3-D seismic attributes applied to carbonates

CHRISTINE SKIRIUS, Amoco Exploration & Production Technology Group, Houston, Texas, U.S.
SUSAN NISSEN, NORMAN HASKELL, and KURT MARFURT, Amoco Exploration & Production Technology Group, Tulsa, Oklahoma, U.S.
SCOTT HADLEY, DAVE TERNES, KARIN MICHEL, IAN REGLAR, DAVE D'AMICO, and FRED DELIENCOURT, Amoco Canada Petroleum Co. Ltd., Calgary, Alberta, Canada
TONY ROMERO, Amoco Sharjah Oil Company, Sharjah, United Arab Emirates
RICHARD D'ANGELO and BILL BROWN, Amoco Norway Oil Company, Stavanger, Norway

Coherency mapping has become a widely used tool within Amoco and is being applied in both frontier exploration and exploitation areas. Coherency and other 3-D seismic attributes have been successfully used to identify and delineate features in clastic depositional environments, including reworked deltaic sand bodies, deltaic channels with associated point bars, slump features, debris flow outrunner blocks, and various geologic drilling hazards including faults, salt diapirs, buried channels, and shallow gas pockets.

Coherency techniques have shown to be particularly useful for recognizing and interpreting these features because of the ability to easily detect faults and boundaries indicating apparent lithologic contrasts. Interpretations of sedimentological features observed on 3-D seismic coherency maps have been confirmed by correlation with standard seismic data and well logs. Similar calibration efforts could be used to confirm the significance of many of the coherency patterns and textures associated with carbonate depositional environments. This report documents several examples where coherency techniques have been applied to different types of carbonate terrains and the results of various degrees of calibration applied to each.

Problems with carbonates. Carbonate systems, by virtue of their inherent complexities, present many challenges when attempting to identify and delineate a carbonate reservoir from seismic data. Although 3-D seismic data offer the advantage of mapping lateral variations within a survey area, carbonate reservoirs are typically not "well-behaved" or laterally predictable as are many clastic reservoirs. Carbonate reservoirs are largely controlled by original depositional environment or facies and, importantly, later diagenetic changes. In carbonates, unlike clastics, porosity and permeability can be strongly dependent on diagenesis that does not necessarily follow facies boundaries. This can make carbonate reservoirs extremely heterogeneous and unpredictable in the subsurface. In addition, facies changes in carbonates can be subtle and overprinted by multiple stages of diagenesis, making identification of reservoir boundaries by any means a particular challenge.

Production in carbonates is often complicated by compartmentalization of high permeability zones that require natural or induced fracturing or other costly enhanced recovery techniques to make the reservoir economic.

In addition to sedimentological and production issues, carbonates also present challenges in seismic imaging because of poor contrasts in acoustic impedance. Typically, carbonate reservoir compositions can be represented by a very limited mineralogy, limestone or dolomite, with a very small velocity contrast. Contrast in velocity between carbonate reservoir and surrounding rock may or may not produce a strong reflection, depending on the compositions of the rocks and the fluid/gas occupying pores. Typical shale sealing facies is poorly distinguished seismically from porous, oil/gas-charged carbonate reservoir. This poor velocity contrast between reservoir and sealing facies leads to the common problem of accurately delineating the economic reservoir limits or trap definition. Details on the current state-of-the-art seismic expression of carbonate reservoirs can be found in *Carbonate Seismology* (SEG, 1997).

3-D seismic attributes and carbonates. An ultimate goal of seismic imaging techniques is to locate hydrocarbons. Because diagenetic complications can make the distribution of porosity and permeability in carbonates difficult to predict, a tool that could map lateral and vertical variations in porosity and/or permeability from 3-D seismic data would be extremely useful in delineating a carbonate reservoir. Seismic amplitude maps traditionally have been used as a tool for delineating porosity in 3-D carbonate data sets. Spectral decomposition and the tuning cube applied to a horizon of interest could have a potential advantage over conventional amplitude extraction for imaging aspects of carbonates because variability in the local rock mass (i.e., local geology, fluids, sedimentology) is involved in tuning the seismic wavelet's amplitude spectrum. Decomposition of the seismic wavelet into discrete frequency components allows the interpreter to analyze and map seismic features as a function of spatial position, two-way traveltime or depth, amplitude, and frequency. Interpreting what aspects of the local rock mass are contributing to a spectral decomposition image requires integration and calibration of seismic, log, core, and production data. The coherency technique images discontinuities (i.e., faults and stratigraphic features) and can also provide map views of a horizon of interest that leave the interpreter with patterns and subtle textures that may or may not have geologic meaning.

An important consideration when running coherency, as well as any seismic attribute, is whether to apply it to a horizon of interest or to apply it to a slab of data and then extract it as a time slice. A seismic attribute along a picked horizon forces the attribute to be dependent upon the interpreter's picking and in this sense is not an entirely objective process. This should be kept in mind when interpreting attribute horizon maps because picking poorly defined or discontinuous reflectors of some carbonate units can be difficult. However, extracting an attribute along an interpreted horizon should best encompass the geology of the unit. The alternative is to take attribute time slices that could indiscriminately cut through geology that may be dipping or otherwise structured and not representative of the horizon of interest. The following examples show the seismic details that can be captured and calibrated when 3-D seismic coherency and spectral decomposition techniques are applied to carbonates.

Reef edge detection in a Leduc carbonate reef bank. Numerous upper Devonian Leduc reef gas traps occur

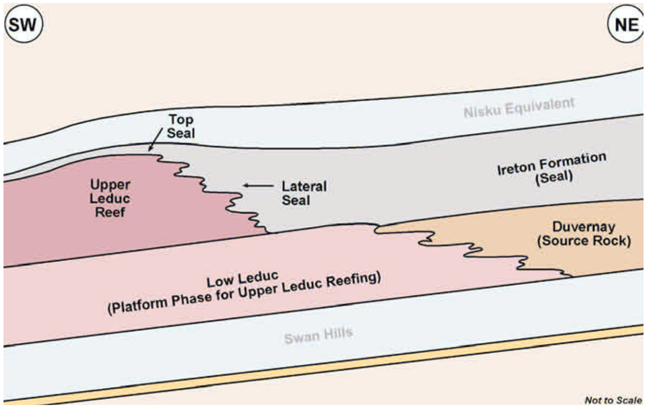

Figure 1. Schematic representation of a southwest-dipping Leduc reef margin showing the Ireton Formation as a lateral seal and partial top seal to the reef. Hydrocarbons are trapped at the updip edge of the reef. A structural rim is often found at these margins and is primarily a result of compaction.

