

Increasing the effective bandwidth of seismic data through sparse-layer inversion: A case study from Mangala field, Rajasthan, India

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Abstract

Mangala field is in the northern part of the onshore Barmer Basin in India. The primary reservoir in the field is the Fatehgarh Formation, deposited in the rifting phase that created the Barmer Basin during the Late Cretaceous to early Paleocene period. The majority of reservoir oil is contained within the upper FM1 member of the Fatehgarh Formation, composed of single-story and multistory stacked, meandering-channel sands. These sands vary in thickness from 3 to 7 m, with net to gross ranging from 18% to 78%. For such a heterogeneous fluvial system, correlation of floodplain shales and fluvial sands poses a major challenge for reservoir characterization when based on well data alone. Conventional 3D seismic data do not resolve the thin FM1 sands. For more accurate reservoir modeling, various techniques, which included sparse-spike inversion and spectral decomposition, were attempted with limited success. Sparse-layer reflectivity inversion performed on 3D stack PSTM seismic data, however, resulted in improved detectability and resolution and has provided a greater understanding of the lateral continuity of these thin fluvial reservoir units. The 7- to 50-Hz bandwidth of the input seismic data increased to 7 to 100 Hz by the inversion process. The improved imaging of channel geometries has enabled geobody mapping and their input into a revised geologic model.

Introduction

The Mangala field is in the onshore northern Barmer Basin of Rajasthan State, India (Figure 1). The basin is a Tertiary rift consisting predominantly of Paleocene to Eocene clastic sediments. The Mangala field was discovered in 2004 with the Mangala-1 well and production commenced in 2009.

Mangala field is contained within a simple tilted fault-block structure that dips approximately 9° southeast (Figure 2). Lateral seal is provided by the tight Barmer Hill and Dharvi Dunger Formations, which are juxtaposed against the reservoir along

two regionally extensive northeast-southwest- and northwest-southeast-trending normal faults (considered together as the main bounding fault, or MBF) with throws down to the northwest and southwest, respectively. Vertical seal is provided by the tight Barmer Hill Formation, which overlies the main oil-bearing Fatehgarh Group.

The Fatehgarh Group consists of interbedded sands and shales (Figure 3). It is subdivided into the Lower Fatehgarh Formation, consisting of well-connected sheet-flood and braided-channel sands, and the Upper Fatehgarh Formation, which is dominated by sinuous, meandering, fluvial-channel sands. Five reservoir units are recognized in the Fatehgarh Group in Mangala field, named FM1–FM5 from shallowest to deepest,

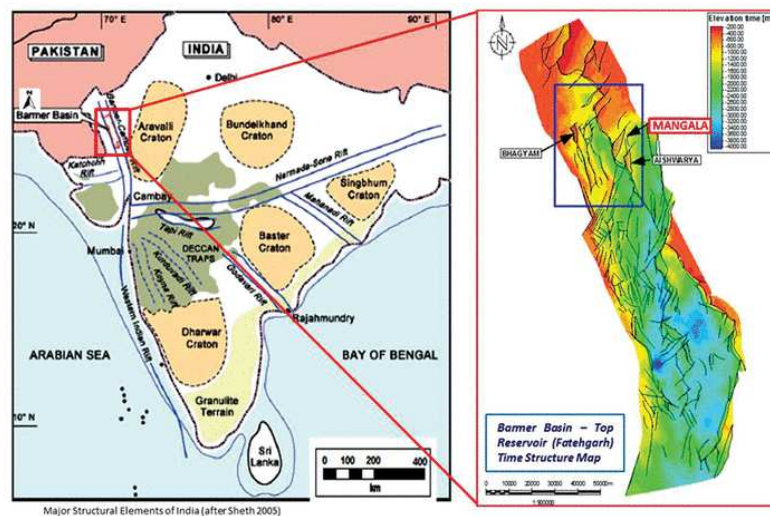


Figure 1. Mangala field location map.

