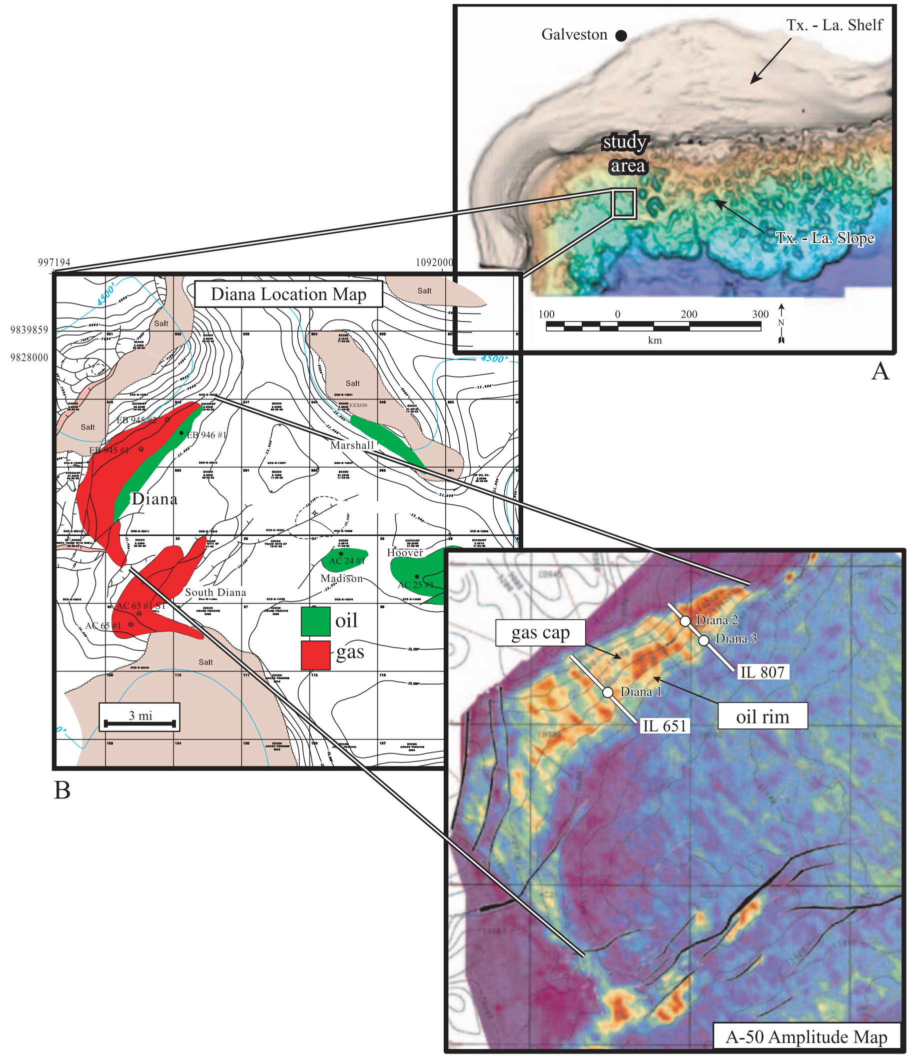

FIGURE 1. (A) The Diana Subbasin is located in the western Gulf of Mexico 255 km (160 mi) south of Galveston. (B) Prior to the 1990s, no wells had been drilled in the Diana Subbasin. Today, however, five discoveries have been made in ExxonMobil's operated blocks. (C) Combined structure and composite amplitude extraction for the upper Pliocene A-50 reservoir. Structural contours are in 60-m (200-ft) intervals. Seismic amplitude extractions display distinct stripes in the in-line direction. This complicates any quantitative attribute analysis of the reservoir and restricts the application of seismic amplitude map patterns to delineate sand-body dimensions.

composed of stacked turbiditic sandstones and mudstones deposited in a channelized basin-floor fan setting. These laterally continuous outcrops provide an excellent opportunity to characterize detailed bed-scale reservoir architectures and internal heterogeneities that affect the producibility of deep-water sand bodies in both depositional strike and dip perspectives. The selection of appropriate outcrop analogs, however, is extremely important. The criteria for choosing the outcrops of the Skoorsteenberg and Ross Formations as analogs for A-50 reservoir at Diana was based on comparison of key reservoir characteristics such as grain size, lithofacies, net-to-gross (ratio of sandstone vs. mudstone), and sand-body architecture. Because of the strong similarities between the selected outcrop analogs and the A-50 reservoir, dimensional and architectural data from these outcrops can be used to help constrain an object-based three-dimensional (3-D) geologic model to predict well performance, connected volumes, and recovery efficiencies for the Diana development.

Based on detailed characterization, the deep-water sandstones present in the outcrop localities can be divided into proximal, transition from proximal to medial, and medial fan settings (Figure 2). Distal fan deposits are also present but were not a focus of this study because of their limited reservoir potential and relatively poor exposure. The presented proximal-to-distal subdivision is for an idealized slope-to-basin transition. It is recognized, however, that it is the change in the slope gradient that ultimately controls the degree of channelization (Imran et al., 1998). Therefore, appropriate outcrop analogs for subsurface data sets need to be selected based on similarities in interpreted sand-body architecture and not on interpreted similarities in location in a slope-to-basin profile.

Proximal Fan

The most proximal exposures of both the Skoorsteenberg and Ross Formations are dominated by compensationally stacked, erosionally confined channels and interchannel sheets. These narrow proximal fan channels are typically less than 400 m (1300 ft) wide and 5–12 m (16–39 ft) thick, with aspect ratios (width vs. thickness) ranging from 30:1 to 80:1 (Figures 3, 4). Net-to-gross ratios for individual measured sections range

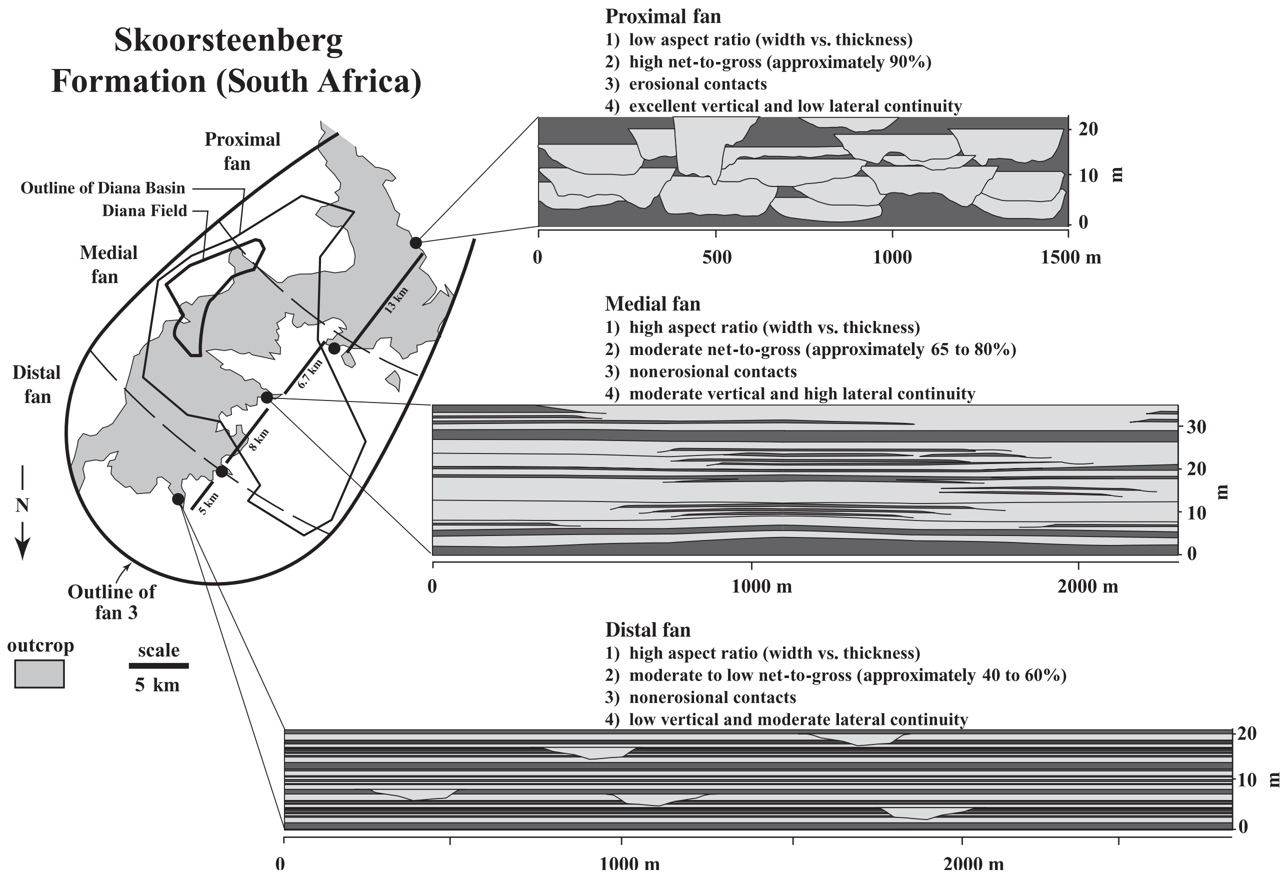

FIGURE 2. The deep-water deposits of the Skoorsteenberg Formation in Tanqua Karoo Basin, South Africa, can be subdivided into proximal, medial, and distal fan settings, each with their own key characteristics. Note the outline of the Diana Subbasin and Diana field projected on to outline of fan 3 of the Skoorsteenberg Formation. The outline of fan 3 is modified from Bouma and Wickens, 1994.

from 70 to 95%, with an average of approximately 90%. Two distinct styles of channel fills are recognized. The proximal fan channels of the Skoorsteenberg Formation are typically filled from axes to margins by amalgamated, thick-bedded (>30 cm), fine- to medium-grained, massive sandstones (Figure 3). Massive sandstones commonly grade upward into thick-bedded, fine-grained, planar-stratified sandstones and rare thin-bedded (<30 cm), very fine- to fine-grained, current-ripple–stratified sandstones. The interchannel strata are comprised of nonamalgamated thin- to thick-bedded current-ripple–laminated sandstones and interbedded laminated silty mudstones. In contrast, the proximal fan channels in the Ross Formation exhibit a lateral degradation in reservoir quality. They are dominated by highly amalgamated massive to cross-bedded sandstones in an axial position that grade laterally into progressively thinner-bedded, less-amalgamated massive sandstones toward the margins (Figure 4).

This difference in the lateral degree of amalgamation, from axis to marginal, for the proximal fan channels of the Skoorsteenberg and Ross Formations may suggest differences in the scale and size of the turbidity currents that deposited the sandstones. The vertically and laterally amalgamated massive sandstones, which comprise the channel fills in the Skoorsteenberg Formation, are interpreted to have been deposited by high-concentration turbidity currents that completely filled the channels and, therefore, display no variations from axis to margin (Figure 3). Overbanking of these turbidity currents is interpreted to have produced the distinct interchannel association dominated by low-concentration turbidites (planar- and current-ripple–stratified sandstones). By contrast, the distinct axis-to-margin variations in the Ross Formation suggest that the turbidity currents that deposited these sandstones were underfit relative to the channels (Figure 4). This conclusion is also supported by the general lack of low-concentration turbidite-dominated interchannel deposits in the Ross Formation.

