3-D geological modeling of Birsa field offshore Tunisia

Combining a variety of data with the right tools and geologic knowledge of the area allowed quick 3-D model building, resulting in comprehensive planning and risk assessment

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This article describes a preliminary study, done in a very short timeframe, which integrated geological interpretation, and geophysical and reservoir analysis for 3-D model building. The objectives of the study were to assess Birsa field reserves in the Gulf of Hammamet, offshore Tunisia, and to propose a development plan, including evaluation of production uncertainties. A newly acquired 3-D seismic survey was available and interpreted. It was used to build a 3-D geological model of the field and review field-development options.

HISTORY OF BIRSA FIELD

Birsa is located in the Hammamet Grands Fonds permit, which was granted to Shell in December 1973. The permit comprised a total initial acreage of 13,284 sq km, in which Agip acquired 50% participation in March 1975. Reservoir depth is about 900 m below sea level, with seafloor at about 140 m, Fig. 1.

Birsa is one of the most significant discoveries by Shell Tunirex. In 1976, discovery Well BRS-1 tested 480 bpd, 31° API oil from Miocene Birsa sands with a GOR of about 300 scf/bbl. The structure was further appraised by five wells drilled in 1978-79. Well BRS-2 tested 2,489 bopd and 8.95 Mcfgd. BRS-3 found oil in the Upper and Middle Sands at rates of 4,560 bopd and 589 bopd, respectively; the Lower Sands contained water. Three other wells (BRS-4, 5 and 6) proved to be water bearing.

A concession was granted to Shell for a 30-year period beginning in January 1981. Shell evaluated vertical-well development, but that project never materialized. Samedan took over operatorship in 1990, followed by acquisition of the Samedan interest in Birsa by COPAREX Int. (40%) and the Neste interests by Atlantis (40%) in late 1996. A 3-D seismic survey was acquired by PGS in 1997 and interpreted in 1998.

ETAP, the Tunisian state-owned oil company, exercised its option to acquire a 20% interest in the Birsa concession and has a secondary option that could be made six months from filing a normal Plan of Development.

REGIONAL SETTING

The Gulf of Hammamet lies at the northern margin of the African plate, and interplate movements between the African and European plates have resulted in a complex geologic history.

A Gulf of Hammamet geologic cross-section is shown in Fig. 2. Birsa field is an anticline in which a SW-NE fault separates the main reservoir into two compartments. Numerous other faults separate the field into different blocks. Three of six wells drilled on the structure have intersected a fault, so odds are that the real picture is even more compartmentalized. Anticlinal dip is generally much higher in the north flank (8° to 11°) than in the south (2° to 4°).

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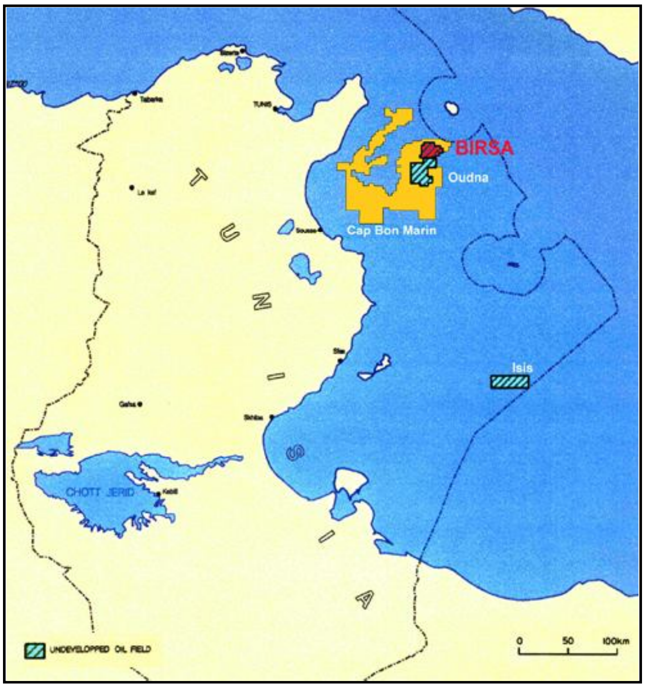

Fig. 1. Location of Birsa oil field.