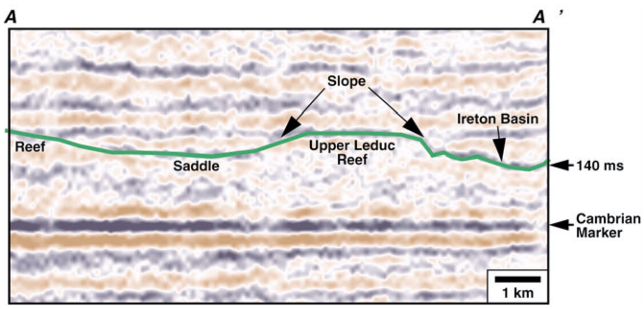

Figure 2. Strike-oriented seismic line A-A′ from the 3-D survey, flattened on Cambrian marker.

throughout the western Canada sedimentary basin. A schematic representation of a Leduc trap is shown in Figure 1. Gas is found at the updip terminations of Leduc reefs that are laterally juxtaposed against sealing Ireton Formation basinal rocks. 2-D seismic data over a deep (>5 km) Devonian reef target located in an autocthonous sub-thrust position is poor, making reef edge detection difficult. Hence, trap definition risk and reservoir limits are concerns in this area. A sparse 3-D was acquired in 1993 by Amoco Canada to address these risks.

A strike-oriented seismic line from the 3-D survey is displayed in Figure 2 and an amplitude time slice in Figure 3. Although the data are "noisy," the figures clearly show a continuous reef slope signature (blue amplitudes, Figure 3) separating basinal sediments to the north and east from the carbonate reef body to the south and west. A drill location (yellow dot, Figure 3) confirmed the interpretation of a full Leduc reef. Pyrobitumen (a product of thermal cracking of oil) is found throughout the Leduc at this location, and its presence is an indication of a gas trap. Production testing of the well shows the reef to be wet.

Application of the seismic coherency technique provides confirmation of the reef edge interpretation (from amplitude) and enhances definition of basement faults (Figure 4). Numerous linear faults strike northwest to southeast paralleling structural strike of the basin. The faults cut across the low Leduc platform as well as the upper Leduc reef margin. These faults could have created localized highs to initiate Leduc reefing. Reactivation of the faults in Late Cretaceous–Early Tertiary time is thought to have been the main mechanism for gas leakage here.

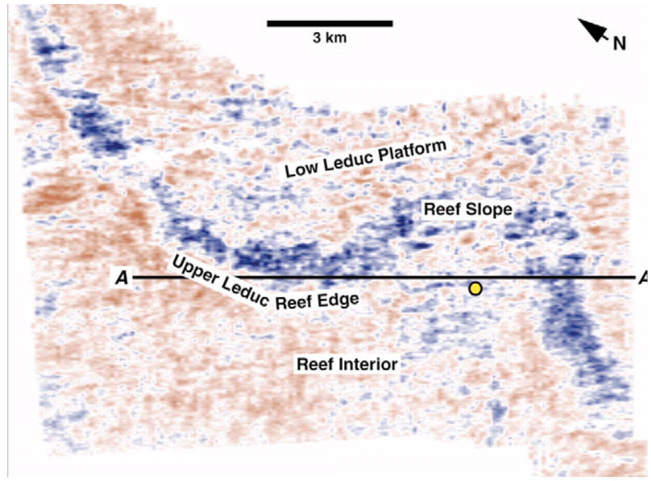

Figure 3. Amplitude time slice of the 3-D survey at 140 ms above the flattened Cambrian marker. The reef slope is seen as a continuous blue pattern.

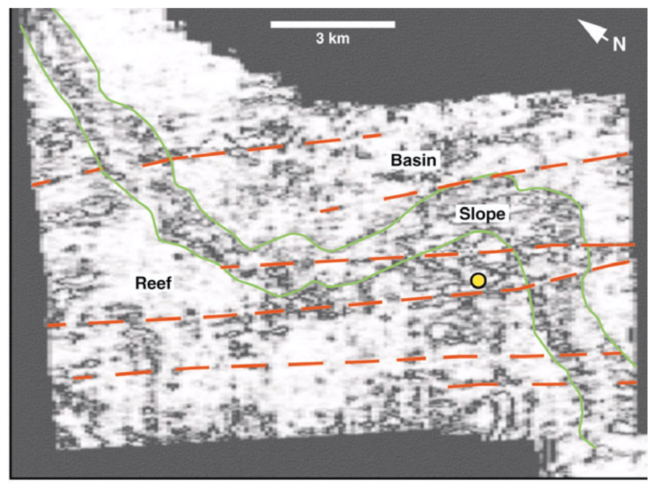

Figure 4. Coherency time slice from the 3-D survey at 140 ms above the flattened Cambrian marker. Note the basement faults (red) and the sharp coherency response of the reef edge to basin transition (green).

Pinnacle reefs in Alberta. Amoco Canada acquired a 3-D data set in southwest Alberta to explore for Leduc pinnacle reefs of Devonian age. The pinnacles are encased in Duvernay and Ireton shales. The seismic panel in Figure 5 runs through pinnacle reef wells at L1, L2, L3, and L5, and a basinal well at L4. The Leduc is the picked horizon between 2025 and 2065 ms. The pinnacle reefs are characterized by a dimming of the platform event underneath the pinnacles and a subtle character change above the platform event. Coherency was run to see if it could shed any light on whether the proposed location at L3 would encounter the same reef mass as the L2 well bore.

Figure 6 shows a horizon-based coherency run on the smoothed Leduc horizon with a 50-ms window and 0-ms offset. There is a zone of moderate to strong incoherency where the horizon picking jumps from the strong platform event to the weak pinnacle reef event. Notice that the L4 well has just missed a pinnacle to the east of the well bore. The low coherency in the southwest, southeast, and northwest corners of the survey is due to poor data quality.

Figure 7 shows coherency run at the time of 2060 ms with a 50-ms window and 0-ms offset (2060 ms corresponds to the basal part of the pinnacle at L5 and L3). Noise is again the cause of the incoherency in the corners and edges of the 3-D survey. The coherency patterns are, in general, much subtler although still strong at the L5 well. The pinnacles can be picked out in a series of time slices but do not stand out as well as they did on the horizon-based run.

