

**QUANTITATIVE RESERVOIR CHARACTERIZATION BY INTEGRATING
ROCK PHYSICS ANALYSIS AND SEISMIC INVERSION, OFFSHORE INDUS
BASIN OF PAKISTAN**



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BAHRIA UNIVERSITY, ISLAMABAD

2026

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PHYSICS ANALYSIS AND SEISMIC INVERSION, OFFSHORE INDUS BASIN OF
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A thesis submitted in fulfilment of the requirements for the award of the degree of Masters
of Geophysics

Department of Earth and Environmental Sciences

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ABSTRACT

The Offshore Indus Basin, along Pakistan's passive continental margin in the Arabian Sea, holds a thick Cenozoic clastic succession with all the essential petroleum system elements, yet remains lightly drilled and commercially unproven. Conventional seismic interpretation maps structure adequately but cannot uniquely resolve porosity, lithology, and fluid saturation at the resolution exploration decisions require. This study addresses that gap by applying an integrated quantitative reservoir characterization workflow — combining petrophysical evaluation, structural seismic interpretation, model-based acoustic impedance inversion, and rock physics analysis to a Miocene–Pliocene clastic interval within the basin.

The dataset comprises eleven 2D seismic lines and wireline logs from three wells, two of which carry the log suite required for petrophysical evaluation. The reported tops place all three wells on a common chronostratigraphic scheme but are too widely spaced to define reservoir units, so four reservoir intervals were established within that framework by gamma ray and deep resistivity correlation, two in the Late Miocene and two in the Middle Miocene, and all subsequent analysis was conducted within them. Petrophysical analysis in GVERSE yielded shale volume (Larionov non-linear correction), average and effective porosity, and water saturation. Seismic interpretation in Kingdom, calibrated by synthetic seismograms, produced fault and horizon picks and time and depth structure maps for four key horizons. Model-based post-stack inversion in Hampson-Russell was applied to two of the strike lines, SPC-86-9007 and SPC-86-9019, and rock physics crossplots of V_p/V_s against P-impedance, bulk density and S-impedance, colour-coded by computed gamma ray, supplied the litho-fluid discrimination template.

The results define a vertically stacked sand–shale system in which reservoir quality is governed principally by clay content. All four intervals are shale-rich when averaged over their gross thickness, with shale volumes of 51 to 77 per cent, and the clay correction reduces average porosities of 21 to 32 per cent to effective porosities of 6 to 11 per cent. Water saturations are high throughout, at 80 to 98.5 per cent. The deeper PakCan-01 interval at 2700–2730 m is the cleanest and returns the highest effective porosity and hydrocarbon saturation, at 10.02 and 20.01 per cent; the two Sadaf-01 intervals return 10.64 per cent hydrocarbon saturation; and the shallower PakCan-01 interval at 1710–1770 m is effectively water-bearing at 1.50 per cent. Inversion, validated by well-tie correlations of approximately 0.99, imaged laterally coherent low-impedance anomalies confined to the

reservoir interval on both inverted lines and spatially coincident with fault-bounded structural closures persistent across all four mapped horizons. Because the computed water saturations are high and the shale volumes substantial, those anomalies are attributed principally to variation in clay content and porosity rather than to fluid fill, and the crossplots separate the data by lithology more clearly than by fluid. The fluid interpretation therefore remains an inference from elastic response rather than a measurement; pre-stack simultaneous inversion, shear velocity control in more than one well, and 3D coverage are recommended as the next steps.

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CHAPTER 1

INTRODUCTION

1.1 Introduction

Reservoir characterisation is the process of converting geological, geophysical and petrophysical measurements into a quantitative description of the rocks and fluids that make up a hydrocarbon reservoir. In most explored basins the difficulty is not a shortage of data but the interpretation of it. Seismic and wireline measurements record the physical response of the subsurface, and that response has to be translated into properties such as lithology, porosity and fluid saturation before it can inform a decision. Reservoir characterisation provides that translation, and it does so by combining disciplines rather than applying any one of them in isolation.

The results of this process govern where wells are drilled, how much hydrocarbon a structure is estimated to contain, and how a field is subsequently developed. Where the characterisation is reliable, exploration risk falls and development planning rests on a defensible description of the subsurface. Where it is not, structural maps may be accurate while the properties of the rock between the wells remain effectively unknown.

The requirement is more demanding offshore. Offshore wells are expensive, well control is sparse, and the cost of an unsuccessful well is high enough that predictions made between wells carry disproportionate weight. Seismic reflection data have long been used to image offshore structure, and they resolve faults and layering well, but reflection amplitude alone constrains neither the composition of the rock nor the fluid it contains.

This limitation has directed attention towards quantitative interpretation: the use of seismic data to estimate reservoir properties rather than to map geometry alone. Two methods are central to that shift, and this study applies both.

Rock physics bridges petrophysical measurements from wells with the seismic response captured at surface (Bosch et al., 2010; Grana & Della Rossa, 2010). It defines quantitative relationships among lithology, porosity, mineral composition, pore fluids, density, and elastic properties. Applied through models such as the Xu–White clay-sand mixing model and Gassmann’s fluid substitution equations, and through diagnostic cross-plots, rock physics makes it possible to understand how changes in reservoir properties show up in seismic attributes (Azeem et al., 2017; Grana & Della Rossa, 2010). That

understanding is what allows geoscientists to separate reservoir from non-reservoir facies, recognize fluid effects, and build predictive models applicable across the seismic volume (Azeem et al., 2017; Ali et al., 2019; Bosch et al., 2010).

Seismic inversion converts seismic reflection amplitudes into models of subsurface elastic properties (Bosch et al., 2010; Ali et al., 2019). Unlike a conventional seismic section, the output of inversion is a layer property—acoustic impedance in particular—that can be related directly to reservoir characteristics (Toqeer et al., 2021; Ali et al., 2019). Impedance variations track changes in lithology, porosity and fluid content, which makes inversion an effective tool for delineating and characterising reservoirs (Ali et al., 2019; Naeem et al., 2018; Asim et al., 2015). Linking inversion results to rock physics models derived from well logs constrains that interpretation and improves the reliability of the resulting prediction (Bosch et al., 2010; Grana & Della Rossa, 2010; Azeem et al., 2017).

This study applies an integrated rock physics and seismic inversion workflow to a selected area of the Indus Offshore Basin of Pakistan, using industry seismic and wireline log data obtained under a corporate–academic data sharing agreement. The objectives are to identify reservoir lithology, to quantify the variation in elastic properties across the reservoir intervals, and to improve the prediction of reservoir quality and hydrocarbon-bearing zones in an offshore setting where well control is limited.

1.2 Study Area

The study area lies within the Offshore Indus Basin of Pakistan, on the southern continental margin in the Arabian Sea west of Karachi. Water depths across the basin range from shallow continental shelf settings to deep water in excess of 3,000 m (Zaigham & Mallick, 2000). The principal exploration acreage lies approximately between latitudes 23°N and 25°N and longitudes 66°E and 68°E, and the three wells used in this study fall within that area (Figure 1.1).

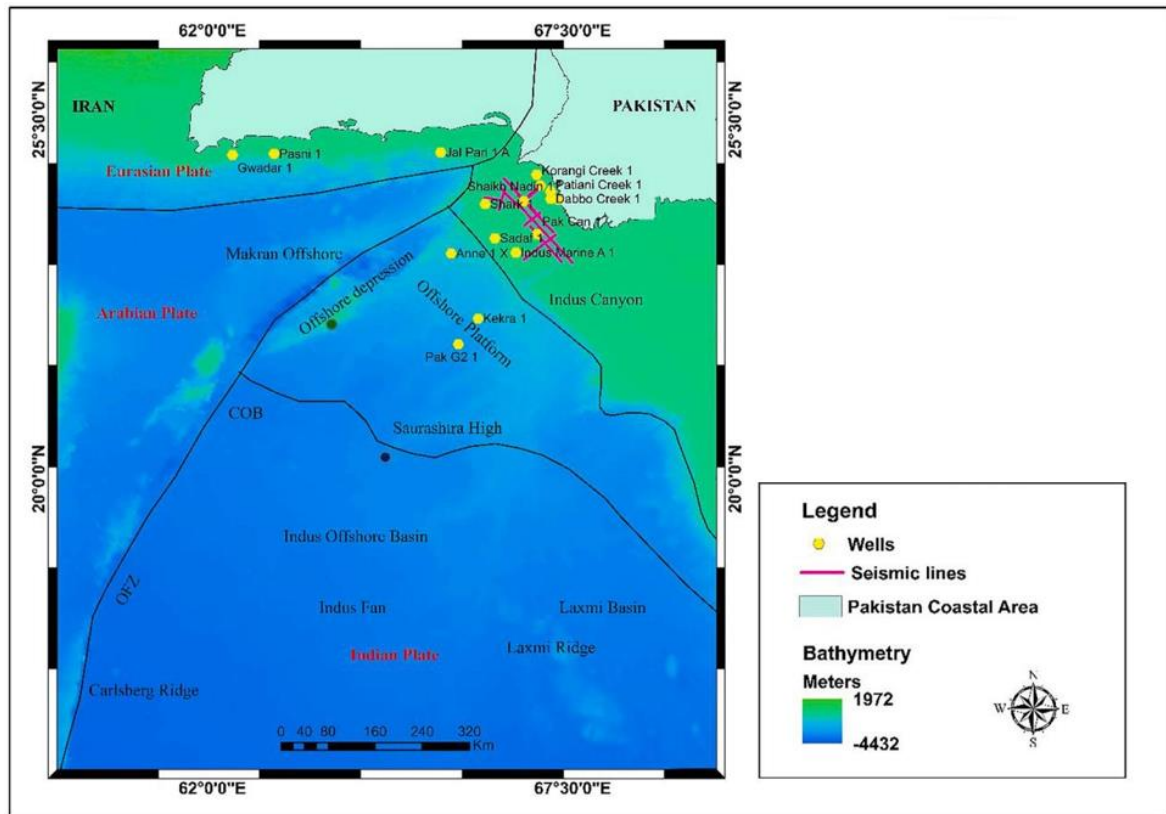


Figure 1. 1 Geological location map of the Offshore Indus Basin.

The basin forms part of the Indus Delta and submarine fan system, one of the largest siliciclastic sedimentary complexes in the world. Sediment delivered by the Indus River and deposited in the marine environment over an extended period has built a thick succession of sandstone, shale and siltstone. Depositional settings range from deltaic and shallow marine on the shelf to slope and deep marine basinward.

Tectonically the basin lies close to the western edge of the Indian Plate, in a setting governed by the interaction of the Indian, Eurasian and Arabian plates (Kazmi & Jan, 1997). It is bounded by the Kirthar Fold Belt to the north-west, the Indus Suture Zone to the north and the Makran Accretionary Prism to the west (Kazmi & Jan, 1997; Farah et al., 1984). These elements have controlled the subsidence history of the basin, the distribution of its sediments, and the deformation that produced its trapping geometries.

The basin is geologically continuous with the hydrocarbon-producing province of Sindh and contains stratigraphic equivalents of the intervals producing at fields such as Bhit, Zamzama and Sawan (Ali et al., 2018). The elements of a working petroleum system—source rock, migration pathway, reservoir and trap—are all present (Ali et al., 2018; Asim et al., 2015). The combination of thick reservoir-prone sequences and large

sediment volumes has sustained exploration interest despite the absence of a commercial discovery.

The area is well suited to the workflow applied here for two further reasons. Reservoir properties vary laterally over distances shorter than the well spacing, so a method that predicts those properties between wells has clear value, and the outstanding exploration questions concern rock and fluid properties rather than structure.

1.3 Exploration History

Exploration of the Offshore Indus Basin began in the early 1960s, prompted by regional geological studies suggesting that the offshore extension of the Lower Indus Basin might be prospective (Quadri & Shuaib, 1986). Early work comprised reconnaissance geological mapping, gravity surveys and 2D seismic acquisition aimed at identifying structures and sedimentary sequences capable of hosting hydrocarbons. These surveys confirmed a thick sedimentary section and conditions favourable for hydrocarbon generation and accumulation.

Activity increased through the 1970s and 1980s, when a number of exploratory wells were drilled, among them PakCan-01. Several of these wells encountered hydrocarbon shows, but none established a commercial accumulation. High offshore drilling costs, the technology available at the time, and continuing uncertainty over the offshore petroleum system together limited sustained investment.

Seismic acquisition and processing improved substantially during the 1990s, producing clearer images of the subsurface and better definition of potential reservoir intervals. International operators, including Shell and BP, entered the offshore through partnerships and concession agreements. Despite the improved data, no commercial discovery followed, and questions over source rock maturity and migration timing remained unresolved.

Interest returned during the 2000s and 2010s with the availability of 3D seismic acquisition, deep-water drilling capability and improved interpretation methods. The most recent deep-water test was Kekra-1, drilled in 2019 in the Indus G Block by a consortium comprising ExxonMobil, Eni, Pakistan Petroleum Limited and Oil and Gas Development Company Limited. The well did not encounter commercial hydrocarbons, but the expenditure it represented indicates continued industry confidence in the deep-water

portion of the basin. Current work is directed towards improved seismic imaging, quantitative interpretation and basin-scale assessment of the remaining potential (Ali et al., 2019; Durrani et al., 2020).

1.4 Hydrocarbon Potential

The Offshore Indus Basin retains significant hydrocarbon potential on geological grounds, but it remains lightly drilled. Approximately twelve wells have been completed offshore, of which only a small number tested deep-water objectives, and no commercial production has yet been established. Gas has, however, been encountered in Miocene intervals in several wells, which demonstrates that the elements required for hydrocarbon generation and accumulation are present.

The principal reservoir objectives are clastic units deposited in deltaic, shelf, slope and deep-marine settings. Miocene and Plio-Pleistocene sandstones are the primary targets because of their porosity and permeability, and Oligocene deep-water fan deposits are regarded as a secondary objective.

A range of trapping styles has been identified, including extensional rollover anticlines, drape structures, stratigraphic pinch-outs and fold-related closures. These geometries reflect the structural history of the area, in particular Murray Ridge tectonics and shale diapirism, and they indicate that more than one play type may be viable.

The Lower Cretaceous Sembar Formation is the established source rock of the Lower Indus Basin and is expected to be present at depth beneath the offshore, although in parts of the basin it may be overmature. Paleocene and Eocene marine carbonate units have also been proposed as potential source intervals, but their source potential offshore has not been demonstrated and remains a subject for further work.

No commercial accumulation has therefore been proven offshore, yet gas shows, multiple trapping styles and thick reservoir-prone sequences continue to sustain exploration interest. Realising that potential is likely to require quantitative methods—rock physics analysis, seismic inversion and basin modelling—rather than structural interpretation alone.

1.5 Geological Setting

The interpretation presented in this thesis sits within a regional geological framework established by earlier work. This section summarises that framework: the tectonic evolution of the Indus Basin, the structural style of the offshore area, its

stratigraphy, and the elements of its petroleum system. The literature from which the framework derives is reviewed critically in Chapter 2; the purpose here is to supply the geological context needed to read the results.

1.5.1 Regional Tectonic Framework

The Indus Basin is the principal hydrocarbon province of Pakistan, and its present configuration is a product of the collision between the Indian and Eurasian plates. Obduction of the Kohistan–Ladakh arc onto the Indian plate margin at approximately 65 Ma was followed by collision with Eurasia at around 50 Ma, and convergence continues today (Farah & DeJong, 1979; Molnar & Tapponnier, 1975; Treloar & Coward, 1991). The resulting crustal shortening built the Himalayan orogen and drove subsidence in the foreland basins to the south.

Pakistan's structural domains record successive stages of that collision. The Indus Suture Zone in the north separates the Kohistan arc from the Indian plate and is marked by ophiolite sequences, mélangé and fragments of oceanic crust (Gnos et al., 1997; Kazmi & Jan, 1997). The Main Mantle Thrust, Main Central Thrust and Main Boundary Thrust divide the fold-and-thrust belt and control the emplacement of Himalayan crystalline rocks over the Lesser and Sub-Himalayas (Treloar & Coward, 1991). The western margin of the basin follows the Chaman Transform Fault, which has accommodated strike-slip motion between the Indian and Afghan blocks since the Oligocene (Lawrence et al., 1992), while the Sulaiman and Kirthar fold belts formed by thin-skinned deformation and host major structural gas accumulations, including Sui (Kadri, 1995; Wandrey et al., 2004).

The basin is divided into an Upper and a Lower Indus Basin, separated by the Sargodha High. Mesozoic extension associated with the separation of India from Gondwana produced basement-controlled horst and graben structures in the Lower Indus Basin, and these were inverted during the Cenozoic so that they now act both as sediment sources and as trapping geometries (Kemal et al., 1991; Wandrey et al., 2004). Cretaceous rifting in the Badin Rift Zone created accommodation for thick reservoir-quality sandstones (Khalid et al., 2018).

The Offshore Indus Basin is the submarine continuation of the Lower Indus Basin and comprises the Pakistan Shelf, the continental slope and the deep-water Indus Fan (Clift & Blusztajn, 2005). The fan covers more than 1.1×10^6 km², and sediment thickness exceeds 10 km in places (Kolla & Coumes, 1987). Basement is Precambrian rock of the

Indian craton, overlain by a Late Triassic to Holocene sedimentary succession (Kazmi & Jan, 1997). Sediment supply from the rising Himalaya has dominated the basin fill since the Mesozoic (Qayyum et al., 1997; Clift & Plumb, 2008), and the Indus Submarine Canyon has routed that sediment to the deep-water fan since the Miocene, building the reservoir-prone sand bodies of the fan system (Kolla & Coumes, 1987; Droz & Bellaiche, 1991).

1.5.2 Structural Framework of the Study Area

The structural framework of the offshore basin is the product of multiphase deformation and includes normal faults, inversion structures and gravity-driven features. The dominant structural trend in the eastern offshore is north-north-west to south-south-east, broadly parallel to basement lineaments of the Indian craton and to the Cretaceous rift system (Kemal et al., 1991; Khalid et al., 2018). Basement-involved normal faults active during Late Cretaceous rifting controlled the thickness and facies distribution of the syn-rift succession.

Structural style varies with depth. The shallow shelf section consists of gently dipping strata cut by normal faults that define extensional half-graben, and these have been the principal conventional exploration targets. At greater depth, compressional features associated with Cenozoic convergence become more prominent, particularly towards the Makran front, where thrust-related folds add further trap geometries. Seismic data across the area show a three-layer architecture: a basement-controlled lower section containing rift-related structures, a middle post-rift passive margin succession, and an upper section deformed by sediment loading and gravity tectonics on the continental slope (Kadri, 1995; Wandrey et al., 2004). Horst-and-graben configurations and fault-dependent closures are the dominant trap geometries reported across the Lower Indus Basin (Naeem et al., 2015; Asim et al., 2015).

1.5.3 Stratigraphy

The offshore succession spans the Late Triassic to the Holocene and records the evolution of the area from a Tethyan passive margin, through a rifted continental margin, to a rapidly subsiding basin receiving Himalayan sediment (Kadri, 1995; Kazmi & Jan, 1997). It is broadly comparable to the onshore Lower Indus Basin, differing mainly in the greater thickness of its Cenozoic section towards the Indus Fan. Figure 1.2 summarises the chronostratigraphy of the basin against the principal tectonic events.

The Mesozoic section begins with Triassic and Jurassic carbonates and evaporites deposited on the Tethyan passive margin (Wandrey et al., 2004). The Cretaceous interval carries the established petroleum system of the Lower Indus Basin: the Sembar Formation, an organic-rich marine shale; the Lower Goru Formation, a deltaic to shallow-marine sandstone and shale succession divided into sand packages that form the main reservoirs; and the Upper Goru Formation, a deeper-marine shale and mudstone that provides the regional seal (Asim et al., 2015; Qadri et al., 2019; Wandrey et al., 2004; Khalid et al., 2018).

The Cenozoic section records increasing clastic supply from the Himalaya. The Paleocene Ranikot and Eocene Kirthar formations reflect that influx alongside platform carbonate deposition, and the Eocene Habib Rahi and Sui Upper limestones have proved productive onshore, notably at Qadirpur (Ali et al., 2019). Offshore, the Miocene and Pliocene section of the Indus Fan is dominated by submarine fan sands interbedded with hemipelagic mud, which together form potential reservoir–seal pairs in the deep-water setting. The reservoir intervals analysed in this study lie within that Miocene clastic section.

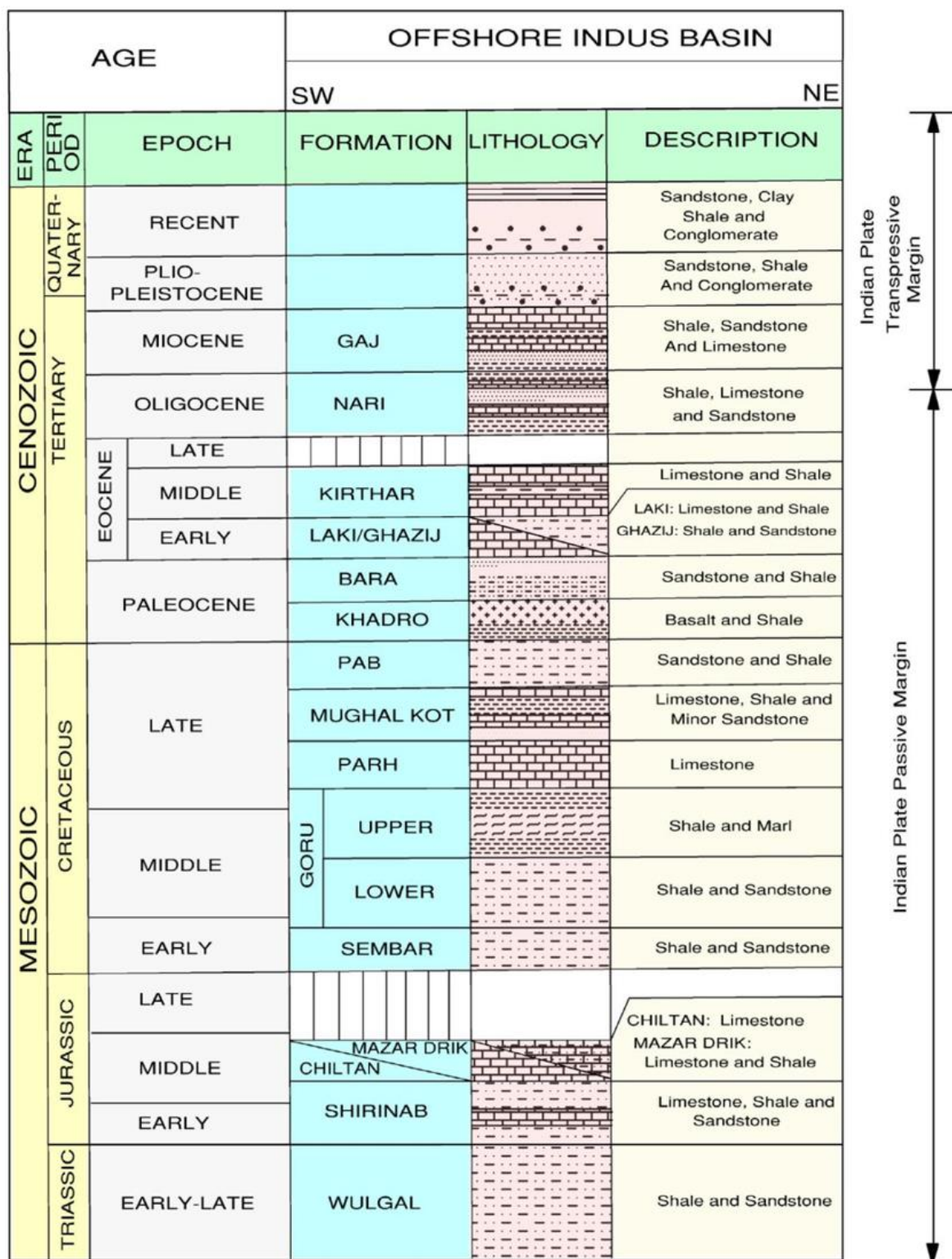


Figure 1. 2 Chronostratigraphic chart for the onshore and offshore Indus Basin of Pakistan, compiled from well control points. The right-hand column shows the principal tectonic events affecting the study area and its surroundings.

1.5.4 Petroleum System

The offshore petroleum system is the seaward continuation of the Sembar–Goru system of the Lower Indus Basin. It comprises Sembar shale source rocks, Lower Goru sandstone reservoirs, Upper Goru shale seals, and a combination of structural and stratigraphic traps (Wandrey et al., 2004).