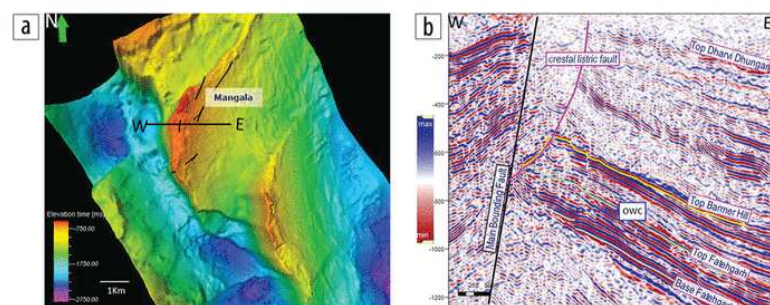


Figure 2. (a) Top Fatehgarh time-structure map. (b) A west-east dip-oriented seismic section.

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respectively. FM1 and FM2 comprise the Upper Fatehgarh Formation, and FM3–FM5 comprise the Lower Fatehgarh Formation. More than 50% of the in-place reservoir oil is contained within the FM1 reservoir unit. This unit is composed of single-story and multistory stacked, meandering channel sands, with individual sands ranging in thickness from 3 to 7 m. This is a highly heterogeneous fluvial system with highly variable net to gross ranging from 18% to 78%. Correlation of floodplain shales and fluvial sands based on well data alone poses a major challenge for reservoir characterization.

The field is covered by 3D seismic data acquired and PSTM-processed in 2008. Data quality varies from poor around the main bounding fault in the west to good in the east-dipping

flank of the structure (Figure 4). Well-seismic ties, primarily using logs and check-shot data from vertical wells, show corresponding variation in correlation quality, ranging from 45% to 80%.

The initial dominant frequency of the seismic wavelet is 25 Hz, yielding a vertical resolution of 20 m in the Fatehgarh interval. Individual FM1 member sands that range in thickness from 3 to 7 m are therefore not resolved. This resolution problem poses a major challenge to reservoir modeling because seismic data are of limited use in characterizing the channelized sand units when building the reservoir static model.

Three seismic horizons — Top FM1, Top FM3, and Base Fatehgarh (Figure 4) — represented by fairly continuous and coherent reflection events are easily interpretable in the 3D PSTM data. Other intra-Fatehgarh horizons, however, were created using isochronal mapping supported by well data because of the lack of interpretable seismic reflections. All these horizons were converted to depth, tied to well control, and used to construct the static structural model.

Facies modeling was performed by sequential indicator simulation constrained to well data, with no input from seismic data. The property model was also created by geostatistical means (sequential Gaussian simulation) using well and core data. The latter process is not optimal for a reservoir containing spatially variant stacked fluvial sands because of undersampling, given the lateral width of channels (approximately 100 to 150 m) and an average well spacing of 200 to 250 m.

In an effort to improve the accuracy of the static reservoir model, numerous geophysical techniques, including sparse-spike inversion and spectral decomposition, were attempted to resolve individual channels in seismic data, with limited success.

A relatively new seismic-inversion technique, high-resolution sparse-layer reflectivity inversion, was then attempted on the stack 3D PSTM seismic data over Mangala field. This yielded a data set with significantly increased seismic resolution. Inversion results have led to improved understanding of the lateral continuity of thin reservoir units, delineation of channel geometries, and mapping of geobodies which can serve as input into a revised static model.

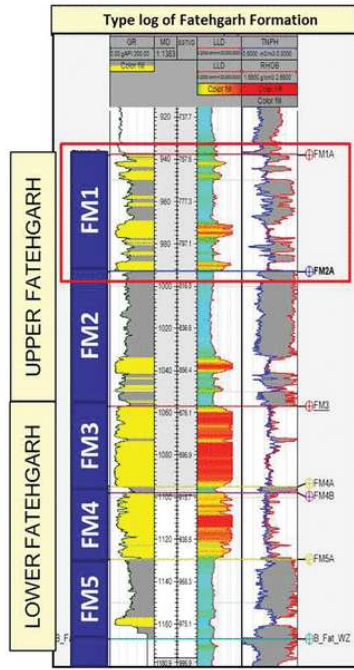


Figure 3. Type log of Fatehgarh Formation at Mangala field.

