HYDROCARBON EXPLORATION RISK MITIGATION THROUGH MAPPING PETROLEUM MIGRATION PATHWAYS USING SEISMIC AND GEOCHEMISTRY DATA, PUNJAB PLATFORM, PAKISTAN

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APPROVAL FOR EXAMINATION

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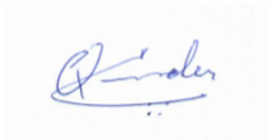

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Dedication

To my parents, whose love and sacrifices have shaped me into the person I am today. Your unwavering support and guidance have been my greatest motivation.

To my wife, whose patience and encouragement have been my strength throughout this journey. Thank you for standing by me and believing in my dreams.

To my children, who inspire me daily with your curiosity and joy. This work is for you, as a reminder to always pursue your passions with courage.

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Finally, my heartfelt appreciation goes to my family. To my parents, thank you for your unconditional love and belief in me. To my wife, your unwavering support and understanding have made all the difference. And to my children, your joy and laughter are my greatest motivation.

Thank you all for being part of this journey.

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ABSTRACT

The Punjab Platform in Pakistan's Central Indus sub-basin faces challenges in unlocking significant hydrocarbon reserves due to variability in source rock properties and uncertainty in mapping hydrocarbon migration pathways. In this study, seismic and geochemistry data were utilized for source rock characterization and hydrocarbon migration pathways mapping. Geochemistry techniques involving rock eval pyrolysis, organic petrography and basin modeling were performed for source rock evaluation and mapping of hydrocarbon migration pathways. The kerogen type was determined by using the Van Krevelen diagram (modified) and the hydrogen index (HI) versus oxygen index (OI) plot determines that the Cretaceous age (Chichali Formation) in Bahu-01, Nandpur-01, and Zakria-01 wells has kerogen type III. Total organic content (TOC, wt.%) is measured using two unique approaches: direct laboratory analysis based on core data of 34 samples by organic geochemistry and an indirect technique employing stochastic post-stack seismic inversion on 2D seismic data. Both techniques yielded TOC values, indicating fair to good source rock richness. Maturity estimation from organic petrography and seismic inversion reveals that the Bahu-01, Panjpir-01, and Nandpur-01 wells have average TOC values below 0.50, indicating immature source rock. However, the average TOC value for the Zakria-01 well is 0.63, confirming maturity and putting it in the oil window, with peak generation occurring during the Eocene age. 2D basin modeling results shows the Chichali Formation in the Sulaiman Foredeep area has a (%Ro) range of 1 to 1.5, representing source rock maturity in the late oil to wet gas window. In most western parts (Sulaiman Fold Belt), the %Ro ranges from 1 to 1.3, representing source rock maturity in the wet gas window. However, the eastern side (Punjab Platform), where three producing fields were present, shows the (%Ro) ranges from 0.4 to 0.48%. The 3D hydrocarbon generation map in Sulaiman Foredeep reveals that the entrance to the early oil window occurs between 65 and 50 Ma, with the main oil window occurring from 65 to 35 Ma. The central part of the study area enters the main all window between 50 and 25 Ma, with early oil windows between 15 to 20 Ma, and late oil windows between 10 Ma. The eastern part remained barren and did not contribute to the hydrocarbon's bulk generation potential. The study introduces novel lateral long path migration pathways in a region using an integrated approach including source rock richness, maturity, ID, 2D basin modeling and 3D hydrocarbon charge modeling. The DHI's confirms the presence of hydrocarbon particularity gas and authenticates our work about the establishment of

migration pathways. It has addressed a previously unresolved issue and is contributing to successful hydrocarbon exploration. It will also help in the mitigation of risks associated with hydrocarbon exploration in other basins worldwide.

Keywords: Punjab Platform, Organic Richness, Thermal Maturity, Seismic Interpretation, Seismic Inversion, Basin Modeling, 3D Petroleum System Modeling and Pakistan

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LIST OF ABBREVIATIONS

%Ro	-	Vitrinite reflectance
1D	-	One dimensional
2D	-	Two dimensional
3D	-	Three dimensional
CIB	-	Central Indus Basin
DHI	-	Direct Hydrocarbon Indicator
DT	-	Sonic log
GR	-	Gamma Ray log
HF	-	Heat flow
HI	-	Hydrogen Index
Km	-	Kilometers
LIB	-	Lower Indus Basin
Ma	-	Million year
MD	-	Milli Darcy
msec	-	Milli second
OGDCL	-	Oil and Gas Development Company Limited
OI	-	Oxygen Index
ONGC	-	The Indian Oil and Natural Gas Corporation
PSI	-	Pound-force per square inch

PWD	-	Paleo water depth
Rm%	-	Random vitrinite reflectance
S_1	-	Free hydrocarbon
S_2	-	Generatable potential
S_3	-	CO_2 yield during thermal breakdown
Sw	-	Water saturation
SWIT	-	Surface water interface temperature
SWP	-	Static water pressure
T_{max}	-	Temperature maximum
TOC	-	Total organic carbon
UIB	-	Upper Indus Basin
V	-	Velocity through the medium
Z	-	Acoustic impedance

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CHAPTER 1

INTRODUCTION

1.1 Rationale

The persistent volatility of the global energy market, combined with growing consumption, has resulted in a large growth in the worldwide demand for oil and gas. The global demand for energy is anticipated to climb at a pace of 41% between 2012 and 2035 (International Energy Agency., 2025). Pakistan's energy industry is substantially dependent on imported fuel (oil and LNG) and will continue to do so for the next 10-15 years (Energy Resource Guide, 2025). Approximately 16–17 million metric tons of oil are consumed in Pakistan each year. This demand is only met by 20–25% of local oil production. The daily gas usage in Pakistan is approximately 4 billion cubic feet. About 80% of this need is satisfied locally. Meeting the gap between production and demand necessitates vigorous exploratory operations (Latief & Lefen, 2019). For undertaking aggressive hydrocarbon exploration, it is vital to comprehend the economic relevance of the petroleum system (Burchette et al.,2025). The petroleum system comprises the collection, conversion and movement of hydrocarbons into a reservoir from source rock over sufficient geologic time. These processes happened under sufficient burial depth and temperature-pressure conditions. Now, inside the petroleum system, source rock assessment constitutes a vital phase that necessitates precise attention. Source rock maturity and the occurrence of hydrocarbon migration, especially secondary migration is significant for exploration companies for maturation/drilling of a prospect in a given location. Secondary migration occurs inside the reservoir rock, which depends upon the porosity of carrier beds. The movement of hydrocarbons is also dependent on the structural configuration. The continuity of reservoir rock and underlying seal rock is also critical for the hydrocarbon movement (Heggland et al.,1997).

Seismic interpretation is very important step in finding hydrocarbon in structural or stratigraphic traps (Zhang et al.,2025). Seismic interpretation involves the marking of prominent formations and faults on the seismic and generate the time and depth structure maps (Shazia et al.,2015). The depth structure maps reflect the subsurface topography and based on depth maps hydrocarbon structural trap can be identified. Seismic interpretation and mapping on regional level is crucial of tracking hydrocarbon migration pathways based on source, reservoir and seal structural configuration. Also, the faults based on seismic interpretation and mapping help in understanding the behavior of faults during hydrocarbon migration (Barecca et al.,2025).

Also, is very important to identify the source rock kitchen area before mapping the hydrocarbon migration pathways. The evaluation of source rock potential comprises the elucidation of organic richness, kerogen type, and thermal maturation (Cappuccio et al., 2021; Ehsan et al., 2024). The complications related to the source rock assessment may be overcome by an integrated approach employing several approaches, including organic geochemistry, petrography and basin modeling. Xiao et al. (2024) analyzed the organic richness by applying an organic geochemistry technique. The diversity of source rock properties has been addressed in the Punjab Platform, which is situated in the Middle Indus sub-basin, Pakistan. Despite intense exploration activity, this region has only discovered limited hydrocarbon resources.

Thirty exploratory wells have gone dry in the region. Only three fields (Bahu, Panjpir and Nandpur) are producing gas. The petroleum system in this location predominantly comprises shales of the Cretaceous Chichali Formation as a potential source rock. Uncertainties related to source rock richness and maturation are the main hindrances for substantial hydrocarbon exploration which could add sizeable reserves. In the past, several authors, including (Gakkhar et al., 2011; Nazeer et al., 2018; Shah et al., 2021), evaluated the source rock potential (TOC) by using Pyrolysis and biomarker techniques. It restricted them from completely evaluate the source rock potential for enhanced hydrocarbon exploration especially the in western part of Punjab Platform, where limited data is available.

TOC may be determined via the seismic inversion approach (Atarita et al., 2017). To avoid data restriction in the western portion of the research region, seismic inversion methods are employed for the assessment and mapping of shales of the Chichali Formation. For the Chichali Formation, total organic carbon (TOC, wt.%) content was estimated via lab analysis utilizing core data obtained from seismic inversion by the use of the stochastic seismic inversion method on post-stack seismic data. Mahmood et al. (2018) also calculated TOC from seismic amplitude response in the Lower Indus Sub Basin, Pakistan. Ali et al. (2023) demonstrated the approach to create correlations between different rock properties and rock physics models by simple cross-plotting.

Besides seismic, well logs are very useful for calculating TOC in potential source rocks. It is possible to detect source rocks with wireline logs, which may also be utilized as an indicator of the potential of the source rocks. By correlating sonic logs with seismic data, it is possible to gain a better understanding of the lithology, structure, and stratigraphy of the subsurface (Ali et al., 2023). Ullah et al. (2023) examined the distribution of minerals and their thermal properties. The natural radiation emitted from the minerals within the geological formations is quite beneficial in detecting the lithological variations through the Gamma Ray (GR) log (Ali et al., 2024). Also, organic petrography is considered one of the most reliable and precise techniques for assessing source rock maturity (Wilkins et al., 2018). Source rock thermal maturity in terms of vitrinite reflectance (%Ro) can be calculated from core samples (Hakimi et al., 2023). The maturity and timing of source maturation can be calculated from the 1D basin modeling, it involves the construction of burial history and source rock maturation levels. This method considers several parameters, including hydrogen index (HI), oxygen index (OI), temperature maximum (T_{max}), TOC, heat flow (HF), paleo water depth (PWD), surface water interface temperature (SWIT), formation depth and formation thickness to calculate modeled %Ro (Cheng et al., 2024).

The explorationists' primary obstacle in locating substantial resources is the variation in source rock richness and maturation. Mousa et al. (2024) assessed the hydrocarbon potential through seismic and geochemical analysis in the northwestern desert, Egypt. Liu et al. (2024) used geochemical methods for the hydrocarbon generation that remained an unexplored potential. To assess the hydrocarbon potential in the Punjab Platform, it is necessary to understand the source rock variation in terms of organic richness, maturity, and timing of hydrocarbon expulsion. In the past, several authors, namely, (Shah et al., 2024; Nazeer et al., 2018; Gakkhar et al., 2011) highlighted the questions related to source immaturity and establishment of a path for the hydrocarbon migration. So far, no one has mapped these hydrocarbon migration pathways from the possible source kitchen area to the trap with the help of seismic and geochemical data.

To address this challenge, comprehensive research has been carried out. Source rock evaluation of shales of Chichali Formation and migration pathways have been established by using different techniques such as seismic inversion, rock eval pyrolysis, organic petrography, basin modeling and 3D hydrocarbon charge modelling. Cretaceous age Chichali formation was evaluated in terms of source rock richness, type of kerogen and maturity. 1D and 2D basin modelling was carried out for source rock maturity and its timing of expulsion. 3D hydrocarbon migration modeling was carried out for mapping hydrocarbon migration pathways. The reservoir rock Lumshiwal Formation and seal rock Ranikot Formation were mapped on whole are by suing 2D seismic data interpretation and mapping.

Literature review of source rock evaluation, 1D, 2D basin modelling and 3D hydrocarbon charge modeling was discussed in Chapter 2. The details about the methodology of the different techniques used in this research were discussed in Chapter 3. The results regarding the application of techniques for the source rock evaluation and mapping hydrocarbon migration pathways were discussed in Chapter 4. The conclusion and discussion of the research work were discussed in Chapter 5. This work is novel in terms of mapping of hydrocarbon migration pathways which were never mapped before. Mapping of Hydrocarbon migration pathways will help the exploration companies to add sizeable reserves in the near future.

1.2 Introduction to the Research Area

The Punjab Platform, located in the Middle Indus Basin, is a westward dipping monocline with alluvium cover. The Middle Indus Basin has three main structural elements: Sulaiman Depression, the Sulaiman Fold Belt, and Punjab Platform (Aadil and Sohail, 2011). Tectonically, the Punjab Platform is the least affected area of the Indus Basin, sloping gently towards the Sulaiman Depression (Shazia et al.,2015). The Punjab Platform is bounded by Mari High in the south and Sargodha High in the north. It merges into the Sulaiman Depression in the west and extends east into Bikaner Nagaur of India (Raza et al., 2008; Kadri 1995).

The area has its petroleum system established within the Cretaceous and Infra-Cambrian rocks. The Cretaceous age Chichali Formation is the potential source rock in the area. The Punjab Platform, which is adjacent to the Bikaner-Nagaur Basin in India (Fig. 1) has some sizeable reserves (Raza et al., 2008) which have yet to be explored. The Punjab Platform, a gradually descending monocline, has been the subject of drilling efforts since the 1960s, resulting in a low success rate. So far thirty wells have been drilled on the Punjab Platform. This area also has only three gas discoveries at Bahu, Panjpir and Nandpur gas fields (Shah, 2023). The Possible source rock of the Cretaceous age Chichali Formation is buried in the western part of the Punjab Platform. The reservoir rocks range from Cretaceous to Cambrian and Infra-Cambrian. The Lumshiwal Formation of Cretaceous age is producing in Bahu, Panjpir and Nandpur fields, located in the Punjab Platform.

In the past, several authors, including (Gakkhar et al., 2011; Nazeer et al., 2018; Shah et al., 2021), evaluated the source rock potential (TOC) by using Pyrolysis and biomarker techniques. Seismic interpretation and attribute analysis of cretaceous sand in Indus Basin, Pakistan was carried by (Tayyab et al., 2017). Stratigraphic trap identification of Palaeocene and cretaceous age formation was carried by (Shazia et al., 2015) in Punjab Platform and Sulaiman Foredeep area. Detailed seismic interpretation and mapping of area was carried by (Shazia et al., 2015). Comprehensive study on the hydrocarbon prospectivity of the Punjab Platform in Pakistan was undertaken by Raza et al. (2008).

1.3 Significance of Study

Hydrocarbon exploration is a need of today as current reserves are depleting. Countries like Pakistan already have a large imbalance between oil and gas production and consumption. The persistent volatility of the global energy market, combined with growing consumption, has resulted in a large growth in the worldwide demand for oil and gas (Zhu et al., 2025). The demand for energy is anticipated to climb at a pace of 41% between 2012 and 2035 (Sohail et al., 2024). Meeting the gap between production and demand necessitates vigorous exploratory operations (Latief & Lefen, 2019). Pakistan is now confronting the tremendous energy crisis that has a direct and indirect influence on all sectors of the economy. This situation was aggravated by an increase in Pakistan's electricity-producing capacity. Pakistan's energy supply is obtained from a variety of sources, comprising gas, oil, liquefied natural gas (LNG), coal, nuclear, biomass and renewable energy sources (solar, wind, and hydro). Pakistan's energy industry is substantially dependent on imported fuel (oil and LNG) and will continue to do so for the next 10-15 years (Energy Resource Guide, 2025). To meet the gap between production and consumption, aggressive exploration activities are re

quired. Hydrocarbon exploration is very risky business, as there are so many elements of the petroleum system that exist. The existence of all elements of the petroleum system is necessary for the successful drilling of hydrocarbons in the area. Source rock maturation and the occurrence of hydrocarbon migration are also important tasks for exploration companies for the maturation/drilling of prospects in certain areas.