It was concluded from the coherency images that the two reef masses at L3 and L2 might be separate. However, when L3 was drilled, it was found that the two reefs were in pressure communication.

Figure 8 is a series of coherency time slices of the Nisku B pool of central Alberta. It produces oil from a Nisku limestone pinnacle reef at a depth of 2400 m. Six wells have penetrated a minimum of 70 m of reef buildup and are positioned within the donut-shaped feature visible on the coherency time slices. The seventh, most southerly, well penetrated only 1 m of reef and is outside the feature. The coherency time slices clearly outline the changing geology

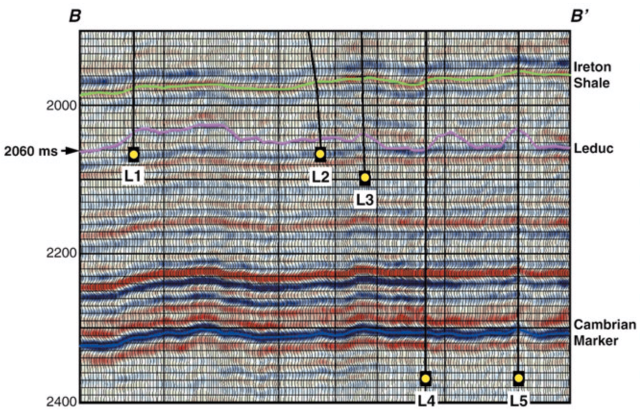

Figure 5. Seismic profile that runs through pinnacle reef wells at L1, L2, L3, and L5 and a basinal well at L4. The Leduc is the purple horizon between 2025 and 2065 ms.

from the surrounding shale basin (solid blue) to pinnacle reef edge (white) to inner reef (light blue).

Coherency mapping of fractured Shuaiba reservoir. The Aptian Shuaiba Formation is a limestone reservoir of the Sajaa Field, onshore Sharjah. Most Shuaiba production occurs in giant structural and stratigraphic traps associated with anticlines and fractures. All rock matrix porosity in the Shuaiba of Sajaa Field is microporosity formed by recrystallization (chemical stabilization) and later leaching. Petrographic and geochemical data indicate that the leaching likely occurred in the shallow to intermediate subsurface from circulation of cold, undersaturated seawater. Porosity is usually better developed and preserved on-structure and on the western margin than on other downdip portions of the field. At least two phases of fracturing have been interpreted from core and petrographic observations. Fracture porosity in Sajaa Field does not account for reservoir storage, nor do large fractures dominate flow. However, very common small, interconnected fractures apparent in core provide fracture connectivity with the rock matrix porosity and could contribute to long-term flow rates. Horizontal wells drilled by Amoco Sharjah are being targeted to cross fractures to enhance productivity, and to intersect possible higher permeability zones.

A coherency map of the Shuaiba Formation (Figure 9a) shows fractures (blue veins) and more subtle patterns (pale blue to white) that are distinct from obvious fractures that can be mapped using other techniques (Figure 9b). A coherency-derived instantaneous dip/azimuth time slice extracted at the Shuaiba (Figure 9c) shows slight variations in dip over the more coherent "top" of the structure (Figure 9d) that may indicate a slightly undulating surface or the influence of the more subtle features observed on the coherency map. The subtle, lower-coherence "channel-shaped" features within the Shuaiba are speculated to be preferential fluid conduits associated with very shallow

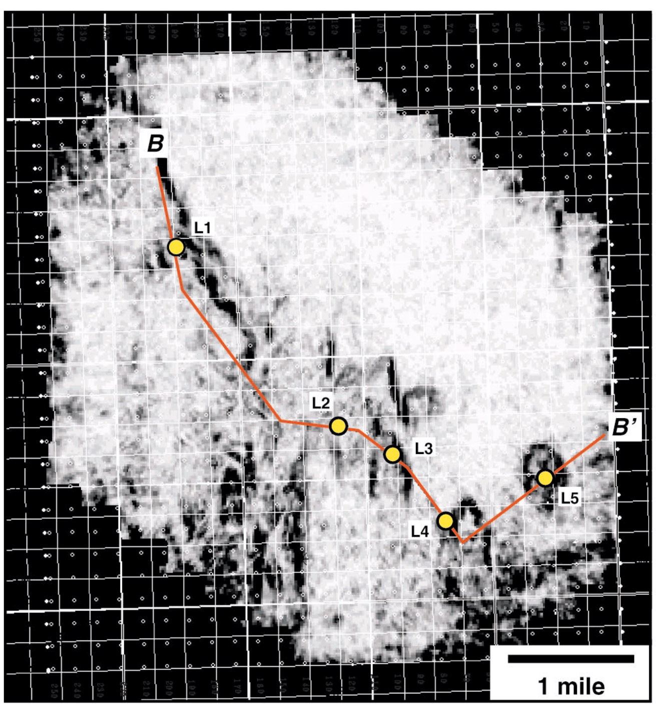

Figure 6. Coherency run on the smoothed Leduc horizon with a 50-ms window and 0-ms offset. Line shows location of seismic profile in Figure 5.

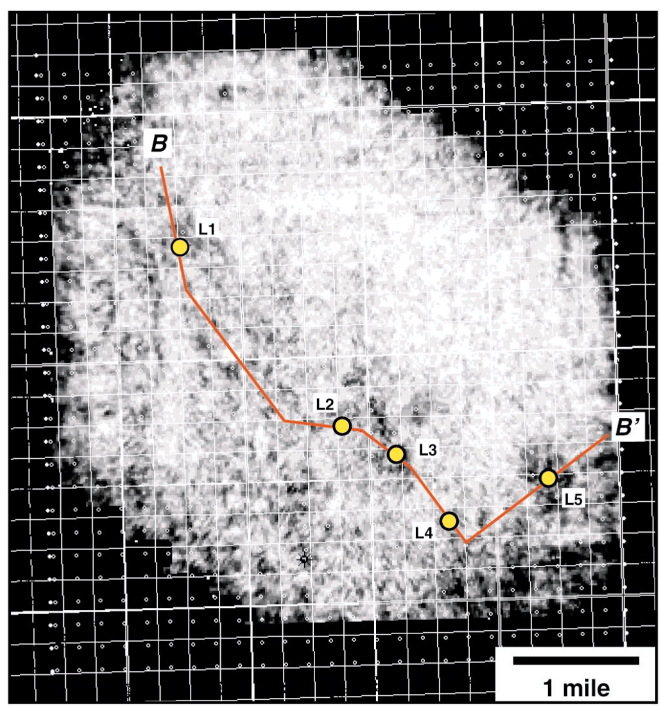

Figure 7. Coherency time slice at 2060 ms with a 50-ms window and 0-ms offset.

water environments and may be higher-permeability zones. Recent horizontal wells have intersected many of the coherency lineations and show gas/condensate (permeability) production differences along the wellbore.