Transition from Proximal to Medial Fan

Dominating the transition from proximal to medial fan settings for both the Skoorsteenberg and Ross

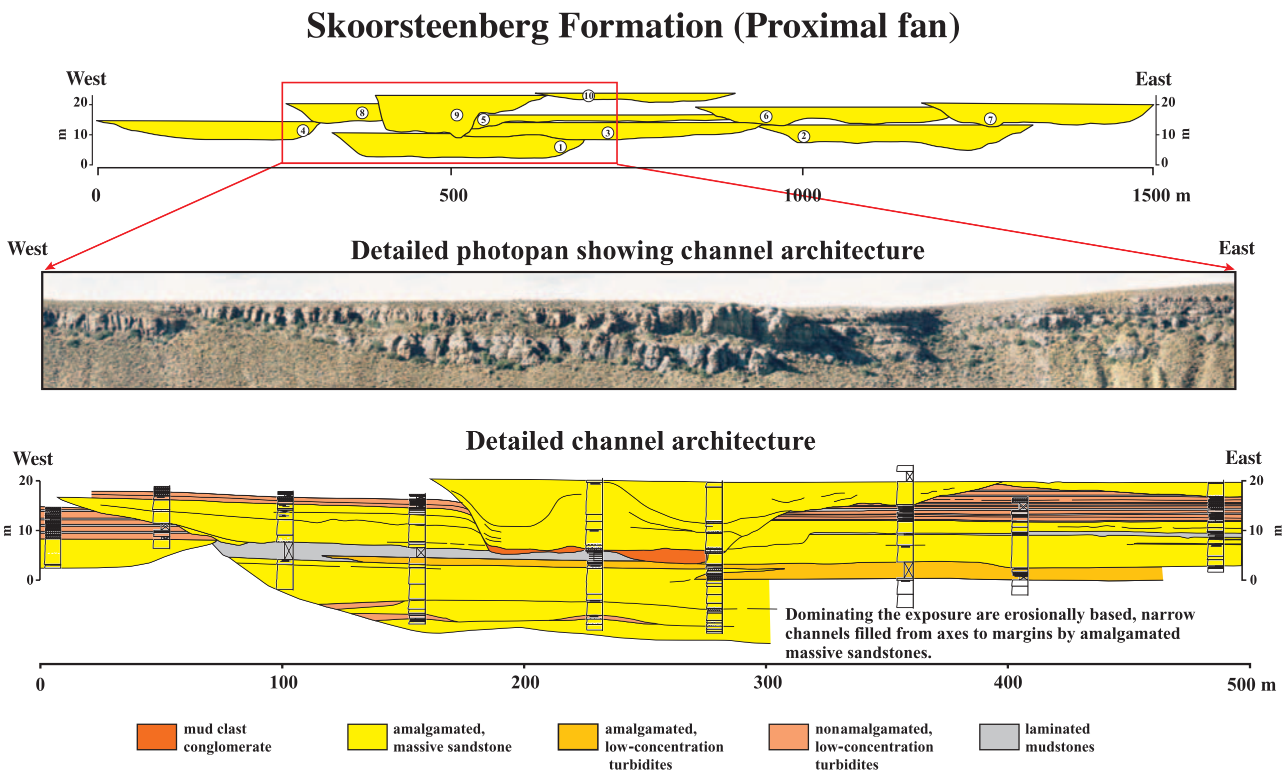

Figure 3. Proximal fan deposits of the Skoorsteenberg Formation are comprised of erosionally based, narrow (low aspect ratio) channels and interchannel sheets. Ten major channels are identified, which range from 300 to 500 m (984 to 1630-ft) wide and are typically 5–10-m (16–32-ft) thick. Channels are filled from axes to margins by amalgamated, thick-bedded massive sandstones. The interchannel areas are characterized by nonamalgamated thin- to thick-bedded current-ripple–laminated sandstones and interbedded laminated silty mudstones (location: Ongeluks River) (modified from Sullivan et al., 2000a).

Formations are compensationally stacked, very broad (high aspect ratio) weakly confined channels. These channels are as much as 1000 m (3270 ft) wide and 8–13 m (26–42 ft) thick (Figures 5, 6). Their bases tend to be nonerosional, suggesting that they are primarily aggradational in origin. In general, these channels do not infill erosional scours; instead, they are compensationally stacked because of preexisting highs related to underlying channels. Individual channelized sand bodies can be further subdivided into distinct channel-axis and channel-margin facies associations. Highly amalgamated, massive sandstones characterize channel-axis deposits. Away from the axis, beds become distinctly less amalgamated and extremely continuous to produce laterally extensive, layered wings at the channel margins (Figure 5). Net-to-gross ratios for these weakly confined to unconfined channels range from 70 to 90%, with an average of 80%. Detailed bed-by-bed correlations show that these sandstones have bed lengths much greater than the dimensions of the outcrop, whereas mudstones have much shorter bed lengths (Figure 6). Therefore, the key to understanding reservoir continuity and internal heterogeneities that affect reservoir performance in this instance is knowing the thickness and lengths of mudstone barriers and not the distribution of sandstones. Eighty percent of these mudstones are less than 0.3 m (1 ft) thick and have bed lengths less than 200 m (655 ft). Although this is a relatively high net-to-gross reservoir type with excellent lateral continuity, the vertical continuity would be moderate to low. This is caused by the preserved interbedded mudstones, although only 5–10% of these mudstones have lengths approaching or greater than 700 m (2295 ft). It is these continuous mudstones that would likely produce significant vertical barriers to fluid flow.

Medial Fan

Medial fan deposits are also similar for both the Skoorsteenberg and Ross outcrops and are comprised of extremely broad, unconfined channels or sheets (Figure 7). The bases of these sand-prone sheets tend to be nonerosional, comparable to the broad channels of the proximal to medial fan transition. They also appear to be compensationally stacked or laterally offset because of depositional highs related to underlying sand bodies.

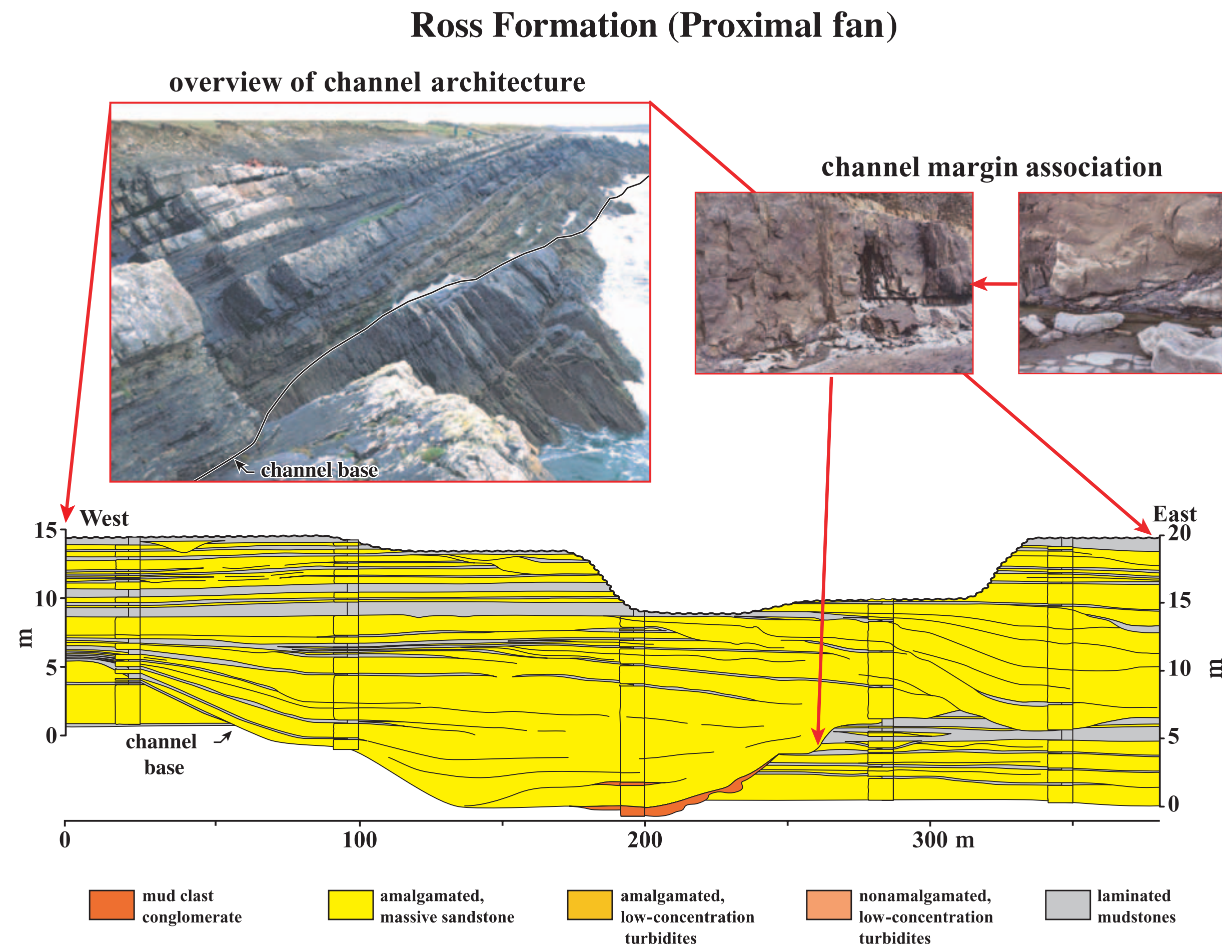

FIGURE 4. The proximal fan channels in the Ross Formation are dominated by highly amalgamated massive to cross-bedded sandstones in an axial position that are replaced by progressively thinner-bedded, less-amalgamated massive sandstones toward the margins. Note the distinct inclined surfaces present in the east portion of the channel. These inclined surfaces are interpreted to represent channel-margin migration and suggest that this channel is somewhat sinuous. (location: Rinevilla Point) (modified from Sullivan et al., 2000b).

Individual sheets are 3–7 m (10–23 ft) thick, with narrow, amalgamated axes and more sheetlike, layered margins. The sheet axes are locally erosionally based and are typically 100–160 m (328–525 ft) wide. They are comprised of highly amalgamated massive sandstones. Away from the axes, progressively thinner-bedded, less-amalgamated sandstones replace amalgamated massive sandstones (Figure 7). The sheet margins have estimated widths in excess of 1600 m (5245 ft) on either side of the axes. Massive sandstones represent the dominant facies type and are interpreted to have been deposited rapidly from suspension from high-concentration turbidity currents in an unconfined setting. Although the sandstone bed sets are highly continuous, they consist of individual lenticular and compensatory sandstone packages. Overall, this produces a very layered architecture, with most of the amalgamation of sheet complexes occurring where axes locally cut into underlying sand bodies. Net-to-gross values for these deposits typically range from 65 to 80%, with an average of approximately 70%.