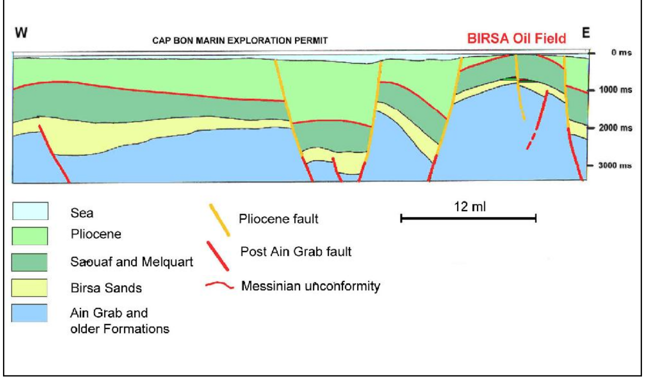

Fig. 2. E-W geological cross-section of the Gulf of Hammamet.

Main Birsa reservoir characteristics

Reservoir	Gross thickness, m	Net to gross	Porosity, %
Upper Sands	23 to 62	0.35 to 0.90	20 to 29
Middle Sands	25 to 38	0.30 to 0.55	17 to 21
Intra Carbonates/ Lower Sands	30 to 50	0.55 to 0.90	17 to 26

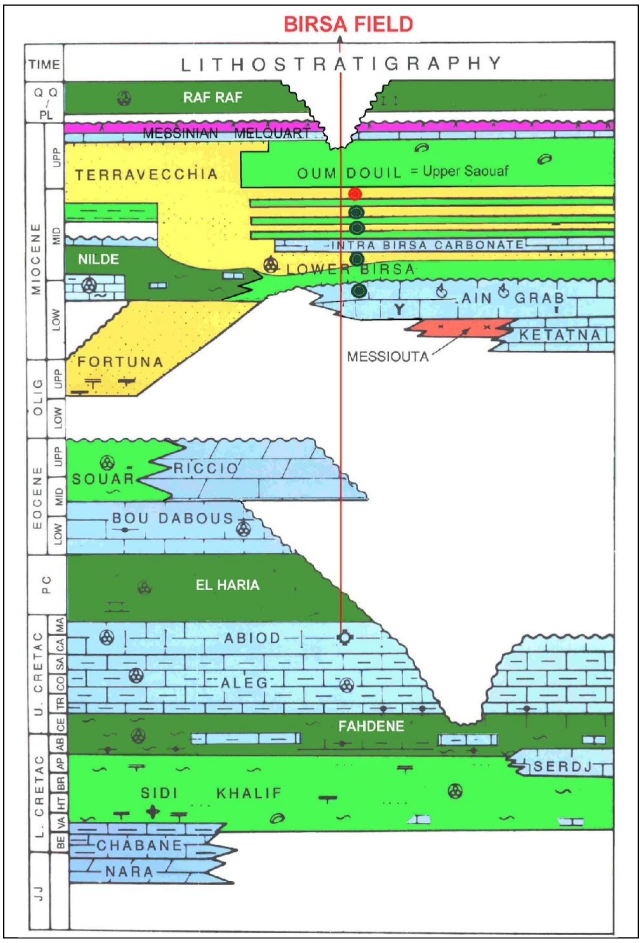

Fig. 3. Lithostratigraphic column of the Gulf of Hammamet.

Reservoir and formation deposition. Birsa comprises three, stacked-sand reservoirs deposited during the Serravallian (Middle Miocene) in a shoreface-to-foreshore marine environment capped by the shaly Saouaf formation. A reservoir of lesser extent exists in the Ain Grab limestone formation (Langhian). Birsa sand reservoirs are separated by 50-m-thick, neritic-shale intervals. Reservoir stratigraphy and a typical lithostratigraphic column are shown in Fig. 3. More detailed reservoir characteristics are listed in the accompanying table.

The series above the reservoir sands comprise Lower Saouaf sandstone and Upper Saouaf shale. Over the major part of Birsa field, Messinian evaporites have been eroded subsequent to Pliocene uplift of the area.

Tectonic history. The latest tectonic episodes of the Gulf of Hammamet, which have had impacts on the Birsa reservoirs, are as follows.