Massive chalk slumping in the Tor Field area. Mobilization and redeposition of pelagic chalk prior to lithification have been recognized for many chalk sequences including those described from Denmark, Sweden, and the North Sea. Redeposited (allochthonous) chalk units also commonly show substantially better reservoir qualities than adjacent autochthonous units. Depending on the proximity to the source area, travel distance, and gradient, chalk redeposition can result in slides and slumps, debris flows, mudflows, and turbidites. The degree of lithification of the chalk determines whether its mobilization results in soft sediment deformation or brittle deformation.

Figure 10 is a coherence time slice that encompasses Tor Field of North Sea Blocks 2/4 and 2/5. A large fracture pattern is visible in the upper right of the display and is associated with massive slumping of Tor Formation and Ekofisk Formation chalk in this area. The slump feature is approximately 5-6 miles wide. Interpretation of paleontological data from well 2/05-07 just to the west of the feature and other nearby wells indicates that the slumped unit is a series of reworked chalk slumps that were successively emplaced. The apparent large scale of the fracturing interpreted from the coherency slice suggests that the chalk was at least par-

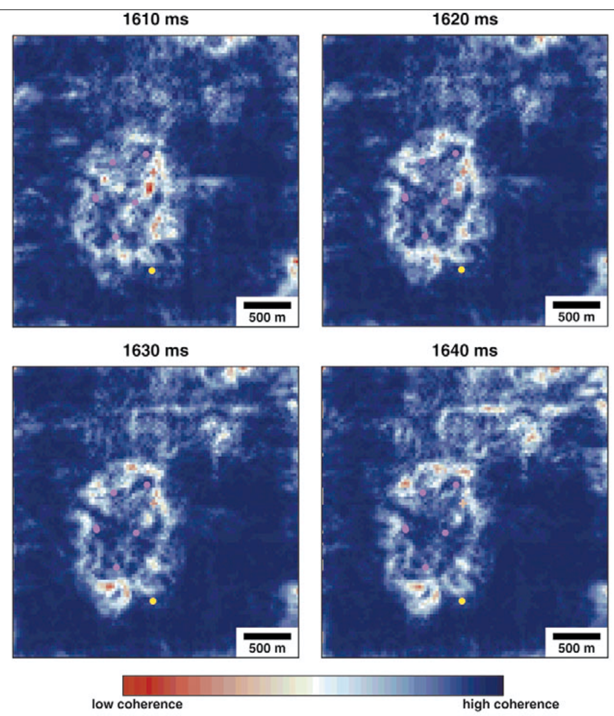

Figure 8. Series of coherency time slices at 1610, 1620, 1630, and 1640 ms of the Nisku B pool. Six wells within the donut-shaped feature (magenta) have penetrated a minimum of 70 m of reef buildup. The seventh well outside of the feature (yellow) penetrated only 1 m of reef.

