



Reservoir mapping and characterization: An integrated approach using geostatistical inversion for untapped reservoir identification

Supriya Deogharia¹, Moumita Sengupta¹, Dibyendu Chatterjee¹, Kondal Reddy¹, and Shakti Jain¹

ABSTRACT

The CB/OS-2 block in the Cambay Basin is located on the west coast of India. The block lies at the boundary between Surat depression and the western part of the Narmada rift. The field was initially developed as a gas reservoir and later it was converted to a predominantly oil producing asset draining from Lower Tarkeshwar reservoirs. The presence of gas in the shallower Babaguru level is responsible for the relatively poor seismic imaging of reservoirs in deeper Lower Tarkeshwar level due to absorption of energy. The current study focuses on how inversion datasets are integrated with existing seismic vintage for improvement of overall interpretation of oil-bearing reservoirs while identifying an undrained pool in Lower Tarkeshwar level with a good in-place and recoverable volumetric potential.

KEYWORDS

PSDM (Pre-Stack Depth Migration), deterministic inversion, stochastic inversion, Bayesian approach, Cambay Basin, angle stacks

INTRODUCTION

The CB/OS-2 block is located in the Cambay Graben area, in the west coast of India as shown in Figure 1. The block straddles between Surat Depression and the western part of the Narmada Rift. Cambay Graben possesses several rift structures where CB/OS-2 block is a part of a series of failed rifts in that region. Tectonically, the block is located in the four-way closure of Cambay Rift, Narmada Rift, Surat Depression and Dahanu Depression. Major tectonic disturbances led to the creation of anticlinal inversion structures which eventually resulted in the hydrocarbon entrapment in that area. CB/OS-2 block consists of three such anticlinal structures named Lakshmi A, Lakshmi B and Gauri A, lying in a geologically complex position. The basin fill consists of clastics, predominantly sandstone, shale and mudstone, which were deposited in a shallow marine environment. Previous research established the fact that during the Late Oligocene there were considerable sea-level changes in what is now the Gulf of Cambay region, which led to the formation of low-relief shallow marine

and coastal plain environments. The primary hydrocarbon accumulations in CB/OS-2 are found in the Gauri and Lakshmi fields, with this study focusing specifically on the Lakshmi Field. The Tarkeshwar and Babaguru formations serve as the main reservoir intervals in the area. Exploration and appraisal drilling in the Lakshmi fields have identified hydrocarbon-bearing sandstones in the lower portion of the Tarkeshwar formation, which dates back to the Lower Miocene. As a result, these reservoirs are the primary targets for characterization in the current study. The sediments of the Lower Tarkeshwar reservoir in the Lakshmi field were deposited from the Late Oligocene to the Early Miocene during a period of rising global sea levels that followed a preceding low sea-level phase. Salinity fluctuations, episodic sedimentation, rapid accumulation of sediments and inconsistent substrate conditions were evidenced from limited core samples from the field. These observations reflect the complex and changing depositional environment of the Lakshmi field during this geological period. Since the Paleocene era, the structural layout of the Gulf of Cambay is believed to be nearly unchanged, this continuity supports the idea that Lower Tarkeshwar formation being characterized by tide dominated estuarine settings with reservoir sands deposited as complex incised valley fills, tidal bars, tidal channels, tidal creeks and tidal flats (Sanyal et al., 2012).

Delineation of one of the Lower Tarkeshwar reservoir units within the Lakshmi-A structure has historically been challenging due to the gas masking effect, which leads to significant energy attenuation at shallower levels and obscures deeper seismic responses. Although the gas masking effect still prevails, the application of geostatistical inversion enabled the identification of a distinct sand reservoir unit that remained unexplored due to the limited resolution of conventional seismic volumes. This approach has significantly improved the imaging and interpretation of the target interval.

DEPOSITIONAL ENVIRONMENT

The stratigraphic succession of the Cambay Basin begins

¹Cairn Oil and Gas, Vedanta Limited, Gurugram, India.

Emails: supriya.deogharia@cairnindia.com; moumita.sengupta@cairnindia.com; dibyendu.chatterjee@cairnindia.com; kondal.reddy@cairnindia.com; shakti.jain@cairnindia.com

with the basement rocks, comprising Deccan Trap volcanics, which form the foundational unit across the basin. Overlying the basement is the Paleocene to Lower Oligocene Hazira Shale. This unit is interpreted as mud deposited in an open marine shelf environment, representing a relatively deep-water transgressive system. The Hazira Shale serves as the primary hydrocarbon source rock in the region and is unconformably overlain by the younger clastic deposits.

Above the Hazira Shale lies the Tarkeshwar Formation, a regressive succession deposited during the Lower to Middle Miocene in a marginal marine setting. The Tarkeshwar Formation reflects dynamic depositional conditions influenced by relative sea-level fluctuations and shoreline shifts and is subdivided into Lower and Upper Tarkeshwar members based on distinct facies assemblages and depositional settings.