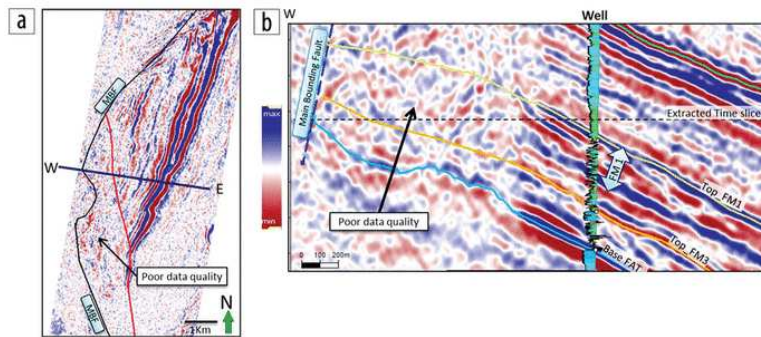


Figure 4. (a) A time slice at Fatehgarh level and (b) a dip seismic section illustrate the poor data quality close to the main bounding fault.

Sparse-layer inversion using basis pursuit decomposition

Sparse-layer reflectivity inversion (Zhang and Castagna, 2011) of seismic-reflection data yields closely spaced reflection coefficients through incorporation of a priori information and spectral decomposition in the inversion process. The inversion is accomplished by building a dictionary of functions representing reflectivity patterns and constructing the seismic trace as a superposition of the patterns. Basis-pursuit decomposition is used to find the sparse number of patterns that sum to form the seismic

trace (Figure 5). When the dictionary of functions is chosen to be a wedge model of reflection-coefficient pairs, the resulting reflectivity inversion is a sparse-layer inversion, as opposed to a sparse-spike inversion.

Information from high-resolution spectral decomposition, (Puryear et al., 2012) of the seismic data is also used during the inversion process. Thin beds below tuning thickness can be imaged by inverting the frequency spectra for layer thickness using complex spectral analysis. The process does not limit the minimum thickness of the layers.

The inversion algorithm does not use well data for the prediction of closely spaced bed reflections. Instead, inversion is performed trace by trace, with no continuity constraints or other spatial conveyance of information. Thus, lateral continuity of stratigraphic features in the inversion data that are consistent with the geologic model is an indication of the stability and robustness of the algorithm. Modeling tests show that sparse-layer inversion using basis-pursuit decomposition is better at resolving thin beds than comparable sparse-spike inversion. The closely spaced reflection coefficients that are produced during sparse-layer inversion effectively increase the bandwidth of the seismic data.

Mangala data results

Sparse-layer reflectivity inversion results at Mangala are shown in Figure 6. Inversion increased the bandwidth of the input seismic data from 7 to 50 Hz to 7 to 100 Hz. The increase in bandwidth is a result of increased detail and resolution obtained through the inversion process. It can be argued that the apparent increase in resolution is because of simple magnification of noise resulting from selection of nonoptimal inversion operators, or inversion nonuniqueness. Matching the inversion results to well logs and spatial stratigraphic interpretation, therefore, should be completed to validate the high-resolution nature of the output data as being geologically meaningful. At Mangala field, there was sufficient well control with which to validate the increased resolution of the inversion data.

Figure 7a is an example of a typical well-seismic tie (Well X). The wavelet used to generate the synthetic was extracted from seismic data across the Fatehgarh interval using data from several wells across the field.

The initial dominant frequency of the wavelet was 25 Hz, yielding vertical resolution of about 20 m. Although the well

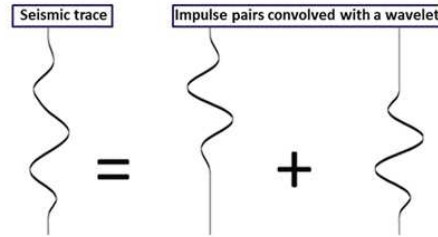


Figure 5. Sparse-layer decomposition of a seismic trace. The seismic trace to the left is modeled by summation of wavelet responses to individual layers or impulse pairs.