Hydrocarbon migration takes place in the reservoir beds, which act as carrier beds for the hydrocarbon migration. The structural arrangement of the interface with the overlying seal controls the migration path; the continuity of the carrier beds and the overlying seal governs this process. Extensive exploration efforts have been done by drilling a number of exploratory wells. Most of the wells went dry except for three gas-producing fields (Bahu, Panjpir and Nandpur). Major structures besides valid traps have failed to produce hydrocarbons. So far, no one has mapped these migration pathways in the Punjab Platform. This study was designed to identify hydrocarbons in the kitchen area and hydrocarbon migration pathways using seismic and geochemistry data. It will help in de-risking the future exploration activities in the study area (Punjab Platform), which will help in tapping hydrocarbon reserves and save Pakistan a significant amount of money that it currently spends on the import of LPG and petroleum products. Besides this, an integrated approach will also provide valuable insights for hydrocarbon exploration in numerous other basins worldwide.

1.4 Research Questions

The Punjab Platform, located in the Middle Indus Basin. The Cretaceous age Chichali Formation is the potential source rock in the area. Extensive exploration efforts in the form of drilling exploratory wells have been done in the area. Among the drilled wells, thirty wells have gone dry in the Punjab Platform. Only three fields Bahu, Panjpir and Nandpur are producing gas. Major structures besides valid traps have failed to produce hydrocarbons. Previous studies highlighted that the source rock is immature at producing fields. Variability in source rock characteristics is big hurdle in the Punjab Platform for unlocking substantial hydrocarbon reserves. The petroleum system in Punjab Platform includes of Cretaceous Chichali Formation as source rock. Lumshiwal formation of early cretaceous age is a proven reservoir in Punjab Platform. Identification of source rock kitchen area and hydrocarbon migration from source kitchen to trap is huge hurdle in unlocking the reserves. So far, no one has mapped these migration pathways in the Punjab Platform. The aim of the study is to mitigate the exploration risks in the area by mapping the source rock mature zone and establishing hydrocarbon migration pathways from the source rock to structural traps in the Punjab Platform Area, which ultimately results in tapping more hydrocarbon reserves in this area, which will benefit the country to manage energy needs from the Punjab Platform.

1.5 Problem Statement

The study area, Punjab Platform, lies in the eastern margin of the Indian Plate. It is a westward descending monocline. Since 1960, a number of exploratory wells have been drilled in the region (Ahmed et al., 1998). Despite aggressive hydrocarbon exploration, just three gas fields were discovered. The source rock is locally immature in the area. The biggest question is how the three field namely Bahu, Panjpir and Nandpur were charged with hydrocarbon. Also, the routes of hydrocarbon charging are never mapped. Despite the valid structural traps in the region, the biggest risk is mapping the source rock kitchen area and establishing hydrocarbon migration pathways and planning future exploration efforts. The following are the key problems present in study area that are addressed in the research:

1. To evaluation of source rock in terms of organic richness, kerogen type and its maturity.
2. To mapping of the source rock kitchen area.
3. To separate the source rock mature area from the source immature area. Also, map the boundaries between the source mature and immature rock.
4. To identify reservoir seal pair based on well log data. Mapping of reservoir and seal rock in entire area on seismic data.
5. To Validate migration pathways and generation of migration pathway vectors-based map.
6. To establish hydrocarbon migration pathway model need to understand how the three field namely Bahu, Panjpir and Nandpur were charged with hydrocarbon.

1.6 Objectives

The aim of this research is to map the source rock kitchen area and identify the migration pathways from kitchen to trap by using seismic and geochemistry data.

Following objectives have been achieved in this research.

1. To Identification of the source rock kitchen area by using 1D basin modeling and mapping the boundaries of source maturity in terms, of the upper boundary of the oil and gas maturation windows.
2. To Map the of beds and generation of subsurface map through interpretation of seismic data sets.
3. To Validate of migration paths through seismic interpretation, seismic attribute analysis, geochemistry data analysis and identification of Direct Hydrocarbon Indicators (DHI's).
4. To develop/construct the model of migration pathway vectors based on all above information. This hydrocarbon migration pathway map helped in understanding

migration pathways directions in the study area which will mitigate exploration risk in future exploration activities.

1.7 Available Data

To assess the source rock potential of shales of Chichali Formation and mapping of migration pathways x,y and z dataset were analyzed. A detailed study was conducted that involving the interpretation of 2D seismic data covering 765 line kilometers across the entire study area (Figure 1.1). The acquisition parameter of 2D seismic utilized for this study has a source and receiver interval of 50 m. The fold of the 2D seismic data is 100.The 2D seismic data has zero phase. American polarity with positive amplitude were represented at peak was used. The quality of the seismic data in the region varied from fair to good. Data from six wells, namely Bahu-01, Panjpir-01, Nandpur-01, Zakria-01, Dhodhak-01, and Zindapir-01, were utilized from this study.

Table 1.1 List of 2D seismic data used in current research. Major of 2D seismic lines have fair to good data quality.

2D Seismic lines	2D Seismic lines
O/805-SK-22	O/857-KBR-111
O/805-SK-26	O/857-KBR-112
O/835-LEA-102	O/2006-MNN-05
O/835-LEA-104	O/20152-FTP-08
O/835-LEA-106	O/20152-FTP-20
O/836-LEA-01	O/20152-FTP-23
O/836-KBR-01	O/20152-LDN-11
O/836-LEA-02	O/20152-LDN-21
O/836-LEA-04	O/20152-LDN-22
O/836-LEA-06	O/20153-LAY-24
O/836-LEA-07	O/20153-LAY-25
O/845-KBR-38	A/W15-BF
O/845-KBR-43	LMT 95-15
O/846-KBR-10	LMT 95-17
O/846-KBR-20	LMT 95-19

Table 1.2 List of well data used in current research. Check shot/VSP, digital las file and well tops were used.

Well Name	Logs	Vertical Seismic Profiling(VSP)/Checkshot Data
Panjpir-01	Gamma, Sonic, Density and Resistivity	VSP/Checkshot
Bahu-01	Gamma, Sonic, Density and Resistivity	VSP/Checkshot
Zakria-01	Gamma, Sonic, Density and Resistivity	VSP/Checkshot
Zindapir-01	Gamma, Sonic, Density and Resistivity	VSP/Checkshot
Nandpur-01	Gamma, Sonic, Density and Resistivity	Nil
Dhodhak Deep-01	Gamma, Sonic, Density and Resistivity	VSP/Checkshot

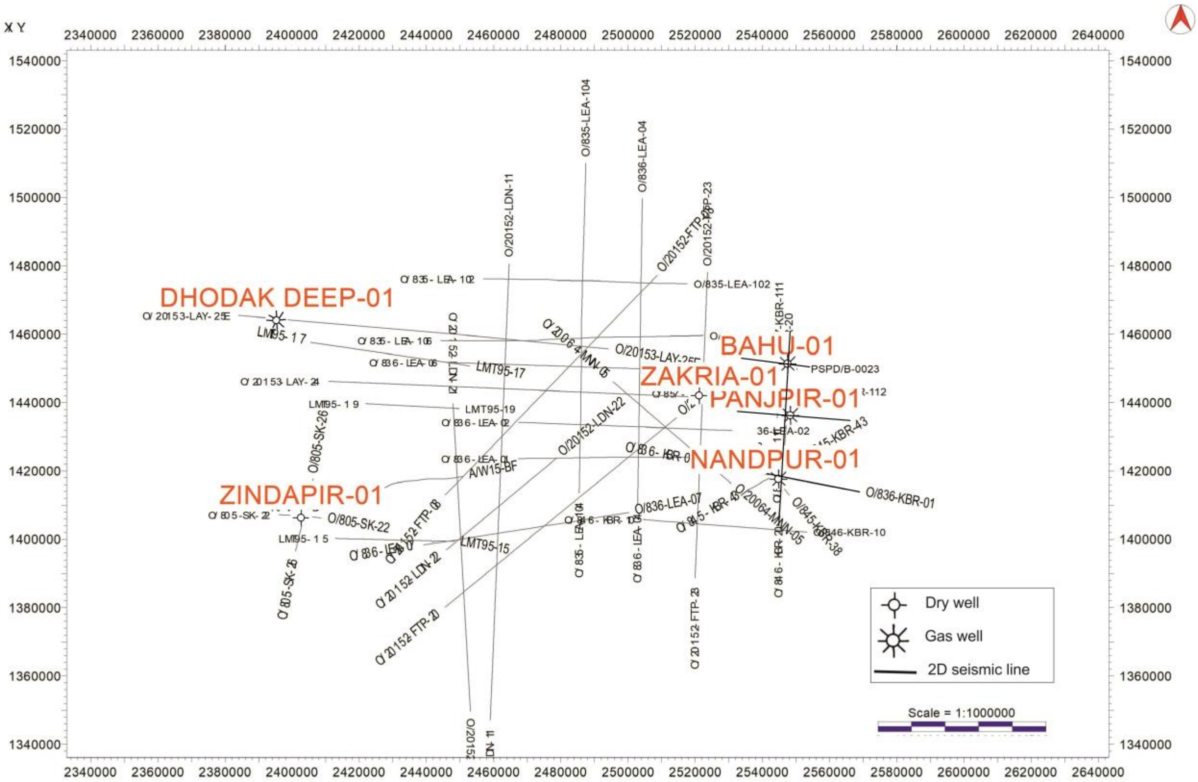

Figure 1.1 Base Map showing the 2D seismic data and wells used for this study. Total of 765-line kilometers 2D seismic data and six well data were utilized to evaluate the source rock potential of Chichali source rock.

1.8 Thesis Outline

This research adopted a comprehensive approach for evaluating the source rock potential of the shales of the Chichali Formation and hydrocarbon migration pathways using the seismic, well and core data. A detailed workflow was adopted for the achievement of below mention objectives (Figure 1.2).

1. Identification of source rock kitchen area by using geochemistry and seismic data.
2. Source rock organic type evaluation using Van Krevelen diagram (modified) graphs.
3. Source rock maturity modeling using ID basin modeling and rock pyrolysis analysis from core data.
4. 2D basin modeling for source rock maturity evaluation.
5. Mis-tie analysis using 2D seismic data and removal of mis-ties from different 2D seismic vintage data set.
6. Forward modeling by generation of synthetic seismogram.
7. 2D seismic interpretation and mapping of carrier bed from source kitchen area to traps.
8. Faults interpretation.
9. 3D petroleum system modeling to established hydrocarbon migration pathways.
10. DHI's identification for the validation of hydrocarbon migration pathways.

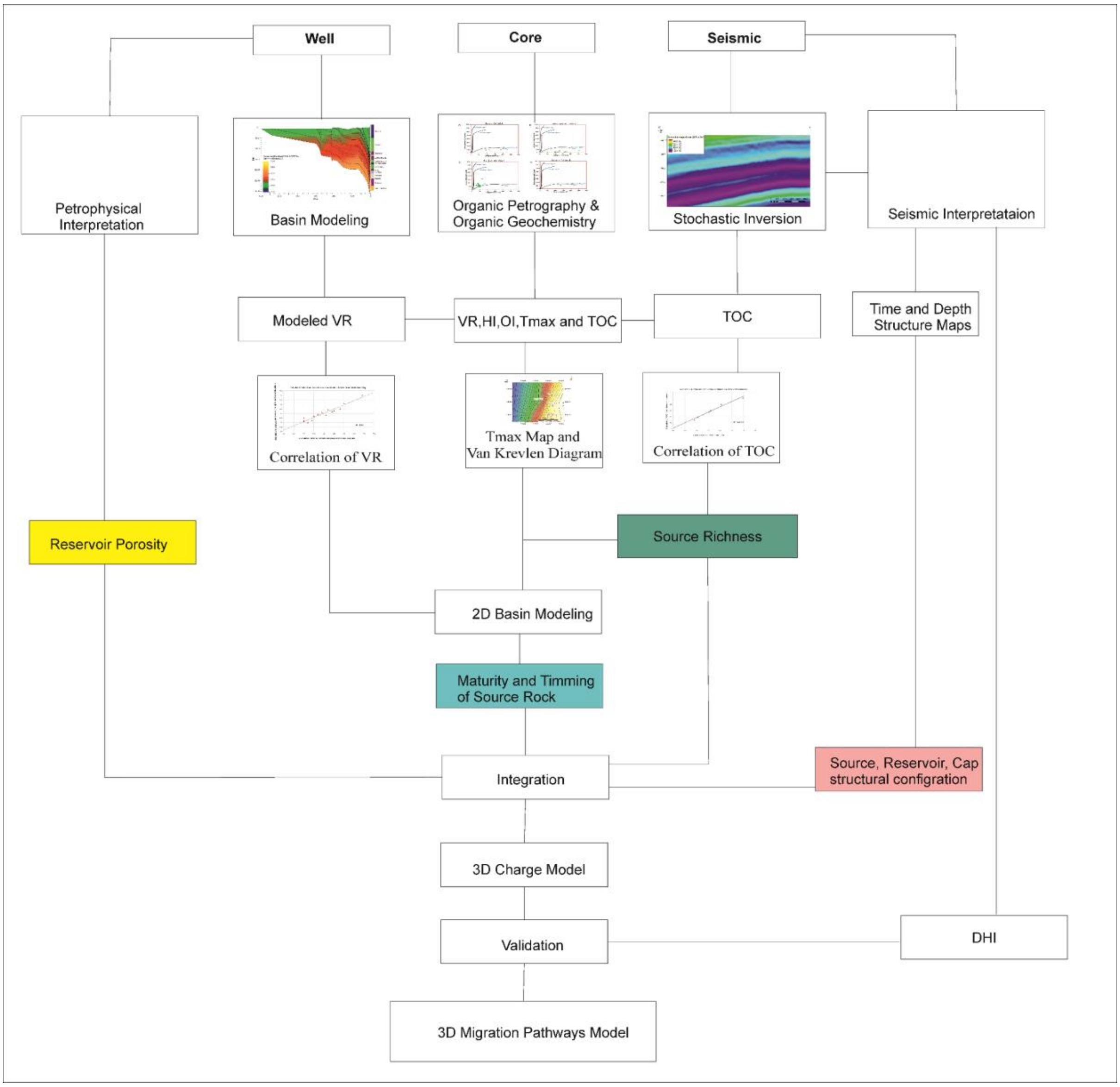

Figure 1.2 Flow chart showing a comprehensive methodological workflow adopted approach. Source rock was evaluated in terms of organic richness, maturity and timing of maturation. Post-stack seismic inversion and organic geochemistry were used for the calculation of TOC. Source rock maturity was calculated from petrography and basin modeling techniques.2D basin Modeling was carried for source rock maturity. Seismic data was incorporated in 3D charge model. Migration pathways were validated by identifying DHI's on seismic data. Finally, 3D migration pathways model was generated, which shows the hydrocarbon migration pathways from source kitchen area to traps.

CHAPTER 2

LITERATURE REVIEW

This chapter comprises of literature review regarding the energy crises in Pakistan, Tectonics and stratigraphy of area, different techniques used for source rock evaluation and mapping of hydrocarbon migration pathways. The different techniques and work done by authors across the globe were also discussed in this chapter. Work related to source rock maturity, 1D, 2D basin modeling, 3D hydrocarbon charge modeling and DHI's analysis were also discussed. However, the detailed workflows, methodology and techniques were discussed in Chapter 3. The results derived from the techniques and adopted methodology were discussed in Chapter 4.

Punjab Platform is part of the Central Indus sub-basin, Pakistan. It is located on the western slope of the Indian Shield. This region demonstrates structural stability in the form of a continuous monocline (Khalid et al., 2014). During the Late Proterozoic epoch, the Indian Plate, which was a component of the Gondwanaland supercontinent, witnessed considerable geological changes (Kemal et al., 1991). Apart from understanding tectonic evolution, petroleum system features are similarly vital for hydrocarbon exploration (Ehsan et al., 2023). The Punjab Platform, near the Bikaner Nagaur Basin in India, holds large deposits that remain undiscovered (Raza et al., 2008). Pakistan is a facing crucial energy crisis. The consumption of petroleum products (energy products) in Pakistan is 19.68 million tonnes/annum against the supply of 11.59 million tonnes per annum from local refineries, while rest of the 8.09 million tonne imported. Pakistan produces around four (4) Billion Cubic Feet Per Day (Bcfd) of indigenous natural gas against an unconstrained demand of over six (6) Bcfd (Pakistan Ministry of Finance energy chapter, 2024). The Outlook predicts a 41% increase in global energy consumption between 2012 and 2035, down from 55% in the previous 23 years, 52% in the previous 20, and 30% in the prior 10. The developing world is predicted to account for 95% of that demand increase (Salami et al., 2025).