The Lower Tarkeshwar is characterized by heterogeneous reservoir facies deposited in middle to inner estuarine environments. These include tidally

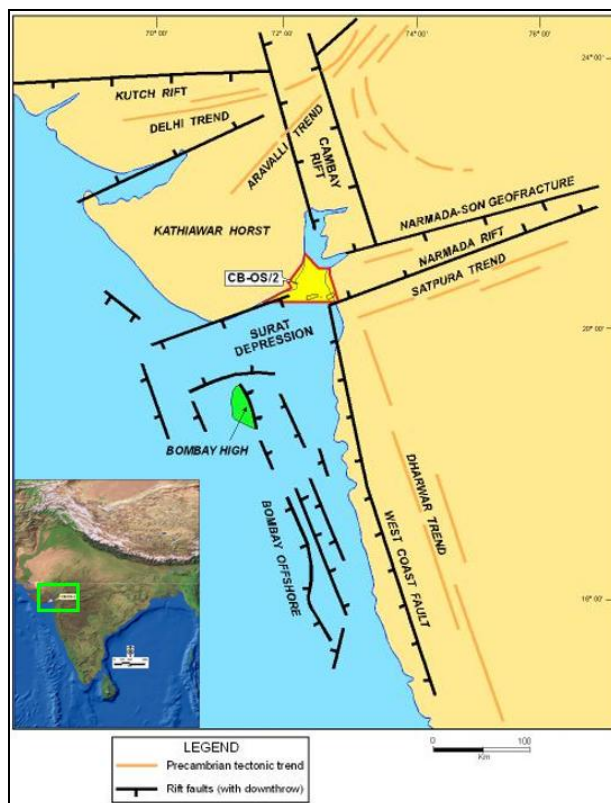
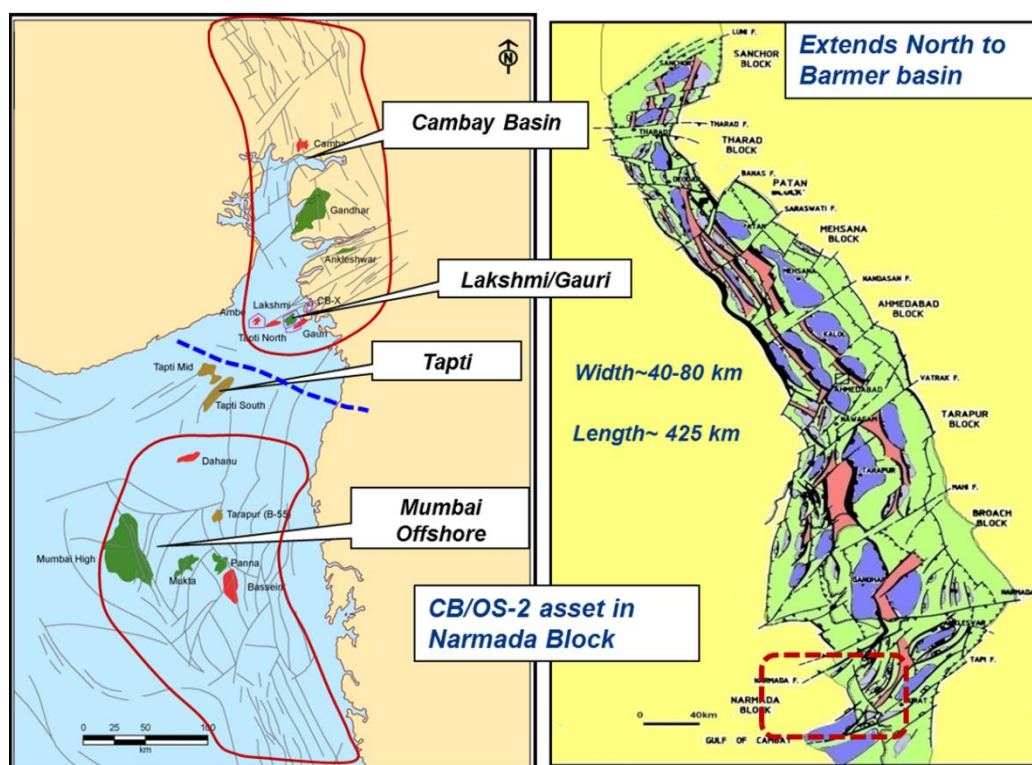


Figure 1. Location maps of CB/OS-2 Block.



influenced incised valley fills, tidal flats, tidal creeks, and tidal bars, which exhibit marked lateral variability. Despite their limited lateral extent, these sand bodies can often be correlated as chronostratigraphic units across well control in the area, suggesting periods of regionally synchronous deposition.

The Upper Tarkeshwar comprises of distributary channel fills, barrier bars, and crevasse splays, interbedded with laterally extensive shale and clay units. This interval reflects deposition in a more deltaic to shallow marine setting, representing the upper portion of the regressive phase.

Conformably overlying the Tarkeshwar Formation is the Babaguru Formation, consisting of transgressive shoreface sands laid down in a sheet-like geometry. These sands indicate a basin-wide marine transgression that reworked earlier deltaic sediments into a more laterally continuous sand sheet.

The Babaguru formation is overlain by shallow shelf muds of Kand formation which acts as a regional seal, playing a crucial role in hydrocarbon entrapment within the basin. Figure 2 illustrates the tectonostratigraphy of Cambay basin.