Foredeep basin. Initiated during the Eocene, convergence between the African and European plates continued during the Oligocene-Miocene period, with progressive creation of a thrust-belt front (Numidian nappes) and the large, Foredeep basin in northern Tunisia.

Except for some high points, most of the relief created during the Upper Eocene compressive phase was peneplaned. This occurred when the fluvio-deltaic and coastal-marine siliciclastic sediments of the Upper Oligocene to Lower Miocene (Fortuna) overlaid the Lower Oligocene unconformity.

Immediately after the Langhian (Ain Grab) transgression, the main Foredeep basin strongly subsided at the front of the Numidian nappes area. Subsequent flexure of the foreland created NNE-SSW-trending, antithetical normal faults, which bounded several Miocene subbasins in the Gulf of Hammamet. These subbasins continued to subside during the Middle Miocene.

Regional subsidence, linked to continued sea-level rise, led to widespread, open marine-shale deposition during the Late Langhian (Begonia shales). Later, associated with various sea-level changes, the Serravallian was characterized by shoreface-to-foreshore siliciclastic (Birsa sands) and neritic-shale depositions. Similar conditions prevailed during the Tortonian (Saouaf).

Late Tortonian to Early Messinian. A major phase of Atlassic (Alpine related) orogeny created NE-SW folds and thrusts in the Gulf of Tunis and Cap Bon peninsula. Regionally, this tectonic phase originated isolation of the Mediterranean Sea; subsequent progressive evaporation caused a dramatic sea-level fall. In the Gulf of Hammamet, this tectonic phase is suggested by some top-lap under the relatively flat, Lower Messinian unconformity, on which lagoonal carbonates and evaporites were deposited during the Messinian period (Melquart formation). Then, as the sea level fell, the top Messinian formation emerged, was eroded and locally incised.

Early Pliocene-to-Quaternary inversion. After the end of the Messinian, a new orogeny—usually known as the "second Atlassic phase"—occurred. Regionally, this tectonic phase reconnected the Mediterranean Sea and the Atlantic Ocean, which initiated the great Pliocene transgression. In the Gulf of Hammamet, this NW-SE-oriented compression led to regional inversion of Miocene subbasins and caused broad, regional NE-SW folding and uplift.

During all the Pliocene to Early Quaternary, the Gulf of Hammamet foreland was simultaneously affected by a NW-SE shortening related to the Atlassic compression, and by a NNE-SSW extension related to the Pantelleria-Malta graben opening. This resulted from: creation of various uplifted areas—sometimes strongly eroded on top—as in Birsa; strike-slip movements on existing normal faults; and formation of a complex set of deep, variably-oriented, Pliocene pull-apart basins filled with Lower Pliocene, deep-marine shales (Raf-Raf) and Upper Pliocene, open-shelf sands (Porto-Farina).

Implications for 3-D modeling. From the above discussion, it can be inferred that the Birsa zone will exhibit: NNW-SSE, Middle Miocene normal faults; WNW-ESE, Pliocene extension faults related to pull-apart basins; and NE-SW, Pliocene strike-slip faults related to the Atlassic shortening. Some normal faults could be subject to inversion.

Reservoir-sand geometry should be typical of a nearshore-to-shoreface marine environment; reservoir isopachs should be mainly controlled by sea-bottom shape in a subsiding zone. Given the fact that shales within the Birsa-sand interval occupy more than 50% of the gross thickness, compaction effects will have to be taken into account in thickness mapping, i.e., thickness-ratio techniques, rather than direct-thickness maps, must be taken into account to model reservoir horizons comprised between seismic markers.

3-D MODEL BUILDING

A 3-D model was constructed from a depth of 1,200 m to sea bottom in the area shown in Fig. 1. EarthVision software, developed by Dynamic Graphics Inc., was used for all geomodeling and programing aspects.

Available data. The following data were available to construct the 3-D reservoir model:

- 128 sq km of 3-D seismic, acquired and processed by PGS in 1997
- About 10,000 individual fault segments, spanning from the Ain Grab formation to surface
- Four picked horizons: top of Intra Birsa Carbonates, Upper Sandstones, Upper Shaly Unit and Saouaf Lower Unit
- Logs from six wells showing the different stratigraphic markers and velocity units
- Cores from three wells: Birsa-2, 3 and 5
- VSP data on five wells.