FORWARD SEISMIC MODELING OF DEEP-WATER OUTCROPS

The major uncertainties associated with exploration and development of deep-water reservoirs are predrill predictions of net-to-gross and assessment of reservoir continuity and net-to-gross away from well penetrations. Based on recent drilling results for deep-water petroleum reservoirs, successfully estimating reservoir continuity and net-to-gross away from well penetrations requires correct interpretation of reservoir type. ExxonMobil's postdrill analyses in several deep-water basins have shown that the information required to successfully predict these parameters is often embedded

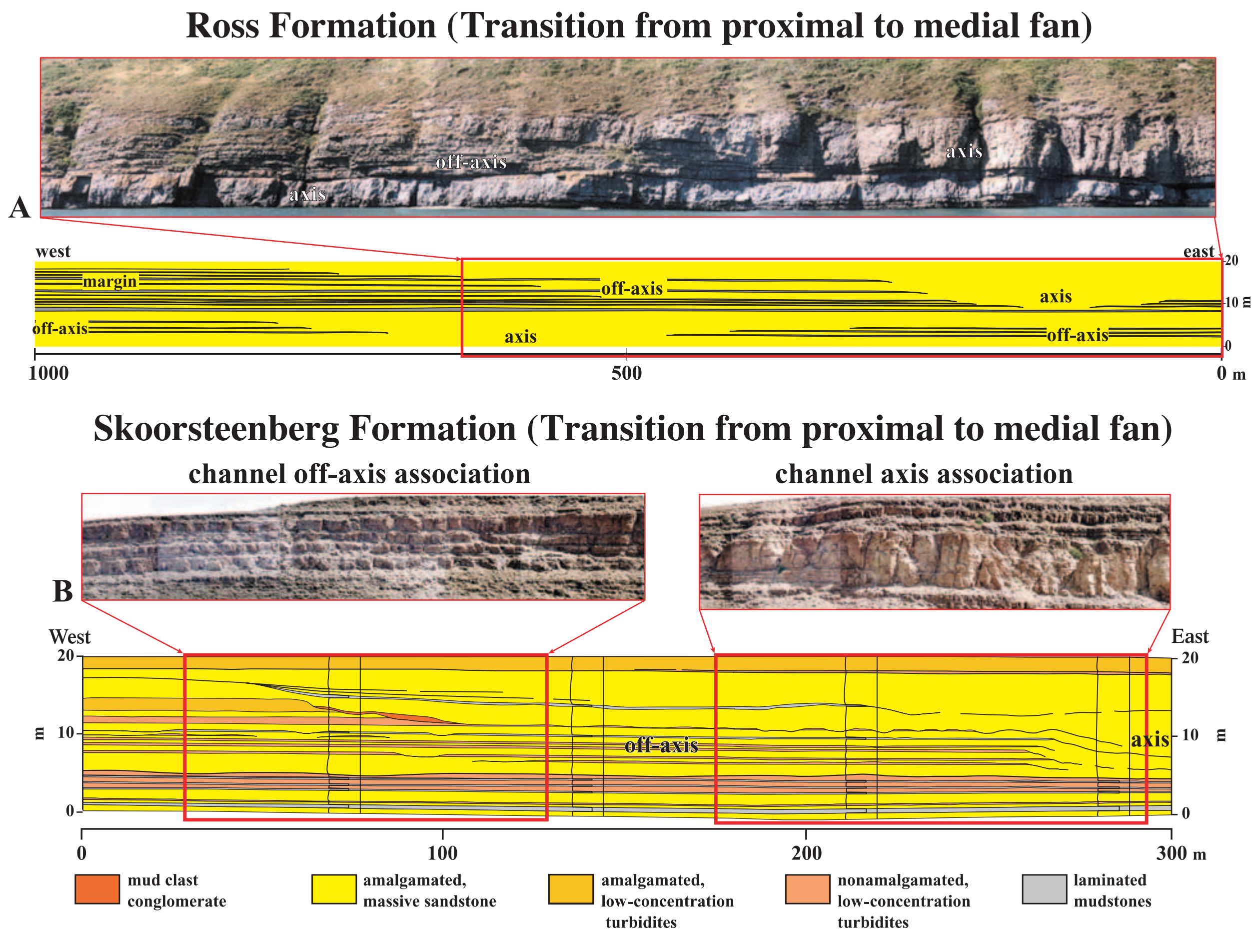

FIGURE 5. The transition from proximal to medial fan settings is dominated by compensationally stacked, very broad (high aspect ratio) channels as much as several thousand feet wide and 8–13 m (26–42 ft) thick for both the Skoorsteenberg and Ross Formations. These channelized sand bodies can be subdivided further into distinct channel-axis and channel-margin associations. Highly amalgamated massive sandstones characterize channel-axis deposits. Away from the axis, beds become distinctly less amalgamated and extremely continuous to produce laterally extensive, layered wings at the channel margins (location A: Rehy Cliffs; location B: Loskop) (modified from Sullivan et al., 2000b).

in the seismic response of reservoirs. The challenge for seismic analysis, therefore, is the proper interpretation of these seismic responses.

The paucity of well control and the abundance of high-quality 3-D seismic data at the exploration and development scales require interpretation of reservoir type, or environment of deposition, to be performed using detailed seismic facies analysis. Key criteria of Exxon-Mobil's deep-water seismic facies scheme include external geometry (e.g., truncation, onlap, mounding, etc.), amplitude strength and continuity (e.g., high-amplitude continuous vs. high-amplitude semicontinuous), and attribute map patterns. Because of the nonuniqueness inherent in seismic facies analysis, translation of these seismic facies into depositional environments requires careful selection of an appropriate analog, be it either subsurface or outcrop based. In the case of outcrops, architectural analysis can provide the characteristics of the fundamental units that comprise subsurface reservoirs.

Different architectural elements yield different seismic signatures, such as channels vs. sheets and axial vs. marginal lithofacies associations. Typically, these elements are at or below seismic resolution. Additional challenges of applying the outcrop analogs appropriately to a seismic response are related to the signatures of individual sand bodies, which can vary with the seismic bandwidth and rock properties. Lastly, most single channels and sheets stack to form complexes, and the interplay between these different individual sand bodies can also modify their seismic signatures.

Normal-incidence forward seismic models have been constructed using GXII seismic modeling software for both the Skoorsteenberg and Ross Formations to calibrate the appropriate outcrop analogs to the Diana subsurface data. These models are shown in Figures 8–10

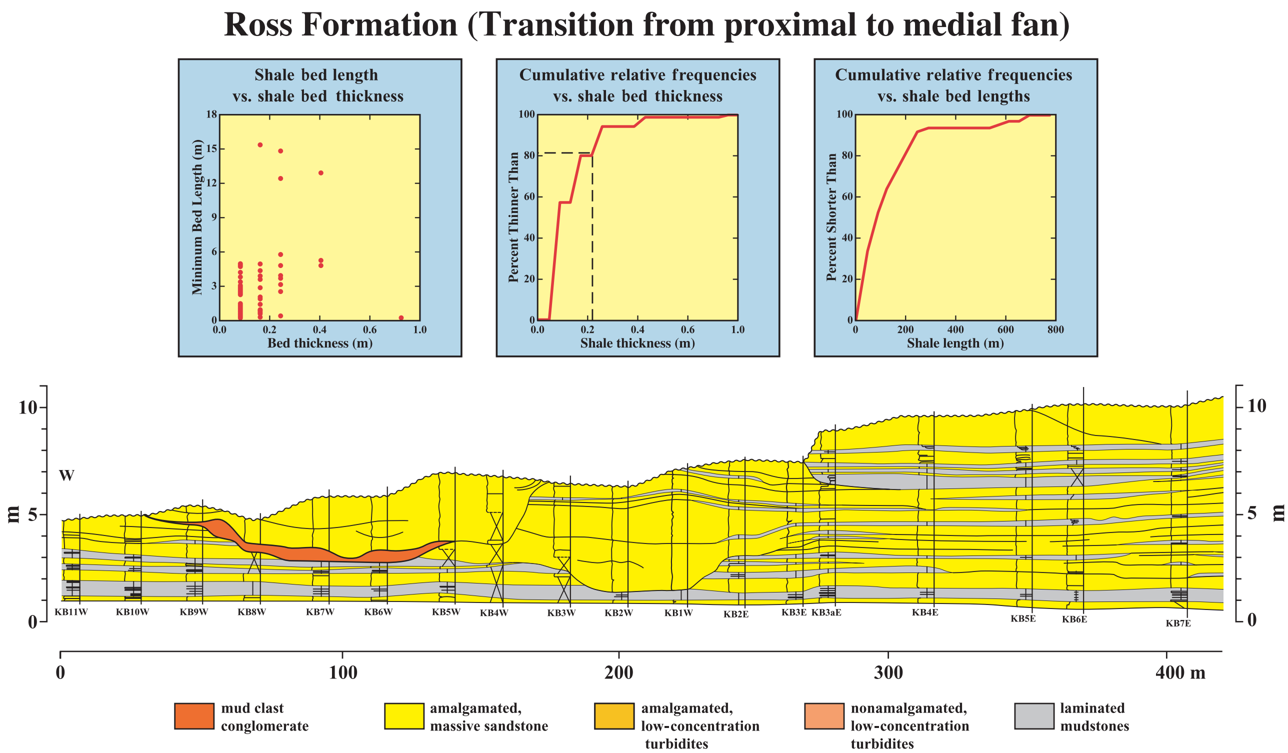

FIGURE 6. Overall this is a very layered reservoir with most of the amalgamation of these broad channels occurring where erosional axes cut into underlying sand bodies. Bed-length data based on detailed bed-by-bed correlations show these sandstones have lengths much greater than the length of the outcrop. In contrast, 80% of all mudstones are less than 0.3 m (1 ft) thick and have bed lengths less than 200 m (655 ft). Although this is a relatively high net-to-gross reservoir type with excellent lateral continuity, the vertical continuity would be moderate to low. Bed continuity, connectivity, and vertical and lateral facies variability data such as this were collected from a variety of channel types to condition the object-based geologic model for the Diana field (location: Kilbaha Bay) (modified from Sullivan et al., 1998).

and illustrate both the seismic facies of individual outcrops using subsurface rock properties (density and velocity) from the Gulf of Mexico and the resolution limits of typical seismic data. All forward seismic models were generated using vertical-incidence ray tracing and a zero-phase Ricker wavelet. A trough (red) represents a negative impedance boundary, and a peak (black) represents a positive impedance boundary. Each of the outcrops discussed in the previous section would be seismically expressed as a single cycle at the bandwidth and rock properties of the deep-water Gulf of Mexico. These models provide a link between the architectures observed in outcrop and seismic data in the same way synthetic seismograms link well-log and core data to seismic data.

The comparative seismic response of the medial, transition from proximal to medial, and proximal portions of the Skoorsteenberg and Ross Formations reveals that the variations in sand-body architecture and degree of vertical and lateral amalgamation are manifested as changes in amplitude strength and continuity and subtle changes in isochron. As would be expected, the layered, extremely continuous medial fan sheets of the Ross Formation (Figure 8) produce a high-amplitude continuous seismic character at typical 30 Hz seismic frequencies. The high net-to-gross section at the top of the outcrop can only be fully resolved on the seismic model generated using a 60-Hz wavelet. At this higher frequency, this interval also is acoustically transparent because of the high percentage of sandstone and resulting lack of internal reflectivity.