Meeting the gap between production and consumption necessitates vigorous exploratory operations (Latief & Lefen, 2019). One of such approach requires carrying out aggressive hydrocarbon exploration which requires a clear-cut understanding of the petroleum system of the potential sedimentary basins (Burchette & Erle, 2024). For carrying out aggressive hydrocarbon exploration, it is vital to comprehend the economic importance of the petroleum system. The petroleum system comprises the collection, conversion and movement of hydrocarbons into a reservoir from source rock over sufficient geologic time. These processes occurred under sufficient burial depth and temperature-pressure conditions. Source rock evaluation is key element of petroleum system. The assessment of source rock potential comprises the elucidation of organic richness, kerogen type, and thermal maturation (Cappuccio et al., 2021; Ehsan et al., 2024).

Variability in source rock characteristics is big hurdle in the Punjab Platform for unlocking substantial hydrocarbon reserves (Shah et al., 2024). By using a variety of techniques, such as organic geochemistry, petrography, and basin modeling, an integrated approach may address the complications surrounding the source rock assessment. Xiao et al. (2024) used an organic geochemistry technique to assess the organic richness in the Southern Margin of the Qinling Orogenic Belt, China. The Punjab Platform, situated in Pakistan's Central Indus sub-basin, is where the variety in source rock properties is resolved. Despite vigorous exploration efforts, only a limited amount of hydrocarbon has been explored in the studied region. Interestingly, this area also has hydrocarbon exploration near the gas deposits of Bahu, Panjpir, and Nandpur (Shah et al., 2025). Chichali Formation, the potential source rock, is buried deep within the Punjab Platform's western region. The organic content of this shale is a key factor in determining its production and quality.

2.1 Source Rock Organic Richness

The petroleum system in Punjab Platform includes of Cretaceous Chichali Formation as probable source rock (Shah et al., 2024). Uncertainties connected to source rock richness and maturity are key hindrances for considerable hydrocarbon exploration which might add size-able reserves. In the past various writers including (Gakkhar et al., 2011; Nazeer et al., 2018; Shah et al., 2021) analyzed the source rock potential by applying TOC and biomarkers approach. Lack of well data hindered an adequate analysis of the source rock potential for improved hydrocarbon exploration specifically in western half of Punjab Platform. TOC may be determined via seismic inversion approach (Atarita et al., 2017). Regions with high TOC content frequently produce the greatest outcomes (Khalil Khan et al., 2022).

Organic material inside shale has unique density, radioactivity, and electrical resistivity properties that impact both seismic and wireline log responses (Zhu et al., 2011). Hence, seismic inversion may be employed accurately to estimate the organic richness in shale

(Broadhead et al., 2016; Ehsan et al., 2018; Tomski et al., 2022). Earth reflectivity was calculated from seismic data using deconvolution methods. For seismic inversion, seismic data was utilized as input and well data was employed as a control in the subsurface modeling technique (Bashir et al., 2024).

Importantly, (Khalid et al., 2019) revealed that in organic-rich intervals, there exists an inverse link between P-wave seismic velocities and TOC. TOC often demonstrates a linear connection with impedance values (Ouadfeul & Aliouane, 2016). Mahmood et al. (2018) additionally emphasized the real reliance of TOC on impedance data. In this research, seismic stochastic inversion on post-stack seismic data was used to determine the TOC. Seismic inversion includes the extraction of a suitable seismic wavelet (Bashir et al., 2021). Seismic inversion was conducted on shales of Chichali Formation source rock top and base seismic horizon units.

In addition to seismic, well logs are valuable tool for determining TOC levels in possible source rocks. Wireline logs may be used to identify source rocks and can also be used as a measure of the source rocks' potential (Mkono et al., 2025). The lithology, structure, and stratigraphy of the subsurface may be better understood by comparing seismic data with sonic logs (Ali et al., 2023). The distribution of minerals and their thermal characteristics were investigated by Ullah et al. (2023). Using the Gamma Ray (GR) log, the natural radiation released by the minerals in the geological formations is very helpful in identifying lithological differences (Ali et al., 2024).

Rock eval pyrolysis is esteemed as one of the most proficient geochemical methodologies for source rock assessment, particularly in identifying kerogen type (Espitalié et al., 1977; Behar et al., 2001). This method is widely used to evaluate the sort of organic matter in source rock, its generation capacity, and maturity level (El Diasty et al., 2022). In this investigation, 100 mg of each sample underwent rock eval measurements with the rock eval 6 apparatus. The investigation yielded findings for Free hydrocarbon (S_1), Generatable potential (S_2), CO2 yield during thermal breakdown (S_2) and T_{max} values (Peters and Cassa, 1994).

Researchers in diverse worldwide basins, such as Riqingwei, Nangu Sag (Sichuan Basin, China), Indus Basin (Pakistan), and Pletmos Sub-Basin (South Africa), have often adopted single approach for source rock assessment. Chen, (2024) used core data from wells to calculate TOC in Riqingwei Basin, Eastern China. Similarly, core samples from wells were utilized for evaluation of source rock in Naiman sag, Songliao Basin, Inner Monglia, Northeast China. For instance, Röth, (2023) employed organic geochemistry to examine source rock, stressing the computation of Total Organic Content (TOC wt.%) from core data as a very accurate approach for TOC evaluation. Shah and Ahmed, (2018) studied the source rock potential in Panjpir field, Punjab Platform Pakistan by employing TOC and rock eval pyrolysis analytical data. The investigation found that all source rock samples exhibit kerogen Type III and have poor source rock generation potential.

Ghakkar, (2011) has analyzed the geochemistry data and biomarker composition for the source rock potential of Cretaceous and Jurassic rocks in the Punjab Platform. Based on the rock eval pyrolysis data, it was proved that the organic matter Eocene strata is type III kerogen with a transition to type II. All samples are immature to marginally mature to expel the hydrocarbon. An average %Ro between 0.4, which is on the lower side. Nazeer, (2018) studied the possible origin of inert gases in the Sulaiman Foldbelt and Punjab Platform. According to the authors, exploratory wells dug in the research region contain various quantities of inert gases (mainly CO_2 and N_2). The Punjab Platform has a substantial amount of nitrogen. The authors found that inert gases are not igneous in origin and were most likely produced during hydrocarbon production, expulsion, and migration.

The author clarified that the mechanism of N_2 creation remained unknown due to a lack of isotopic evidence. The heterogeneous movement of hydrocarbons along the carrier beds most likely has an important effect on altering the composition of inert gases and may warrant additional examination. The presence of N_2 gases indicated that possible migration from the Sulaiman Foredeep to the Punjab Platform may have happened along carrier beds rather than deep-seated fault lines. But his study did not present any map/model or any clear evidence regarding the long path migration of hydrocarbons from the Sulaiman Foredeep to the Punjab Platform, and a study needs to be planned to map the hydrocarbon migration pathways.

A detailed study on the hydrocarbon prospectivity of the Punjab Platform in Pakistan was undertaken by Raza et al. (2008). It found that source rocks in the Nandpur and Panjpir areas are immature; however, the reservoir gases produced from the Panjpir and Nandpur fields are mature, as evidenced by carbon stable isotopic values. This investigation revealed either deep rooted source rocks in structural lows or long-distance migration of hydrocarbons across fault conduits happened. According to the previous studies done in the study area, source rock at producing fields like Bahu, Panjpir has poor source potential and is immature to expel hydrocarbon. All previous studies concluded that source rocks are immature in the Punjab Platform, but at the same time, the fields like Bahu, Panjpir and Nandpur are producing fields. Authors also emphasized the understanding of the petroleum system, especially the mapping of migration of hydrocarbons from the source area to traps.

2.2 Seismic Inversion for Calculation of TOC by Using 2D Seismic Data

The unavailability of core data often presents significant challenges to researchers. To circumvent these issues, seismic inversion techniques have proven invaluable in evaluating source rock richness. Regions with high TOC ranges from 1-2.5 (wt.%) content often yield the best results (Khalil Khan et al., 2022). Organic material within shale has specific density, radioactivity, and electrical resistivity characteristics that affect both seismic and wireline log responses (Zhu et al., 2011). Hence, seismic inversion can be used reliably to quantify the organic richness in shale (e.g., Atarita et al, 2017; Broadhead et al., 2016; Ehsan et al., 2018; Tomski et al., 2022).

The seismic inversion was planned to translate the seismic reflection amplitudes into porosity in the Southern Indus Basin (Mahmood et al., 2018). Importantly, Khalid et al. (2019) showed that in organic-rich intervals, there exists an inverse relationship between P-wave seismic velocities and TOC (wt.%). According to Ouadfeul and Aliouane (2016), TOC (wt.%) generally has a linear relationship with impedance values. Mahmood, (2018) also elaborated on the true dependency of TOC on impedance data.

2.3 Source Rock Kerogen Type and Maturity

Organic petrography is considered one of the most reliable and precise techniques for assessing source rock maturity (Wilkins et al., 2018). Also, %Ro values for core samples can be used to determine source rock thermal maturity (Hakimi et al., 2023). For this research, %Ro values for core samples were determined and utilized to estimate source rock thermal maturity (Hakimi et al., 2023). The age and time of source maturation were also determined using the 1D basin modeling, which incorporates the creation of burial history and source rock maturation levels. This technique analyzes numerous factors, including HI, OI, T_{max}, TOC, HF, PWD, SWIT, formation depth and formation thickness to determine predicted %Ro (Aziz et al., 2020).

Organic petrography is a better and more exact maturity assessment by calculating the vitrinite reflectance, which may offer more correct findings when the facies effects have an influence on the T_{max} (Sadeghtabaghi et al., 2021). %Ro is the most extensively utilized factor for source rock maturity estimation (Burnaz et al., 2023; Ola et al., 2018). Determining the date of maturity and knowing the burial history of source rocks is equally crucial in source rock appraisal (Dembicki Jr & Production, 2017). The 1D basin modeling approach acts as a strong tool for establishing the burial history and measuring the degrees of source rock maturation (Abdel wahhab et al., 2020). In research by (Yasin et al., 2021), the burial history and maturity of source rocks were examined using the 1D basin modeling technique (Elatrash et al., 2021).

2.4 1D Basin Modeling

Determining the timing of maturity and understanding the burial history of source rocks is equally vital in source rock evaluation (Dembicki and Production, 2017). The 1D basin modeling technique serves as a robust tool for constructing the burial history and assessing the levels of source rock maturation (Abdel wahhab et al., 2020). This method considers several parameters, including HI, OI, Tmax, TOC (wt.%), heat flow, PWD, surface water interface depth, and formation thickness to calculate modeled %Ro (Aziz et al., 2020).

Giunta, (2025) used 1D basin modeling approach for hydrocarbon generation and expulsion from Cretaceous kitchen of the Austral-Magallanes basin, Southern Patagonia. Ahmed, (2025) carried 1D basin modelling for Cretaceous Age source rock characterization in Southern Indus Basin, Pakistan. 1D basin modelling can also be used for the evaluation of thermal history and source rock evaluation. Edilbi, (2025) used this approach for Thermal History and Source Rock Maturity Modeling of the Akri-Bijeel Area, NW Zagros Fold Belt, Kurdistan Region, Northern Iraq.

Lathbl, (2024) used 1D basin modeling for the evaluation of hydrocarbon generation potential of Late Cretaceous Source Rock in North-western Tarankai Basin, Offshore, New Zealand. Babai, (2024) also evaluated the hydrocarbon generation and expulsion of Campanian Galhak shale, Rawat Central sub-basin, Sudan by using 1D basin modeling. In a study by Yasin et al. (2021), the burial history and maturity of source rocks were evaluated using the 1D basin modeling approach. Elatrash, (2021) calculated source rock maturation using %Ro values obtained from the EASY% Ro algorithm (Sweeney and Burnham, 1990).

2.5 2D Basin Modeling

2D basin modeling is widely used approach for the source rock evaluation and hydrocarbon migration pathways, especially to evaluate the maturity and timing of expulsion of hydrocarbon from the source rock. 2D basin modeling requires seismic, well, geochemistry and source rock data for the modeling of source rock evaluation. Several authors have utilized 2D basin modeling approach for the prediction of thermal maturity and migration model in the region. Zeng, (2025) performed 2D basin modeling was carried in rift basin (lacustrine) for the hydrocarbon distribution. Bandics, (2025) mapped the petroleum system in Hungarian Pannonian Basin by using 2D basin modeling.

Hydrocarbon generation and expulsion can be mapped through 2D basin modeling (Ghorbani et al., 2025). Petroleum system analysis was carried in Fujairah basin, eastern offshore of United Arab Emirates through 2D basin modeling (Abdelmaksoud et al., 2024). Hydrocarbon accumulation in Abu Zenima and October field in the Gulf of Suez, Egypt was carried through 2D basin modeling by (Tarshan et al., 2024).

According to (Abdul wahhab et al., 2023) petroleum system aspect, hydrocarbon migration is necessary for successful hydrocarbon exploration. He conducted 1D and 2D basin modeling for source maturity and expulsion in Abu Gharadig Basin (Western Desert, Egypt). Setyawan, (2023) conducted 2D basin modeling at tangguh field, Bintuni Basin, Papua for hydrocarbon charging model. Bartha, (2018) has done 2D basin modeling in Pannonian basin, situated in Central Europe to explore the tectono-stratigraphic model of the region and its influences on source rock maturity and maturation during historical time span.

2.6 Seismic interpretation and 3D Hydrocarbon Charge Modeling

Seismic interpretation plays a critical role in the exploration of hydrocarbons located within both structural and stratigraphic traps (Zhang et al.,2025). This process entails identifying significant geological formations and faults through the analysis of seismic data, subsequently creating time and depth structure maps. These depth structure maps are essential as they illustrate the subsurface topography, which aids in discerning the locations of hydrocarbon structural traps (Shazia et al.,2015). Furthermore, seismic interpretation and regional mapping are vital for tracking the migration pathways of hydrocarbons, taking into account the configurations of source rocks, reservoirs, and seals. The analysis of faults through seismic data contributes to a more profound understanding of their behaviour during the migration of hydrocarbons (Barecca et al.,2025), thereby enhancing the effectiveness of exploration efforts.

Seismic interpretation and attribute analysis of Cretaceous sands in the Indus Basin, Pakistan, were conducted by (Tayyab et al. 2017). Their work provided essential insights into the stratigraphic traps present in this region. Additionally, Shazia, (2015) undertook an extensive stratigraphic trap identification study focusing on formations from the Palaeocene and Cretaceous ages within the Punjab Platform and Sulaiman Foredeep areas. Their efforts included detailed seismic interpretation and mapping of these key geological formations, contributing to a better understanding of the subsurface geologic framework in these regions.

3D hydrocarbon charge modeling represents the most sophisticated and effective method for efficiently addressing elements of the petroleum system. Badics, (2025) carried basin modeling using 3D seismic data in Zala North Basin, Hungry for source rock and petroleum system modeling. Asvald, (2025) used 3D seismic data for the investigation of fluid migration and accumulation in Sorvestsnaget Basin, SW Barent Sea. Lee, (2025) used 3D seismic data for the mapping of structures that controls the migration pathways. Spacapan, (2025) carried 3D basin modeling in Asutral and Malvinas basin for mapping of 3D petroleum system. History, source rock evaluation and maturity of Permian Shanxi Formation, Southeastern Ordos Basin was carried by Chen, (2025). 3D geological analysis can be also used for the hydrocarbon maturation, migration and acculturation (Ahmed et al., 2024).

Castro Vera, (2024) performed D basin modelling of the hills syncline in Germany for the reconstruction of burial and thermal history and implications for petro physical properties for the Mesozoic shales. 3D basin and petroleum system modeling of early cretaceous play in NW Persian Gulf carried by (Shabani et al., 2023). Badejo, (2021) employed a 3D petroleum system model to identify undrilled Tertiary sandstone prospects on the western margin of the Central North Sea by basin modeling. Abubakar, (2020) employed a multidisciplinary strategy to identify hydrocarbon charge spots and migration within the Wessex Basin, southern England. Arfai, (2018) conducted 3D basin and petroleum system modeling of the NW German North Sea (Entenschnabel) to elucidate the thermal history, maturity, and petroleum generation of three prospective source rocks. Martinelli, (2013) conducted a 3D petroleum system basin model of northern Germany and surrounding regions, along with an extensive 3D modeling analysis of the Munsterland Basin to evaluate future production prospects by utilizing structural analysis. Barnard, (1991) addressed concerns surrounding hydrocarbon charging and vertical migration in tertiary reservoirs in Central and Northern Sear.