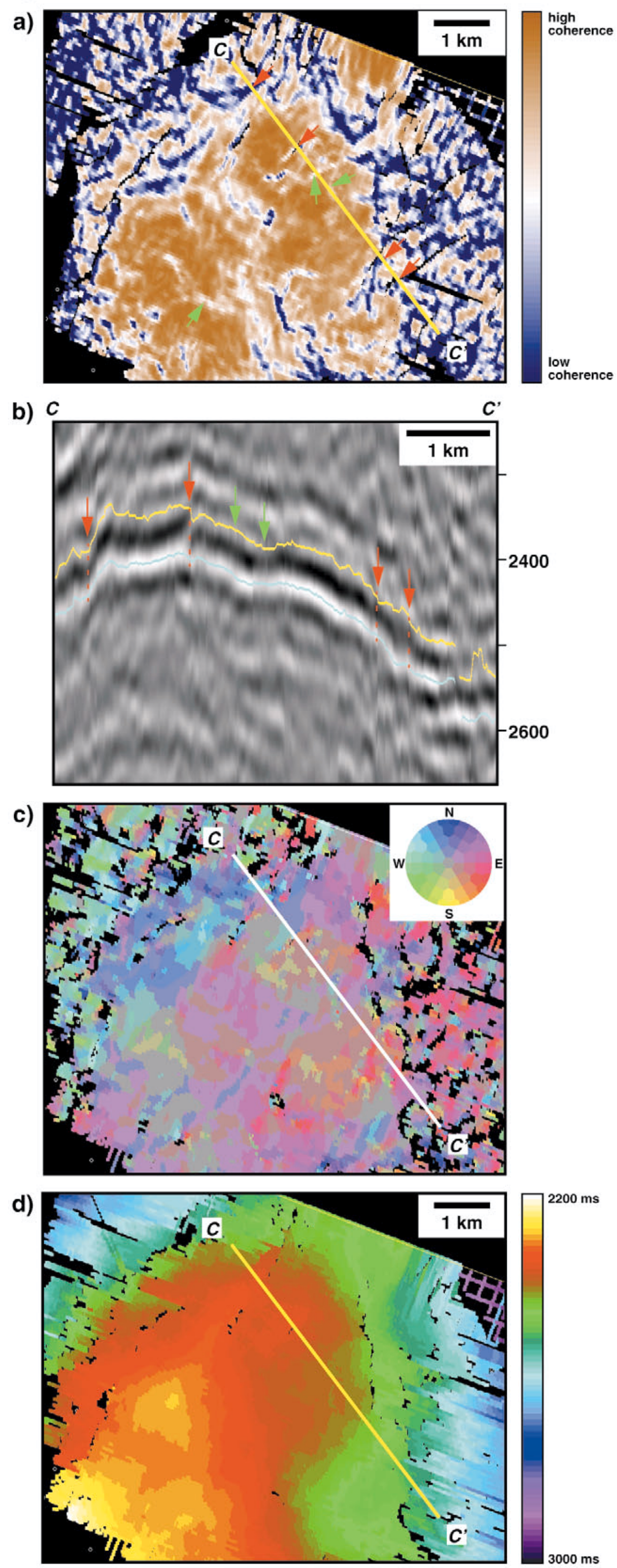

Figure 9. (a) Coherency map of the Shuaiba Formation shows fractures (blue veins) and more subtle patterns (pale blue to white). Green arrows indicate subtle "channel-shaped" features discussed in the text. Red arrows indicate the intersection of larger faults/fractures with line C-C′. (b) Seismic profile C-C′ over part of the Sajaa Field structure shows expression of larger faults/fractures seen on coherency map (red arrows); however, the subtle "channel-shaped" features (green arrows) are not readily evident on this profile. Yellow = Shuaiba Formation. (c) A coherency-derived instantaneous dip/azimuth time slice extracted at the Shuaiba Formation. (d) Time structure map of the Shuaiba Formation.

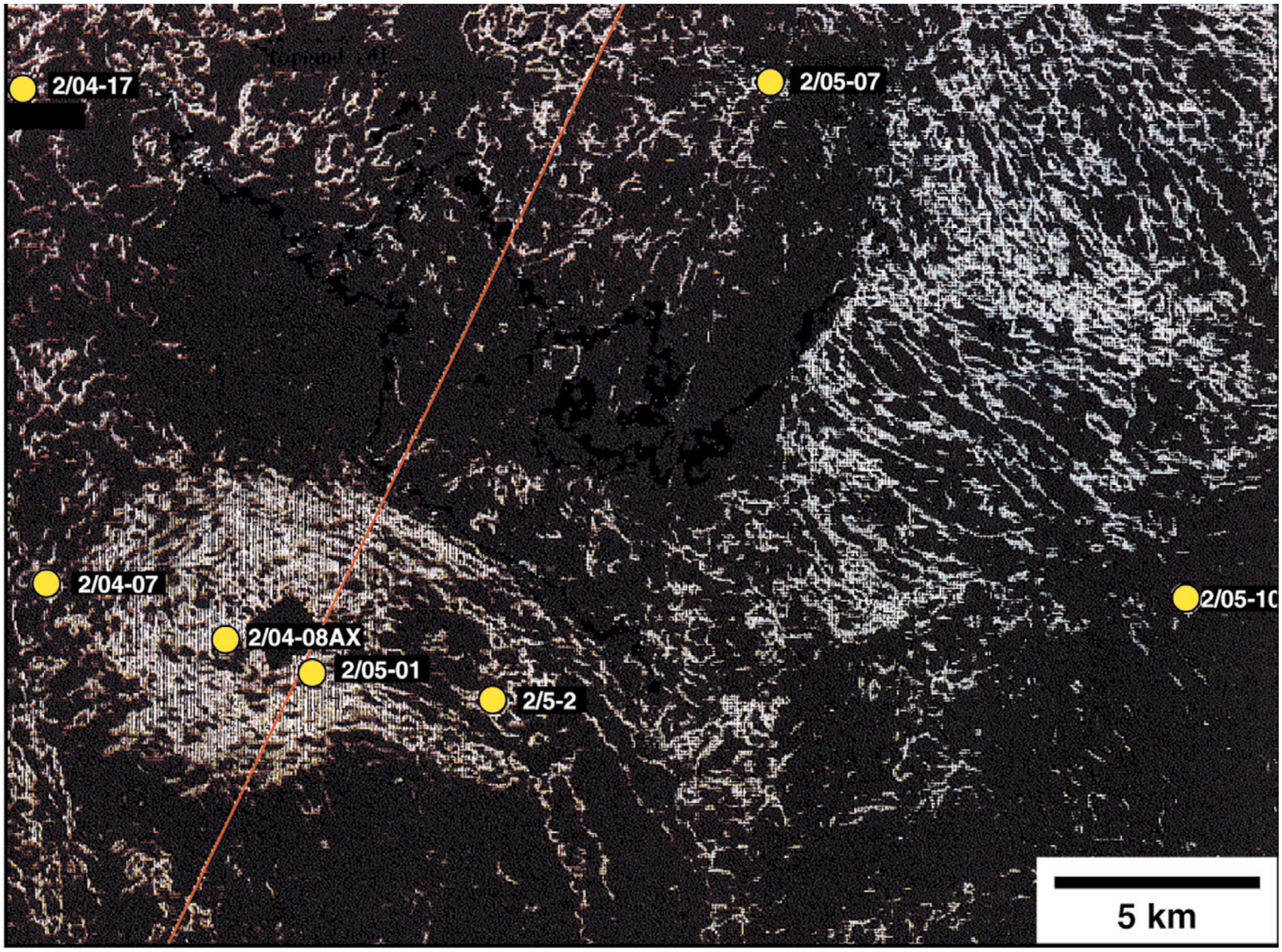

Figure 10. Coherency time slice (3256 ms) of Tor Field area shows a large fracture pattern associated with massive chalk slumping in the upper right.

tially lithified prior to mobilization such that slumping movement would cause brittle deformation and the observed en echelon fracturing. The fracture pattern also suggests that the direction of movement or gradient was downslope to the southwest. Because of the enhanced permeability and reservoir capacity provided by fractures in low-matrix permeability chalks, detection of massively fractured chalks on a seismic scale could have important exploration potential. Fractured chalks become important targets because of their potential for enhanced production and also for providing routes for hydrocarbon migration in a low-matrix permeability reservoir. Coherency mapping has an important advantage in chalk exploration areas because it can identify fractures and can also help to integrate the fracture information with seismic amplitudes associated with porosity and with the identification of structural closure.

Imaging reef edges and porosity in Devonian carbonate. A 3-D survey was shot in 1997 over a known producing gas field area to evaluate the ability to define the reef edge of an isolated reefal buildup and to detect a possible new reefal buildup to the north of the field. It was further hoped that possible indications of porosity could be confirmed and the areal distribution mapped with 3-D seismic imaging techniques such as coherency and spectral decomposition. The 3-D seismic interpretations could then be integrated with other 2-D seismic, well, and production data to better characterize and assess any further targets within the field area and northern reef as well as regionally.