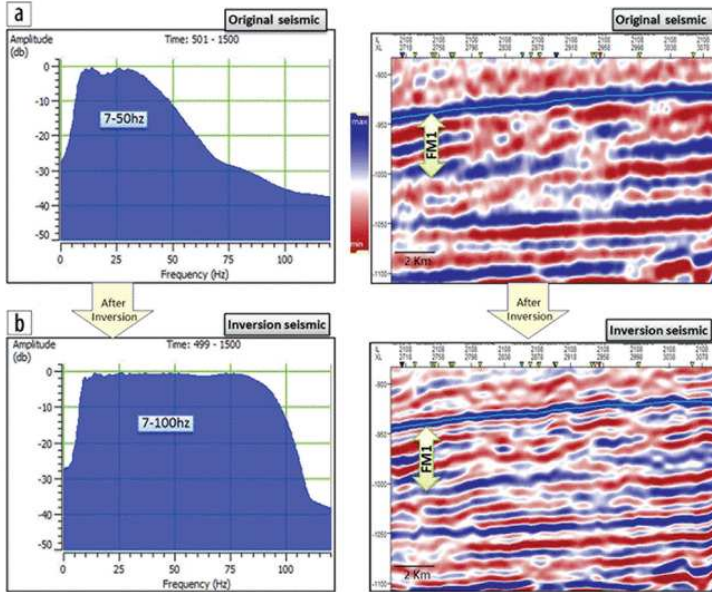


Figure 6. Sparse-layer reflectivity inversion results from Mangala field. (a) Input seismic data and associated amplitude spectrum; (b) corresponding inversion data.

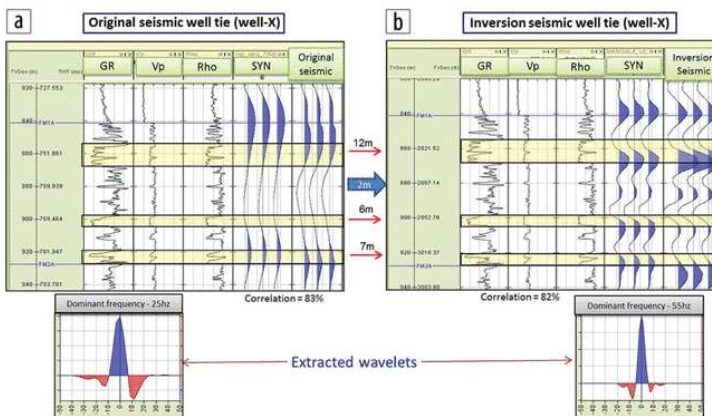
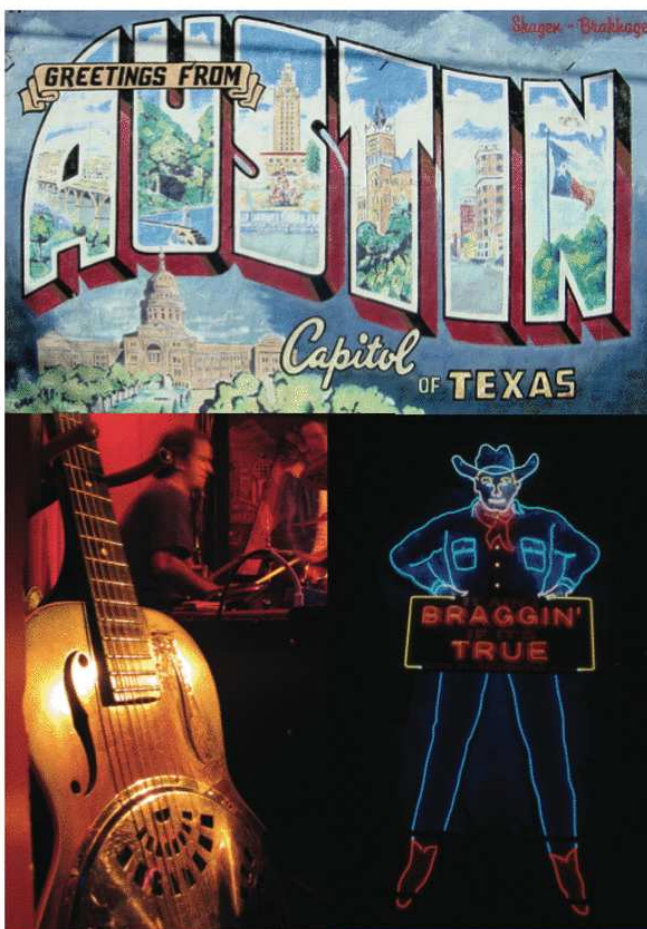