2.7 DHI’s

Petroleum system modeling includes of study of main parts of petroleum system including reservoir, source, seal, charge. Evaluation of these critical aspects leads in development to map the migration paths from source rock. Also, it is important to identify the sweet spots that can hold the hydrocarbon. DHI’s analysis is very helpful in identifying the sweet spots which indicates the presence of possible hydrocarbon presence. 2D and 3D seismic data can be used for the mapping of DHI’s. Integrated approach using well logs, geochemical data and seismic data is effective in identifying DHI’s.

Lee, (2025) carried DHI’s analysis for the mapping of hydrocarbon migration pathways in Ulleung Basin, East Sea. Multi attribute by using seismic data can be used in identifying the hydrocarbon presence in rock (Bashir et al., 2025). Integrated approach by using well logs, seismic data can also be used for identifying DHI’s, which could have led to the presence of possible hydrocarbon (Olutoki et al., 2025).

In the Indonesian oil field of Banyubang, Priyono (2024) exploited low frequency passive seismic as a direct hydrocarbon indicator. Handoyo, (2024) employed the DHI’s to analyze the carbonate reservoir potential in the Salawati Basin, West Papua. Dim spots, flat spot and polarity reversals are signals of hydrocarbon potential. Guo, (2024) utilized seismic spectral decomposition and seismic attributes for the identification of DHI’s in carbonate reservoir in Salawati Basin, West Papua for hydrocarbon presence. Ibekwe, (2024) performed seismic attributes and fault detection and DHI’s for enhanced hydrocarbon recovery in Tomboy field, western offshore, Nigera. Integrated surface geochemical and seismic can be used for hydrocarbon exploration (Priyono et al., 2024).

Abdel wahhab, (2023) undertook petroleum system study in western Egypt for the discovery of Sweet spots that potentially entrap hydrocarbons. Khawaja, (2023) exploited DHI’s to illustrate the occurrence and development of hydrocarbons in the Dujaila field in southeast Iraq. DHI’s to verify the existence of hydrocarbon presence and buildup in Dujaila field, SE of Iraq was employed by Khawaja et al., 2023. (Nanda, 2021) efficiently executed DHI’s analysis for hydrocarbon exploration and production. Rowi, (2020) employed DHI’s for prospect assessment and development. DHI’s and AVO were utilized for sweet spot identification in clastic reservoir in Pakistan (Ahmed et al., 2017). Foschi, (2014) highlighted those seismic indications, such as DHI’s may be connected to the presence of hydrocarbons and will assist in hydrocarbon migration modeling. It may also evaluate their habitat and pathways in relation to the basin's architecture.

2.8 Generalized Geology and Tectonic

Pakistan has an area of 827,000 km^2 and consists of three sedimentary basins: The Indus Basin, Baluchistan Basin and the Pishin Basin. The Cretaceous and Paleocene epochs saw the amalgamation of the Indus and Baluchistan basins. As a result, the Chaman and Ornach Nal faults were also affected (Morton and Woods, 1993). Pishin Basin is the least discussed, but it is the third basin, also known as Khorasan, formed as a result of the collision of the Eurasian and Indian Plates (Siddiqui and Jadoon, 2013). The Indus Basin is a well-known basin in Pakistan, considered the country's largest, and it contains the oldest Precambrian formation (Malkani and mahmood, 2017). Formations and the rocks exposed in the Salt Range of the aforementioned basin are Precambrian to recent in age (Yaseen et al., 2021). Indian Plate movements caused the development of this basin. The Indus Basin covers a large area. Because of Kirana Hills and Nagar Parkar Ridge, the Indian Shield remained the primary control on Indus basin sedimentation until the Jurassic period. The Fold Belt regime is bounded by the Indian Plate boundary in the north and the Kohat Plateau in the southwest (Khan et al., 2023). The Sulaiman and Kirther Ranges are located on the western side. The basin is further divided into three parts: Upper, Middle and Lower Indus basin. Sargodha High separates the Upper Indus Basin from Central Indus Basin, whereas Jacobabad –Kandkot high separates the Middle and Lower Indus Basin (Kadri, 1995). Following are the three sub-basins of Indus basin.

(i) Lower Indus Basin

(ii) Middle Indus Basin

(iii) Upper Indus Basin

Lower Indus Basin

The Lower Indus Basin is located in Pakistan's Sindh region and is divided into four subdivisions: Kirthar Fore Deep, Kirthar Fold Belt, Lower Indus Platform, and Indus Offshore (Daud et al., 2011). It is mostly thought to be the product of inferred rift related crustal features, which formed beneath the sequences and sedimentary layers (Zaigham et al., 2000). The described extension is the outcome of Indo-Pakistan subcontinent divergence, which occurred in the early Paleozoic (Chatterjee et al., 2013). Magnetic anomaly trends aided in the development of distinguishing aspects of fossil rifts caused by horst and graben structures (Ramana et al., 2015). Horst blocks can be found in Mari Kandkhot, Lakhra highlands, and Jacobabad (Shah et al., 2024). Madagascar and Indo-Pakistan separation is regarded to be the primary reason for the genesis of these structures (Hasany et al., 2023). Transpression caused by the convergence of the Indian and Eurasian Plates resulted in inversion of transform styles (Ghazi et al., 2024). Crustal feature observation revealed a relationship between these features and the basement, and the occurrence of several seismic events indicated the activation of an individual unit three times (Ahmed et al., 2015).

Rift features cause normal faulting, which is the primary explanation for the formation of horst and basement features of the Indus basin (Khan et al., 2020). The Lower Indus sub-basin has a high potential for a favorable depositional environment in terms of structures, seals, reservoirs, and thermally matured source rocks for the hydrocarbon exploration (Ehsan et al., 2021). The depositional activities were controlled by the rifting phase. The Gondwanaland rifting in the Indian Plate is the dominant tectonic activity and is thought to be the primary regulating factor of sedimentation in the Lower Indus basin (Umar et al., 2025). These causes triggered the raising and tilting of the Indian Plate in the early Cretaceous period. During the Cretaceous time, the Indian separated from Madagascar as a result of rifting the normal faults generated in the Cretaceous time (Reeves et al., 2018). After the rifting phase, it moved away from Madagascar and passed through the hotspot (Scotese et al., 2025). It also uplifted the flood basalts, which then eroded away. Normal faults are observed on the north to northwest side. The feature in the fold belt, namely, the Bela-ophiolites was formed through gentle folding and carbonate deposition, and structural quiescence occurred throughout the Eocene period. In the later stage, the collision of the Indian and Eurasian plates resulted in Himalayan orogeny. The Himalayan impact resulted in sinistral transpression in the Sulaiman and Kirthar fold and thrust belt of Pakistan (Penyongsangan et al., 2023).

The Kirthar Fold Belt, which runs north-south, is tectonically and stratigraphically comparable to the Sulaiman Fold Belt. The play type has a high petroleum system potential and has a Cretaceous age reservoir in the Upper Goru Formation. It is also a good source of hydrocarbons because of the presence of shales of Goru and Sembar Formations. There are two forms of play in the Offshore Indus Basin. Eocene-Oligocene shales are regarded as suitable seal rocks, whereas the Miocene and Pliocene deltaic sequences include a good petroleum system (Kadri, 1995). Eocene prospective reservoirs include the Kirthar, Habib Rahi Limestone and the Pirkoh Formations (Khan et al., 2023). The major reservoir for Dhodak's oil and gas reserves is the sandstone of the Ranikot Formation. Based on the lab analysis of Jurassic age Chiltan Limestone (Takatu Limestone) is also promising in the area. The Rodho and Salsabil fields are producing from Chiltan Limestone (Iqbal et al., 2011). The Lower Goru and Lumshiwal Formations, which are predominantly deltaic or shallow marine depositional environments, have the potential for reservoirs. The Limestone of Ghazij Group, which dates to the Eocene, is also an important reservoir (Ahmed et al., 2015). The Pab Formation has thickness of up to 450 m, with sandstone having 25-30% porosity and limestone ranging from 2 to 8%. Reservoirs have permeability ranging from 1 to 5 mD, with Sui Main Limestone having the thickest deposits with 625 m thickness. Limestone of Habib-Rahi and Sui Limestone are the proven reservoirs (Siddiqui, 2004). The Pab Sandstone began producing gas from the Sui Gas Field reserves in 1999. Historically, data shows that from 1955 to 1984, several companies began digging 55 wells for exploration in the southern section of the Indus Basin, and they conducted a multifold seismic survey on 27 of the 55 wells. Even though the fact that these wells are highly productive, gas finds outnumber oil discoveries. Five major gas finds highlighted the region's petroleum potential. Qadri, (1986) identified and classified Mesozoic tilting fault blocks, Tertiary reef banks, draping and compressional anticlines as the primary indicators of hydrocarbons.

The Middle Indus Basin formed on the northern margin of the Indian Plate between the Late Jurassic and Early Cretaceous periods. The Indian Plate acted as a passive boundary, as evidenced by sedimentary records, remaining far from the west and near Afghanistan (Mahar et al., 2010). The basin was blocked when the Ghazij Formation was being deposited. From the northwestern side, a deltaic depositional system entered the basin. The Kirthar Formation deposition came to a stop during the Early Oligocene period. The western part of the basin exhibits deformation similar to the Himalayan orogeny. Around the K-T boundary, uplifting began, which is known as the Tertiary unconformity. The Ranikot Formation thickened away from highs. There were intermittent structural alterations on the northwest to western side. The shapes of the traps were finally adjusted. Secondary migration occurred, and the reservoir began to fill (Mahar et al., 2010).

In this basin, Miano is a major gas discovery. Miano field is a complex area with complicated tectonics that make understanding the structural framework difficult (Jadoon et al., 2020). The normal faulting in the Middle Indus basin continues throughout the Cretaceous time (Saif-Ur-Rehman et al., 2020). The basement highs continued to uplift because Jurassic and Paleocene strata were eroded from the crustal region and also in surrounding locations. The erosion of the delta resulted in the deposition of strata in the nearby region. The alluvium was deposited and has massive alluvium thickness with no outcrops rising above the ground. The Kirther Fold and Thrust Belt, which extends from north to northwest and south to southeast, has huge surface and subsurface anticlines and is made up of Mesozoic to Neogene sediments (Khan et al., 2024).

The Sulaiman lobe, which lies in the Middle Indus Basin, is considered an active fold belt, with transitional crust belonging to the oblique passive border of the Indian Plate (Jadoon et al., 1994; Jadoon and Khurshid, 1996). On the other hand, due to the Indian Plate's northward drift from Africa, structural highs may have formed as a result of Cretaceous and Cenozoic passive margin development along the Plate's southwestern edge (Chatterjee et al., 2024). From the Jurassic to the Late Cretaceous, the area now known as Khairpur High occupied a basinal position. The Early Cretaceous depocenter, due to rapid subsidence, was located east of the summit. Tectonics, either wrench or extensional, during the early Tertiary period resulted in uplift that formed structural highs and began the erosion of the Mughal Kot and Pab Formations, which date back to the Late Cretaceous (Smewing et al., 2024). Jacobabad-Khairpur High, with a north-south orientation, is considered a basement-induced structure that stops the Sindh Platform's dip towards the west (Krois et al., 1998).

The Sindh Platform, which is part of the Lower Indus Basin dips west of the Jacobabad-Basement High. The Jacobabad-Khairpur Highs separates the Sulaiman and Kachhi Foredeeps. Based on the Tertiary unconformity, it is evident that it remained active from the Mesozoic to the early Tertiary (Jadoon et al., 1998). The Khairpur High began its final development along the basin's northern and western borders during the Oligocene age and continued until the late Cenozoic (Malkani & Mahmood, 2016).

The Punjab Platform is a key geological feature, located in Pakistan's Middle Indus Basin. It is located on the western slope of the Indian Shield, this region exhibits structural stability in the form of a continuous monocline (Khalid et al., 2014). Geographically, it is bordered by the Sargodha High to the north, the Mari High to the south and the Sulaiman Depression to the west (Figure 2.1). Its eastern boundary extends to the Bikaner Nagaur Basin in India (Raza et al., 1989). Notably, the Punjab Platform gradually descends westward from the Indian Shield to the Mesozoic to Tertiary core of the Sulaiman Depression (Aadil & Sohail, 2011). During the Late Proterozoic era, the Indian Plate which was a part of the Gondwanaland Supercontinent underwent significant geological changes (Kemal et al., 1991). Rift-related faulting during this period had a discernible impact on the seismic profiles of the Bikaner Nagaur Basin in India (Biswas et al., 2024). In contrast, although the Punjab Platform does show normal faults, their displacement is relatively minor. The Precambrian basement in the study area is characterized by metavolcanics, metasediments, and granites. The overburden sedimentary sequence has undergone several cycles of sea level regression and transgression, resulting in age-specific unconformities. In the southern part of the study area, these strata were later folded to form anticlines with salt cores (Kadri, 1995).

The Infra-Cambrian deposits overly the Precambrian basement. The faults produced as a result of rifting show a noticeable throw on the 2D seismic sections in Bikaner-Nagaur Basin India. While in Punjab Platform the normal faults are present, they have a minimum throw (Raza et al., 2008). The plate tectonics brought about the phenomenon of rifting of Gondwanaland during the Permo-Triassic period, after a long-time gap of 250 million years (Wopfner et al., 2009). The seismic sections for both Bikaner-Nagaur Basin in India and the Punjab Platform provide the evidence for this tectonic effect of rifting. The second phase of rifting, in Bikaner-Nagaur Basin, produced a small shift in the Permo-Triassic succession in comparison with the underlying basement rocks. This rift event is not quite visible on the Punjab Platform because of the dragging effect in Infra-Cambrian strata (Raza et al., 2008). The Indian Plate separated from Africa and Madagascar in the Cretaceous age, and it resulted in rifting (Kazmi & Jan, 1997).

This effect is also visible along a system of normal faults as a shift in Cretaceous strata on seismic sections of the Punjab Platform. During the Early Companian time the Indian Plate initiated its drift towards north, whereby in Late Eocene it collided with Eurasian Plate in continent-continent collision. Consequently, after this collision the Indian Continental Plate subducted under Eurasian Continental Plate and this collision is still active along respective Plate margins (Hedley, 2001).