AVAILABLE DATABASE

The seismic data initially acquired using conventional streamer cable was further reprocessed in multiple phases with Kirchhoff pre-stack time migration (PSTM), refined velocity picking, anisotropic pre-stack depth migration (PSDM) to address the challenge of gas masking effect observed at deeper levels. Despite these efforts, the gas masking effect persists, leading to uncertainties in the continuity of reflectors. Geostatistical inversion, which utilizes PSTM time-converted, NMO corrected offset gathers and well log data, has generated different probabilistic volumes that can offer better reservoir characterization.

METHODOLOGY

Rock physics modelling in the study area indicates that hydrocarbon sands, brine sands, and shales can be distinguished from each other in log scale based on their differing elastic properties. As a result, AVO analysis and inversion techniques could prove to be effective tools for hydrocarbon and reservoir characterization in the area. Additionally, the reservoir sands in the Lower

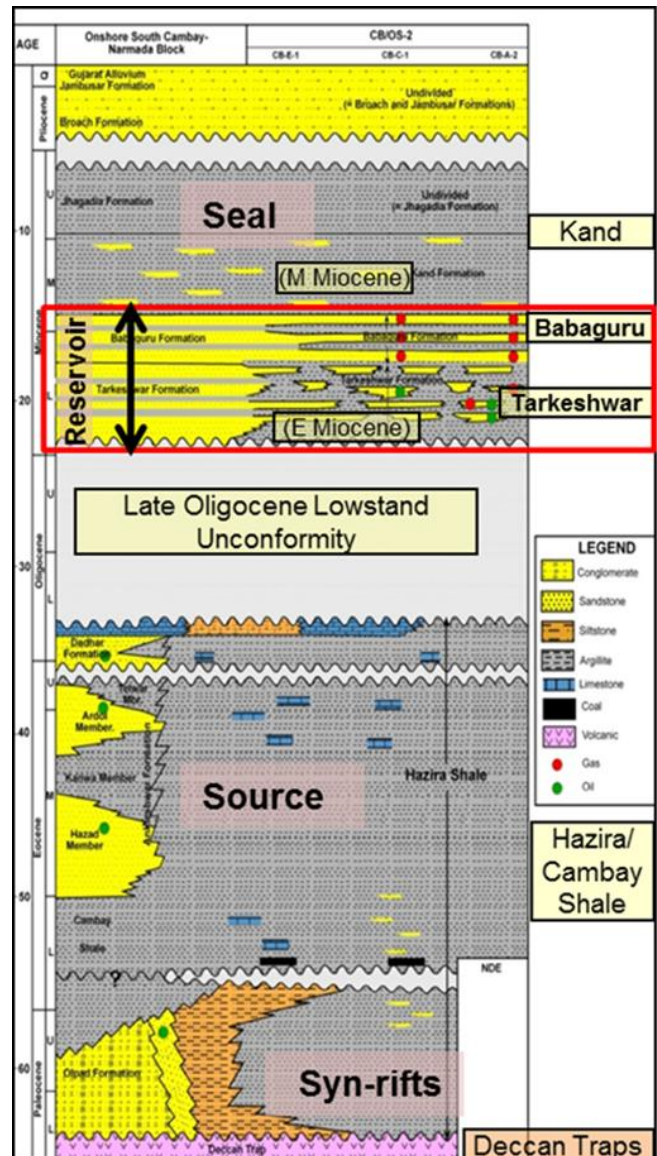


Figure 2. Tectonostratigraphic column of Cambay Basin.

Tarkeshwar formation are below tuning thickness in most of the wells (ranging from 5-12 m). However, the presence of AVO effects in the far-angle traces greatly improves the detectability of the hydrocarbon-charged sands.

For better characterizing the reservoir and fluids in the area, a 3D geostatistical inversion was performed on pre-stack seismic data using advanced geostatistical methods. This process simultaneously resolves for the reservoir and elastic properties through a Bayesian approach. The properties are initially generated on a stratigraphic grid in time and then transferred to depth

retaining the vertical and lateral heterogeneity. The challenge in mapping Lower Tarkeshwar sands with existing seismic data is primarily due to absorption of energy in shallower levels. In this geostatistical inversion study, pre-stack gathers, and prior models were effectively integrated to delineate the thin beds. One such sand horizon has been mapped using P-impedance-Poisson's ratio based hydrocarbon sand probability volume. This horizon was then cross-validated using conditioned seismic data to confirm the accuracy of inversion-based horizon mapping. Thereafter, different types of post-stack windowed attributes were used for delineation of the fairway. Based on the results from attribute analysis and horizon mapping within stochastic volumes, a new sand unit, named as sand 2 was identified as a potential development target.

GEOSTATISTICAL INVERSION

Geostatistical seismic inversion is an advanced algorithm designed to address the non-uniqueness typically associated with seismic inversion. Unlike deterministic inversion which obtains a single solution to the inverse problem, geostatistical inversion generates multiple subsurface realizations using conventional geostatistical methods such as Sequential Gaussian Simulation. The primary outputs of this approach include the probability of facies occurrence, statistical distributions of reservoir and hydrocarbon trends, as well as identification of reservoir connectivity based on the analysis of these stochastic realizations.