The Early Cretaceous Sembar Formation was deposited in a marine setting and carries total organic carbon values of 2 to 4 per cent across much of the basin, rising to as much as 8 per cent in mature areas (Wandrey et al., 2004; Aziz et al., 2018). Its organic matter is predominantly Type II kerogen, which generates gas and condensate on maturation.

The Lower Goru sandstones were deposited in deltaic to shallow-marine settings and are divided into A, B, C and D sand packages separated by shale intervals (Asim et al., 2015; Naeem et al., 2015). Porosity in the producing areas ranges from about 12 to 25 per cent and permeability from 10 to 500 mD (Qadri et al., 2019; Berger et al., 2009). The Eocene Habib Rahi and Sui Upper limestones provide a secondary carbonate objective, with porosity developed by fracturing and dissolution (Ali et al., 2019).

The Late Cretaceous shales and marls of the Upper Goru Formation form the regional top seal, with permeability commonly below 0.001 mD (Khalid et al., 2018; Wandrey et al., 2004). Within the Lower Goru, individual sand bodies are bounded above and below by shale, which maintains separate fluid contacts and pressure regimes between them (Naeem et al., 2015).

Trapping is dominated by four-way dip closures on horst blocks and by fault-dependent closures associated with the Cretaceous rift system (Naeem et al., 2015; Asim et al., 2015). Stratigraphic traps—pinch-outs, channel sands and incised valley fills—are also present but remain underexplored. Migration from the Sembar source into the overlying Goru reservoirs is inferred to take place along the steep normal faults that bound the rift blocks (Wandrey et al., 2004).

1.6 Data Used

The analysis rests on two datasets. The first is a grid of eleven 2D post-stack time-migrated seismic reflection lines covering the study area, acquired in at least three separate programmes. The second is wireline log data from three exploratory wells: Sadaf-01,

PakCan-01 and Indus Marine-1A. Sadaf-01 and PakCan-01 carry the log suite required for petrophysical evaluation; PakCan-01 additionally records shear sonic data and therefore anchors the rock physics analysis; Indus Marine-1A supplied the synthetic seismogram used for the seismic-to-well tie. Both datasets were obtained under a corporate–academic data sharing agreement. The wells are listed in Table 3.1 and the seismic lines in Table 3.2, and their spatial relationship is shown on the base map in Figure 3.2. The constraints these data impose on the results are set out in Section 1.10.

1.7 Research Gap

The Offshore Indus Basin occupies an unusual position in Pakistan's exploration history. Decades of geological and geophysical study have not resolved the key uncertainties, and those uncertainties concern reservoir distribution, lithological variability and fluid characterisation rather than structure.

Most previous work has relied on conventional seismic interpretation supported by sparse well control. That approach yields structural maps but says little about reservoir properties between wells (Bosch et al., 2010; Ali et al., 2019). Offshore conditions compound the difficulty: facies change laterally, depositional environments are complex, and subsurface control is limited.

Seismic inversion addresses part of the problem, and acoustic impedance estimation is now routine (Toqeer et al., 2021; Ali et al., 2019). Inversion alone, however, does not identify the fluid present or establish the quality of the reservoir. Without a rock physics framework to anchor the interpretation, lithological effects are easily confused with fluid effects (Bosch et al., 2010; Grana & Della Rossa, 2010; Azeem et al., 2017).

Rock physics has been used successfully in many basins to link petrophysical and elastic properties (Bosch et al., 2010; Grana & Della Rossa, 2010), and it has been applied onshore in Pakistan. It has not, however, been integrated systematically with seismic inversion in the Offshore Indus Basin. Published work on the offshore has concentrated on regional geology and petroleum system assessment, and a workflow combining well-log rock physics modelling with seismic inversion for reservoir prediction has not been tested in this setting.

That is the gap addressed here. This study integrates well-log analysis, rock physics modelling and seismic inversion to establish quantitative relationships between reservoir

properties and the seismic response, with the aim of improving the prediction of lithology, elastic properties and hydrocarbon-bearing intervals in the Offshore Indus Basin of Pakistan.

1.8 Research Problem

The hydrocarbon potential of the Offshore Indus Basin remains unresolved. Reservoir characterisation there is difficult because the subsurface geology is complex and well control is sparse. Conventional seismic interpretation maps structure adequately but does not resolve porosity, lithology and fluid saturation at the resolution exploration decisions require (Bosch et al., 2010; Grana & Della Rossa, 2010). Combining rock physics analysis with seismic inversion offers a more quantitative and reproducible route to estimating those properties (Azeem et al., 2017; Toqeer et al., 2021).

The problem addressed by this study is therefore how that integration can be made to work under the specific conditions of the Pakistani offshore: three wells across the study area, post-stack seismic data only, and a shear sonic log in one well. The study develops a workflow suited to those conditions, calibrates it against the available well data, and assesses how far it constrains reservoir properties within the Miocene clastic section.

1.9 Research Objectives

This study is guided by the following specific objectives:

- Structural interpretation of the study area using seismic data to interpret subsurface structure and understand potential hydrocarbon prospects.
- Petrophysical analysis to identify reservoir zones and calculate key reservoir properties including porosity, shale volume, and water saturation.
- Seismic inversion analysis targeted at estimating the inverted acoustic impedance (Z_p) of the identified reservoir zones.
- Rock physics analysis of the reservoir to derive elastic properties and establish a quantitative reservoir model linking well-log observations with seismic inversion results.

1.10 Limitations and Data Constraints

Every result presented in this thesis is bounded by the data that was available to produce it. The constraints are set out here so that the interpretations in Chapters 4 and 5 can be read with them in mind rather than being read as more certain than they are.

Well control is the first constraint. Three wells cover the study area and they are widely spaced. Sadaf-01 and PakCan-01 lie about 58 km apart, Indus Marine-1A sits roughly 35 km from PakCan-01, and about 52 km separates Sadaf-01 from Indus Marine-1A. Only two of the three wells carry the log suite needed for petrophysical evaluation, so the petrophysical results are point measurements at two locations and cover four reservoir intervals in total. Reservoir behaviour between those points has to be inferred from seismic, and any lateral change occurring over distances shorter than the well spacing cannot be tested against a log.

The seismic database is 2D rather than 3D. Coverage is a grid of lines separated by several kilometres, so surfaces mapped between lines depend on interpolation, and structures narrower than the line spacing can be missed. The lines also belong to more than one acquisition programme, and their names indicate at least three vintages. Acquisition and processing parameters differ between those vintages, so amplitude character is not strictly comparable from one line to the next, and mis-ties at line intersections had to be reconciled during horizon picking. Bandwidth narrows with depth, so beds thinner than the tuning thickness at reservoir level are not resolved individually. Eleven lines were interpreted, but only two of them, SPC-86-9007 and SPC-86-9019, were inverted, so the impedance picture covers two profiles rather than the whole grid.

Only post-stack data were available for inversion. Pre-stack gathers and angle stacks were not, which restricts the inversion to acoustic impedance: shear impedance and density cannot be recovered from post-stack seismic. Lithology and fluid both move acoustic impedance in the same direction, so the two effects cannot be separated by inversion on its own. That separation comes from the well-log rock physics in Section 3.6, and its extension away from well control is qualitative. Model-based inversion is also non-unique. Seismic data are band-limited, and the missing low frequencies are supplied by a model built by interpolating impedance from the wells along each line. With so few wells that low-frequency model is weakly constrained away from well control, so impedance values in the middle of a long line carry more uncertainty than the smooth appearance of the inverted sections suggests.

The log suite is neither complete nor uniform across the wells. Shear sonic data are available in one well only, so the V_p/V_s crossplots in Section 4.5 rest on PakCan-01 and cannot be checked against a second well. No core data were available, which means log-

derived porosity is not calibrated against measured core porosity, and permeability is not measured at all. The Archie parameters were taken as standard values ($a = 1$, $m = 2$, $n = 2$) rather than derived from special core analysis, and formation water resistivity was estimated from the SP log and regional salinity rather than measured on a produced water sample. Absolute water saturation values carry both of those assumptions. There are no production or well test data for the intervals studied, so hydrocarbon saturation estimates cannot be validated against flow.

The reported well tops place the three wells on a common chronostratigraphic scheme, but they are age assignments spaced hundreds to thousands of metres apart, so they cannot define reservoir units on their own. The reservoir intervals used here were therefore picked on log character within that framework, as described in Section 3.2. They are local working units defined on log signature rather than formal lithostratigraphic units, and correlating them in detail to units named elsewhere in the basin would require biostratigraphic control that was not available for this work. One reported pick, the Upper Miocene (Tortonian) top at Indus Marine-1A, is out of stratigraphic order and was excluded.

Depth conversion adds a further layer of uncertainty. The velocity model was built from sonic and check-shot data at a small number of wells and treats velocity as varying smoothly between them. Real velocity fields are rarely that well behaved, so absolute depths on the depth structure maps, and any closure area read from them, should be treated as approximate.

Finally, several methods that would have narrowed these uncertainties fell outside the scope of the study. AVO analysis, pre-stack simultaneous inversion and geostatistical or stochastic inversion were not attempted, and no petroleum system modelling was carried out, so nothing here speaks directly to source rock maturity or migration timing. What the study delivers is a calibrated link between log properties and elastic response, and a mapped impedance distribution consistent with that link. It does not deliver a volumetric estimate or a drilling recommendation.

1.11 Thesis Outline

Chapter 1 introduces the study. It defines reservoir characterisation and its role in offshore exploration, describes the study area, its exploration history and its hydrocarbon potential, summarises the geological setting and the data used, and states the research gap,

the research problem and the objectives. It closes with the limitations imposed by the available data.

Chapter 2 reviews previous work. It examines the development of reservoir characterisation, petrophysical evaluation and the use of well log data, then assesses the international literature on rock physics and seismic inversion and the body of work carried out in the Indus Basin, concluding with a synthesis of what remains unresolved.

Chapter 3 sets out the datasets and the methodology. It describes the seismic and well data, the base map and well correlation, seismic interpretation, petrophysical analysis, model-based post-stack inversion and rock physics analysis, together with the parameters used at each stage.

Chapter 4 presents the results: petrophysical evaluation of the four reservoir intervals, seismic interpretation and structure mapping, acoustic impedance inversion of lines SPC-86-9007 and SPC-86-9019, and the rock physics crossplots and template.

Chapter 5 discusses those results against previously published work, and the concluding chapter assesses the study against each of its stated objectives.

CHAPTER 2

LITERATURE REVIEW

This chapter reviews the work on which the present study builds. The regional geology and petroleum system of the Indus Basin are described in Section 1.5; the concern here is with method rather than with setting. The review covers the development of reservoir characterisation as a discipline, what previous workers have established about petrophysical evaluation and the use of well logs, the international literature on rock physics and seismic inversion, and the body of work carried out in the Indus Basin. It closes by identifying what that work leaves unresolved.

2.1 Reservoir Characterisation

Reservoir characterisation combines petrophysical, geophysical and engineering measurements into a model of the subsurface that supports production estimation, development planning and infrastructure design. The scope of what can be modelled has widened considerably over the past four decades, driven largely by increases in computing capacity and by the availability of 3D seismic data (Doyen, 2007; Avseth et al., 2010).

The case for detailed characterisation is strongest offshore, where drilling costs are high and the penalty for a mis-predicted reservoir is correspondingly large. Chopra and Marfurt (2008) argue that the value of characterisation lies less in the model itself than in the reduction of uncertainty achieved before a well is committed.

Early characterisation workflows relied on 2D seismic data interpreted alongside well logs. The introduction of 3D seismic acquisition during the 1980s and 1990s changed the discipline, since a densely sampled volume permits properties to be mapped rather than interpolated between widely spaced lines.

Current practice integrates seismic inversion, petrophysical analysis and rock physics modelling rather than treating them separately, and it is applied both onshore and offshore (Durrani et al., 2020; Ali et al., 2018). What the literature makes clear, however, is that the value of the integrated approach depends on the quality of the calibration between seismic and well. Where well control is sparse, as it is in the offshore Indus Basin, the same workflow yields a weaker result than it does in a well-drilled onshore field, and that difference is a central concern of this study.

2.2 Petrophysical Evaluation of Reservoirs

Petrophysical evaluation converts wireline measurements into the reservoir parameters used for volumetric and production assessment: porosity, permeability, fluid saturation and lithology (Serra, 1984; Rider, 2002). The methods are long established; what varies between studies is the choice of model and the calibration available to support it.

Porosity is derived from neutron, density and sonic measurements, each of which responds differently to lithology and pore fluid (Rider, 2002). In the Lower Indus Basin, Qadri et al. (2019) reported total porosity between 14.6 and 18.02 per cent and effective porosity between 12.5 and 16.5 per cent across five wells, while Naeem et al. (2015) documented a systematic reduction in porosity with depth attributable to compaction. Permeability cannot be measured from logs and is instead inferred from porosity relationships calibrated on core. Berger et al. (2009) established such a relationship for the Lower Goru sandstones and showed that porosity preservation there is controlled by chlorite grain coatings that inhibit quartz cementation, a diagenetic control that log analysis alone cannot recover. Neither core measurements nor a calibrated porosity–permeability relationship were available for the present study, which is why permeability is not estimated here.

Water saturation is most commonly estimated using the relationship established by Archie (1942), with the Simandoux, Waxman–Smits and dual-water models developed subsequently to account for the additional conductivity contributed by clay minerals (Rider, 2002; Serra, 1984). Reported water saturations in gas-producing Lower Goru sands fall between 14 and 35 per cent (Qadri et al., 2019; Naeem et al., 2015). The choice of model matters: applying Archie to a shaly sand underestimates water saturation, so the cleanliness of the interval has to be demonstrated rather than assumed, and that requirement governs the interval selection described in Section 3.4.3.

Lithology is determined from the combined response of gamma ray, neutron and density logs, with the gamma ray log the primary shale indicator (Qadri et al., 2019; Naeem et al., 2015). Crossplot templates are widely used to relate log-derived lithology to elastic properties. Durrani et al. (2020) applied them to carbonates of the Middle Indus Basin and Naeem et al. (2017) to Cretaceous sand intervals, and in both cases the lithologies identified from logs proved consistent with those predicted from seismic data, which supports the use of the same approach here.

2.3 Well Log Data in Reservoir Characterisation

Well logs provide the highest-resolution direct measurement of formation properties available in an exploration setting, sampling the formation at intervals of roughly 0.1 to 0.5 m. They are the reference against which every seismically derived property is calibrated.

Exploration wells in the Indus Basin typically carry gamma ray, spontaneous potential, resistivity, density, neutron, sonic and photoelectric factor logs (Rider, 2002; Serra, 1984). Sonic logs recording compressional and, where available, shear velocity are the essential input to rock physics analysis, since they supply the elastic properties directly rather than through inference.

Shear sonic data are frequently absent. Where they are, shear velocity is estimated from empirical relationships. Naeem et al. (2017) tested such predictions against measured shear data in the Middle Indus Basin and found them adequate for trend analysis, though less reliable in gas-bearing intervals, since the empirical relationships are calibrated largely on brine-saturated rock. That limitation bears directly on the present study, in which shear data exist in one well only.

Well logs also control the seismic inversion itself. They calibrate the extracted wavelet, supply the low-frequency component of the initial impedance model, and provide the tie between the depth and time domains. Naeem et al. (2015) and Khalid et al. (2018) both emphasise that errors in wavelet extraction or in the well tie propagate directly into the inverted impedance and into any reservoir property predicted from it, which makes log conditioning—depth matching, despiking, normalisation and environmental correction—a prerequisite rather than a preliminary (Doyen, 2007).

The principal constraint in the offshore Indus Basin is the scarcity of wells carrying a complete log suite, and in particular the near-absence of shear velocity measurements. Every quantitative study of the offshore, including this one, is limited by that scarcity.

2.4 Rock Physics and Seismic Inversion: International Studies

Han et al. (1986) measured compressional and shear velocities on 75 water-saturated sandstone samples and established the linear dependence of velocity on porosity and clay content. The resulting relationships remain in routine use as calibration equations, including in the Indus Basin (Naeem et al., 2017; Asim et al., 2015). They were derived on consolidated samples, however, and are correspondingly less reliable for the poorly

consolidated sands typical of a young deltaic and fan section, which is one reason an unconsolidated rock physics model is adopted in Section 3.7.

Bosch et al. (2010) reviewed methods for combining seismic inversion with rock physics information, classifying them as sequential or joint workflows. They concluded that joint inversion produces formally consistent estimates of elastic and reservoir properties and avoids the error accumulation inherent in sequential approaches. Grana and Della Rossa (2010) demonstrated a full Bayesian treatment on North Sea clastic data and quantified the uncertainty attached to petrophysical properties estimated from seismic. Both approaches require more data than are available offshore Pakistan—pre-stack gathers in the first case, and a statistically meaningful number of wells in the second—which is why the deterministic, sequential workflow described in Chapter 3 is adopted here.

Other work has extended the range of properties recoverable from seismic data. Hampson et al. (2001) introduced multi-attribute transforms for predicting log properties from combinations of seismic attributes. Cyz and Azevedo (2019) inverted directly for rock properties without first estimating elastic properties, removing one stage of error propagation. Garia et al. (2023) mapped petrophysical properties in the Upper Assam Basin of India using inversion constrained by laboratory-derived rock physics models, demonstrating a multi-scale workflow applicable to underexplored basins. In carbonates, Eberli et al. (2003) showed that the relationship between porosity, pore type and velocity is poorly predictable without additional laboratory or borehole image constraints, a finding directly relevant to the carbonate objectives of the Indus offshore (Durrani et al., 2020; Avseth et al., 2010).

2.5 Previous Work in the Indus Basin

Work on the Lower Indus Basin over the past two decades reflects its importance to Pakistani hydrocarbon production. Kadri (1995) and Wandrey et al. (2004) established the regional geological and petroleum system framework, and Zaigham and Mallick (2000) showed that inherited basement faults exert a strong control on hydrocarbon distribution. Berger et al. (2009) explained porosity preservation in the Sawan Gas Field sandstones through chlorite grain coating.

Naeem et al. (2015, 2018) combined seismic and well log data to characterise the structure and reservoir quality of the Lower Goru Formation. Asim et al. (2015) applied impedance inversion in the Miano block and distinguished gas-bearing sands from shale.

Qadri et al. (2019) quantified the petrophysical range of the Lower Goru across five wells, and Khalid et al. (2018) mapped the fault-bounded Cretaceous sandstone reservoirs of the Badin area. Together these studies establish what a well-calibrated impedance inversion can deliver onshore, where wells are numerous and shear data are more widely available.

A second group of studies has addressed the Sembar Formation as an unconventional objective. Aziz et al. (2018) estimated total organic carbon from acoustic impedance, demonstrating that source rock richness can be predicted away from well control. Sohail et al. (2020) assessed the geomechanical properties of the formation and identified intervals whose brittleness and stress conditions suit hydraulic fracturing. Abid et al. (2021) used seismic attributes to track lateral variation in shale properties, producing a method transferable to other unconventional plays.

The Sawan Gas Field has received the most detailed treatment. Ali et al. (2018, 2019) compared seismic inversion algorithms and characterised secondary reservoir potential in Eocene carbonates; Anwer et al. (2017) demonstrated the importance of anisotropy in interpreting the seismic response; and Qiang et al. (2020) applied machine learning to inversion for reservoir property prediction. In the Middle Indus Basin, Azeem et al. (2017) and Naeem et al. (2017) applied rock physics models to Cretaceous sand intervals, Durrani et al. (2020) used pre-stack simultaneous inversion on tight carbonates, and Naseer (2017) delineated gas-bearing channel fills using post-stack colour inversion.

What this body of work has in common is that it is onshore. The offshore basin, despite a broadly comparable stratigraphy, has attracted far less quantitative study, and the reasons are practical rather than geological: wells are few, shear sonic data are rare, and most of the available seismic coverage is 2D and post-stack.

2.6 Synthesis and Research Gap

The onshore literature therefore supplies both a method and a benchmark. Porosity, water saturation and shale volume for the Lower Goru are documented across many wells; rock physics relationships between porosity, clay content and velocity have been calibrated locally; and impedance inversion has been shown to discriminate gas-bearing sand from shale where the well control is adequate. These results provide the expectations against which an offshore result can be judged.

The unresolved question is whether the same workflow holds where the calibration is weak. No published study has integrated well-log rock physics with seismic inversion in the Offshore Indus Basin, and the conditions there differ from the onshore case in ways that matter: three wells rather than tens, one shear sonic log rather than several, post-stack rather than pre-stack seismic, and 2D line coverage rather than a 3D volume. The present study addresses that gap directly, and in doing so it also tests how far a workflow developed under favourable onshore conditions degrades when those conditions are absent.

CHAPTER 3

METHODOLOGY

3.1 Adopted Methodology

This study characterized subsurface geology and reservoir properties within the Indus Offshore Basin using three interconnected analytical workflows—seismic interpretation, petrophysical analysis, and seismic inversion—supplemented by rock physics evaluation, all conducted within a shared stratigraphic framework established through well correlation.

Seismic interpretation was carried out in Kingdom software. This stage built a base map to establish spatial context, generated synthetic seismograms for seismic-to-well calibration, picked key horizons and faults on the 2D seismic lines, and produced time and depth contour maps for the interpreted horizons.

Petrophysical analysis was performed in GVERSE using wireline log data from the study wells. Of the three wells available, only Sadaf-01 and PakCan-01 carry the log suite required for quantitative evaluation, so the petrophysical work was confined to those two. Indus Marine-1A was used for the seismic-to-well tie and was not analysed petrophysically. The work included log quality control, identification of reservoir intervals, and calculation of shale volume, porosity, water saturation, and hydrocarbon saturation.

Seismic inversion was conducted in Hampson-Russell software using a post-stack model-based inversion algorithm to convert the 2D seismic reflection data into acoustic impedance volumes. This covered data loading, wavelet extraction, seismic-to-well tie, construction of a low-frequency model, inversion, and evaluation of the inverted acoustic impedance output.

The petrophysical and seismic inversion results were then brought together through rock physics analysis—crossplots interpretation and Rock Physics Template construction—to produce a reservoir model synthesizing structural, petrophysical, and elastic property information across the study area.

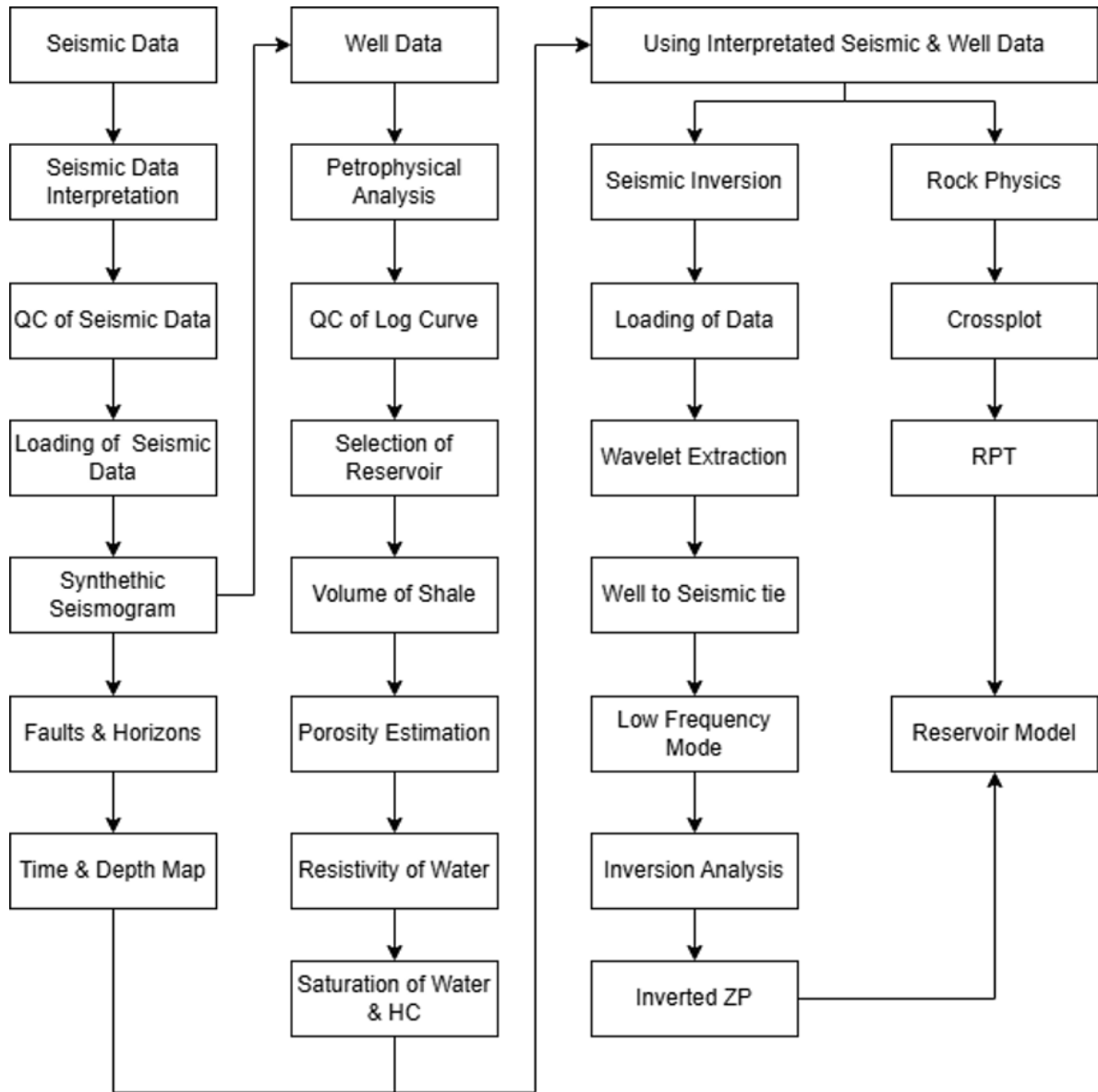


Figure 3. 1 Methodology workflow

3.1.1 Data Set

The work rests on two kinds of input. The first is a grid of 2D post-stack time-migrated seismic reflection lines covering the study area. The second is the wireline log data from the exploratory wells drilled within that area. Table 3.1 lists the wells, and Table 3.2 lists the seismic lines. Well positions were read from the coordinates recorded in the log file headers, and line geometry came from the navigation files supplied with the seismic data, which is what allowed both to be placed together on the base map described in the next section.