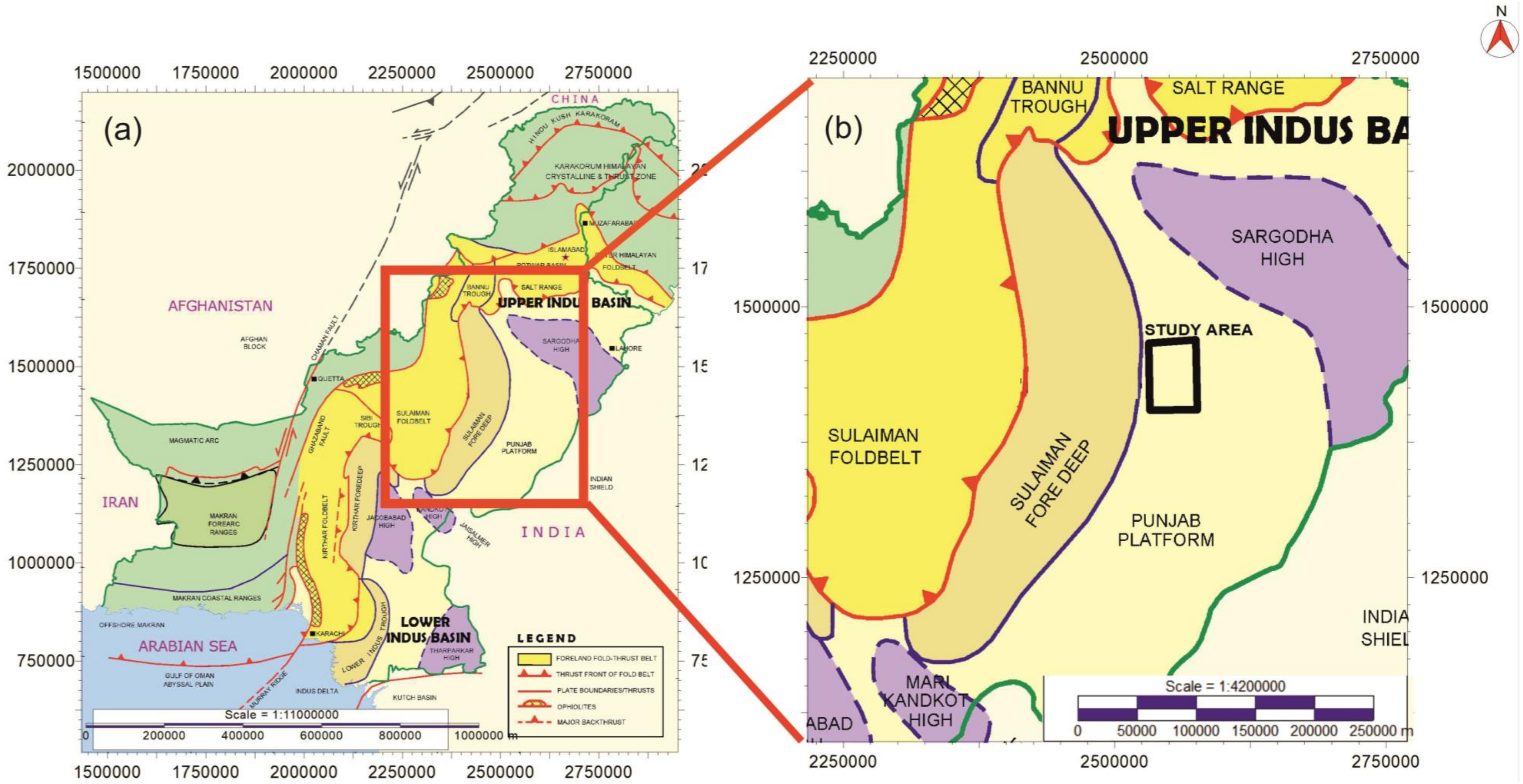

Figure 2.1 (a) Represents tectonic map shows major tectonic elements. Punjab Platform is part of Indus basin (Raza et al., 2008) (b) Black color box shows the location of study area which mainly lies in Punjab Platform, Pakistan. Study area is bounded by Sulaiman Foredeep in in west, Sargodha High in north and Mari Kandkot High in south

2.9 Generalized Stratigraphy and Petroleum System

2.9.1 Source Rock

The Chichli Formation, which is Cretaceous in age, is a potential source rock (Shah, 2023). Laterite, glauconitic sandstone, and carbonaceous green shale lithofacies were observed in the Chichali Formation, which indicates a depositional location in the middle to outer ramp (Hashmi, 2018). It is made up of glauconitic shale, which is characterized by a dark greenish gray hue. Organic matter is broadly categorized into two categories based on its origin: sapropelic and humic. The sapropelic is the result of the deposition of planktonic algae and herbal components in subaquatic (marine and lacustrine) environments under oxygen-restricted conditions (Hunt, 1979). Humic refers to the formation of peat, which is predominantly composed of land plants that are deposited in swamps in the presence of varying levels of oxygen (Zykova et al., 2018). Marine organic matter is abundant in amorphous material that contains hydrogen-rich organic components, whereas terrestrial organic matter is abundant in deciduous materials that contain oxygen-rich organic materials. The oxygen index (OI) value will be high in the case of humic organic matter and low in sapropelic matter as a result (Hashmi, 2018).

2.9.2 Reservoir Rocks

Lumshiwal formation of early cretaceous age is a proven reservoir in Punjab Platform (Shah, 2021). It is composed of cross-bedded sandstone and was formed in a marine coastal environment (Khan, 2024). An inter-tidal to inner ramp depositional context was evidenced by the presence of bioclastic sandy limestone, quartz arenite, and glauconitic sandstone lithofacies in the Lumshiwal Formation that covered it. The coarse-grained facies of the Chichali Formation contained cements such as calcite, hematite, smectite, ferroan dolomite, and glauconite, which decreased porosity. Grain fracture porosity, as well as dolomitization, intergranular, and dissolution porosity, increased porosity (Hashmi, 2018). Physical and chemical compaction, authigenic mineralization, cementation, and late-stage dissolution were all observed in the Lumshiwal Formation that covered it.

In the Lumshiwal Formation, calcite, ferroan dolomite, smectite, illite, and cements with quartz overgrowth are the most common cement types. The reservoir quality of the Lumshiwal Formation was enhanced by the primary intergranular porosity and secondary porosity caused by dolomitization and late-stage diagenetic dissolution. According to the sequence stratigraphic analysis, the Chichali Formation was deposited during the second order depositional cycle's transgression system tract (Hashmi, 2018). Enclosed by carbonaceous green shale associated with the maximum flooding surface, the Chichali Formation's transgression-related glauconitic sandstone facies serves as an excellent reservoir (Ali et al., 1995). The delta plain facies indicate the regressive 2nd order cycle in which the Lumshiwal Formation was deposited. Excellent reservoir potential can be found in the Lumshiwal Formation's quartz arenites (Hashmi, 2018).

The Infra-Cambrian oil sands from Baghewala-01 in Rajasthan, India, are an excellent example of reservoir rocks. High porosity sandstones and carbonates from the Infra-Cambrian are found in Marot-01 and Bahawalpur East-01. In the direction of the south in India, the Jodhpur Sandstone mark at Baghewala-01 is a reservoir formation with acceptable source possibilities in the Infra-Cambrian Salt Range Formation, behind which are layers of shale and dolomite, salt, and anhydrites. Following the finding in Baghewala, the search for hydrocarbons in the Punjab Platform has intensified. However, the source, seal, and reservoir under the salt layers were still be established. (Peters et al., 1995).

2.9.3 Seal Rock

The early Paleocene Ranikot deposit serves as Lumshiwal Reservoir's seal rock. Up to 60% of the Ranikot section is composed of clay, hence the unit of interest could be referred to as the Ranikot shale. The intercalations of mudstones and sandstones formed thin beds in the shoreface system where it was deposited. With organic-rich shales and organic-lean sandstones, the formation can be viewed as a hybrid unconventional petroleum system due to its lithology and source section characteristics (Makos et al., 2021).

2.9.4 Traps

Both structural and stratigraphic traps are present in the area. The structural Traps are related to normal faulting (Raza et al., 2008). The traps are fault bounded with faults having negligible throw. The stratigraphic traps are related to incised valley fills, and truncation of formations (Khalid et al., 2014).

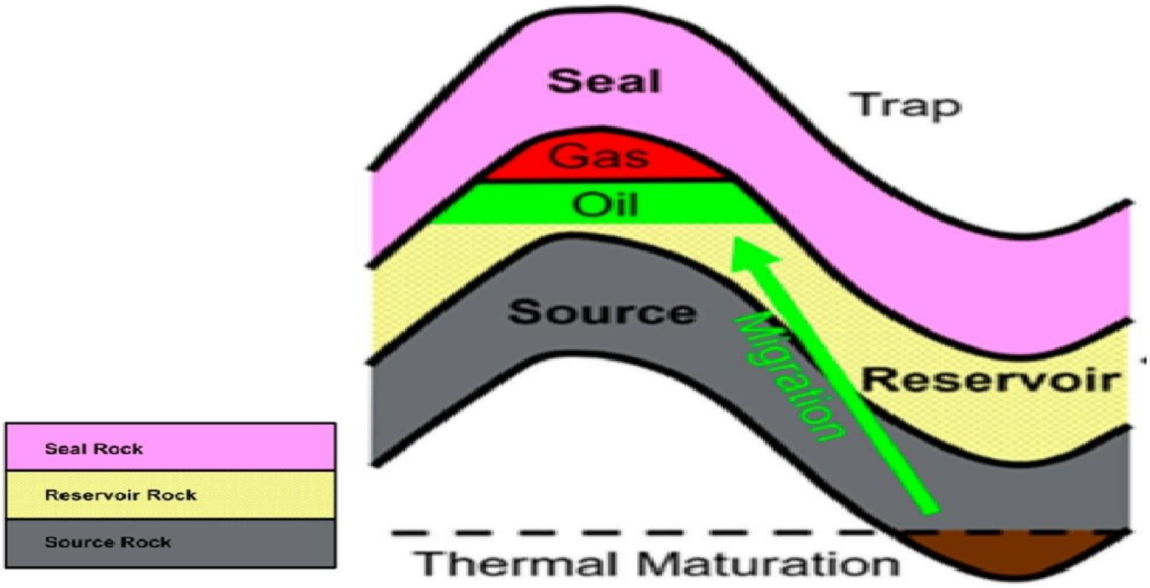

Figure 2.2 Represents the petroleum system elements. Petroleum systems elements consists of source, reservoir, seal, trap, maturation and migration.

2.10 Stratigraphy and Petroleum System of the Area

Apart from understanding tectonic evolution, petroleum system elements are equally important for hydrocarbon exploration (Ehsan et al.,2023). A petroleum system is characterized by a genetic connection that connects a source rock to the oil and gas that it has produced (Zao et al., 2019). Additionally, a petroleum system is comprised of all of the geologic materials and processes that are necessary for the production of petroleum accumulation (Figure 2.2). The petroleum system in this area primarily includes Cretaceous and Infra-Cambrian rock formations. Among these, the Chichli Formation of Late Cretaceous age stands out as a potential source rock. It is composed of glauconitic shale that has a dark greenish gray color (Figure 2.3).

The Lumshiwal Formation of Early Cretaceous age is a proven reservoir in the study area (Hashmi, 2018). It consists of cross bedded sandstone and is deposited in a coastal marine environment. The Ranikot Formation of Early Paleocene age acts as the seal rock for the reservoir of Lumshiwal Formation (Shah, 2024). The Punjab Platform, next to the Bikaner Nagaur Basin in India, hosts considerable reserves that remain unexplored (Raza et al., 2008). Notably, this region also boasts of exploring the hydrocarbon in the vicinity of Bahu, Panjpir, and Nandpur gas fields (Shah, 2023). The possible source rock, the shales of Chichali Formation, is buried deep in the western part of the Punjab Platform.

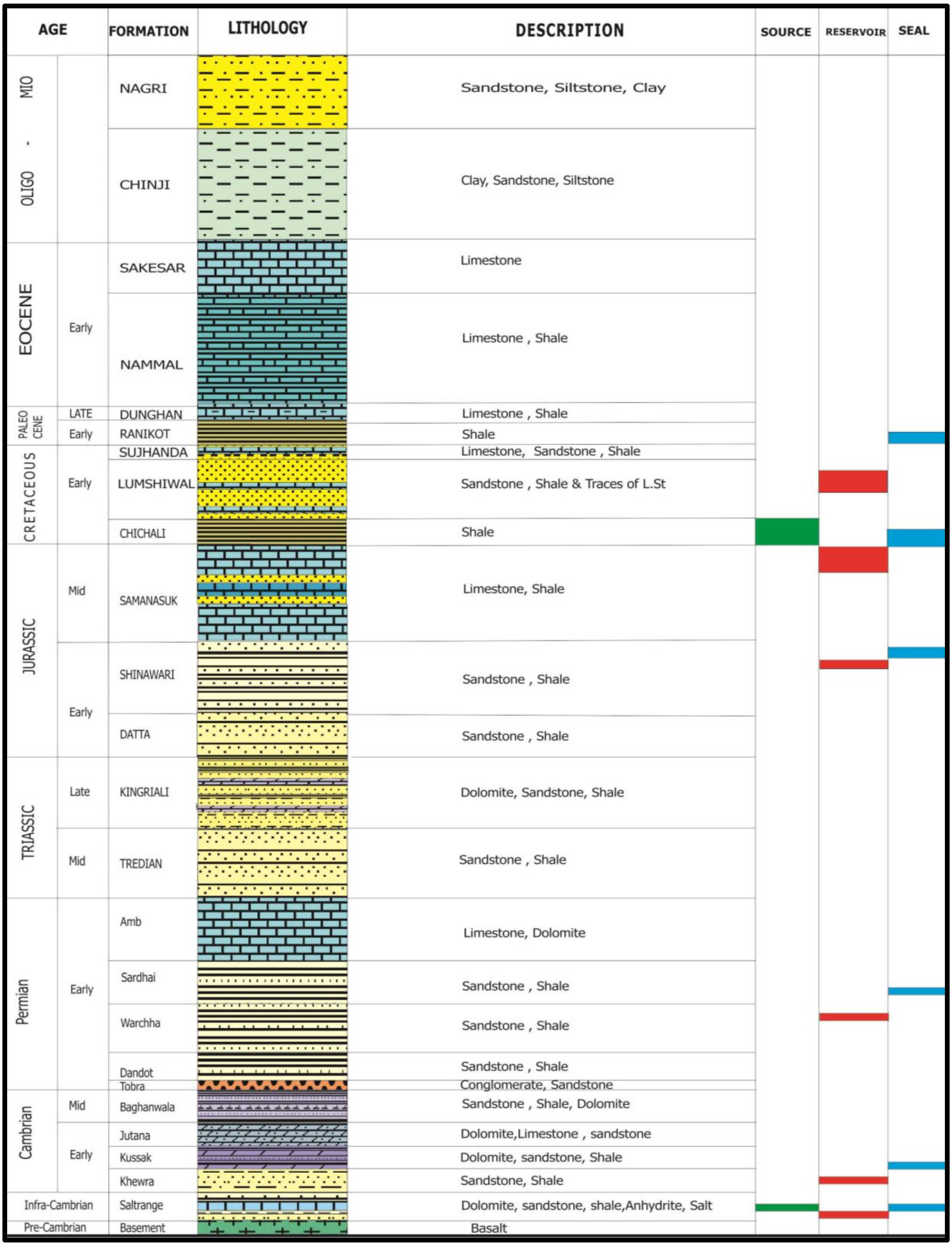

Figure 2.3 Represents the petroleum system elements of Punjab Platform. The shales of Chichali Formation are the source rock lies in Late Cretaceous age. The sandstone of Lumshiwal Formation acts as main reservoir, the Ranikot Formation providing seal to Cretaceous reservoirs (modified after Malkani & Mahmood, 2016).

2.11 Exploration History of Punjab Platform

Paleozoic and Mesozoic reservoirs are the two main exploration targets that have shaped the Punjab Platform's past. In the past, the main objectives for exploration were rocks from the Infra-Cambrian and Permian periods (Khalid et al. 2020). The Cretaceous and Jurassic reservoirs in the lower to intermediate layers were regarded as primary exploration prospects (Figure 2.3) (Malkani & Mahmood, 2016).

The first exploratory well (Karampur-1) in the region was drilled up to basement rocks by Shell in 1958. It encountered the heavy oil shows in Infra-Cambrian reservoirs of the Salt Range formation. Also in the Indian side, in 1960, the Indian Oil and Natural Gas Corporation (ONGC) drilled Puga-1 tested the same Infra-Cambrian reserves, but the well did not produce hydrocarbons (Raza et al., 2008). In the 1970s, Amoco Corporation drilled two more wells to investigate the Permian and Salt Range Formations, but they produced any economic discoveries. The exploration company, namely Shell Pakistan Limited drilled two further wells (Bahawalpur East-1 and Marot-1) a few years later. The Permian reservoirs were the targets in of both wells. The wells, however did not reach the Infra-Cambrian reservoirs. Because of inadequate closure and low reservoir quality, the wells were unable to produce any hydrocarbon discoveries. OGDCL discovered the first hydrocarbon in the shape of gas discovery in the Punjab Platform by the name of (Panjpir-1) in 1985.The well flowed hydrocarbons from the Cretaceous Lumshiwal Formation. OGDCL drilled many failed wells in the late 1980s, based on this finding. Before ONGC announced the first finding of heavy oil in the Infra-Cambrian reservoir (Baghewala-1) in the Bikaner–Naguar basin of India (Peters et al. 1995; Singh and Tewari 2011), there was little interest in the region from explorationists. In February 2006, this field's production began. ONGC has the development of this fields by drilling a number of wells and currently actively exploring from locations east of the Baghewala field. The drilled wells on the Punjab Platform have met all comparable source, reservoir, and cap rocks (Singh and Tewari 2011). A few years later, OGDCL drilled another well (Fort Abass-1) to go a little bit further into the northern part, but unfortunately no hydrocarbon was found. After the Baghewala-1 results, OGDCL drilled another well (Bijnot-1) later in 1996 to investigate the hydrocarbon potential in the Infra-Cambrian reservoir. Only Bijnot-1 showed excellent heavy oil. The discovery of oil and gas in Bijnot-1 spurred OMV to drill a well on the Punjab Platform. When the firm drilled Suji-01 exploratory well in year 2000, they did not find any Infra-Cambrian reservoir since they were drilling into the basement.