Individual channels from the proximal to medial fan transition of the Ross Formation are not resolvable except at the highest frequency (Figure 9). At the channel-complex scale, however, the lateral change from high net-to-gross axis to lower net-to-gross margin is reflected clearly in a lateral degradation of amplitude strength. This indicates that these distinct lateral changes in sand percentage should be seismically detectable.

The vertically and laterally amalgamated, high net-to-gross proximal fan channels of the Skoorsteenberg Formation also display a high- to moderate-amplitude, moderately continuous seismic character (Figure 10). In contrast to the medial fan sheets, however, modeling of these outcrops exhibits greater evidence of variation in isochron because of the channelized nature of the outcrops.

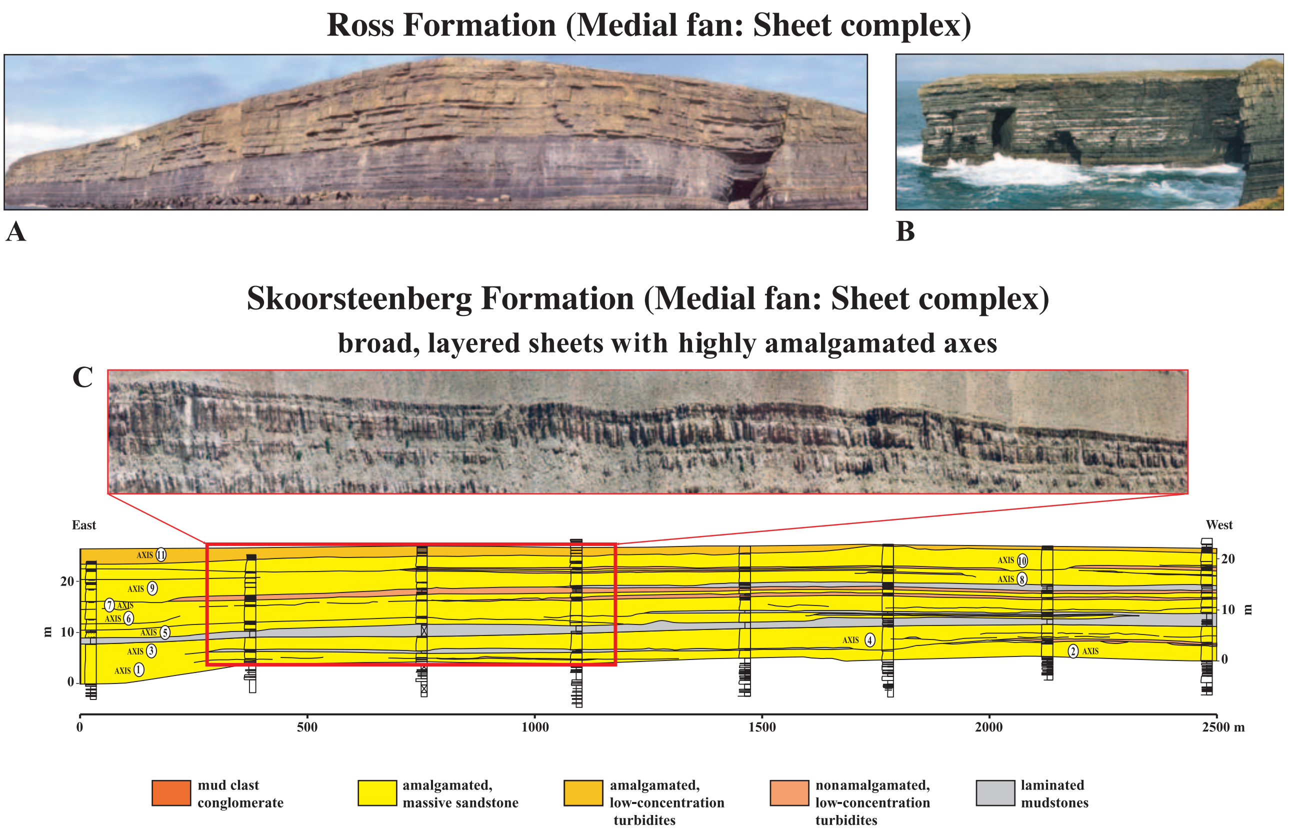

FIGURE 7. Medial fan deposits also are similar for both the Skoorsteenberg and Ross outcrops and are comprised of extremely broad channels or what can be more correctly termed as sheets. Individual sheets are 3–7 m (10–23 ft) thick with narrow, amalgamated axes and more sheetlike, layered margins. Although the sandstone bed sets are highly continuous, they consist of individual lenticular and compensatory sandstones (location A: West Kilcholer Cliffs; location B: Loophead; location C: Grootfontein) (modified from Sullivan et al., 2000b).

Each of these forward seismic models is subtly different. These differences reflect the proximal to distal variations that are inherent in many deep-water depositional systems. Integrating the knowledge from detailed analysis of these deep-water outcrops and forward seismic modeling can provide important information concerning variations in reservoir architecture and net-to-gross values that can ultimately control the development potential of many deep-water reservoirs.

DIANA SUBSURFACE DATA

Based on detailed analysis, the 3-D seismic data at the Diana field appears to be of variable quality and does not allow direct geometric analysis of reservoir elements (Figure 1B). To assist with assessment, deep-water outcrop analog data and forward seismic modeling were integrated with seismic and well data to produce a more accurate characterization of the reservoir. Seismic amplitude extractions for the A-50 reservoir display distinct stripes in the in-line direction that are interpreted to be related to the acquisition of the survey. This complicates any quantitative attribute analysis of the reservoir and restricts the application of seismic amplitude map patterns to delineate sand-body trends and dimensions. Qualitative examination of vertical seismic in-lines and cross-lines, however, provides valuable information concerning the architecture of the reservoir elements (Figures 11, 12). The A-50 sands are low impedance where they are hydrocarbon charged and are typically represented by a single-cycle seismic event (trough-peak pair) with a trough (red = negative impedance boundary) at the top and a peak (black = positive impedance boundary) at the base on zero-phase data.

The proximal portion of the Diana field, which includes the Diana 2 and Diana 3 well penetrations, is represented by high-amplitude, continuous seismic character above the gas-oil contact (Figure 11). The observed amplitude dimming toward the Diana 3 location is fluid related (change from gas to oil) and is not associated with variations in net-to-gross (Figures 13–15A). This suggests that, if variation in net-to-gross and reservoir architecture exists in this portion of the reservoir, it is below seismic detection. Furthermore, forward seismic

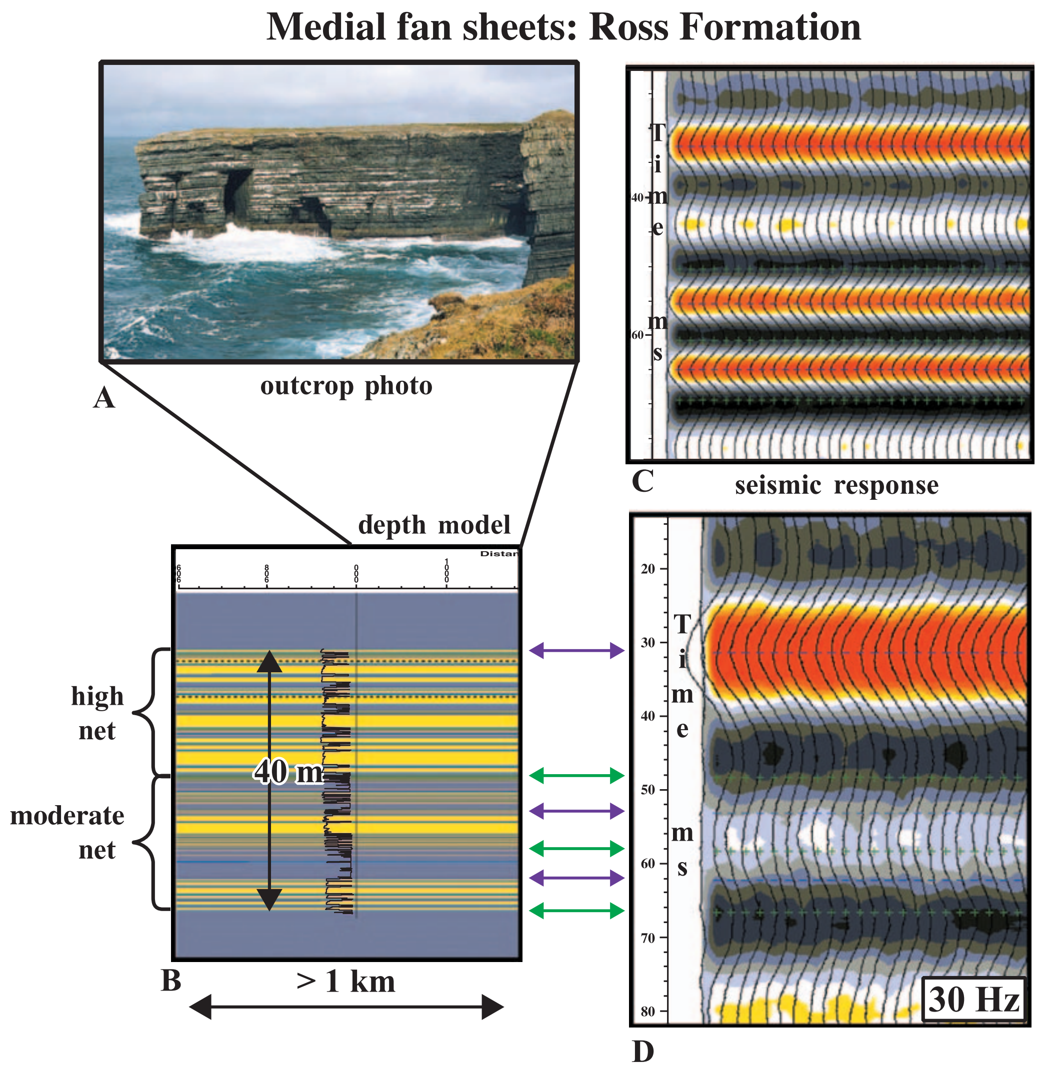

FIGURE 8. Forward seismic model for medial fan sheets from the Ross Formation built using GXII seismic modeling software. (A) Outcrop photo of the layered sheets, which dominate the medial fan deposits of the Ross Formation at Loophead (Figure 7). (B) Depth model constructed for this outcrop by applying subsurface rock properties (density and velocity) from deep-water reservoirs in the Gulf of Mexico to the digitized interpretation of this outcrop. Also shown in overlay is a detailed measured section for this outcrop. (C) The high net sandstone section at the top of the outcrop can only be fully resolved on the seismic model generated using a 60-Hz wavelet. At this higher frequency, this interval is also acoustically transparent because of the high percentage of sandstone and resulting lack of internal reflectivity. (D) On the forward seismic model generated using a 30-Hz frequency wavelet, the upper sandstone-prone interval has a high-amplitude continuous seismic response, whereas the lower package has a low-amplitude continuous response (modified from Sullivan et al., 2000b).

modeling indicates that both high net-to-gross, amalgamated proximal fan channels (Figure 10) and moderate net-to-gross, layered medial fan sheets can have a similar high-amplitude continuous seismic response (Figure 8). Subtle variations in isochron are observed for the A-50 interval and may suggest a more channelized reservoir, but it is not conclusive. The Diana 2 and Diana 3 wells, however, penetrate a very high net-to-gross interval dominated by amalgamated high-concentration turbidites and shale clast conglomerates (Figures 13–15A). This association of facies, in conjunction with the seismic character of the A-50 interval, suggests a relatively channelized reservoir (Figures 11C, 15A).