Eleven 2D lines cross the study area and they fall into two families. Six long lines run broadly NW–SE, parallel to the structural strike, and carry the main regional coverage. The remaining five run NE–SW to nearly E–W in the dip direction and cross the first family, providing the intersections at which a horizon picked on one line can be checked against the same horizon on another. All eleven lines were interpreted for structure. Two of the strike lines, SPC-86-9007 and SPC-86-9019, were also carried into the seismic inversion described in Section 3.5. They were selected because they run closest to the wells that calibrate the inversion and because they carry the most continuous reflector character of the strike family. The two are sub-parallel and do not intersect each other, so they provide two independent profiles through the same stratigraphic interval rather than a tie point: an impedance response seen on one can be checked against the other at the same stratigraphic level, but not at a common point.

The three wells contribute different things. Sadaf-01 and PakCan-01 carry the log suite needed for petrophysical evaluation, and the four reservoir intervals analysed in Chapter 4 come from those two wells: two in Sadaf-01 and two in PakCan-01. PakCan-01 also records shear sonic data, which is why the rock physics crossplots in Section 3.6 are anchored to it. Indus Marine-1A was not analysed petrophysically; its density and sonic curves supplied the synthetic seismogram used for the seismic-to-well tie.

Well	Operator	Well identifier (UWI)	Latitude (°N)	Longitude (°E)
Indus Marine-1A	Wintershall Ltd.	AUWI000298	23.457747	66.807089
Sadaf-01	OXY	AUWI000156	23.735528	66.394139
PakCan-01	OGDCL	AUWI000119	23.742631	66.959994

Table 3. 1 Wells used in this study, with operator, well identifier, surface coordinates and the role of each well in the workflow.

S. No.	Seismic line	Approximate trend	Orientation	Use in this study
1	SPC-86-9007	NW–SE	Strike line	Interpretation and seismic inversion
2	SPC-86-9019	NW–SE	Strike line	Interpretation and seismic inversion
3	SPC-86-9027	NW–SE	Strike line	Structural interpretation
4	SPC-86-9033	NW–SE	Strike line	Structural interpretation
5	SID88-112	NW–SE	Strike line	Structural interpretation

S. No.	Seismic line	Approximate trend	Orientation	Use in this study
6	SW-86N	NW–SE	Strike line	Structural interpretation
7	SW-53	WSW–ENE	Dip line	Structural interpretation
8	SPC-86-9052	NE–SW	Dip line	Structural interpretation
9	SL98-IM-61	NE–SW	Dip line	Structural interpretation
10	SL98-IM-83	NNE–SSW	Dip line	Structural interpretation
11	SL98-IM-124	WNW–ESE	Dip line	Structural interpretation

Table 3. 2 2D seismic lines available across the study area. Trends are approximate and were read from the base map (Figure 3.2).

3.1.2 Base Map

A base map was the first product of the interpretation, and everything that follows is referenced to it. It was built in Kingdom once the navigation data and the well coordinates had been loaded, and it places the eleven 2D lines and the three wells in their correct positions relative to one another. The map is plotted in projected metric coordinates, spanning roughly 171,900 to 340,000 m in easting and 2,538,400 to 2,738,400 m in northing, at a scale of 1:1,900,000. Shot point numbers are annotated along every line at 500-point intervals, and a north arrow and scale bar are included for orientation.

Figure 3.2 shows the result. The geometry it displays governs how the seismic data can be used. The long NW–SE lines carry the regional picture, the cross lines intersect them, and the reliability of a mapped horizon depends on how those intersections behave: a horizon picked on one line has to arrive at the same two-way time where a crossing line meets it, and any mis-tie has to be resolved before contouring. The map also shows which lines pass close enough to a well for a synthetic seismogram tie to be meaningful, and which parts of the area sit far from any line and are consequently the least constrained. Line intersections and well positions were used later as control points during horizon picking, time-to-depth conversion and gridding.

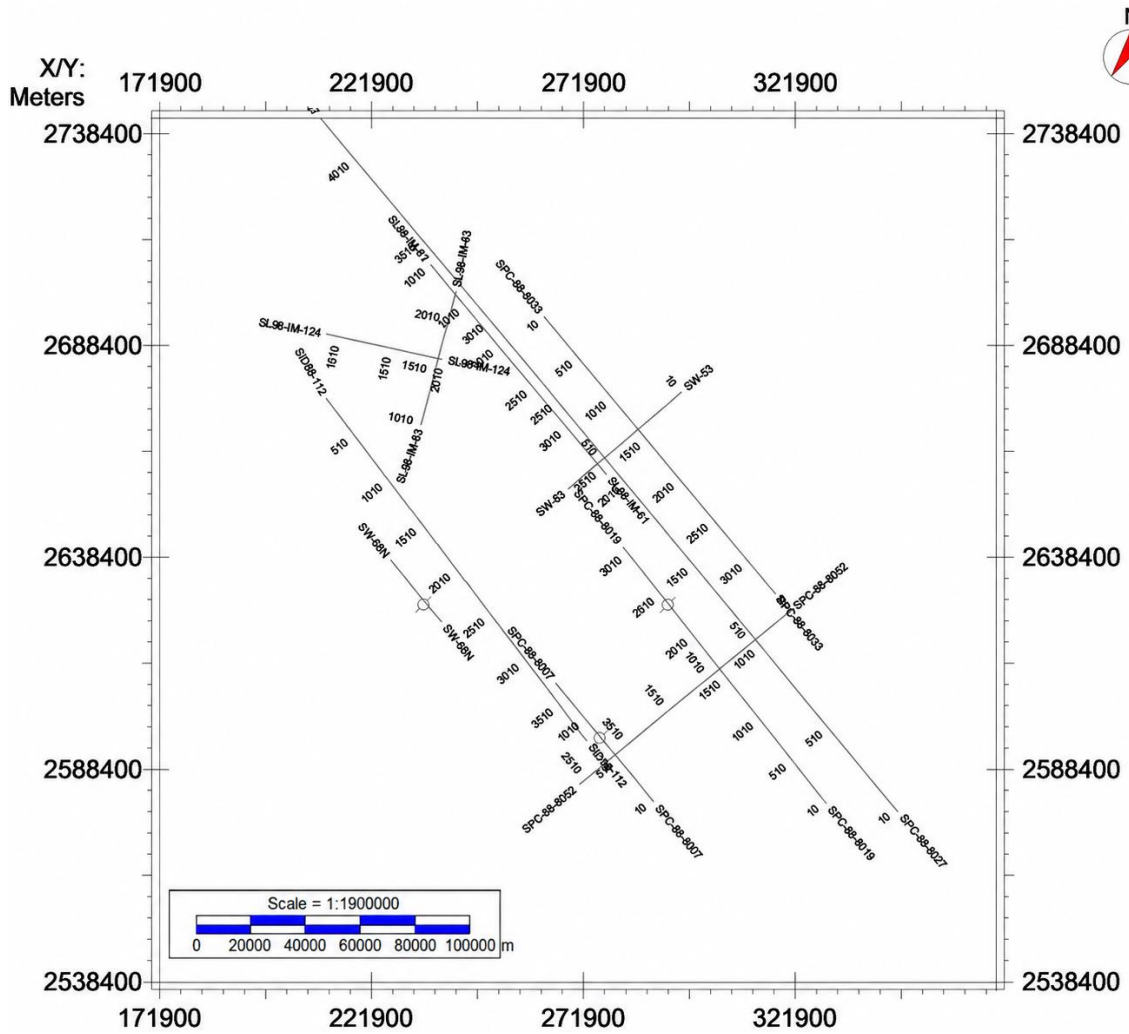


Figure 3. 2 Base map of the study area showing the 2D seismic line grid, annotated shot points and the locations of the three wells.

3.2 Well Correlation

The tops supplied with the well data are listed in Table 3.3. All three wells are picked on the same chronostratigraphic scheme, so the Pliocene and Miocene boundaries carry from one well to the next. These tops provide the regional framework within which the reservoir work sits, and the five seismic horizons interpreted in Section 3.3.5 are named after them.

Read across the three wells the framework is consistent. The Pliocene is subdivided into an upper and a lower unit at Indus Marine-1A and at PakCan-01, and Sadaf-01 carries a single Pliocene pick at 716.25 m. The Miocene is subdivided in all three wells. What these tops cannot do is define reservoir units, for two reasons. They are age assignments rather than log or lithology boundaries, so a top need not fall on a surface that a log or a

seismic reflector can see. And they are very widely spaced: the Middle Miocene at Indus Marine-1A is 1828.42 m thick, and at PakCan-01 the Middle Miocene pick at 2550.00 m is the last one above total depth. One ordering anomaly should also be noted. At Indus Marine-1A the Upper Miocene (Tortonian) pick at 2630.00 m lies below the Middle Miocene (Helvetian) pick at 801.59 m, which reverses the expected order, so that pick was not used in the correlation.

Well	Reported top	Depth (m)
Indus Marine-1A	Quaternary	0.00
Indus Marine-1A	Upper-Mid Pliocene	406.89
Indus Marine-1A	Lower Pliocene	481.56
Indus Marine-1A	Middle Miocene (Helvetian)	801.59
Indus Marine-1A	Upper Miocene (Tortonian)	2630.00
Sadaf-01	Top Pleistocene–Holocene	145.90
Sadaf-01	Top Pliocene	716.25
Sadaf-01	Top Late Miocene	1798.23
Sadaf-01	Top Middle Miocene	2133.50
Sadaf-01	Top Early Miocene	3046.94
PakCan-01	Holocene	89.40
PakCan-01	Late Pliocene	520.00
PakCan-01	Lower Pliocene	1030.00
PakCan-01	Late Miocene	1440.00
PakCan-01	Middle Miocene	2550.00

Table 3. 3 Reported well tops for the three study wells, listed as received.

Log-based correlation was therefore used to subdivide the section within that framework, using the Gamma Ray (GR) and deep laterolog resistivity (LLD) logs as the correlation basis. The GR log was the primary tool, separating high-radioactivity shale-dominated intervals from low-radioactivity sand-dominated ones. The LLD log provided supplementary control through resistivity contrasts associated with lithology and fluid content changes. Tracing consistent log signatures across the wells produced four reservoir intervals, two in Sadaf-01 and two in PakCan-01. These four intervals sit inside the Miocene section defined by the reported tops. At Sadaf-01 the 2000-2050 m interval lies within the Late Miocene, and the 2130-2200 m interval straddles the Top Middle Miocene pick at 2133.50 m and lies mostly within the Middle Miocene. At PakCan-01 the 1710-1770 m interval lies within the Late Miocene and the 2700-2730 m interval within the Middle Miocene. All subsequent petrophysical analysis was conducted within these four intervals.

Correlation was carried out in GVERSE. The logs were depth-matched and despiked, the wells were displayed side by side in the order of their positions on the base map, and markers were picked on log character rather than on depth. The gamma ray log did most of the work, with the thick shale packages used as tie surfaces because they are the most laterally persistent units present, and the deep laterolog confirmed each pick through its resistivity contrast. Reading across the three wells, the shale packages bounding the Late Miocene section can be followed from Sadaf-01 to PakCan-01, which is what allows the 2000–2050 m interval at Sadaf-01 and the 1710–1770 m interval at PakCan-01 to be treated as stratigraphic equivalents; the Middle Miocene section carries the 2130–2200 m interval at Sadaf-01 and the 2700–2730 m interval at PakCan-01. Indus Marine-1A was included in the correlation to carry the chronostratigraphic framework across the survey, but it contributes no reservoir interval because it lacks the log suite required for petrophysical evaluation.

The synthetic seismogram tie described in Section 3.3.4 then placed these intervals in two-way time, so that the same framework could be followed on the seismic lines and the petrophysical, inversion and rock physics results compared at equivalent stratigraphic levels.

3.3 Seismic Data

3.3.1 Seismic Data Interpretation

Seismic interpretation was performed in Kingdom software on the eleven 2D lines listed in Table 3.2. All eleven were interpreted for structure so that reflector continuity could be assessed in both the strike and the dip direction, and two of them were subsequently carried into the acoustic impedance inversion described in Section 3.5.

Structural interpretation focuses on identifying key reflectors corresponding to stratigraphic boundaries, characterizing the geometry of subsurface structures, and mapping fault systems. The study area's tectonic framework is extensional, and normal faults are the dominant structural element in the seismic data—recognized from lateral displacements and reflector discontinuities. Structural interpretation results guided horizon picking and constrained the depth conversion and contouring workflows.

3.3.2 Quality Control of Seismic Data

Before interpretation began, the seismic dataset was assessed for data quality. The time-migrated data were examined for signal-to-noise ratio, reflection continuity and coherence, and acquisition or processing artefacts. Frequency content was reviewed to confirm the dominant frequency range was appropriate for resolving target stratigraphic intervals at their respective depths. Phase characteristics were checked to confirm zero-phase processing, a requirement for the seismic inversion workflow. Anomalous traces, data gaps, and localized noise bursts were noted. Data quality was judged adequate for structural interpretation and model-based post-stack seismic inversion within the target intervals.

3.3.3 Loading of Seismic Data

The 2D seismic data were loaded into Kingdom and a base map was constructed. Navigation files provided positional information to place all lines in their correct geographical locations. Shot point positions along all eleven lines were extracted from the navigation data, and well locations were georeferenced from coordinates in the wireline log file headers. Well control points were added to the base map as anchor locations for seismic-to-well correlation.

3.3.4 Synthetic Seismogram Generation

Synthetic seismograms were generated to tie well log data to the seismic reflection data—without this tie, reliable horizon identification and correlation are not possible. The synthetic at each well was produced by convolving the reflectivity series derived from the acoustic impedance log ($Z_p = \rho V_p$, computed from bulk density and P-wave sonic logs) with a representative seismic wavelet, producing a 1D synthetic trace approximating the seismic response at the well location.

To make this comparison possible, a time-depth (T-D) relationship was established for each well from the sonic log velocity data. Reflector depth was converted to two-way travel time (TWT) using:

$$S = V \times t / 2000$$

where S is depth (m), V is interval velocity (m/s), and t is two-way travel time (ms).

The T-D chart was used to project formation interval boundaries into the TWT domain and guide initial horizon positioning. Synthetic traces were iteratively refined by

adjusting the T-D relationship through log stretching and squeezing until the best match with the real seismic trace was achieved. Seismic line SPC-86-9007 was the primary reference for seismic-to-well tie calibration.

3.3.5 Fault and Horizon Marking

Using the calibrated T-D charts and synthetic seismograms, five key stratigraphic horizons were identified and picked across all eleven 2D seismic lines: the Top of Upper Mid-Pliocene, the C interval of the Top of Lower Pliocene, the Top of Middle Miocene, the D interval of Middle Miocene, and the E interval of the Top of Late Miocene. Each horizon was traced laterally using the amplitude and wavelet character established at the well location, with picks extended along each line using TWT values from the T-D chart.

Faults were identified after horizon picking by recognizing lateral displacements and truncations of seismic reflectors across the eleven lines. Normal faults were the dominant structural element, consistent with the extensional tectonic regime. Fault polygons were delineated where reflector offsets were unambiguous enough to permit reliable mapping, and fault positions were reconciled between adjacent lines at their intersections.

3.3.6 Time and Depth Maps

Following horizon and fault picking, time structure maps were generated for the three principal horizons: the Top of Middle Miocene, the D interval of Middle Miocene, and the E interval of the Top of Late Miocene. TWT values picked along the seismic lines were gridded by spatial interpolation to create regular surfaces from the irregular line coverage, then contoured in Kingdom at a 0.2-second interval.

Depth structure maps were derived by converting the time maps using a velocity model built from sonic log data and check-shot velocity information. The depth conversion was applied trace-by-trace to produce depth-converted horizon surfaces, contoured at 100-metre intervals. The depth maps provided a more accurate picture of the true subsurface geometry and formed the basis for structural interpretation and area calculations.

3.4 Well Data

3.4.1 Petrophysical Analysis

Petrophysical analysis of the two wells carrying a complete log suite, Sadaf-01 and PakCan-01, was conducted in GVERSE using the gamma ray (GR), bulk density (RHOB),

neutron porosity (NPHI), deep laterolog resistivity (LLD) and, where available, spontaneous potential (SP) logs. The analysis estimated shale volume, porosity, fluid saturation and hydrocarbon saturation within each of the four log-defined reservoir intervals, providing the constraints used to identify hydrocarbon-bearing zones and to calibrate the seismic inversion outputs (Asquith & Krygowski, 2004; Ellis & Singer, 2007).

3.4.2 Quality Control of Log Curves

All wireline logs were quality-checked in GVERSE before quantitative analysis. Individual log curves were inspected for cycle-skipping on sonic logs, spiking artefacts on resistivity and density logs, and borehole-induced effects. The caliper log identified intervals of borehole washout or enlargement where pad-contact tools such as the density and micro resistivity devices may read unreliably. Log readings in severely washed-out intervals were flagged and treated with caution. Where repeat sections existed, they were compared to check measurement reproducibility. Environmental corrections—mud weight corrections for the density log and borehole diameter corrections for the neutron log—were applied where warranted. The corrected log data formed the basis for all petrophysical calculations.

3.4.3 Selection of Reservoir Intervals

Reservoir intervals were selected within the stratigraphic framework established by the well correlation described in Section 3.2, using the combined response of several log types rather than any single curve. Three criteria were applied. The first was a low gamma ray reading, taken as below approximately 75 API, indicating a sand-dominated lithology with limited clay content. The second was elevated deep laterolog resistivity relative to the adjacent shale baseline, which indicates either hydrocarbon saturation or reduced water saturation. The third was separation between the density and neutron curves consistent with enhanced porosity or with a gas effect. An interval was carried forward only where all three criteria were satisfied over a thickness the logs could resolve unambiguously. Four intervals met the criteria, two in Sadaf-01 and two in PakCan-01. Their depths, thicknesses, stratigraphic position and the log responses on which they were picked are set out in Table 3.4, and all subsequent petrophysical calculation was confined to them.

Well	Interval (m)	Gross thickness (m)	Stratigraphic position	Gamma ray response	Deep laterolog response	Density–neutron response
Sadaf-01	2000–	50	Late Miocene	Serrated;	Rises over	Separation

Well	Interval (m)	Gross thickness (m)	Stratigraphic position	Gamma ray response	Deep laterolog response	Density–neutron response
	2050			clean sand units below ~75 API	clean sand units	, with local crossover
Sadaf-01	2130–2200	70	Straddles Top Middle Miocene (2133.50 m); mainly Middle Miocene	Cleaner and thicker sand units	Elevated across sand units	Clear crossover (gas effect)
PakCan-01	1710–1770	60	Late Miocene	Clean sand units identified	Weakly elevated only	Separation without crossover
PakCan-01	2700–2730	30	Middle Miocene	Low to moderate	No significant increase	Reduced separation (compaction)

Table 3. 4 Criteria used to select the four reservoir intervals, with depths, gross thickness, stratigraphic position and the log responses on which each interval was picked.

3.4.4 Volume of Shale

The volume of shale (Vsh) was estimated from the GR log, which responds to the concentration of radioactive clay minerals in the formation (Schlumberger, 1989). The Gamma Ray Index (IGR) was computed for each depth sample as:

$$\text{IGR} = (\text{GRlog} - \text{GRmin}) / (\text{GRmax} - \text{GRmin})$$

where GRlog is the measured gamma ray reading, GRmin is the minimum gamma ray value representing the cleanest sand, and GRmax is the maximum gamma ray value representing pure shale within the study interval.

A non-linear correction was then applied to account for the typical radioactive mineral distribution in Tertiary-age formations, following Larionov (1969):

$$\text{Vsh} = 0.083 \times (2^{(3.7 \times \text{IGR})} - 1.0)$$

This correction reduces the systematic overestimation of shale content that results from applying the linear IGR directly to younger formations. The resulting Vsh values were used both as a lithological discriminator and as input to the effective porosity calculation.

The gamma ray minimum and maximum were read separately for each reservoir interval, from the cleanest and the most shale-rich responses within that interval, rather than being applied as single values across the whole log. Reading them locally prevents the shale volume from being biased where the background gamma ray level changes with depth.

3.4.5 Volume of Clean

The volume of clean formation (V_{clean}) is the complement of shale volume, quantifying the fraction of the formation matrix not attributable to clay minerals (Schlumberger, 1972):

$$V_{\text{clean}} = 1 - V_{\text{shale}}$$

Intervals with high V_{clean} were considered more favorable for reservoir development, as cleaner sands generally have higher porosity and permeability than shaly equivalents. V_{clean} was used alongside the other petrophysical outputs to rank the quality of identified reservoir intervals.

3.4.6 Porosity Estimation

Porosity was estimated using three complementary approaches from the available log data, allowing cross-validation and lithology discrimination.

Density Porosity (Φ_D): Derived from the bulk density log using the standard density-porosity transform (Schlumberger, 1989):

$$\Phi_D = (\rho_{\text{ma}} - \rho_b) / (\rho_{\text{ma}} - \rho_f)$$

where ρ_{ma} is the matrix density (g/cm^3), ρ_b is the measured bulk density (g/cm^3), and ρ_f is the pore fluid density (g/cm^3). Matrix density values were assigned based on the lithological interpretation of each interval.

Matrix density was assigned from the lithological interpretation of each interval, using standard sandstone and shale matrix values, and pore fluid density was taken as that of the mud filtrate occupying the invaded zone read by the density tool. Because the intervals are shale-rich, the average porosity computed from the density and neutron logs includes clay-bound water, which is why the effective porosities reported in Chapter 4 are substantially lower than the average values.

Neutron Porosity (Φ_N): Read directly from the neutron log, which measures formation hydrogen index as a proxy for pore fluid volume. In shaly or gas-bearing intervals, the neutron log was corrected for clay effects, and the gas crossover effect was noted as a lithological indicator.

Average Porosity (Φ_{Avg}): The arithmetic mean of density and neutron porosities (Schlumberger, 1989):

$$\Phi_{Avg} = (\Phi_D + \Phi_N) / 2$$

Combining the two measurements mitigates the individual limitations of each log type. Their characteristic separation in gas-bearing intervals also serves as a diagnostic indicator.

Effective Porosity (Φ_E): Calculated by correcting average porosity for clay-bound water, which does not contribute to producible fluid storage (Schlumberger, 1989):

$$\Phi_E = \Phi_{Avg} \times (1 - V_{sh})$$

Effective porosity is the pore volume available for fluid flow and the most directly useful porosity measure for reservoir evaluation and volumetric calculations.