Available fault segments were not organized into individual faults, Fig. 4. Maps of the picked horizons showing fault polygons were available. However, it quickly turned out that such maps could tie together different individual faults; therefore, fault intersections or fault/horizon intersections would be mishandled if these were used directly. Given the number of low-angle faults, many reservoir zones stand a high chance of being in the shadow of a fault intersection in the upper formations.

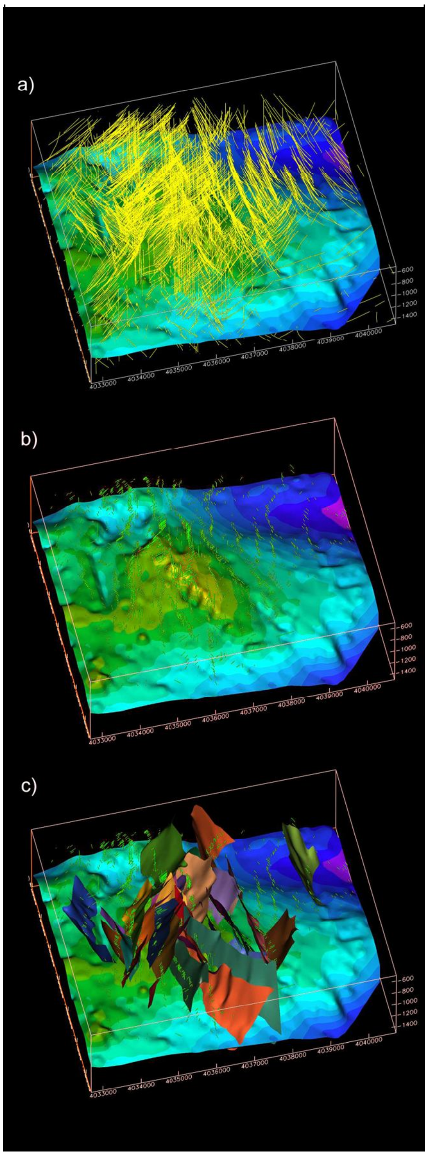

Fig. 4. Fault-modeling process: (a) initial fault data; (b) organizing faults; (c) creating fault surface picks

Precise methodology. A good velocity model—as well as a detailed reservoir model—required that precise methodology be developed to accurately handle fault intersections in and above the reservoir zone.

First, a reference horizon is selected. Next, fault segments intersecting this horizon are automatically identified, their intersection with the horizon is calculated, and they are truncated 10 ms above and below the intersection so that they can be easily mapped with the intersected horizon, Fig. 4b. Individual faults can be easily spotted on these maps and fault-picking polygons are delineated.

For each identified fault, examination in 3-D of the picked fault segments is used to ensure that, indeed, only one fault is picked and to eliminate some outsiders, points or fault segments. A surface is then calculated for each fault identified at this horizon, and the hierarchy of the fault intersection is identified, Fig. 4c. This procedure is repeated for another horizon; only fault segments not belonging to a previously calculated surface have to then be considered. At the end of this process, about 60 individual faults were identified and their intersections analyzed.

Creating geo-objects. To speed up calculations and create a manageable field model, the above tectonic framework was simplified by regrouping or eliminating faults, without loss of geometric accuracy. Twenty-seven faults, resulting in 28 individual fault blocks, were used for the model.

Picked horizons were intersected with the fault framework, and horizon-pick anomalies near faults were both automatically and manually removed. These anomalies were mainly due to loss of horizon-picking accuracy near faults. The number of modeled horizons in the time model reflects different velocity units; these were considered necessary to achieve a good level of accuracy in the time-to-depth conversion process.

Time-to-depth conversion. Conversion of the time model to depth was achieved using a 3-D interval-velocity cube, Fig. 5. In this way, pull-up/pull-down effects from faults above the reservoir are better taken into account. VSP analysis showed that constant velocities could be used for each layer. It would have been possible to use depth-dependent interval velocities that integrate compaction effects, but there was not enough well data available to calibrate such laws.

Additionally, the depth range for any formation above the reservoir is sufficiently small that it limits depth-dependency effects. An average velocity was mapped between the Saouaf top and sea bottom, and the sea was considered a velocity layer as well. The time model was used to fill the different fault blocks and formations with discrete interval velocities. This process can easily be reiterated in the future, as additional velocity information becomes available.