The target formation is an aggradational to backstepping carbonate reef-shelf buildup. The play is stratigraphically subtle—a roughly tabular stratal package averaging 50 m in thickness. Porosity development is directly related to depositional facies in this predominantly limestone section and is found in the fringing reef/shelf margin system or in isolated reefs occurring within a widespread embayment. The laterally sealing, highly calcareous embayment fill facies renders seismic resolution of isolated reef and shelf margins difficult. The producing gas field represents an isolated reefal buildup developed within this embayment (Figure 11). Depositional facies patterns have been worked out in detail from core and log data within the target formation in this area. A trap is formed where porous grainy shoal deposits at the reef edge are sealed updip against tight embayment facies. The best producing wells in the field are located nearest to the reef edge facies (S1 and S2). More interior wells (S3, S4, and S5) have reduced rates, and wells in an interior position (S6, S7) encounter generally tighter, restricted muddy facies. The reefal buildup is isolated from another reefal buildup to the north based on a very thick (~60 m) embayment succession encountered in one well (E1) and by contouring of the facies distribution patterns.

Along with conventional 3-D seismic time-structure and amplitude displays, coherency and spectral decomposition maps were created from the target horizon to see what features could be identified and calibrated with the existing well data.

A very vague partial outline of the southern isolated reef edge is visible on a time-structure map of the top of the target formation from the processed 3-D data (Figure 12). The majority of the time-structure related to the reef edge is due to wavelet tuning not real structure.

The south reef edge is more completely defined on an amplitude map extracted at the top of the target formation (Figure 13). Also visible on the amplitude map are the boundaries of the embayment (low amplitude, dark gray

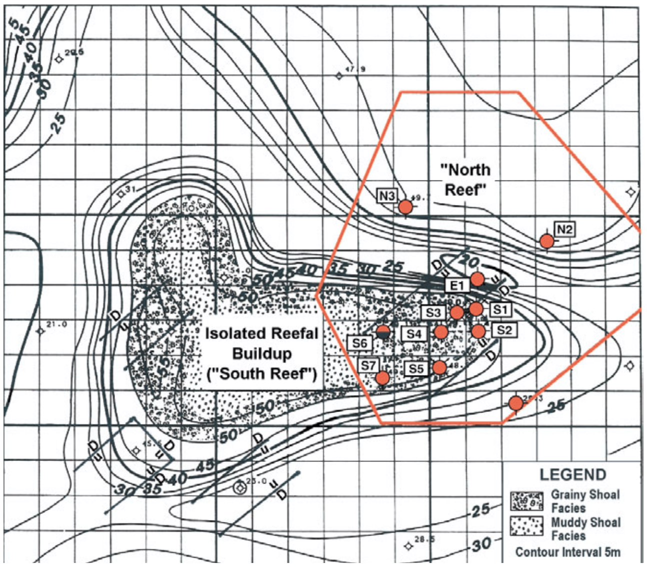

Figure 11. Map of producing gas field shows approximate outline of isolated south reef and north reef margin. Contours represent isopach from top reservoir to datum. Mapped faults are also indicated. Area of 3-D survey is outlined in red.

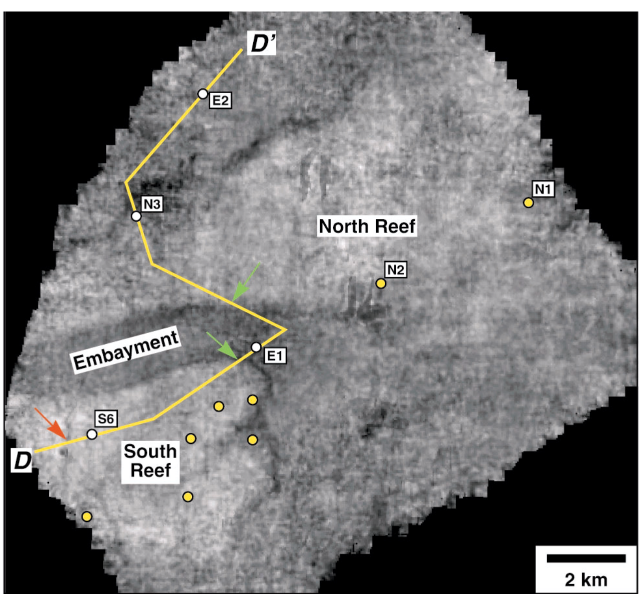

Figure 13. Seismic amplitude map extracted at the top of the target formation. Green arrows indicate the boundaries of the embayment. The red arrow corresponds to the location of a north-south fault seen in the coherency map (Figure 14) and vertical seismic profile D-D′ (Figure 15).

color) that define the northern edge of the isolated south reef and a (partial) southern edge of another reefal buildup on the other side of the embayment. Little well control exists in the north reef to establish its areal extent. However, wells N1, N2, and N3 cored porous reefal material in a downdip (wet) position. Another embayment area defines the northern edge of the north reef as indicated by low amplitudes. Logs and core from E2 and N3 in this area also indicate

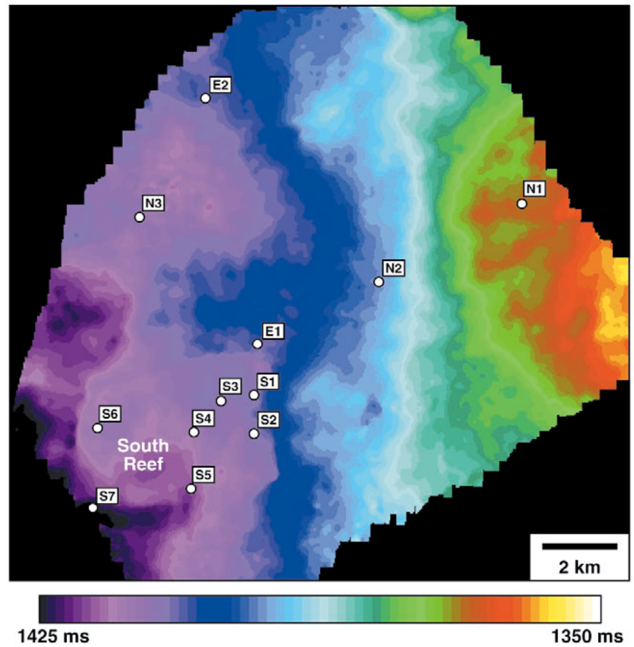

Figure 12. Time-structure map of the top of the target formation shows general westward dip and a vague outline of the southern reef.