3.4.7 Resistivity of Formation Water

Formation water resistivity (R_w) is a key input for the water saturation calculation. Where SP log data were of sufficient quality, R_w was estimated from the static SP deflection using the standard SP equation relating the electrochemical component to the ratio of mud filtrate to formation water resistivities. R_w estimates were cross-checked against regional salinity data where available. In intervals where SP data were unreliable—due to borehole conditions or resistive formations— R_w was estimated using the Arps equation (Arps, 1953), which accounts for the temperature dependence of water resistivity:

Formation water resistivity was estimated from the resistivity response of a clean, water-bearing interval within each well and corrected to formation temperature using the relationship above, with formation temperature obtained from the bottom-hole temperature recorded in the log headers. No formation water sample or produced water analysis was available for either well, so the value used is an estimate rather than a measurement, and that uncertainty is carried into the computed water saturations.

$$R_w(T_2) = R_w(T_1) \times (T_1 + 21.5) / (T_2 + 21.5)$$

where $R_w(T1)$ is the known water resistivity at reference temperature $T1$, and $R_w(T2)$ is the estimated water resistivity at formation temperature $T2$. Formation temperature was calculated using a linear geothermal gradient applied from the measured surface temperature to the depth of each reservoir interval.

3.4.8 Water Saturation

Water saturation (S_w) was calculated using Archie's equation (Archie, 1942), which relates formation resistivity to porosity and fluid saturation in clean, argillaceous-free sandstone intervals:

$$S_w = [(a \times R_w) / (R_t \times \Phi E^m)]^{1/n}$$

where S_w is water saturation (fraction), a is the tortuosity factor ($a = 1$), R_w is the formation water resistivity ($\Omega \cdot m$), R_t is the true formation resistivity from the deep laterolog LLD ($\Omega \cdot m$), ΦE is the effective porosity (fraction), m is the cementation exponent ($m = 2$), and n is the saturation exponent ($n = 2$).

Computed S_w values were constrained to the range 0 to 1; values exceeding unity were set to 1.0. In intervals where shale volume exceeded acceptable thresholds, shaly-sand saturation models were considered to account for the additional conductivity introduced by clay minerals, which can cause Archie's equation to underestimate water saturation.

Archie's equation was applied throughout, and the shale volumes reported in Chapter 4 mean that this choice requires justification. Archie's relation is strictly valid only in clean, argillaceous-free formations, and the interval-average shale volumes computed here range from 51 to 77 per cent. Those averages are taken over gross intervals of interbedded sand and shale, however, and the saturation calculation was applied within the cleaner sand units picked on the criteria set out in Section 3.4.3, where shale volume is substantially lower than the interval average. The shaly-sand alternatives were considered and not adopted for a practical reason: Simandoux and Waxman–Smits both require parameters that could not be determined from the available data, namely a measured shale resistivity or a cation exchange capacity, and no core or special core analysis was available for either well. Adopting either model with assumed parameters would have replaced one source of error with another without any means of testing it. The consequence of using Archie in a clay-bearing formation is that the additional conductivity contributed by clay minerals is attributed to formation water, so water saturation is underestimated and

hydrocarbon saturation correspondingly overestimated. The hydrocarbon saturations reported in Section 4.2 should therefore be read as upper bounds, and the comparison between intervals is more reliable than any absolute value.

3.4.9 Hydrocarbon Saturation

Hydrocarbon saturation (SHC) is the complement of water saturation, expressing the fraction of effective pore volume occupied by hydrocarbons:

$$SHC = 1 - S_w$$

High hydrocarbon saturation combined with adequate effective porosity and low V_{sh} identified prospective hydrocarbon-bearing intervals within the stratigraphic framework. SHC distributions across the four reservoir intervals were compared to assess lateral continuity of the hydrocarbon accumulation.

3.5 Seismic Inversion

Seismic inversion was performed in Hampson-Russell software using a post-stack model-based algorithm to convert the 2D seismic reflection amplitude data into acoustic impedance (Z_p) volumes. Post-stack inversion uses the convolution model of the seismic trace—seismic amplitude at any point is the result of convolving an Earth reflectivity series with a seismic wavelet—and reverses this process to recover the underlying impedance model (Russell & Hampson, 1991). The resulting acoustic impedance data are more directly interpretable in terms of lithology and fluid content than raw reflection amplitudes and are the primary input for rock physics analysis and reservoir characterisation (Ali et al., 2019).

3.5.1 Loading of Data

The 2D seismic data and wireline log data were loaded into Hampson-Russell. Seismic sections were imported in SEG-Y format and cross-referenced to the Kingdom interpretation project to ensure consistency of horizon picks and well positions. Well logs—gamma ray, P-wave sonic (DT) and bulk density (RHOB)—were loaded for each of the three study wells and depth-matched to the seismic two-way time domain using the time–depth relationships established during synthetic seismogram generation. The acoustic impedance log ($Z_p = \rho \times V_p$) was computed within Hampson-Russell for each well and used as the primary well constraint for the inversion. Log value consistency between wells at equivalent stratigraphic levels was verified before proceeding.

3.5.2 Wavelet Extraction

A representative seismic wavelet was extracted from the data. The wavelet connects the Earth's reflectivity series to the recorded seismic trace; an accurate wavelet is needed for inversion to recover reliable impedance (Russell & Hampson, 1991; Ziolkowski et al., 1998). Statistical wavelet extraction was performed by computing the autocorrelation of the seismic data within a time window covering the target reservoir intervals. A zero-phase wavelet was extracted under the assumption that the data had been processed to zero phase. The frequency content of the extracted wavelet was checked to confirm it represented the dominant frequency range of the input data. The wavelet was then used for both the seismic-to-well tie and as the inversion operator.

The wavelet was extracted statistically over a window centred on the reservoir interval, and its amplitude and phase spectra are shown for each inverted line in Figures 4.19 and 4.25. The extracted wavelets are compact and near-zero-phase, and their amplitude spectra are comparable between the two lines, which is what allows the impedance results derived from them to be compared directly.

3.5.3 Seismic-to-Well Tie

A seismic-to-well tie was performed for each study well to calibrate the relationship between the well log response and seismic amplitude. The synthetic seismogram—generated by convolving the well-derived reflectivity series with the extracted wavelet—was compared directly with the nearest real seismic trace at each well location. Tie quality was quantified using the cross-correlation coefficient between the synthetic and recorded trace; a coefficient approaching 1.0 indicates a reliable calibration (White, 2003). Wavelet phase and the T-D relationship were iteratively adjusted through controlled stretching and squeezing of the synthetic until the best achievable correlation was obtained. The optimized T-D relationships and wavelet were then carried forward into the inversion.

3.5.4 Low-Frequency Model (LFM)

Seismic data are band-limited and lack energy below roughly 5–8 Hz. A low-frequency model (LFM) was therefore constructed to supply the low-frequency background impedance trend that the seismic data cannot recover on its own (Sams & Carter, 2017). Without this component, the absolute impedance values from inversion are unreliable and the result resembles a relative rather than absolute impedance volume.

The LFM was built by applying a low-pass filter with a 10 Hz cut-off to the acoustic impedance logs from all available wells. The filtered low-frequency impedance curves were then interpolated laterally between and beyond the well locations, guided by the interpreted seismic horizons to honor the structural and stratigraphic geometry of the subsurface. Only the P-impedance (Z_p) log was used in the LFM, consistent with the post-stack model-based inversion framework. The resulting LFM captured large-scale, laterally varying impedance trends across the study area and kept the absolute impedance volumes from inversion geologically consistent with the borehole measurements.

3.5.5 Inversion Analysis

Post-stack model-based inversion was applied to the 2D seismic data within Hampson-Russell. In model-based inversion, the LFM-derived initial impedance model is iteratively updated at each trace location until the synthetic seismogram computed from the model best matches the recorded seismic trace in a least-squares sense, subject to constraints that prevent the solution from drifting too far from the initial model (Veeken, 2007; Ashcroft, 2011). The inversion was applied within the stratigraphic window bounded by the interpreted horizons.

The inversion parameters—the number of iterations, the hard constraint limiting how far the solution may depart from the initial model, and the relative weighting of seismic misfit against model deviation—were established through test inversions at the well locations before the algorithm was applied along the full length of each line, and were then held fixed for both lines so that the two results remain comparable. Inversion was run within a window bounded above and below by the interpreted horizons. Quality was assessed by comparing the synthetic seismogram regenerated from the inverted impedance model with the recorded seismic trace at the well: the correlation obtained was 0.99 on line SPC-86-9007 and 0.99 on line SPC-86-9019.

3.5.6 Inverted Acoustic Impedance (Z_p)

The inversion produced acoustic impedance (Z_p) sections in the TWT domain along each 2D seismic line. The inverted Z_p sections were calibrated against well-log-derived acoustic impedance at the well locations to confirm that the recovered absolute impedance values were consistent with the borehole measurements. Compared with the input seismic reflection data, the inverted Z_p gives higher spatial resolution by effectively removing the band-limiting effect of the wavelet.

Impedance contrasts in the inverted sections were interpreted in terms of lithological and fluid variations: relatively low acoustic impedance within reservoir horizons was interpreted as potentially porous and/or gas-bearing sand, while higher impedance indicated denser, compacted, or brine-saturated lithologies. The inverted Z_p sections were then used as the primary input for rock physics analysis.

3.6 Rock Physics

Rock physics linked the petrophysical parameters from well logs to the elastic properties—principally acoustic impedance—derived from seismic inversion. This link is what allows the spatially extensive but indirect seismic measurement to be read as reservoir property information (Avseth et al., 2005; Dvorkin & Nur, 1996).

The analysis was carried out on wireline log data rather than on the inverted seismic sections, and it is anchored to PakCan-01, the only well in the dataset recording a shear sonic log. Compressional velocity was taken from the P-wave sonic, shear velocity from the dipole shear sonic and bulk density from the density log. From these three measurements, three elastic attributes were computed over the logged interval: P-impedance ($Z_p = \rho V_p$), S-impedance ($I_s = \rho V_s$) and the velocity ratio V_p/V_s . Computed gamma ray (CGR) was carried through the analysis as the lithology curve and used to colour every crossplot, so that the separation between populations could be read directly in terms of clay content. Data were extracted at the log sampling interval across the reservoir intervals and their bounding shales, so that reservoir and non-reservoir populations are represented on the same plot rather than only the reservoir case.

3.6.1 Crossplots Analysis

Three crossplots were constructed, each with the V_p/V_s ratio on the vertical axis: V_p/V_s against P-impedance, V_p/V_s against bulk density, and V_p/V_s against S-impedance. The combination is deliberate. P-impedance responds to the rock frame and to the pore fluid together; bulk density isolates the contribution of porosity and pore fluid density; and S-impedance, because shear waves do not propagate through pore fluid, responds essentially to lithology alone. Reading the three plots together therefore allows a lithology effect to be separated from a fluid effect, which impedance alone does not permit (Avseth & Bachrach, 2005; Chi & Han, 2009).

Polygons were annotated on each crossplot to delimit shale, shaly sand, brine-bearing sand and hydrocarbon-bearing sand. Their boundaries were positioned on the

observed clustering of the data and cross-checked against the computed gamma ray colour scale rather than being imposed from a published template. The elastic signatures established in this way provide the basis on which the inverted impedance sections are interpreted in Chapter 4.

3.7 Rock Physics Template (RPT)

A rock physics template was constructed to interpret the measured elastic properties in terms of reservoir variables such as porosity and fluid saturation (Ødegaard & Avseth, 2004). The template used here is the unconsolidated sandstone rock physics template, which is appropriate to the young, shallowly buried and poorly cemented deltaic and fan sands of the Miocene section. It plots P-impedance against the V_p/V_s ratio and overlays modelled trajectories for varying porosity and water saturation, so that the measured data can be assessed against theoretical predictions rather than by clustering alone.

The dry-frame elastic moduli were computed from the Hertz–Mindlin contact model for an unconsolidated grain pack, using contact-model parameters appropriate to a poorly consolidated sand at the burial depth of the reservoir intervals, with mineral moduli for quartz and clay taken as standard published values (Dvorkin & Nur, 1996; Mavko et al., 2009). Gassmann's equations (Gassmann, 1951) were then used to substitute the pore fluid and generate the constant-saturation trajectories, with brine and gas properties calculated for the formation temperature and pressure of the reservoir intervals. The template was used to guide the position of the litho-fluid polygons annotated on the crossplots presented in Section 4.5, so that those boundaries rest on a physical model of the rock rather than on the clustering of the data alone.

3.8 Reservoir Model

An integrated reservoir model was built by combining the outputs of well correlation, petrophysical analysis, seismic inversion, and rock physics evaluation. The model sits within the stratigraphic framework defined by the four log-defined reservoir intervals and the five interpreted seismic horizons, keeping the well-based and seismic-based components consistent with one another.

The inverted acoustic impedance sections, interpreted through the crossplots and RPT analysis, were used to map the lateral distribution of reservoir quality and fluid saturation across the study area. Intervals showing low acoustic impedance combined with high effective porosity and high hydrocarbon saturation at the well locations were

identified as the primary exploration targets. The reservoir model defined the estimated areal extent, gross thickness, and petrophysical characteristics of the key identified intervals, providing an integrated subsurface picture that supports assessment of hydrocarbon potential in the study area.

CHAPTER 4

RESULTS AND INTERPRETATIONS

4.1 Introduction

This chapter presents the results of the integrated workflow set out in Chapter 3. Four analyses are reported: petrophysical evaluation of the four reservoir intervals identified at well control, structural interpretation and mapping of the 2D seismic grid, model-based post-stack inversion of lines SPC-86-9007 and SPC-86-9019, and rock physics analysis of the logged elastic properties.

The four are presented in the order in which they constrain one another. The petrophysical results define the rock and fluid types present at the wells and establish their log signatures. The seismic interpretation places those rocks within a structural framework and supplies the horizons that bound the inversion. The inversion then extends impedance information away from the wells along two lines. Finally the rock physics crossplots and template resolve the ambiguity that remains in the impedance result, since acoustic impedance responds to lithology and fluid together. All reservoir intervals discussed lie within the Miocene clastic section defined by the well correlation in Section 3.2.

4.2 Petrophysical Analysis

The petrophysical results are the reference against which every seismic and elastic attribute in this chapter is read. For each well the standard triple-combo suite was interpreted: gamma ray and spontaneous potential for lithology, deep laterolog resistivity for fluid content, and the density–neutron pair for porosity and gas indication. Shale volume, average and effective porosity, water saturation and hydrocarbon saturation were computed within each interval using the equations given in Section 3.4, and the results are collected in Table 4.1. The values quoted are averages over the gross interval, so they include the shale interbeds as well as the sand units; the individual sand units within each interval are cleaner and more porous than the interval average implies.

Well	Interval (m)	Vsh (%)	Average porosity (%)	Effective porosity (%)	Sw (%)	SHC (%)	Interpretation
Sadaf-01	2000–2050	67.89	31.81	10.57	89.36	10.64	Interbedded sand and shale; low residual

Well	Interval (m)	Vsh (%)	Average porosity (%)	Effective porosity (%)	Sw (%)	SHC (%)	Interpretation
							hydrocarbon saturation
Sadaf-01	2130–2200	67.89	24.79	8.21	89.36	10.64	Cleaner sand units, but lower porosity than the interval above
PakCan-01	1710–1770	76.66	27.89	6.15	98.50	1.50	Shaliest interval; effectively water-bearing
PakCan-01	2700–2730	51.20	20.89	10.02	79.99	20.01	Cleanest interval; highest effective porosity and hydrocarbon saturation

Table 4. 1 Petrophysical results computed for the four reservoir intervals in Sadaf-01 and PakCan-01. All values are interval averages over the gross interval.

4.2.1 Sadaf Well (2000–2050 m)

Figure 4.1 shows the petrophysical interpretation of Sadaf-01 between 2000 and 2050 m. The gamma ray curve is strongly serrated, alternating between clean and shale-rich responses, which indicates interbedded sand and shale rather than a single massive sand body. The density and neutron curves separate over the cleaner units and the deep laterolog resistivity rises across the same depths. The low gamma ray over those units indicates limited clay content, the density–neutron separation indicates porosity, and the resistivity increase indicates pore fluid less conductive than formation water.

The computed values reflect the interbedded character of the interval. Average shale volume is 67.89 per cent, which is a measure of the gross interval rather than of the individual sand units, and average porosity is high at 31.81 per cent. Correcting that figure for clay-bound water reduces effective porosity to 10.57 per cent, and this difference between average and effective porosity is the single most important result for the interval: the pore volume actually available to flow is roughly a third of the total. Water saturation averages 89.36 per cent, giving a hydrocarbon saturation of 10.64 per cent. The interval therefore carries hydrocarbon, but at a saturation low enough to be consistent with a residual or dispersed charge distributed through thin sand units rather than with a continuous hydrocarbon column. A sand of this character still has lower bulk density and

lower compressional velocity than the enclosing shale, and therefore lower acoustic impedance, which is the response examined in the inversion in Section 4.4 and tested against the rock physics crossplots in Section 4.5.

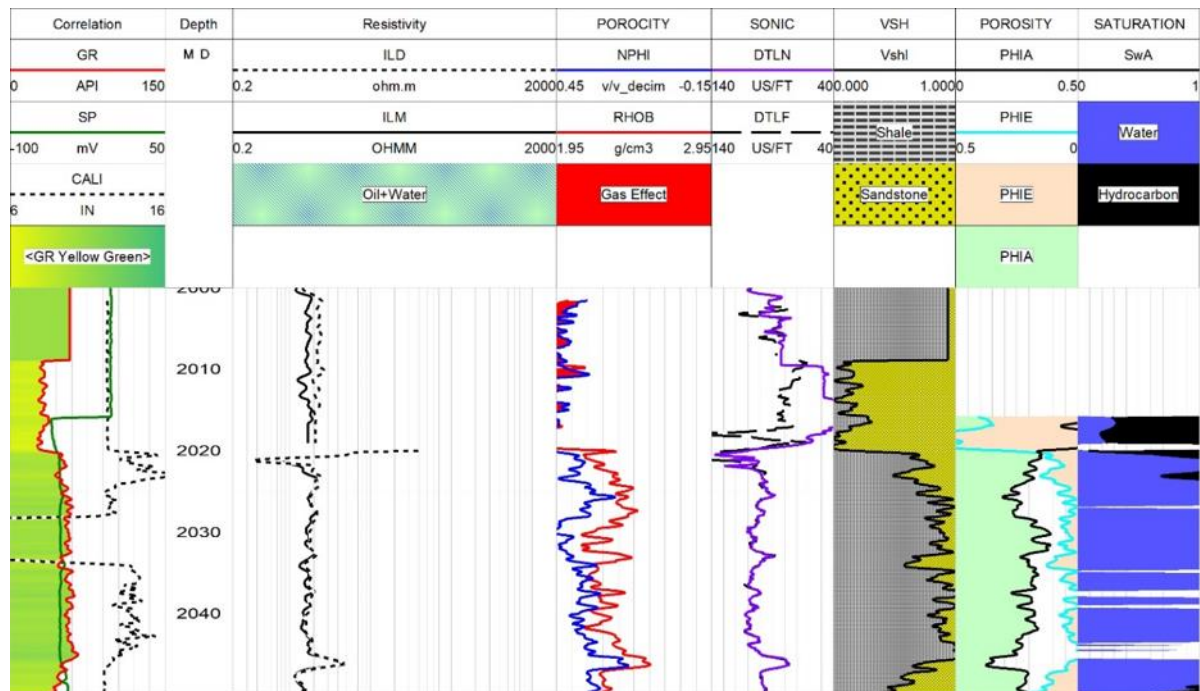


Figure 4. 1 Petrophysical interpretation of the Sadaf well, 2000–2050 m.

4.2.2 Sadaf Well (2130–2200 m)

Figure 4.2 shows Sadaf-01 between 2130 and 2200 m. The gamma ray response is cleaner than in the shallower interval and the sand units are thicker and more continuous, and the density and neutron curves cross over across parts of the interval. Deep laterolog resistivity is elevated across the same units.

The computed values give average shale volume of 67.89 per cent, average porosity of 24.79 per cent and effective porosity of 8.21 per cent, with water saturation of 89.36 per cent and hydrocarbon saturation of 10.64 per cent. Two points follow. First, although the gamma ray response is cleaner than in the interval above, both average and effective porosity are lower, which indicates that the sands here are more compacted or more cemented rather than better developed. Second, the density–neutron crossover is not corroborated by the saturation result: a gas fill sufficient to produce a crossover would be expected to reduce water saturation well below the 89.36 per cent computed here. The crossover is therefore more likely to reflect the clay and lithology response of the interval than a gas effect, and it should not on its own be read as a hydrocarbon indicator. This is

the interval that produces the clearest impedance contrast against the bounding shales, and it straddles the reported Top Middle Miocene pick at 2133.50 m, lying mainly within the Middle Miocene.

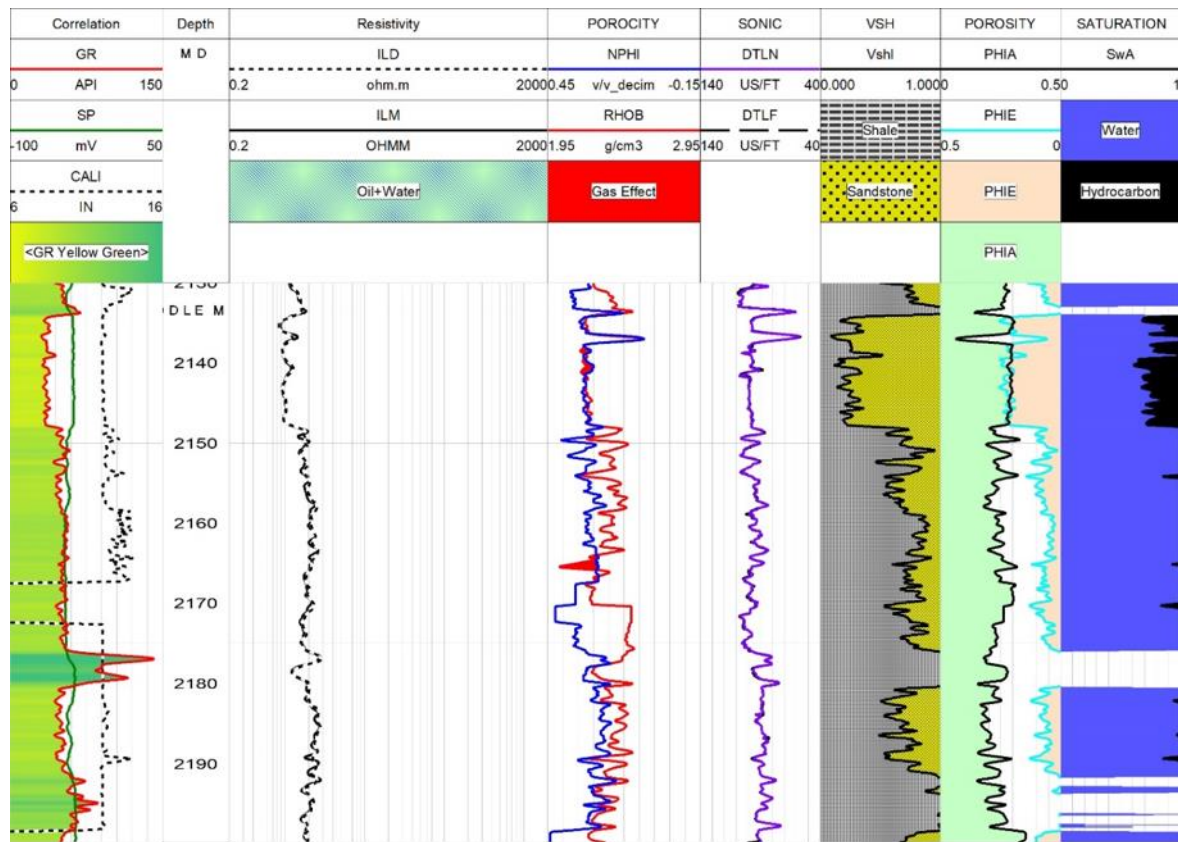


Figure 4. 2 Petrophysical interpretation of the Sadaf well, 2130–2200 m.

4.2.3 Sadaf Well — Composite Interpretation (2000–2200 m)

Figure 4.3 shows the composite petrophysical interpretation of Sadaf-01 across the full 2000–2200 m section, placing the two intervals described above in their stratigraphic context. The section is a stacked sand–shale sequence: sand units separated by shale interbeds, with the shales acting as internal barriers that permit separate fluid contacts and pressure regimes within a single gross interval. The high interval-average shale volumes reported in Table 4.1 are a direct consequence of that architecture.

Two consequences follow for the seismic work. Individual sand units are thin relative to the seismic bandwidth at this depth, so several of them fall below tuning thickness and will not be resolved separately on the reflection data. And because the section is layered rather than massive, the impedance response of the gross interval is a composite of sand and shale rather than the response of a single unit, in the same way that

the petrophysical averages are composites. Inversion improves on the reflection data by removing the band-limiting effect of the wavelet, but it does not recover beds below the resolution of the input data. This is the context in which the impedance sections in Section 4.4 should be read, and it is why the elastic response of the interval is muted relative to what a clean, thick sand of the same porosity would produce.