The medial portion of the field (Diana 1 well penetration) has a distinctly different seismic character than the updip portion of the reservoir (Diana 2/Diana 3 region) and is represented by a high-amplitude, semicontinuous seismic character above the gas/oil contact (Figure 12A). Forward seismic modeling shows that lateral change from high net-to-gross to lower net-to-gross should be reflected by a degradation of amplitude strength (Figure 9). This suggests that the lateral variation

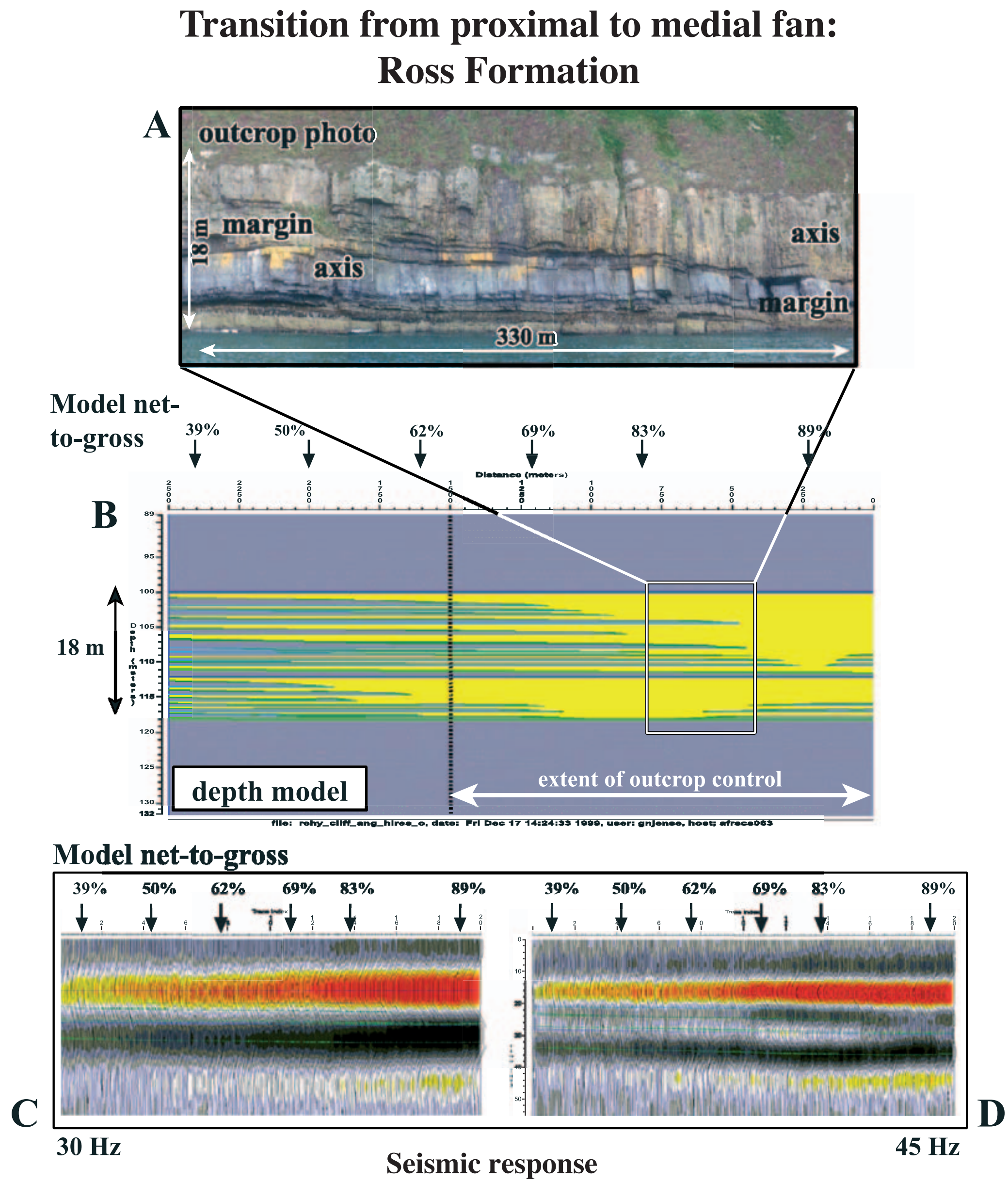

Figure 9. Forward seismic model for the proximal- to medial-fan transition channels of the Ross Formation built using GXII seismic modeling software. (A) Outcrop photo of the broad, compensationally stacked channels that dominate the transition from proximal to medial fan setting at Rehy Cliffs (Figure 5). These channels are highly amalgamated in an axial position but become less amalgamated and lower net-to-gross toward the margins. (B) Depth model constructed for this outcrop by applying subsurface rock properties (density and velocity) from deep-water reservoirs in the Gulf of Mexico to the digitized interpretation of this outcrop. The depth model was extended approximately 1 km beyond the outcrop control by continuing the observed patterns of deposition. (C and D) The measured net-to-gross for various points along the model are plotted across the top and can be used to locate seismic models relative to the depth model. Forward seismic models for 30- and 45-Hz peak frequencies are shown. The seismic response for both models is very continuous, but the net-to-gross variations from axis to margin are directly related to the amplitude of the seismic response. This indicates that these distinct lateral changes in sand percentage should be seismically detectable. The individual channels can only be resolved on the higher resolution (45 Hz) seismic model, but there is still substantial interference between the stacked channels (modified from Sullivan et al., 2000b).

in seismic character of the A-50 sands in the vicinity of Diana 1 is caused by seismically detectable variations in net-to-gross and reservoir architecture. Well penetrations confirm this interpretation, as Diana 2 was drilled in a higher-amplitude portion of the reservoir and encountered approximately 85% net-to-gross (Figure 15A). Diana 3 also is extremely high net-to-gross (Figures 13–15A), but it was drilled in the oil leg and, as

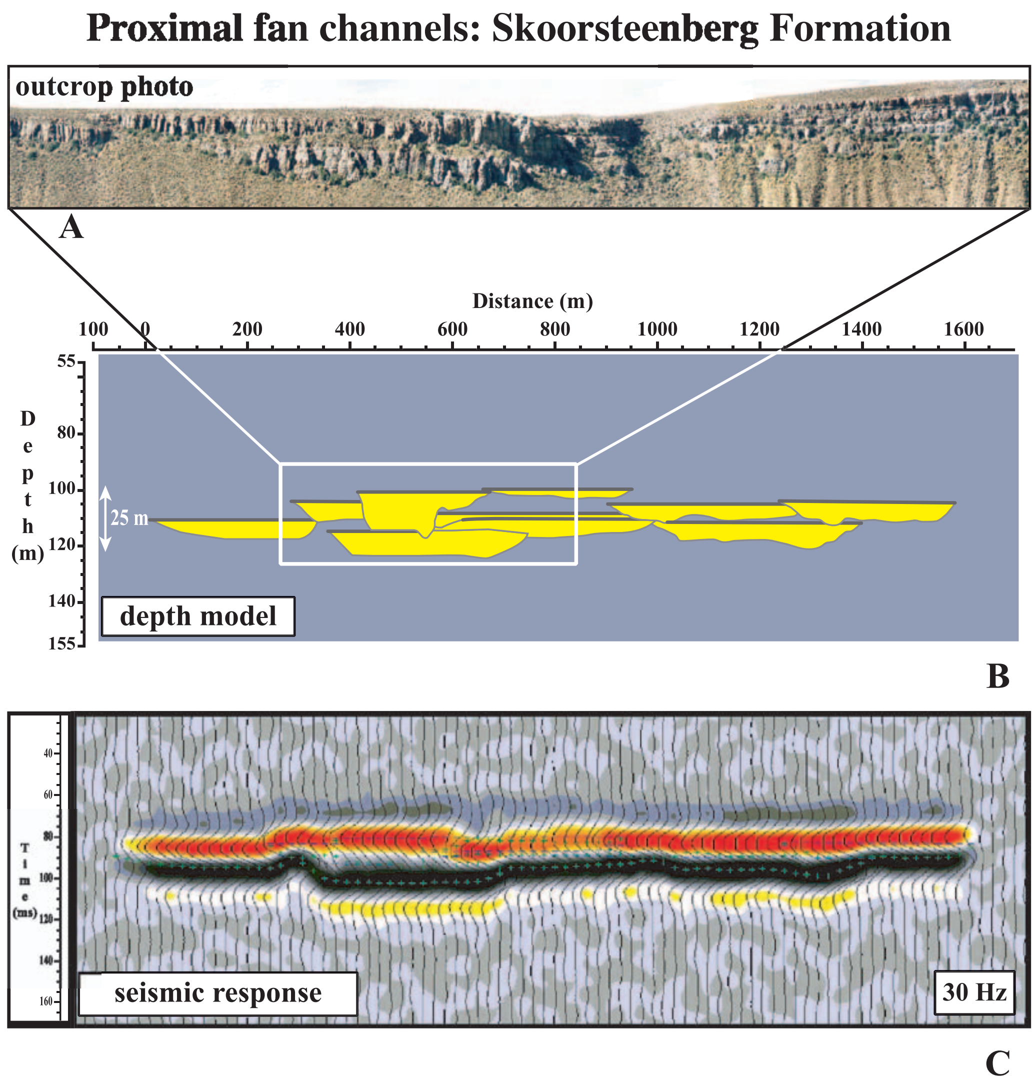

FIGURE 10. Forward seismic model for proximal fan channels from the Skoorsteenberg Formation, Tanqua Karoo Basin, South Africa (Figure 3), built using GXII seismic modeling software. (A) Outcrop photo of the compensationally stacked, erosionally based, narrow (low aspect ratio) channels and interchannel sheets that dominate the most proximal exposures of the Skoorsteenberg Formation at Ongeluks River. (B) Depth model constructed for this outcrop by applying subsurface rock properties (density and velocity) from deep-water reservoirs in the Gulf of Mexico to the digitized interpretation of this outcrop and assuming that the reservoirs are encased by mudstones. (C) The seismic response for a 30-Hz wavelet images these intercutting channels as a single-cycle event. Amplitude, isochron, and dip variations on the base reservoir can yield clues to the net sand and channel locations, as the brightest amplitudes and thickest isochron correspond to the most channelized and highest net-to-gross portion of the outcrop. The distribution of interreservoir mudstones, however, is not resolved by the forward seismic model (modified from Sullivan et al., 2000b).

a result, has a lower amplitude. In contrast, Diana 1 is drilled in a lower amplitude within the gas cap, and the net-to-gross is significantly lower (approximately 65%). Laterally away from the Diana 1 penetration, the amplitudes brighten, and this is interpreted to reflect more axial, higher net-to-gross portions of the reservoir (Figure 12A). The seismic character of this segment of the reservoir, therefore, suggests a less-channelized reservoir than updip (Figure 12C). In fact, the seismic character is very similar to the forward seismic model for the channelized sheets, which dominate the transition from proximal to medial fan deposits of the Ross Formation (Figures 9, 12). This supports the proximal fan interpretation for the updip deposits around Diana 2 and 3 (Figure 11).