The key difference between conventional deterministic and geostatistical inversion lies in the model used for realizations. Deterministic seismic inversion produces a single P-impedance model whereas geostatistical inversion generates multiple P-impedance models (Sams and Saussus, 2010; Nunes et al., 2017). This non-unique inverse problem and the associated uncertainty in inversion results are quantified through the generation of these multiple realizations (Francis, 2006; McCrank and Lawton, 2009). These realisations are constrained by probability density function derived from both well log and seismic data, with uncertainty being assessed through an ensemble of generated realisations. Figure 3 depicts the basic workflow for geostatistical inversion following deterministic inversion. The process begins with conditioning the

seismic data to assess its suitability for elastic inversion. This involves, gather conditioning and angle stack generation, which were performed after applying high-pass frequency filter and designing a dedicated offset mute to clear low-frequency and surface wave contamination. Once conditioned, angle ranges were selected to correctly spread AVO information across all angle stacks. Residual normal moveout (RNMO) was applied after initial conditioning to ensure that seismic events are properly aligned at the same time across each angle stack, preventing artifacts during the inversion process. After conditioning, rock physics analysis and petro-elastic modelling are necessary for relating lithology, porosity, water saturation to elastic parameters like P-impedance, S-impedance and density.

Wavelet estimation for each angle stack (near-, mid-, and far-angle stacks) and well calibration were performed to choose the appropriate wavelet. The low-frequency model (LFM) was constructed by integrating the interval velocity volume with interpolated well log data, calibrated using measurements from 20 wells. Thereafter, a model-based inversion approach is followed to generate different property volumes, including P-impedance, S-impedance, and V_p/V_s . For geostatistical inversion, the P-impedance and S-impedance volumes, derived from the model-based approach, were used in conjunction with the time structural grid. Variograms were created from P-impedance, S-impedance and density logs. These variograms along with the property volumes were used for creating synthetic angle stacks. The inversion process aimed to achieve global minima by maximizing the correlation coefficient between the synthetic angle stacks and the real angle stacks. Finally, a time-to-depth conversion was performed to ensure that depth volumes aligned with the time volumes.

GEOSTATISTICAL INVERSION-BASED HORIZON MAPPING

In the Lower Tarkeshwar formation, the sands are acoustically softer than the adjacent mudstone and claystone units, creating a distinct contrast that is evident in all vintage zero-phase seismic datasets. Individual sand bodies in the region are identified by a negative amplitude (represented by a red trough), which corresponds to a decrease in acoustic impedance at the sand top. In contrast the tops of mudstone units