Depth model. The depth model was readily calculated from the time model and the velocity cube, as described above. Horizons and fault surfaces were re-computed and re-intersected in depth using this technique, Fig. 6. Depth matching was good at most wells, although minor adjustments had to be made in a few places, especially at those wells located close to faults.

The next stage was to introduce intermediate reservoir horizons that did not have good seismic reflectors. These were: base of the Upper Sand, top/base of Middle Sand, and top/base of Lower Sand. This amounted to adding five new horizons in the depth model. Thickness-ratio techniques were used to interpolate horizon thickness between wells. These

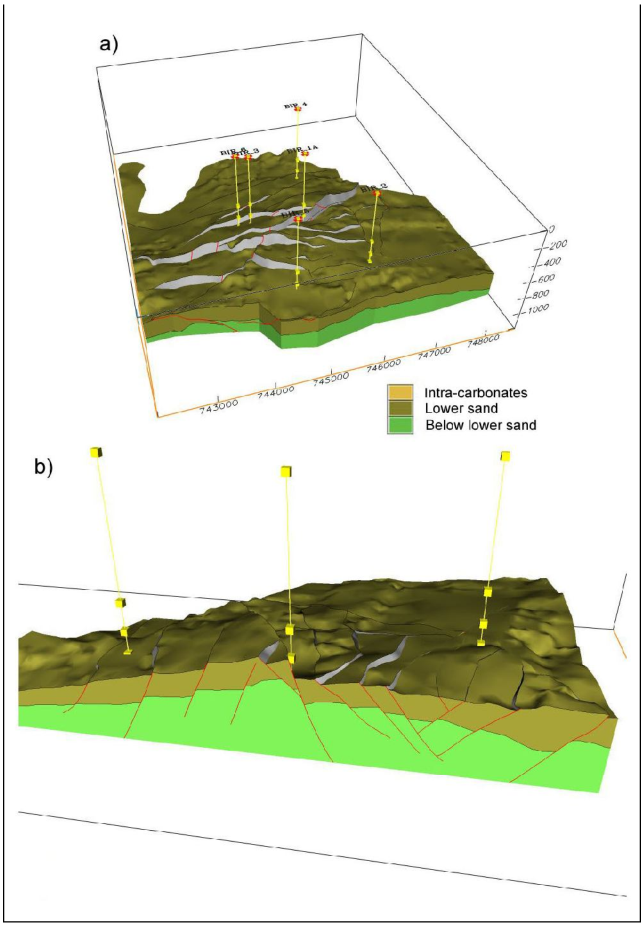

Fig. 5. Time model: (a) global view; (b) cross-section

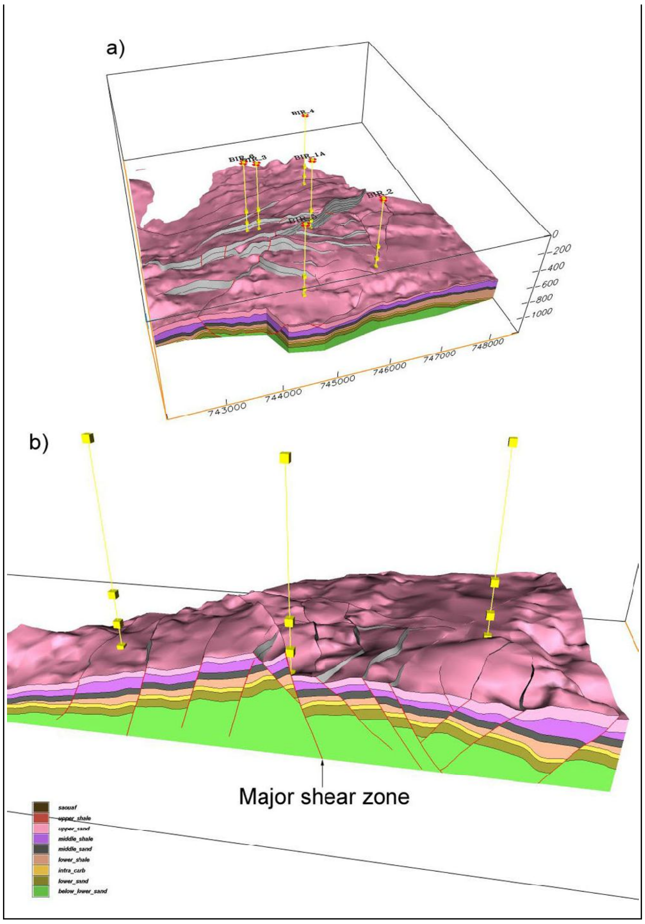

Fig. 6. Depth model: (a) global view; (b) cross-section.