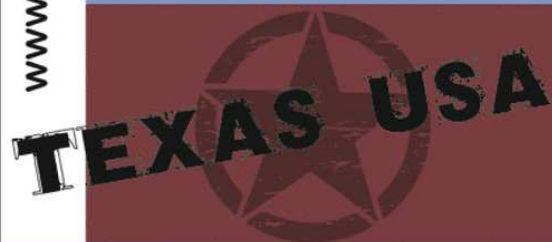
Figure 7. (a) Well-seismic tie using input seismic data at Well X. (b) Corresponding well-seismic tie using inversion data. Sparse-layer inversion using inversion data could resolve/detect thin sands (red arrows) compared with the original seismic.



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tie yields a high correlation of 83% within the zone of interest, the usefulness of the data is limited to detecting gross lithologic packages only. The corresponding well-seismic tie using sparse-layer reflectivity inversion data (Figure 7b), however, shows that individual thin sands are detected or resolved. This is because of the increased bandwidth of the seismic data from 7 to 50 Hz to 7 to 100 Hz through sparse-layer reflectivity inversion process.

For validation purposes, original and inverted quadrature-phase seismic traverses (Figure 8a) from Well X to Well Y (200-m separation) and from Well Y to Well Z (100-m separation) were closely inspected at the Fatehgarh interval. The intent was to determine if thinly bedded sands which were not resolved in the input seismic data (Figure 8a, left panel) are detected or resolved in the inverted data (Figure 8a, right panel).

Although the logs from Wells X, Y, and Z show several thin sands within the FM1 unit, conventional seismic data could not resolve any of these individual sands. By contrast, the inverted seismic data resolves four distinct thin-bedded sand units (wavelet loops in red) within the gross FM1 unit. These sand units were autotracked to determine their spatial distribution. Figure 8b shows that these sands extend beyond Wells X, Y, and Z. Of particular interest is the 2-m sand interval (blue arrow on the right side of Figure 8a), which is detected in the inverted data at Well X and is seen to extend to Well Y but not to Well Z (Figure 8b). The ability of the inverted data to detect or resolve these thin-bedded sands and thereby enable mapping of their areal extent (validated by well control) provides confidence in the sparse-layer inversion results.