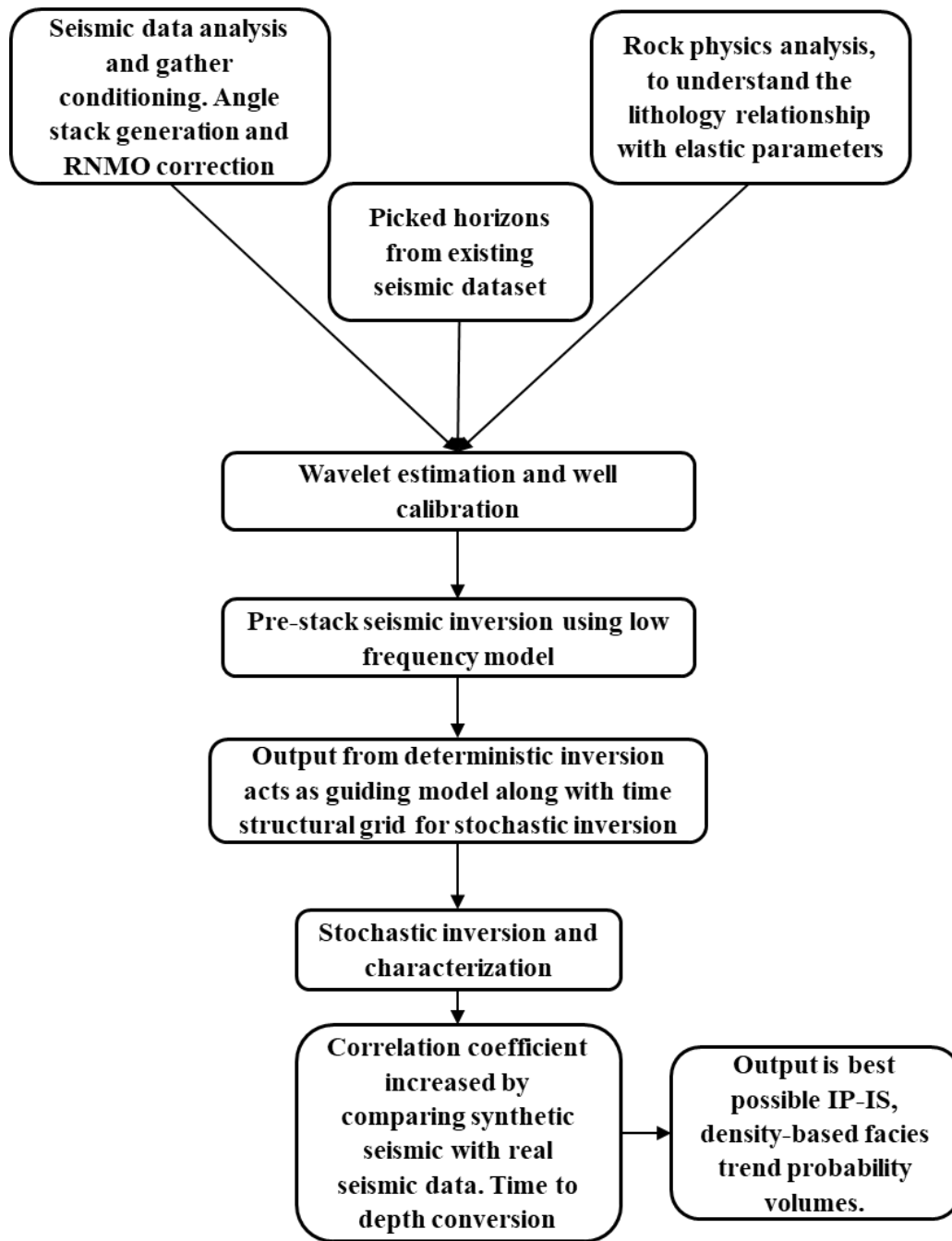


Figure 3. Workflow for geostatistical inversion.

produce a positive amplitude (represented by a black peak), indicating an increase in impedance as illustrated in Figure 5. This study primarily focuses on sand packages namely Sand 1 and Sand 2, observed across four wells, namely, Well-1, Well-2, Well-3, Well-3z. All four wells intersected Sand 1, with Well-2 identified as

exhibiting the highest quality sand package, making it the primary drainage point for the oil pool as shown in Figure 4. In contrast, Sand 2 was considered during the planning phase for an injector well. The continuity of Sand 1 over the wells was not clearly visible in the

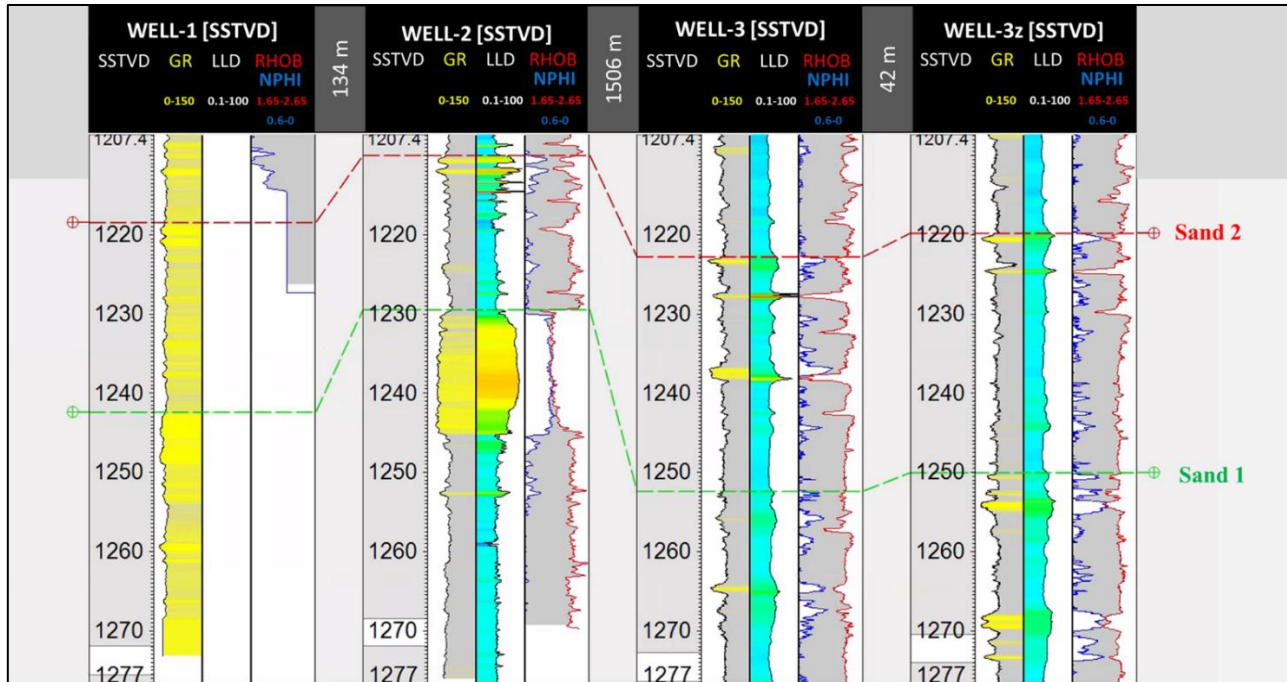


Figure 4. Well correlation for four wells, namely, Well-1, Well-2, Well-3, Well-3z. Notice that Sand 1 exhibits the highest-quality sand package in Well-2, which serves as the primary drainage point from the oil pool. On the other hand, Sand 2 appears less promising in these wells, particularly showing very limited sand presence in Well-3 and Well-3z.

vintage seismic datasets, as shown in Figure 5. When analyzed using subsequent hydrocarbon probability volumes derived from geostatistical inversion, sand 1 appeared unresolved, whereas Sand 2 appeared to be disconnected, untapped sand body localized near Well-3 and 3z. Figure 6 illustrates this untapped sand unit in P-impedance-Poisson's ratio-based hydrocarbon sand probability volume, where relatively higher anomalies (indicated in red) were identified, with an overall probability of 0.12 on the colour scale. The untapped hydrocarbon bearing Sand 2 is demarcated and encircled in yellow.