Excellent core coverage in the Diana field also enables close calibration of seismic and well data. The cored interval is comprised of stacked, sharp-based, upward-fining channels (Figures 13, 14). Individual channel-fill successions can be subdivided into channel-axis,

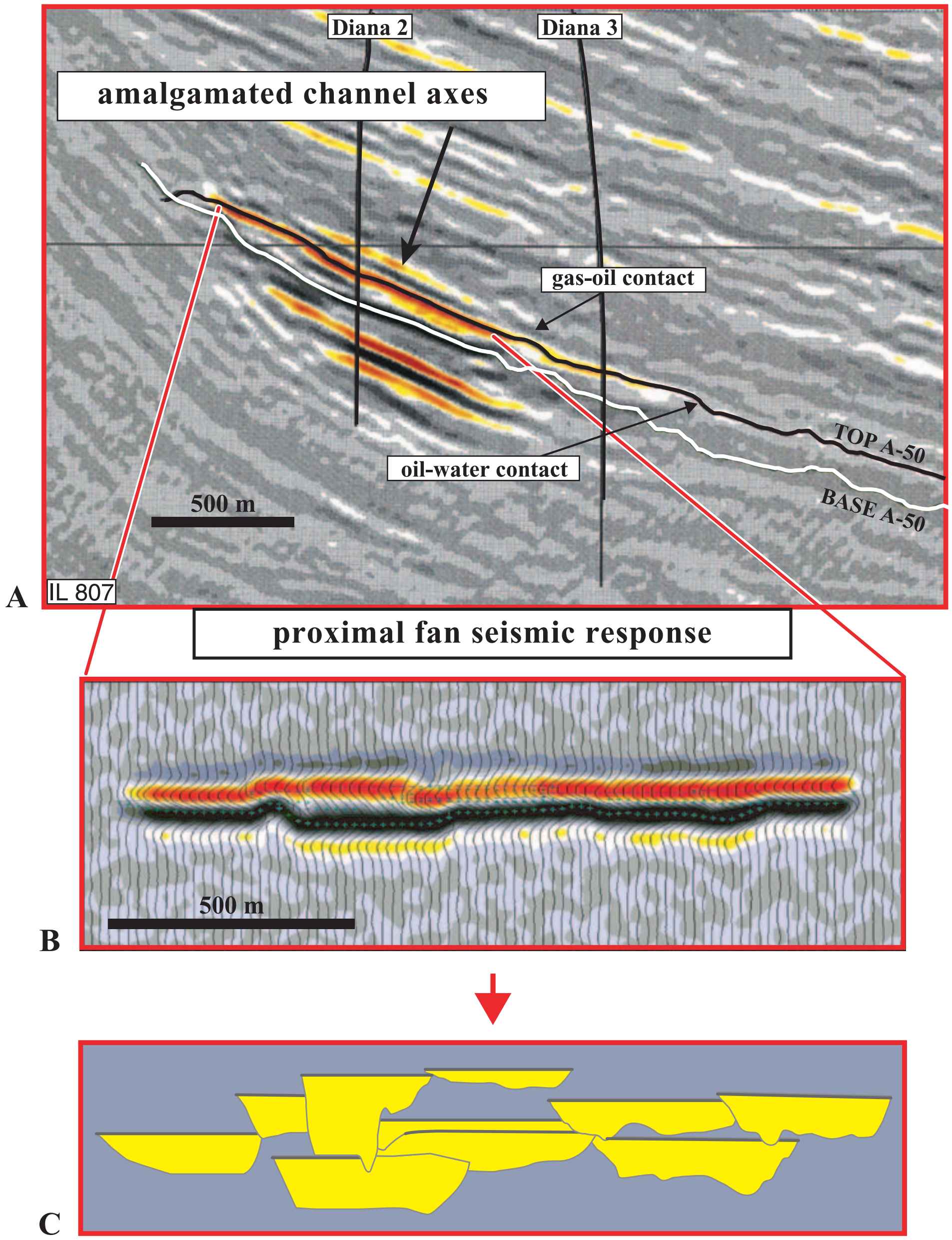

Figure 11. (A) Inline 807 is a depositional strike section through the reservoir (see Figure 1 for location). The proximal portion of the Diana Subbasin, which includes the Diana 2 and Diana 3 well penetrations, is represented by high-amplitude, continuous seismic character above the gas-oil contact. The observed amplitude dimming toward the Diana 3 location is fluid related (change from gas to oil) and is not associated with variations in net-to-gross. Subtle variations in isochron are observed for the A-50 and may suggest a more channelized reservoir, but it is not conclusive. (B) The forward seismic model of the proximal fan channels from the Skoorsteenberg Formation is very similar to the seismic character observed on the seismic line through the Diana 2 and Diana 3 wells. (C) This similarity between the forward seismic model of the proximal fan outcrop and the actual seismic data supports the channelized, proximal fan interpretation for the A-50 reservoir in this portion of the basin.

channel off-axis, and channel-margin associations in a similar fashion as the outcrops of the Skoorsteenberg and Ross Formations (Figures 3–7). Channel-axis deposits are characterized by highly amalgamated, massive sandstones deposited from high-concentration turbidity currents (Figures 13, 14). The channel off-axis association is composed of stacked, semi- to nonamalgamated, massive to planar-stratified sandstones and interlaminated mudstones (Figure 14). The channel-margin deposits contain a variety of lithofacies and are characterized by a heterolithic mixture of interbedded sandstones and mudstones (Figures 13, 14). Statistical foot-by-foot comparisons of log curves vs. core-described lithofacies were used to interpret depositional facies in uncored portions of wells. Blocked wells were further used to condition an object-based geologic model and to control the distribution of channel elements and vertical stacking patterns (Figure 14).

Integration of seismic, well-log, and core data with forward seismic models of deep-water outcrop analogs, therefore, suggests a more channelized reservoir updip (Figure 11), becoming more distributive and sheetlike downdip (Figure 12). This subsurface data, however, does not have the resolution to provide the dimensional and architectural data required to populate a geologic model for flow simulation and well-performance prediction.

DIANA RESERVOIR MODEL

To solve these uncertainties, dimensional and architectural data (e.g., width vs. thickness measurements) from the Skoorsteenberg and Ross deep-water outcrops

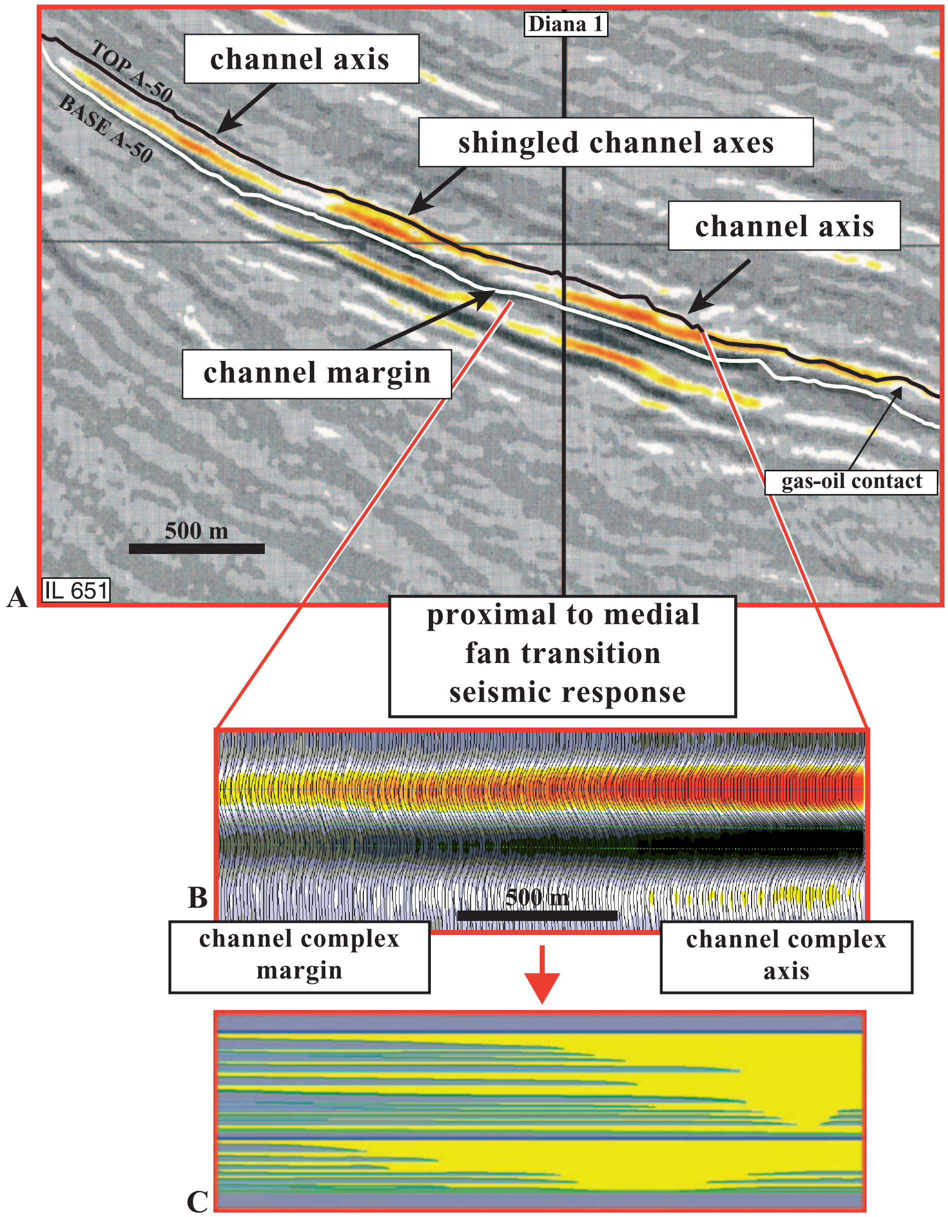

Figure 12. (A) Inline 651 is a depositional strike section through the reservoir (see Figure 1 for location). The medial portion of the reservoir (Diana 1 well penetration) has a distinctly different seismic character than the updip interpreted proximal portion of the reservoir (Figure 11A) and is represented by a high-amplitude, semicontinuous seismic character above the gas-oil contact. The observed lateral variation in seismic character of the A-50 sands in the vicinity of Diana 1 suggests that seismically detectable variations in net-to-gross and reservoir architecture exist. (B) The forward seismic model of the channels/sheets, which characterize proximal to medial fan transition in the Ross Formation, bears a striking resemblance to the seismic character of the A-50 reservoir where Diana 1 is drilled. (C) The seismic character of this segment of the reservoir, therefore, suggests this portion of the A-50 reservoir is less channelized than updip in the vicinity of Diana 2 and Diana 3.