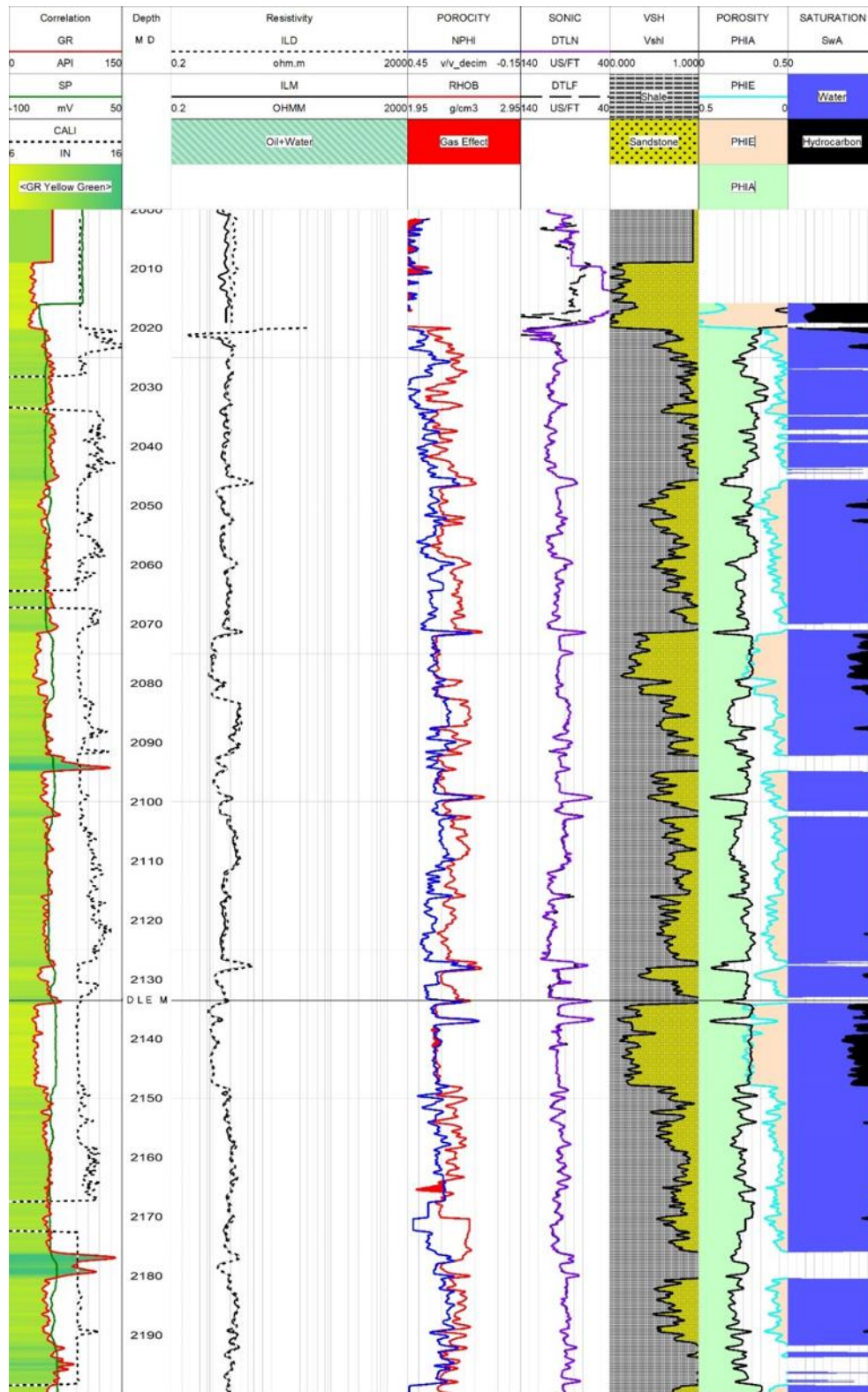


Figure 4. 3 Composite petrophysical interpretation of the Sadaf well, 2000–2200 m.

4.2.4 PakCan Well (1710–1770 m)

Figure 4.4 shows PakCan-01 between 1710 and 1770 m. The gamma ray identifies clean sand units, but the density–neutron separation across them is smaller than at Sadaf-01 and the resistivity increase is weak.

The computed values confirm what the log character suggests. This is the shaliest of the four intervals, with an average shale volume of 76.66 per cent, and although average porosity is 27.89 per cent the clay correction reduces effective porosity to 6.15 per cent, the lowest of the four. Water saturation is 98.50 per cent and hydrocarbon saturation only 1.50 per cent, so the interval is effectively water-bearing. It contributes to the study in two ways. It demonstrates that sand is developed at this stratigraphic level away from Sadaf-01, which supports the lateral continuity of the clastic system across the study area. And it supplies the elastic response of a porous, brine-saturated sand, which is the population that must be distinguished from hydrocarbon-bearing sand if a low-impedance anomaly on the inverted sections is to be attributed to fluid rather than to porosity. It is used for exactly that purpose in the crossplots in Section 4.5.

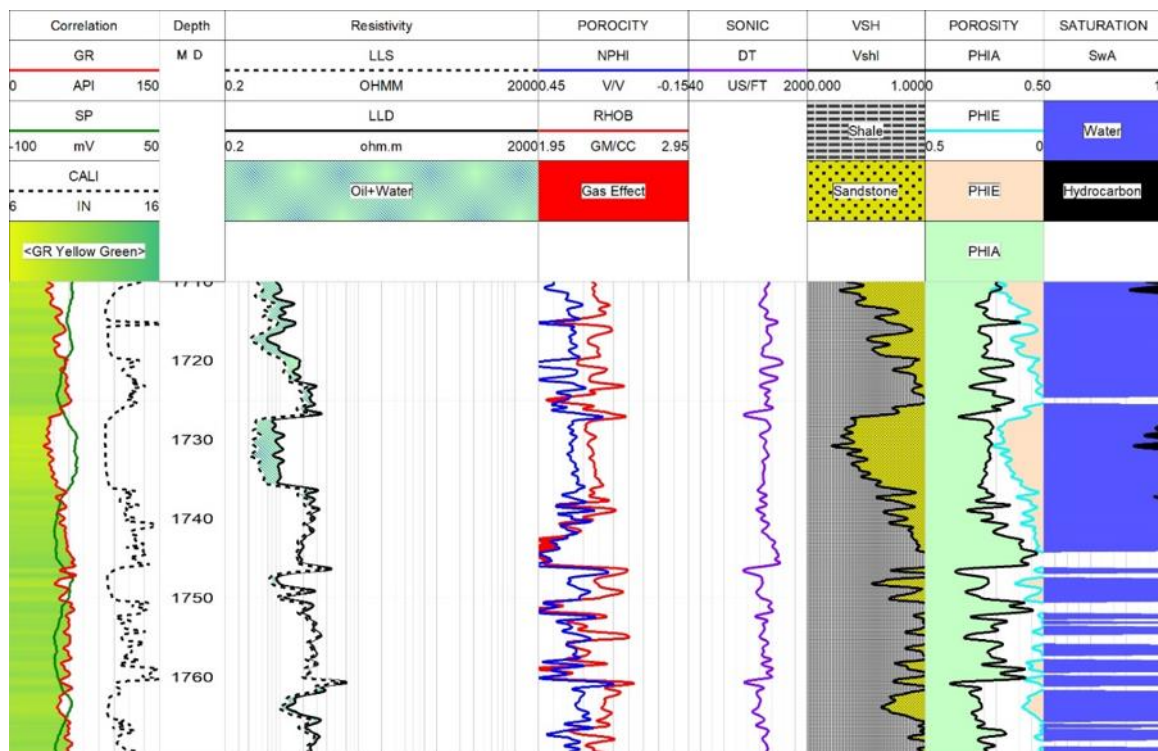


Figure 4. 4 Petrophysical interpretation of the PakCan well, 1710–1770 m.

4.2.5 PakCan Well (2700–2730 m)

Figure 4.5 shows PakCan-01 between 2700 and 2730 m. The sand at this depth is visibly more compacted: bulk density is higher and the density–neutron separation is reduced relative to the shallower intervals.

The computed values show the effect of that compaction and, at the same time, an unexpected result. Average porosity is 20.89 per cent, the lowest of the four intervals, which is consistent with mechanical compaction and diagenetic modification with increasing burial depth. Average shale volume, however, is 51.20 per cent, substantially lower than in any other interval, so the clay correction removes less of the pore volume and effective porosity is 10.02 per cent — the highest of the four. Water saturation is 79.99 per cent and hydrocarbon saturation 20.01 per cent, also the highest of the four. On the computed values, therefore, the deepest interval carries the best combination of effective porosity and hydrocarbon saturation, despite having the poorest total porosity. The result illustrates that lithological cleanliness, and not total porosity, is what controls producible pore volume in this section, and it is the reason effective rather than average porosity is used throughout the elastic analysis that follows.

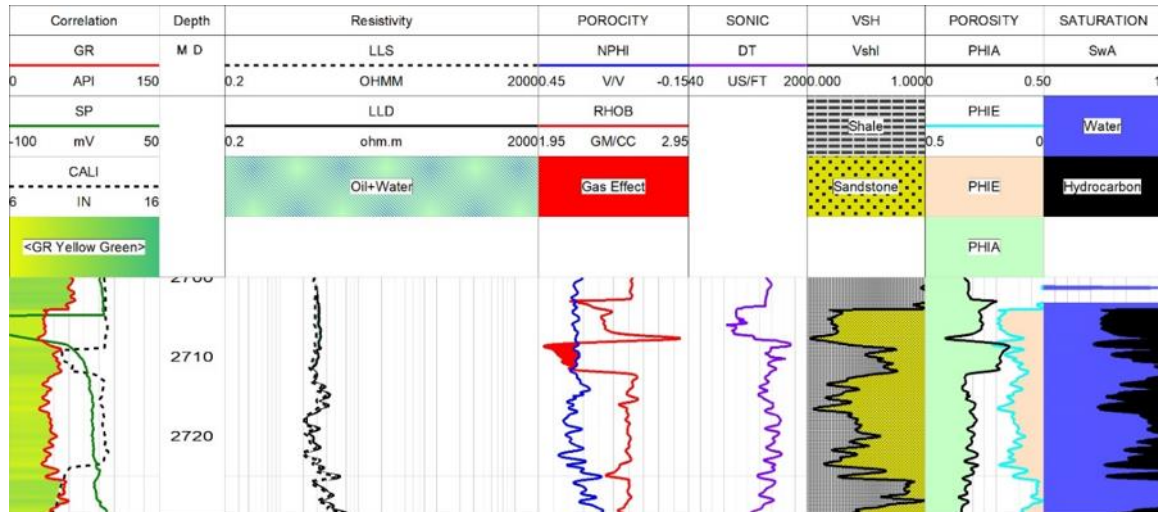


Figure 4. 5 Petrophysical interpretation of the PakCan well, 2700–2730 m.

Taken together the two wells describe a stacked Miocene sand–shale system in which reservoir quality is controlled principally by clay content. All four intervals are shale-rich when averaged over their gross thickness, with shale volumes between 51 and 77 per cent, and in every case the clay correction reduces a high average porosity of 21 to 32 per cent to an effective porosity of between 6 and 11 per cent. Hydrocarbon saturations are

correspondingly modest. The deeper PakCan-01 interval at 2700–2730 m is the cleanest and returns the highest effective porosity and hydrocarbon saturation, at 10.02 and 20.01 per cent; the two Sadaf-01 intervals are intermediate, both returning a hydrocarbon saturation of 10.64 per cent; and the shallower PakCan-01 interval at 1710–1770 m is the shaliest and is effectively water-bearing. Four rock and fluid classes are therefore present at well control—sand carrying a partial hydrocarbon charge, brine-bearing sand, compacted sand and shale—each with a distinct log signature and, through density and velocity, a predictable elastic response. These four classes are the basis on which the inverted impedance sections and the rock physics crossplots that follow are interpreted, and the modest hydrocarbon saturations mean that the elastic contrast between the hydrocarbon-bearing and brine-bearing cases is expected to be small.

4.3 Seismic Interpretation

Seismic interpretation places the intervals described above within a structural framework and supplies the horizons that bound the inversion. The sequence followed here is the sequence of the workflow: the well is first tied to the seismic data through a synthetic seismogram, horizons and faults are then interpreted on the dip and strike lines, and the picked horizons are finally gridded into time and depth structure maps.

4.3.1 Synthetic Seismogram - Indus Marine-1A Well

Figure 4.6 shows the synthetic seismogram generated for Indus Marine-1A and its comparison with the seismic data at the well location. The acoustic impedance profile was computed from the sonic and density logs, converted to a reflectivity series, and convolved with the wavelet extracted from the data to produce a synthetic trace, which was then compared with the recorded trace at the well. The data are zero-phase and are displayed in reverse polarity, so that an increase in acoustic impedance is expressed as a trough. Each mapped horizon was tied to that event: the reflection picked at the Top Middle Miocene, for example, is the trough generated by the impedance increase at that boundary, and the same convention was applied consistently to the remaining picks. Matching the troughs on the synthetic to the corresponding troughs on the recorded trace produced a stable alignment through the interval of interest.

The quality of this tie governs everything that follows from it. It fixes the two-way time at which each stratigraphic boundary appears on the seismic data, which allows the five horizons to be picked with confidence and traced across the grid. It also supplies the

wavelet and the time–depth relationship used in the inversion, so that the structural interpretation and the inversion share a single calibration rather than two independent ones. Without it the reservoir intervals identified in the logs could not be located on the seismic sections at all.

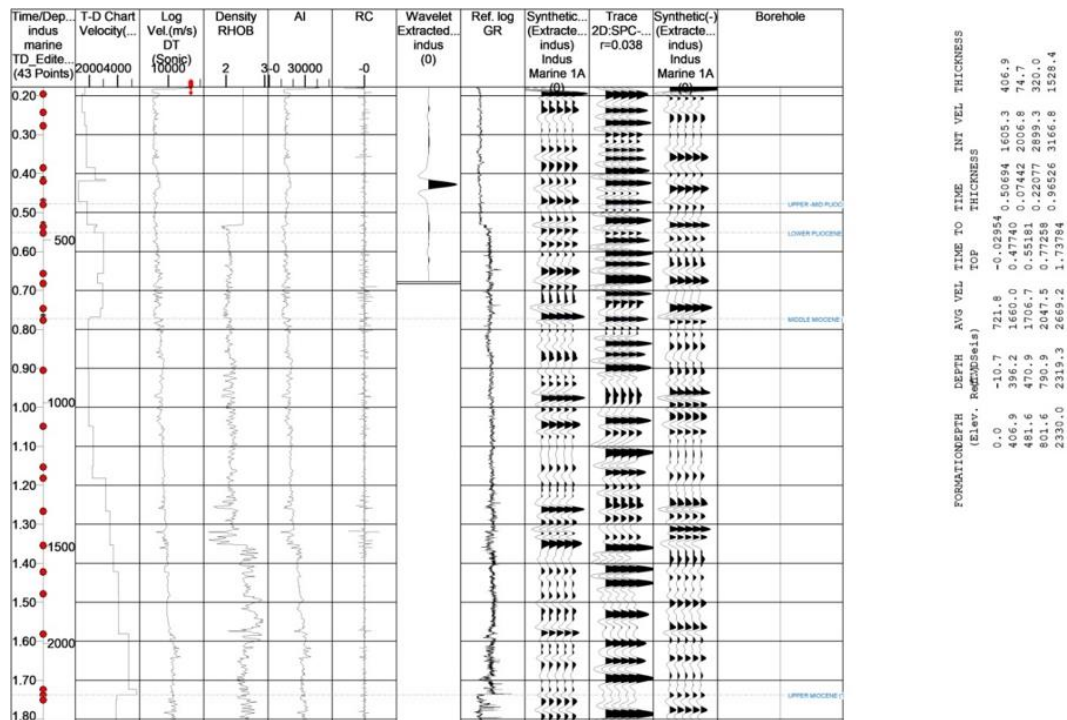


Figure 4. 6 Synthetic seismogram and well-to-seismic tie, Indus Marine-1A well.

4.3.2 Interpreted Seismic Sections

Figure 4.7 shows the interpreted dip line SW-53, whose position within the survey grid is shown on the base map in Figure 3.2 and whose trend is given in Table 3.2. Four mapped horizons are displayed as colour-coded surfaces and the principal faults are annotated. The section is dominated by normal faults that divide the succession into a series of blocks, with reflectors displaced consistently in one sense across each fault. The geometry is extensional and is consistent with the structural style reported for the Indus offshore margin, where growth faulting exerts the primary control on structure.

Between the faults the reflectors are continuous and broadly parallel, indicating a layered succession deposited without significant syn-depositional deformation, and continuity is disturbed only in the immediate vicinity of the larger faults. The horizon geometry seen here, together with the mapped fault positions, is what is carried into the gridding described in Sections 4.3.3 and 4.3.4.

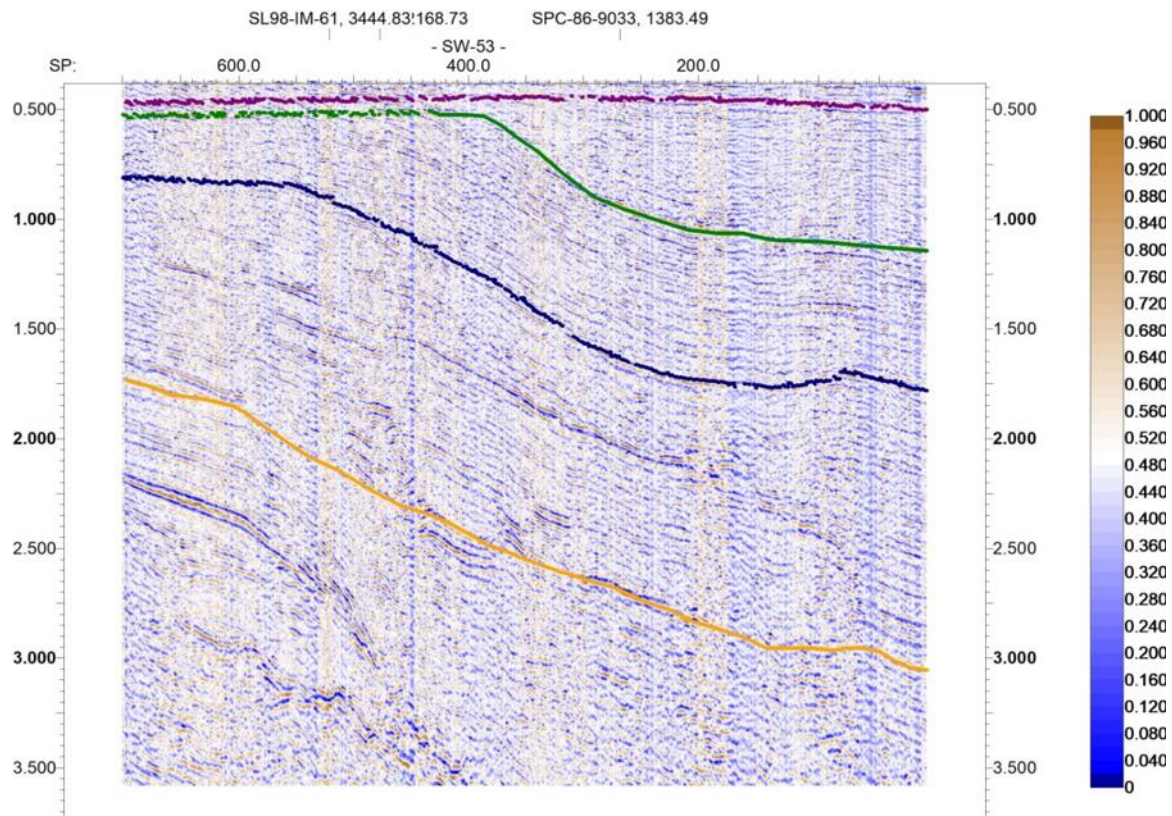


Figure 4. 7 Interpreted seismic dip line SW-53.

Figures 4.8 and 4.9 show the interpreted lines SPC-86-9007 and SPC-86-9019, the two strike lines subsequently carried into the inversion. Both cross the dip line SW-53, and their positions and trends are given on the base map and in Table 3.2. The two are sub-parallel to each other and do not intersect. Horizons were traced across both sections, and the faults intersecting them were correlated with those interpreted on SW-53, so that individual fault planes could be followed between lines rather than treated independently on each section.

The two lines confirm the horizon and fault pattern established on SW-53 and, because they lie along strike of each other, show how that pattern is maintained laterally. Both are also the lines carried into the inversion, so the structural interpretation on them is directly comparable with the impedance results presented in Section 4.4, and a low-impedance zone can be assessed against the mapped structure on the same section rather than on a neighbouring one.

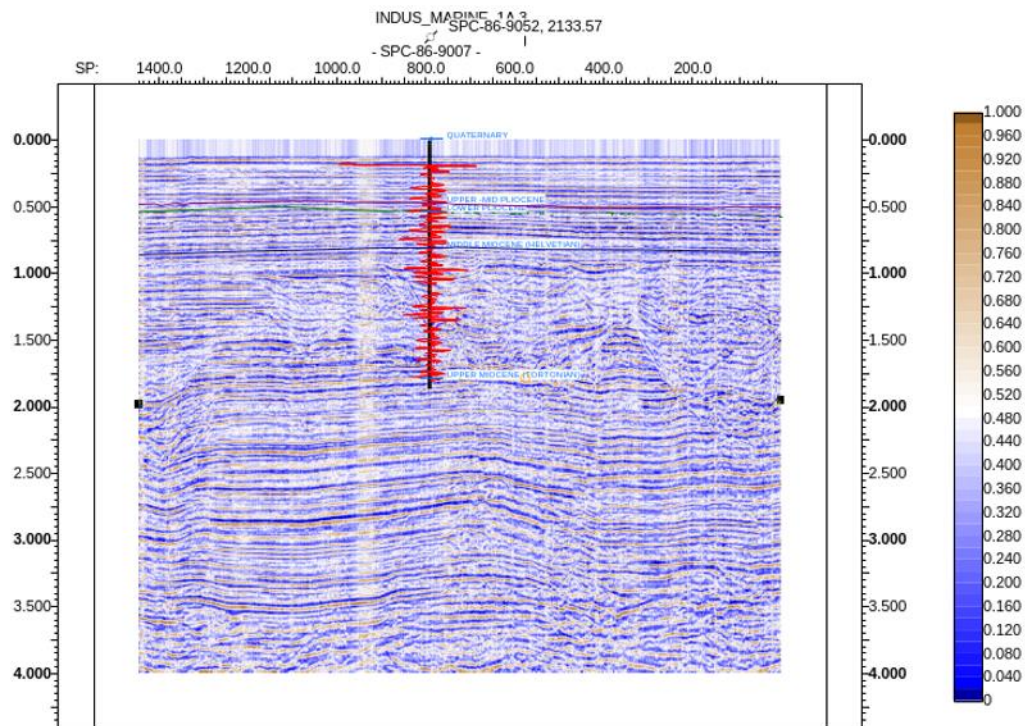


Figure 4. 8 Interpreted seismic line SPC-86-9007.

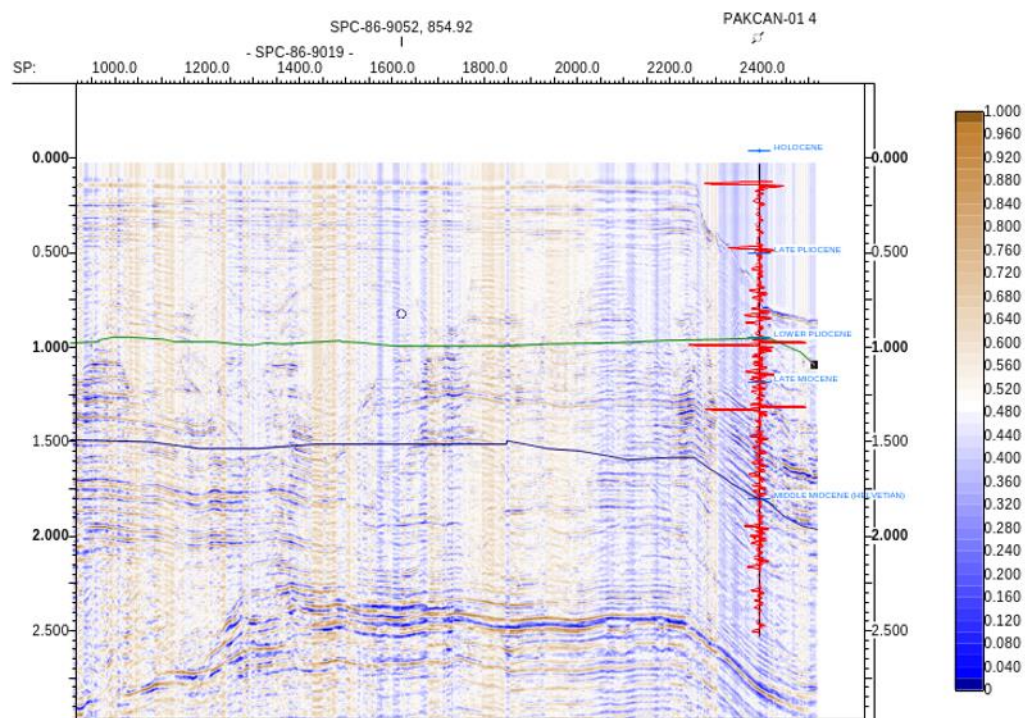


Figure 4. 9 Interpreted seismic line SPC-86-9019.