The Middle and Lower Indus Basin are rich in resources from the Cretaceous and Jurassic formations. However, Amoco Corporation drilled exploratory wells in Kamiab-1 and Budhana-1 wells, reaching the Samana Suk Formation of the Jurassic without discovering any economic hydrocarbons, the interest in the Mesozoic strata began. Ten years later, OGDCL was drilling into the Triassic Kingriali reservoir when they discovered gas in the region. POL drilled Ahmadpur-1 in the region in 1992. A stratigraphic pinch-out was expected by the operator based on the seismic interpretation. But because of the well's significantly down-dip placement, it failed. The Triassic and Jurassic reservoirs were the primary focus of the bulk of the remaining exploration. OGDCL discovered more gas in the Cretaceous Lumshiwal Formation (Bahu-1) in year 2006. In order to investigate a stratigraphic trap identified by a seismic survey that revealed the truncation of the Cretaceous (Goru Formation) behind a Tertiary unconformity, OGDCL drilled Saro-1, a dry hole, in 1992. The Jiwanwala well was drilled to test the fault bounded normal fault structure with a structural relief of 20–40 ms on seismic. The structural orientation of structure is NE to SW direction. It has also tested the Chiltan Formation. The potential comprises a 6-kilometer confined area and a 30- to 35 m vertical closure. The porosity of the Chiltan limestone in the Nandpur and Panjpir regions ranges from 5% to 25%, and Jiwanwala-1 is predicted to have comparable porosity (Khalid et al. 2014). For the main reservoirs, the shales of Sembar Formation were thought to be the seal rock. An excellent source of primary reservoirs (Chiltan Limestone), interbedded sands in the Sembar Formation and sand reservoir of the Goru Formation has been presented in this prospect by the tilted fault block that juxtaposes the Chiltan Limestone against the Sembar Formation (Nisar et al. 2024). Two plays, one structural and one stratigraphic were found in Chak-255. From the carbonate level of the Eocene/Paleocene to the Lower Cretaceous Goru sand level, there is structural play. The four-way closure was mapped at two different levels: 3.2 km at the Goru Formation and 5.5 km at the Sui Main Limestone (SML) level, with a structure having the vertical relief of 25 m. A primary reason for failure is thought to be inadequate source potential (Khalid et al. 2014). The Lower Goru Formation's sand and the carbonates of the SML and Dungan Limestone were found to have good reserves. These and every other interval were found to be water moist, according to the wireline log examination. The Punjab portion of the Platform was unaffected throughout the Jurassic to Late Cretaceous period, whereas the Lower Indus Platform region saw significant rifting and the formation of horst and graben structures (Zaidi et al. 2012). In the Punjab Platform, there is only very little normal faulting with very little throw (Waples and Hegarty, 1999).

CHAPTER 3

RESEARCH METHODOLOGY

This chapter comprises of research methodology regarding the source rock evaluation, well logs correlation, Isopach maps, forward modeling, mis-tie analysis, velocity modeling, subsurface seismic interpretation/ mapping, mechanisms of hydrocarbon migration, 2D basin modeling and 3D hydrocarbon charge modeling and identification d sweet spots using DHI's. Results and conclusion were discussed in Chapter 4 & 5.

This research has emphasized using an integrated approach for the source rock evaluation and mapping hydrocarbon migration pathways from kitchen areas to traps. The following techniques have been employed for advanced hydrocarbon exploration in Punjab, Platform Pakistan.

3.1 Source Rock Evaluation

To assess the source rock potential of shales of the Chichali Formation, a detailed study that involved the interpretation of 2D seismic data covering 765-line kilometres across the entire study area was carried out. The acquisition parameter of 2D seismic utilized for this study has a source and receiver interval of 50 m. The fold of the 2D seismic data is 100. The quality of the seismic data in the region varied from fair to good. We obtained a total of thirty-four core samples from the Cretaceous shale of the Chichali Formation; these samples were collected from four wells, namely Bahu-01, Panjpir-01, Nandpur-01, and Zakria-01. Detailed information on these samples can be found in the Table. 3.1. TOC and rock eval on thirty-four core samples of the Chichali Formation were performed in G&R (Geological and Research) Lab, Pakistan. Additionally, %Ro analysis was carried out at the Hydrocarbon Development Institute of Pakistan Lab (Table. 3.2).

Table 3.1 Rock eval and TOC analysis results from core samples of Cretaceous Chichali Shale.

Sr.no	Well Name	Sample Name	(TOC, wt.%)	HI (mg/g)	OI (mg/g)
1	Bahu-01	Sample 1	0.41	110	120
2	Bahu-01	Sample 2	0.25	98	100
3	Bahu-01	Sample 3	0.37	114	190
4	Panjpir-01	Sample 1	1.20	83	43
5	Panjpir-01	Sample 2	1.54	124	28
6	Panjpir-01	Sample 3	1.02	125	47
7	Panjpir-01	Sample 4	1.53	75	50
8	Panjpir-01	Sample 5	1.42	101	48
9	Panjpir-01	Sample 6	1.02	302	67
10	Panjpir-01	Sample 7	1.40	138	41
11	Panjpir-01	Sample 8	1.34	128	51
12	Panjpir-01	Sample 9	1.21	163	40
13	Panjpir-01	Sample 10	1.23	160	82
14	Panjpir-01	Sample 11	0.99	119	45
15	Panjpir-01	Sample 12	1.10	103	37
16	Nandpur-01	Sample 1	2.01	11	54
17	Nandpur01	Sample 2	2.57	38	69
18	Nandpur-01	Sample 3	1.81	6	60
19	Nandpur-01	Sample 4	1.14	6	93
20	Nandpur-01	Sample 5	1.21	8	88
21	Nandpur-01	Sample 6	1.65	6	64
22	Nandpur-01	Sample 7	1.20	47	136
23	Nandpur-01	Sample 8	1.78	3	52
24	Nandpur-01	Sample 9	0.96	2	84
25	Nandpur-01	Sample 10	1.19	2	26
26	Nandpur-01	Sample 11	0.42	4	30
27	Nandpur-01	Sample 12	0.43	6	55
28	Zakria-01	Sample 1	0.99	120	96
29	Zakria-01	Sample 3	1.19	56	290
30	Zakria-01	Sample 3	0.42	48	302
31	Zakria-01	Sample 4	0.36	67	270
32	Zakria-01	Sample 5	0.61	61	250
33	Zakria-01	Sample 6	0.64	130	198
34	Zakria-01	Sample 7	0.82	99	132

Table 3.2 Measured %Ro from core samples (shales of the Chichali Formation) in Bahu-01, Panjpir-01, Nandpur-01 and Zakria-01 wells.

Sr.no	Well Name	Sample Name	Formation Name	Depth (m)	%Ro
1	Bahu-01	Sample 1	Chichali	1622	0.44
2	Bahu-01	Sample 2	Chichali	1626	0.35
3	Bahu-01	Sample 3	Chichali	1630	0.30
4	Panjpir-01	Sample 4	Chichali	1682	0.34
5	Panjpir-01	Sample 5	Chichali	1710	0.30
6	Panjpir-01	Sample 6	Chichali	1750	0.45
7	Panjpir-01	Sample 7	Chichali	1780	0.48
8	Panjpir-01	Sample 8	Chichali	1950	0.50
9	Nandpur-01	Sample 9	Chichali	1680	0.30
10	Nandpur01	Sample 10	Chichali	1690	0.32
11	Nandpur-01	Sample 11	Chichali	1695	0.37
12	Nandpur-01	Sample 12	Chichali	1780	0.39
13	Nandpur-01	Sample 13	Chichali	1782	0.42
14	Nandpur-01	Sample 14	Chichali	1790	0.41
15	Zakria-01	Sample 15	Chichali	2040	0.59
16	Zakria-01	Sample 16	Chichali	2142	0.55
17	Zakria-01	Sample 17	Chichali	2148	0.76
18	Zakria-01	Sample 18	Chichali	2156	0.51
32	Zakria-01	Sample 19	Chichali	2173	0.78

This research adopted a comprehensive approach for evaluating the source rock potential of the shales of the Chichali Formation using the seismic, well and core data (Figure 3.1). TOC was calculated from core and seismic data, using organic geochemistry and Post stack seismic inversion techniques. Source rock maturity was determined through 1D basin modeling and organic petrography.

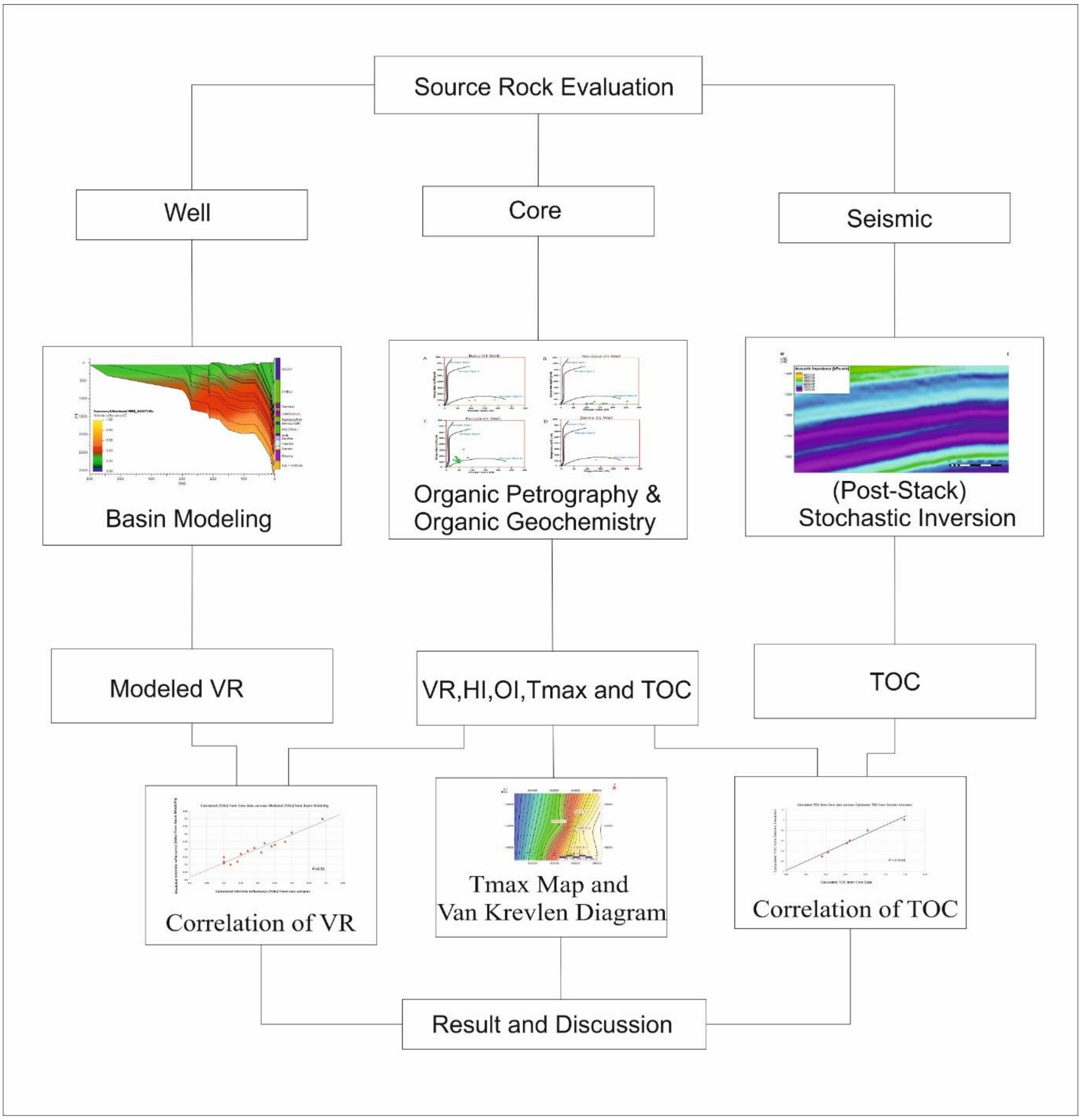

Figure 3.1 Flow chart showing a comprehensive approach for shales of the Chichali Formation source rock evaluation. Source rock is evaluated in terms of organic richness, maturity and timing of maturation. Post-stack seismic inversion and organic geochemistry were used for the calculation of TOC. Source rock maturity was calculated from petrography and basin modeling techniques.

3.1.1 Source Rock Organic Richness

The organic richness of shale plays a crucial role in deciphering their quality and productivity. Regions with high TOC content often yield the best results (Khalil Khan et al., 2022). The assessment of organic richness, quantified in terms of TOC was carried out using geochemical and seismic inversion techniques. The obtained results from these two separate methods were compared. To measure TOC from core samples, samples were taken through several steps. First, the samples were washed and dried. Once dried, they were pulverized and acid treatment was employed to remove any carbonate or other contaminants. Subsequently, (TOC, wt.%) analysis was conducted using an ELTA C/S analyzer. During this analysis, the samples were combusted at 1250°C in a furnace. The carbon trapped within the kerogen was transformed into CO and CO_2. The carbon fractions released during this process were measured, converted into (TOC, wt.%) and recorded as the mass weight percentage of the rock. The TOC can also be calculated from a seismic inversion technique by using seismic data. Organic material within shale has specific density, radioactivity, and electrical resistivity characteristics that affect both seismic and wireline log responses (Zhu et al., 2011). Hence, seismic inversion can be used reliably to quantify the organic richness in shale (Broadhead et al., 2016; Ehsan et al., 2018; Tomski et al., 2022).

Earth reflectivity was obtained from seismic traces using deconvolution algorithms. For seismic inversion, seismic data was used as input and well data was used as a control in the subsurface modeling approach after (Bashir et al., 2024). The stochastic inversion technique was used to model the small-scale variability seen in the well log data but cannot be identified from seismic data. Multiple realizations that were compatible with the well and seismic data were performed to solve the non-uniqueness problem. There were a great number of potential outcomes that can be produced using stochastic procedures. Importantly, (Khalid et al., 2019) showed that in organic-rich intervals, there exists an inverse relationship between P-wave seismic velocities and TOC. TOC generally exhibits a linear relationship with impedance values (Ouadfeul & Aliouane, 2016). Mahmood et al. (2018) also elaborated on the true dependency of TOC on impedance data. In this study, seismic stochastic inversion was applied to post-stack seismic data to calculate the TOC. Post stack stochastic seismic inversion was performed on these source rock top and base seismic horizon units that were located within the study area. Seismic inversion involves the extraction of an appropriate seismic wavelet (Bashir et al., 2021). Continuous repetition of the wavelet extraction and synthetic seismogram was carried out until the correlation coefficient between the synthetic and the actual seismogram reached a satisfactory level, with the well location exhibiting only a small amount of inaccuracy. Acoustic impedance was calculated from well logs using sonic and density logs. The acoustic impedance is defined as $Z=\rho v$, where ρ is the density of the medium and V is the velocity through the medium. Velocity is computed from the sonic log, while density is determined from the density log. Velocity is calculated from sonic by using $V=1/DT$, where DT is the sonic log and V indicates velocity. Initially, the relationship between acoustic impedance and TOC was established at the Zakria-01 well (Figure 3.2). The acoustic impedance and TOC are inversely proportional to each other. High value of acoustic impedance yields low values of TOC and vice versa.