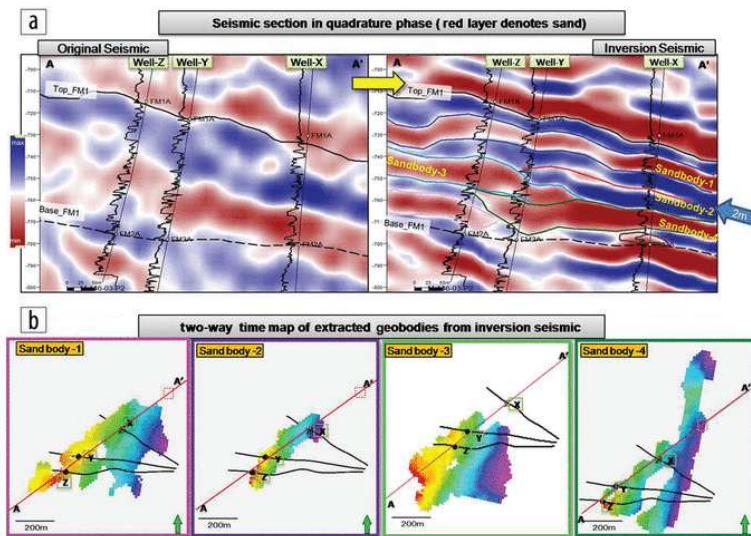


Figure 8. (a) Quadrature-phase seismic section along Top FM1 at Wells X, Y, and Z from original seismic data and the inverted seismic data (sands are in red). (b) Two-way time map of the extracted sand bodies from the inverted seismic. Black lines show the deviated well path from a common surface location, and black dots on the wells indicate the top of respective sand bodies.

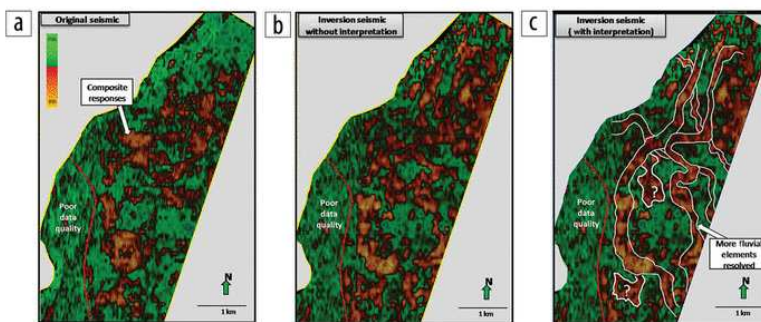


Figure 9. (a) Minimum amplitude extracted at 10 ms below Top FM1 from original seismic data. (b) Corresponding minimum amplitude extracted using inversion seismic data without interpretation. (c) Minimum amplitude extracted using inversion seismic data with possible interpretation of fluvial elements.

Sands within the Fatehgarh Group are acoustically softer than the surrounding Intra-Fatehgarh mudstones, with the top of individual sand bodies represented by a (red) trough and the top of mudstone units by a (blue) peak in synthetic seismograms and in zero-phase seismic data (Figure 7b). The reflection amplitude differences between channel sands and ambient mudstones were investigated to assess the spatial continuity of the fluvial channel sands resolved in the broad-band seismic data.

Figure 9a depicts a minimum amplitude extraction 10 ms below the Top FM1 horizon, within a ± 5 -ms window, from both the original and the inverted seismic data. The amplitude map from the original seismic data shows a patchy distribution, not suggestive of a fluvial depositional system. This is because the map represents the composite seismic response to unresolved thin-bedded units with individually varying spatial geometries.

The corresponding amplitude map generated using inverted seismic data (Figure 9b), however, shows spatially consistent characteristics of sinuous meandering channels. Figure 9c shows a possible interpretation of fluvial elements in the amplitude map extracted using inverted seismic data. A more detailed view of the most obvious fluvial elements (highlighted by the white polygon in Figure 9c) is shown in Figure 10, alongside input and inverted seismic sections datumed at the Top Fatehgarh. The inverted section clearly

shows the uppermost Fatehgarh sand encountered in Wells B and C (green outline) as being distinct and separate from the uppermost sand encountered in Well A. The amplitude map in Figure 10 correspondingly shows that although Wells B and C were drilled into the sinuous channel unit, well A lies outside it.

Figure 10 illustrates the difference in stratigraphic detail obtainable from the inverted data in comparison with conventional seismic data. For the first time at Mangala, seismic data provide insight into the vertical and spatial behavior of the thin-bedded Upper Fatehgarh sand units that facilitates building a higher-quality static reservoir model.

It is worth noting that the area of poor data quality in the original seismic data remains poor in inversion seismic data. The inversion process obviously is sensitive to and does not compensate for input seismic data quality.

The FM1 reservoir interval, characterized by heterogeneous fluvial units, is now being developed with pattern flood wells to optimize reserves recovery. Improved understanding of the connectivity of individual FM1 sand units between producer and injector pairs will aid in better reservoir-management decision-making.