To further delineate the characteristics of Sand 2, various post-stack windowed horizon attributes were generated. Figure 7 illustrates the sum of negative amplitudes extracted on far angle stack volume, calculated within a 10 ms time window of Sand 2. This attribute sums all the negative amplitudes over a window of +/-10 ms. This has been used significantly in this field where sands are known to be softer than shales emphasizing the presence of reservoir sands across the spatial extent of the horizon. Additionally, geobody extraction technique was employed to assist in

volumetric calculations of hydrocarbons within the sand reservoir. The analysis of negative amplitude attributes and geobody extraction provides valuable insights into the spatial extent and quality of Sand 2, which are critical for firming up future drilling and injection strategies aimed at optimizing hydrocarbon recovery.

RESULTS

The effective use of stochastic inversion results has immensely helped to successfully identify and characterize the unpenetrated reservoir unit within the otherwise developed and producing asset. Interpretation from the hydrocarbon probability volume reveals two distinct sand bodies, with Sand 2 occurring as a separate stratigraphic unit above the underlying Sand 1. The lack of connectivity between the two suggests that Sand 2 constitutes an independent hydrocarbon-bearing reservoir, presenting additional potential for targeted drainage and optimized development planning. The interpretation of the lateral extent of the two sands was based on a few considerations. First was the hydrocarbon sand probability volume obtained from geostatistical invers-

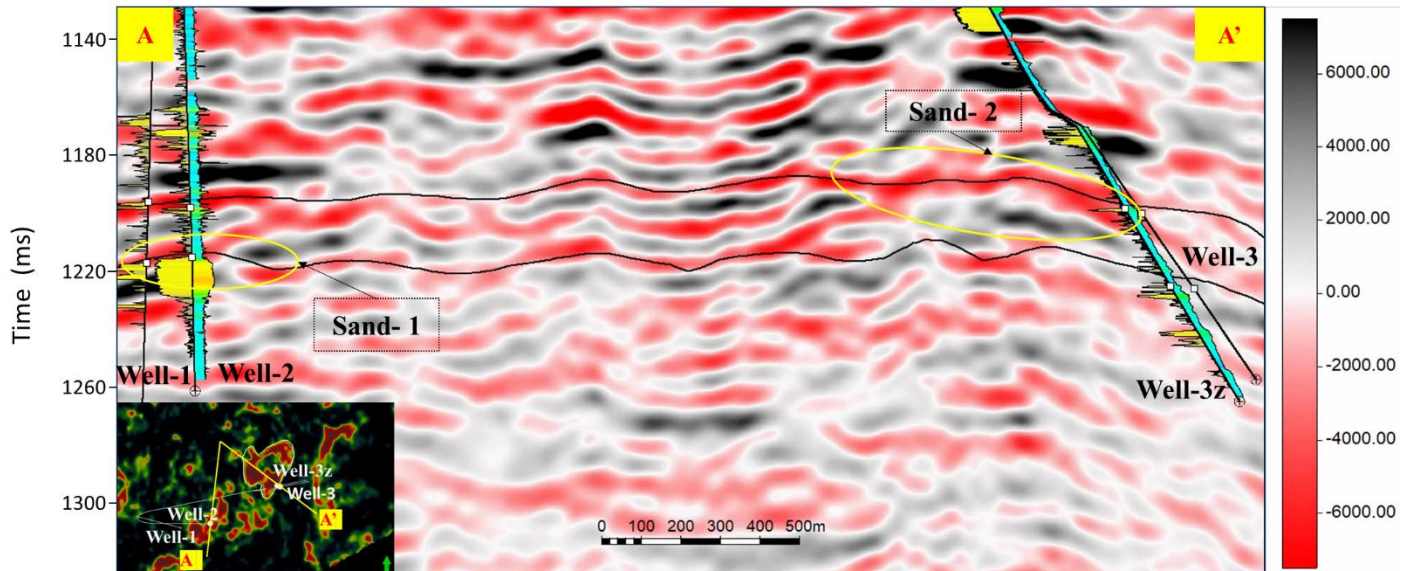


Figure 5: An arbitrary line section AA' shown, extracted from the far-angle stack (25 – 35°), with the V_{shale} and resistivity curves from the four wells overlaid along the section. Notice that the Sand 1 is not continuous and unresolved over the wells, and Sand 2 is also unresolved.