(Figures 3–7) were compared to the interpreted thickness data derived from the Diana-specific seismic, well-log, and core data and were adjusted accordingly (Figures 13–15A). From these measurements, a spectrum of channel dimensions and shapes was collected. Comparison of the forward seismic models of the Skoorsteenberg and Ross deep-water outcrops to the actual Diana seismic data was made to select the appropriate architectural data to populate the reservoir model (Figures 11, 12, 15). In addition to the collection of channel dimensions and shapes, bed continuity, and lateral and vertical facies, variability data also were gathered from both outcrop analogs and well logs/core to condition the reservoir model, as these factors ultimately control the reservoir behavior (Figures 6, 13, 14).

In the case of the Diana field, this data was used to help maximize the development of the relatively thin, yet economically important oil rim. This was accomplished by building a detailed object-based reservoir model, which integrated both subsurface and outcrop data. The model was built using ExxonMobil proprietary code for modeling deep-water reservoirs and the reservoir modeling system IRAP-RMS object-based modeling tool. This model consists of discrete objects (facies bodies), each with specific dimensions, facies juxtapositions, and continuity. This type of modeling is appropriate in data-limited situations where a facies model is based on a conceptual interpretation of reservoir architecture. The reason for choosing this technique to model the Diana reservoir included (1) the poor quality of the seismic data, (2) limited well penetrations, (3) interpretation of the reservoir being comprised of channels with distinct lateral changes in facies (axis to margin), (4) interpretation of updip to downdip changes in channel

FIGURE 13. Plain light (left side) and ultraviolet (right side) core photos from Diana 3 well. The cored interval is comprised of sharp-based, upward-fining channels (red arrows mark interpreted channel bases) and individual channel-fill successions that can be further subdivided into channel-axis, channel off-axis, and channel-margin associations. Note: core depth is in feet (modified from Sullivan and Templet, 2002). See Figure 14 for key to bed types.

architecture and net-to-gross, and (5) desire to apply a concept-driven geologic model that incorporated outcrop analog information.

The fundamental object in this reservoir model is a turbidite-dominated deep-water channel. In the Diana model, individual channels are narrow updip and become wider and less amalgamated downdip (Figures 16, 17), as observed in the outcrops of both the Skoorsteenberg and Ross formations (Figures 3–7). Modeled channels are divided into proximal, medial, and distal regions with their own specific set of characteristics. Channels are subdivided further into axis, off-axis, and margin associations. Lateral degradation in reservoir quality from axis to margin is interpreted from core data, as observed in the outcrops of the Skoorsteenberg and Ross Formations (Figures 3–7). Shales were inserted as objects in a fine-layer (0.1 m) framework. The spatial distribution of shales in a given facies type is random (e.g., there was no preferential placement of shale either areally or vertically in the 3-D model volume). The volume of shale added to a facies depended on the net-to-gross of the facies type (e.g., axis vs. margin). Shale dimensions were obtained from the Skoorsteenberg and Ross Formations (Figure 6). Shale objects in the model are square or rectangular in shape, and their dimensions depend on facies type (e.g., axis vs. margin) and location (e.g., proximal vs. distal).

The final model contains more than 100 individual channels, each one stochastically generated from a range of possible widths and thicknesses (Figures 16–18). The facies objects were inserted first at the well locations and then subsequently inserted stochastically into interwell regions according to geologic constraints (e.g., vertical stacking patterns), until volume targets were met. Net-to-gross maps, which were generated by calculating the average value of the sand-shale parameter at a given X, Y location in the model, provide an indication of how the net sand is distributed in the model (Figure 18). The resulting net-to-gross maps strongly resemble modern deep-water systems, such as the Mississippi Fan (Figure 19), and further support this

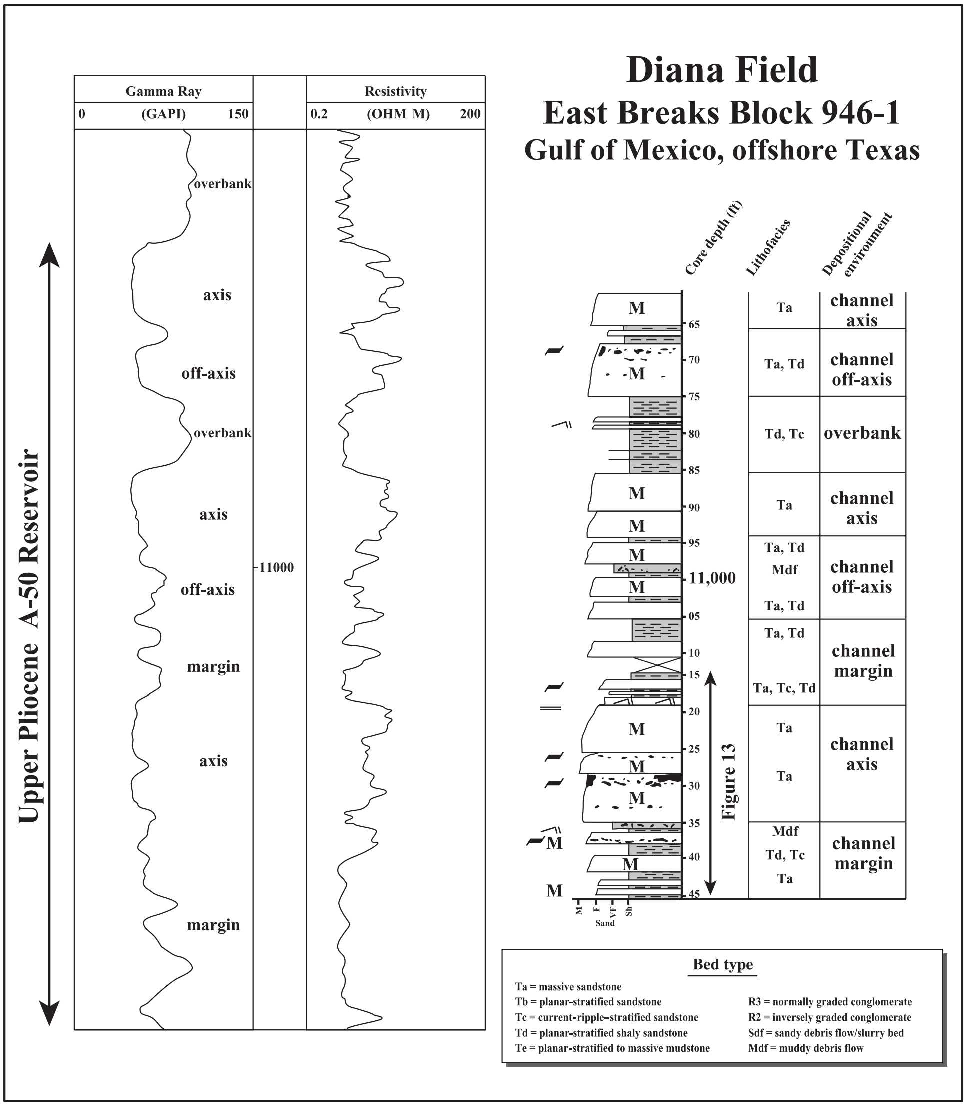

FIGURE 14. Summary plot for EB 946-1 well (Diana 3) illustrating core lithofacies, interpreted depositional setting, and relationship between log and core depths for the A-50 reservoir. A statistical foot-by-foot comparison of gamma-ray logs vs. core-described facies for all cored intervals was used to interpret the depositional facies in uncored portions of wells. These facies-blocked wells were then used to condition the object-based model and control channel distribution and vertical stacking patterns (modified from Sullivan and Templet, 2002).

integrated study. Each facies and subfacies body was then populated with petrophysical properties using Gaussian simulation drawn from subfacies property histograms generated from available well data. To preserve the facies architecture and heterogeneity expected in a channel-dominated deep-water setting, the rock property modeling was performed in individual channel objects.

Based on this modeling effort and flow simulation, significant variations in reservoir performance exist from updip to downdip (Figure 20). The development strategy for the Diana field is to produce oil initially from horizontal wells high in the oil rim. Once water breaks through in significant quantities, these wells will be recompleted in the gas cap. The goal is to maximize oil production while minimizing water production and movement of oil into the gas cap. Typically, reservoir models are scaled up for flow simulation. However, in this case, the updip portion of the reservoir was actually scaled down to preserve its more channelized and amalgamated nature (Figure 20). The updip portion of the reservoir has higher initial oil saturations because of its higher porosities. It also starts producing water earlier than the downdip portion of the reservoir because of its higher porosities and more channelized nature. This study, therefore, predicts significant variations in reservoir producibility that exist across the Diana field. This information was used to place wells in optimum locations to maximize the architectural controls on reservoir performance and has had a significant impact on the final development strategy for the field.

CONCLUSIONS

This study shows the importance of incorporating outcrop analogs in the analysis of subsurface reservoirs. Outcrop research is critical because the observed updip to downdip variability in sand-body geometry, continuity, and net-to-gross of deep-water reservoirs affects both the exploration and production potential of these sandstones. Commonly, this variability, as in the case of the A-50 reservoir at the Diana field, is at or below seismic resolution, and well penetrations are