The interpreted sections indicate that the structural requirements for trapping are met. Fault-bounded closures are present at several horizons, and the stacked sand–shale

architecture identified at Sadaf-01 and PakCan-01 places porous sand units directly beneath shale intervals capable of acting as seals. Whether those faults seal cannot be determined from the present data. Fault seal analysis requires juxtaposition and shale gouge estimates that the available 2D coverage and three wells do not support, so the structures described here are treated as geometrically valid traps whose sealing capacity remains unproven.

4.3.3 Time Structure Maps

Figures 4.10 to 4.13 show the time structure maps for the Upper Miocene, Lower Pliocene, Middle Miocene and Upper Mid-Pliocene horizons. Each map shows the gridded horizon in two-way travel time, contoured at an interval of 0.2 s, with the colour bar scaled in seconds two-way time and the fault polygons from the interpretation superimposed. Structural highs appear as areas of shallower two-way time and are separated from the adjacent lows by the mapped fault system. The same high is present on all four horizons, which indicates a structure that persists vertically through the section rather than a feature developed at a single level.

The maps give the plan-view geometry of the closures and show that they are vertically stacked, which means that more than one reservoir objective may lie within a single structure. This is consistent with the stacked sand architecture observed at Sadaf-01. Because the maps are in the time domain they remain distorted by lateral velocity variation, so they establish the position and extent of the closures but cannot be used for spill-point analysis or area calculation. Those require the depth conversion described in the following section.

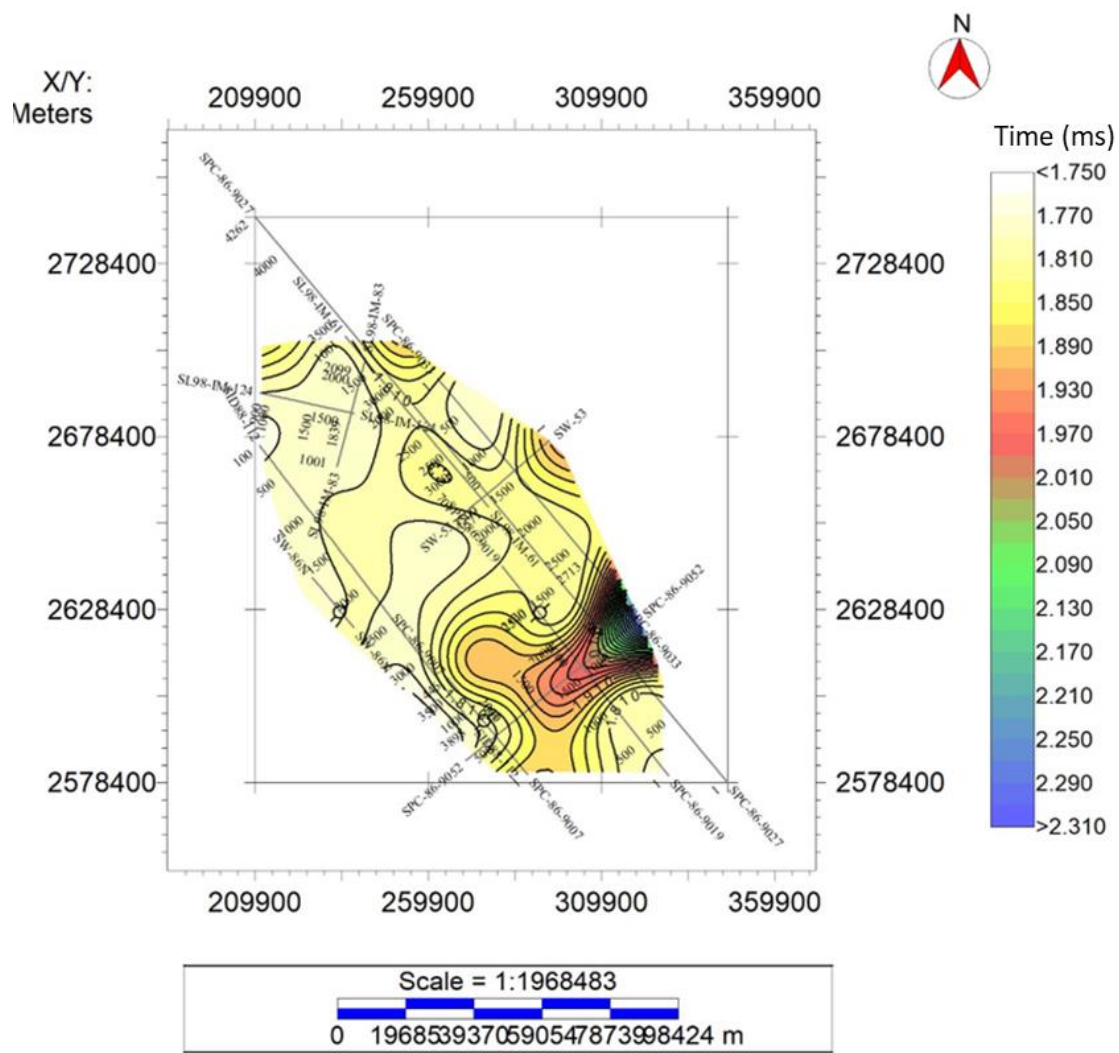


Figure 4.10 Time structure map — Upper Miocene horizon.



Figure 4. 11 Time structure map — Lower Pliocene horizon.

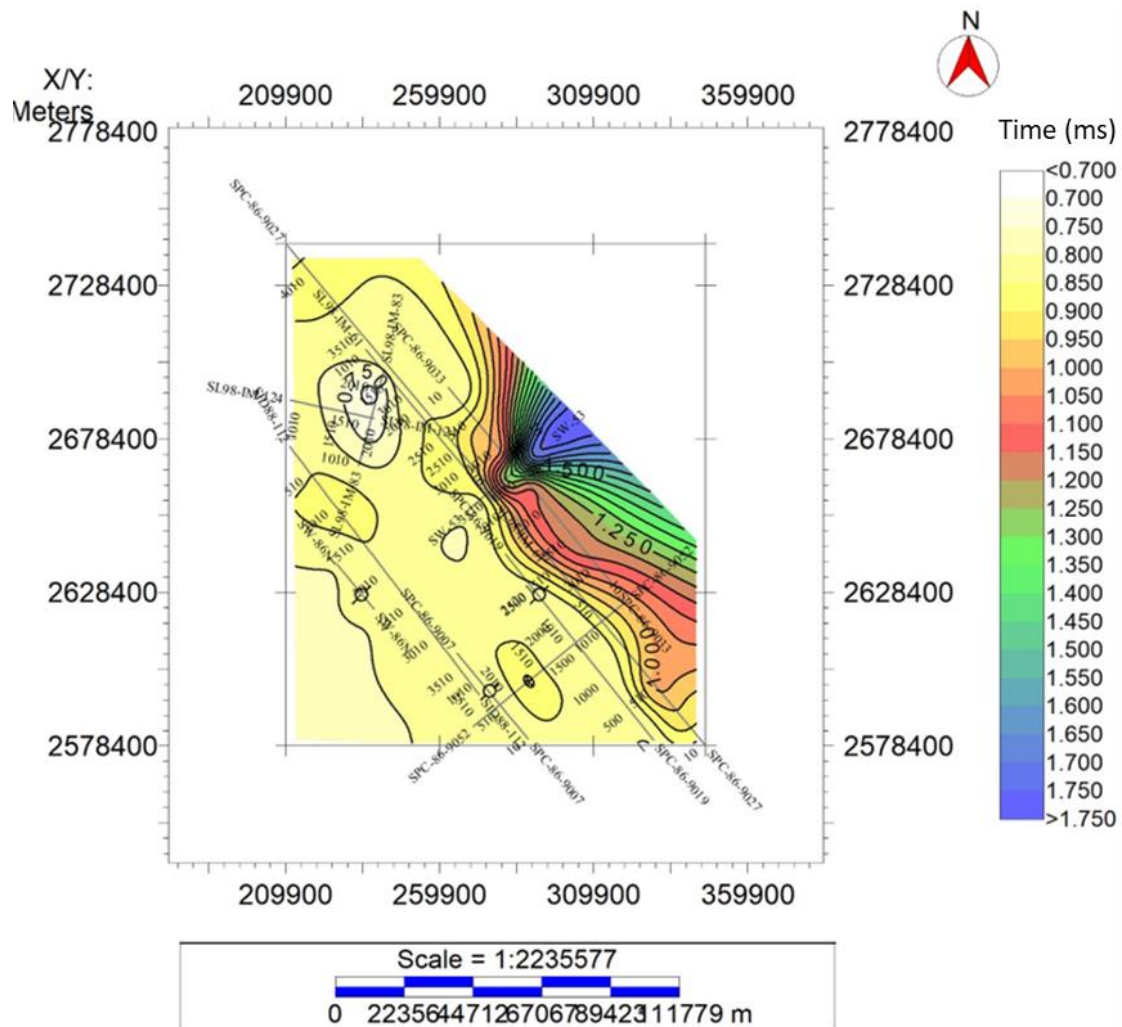


Figure 4.12 Time structure map — Middle Miocene horizon.

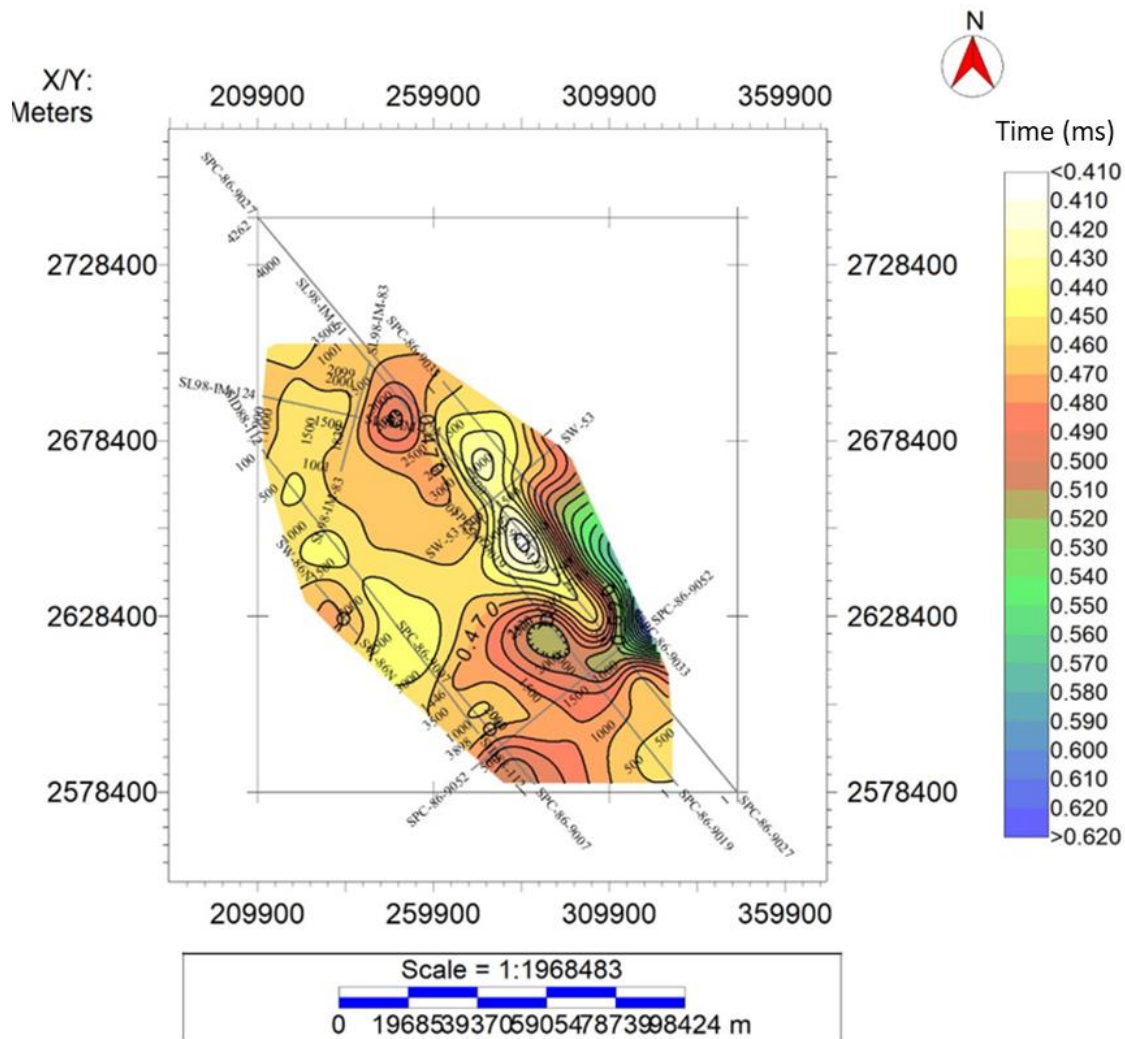


Figure 4. 13 Time structure map — Upper Mid-Pliocene horizon.

4.3.4 Depth Structure Maps

Figures 4.14 to 4.17 show the corresponding depth structure maps for the same four horizons, contoured at an interval of 100 m with the colour bar scaled in metres below datum. They were produced by converting the time surfaces using a velocity model built from sonic and check-shot data at the wells. The structural highs and the fault-bounded closures identified on the time maps are reproduced in depth, so that their geometry, areal extent and relative relief can be read directly.

That the closures survive depth conversion is significant, since it establishes that they are structural features rather than artefacts of lateral velocity change. The depth maps also place the reservoir intervals at their true depths, which is what allows the calibrated reservoir sands and the impedance anomalies from the inversion to be tied to a specific trap. The velocity model is constrained at three wells only and treats velocity as varying

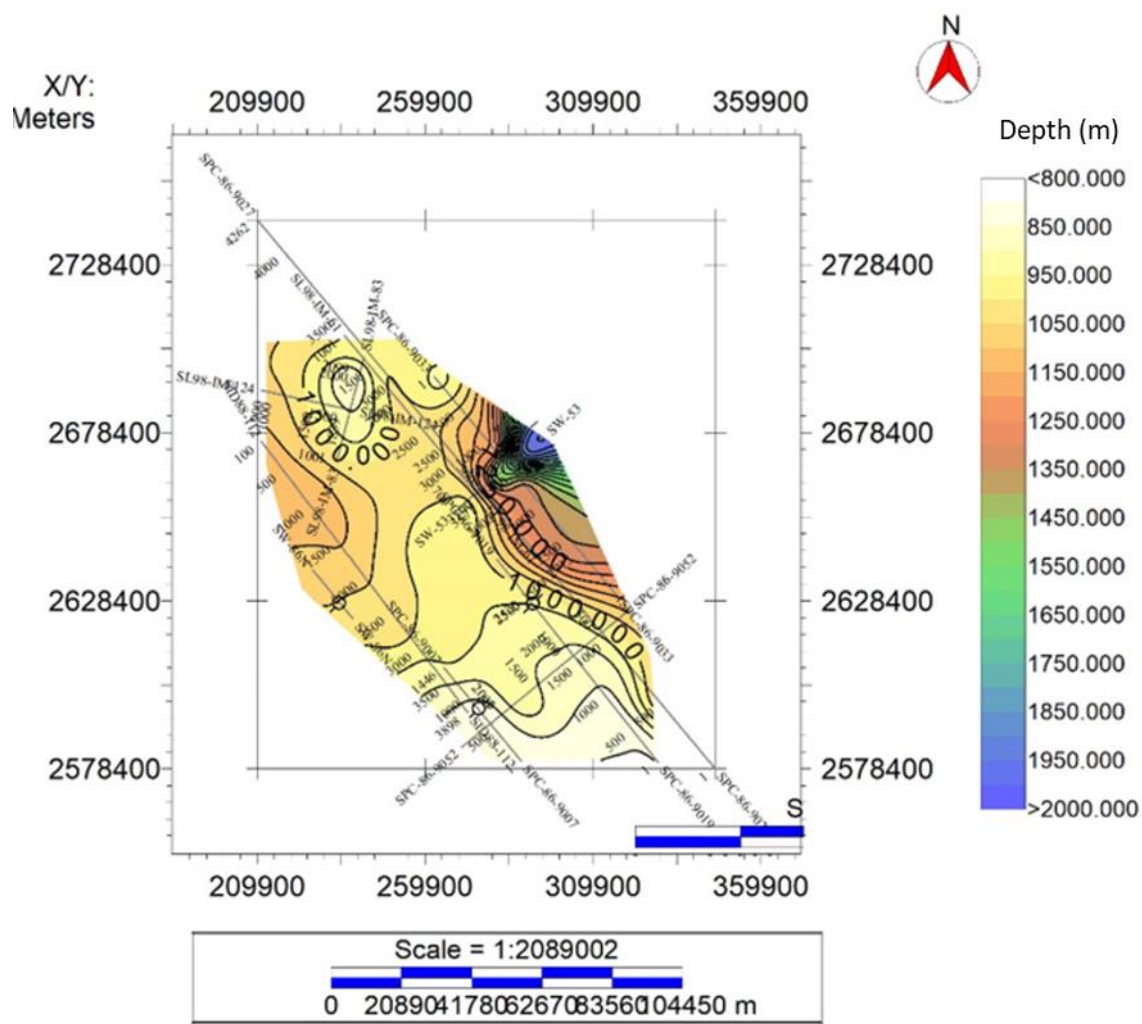


Figure 4. 16 Depth structure map — Middle Miocene horizon.

4.4 Seismic Inversion

Seismic inversion converts the interface-based reflectivity recorded in the seismic data into acoustic impedance, a layer property that can be compared directly with well log measurements and related to reservoir rock and fluid properties. Model-based post-stack inversion was applied to lines SPC-86-9007 and SPC-86-9019, the two strike lines that run closest to well control. The results for each line are presented in the same sequence: the input seismic data, the extracted wavelet, the seismic-to-well tie, the low-frequency model, the inversion analysis at the well, and the final impedance section. The reason for inverting two lines rather than the full grid is given in Section 3.1.1. The two are sub-parallel and do not cross, so they cannot be tied at a common point; what they provide instead is a second, independent profile through the same stratigraphic interval, against which an impedance response seen on the first can be checked.

4.4.1 Line 9007

Figure 4.18 shows the input post-stack seismic data for line SPC-86-9007. Reflector continuity is good and both the stratigraphy and the interpreted faults are clearly expressed. This is the precondition for a stable inversion: adequate bandwidth, a high signal-to-noise ratio and a wavelet that does not vary appreciably along the line. The coherence and lateral continuity evident in the section establish that the data are suitable for the model-based inversion that follows.

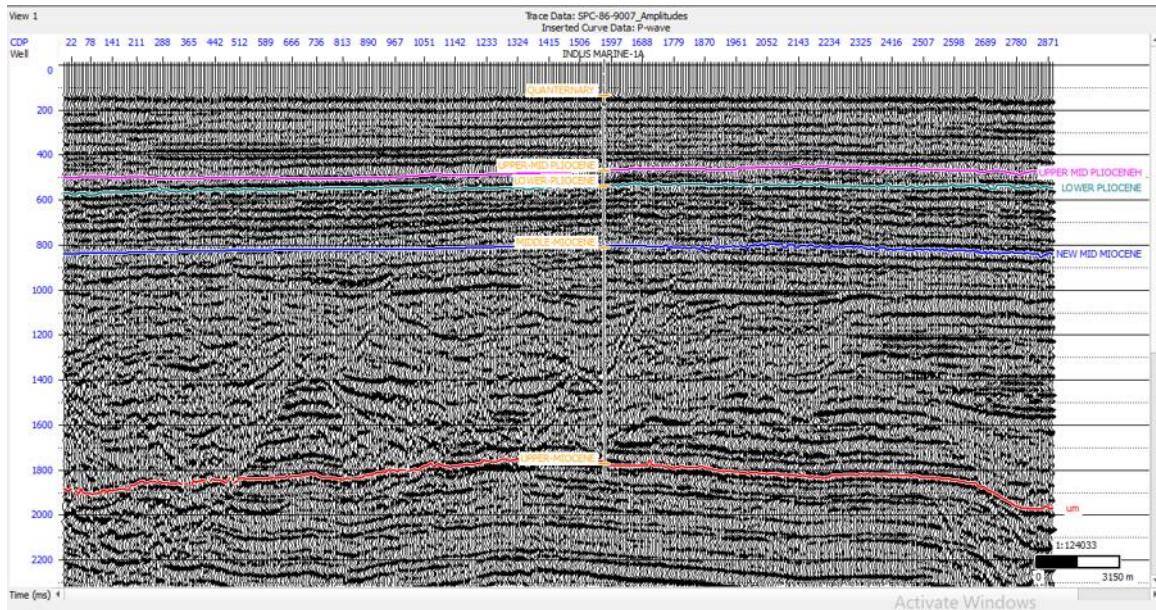


Figure 4. 18 Input post-stack seismic data, line 9007.

Figure 4.19 shows the wavelet extracted statistically from line SPC-86-9007, together with its amplitude and phase spectra. The wavelet is compact and near-symmetric, and the phase spectrum is close to zero across the usable bandwidth, which confirms that the data are effectively zero-phase as the inversion requires. Because inversion deconvolves this wavelet from the data to recover impedance, the fidelity of the wavelet controls the fidelity of the result, and a stable, near-zero-phase wavelet of this character is a necessary condition for the impedance section to be interpretable.

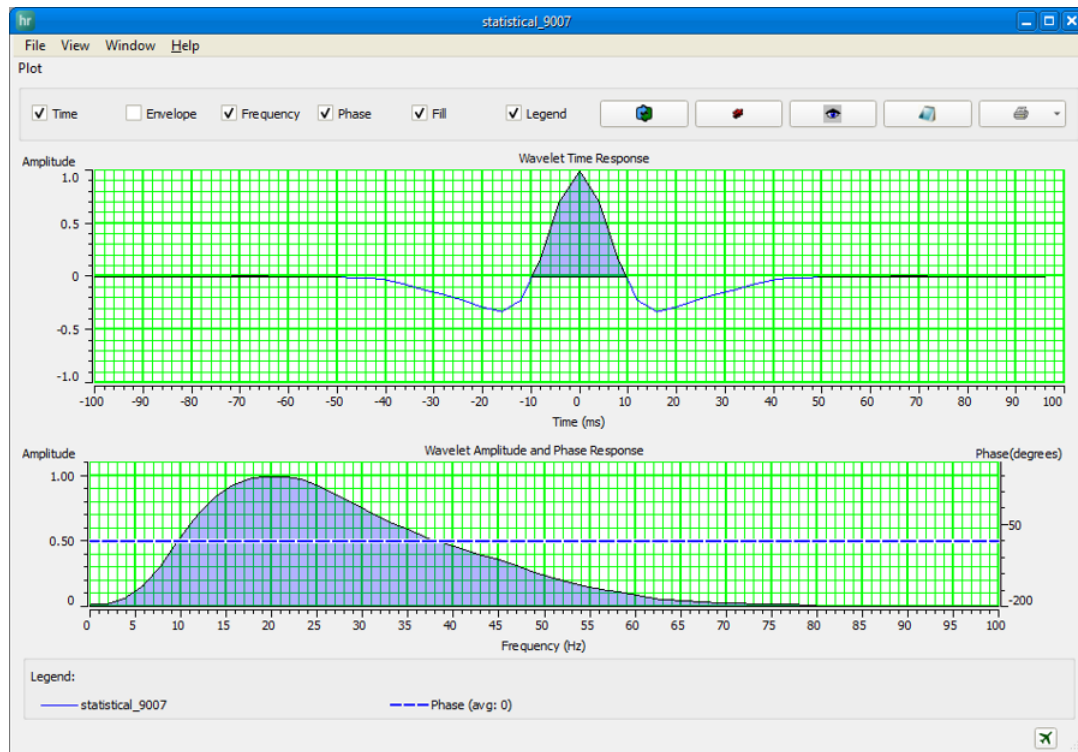


Figure 4. 19 Extracted statistical wavelet with amplitude and phase spectra, line 9007.