Figures 11 and 12 illustrate how the inverted seismic, when integrated with relevant well-log data and production-log information, results in improved understanding of reservoir behavior. In Figure 11, although all the sands penetrated by well Inj-1 were perforated for injection into the FM1 unit, the injected fluids followed a preferential flow path through the 4-m sand interval highlighted by the blue rectangle. Production data indicated that injection into the 4-m sand at well

Inj-1 supported production from the stratigraphically correlative 25-m-thick stacked sand at Well Prod-1 but not from its stratigraphically equivalent sand at Well Prod-2. Rather, Well Prod-2 produces from sands highlighted by the green rectangles but not from the sands located between them.

Figure 12, which shows input and inverted seismic transects across the three wells, explains the observations described above. The original seismic data (Figure 12a) do not resolve the injected sand in Well Inj-1 and as a result is of little value in explaining the observed production behavior. The inverted seismic data (Figure 12b), however, not only resolve the sand at Well Inj-1 but also clearly show its connectivity and means of pressure support to the two producing sands at Well Prod-2 (green rectangles).

Figure 12 also explains why the sands in Well Prod-2 lying between the two green polygons are not contributing to

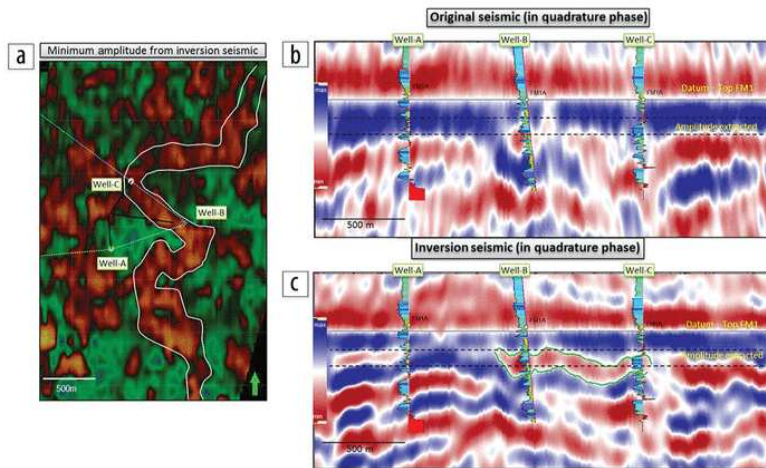


Figure 10. (a) Minimum-amplitude map near Top FM1, with locations of the wells relative to an interpreted channel body. (b) and (c) show quadrature-phase seismic sections datumed at Top Fatehgarh containing Top FM1 penetrations at Wells A, B, and C in (b) original seismic and (c) inversion seismic data.

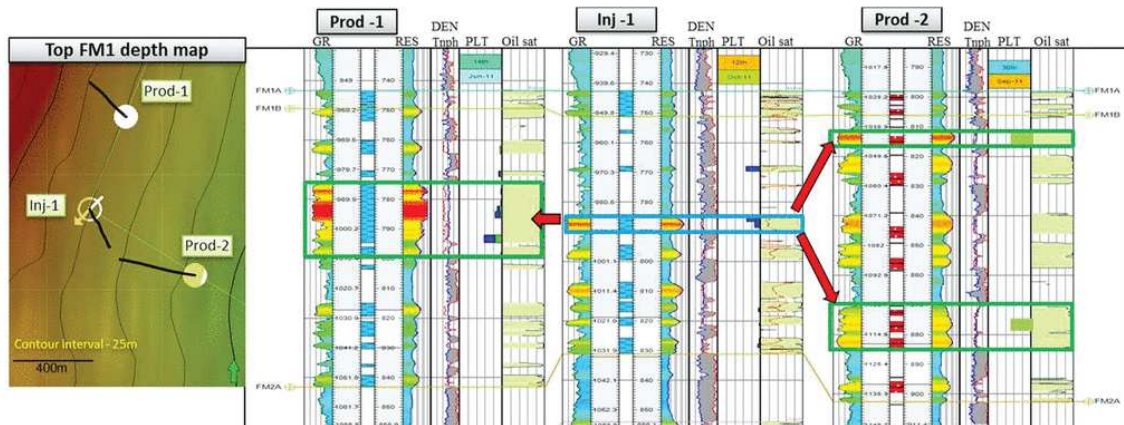


Figure 11. Well correlation among Prod-1, Inj-1, and Prod-2, datumed at top Fatehgarh.