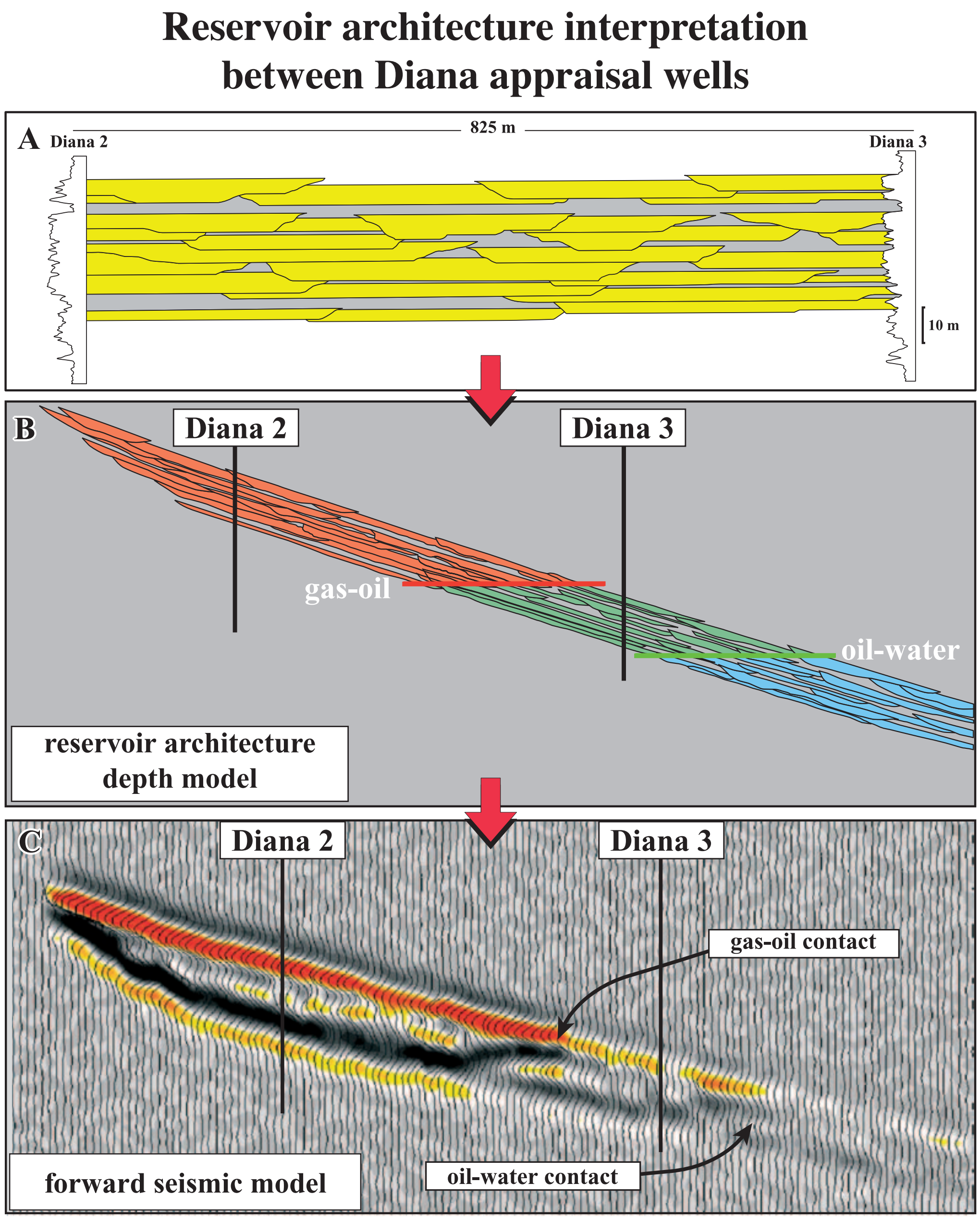

FIGURE 15. (A) Integration of Diana seismic, well-log, core, and appropriate outcrop analog data provided the detailed geometric data required for interpreting the reservoir architecture at a subseismic scale. (B) Depth model constructed for interpreted reservoir architecture between Diana appraisal wells by applying subsurface rock properties (density and velocity) from the A-50 sandstones at the Diana field. (C) The forward seismic model generated from the interpreted reservoir architecture between the Diana appraisal wells produces a seismic response extremely similar to the actual seismic data (see Figure 11), suggesting that the appropriate architectural data had been selected to populate the reservoir model.

typically limited. Properly calibrated deep-water outcrops can provide constrained geometric and architectural data to fill the gaps between wells or stochastic modeling uncertainties below the resolution of seismic data. Dimensional and architectural data from outcrops and forward seismic modeling can therefore be integrated with seismic and wellbore data to build regional depositional models to better understand reservoir distribution and delineate exploration plays. Deep-water outcrop data can also be used to help populate object-based models that can be used to more accurately predict well performance, connected volumes, and recovery efficiencies for newly discovered fields. Furthermore, the integration of seismic, well-log, core, and outcrop data with object-based models provides the framework for optimal placement of wells to maximize the architectural controls on reservoir performance. The bottom-line impact of this type of integrated analysis has been a significant reduction in the range of uncertainty attached to reservoir assessment parameters for deep-water sandstones, both in the Diana Subbasin and in many other areas where exploration and development of deep-water reservoirs is currently occurring.

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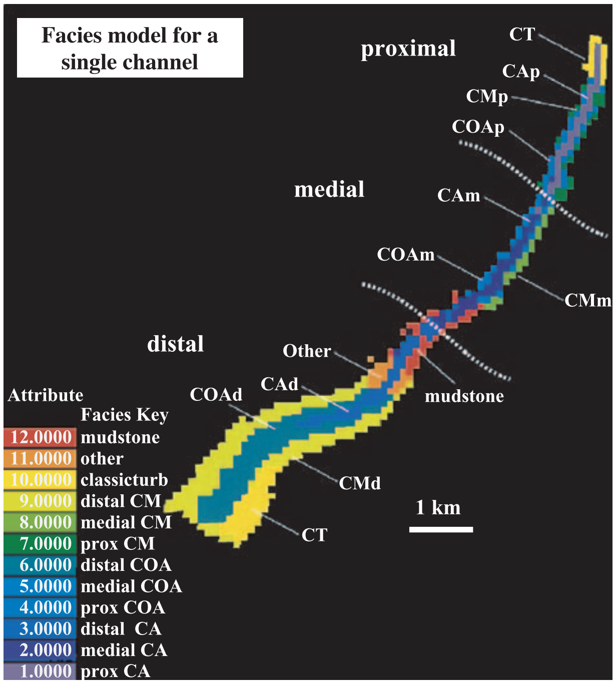

FIGURE 16. Single-channel (facies body) model. Modeled channels are divided into proximal (p), medial (m), and distal (d) regions, each with their specific set of characteristics. Channels are further subdivided into axis (CA), channel off-axis (COA), and margin associations (CM). The final model contains more than 100 individual channels generated from a range of possible widths and thicknesses (modified from Sullivan et al., 2000a).

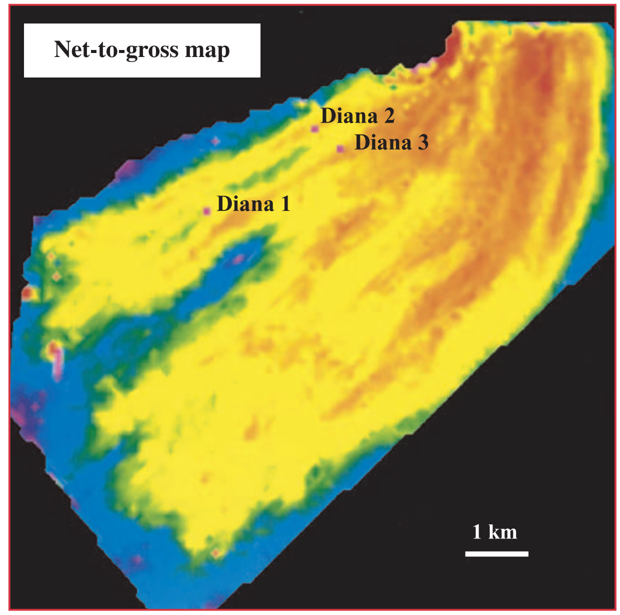

FIGURE 18. Net-to-gross map generated from the facies model, assuming a constant net-to-gross of 0.95, 0.85, 0.65, and 0.10 for the channel axis, channel off-axis, channel margin facies, and overbank facies, respectively. Net-to-gross ranges from greater than 0.95 in the proximal area (red) to less than 0.40 in the distal area (purple). A low net-to-gross "crease," shown just east of the southern stewardship polygons, honors an interpreted net-to-gross low, visible on seismic amplitude maps.

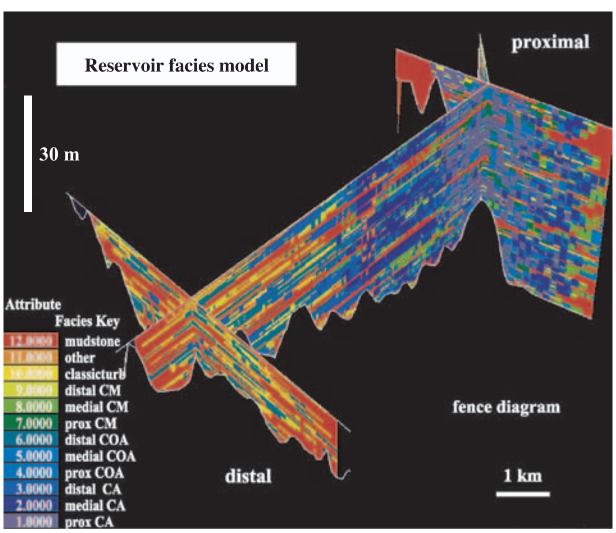

FIGURE 17. Based on this modeling effort, notable variability exists in both the vertical and lateral continuity of the reservoir facies from updip to downdip. This is illustrated by the change in cell dimensions from thicker and more equal dimensional (amalgamated) updip to thinner and more elongate (nonamalgamated) downdip (modified from Sullivan et al., 2000a).

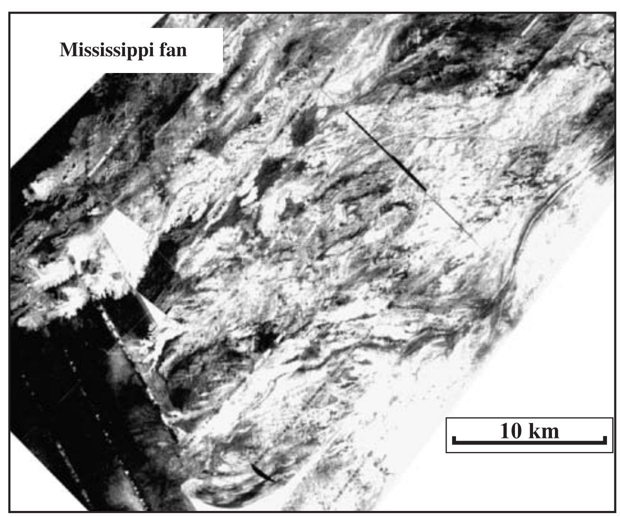

FIGURE 19. Side scan sonar image for Mississippi Fan illustrating the detailed sand-body architecture. The bright colors represent more sand-prone regions of the fan. The map pattern of this modern fan, which has been rotated to match the orientation of the Diana net-to-gross model, is extremely similar to the map pattern produce by the Diana net-to-gross model. This similarity between the map patterns of the Mississippi Fan and the object-based model for the A-50 reservoir helps to validate the modeling effort (modified from Twichell et al., 1995).

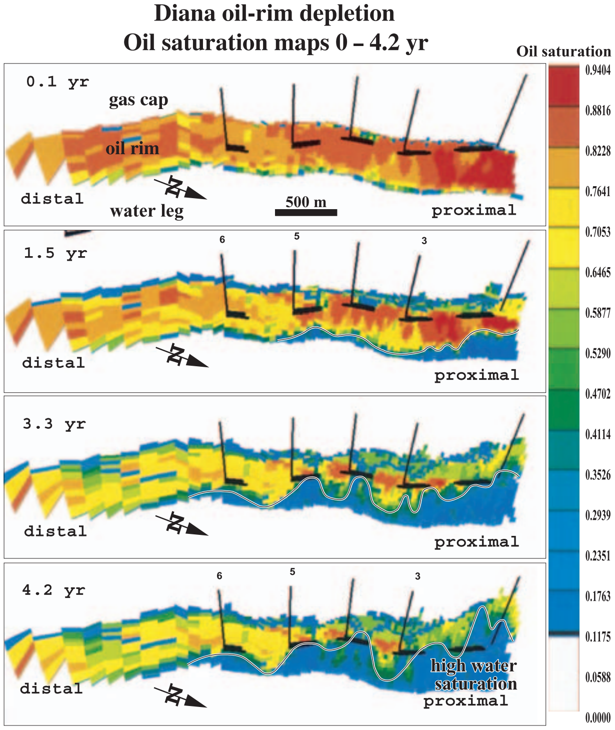

FIGURE 20. Oil saturation maps for the Diana oil rim for the first 4 yr of production. Note that the Diana gas cap and aquifer are not shown. The updip portion of the reservoir has higher initial oil saturations because of its higher porosities and also starts making high water cuts earlier than the downdip portion of the reservoir because of its more amalgamated character and better reservoir quality. The smaller cell size observed at the proximal portion of the model reflects the downscaling of the reservoir relative to the distal portion of the reservoir that was upscaled (modified from Sullivan et al., 2000a).

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