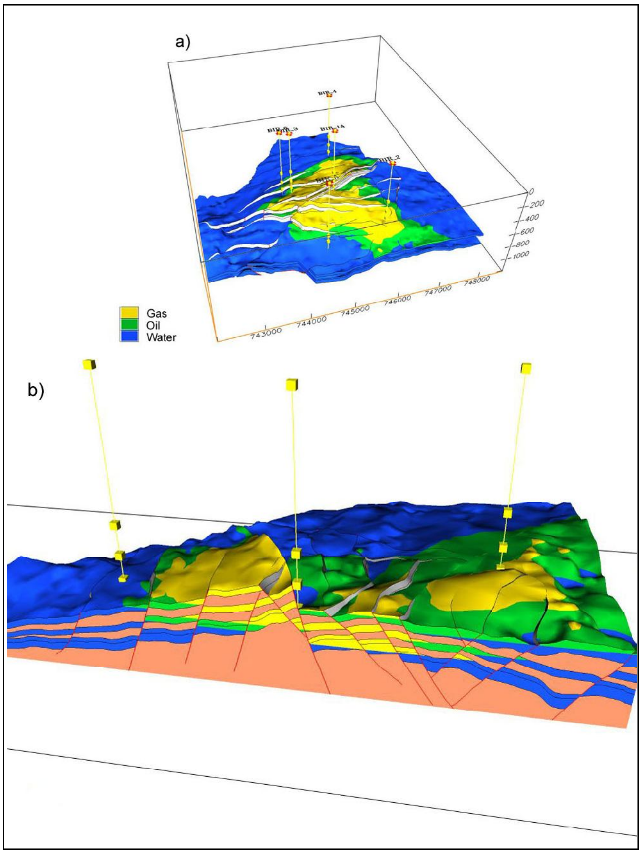

Fig. 7. Fluid model: (a) global view; (b) cross-section

were input into the geological-modeling tool, which used the tectonic framework to calculate new horizon surfaces as well as their fault intersections.

At this stage, the model included more than 200 individual objects in 28 tectonic blocks over 8 horizons. It has been interactively checked in 3-D and is used to make sections, 2-D mapping and volumetric calculations.

Reservoir fluid model. Well logs and well tests provided fluid-contact information. As shown by the geological model, a strong compartmentalization exists; from a fluid-contact standpoint, at least five individual zones can be identified in each of the three reservoirs. These zones may be connected in the hydrocarbon zone, depending on fluid-contact depths and fault-sealing characteristics. Log and production data analyzed in the geological model yielded the following conclusions:

- The major shear zone is likely to be sealing, Fig. 6. The geological model clearly shows that oil or gas would communicate with water if this fault were nonsealing.
- It is more difficult to determine the sealing character of other faults based on examination of the geological model.

All types of fluid contacts, varying with reservoir and fault block, were input to the model, Fig. 7. A dozen likely scenarios, compatible with well-test/well-log data, were simulated and checked by slicing the model in all directions to assess their likelihood from a fluid-communications standpoint. With these scenarios, OOIP and IGIP were calculated for each reservoir layer and zone.

THE AUTHORS

***Patrick Portolano** graduated from Ecole Nationale des Ponts et Chaussées, Paris, in 1979. He also holds an MSc in water resources from the University of Newcastle-Upon-Tyne, UK, and a reservoir engineering degree from ENSPM, Rueil. He worked in the IFP group from 1981 to 1987 on integrated reservoir studies, simulations and reserve evaluations in the U.S., Middle East and North Africa. From 1988 to 1991, he developed a new company specializing in CAD systems for infrastructure projects. In 1992, he created EOSYS (www.eosys.fr), a Paris-based geological consulting and service company.*

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Model refinement/seismic interpretation. The detailed fluid model was back-transformed to time. Time or horizon slices extracted from the 3-D seismic cube were merged with it. The fluid model is currently used to test for oil- or gas-bearing zones using the wave signature in the seismic cube, as well as to adjust horizon and fault picking to improve the match between zones likely to bear oil or gas in the seismic cube and those calculated by the model, Fig. 8.