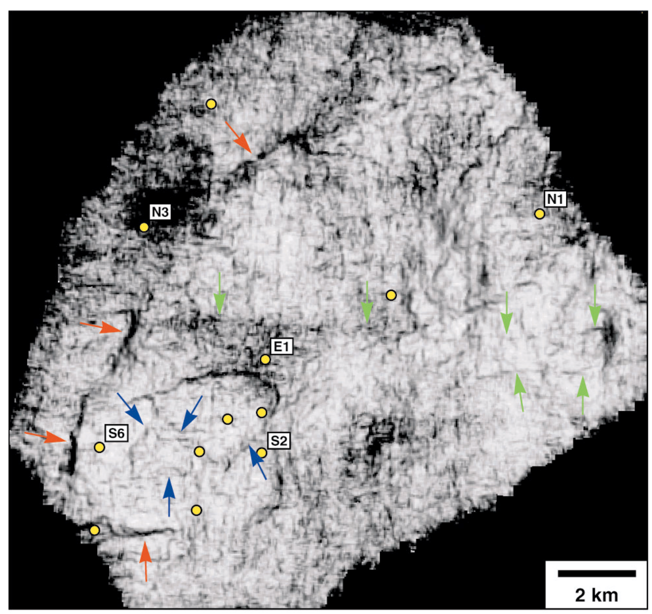

Figure 14. Coherency map of the target formation. Red arrows point to low-coherency feature along western portion of survey, indicating a possible northern reefal boundary and faults. Blue arrows point to possible faults (faint lineaments) separating reefal blocks within the south reef. Green arrows point to subtle indications of possible reef edge or channels within the embayment area.

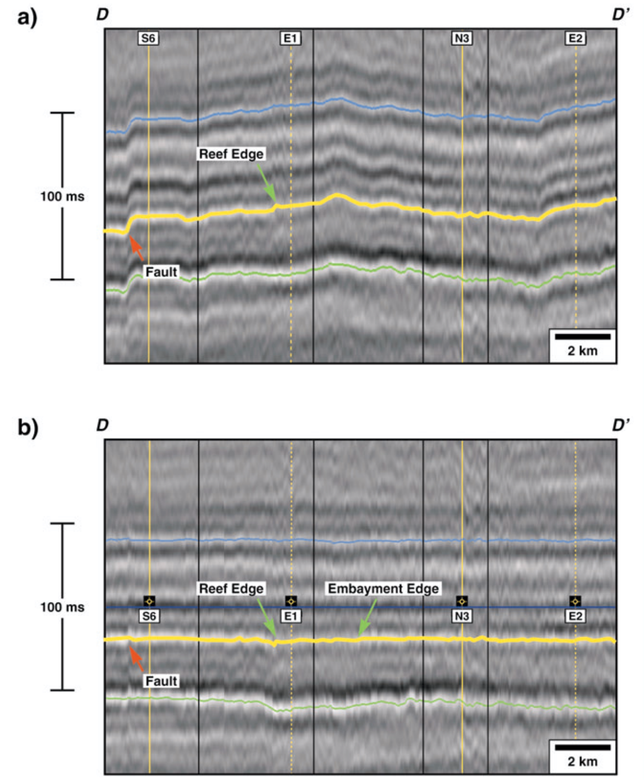

Figure 15. (a) Seismic profile over south reef, embayment, and north reef shows expression of south reef edge (green arrow) and fault to west of well S6 (red arrow). Light blue = overlying carbonate unit; yellow = reef (target formation); green = underlying carbonate unit. (b) Seismic profile flattened on horizon (dark blue marker) within the overlying carbonate unit. The red and green arrows correspond to the features highlighted in (a) and on the amplitude map in Figure 13.

embayment fill and slope facies, respectively.

Coherency was run on the target formation and shows a segmented, approximate edge of the south reef, a vague indication of the southern edge of the north reef, and several probable faults as dark, low-coherency lineaments (Figure 14). Faint lineaments outlining a triangular area within the central portion of the south reef (blue arrows, Figure 14) are also likely to be faults separating slightly upthrown and downthrown reefal blocks. These faults also separate a higher amplitude area around well S6 from a lower amplitude area in the central portion of the reef. These faulted blocks may have influenced facies development during reef growth and/or subsequent porosity development. Note that the producing wells in the south reef are separated from tight well S6 by these faults.

Subtle east-west to northeast-southwest indications of possible reef edge or channels within the embayment are noted in the eastern part of the coherency image (green arrows, Figure 14). A northeast-to-southwest low-coherency "edge" paralleling the northwestern boundary of the survey (red arrows, Figure 14) may indicate a northern reefal boundary, possibly influenced by an underlying basement fault that becomes more apparent as it crosses the embayment channel and into the south reef to the west of well S6. Although carefully processed, a subtle north-south, east-west acquisition footprint pattern is apparent in the coherency image, as well as a few bad data areas, particularly around wells N3, E1, and to the east of wells N3, N1,

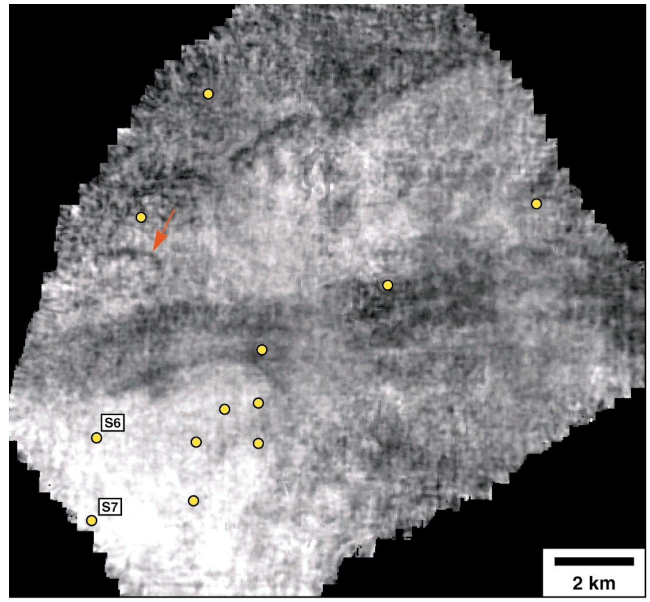

Figure 16. 30-Hz slice (100-ms window) of the target formation spectral decomposition. Arrow points to elliptical feature visible at low frequencies.

and S2. Most coherency features, however, are at an angle to the acquisition footprint direction and are therefore distinguished with more confidence.