Figure 4.20 shows the seismic-to-well tie for line SPC-86-9007. The panel displays, from left to right, the well impedance log, the derived reflectivity series, the extracted wavelet, the synthetic trace and the recorded seismic traces at the well location. The tie confirms that the well is correctly positioned in two-way time relative to the seismic data, and that the wavelet and time–depth relationship used in the inversion are the same as those used in the structural interpretation. The synthetic reproduces the character of the recorded trace through the reservoir interval, with the troughs marking the principal impedance increases aligned on both. A tie of this quality means that an impedance change appearing at a given time on the inverted section corresponds to the geological boundary at that depth in the well, which is what permits the impedance anomalies to be attributed to the intervals identified in the logs.

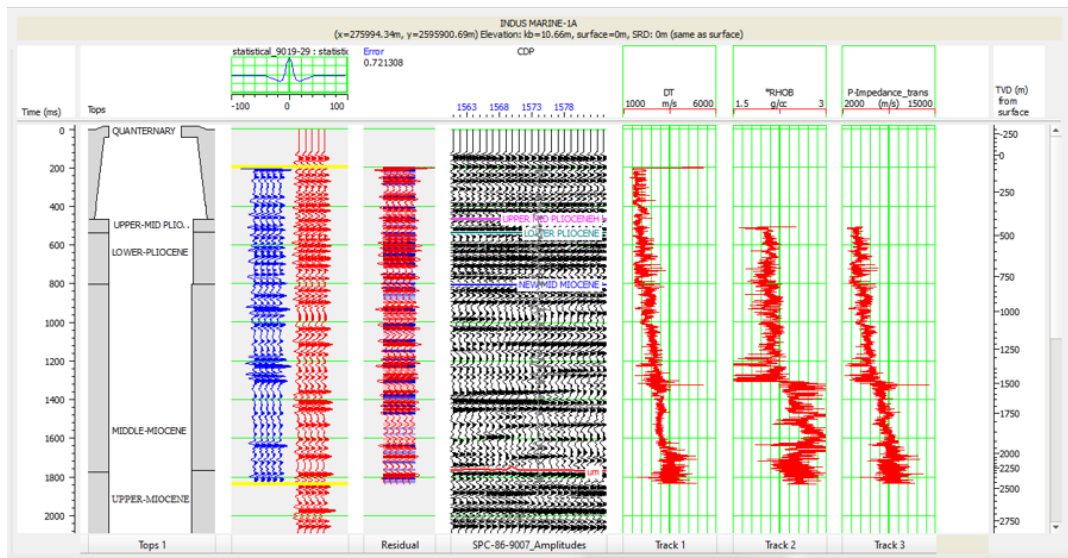


Figure 4.20 Seismic-to-well tie, line 9007.

Figure 4.21 shows the low-frequency model for line SPC-86-9007. The model supplies the background impedance trend, including the compaction and background-velocity component, that the band-limited seismic data cannot recover on their own. Without it the inversion returns relative rather than absolute impedance, and the output cannot be compared with log values.

The model was built by low-pass filtering the impedance logs and interpolating the result laterally along the interpreted horizons, so that the background trend follows the structural geometry rather than a horizontal datum. It provides the framework against which the seismically derived impedance contrasts are added, and it is what allows the low-impedance zones to be evaluated against absolute, log-calibrated values. It is also the principal source of non-uniqueness in the result: away from the wells the low-frequency trend is an interpolation, so the confidence attached to an absolute impedance value in the middle of a long line is lower than the smooth appearance of the section suggests.

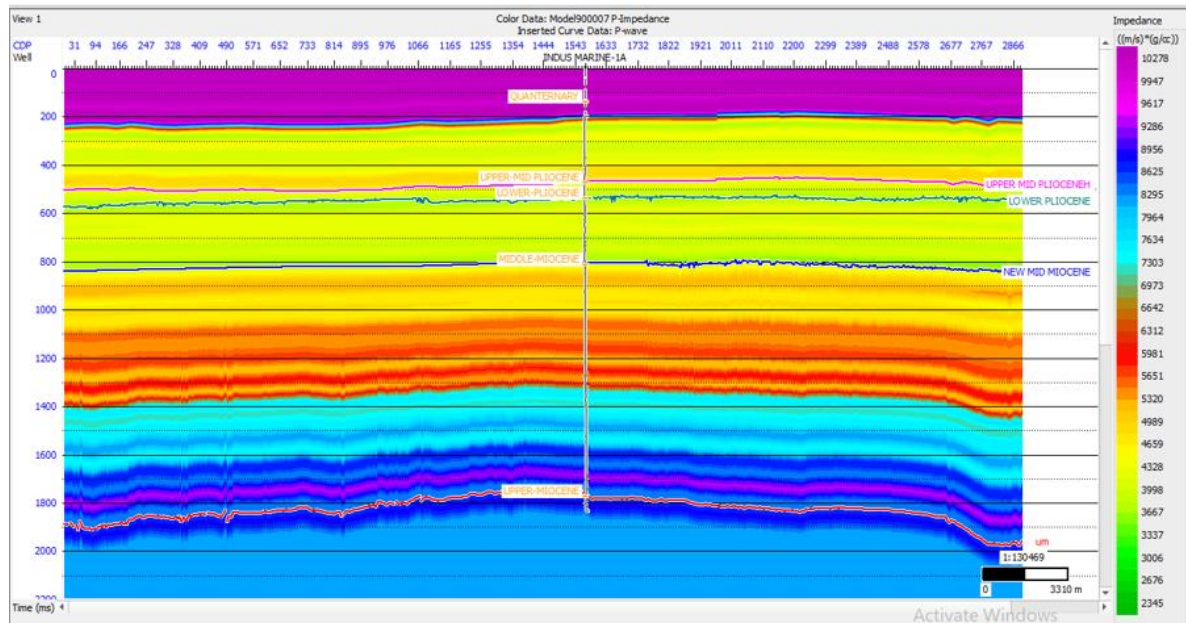


Figure 4. 21 Low-frequency (background) impedance model, line 9007.

Figure 4.22 shows the inversion analysis at the well for line SPC-86-9007. This is the quality control step of the workflow. The panel compares the inverted impedance (red) with the impedance computed from the well logs (blue) and with the initial model (black) over the analysis window. The inverted trace departs from the initial model where the seismic data require it and follows the log impedance closely, reproducing the impedance reductions that correspond to the sand-bearing intervals. The correlation between the synthetic regenerated from the inverted model and the recorded trace is 0.99, and the residual error trace shows no systematic structure within the reservoir window. The inversion at this location is therefore recovering the impedance structure that the well independently measures, and that is the basis on which the impedance anomalies mapped elsewhere along the line are accepted.

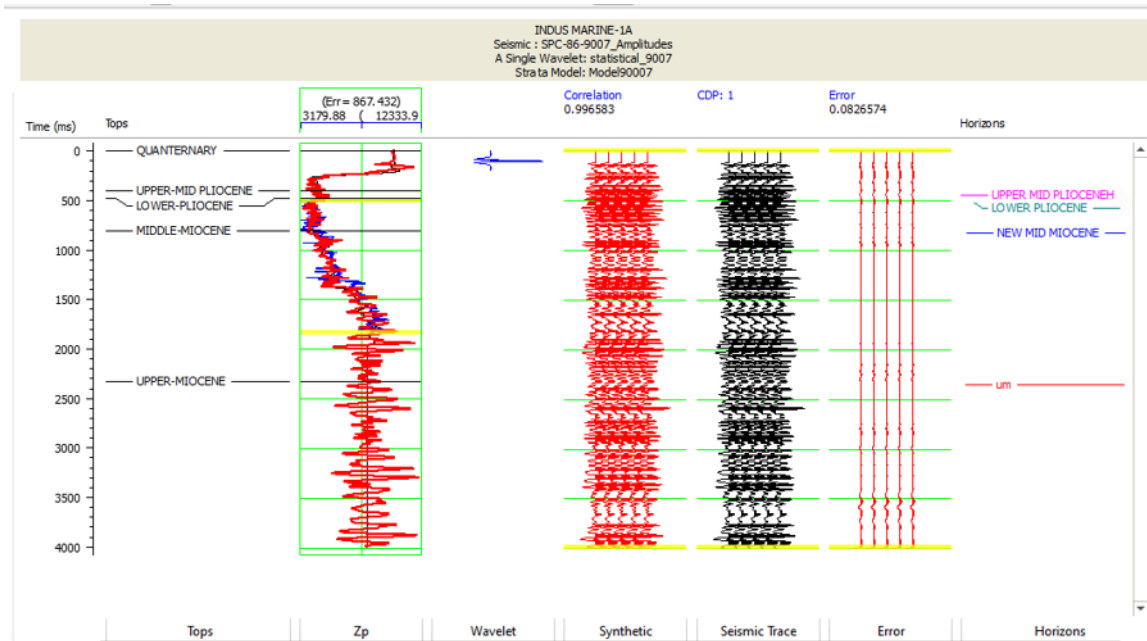


Figure 4. 22 Inversion analysis at the well: inverted (red), original log (blue) and initial-model (black) impedance, line 9007.

Figure 4.23 shows the inverted P-impedance section for line SPC-86-9007, displayed as a colour-coded section with the colour bar scaled in $(\text{m/s}) \cdot (\text{g/cm}^3)$. Low-impedance zones are developed within the reservoir interval, bounded above and below by the mapped horizons, and are surrounded by the higher impedance of the enclosing shales and of the more compacted section at depth.

Low impedance in this setting indicates a rock of lower density and lower velocity than its surroundings, which in this stratigraphic section means either higher porosity or lower clay content, or both. The petrophysical results in Section 4.2 place the emphasis on the second of these: shale volume varies from 51 to 77 per cent between the four intervals and is the property that separates them most strongly, while effective porosity spans a narrow range of 6 to 11 per cent. The low-impedance zones are developed on the crests and flanks of the structures mapped in Section 4.3, which places the cleaner, more porous intervals within the closures identified from the structural interpretation.

Acoustic impedance alone does not establish that those zones are hydrocarbon-bearing, and in this dataset the case for a fluid contribution is weak. Water saturation exceeds 79 per cent in every interval analysed and reaches 98.5 per cent in the shallower PakCan-01 sand, so the volume of hydrocarbon present is small and the impedance reduction it can produce is correspondingly small against the much larger effect of clay

content. Separating any residual fluid effect from the lithological one requires the V_p/V_s and shear impedance information presented in Section 4.5.

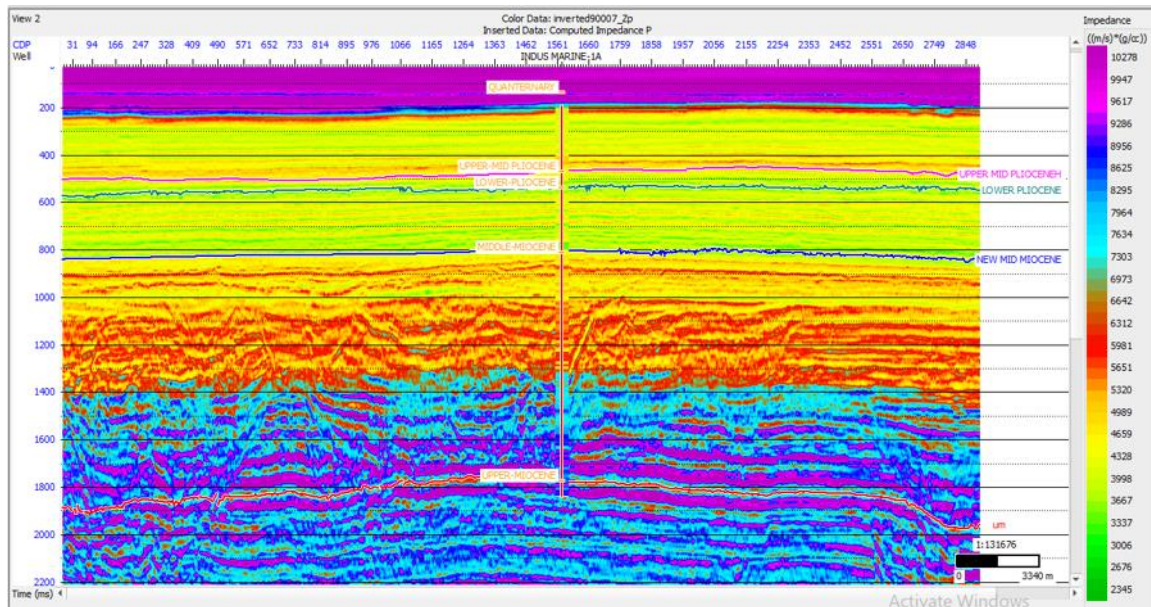


Figure 4. 23 Inversion result: computed P-impedance section, line 9007.

4.4.2 Line 9019

Figure 4.24 shows the input post-stack seismic data for line SPC-86-9019. Data quality is comparable to that of line SPC-86-9007, with continuous reflectors and clearly expressed faults. The line runs sub-parallel to SPC-86-9007 along the same structural strike, so it samples the same stratigraphic interval on a separate profile. It does not intersect SPC-86-9007, so the two cannot be tied at a shared point; the comparison between them is made at the level of the mapped horizons, which are continuous across both.

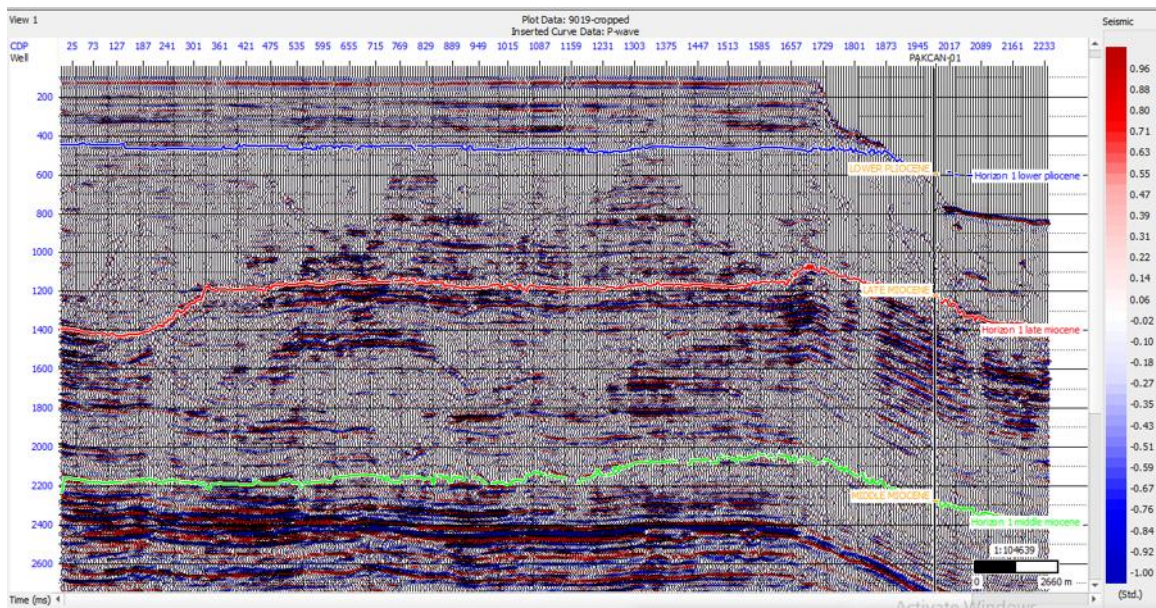


Figure 4. 24 Input post-stack seismic data, line 9019.

Figure 4.25 shows the wavelet extracted from line SPC-86-9019 with its amplitude and phase spectra. The wavelet is compact and stable, and its amplitude spectrum is comparable to that extracted from SPC-86-9007, which indicates that the two lines carry similar bandwidth and that impedance results derived from them may be compared directly.

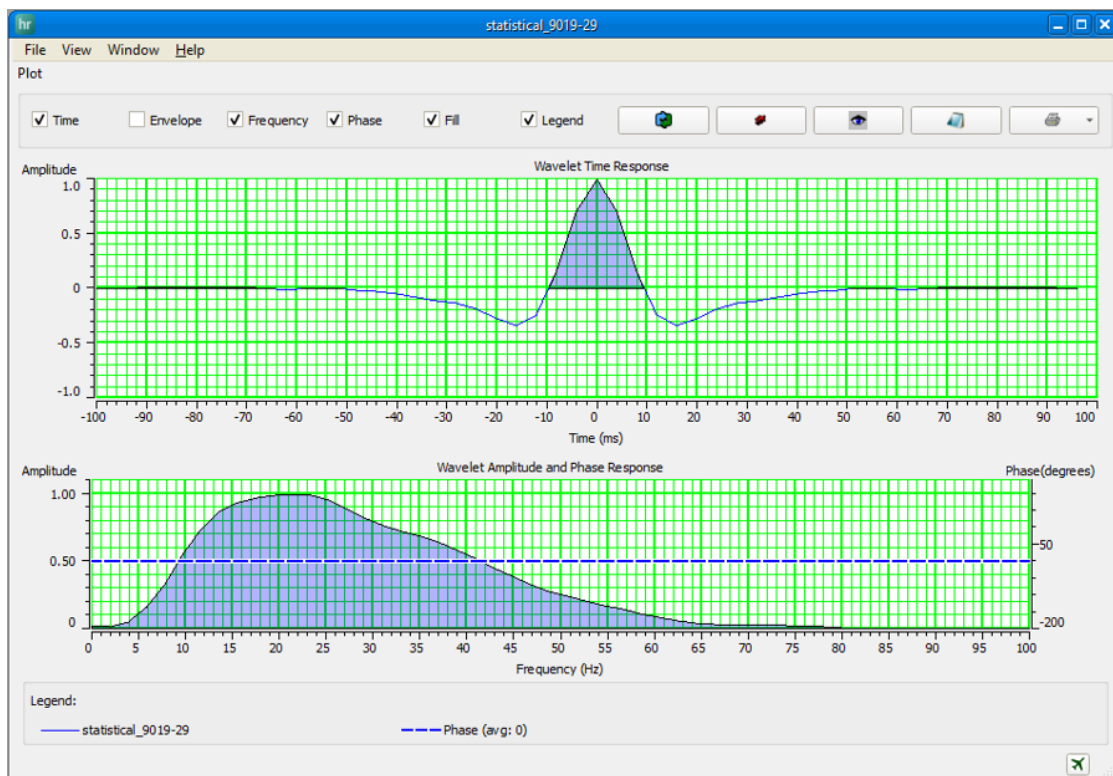


Figure 4. 25 Extracted statistical wavelet with amplitude and phase spectra, line 9019.

Figure 4.26 shows the seismic-to-well tie for line SPC-86-9019. As on line SPC-86-9007, the tie confirms that the well events are correctly positioned in two-way time and that the wavelet and time–depth relationship are consistent between the two lines. That consistency is what allows the impedance sections from the two profiles to be read against one another, since both are calibrated to the same well control and the same time–depth relationship.

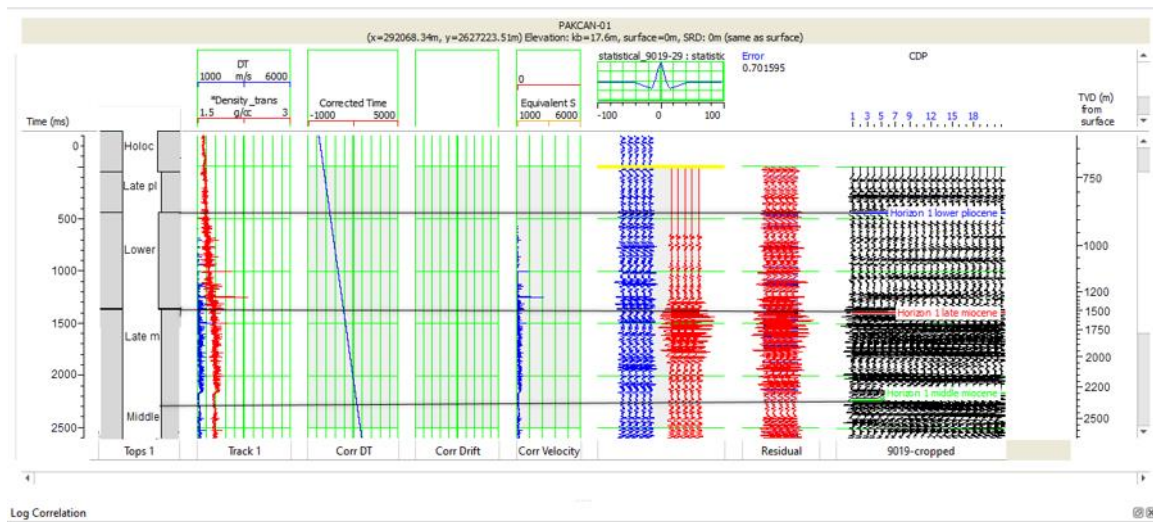


Figure 4. 26 Seismic-to-well tie (log correlation), line 9019.

Figure 4.27 shows the low-frequency model for line SPC-86-9019, built by the same procedure and from the same well impedance logs as the model for SPC-86-9007. Because both models derive from the same log data and the same interpreted horizons, the two inversions share a common absolute reference, and impedance values may therefore be compared between the two sections even though the lines themselves do not meet.

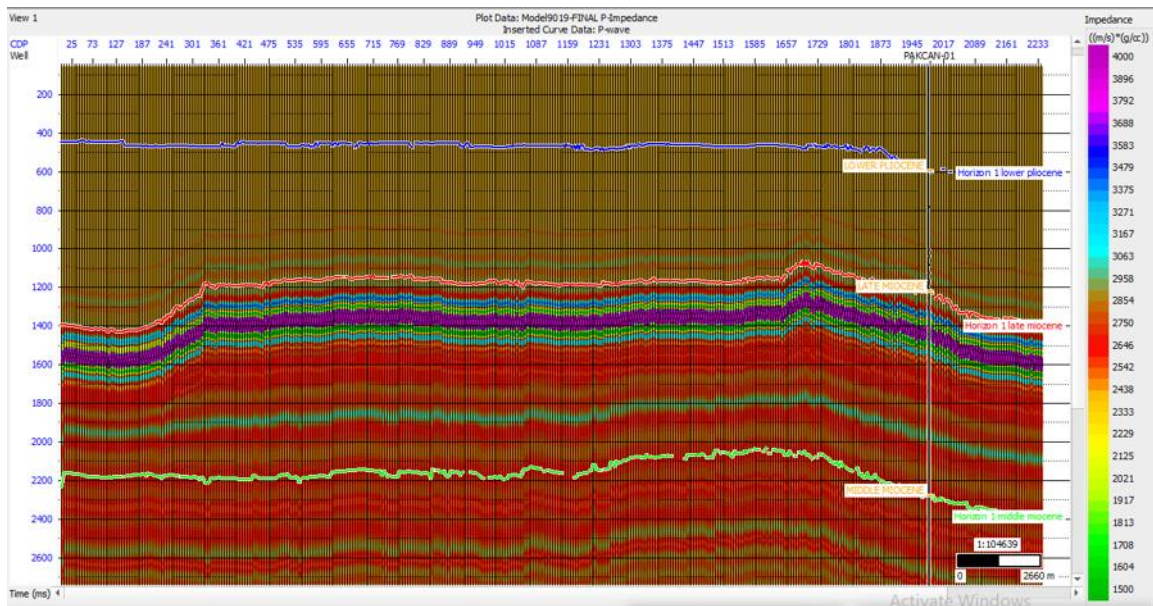


Figure 4. 27 Low-frequency (background) impedance model, line 9019.

Figure 4.28 shows the inversion analysis at the well for line SPC-86-9019, comparing the inverted impedance (red), the impedance computed from the well logs (blue) and the initial model (black) at the tie location. As on line SPC-86-9007, the inverted trace reproduces the log impedance closely, with a correlation of 0.99 between the regenerated synthetic and the recorded trace. The inversion on this line is therefore accepted on the same basis as the first.