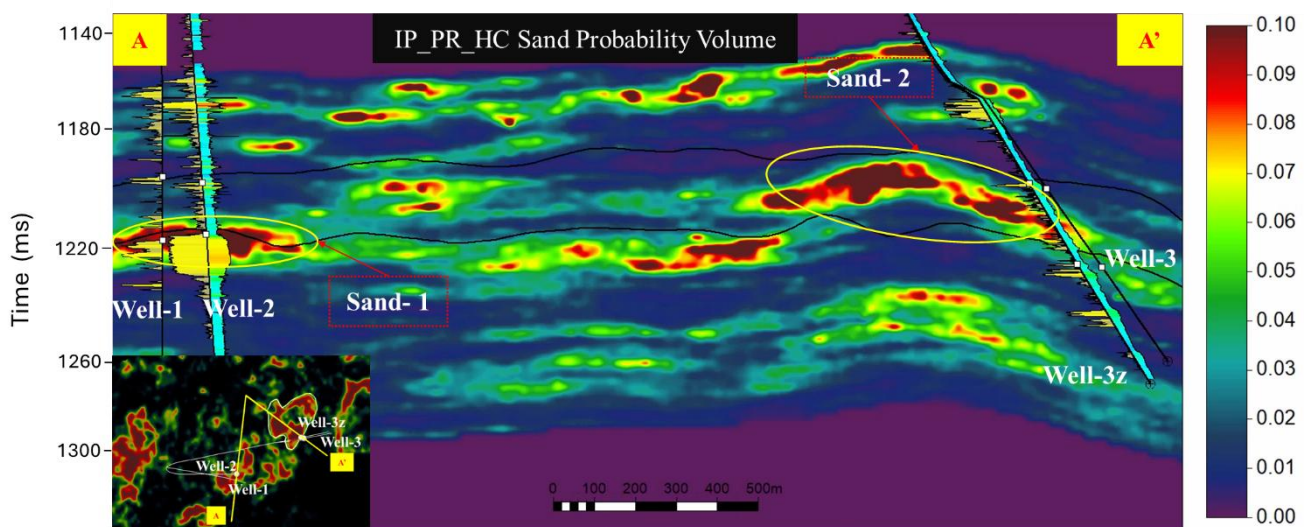


Figure 6: The arbitrary line section AA' extracted from the hydrocarbon sand probability volume obtained from geostatistical inversion, with the V_{shale} and resistivity curves from the four wells overlaid along the section. Notice that Sand 1 is clearly seen and correlates well with the well signature at Well 2. Sand 2 is also seen defined and aids the demarcation of the untapped potential for this sand. (Inset map shows sum of negative amplitude attribute where red area marked with a yellow boundary shows the untapped sand 2.)

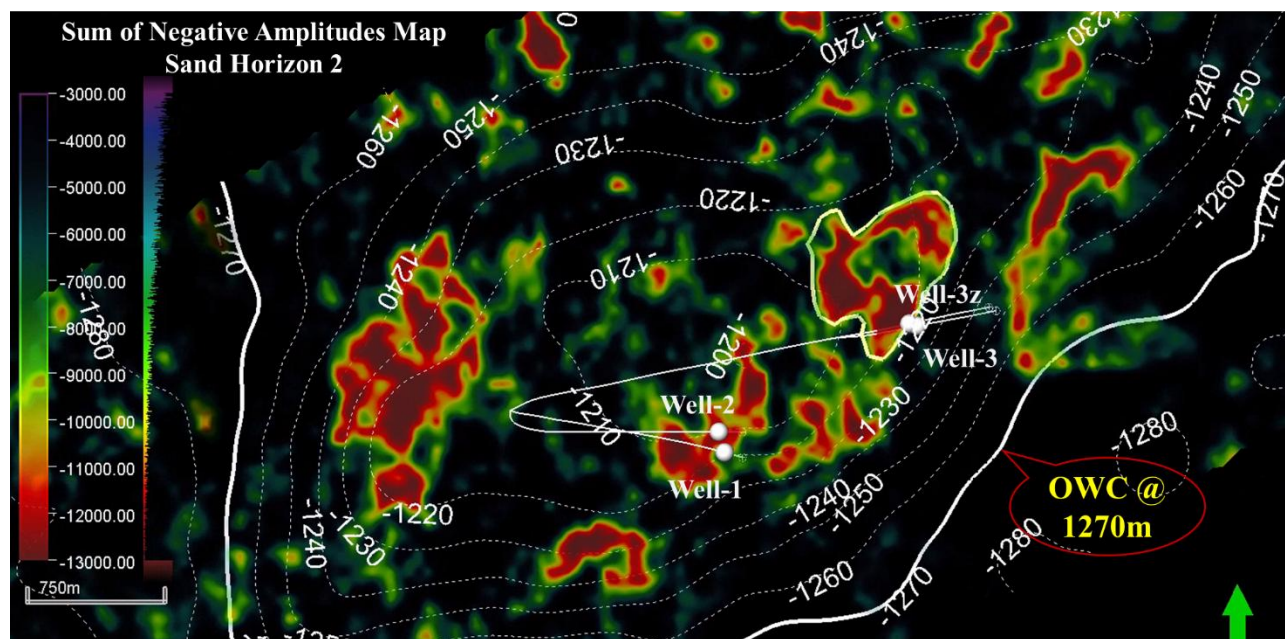


Figure 7: Map showing the sum of negative amplitudes extracted on far-angle stack volume, delineating the areal extent of Sand 2 (in yellow) near Well-3z. Notice that the amplitude response aligns well with the reservoir sand and hydrocarbon presence in Well 3z, which is further constrained by the OWC established at 1270m TVDSS in the field.

ion. Second was the sum of negative amplitude attribute generated, and finally the geobody extraction technique was employed which helped in providing a 3D representation of the reservoir and volumetric calculations as explained above. These datasets were supplemented with the standard petrophysical parameters derived from the wells and the thickness of

the sand bodies was guided by the well penetrations from the four wells.