A seismic profile taken across the south reef, embayment channel and north reef (Figure 15) shows the subtlety of the seismic expression of the reef (yellow), the edge of which is identified by a small vertical jog to the left of the embayment well E1. Flattening on a horizon within an overlying carbonate unit (dark blue) exaggerates the reef edge profile (somewhat more apparent in the underlying formation). A northern edge to the north reef in the vicinity of well N3 is less discernible in the coherency as well as the seismic profile, since the profile crosses near a "bad data" area. The existence of the apparent north-south fault identified in the coherency image to the west of well S6 is confirmed by the offset at this location visible in the seismic profile.

Spectral decomposition was run using 100 ms and 60 ms windows from the top of the target formation over the frequency range 1-80 Hz. Individual frequency slices show different details, with brighter areas indicating higher amplitudes.

The south reef edge is poorly imaged at frequencies of 30 Hz and lower; however, an elliptical feature north of the embayment channel is only visible at frequencies near 30 Hz (Figure 16). The highest amplitudes on the 30 Hz slice are in the southern and western portions of the south reef, coincidentally also the portions containing tight, mainly muddy shoal or lagoonal rock as penetrated by wells S6 and S7.

A frequency slice at 60 Hz (Figure 17) seems to show the most complete and clearly definable boundaries to the south reef and north reef. The dark, low amplitude indentation in the south reef edge just north of well S2 (also apparent in most other frequency slices) may be a minor reentrant, possibly influenced by the presence of an underlying fault. A flattened seismic profile that crosses this feature supports the reentrant interpretation by a slight downwarp in the target formation and underlying unit reflections just to the right (north) of well S2 (Figure 18). An underlying fault is not apparent from this profile. There is also a redistribution of higher amplitude areas within

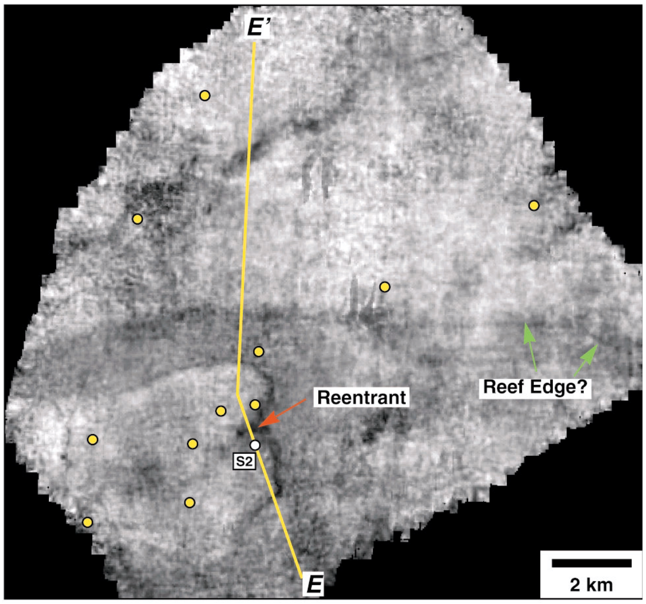

Figure 17. 60-Hz slice (60-ms window) of the target formation spectral decomposition. Red arrow points to a reentrant in south reef edge. Green arrow shows possible southern edge to "north reef." Line indicates location of seismic profile in Figure 18.

the "south reef," with a low amplitude area in the center that is not penetrated by a well.

Although the south reef edge was already known with some confidence from 2-D seismic and well control before the 3-D seismic data were acquired, 3-D seismic imaging techniques help to reinforce and refine the prior interpretation. The edges of both the isolated south reef and the north reef can be imaged with apparently greater confidence with coherency and spectral decomposition than from an amplitude slice alone. This allows the areal extent of the reef to be mapped such that further infill drilling locations may be considered. Where there is little well control, the 3-D coherency and spectral decomposition images locate previously indistinguishable or poorly defined "edges," especially for the unknown north reef. In addition to better defining reefal boundaries, the locations of major and minor faults are interpreted with more confidence using the coherency image. Fault locations are not always apparent in 2-D seismic profiles and can have important implications regarding early reef establishment, reef growth, and later diagenetic influences.

Conclusions. Application of coherency and spectral decomposition mapping techniques to carbonate depositional environments aids in the identification and delineation of several features. Coherency is particularly useful for locating faults, including basement faults and reefal fault blocks that could influence facies development and subsequent porosity enhancement. Location of more subtle features such as fracture patterns and possible higher permeability zones can also be important when exploring and producing from microporous carbonate reservoirs.

In these cases, coherency maps can be used to help direct the wellbore to intersect fractures during horizontal drilling for increased production. Reef margins, including boundaries of pinnacle reefs, low relief, isolated reef buildups, and shelf margin buildups can also be interpreted from coherency and spectral decomposition images and verified by well data where possible. Accurate definition of reef margins determines trap definition and economic reservoir limits which can be critical risk factors in making a play viable.

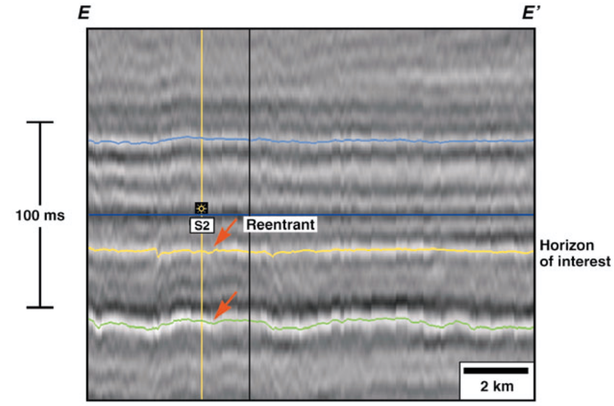

Figure 18. Flattened seismic profile shows a slight downwarp in target formation (yellow) and underlying unit (green) reflections to the right of well S2 suggestive of a reentrant. Interpreted horizons as in Figure 15.

Acknowledgments: We thank Amoco Canada Ltd., Amoco Sharjah Oil Company, Amoco Norway Oil Company, Amerada Hess, Enterprise Oil, and Elf Norge for permission to use the various data sets shown in this paper.

Corresponding authors: C. Skirius, cmskirius@altavista.net, S. Nissen, snissen@intcon.net