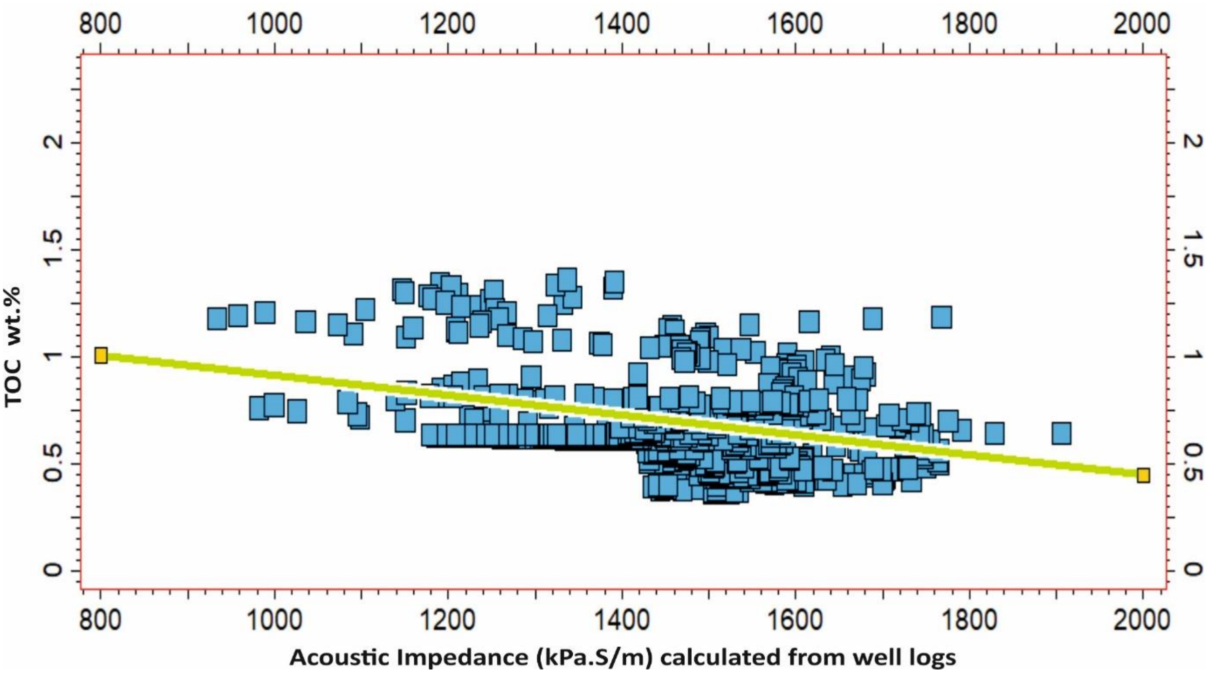

Figure 3.2 The graph shows the linear relationship between P-impedance and TOC created at the Zakria-01 well utilizing Chichali Formation shales. It reveals a linear connection between P-impedance and TOC. This cross-plot also yielded an equation (Y = -0.000466368 * X + 1.37812), which was then utilized to convert seismic impedance data to TOC.

The calculated acoustic impedance was plotted against TOC (calculated from core samples), leading to the establishment of a linear relationship at the Zakria-01 well (Figure 3.2). The equation derived from this cross-plot (Y = -0.000466368 * X + 1.37812) was then used to transform seismic impedance data into TOC values through the seismic inversion technique (Figure 3.3).

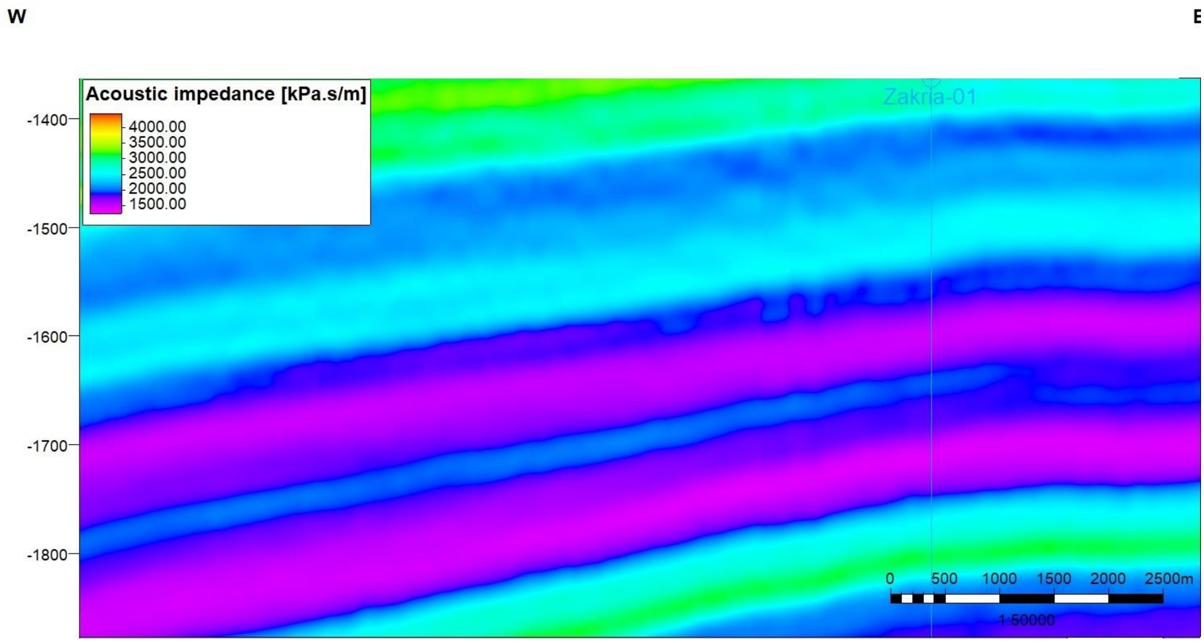

Figure 3.3 P-impedance 2D seismic section passing through Zakria-01 well generated by using seismic inversion technique. P-impedance values are decreasing toward the west.

3.1.2 Type of Kerogen

Rock eval pyrolysis is widely recognized as one of the most effective geochemical techniques for source rock evaluation, especially regarding the determination of kerogen type (Espitalié et al., 1977). This technique is extensively used to assess source rock organic matter type, generation potential, and maturity level (El Diasty et al., 2022). In this study, 100 mg of each sample were subjected to rock eval measurements using the rock eval 6 machines. The analysis provided results for S_1, S_2, S_3, and T_{max} values (Peters & Cassa, 1994). During pyrolysis, the first peak S_1 was obtained at 300°C, representing the amount of free hydrocarbons (mg HC/g) present in the rock without cracking the kerogen. The S_2 peak showed the quantity of hydrocarbon generated through the thermal cracking of kerogen during programmed pyrolysis within the temperature range of 300–600°C. According to (Kibria et al., 2020), the S_2 peak is considered more reliable, as (TOC, wt.%) includes dead carbon that cannot generate petroleum. The S_3 peak corresponds to CO_2 yield produced during the thermal cracking of kerogen. Additionally, the temperature at which the maximum amount of hydrocarbon was generated during pyrolysis, known as T_{max}, was recorded. HI was used to normalize the S_2 value to HC/g of (TOC, wt.%), while the OI is the amount of oxygen in kerogen and expressed in CO_2/g of (TOC, wt.%). Kerogen type was determined by plotting the HI against the OI.

3.1.3 Source Rock Maturity

Source rock maturity is a critical element of source rock evaluation. In this study, source rock maturity was calculated using a direct approach (organic petrography) by estimating %Ro from core samples in the laboratory. Additionally, %Ro was calculated using the modeled easy % Ro algorithm in basin modeling (Sweeney & Burnham, 1990). Results obtained from both organic petrography and basin modeling were compared. Rock eval data Tmax was also used for maturity assessment. Maturity estimation from Tmax in some cases gives suspicious results when S2 has more than one peak or suffers weak intensity (Snowdon, 1995).

Organic petrography is a better and more precise maturity evaluation by calculating the vitrinite reflectance, which can deliver more accurate results when the facies effects have an impact on the Tmax (Sadeghtabaghi et al., 2021). Vitrinite reflectance is the most widely used factor for source rock maturity determination (Burnaz et al., 2023; Ola et al., 2018). For source rock maturity, vitrinite reflectance was measured from a Zeiss Z1M microscope fitted with a spectrometer. The microscope has both fluorescent and white (halogen) light sources. The microscope was attached with a high-resolution C-mount camera. The Spectra Vision software program was used for measuring vitrinite reflectance. The immersion oil used was made by Carl Zeiss (518 C, DIN 58 884, ISO 8036/1 Ne = 1.518 at 230 C). Random vitrinite reflectance (Rm%) measurements were made using monochromatic non-polarized light and a 50X ocular oil immersion objective, calibrated against three sets of reference standards: sapphire (Rm%) = 0.589%, yttrium-aluminum-garnet (Rm%) = 0.907% and gadolinium-gallium-garnet (Rm%) = 1.711%. The measured vitrinite reflectance from Zeiss Z1M was plotted versus depth to see the maturity of Cretaceous rock.

Determining the timing of maturity and understanding the burial history of source rocks is equally vital in source rock evaluation (Dembicki & Harry, 2017). The 1D basin modeling technique serves as a robust tool for constructing the burial history and assessing the levels of source rock maturation (Abdelwahhab et al., 2020). In a study by (Yasin et al., 2021), the burial history and maturity of source rocks were evaluated using the 1D basin modeling approach. Elatrash et al. (2021) calculated source rock maturation using vitrinite reflectance values from the EASY% Ro algorithm.

1D basin modeling technique was employed in this study to develop the burial history and maturation profiles of source rocks. This was achieved by considering factors such as formation age, depth, lithology, TOC and boundary conditions. We conducted 1D basin modeling at four well locations, namely Bahu-01, Panjpir-01, Nandpur-01, and Zakria-01. Paleo-bathymetry inputs were adopted using the deposition environment of each formation. SWIT was used for each well. The model also incorporated kinetics, Rock eval data, bottom hole temperature, lithology of formations, thickness, erosion, and paleo-bathymetric data to construct the maturity model within the Petrel software. Kinematics (heat flow) is the main factor that impacts the reconstruction of the history of the sedimentary basin to predict the process of hydrocarbon maturity, timing, migration and trapping. For heat flow, the McKenzie method was adopted. Inputs for the rift phase, post rift phase, depth of crust, and mantle were incorporated. To validate the source rock maturity results, modeled (%Ro) values generated using the modeled EASY% Ro algorithm (Sweeney & Burnham, 1990) compared with (%Ro) values obtained through organic petrography in the laboratory.

3.2 Well Log Correlation

In geology, correlation referred to as stratigraphic correlation, is the process of equating two or more geological periods in spite of their geographic differences. According to the International Stratigraphic Guide, correlation varies based on the characteristic being stressed. Lithologic correlation shows lithologic character and lithostratigraphic position, while fossil-bearing bed correlation shows fossil content and biostratigraphic position. Chronological correlation shows age and chronostratigraphic position.

The different types of logs, e.g., sonic, density, gamma ray and spontaneous potential logs, are widely used for correlation purposes. Although only one of the elements with radioactivity is uranium, thorium and potassium are present in the primary minerals that make up rocks, namely potassium, which is found in mica illites and potassium feldspars. The radioactive log, or gamma ray log is very effective for mapping the stratigraphic changes and marking the boundaries of formation. On the other hand, high concentrations of thorium and uranium may develop via minor increases in heavy minerals, heavy oil, or even tar, all without causing a significant alteration in the lithologies. Therefore, in good correlation, the total gamma ray is not usually particularly beneficial. Since it separates the potassium content from the other components by dissecting natural radioactivity, a natural gamma ray measurement is already more appropriate. For a proper lithological characterization, it is much preferable to have more significant element concentrations available. This condition is extremely effectively met by the nuclear spectroscopy records (Liang et al., 2025).

As discussed, the majority of well correlations that use logs are essentially lithostratigraphic correlations. For the lithostratigraphic correlation in the study area north-south correlation was generated using three well logs. The well logs, sonic and density logs, were loaded in the Kingdom software. The QC of loaded logs was well carried out. The unusual spikes in the logs were adjusted. The sonic and density logs of Bahu-01, Panjpir-01 and Nandpur-01 wells were used to generate the stratigraphic correlation. The formations from the Eocene Sakesar formation to Tredian formations were correlated. The thickness among the three wells remains almost constant. The source rock Chichali Formation is slightly less in the Bahu-01 well as compared to the Nandpur-01 and Panjpir-01 wells (Figure 3.4). Also, another good correlation in the other direction, which is east-to-west was generated using GR and DT logs of Bahu-01, Paanjpir-01, Nanpur-01, and Zakria well logs (Figure 3.5). The formations from the Eocene Sakasar Formation to the Tredian Formation were correlated. The most critical source, Chichali Formation thickness, varies in the area. The source Chichali Formation thickness varies in the area, increases in western Zakria-01 and it decreases in eastern side in Panjpir-01 and Nandpur-01 wells. Similarly, the thickness of reservoir rock of the Lumshiwal Formation increased in western side in Zakria-01.

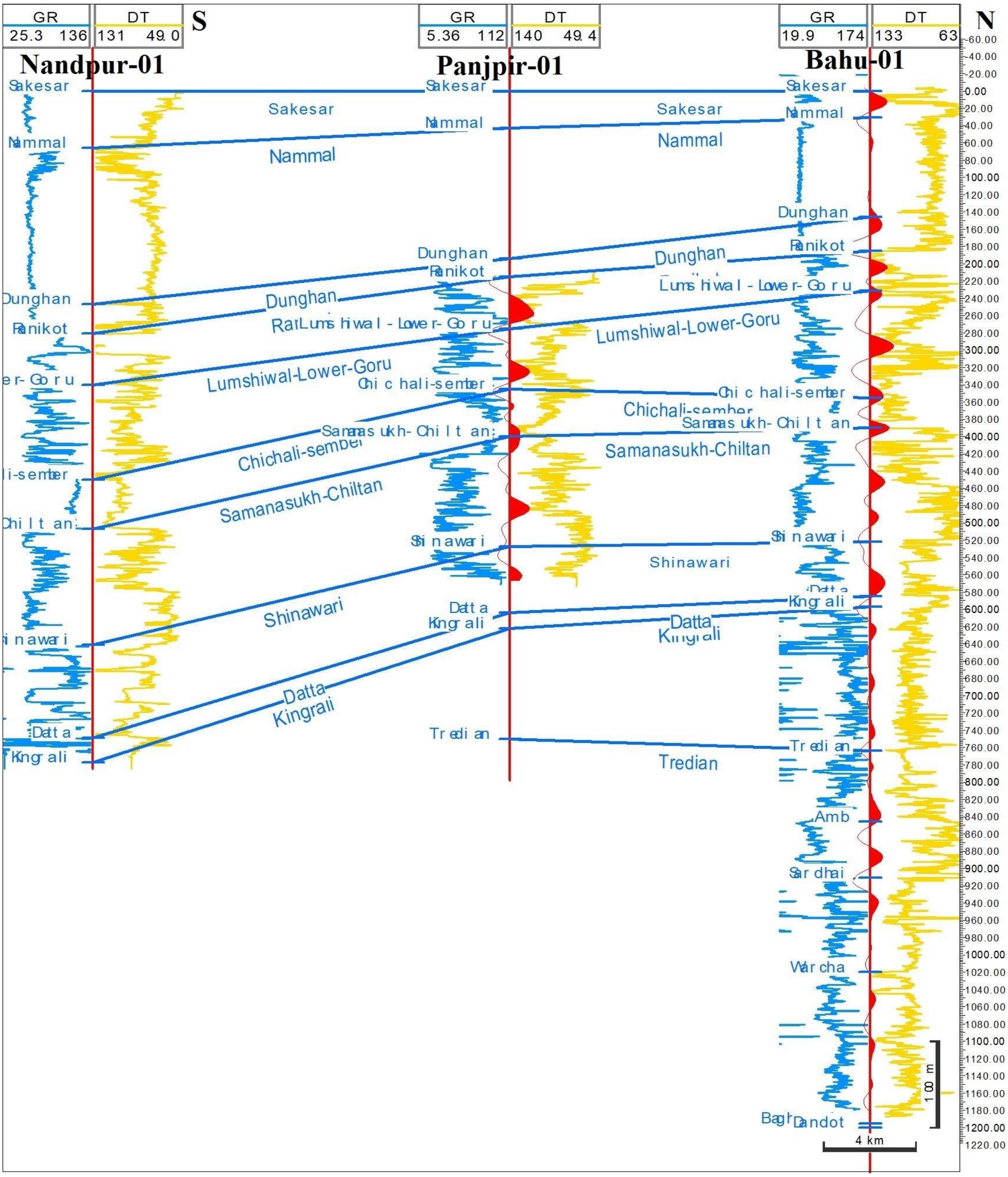

Figure 3.4 Reservoir and source correlation based on well logs. The source thickness is same in Nandpur-01 and Panjpir-01 wells, however, its thicknesses decrease in Bahu-01 well. The reservoir thickness remains same among three producing fields Nandpur-01 and Panjpir-01 wells and increases in Bahu-01 wells.