Comparing Figs. 8a, 8b and 8c, it is easy to spot where the tectonic model matches/mismatches fault traces in the amplitude section, as well as where bright spots in the seismic cube can be associated with zones of high gas content in the fluid model. Fluid contact scenarios can be selected or ruled out based on these analyses. This work is ongoing and will reduce uncertainties related to fluid distribution in these reservoirs.

RESULTS/CONCLUSIONS

Volumetric data—oil, gas and water in place for each fluid zone in each reservoir for different fluid scenarios—was calculated from the model and used by the reservoir-engineering team to feed a coarsely gridded reservoir-simulation model. A likely production scenario was calculated, as well as pessimistic and optimistic scenarios. The model was also used to evaluate the cost of horizontal or deviated wells, which would tap the oil rim in an optimal way, minimizing gas- and/or water-coning effects.

At present, an iterative process is being conducted between geological modeling and seismic interpretation to reduce uncertainties related to reservoir fluids and assess sealing/nonsealing behaviors of secondary faults which may strongly compartmentalize the field.

Various inputs—including well logs, cores, VSP and seismic data, combined with the right tools, interpretations and geologic knowledge of the area—resulted in a 3-D model, which allowed:

- Correlation of fault segments along and across seismic horizons picked, with validation in 3-D view
- Modeling and definition of fault blocks in a complex structural environment
- Conversion to depth of modeled horizons and fault segments
- Infilling the model with geologic horizons inferred from well tops
- Testing of fluid-level assumptions, visualization of corresponding oil-rim geometry and characterization of the sealing capacity of the major NE-SW Pliocene fault (shear zone).

Iterations with various geological infilling and fluid-level assumptions allowed easy "what if" analysis and, therefore, contributed to comprehensive planning and risk assessment.

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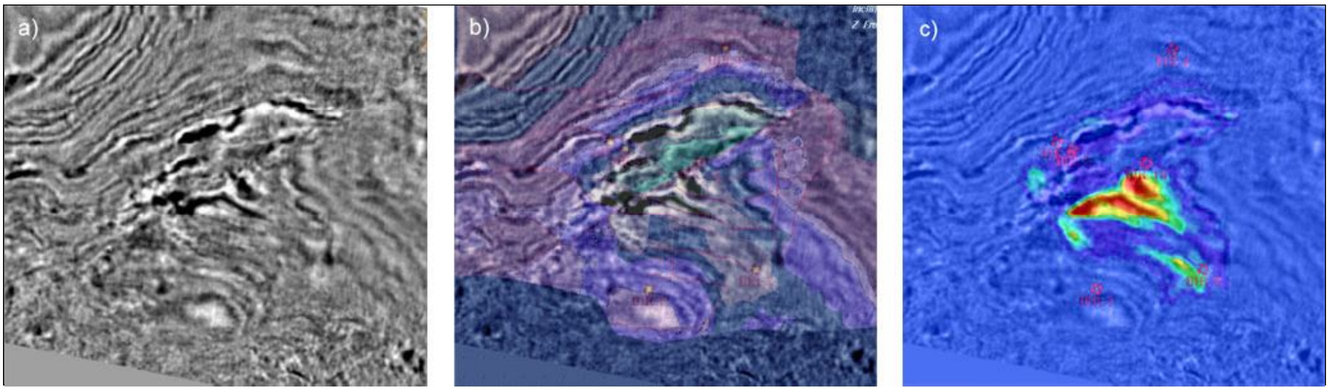

Fig. 8. (a) Seismic-amplitude time slice at 900 ms TWT; (b) Match between depth model and 900-ms time slice; color scale is as in Fig. 6; (c) Integration of fluid and seismic models. Accumulated gas thickness calculated in the fluid model in a slice 10 ms above/below the 900-ms isochron. Red = high gas content; blue = no gas.