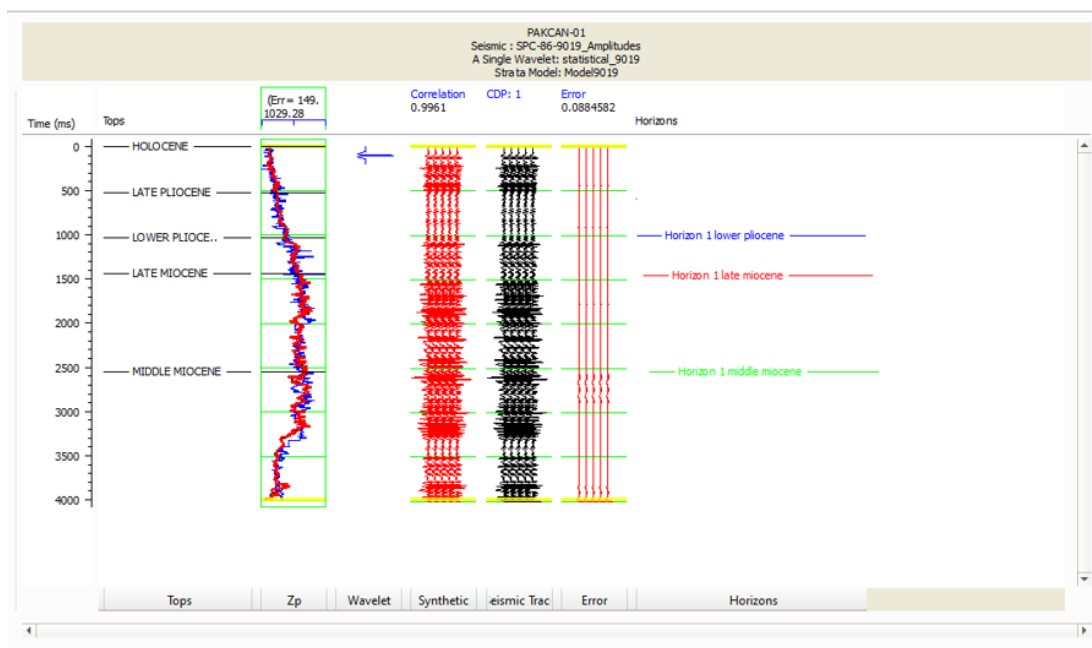


Figure 4. 28 Inversion analysis at the well: inverted (red), original log (blue) and initial-model (black) impedance, line 9019.

Figure 4.29 shows the inverted P-impedance section for line SPC-86-9019, with the colour bar scaled in $(\text{m/s}) \cdot (\text{g/cm}^3)$. Low-impedance zones are developed within the reservoir interval against a higher-impedance background, as on line SPC-86-9007, and they occupy the same position relative to the mapped horizons. Since the two lines are separate, sub-parallel profiles processed independently, the appearance of the same impedance response at the same stratigraphic level on both argues against its being an artefact of the processing or of the low-frequency model on a single profile. It is not, however, the same evidence that a tie at a line intersection would provide, and the correspondence is stratigraphic rather than point for point.

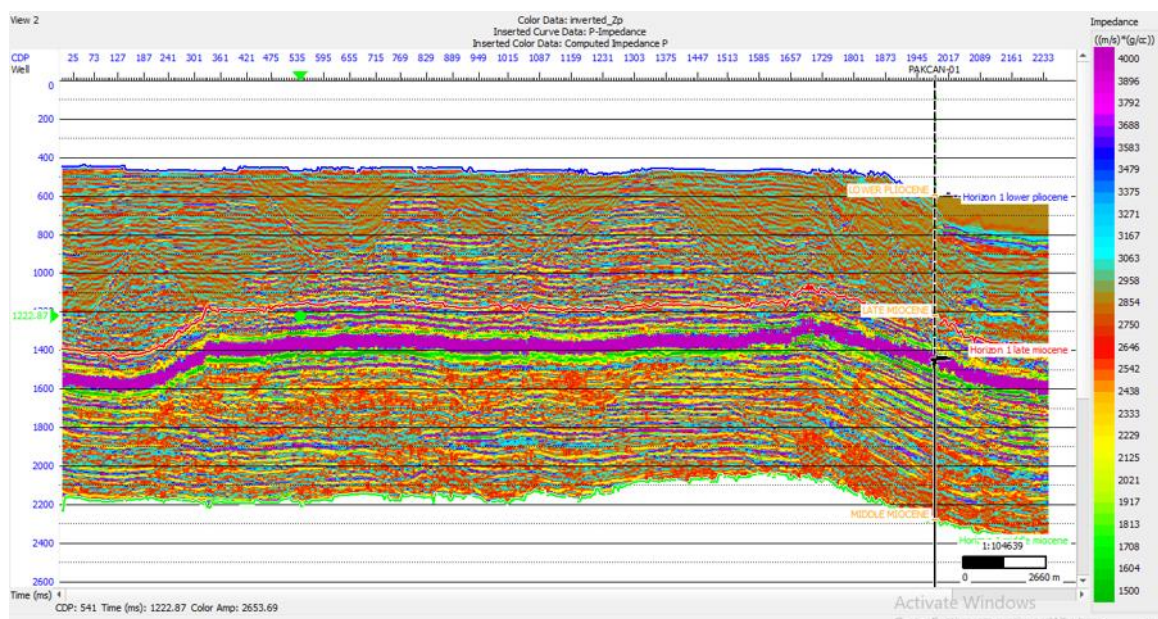


Figure 4. 29 Inversion results computed P-impedance section, line 9019.

The inversion therefore extends the point calibration available at the wells into a two-dimensional distribution of impedance along both lines. The input data are of adequate quality, the extracted wavelets are stable, the well ties are good and the inversion analyses correlate at 0.99 at well control, so the inverted sections may be treated as a reasonable representation of subsurface impedance within the limits imposed by the low-frequency model.

Persistent low-impedance zones are developed within the reservoir interval on both lines. They lie within the part of the section calibrated by the wells, they coincide with the closures mapped in Section 4.3, and they occupy the same stratigraphic position on both profiles. On that basis they are interpreted as intervals of lower clay content and higher

porosity than the enclosing section, and they indicate how those intervals are distributed away from well control. Whether any part of the impedance reduction is attributable to pore fluid is examined in the following section.

4.5 Rock Physics Analysis (Crossplots)

Rock physics crossplots resolve the ambiguity that remains after impedance inversion. Acoustic impedance responds to the rock frame and to the pore fluid together, so a low-impedance zone may indicate porous sand, a hydrocarbon fill, or both. Adding the V_p/V_s ratio and shear impedance separates the two effects, because shear waves do not propagate through pore fluid and shear impedance therefore responds essentially to lithology, while V_p/V_s is strongly sensitive to fluid.

The analysis is anchored to PakCan-01, the only well recording a shear sonic log, and covers the reservoir intervals and their bounding shales sampled at the log increment. Three crossplots are presented, each with the V_p/V_s ratio on the vertical axis and each coloured by computed gamma ray (CGR) so that clay content can be read directly from the plot. The polygons annotated on each plot delimit shale, shaly sand, brine-bearing sand and hydrocarbon-bearing (dry) sand. Their positions were guided by the unconsolidated sandstone rock physics template described in Section 3.7, which is the model appropriate to sands of this burial depth and consolidation state, and were then checked against the observed clustering of the data and against the gamma ray colour scale. Because the plots derive from log measurements rather than from the inverted seismic, they establish the elastic signature of each class at well control, which is then applied to the impedance sections described above.

4.5.1 V_p/V_s Ratio versus P-Impedance

Figure 4.30 plots the V_p/V_s ratio against P-impedance, coloured by computed gamma ray. The data form trends rather than a single cluster, and the annotated polygons delimit shale, shaly sand, dry (gas-bearing) sand and brine-bearing sand, with porosity lines overlain. Shale occupies the high- V_p/V_s , high-impedance field, since clay-rich rock transmits shear waves slowly and has high impedance. Clean, brine-saturated sand falls at moderate V_p/V_s and moderate impedance. Sand carrying light hydrocarbon falls at the lowest V_p/V_s and the lowest impedance, because gas reduces compressional velocity and bulk density while leaving shear velocity almost unchanged.

The colour scale supports that separation: high-CGR points fall within the shale field and low-CGR points within the sand fields, which confirms that the polygons separate lithologies rather than arbitrary regions of the plot. The sands identified petrophysically are elastically distinct from the surrounding shales, and the hydrocarbon-bearing interval carries the expected low-Vp/Vs, low-impedance signature. This provides the physical basis for reading the low-impedance zones on lines SPC-86-9007 and SPC-86-9019 as porous sand, since those zones fall at impedance values corresponding to the sand fields rather than to the shale field.

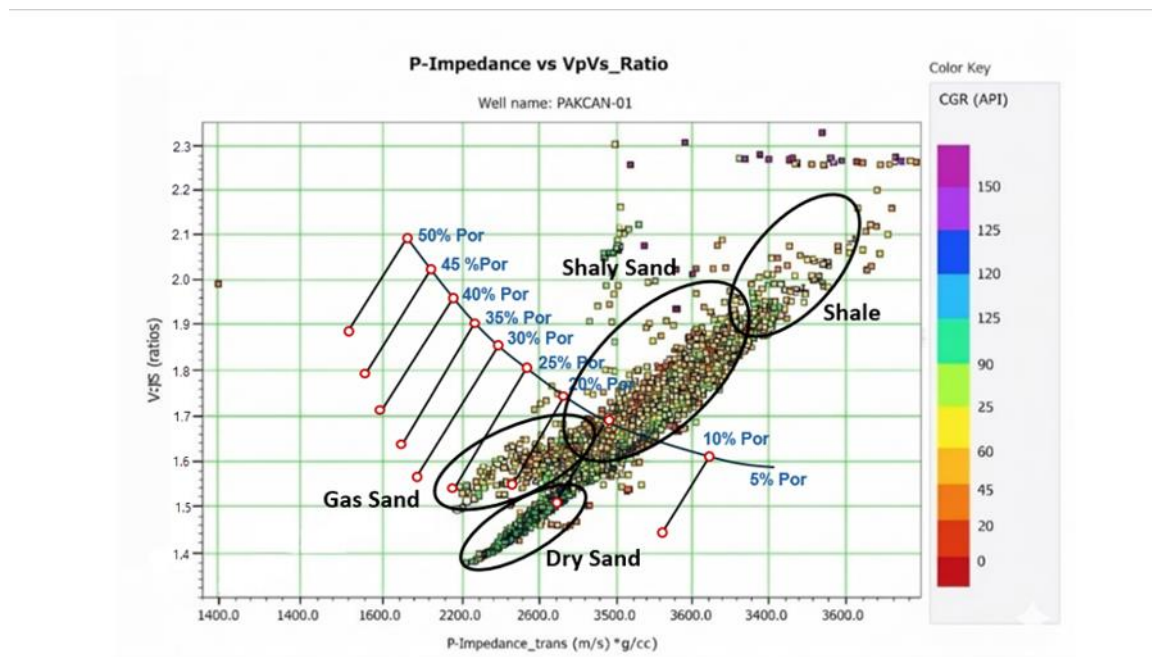


Figure 4. 30 Vp/Vs ratio versus P-impedance crossplots, colour-coded by computed gamma ray (CGR, API), PakCan well.

4.5.2 Vp/Vs Ratio versus Bulk Density (RHOB)

Figure 4.31 plots the Vp/Vs ratio against bulk density, again coloured by computed gamma ray. Because bulk density depends on porosity and on the density of the pore fluid, this crossplot isolates the density contribution to the elastic response. The reservoir sands occupy the low-Vp/Vs, low-density field, where the dry-sand polygon is annotated, while the shales trend towards higher Vp/Vs and higher density. Porosity reduces density through pore volume and a gas fill reduces it further, so hydrocarbon-bearing sands plot in the low-density corner of the plot.

This confirms that the impedance reduction observed in the inversion is driven by density as well as by velocity, and therefore by increased porosity and reduced pore fluid

density rather than by a velocity effect alone. It supports the interpretation of the low-impedance zones on the inverted sections as porous, low-density and potentially gas-charged reservoir sand, and it identifies the density contrast as the property that makes those zones detectable on post-stack data in the first place.

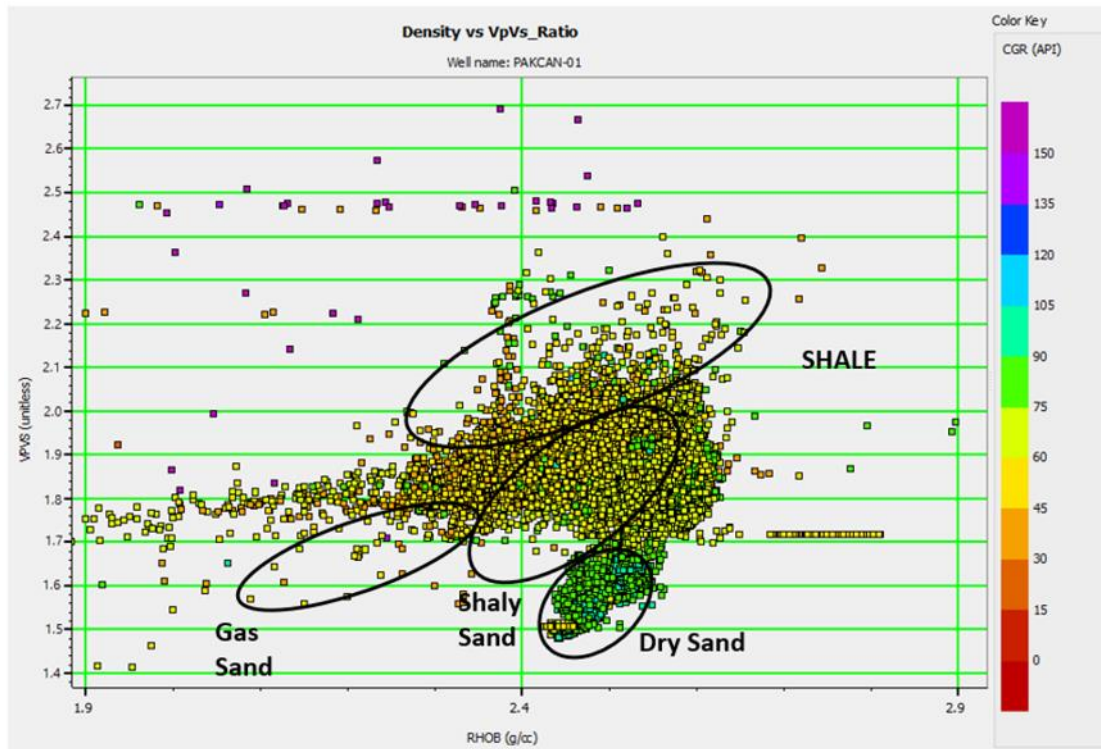


Figure 4. 31 Vp/Vs ratio versus bulk density (RHOB) crossplots, colour-coded by computed gamma ray (CGR, API), PakCan well.

4.5.3 Vp/Vs Ratio versus S-Impedance

Figure 4.32 plots the Vp/Vs ratio against shear impedance. Shear impedance is a property of the rock frame and its constituent minerals: shear waves do not propagate through pore fluid, so shear impedance is largely insensitive to the fluid fill. Plotting it against Vp/Vs, which is strongly fluid-sensitive, therefore separates the two controls on the elastic response and allows the question of whether a given point is governed by lithology or by fluid to be answered directly.

The annotated polygons separate the populations on that basis. Sand and shale occupy distinct ranges of shear impedance, so lithology can be assigned from the horizontal axis alone, and the vertical position of a point within the sand field then indicates its fluid fill. In practice this means that a sand can first be identified as a sand independently of what it contains, and only then classified as brine-bearing or

hydrocarbon-bearing. Acoustic impedance on its own does not permit that separation, which is why the rock physics analysis is required in order to interpret the inversion result.

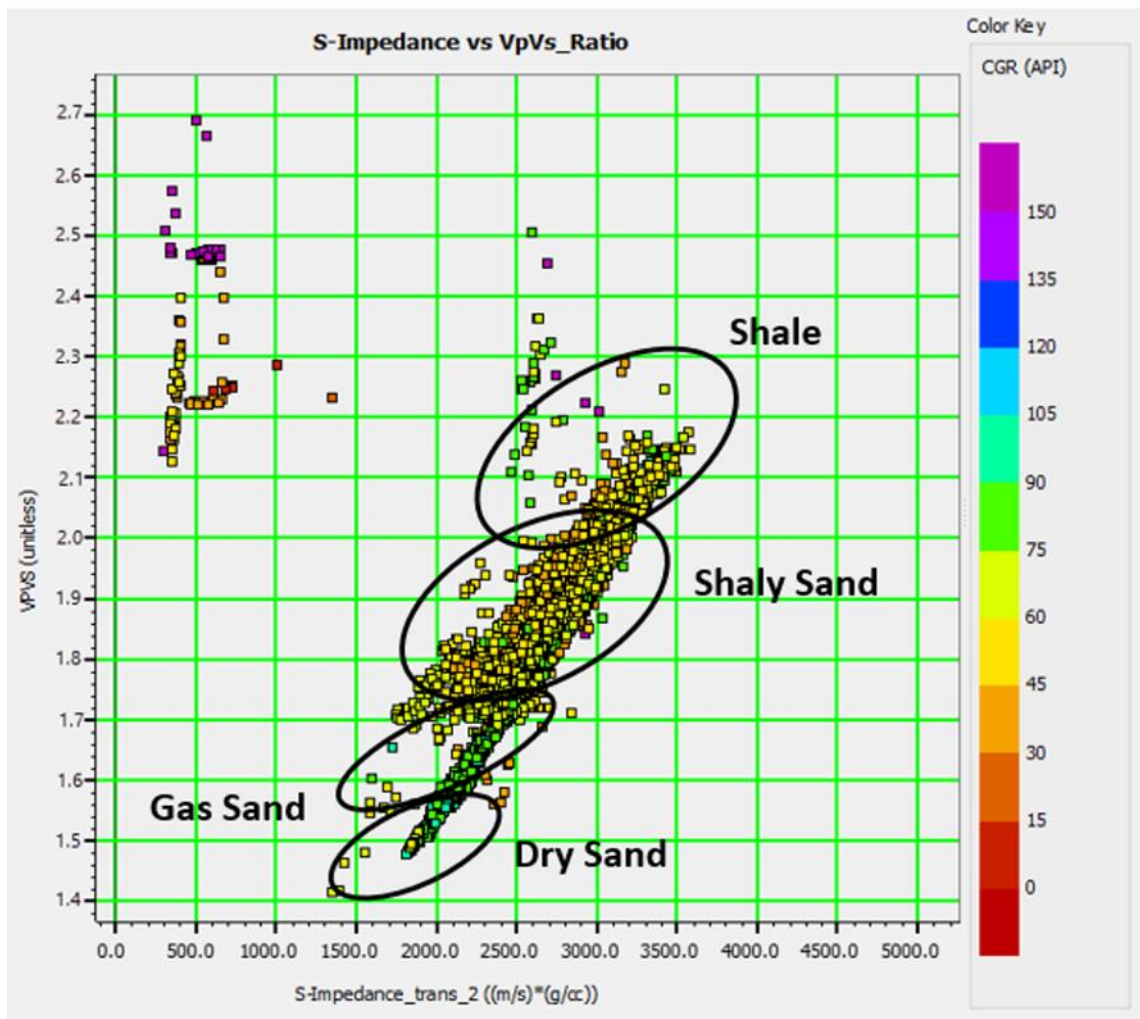


Figure 4. 32 Vp/Vs ratio versus S-impedance crossplots, colour-coded by computed gamma ray (CGR, API), PakCan well.

Read together, the three crossplots provide a consistent basis for discrimination:

- Vp/Vs against P-impedance separates shale, brine-bearing sand and hydrocarbon-bearing sand into predictable fields.
- Vp/Vs against bulk density shows that the reservoir sands are porous and of low density, and that the density reduction is consistent with a light hydrocarbon fill.
- Vp/Vs against shear impedance separates lithology from fluid, confirming that the low-impedance material is sand irrespective of what occupies the pore space.

Applying this template to the inversion, the low-impedance zones mapped on lines SPC-86-9007 and SPC-86-9019 fall within the sand fields of the crossplots and, where they coincide with the closures mapped in Section 4.3, identify intervals of cleaner and more porous rock within those closures. Attributing the impedance reduction to a hydrocarbon fill is not supported by the petrophysical results, since water saturation exceeds 79 per cent in every interval analysed. The elastic response is consistent with the lithology and porosity variation measured at the wells; a fluid contribution cannot be excluded, but neither can it be demonstrated from these data.

One qualification applies to all three crossplots, and it answers directly the question of why the fluid populations do not separate. The first and most important reason is that there is very little fluid contrast in the data to separate. Water saturation computed at well control ranges from 79.99 to 98.50 per cent across the four intervals, so almost every logged point on these plots is drawn from rock that is predominantly water-saturated, and a distinct hydrocarbon-bearing population large enough to form its own cluster does not exist in this dataset. The second reason is that clay content dominates the elastic response. Shale volume ranges from 51.20 to 76.66 per cent, and its effect on velocity and density is far larger than the effect of the small hydrocarbon saturations present, so the data separate along a clay trend and any fluid effect is contained within the scatter about it. The third reason is that the plots derive from a single well, PakCan-01, because it is the only well recording a shear sonic log, so the population available is small and drawn from one location; the Sadaf-01 intervals, which return the intermediate hydrocarbon saturations, cannot be plotted at all. The fourth is that the sands are shallowly buried and poorly consolidated, so their elastic response is governed by the grain frame rather than by the pore fluid, which further suppresses any fluid signature. The polygons should therefore be read as indicating the most probable class for a given elastic response rather than as boundaries separating populations without overlap, and the fluid boundaries in particular rest on the modelled template rather than on measured separation in the data. Resolving fluid effects would require pre-stack data, shear velocity control in more than one well, and saturations high enough to produce a measurable contrast, as noted in Section 1.10.

CONCLUSION

This study set out to characterise a Miocene clastic reservoir system in the Offshore Indus Basin by integrating petrophysical evaluation, seismic interpretation, acoustic impedance inversion and rock physics analysis. Each of the four objectives is assessed below against what the data actually returned.

1. Structural interpretation of the study area using seismic data to interpret subsurface structure and understand potential hydrocarbon prospects. This objective was met. All eleven 2D lines were interpreted and calibrated by synthetic seismogram, and time and depth structure maps for four horizons define a normal-faulted extensional framework containing a fault-bounded closure that persists vertically through the whole mapped section and survives depth conversion. The trapping geometry is therefore established, although fault seal could not be tested with the available data.
2. Petrophysical analysis to identify reservoir zones and calculate key reservoir properties including porosity, shale volume, and water saturation. This objective was met, and the results reframed the study. Four intervals were evaluated in two wells. All are shale-rich, with shale volumes between 51.20 and 76.66 per cent, and the clay correction reduces average porosities of 20.89 to 31.81 per cent to effective porosities of 6.15 to 10.57 per cent. Water saturation ranges from 79.99 to 98.50 per cent, so hydrocarbon saturation reaches only 20.01 per cent at best, in the deepest and cleanest interval at PakCan-01, and falls to 1.50 per cent in the shallower PakCan-01 sand. Because Archie's equation was applied in shaly rock, these hydrocarbon saturations are upper bounds. The intervals are therefore marginal reservoir rock in which clay content, not burial depth, is the principal control on producible porosity.
3. Seismic inversion analysis targeted at estimating the inverted acoustic impedance (Z_p) of the identified reservoir zones. This objective was met at the level of the inversion and only partly at the level of the interpretation. Model-based post-stack inversion of the two sub-parallel strike lines SPC-86-9007 and SPC-86-9019, validated by well-tie correlations of approximately 0.99, produced absolute P-impedance sections carrying laterally continuous low-impedance zones that appear at the same stratigraphic level on both profiles and coincide with the mapped closures. Given the measured saturations, those zones are attributed to lower clay content and higher porosity rather than to hydrocarbon fill, and brine-filled porous sand, thin-bed tuning and the low-frequency model remain viable alternative explanations.

4. Rock physics analysis of the reservoir to derive elastic properties and establish a quantitative reservoir model linking well-log observations with seismic inversion results. This objective was met in part. V_p/V_s was crossplotted against P-impedance, bulk density and S-impedance and colour-coded by computed gamma ray, and the resulting litho-fluid template, guided by the unconsolidated sandstone rock physics model, separates shale from sand consistently. It does not separate the fluids, and the analysis established why: water saturation is high in every interval, so there is almost no fluid contrast to detect; clay content dominates the elastic response; shear velocity is recorded in one well only; and the poorly consolidated sands respond principally through the grain frame. The link between logs and inversion is therefore lithological and quantitative, and fluid-related only as an inference.

Taken together, the study delivers a reliable structural and lithological description of the interval and an honest account of the limits of fluid prediction from post-stack data in a shale-rich section with sparse well control. Its principal contribution is not a prospect but a calibration: it establishes what the seismic response of this section means in terms of rock properties, and it identifies pre-stack acquisition, a shaly-sand saturation model calibrated by core, shear velocity control in more than one well, and 3D coverage as the specific improvements that would allow the fluid question to be answered.

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