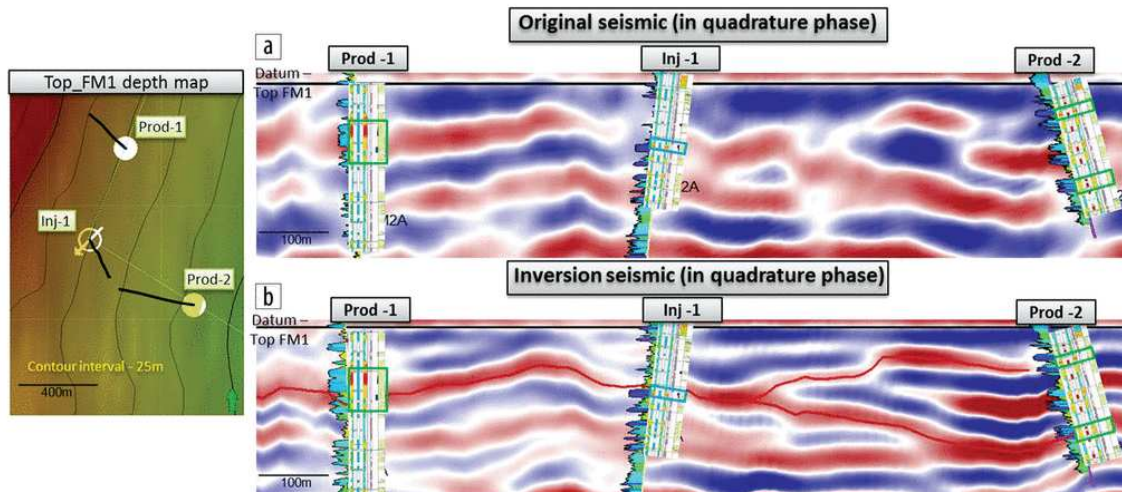


Figure 12. Quadrature-phase seismic section along Top FM1 penetrations at Wells Prod-1, Inj-1, and Prod-2 in (a) original seismic and (b) inversion seismic data.

production. There is a clear and distinct shale interval that encases and isolates these nonproductive sands at Well Prod-2 from Well Inj-1. Thus, integrating observations from the inverted seismic data and production data has helped in unraveling the complex connectivity of individual fluvial-sand packages and shale intervals in the FM1 interval.

Conclusion

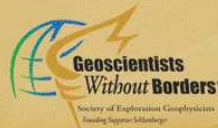
Understanding the connectivity of thin meandering fluvial sands in Mangala field is required for accurate reservoir modeling and for explaining production performance data, saturation data, pressure data, and tracer survey information from producers and injectors across the field. These thin sands, however, are well below conventional seismic resolution, and as a result, seismic data have hitherto provided limited support in building the reservoir static model. Earlier static modeling was thus reliant on well data and geostatistical property interpolation between wells.

To resolve and assess the connectivity of thin reservoir sands at Mangala, sparse-layer reflectivity inversion constrained by high-resolution spectral decomposition was performed on the 3D PSTM stack seismic data covering the field. The process increased the effective bandwidth of seismic data, allowing for the resolution of thin-bedded reservoir units. Results of inversion at Mangala were validated through blind well tests and seismic-attribute maps that imaged expected fluvial-sand geometries. These results enabled detailed interpretation of fluvial packages in the complex meandering system of the main reservoir in the field. This has further led to the building of a more accurate static model of the field and has provided greater confidence in field development planning. **IE**

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