Rock physics analysis and reservoir properties like porosity and lithology will simultaneously help in building static models and dynamic models for further development in this field.

CONCLUSIONS

This study demonstrates the integration of inversion-derived property volumes with seismic datasets, facilitating the delineation of sand bodies which are disconnected from each other and not clearly visible on vintage seismic datasets. The study also emphasizes that the streamlined workflow of using geophysical techniques such as geostatistical inversion can generate

constrained, high-resolution attribute data, which is particularly useful in delineating thin reservoirs. With the successful validation of this study through drilling of wells in future, this approach offers significant potential for sustainability of brown fields, presenting opportunities for similar applications in future projects. 

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BIOGRAPHIES



Supriya Deogharia is currently working as a geophysicist at Cairn Oil and Gas, Vedanta Limited. With a strong focus on development geophysics, Supriya has built a robust career specializing in seismic interpretation, rock physics, AVO analysis, and geostatistical inversion, primarily across complex offshore fields.

He holds an M.Sc. in Geophysics from the Indian Institute of Technology (IIT) Kharagpur. Supriya integrates strong geological fundamentals with advanced geophysical techniques to extract actionable insights from subsurface data. His work focuses on high-resolution reservoir characterization, seismic-to-well calibration, and identifying sweet spots for infill and development drilling.



Moumita Sengupta is a geophysicist with over 18 years' experience with strong skill sets in prospectivity evaluations and opportunities identification with integrated geoscientific workflows in Exploration and Development. She has a solid background in QI and specializes in seismic interpretation, rock physics, and attribute analysis. She is currently working as a DGM in Cairn Oil and Gas.

Moumita earned her Ph.D. degree in geophysics from IIT(ISM) Dhanbad. Her research area mainly focused on mapping of 4D seismic inversion results to predict saturation in gas-water systems for CO₂ sequestration and EOR. She has keen interests in understanding Geophysical challenges & solving it with problem and data specific workflows and writing codes for in geoscience for optimized solutions.



Dibyendu Chatterjee is a geologist with close to 19 years' experience dominantly in development geology, production geology and geo-modelling. Over the years he has gained experience in preparing reservoir model and field development plans for multiple onshore and offshore fields of different reservoir and structural complexities as well as at different stages of field life. He is currently working as a Head Geologist looking after offshore producing assets in Cairn Oil and Gas, Vedanta Limited.

Dibyendu did his M. Tech. in applied geology from IIT Roorkee in 2006. After starting career in wellsite geology and operations, he moved into development geology in early in his career delivering multiple geo-modelling projects as well as preparing infill FDPs (Field Development Plans) for multiple fields.

His work area focuses on multi-disciplinary data integration towards reducing subsurface uncertainties while proposing infill development planning and optimizing the well requirements towards maximizing recovery of the fields.



Kondal Reddy is a well-rounded geophysicist with strong skills in quantitative seismic interpretation. He is currently working as a Chief Geophysicist at Cairn Oil and Gas, Vedanta Limited, where he leads the Geophysics Function.

Kondal earned his M. Tech in geo-exploration from Indian Institute of Technology, Bombay (IITB) and joined Cairn in 2002. He has more than 22 years of experience in geophysics domain including seismic API, field development planning and reservoir monitoring. He is also skilled in quantitative seismic interpretation including rock physics, AVO, inversion, and 4D seismic. He contributed immensely to the exploration and development of oil and gas fields in KG Basin, Cambay, Assam, and Barmer basins.

Kondal is an active member of several professional organizations, including the Society of Exploration Geophysicists (SEG) and European Association of Geoscientists and Engineers (EAGE) and published many papers and abstracts in national and international conferences and journals.



Shakti Jain is a seasoned reservoir and asset management professional with over 18 years of experience in field development, mature field rejuvenation, Enhanced Oil Recovery (EOR), and digital reservoir optimization. A petroleum engineering graduate from IIT (ISM) Dhanbad, he has led impactful projects across major Indian onshore and offshore fields, including the Mangala ASP implementation and fast-tracking monetization of Mangala and Bhagyam wells, significantly enhancing production and recovery.

Shakti specializes in reservoir simulation, EOR design, and AI/ML integration in reservoir engineering—developing automated production forecasting, real-time well anomaly detection, and AI-driven surveillance. His contributions include the SPE-published Bhagyam reservoir model and polymer flood

strategies, unlocking over 15 MMbbls in incremental recovery. Known for his ability to bridge subsurface science with digital innovation, Shakti drives data-informed decision-making and sustainable hydrocarbon recovery, consistently delivering high-value outcomes.