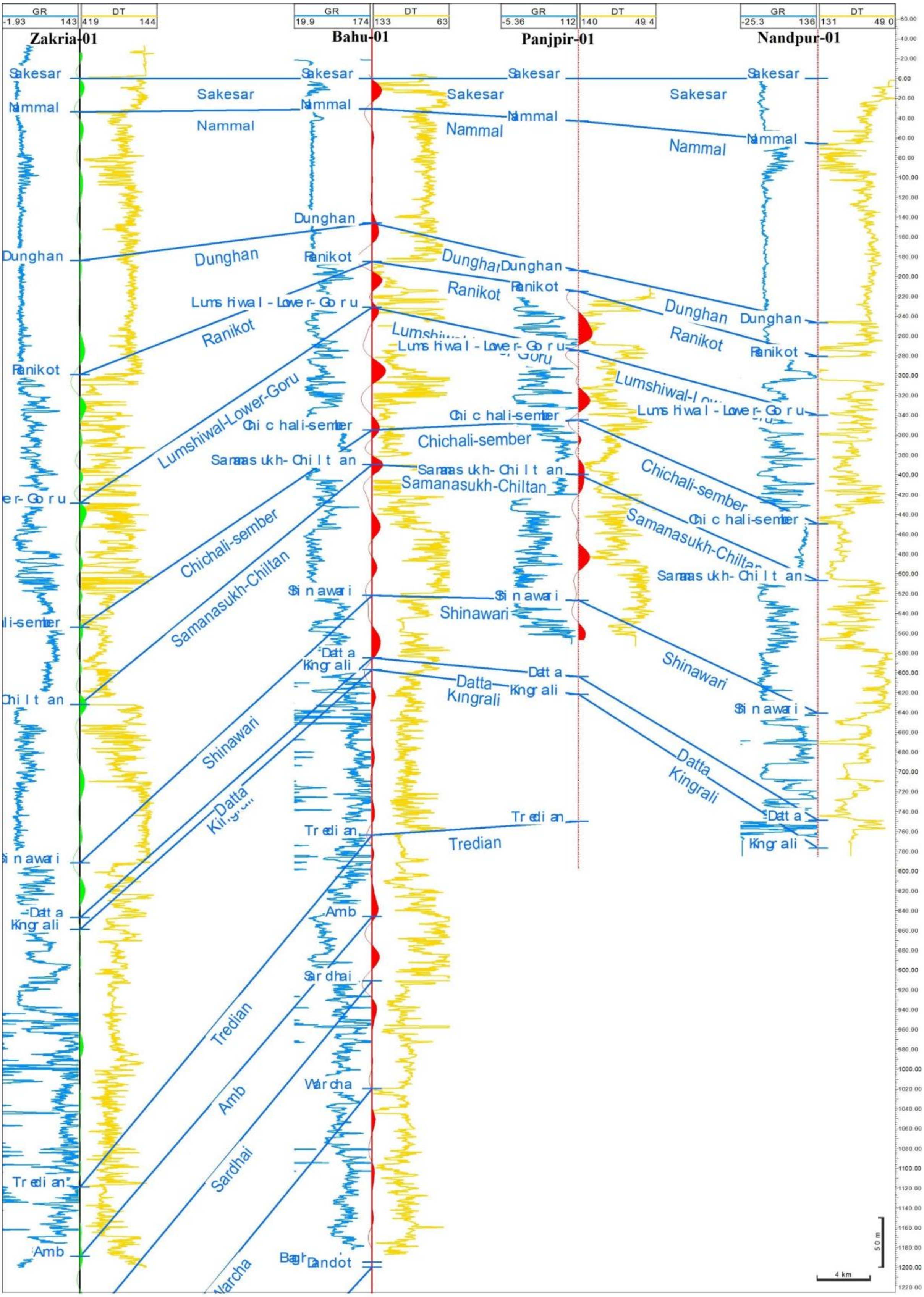

Figure 3.5 Reservoir and source correlation based on four wells namely Zakria-01, Bahu-01, Panjpir-01 and Nadpur-01. Thickness of source rock (the Chichali Formation and reservoir rock (the Lumshiwal Formation) is increasing toward Zakria-01 well which lies in the eastern side of Punjab Platform.

3.3 Isopach Maps

The Isopach maps are the maps created by joining the equal values of stratigraphic thickness. These map shows the thickness of one specific stratigraphic formation. A stratigraphic unit is a rock layer or group of rock strata that geologists have recognized as covering a certain area. Isopach maps can help you understand how a rock thickness varies in the area and deposition (Deng et al., 2025).

The formation thickness was usually obtained from well log interpretation and well coring data. The gamma ray log is very important for the marking the formation boundaries. The isopach map shows the variation of thickness of specific formation. It also indicates the thinning and thickening of formation, sediments influx direction, erosion, or truncation of formation. The isopach maps are widely used in hydrocarbon exploration and development phase. Its application in sedimentology and petroleum exploration is widely known. It also indicates the structural configuration of strata which effects the deposition trend of particular formation (Plantz et al., 2025).

The thickness of formations particular source rock the Chichali Formation and reservoir rock the Lumshiwal Formation were mapped in study area. The thickness of these formation was mapped using well log. The sonic and density logs of Zakria-01, Bahu-01, Panjpir-01 and Dhodak-01 wells were used to generate the well correlation window. The gamma and sonic log were used for correlation purposes. The gamma log showed the shale content in formations and sonic log indicated the velocity behavior of formations. The top and bottom of formation were identified using combination of sonic and density logs. After mapping the upper and lower boundaries of formation, thickness was calculated. The thicknesses of formations encountered in these wells were used to produce an isopach map utilizing Kingdom software. Isopach maps source rock the Chichali Formation and reservoir rock the Lumshiwal Formation and Samana Suk Formations were generated by using thickness calculated from well logs correlation.

3.4 Subsurface Structural Interpretation

Sedimentary rock succession is divided into units known as formations. These formations can be classified according to the age, thickness, and lithology of their continuous strata. The seismic reflection is important aspect in seismic interpretation, seismic interpretation can be structural or stratigraphic. The ultimate goals are to map the subsurface image/structure that can hold the hydrocarbon.

The term 'interpretation' refers to the conversion of seismic information into geological concepts. Corrections, migration, and time-depth conversion are used to convert seismic reflection data into structural images. To analyze seismic reflection data correctly and reliably, one must first understand the geology of the location where the data was collected. In seismic approaches, physical readings are taken at the surface and interpreted in terms of the position and behavior of subsurface contacts. The arrival times of each reflection event are then estimated (Dobrin, 1988).

Outcrop mapping, drilling, mining, and geophysical investigations are all methods for learning about the subsurface. Geophysical techniques produce images of the subsurface. To produce the subsurface image of the area, seismic survey needs to be planned and carried out. Usually, the sound waves are generated by dynamite or vibroseis. These sound waves travel into the subsurface and reflected waves are recorded at the surface by using the geophone spread. The data can be acquired in two-or-three dimensional domain. The decision to acquire the 2D or 3D seismic data is dependent on target size, spacing, economic and surface topography. After the acquisition, the data is processed in processing center (Linear et al., 2019). After processing, the processed data is used by the seismic interpreter to map the subsurface image.

Reflection seismic explores the subsurface using sound waves. The main property of seismic refection survey is the acoustic impedance contrast. The acoustic impedance is the product of velocity and density. The acoustic impedance contrast occurs when the sound wave enters from the low velocity, density layer to high velocity, density layer or vice versa. The change in velocity, density of individual rocks led to the prominent reflector on seismic. The reflection coefficient is equally important in seismic reflection. The change in reflection coefficient indicate the change in lithology, change in formation or discontinuity which can be due to faults. The sophisticated interpretation software’s are used in modern day for the subsurface imaging. The famous interpretation software’s are Kingdom, Petrel and Decision space.

The surface mapping helps in mapping the subsurface image both on local and basin level. The basin level configuration and evolution can be mapped through seismic mapping.

The utilization of surface outcrop data is very important in subsurface mapping. Usually the surface faults and geometries are translated into surface. According to American Association of Petroleum Geologist, the seismic interpretation is the study and mapping of subsurface image by using processed seismic data. In the field of exploration geophysics, seismic interpretation refers to the mapping of subsurface image into meaningful geological information utilizing the seismic data (Nanda et al., 2021).

The primary purpose of seismic reflection survey is to accurately map the subsurface image. Seismic reflection has a simple geological meaning: it shows an acoustic boundary, and the primary goal is to evaluate the surface image and mark the stratigraphy and faults during seismic interpretation. The characteristics that are not delineated by clear borders are need be identify. The sequence of sedimentary rocks is typically grouped by geologists into units known as "formations." The constituent layer's lithology, thickness, and age can all be used to characterize these formations. When analyzing seismic data, which can be structural, stratigraphic, or lithological, it is crucial to determine whether to distinguish between various formations based on seismic reflections (Dobrin and Savit 1976). The two primary methods used to interpret the seismic section are structural or stratigraphic interpretation. The study of seismic reflection shape based on reflection time is known as structural time or depth interpretation. The seismic structural analysis is performed to accurately map the subsurface image and mapped structural traps that can hold the hydrocarbon. Two-way reflection times are more commonly used in structural interpretation than depth, and time structural maps are created to show the geometry of specific reflection events. There are graphics in certain seismic parts that are easily understood. Faults are readily indicated by discontinuous reflections, while fold beds are revealed by undulating reflections. Based on the structurally interpreted subsurface data, the seismic survey data is transformed into a 3D-oriented subsurface map (Zhang et al., 2025).

The seismic mapping of the desired subsurface horizons consists of generation of time contours and conversion of time structure map to depth contours maps by using variable velocity utilized from well VSP data. The seismic interpretation workflow for this research is shown in (Figure 3.6). Seismic pulses that bounce back to the ground surface from binding interfaces or transition boundaries also contain information about the depth position of the horizon in time values, as well as the geological and lithological characteristics of the horizon layers. This information is carried by the seismic reflection wave energy. After smoothing the uneven travel durations caused by geological changes; the subsurface model is created. According to Dobrin and Savit (1976), this model generates a patent depth model with the orientation of the bedrock, geo-body, target horizon, or any other feature intact.

A three-dimensional subsurface structural map that distinguishes between the prime drilling place and other areas is created based on the one-dimensional well-site geology. The best places are up dip positions, which are horst blocks in the extensional regime and anticlines in the compressional regime. Furthermore, essential to a proper structural interpretation is a data collection that includes details about the prehistoric geology and the structural style connected to its tectonics. Subsequently, this interpretation is used to create the corresponding seismic time horizon maps and depth maps for each distinct horizon. Faults are marked in accordance with the structural style compressional or extensional and when mapped, provide a three-dimensional image of the area (Bracke et al., 2001).

3.5 Seismic Structural Interpretation

Seismic interpretation refers to the transformation of seismic data into meaningful geological information through rectification, migration, and time-to-depth conversion. Reflection of seismic data interpretation generally comprises determining the position and identifying purely concealed borders or loud evolution zones caused by seismic pulse reoccurrence to the earth's surface via reflection. The impact of varied terrain is highlighted across the profiles, translating the ambiguous stated transit time into meaningful subsurface image. It is very important to accurately translate the seismic reflection data into subsurface images to map the precise depth, size of structure, bed configuration (Figure 3.6). It helps in mapping valid structural traps that could hold appreciable amount of hydrocarbons (Li et al., 2025).

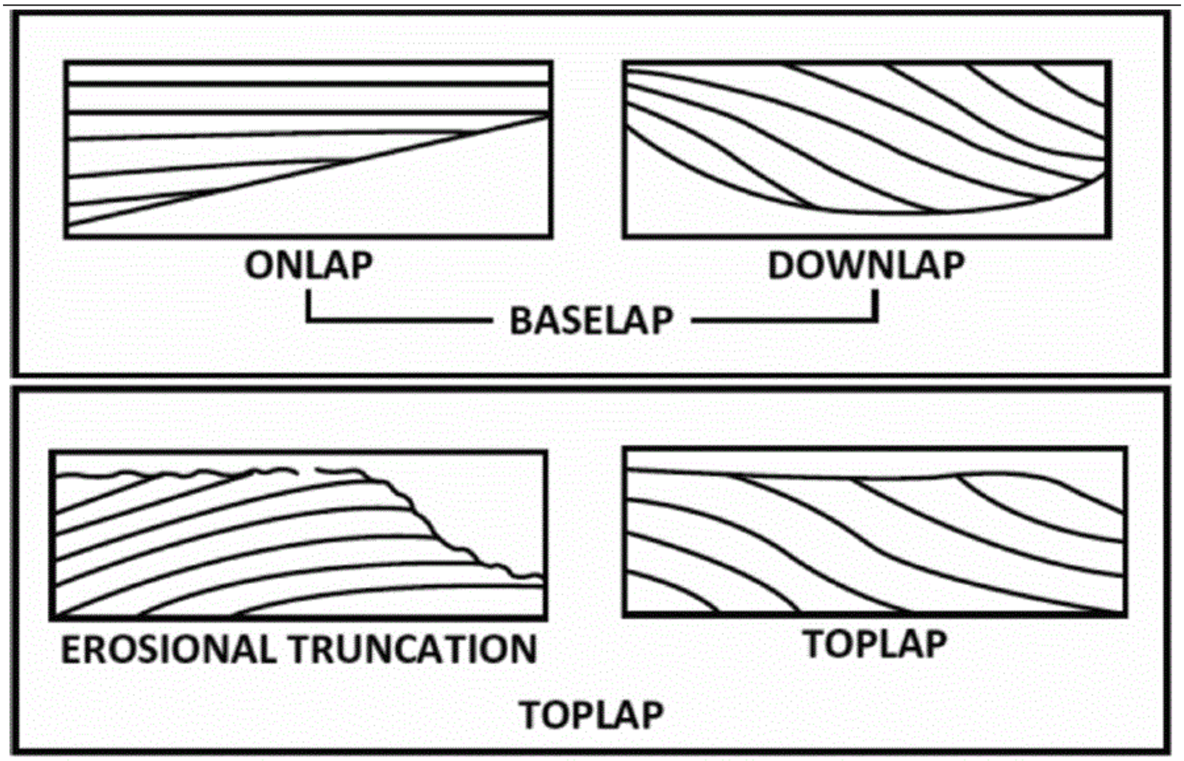

Figure 3.6 Represents the seismic interpretation methods. In Seismic Data Interpretation and Evaluation for Hydrocarbon Exploration and Production: A Practitioner's Guide (pp. 47-81). Cham: Springer International Publishing.

The faults can be identified through terminating reflection, undulations in seismic reflection are usually due to the folds in the strata. Reflection events in the seismic sections are marked in software with unique colour coding. Geologists often classify sedimentary rock sequences as "formations". In seismic reflection, different type of strata can be separated based on structural, stratigraphic configurations. Seismic data without geological features, such as folds and fault are interpreted structurally. There are mainly two different approaches in seismic interpretation (Eid and Amer ,2025).

- Seismic stratigraphic approach
- Seismic structural approach

The stratigraphic analysis divides seismic regions into sets of reflections that may be seen as the seismic representation of naturally occurring sedimentary formations. Seismic sequence analysis is guided by two distinct ideas. To begin, reflections are treated as chrono stratigraphical units since strata surfaces and unconformities are the kind of rock interfaces that cause reflections. Second, genetically linked sedimentary sequences often consist of sedimentary data that differ from the underlying and overlying strata. Unconformity can be marked on seismic data based on reflection patterns. The seismic reflections indicate the deposition trend and configuration. It also helps in identifying erosional boundaries based on termination of reflection events. Seismic reflection can also lead to the identification of stratigraphic traps based on reflection geometry and configuration (Figure 3.7). The common stratigraphic traps are erosional unconformities, reef, sand lenses, mound truncation boundaries. To map the stratigraphic trap following elements need to map (Argyelan and Zadravecz, 2025).

- Formation reflection configuration
- Formation seismic reflection continuity
- Seismic Interval velocity
- Seismic reflection amplitude
- Reflection frequency
- External Geometry

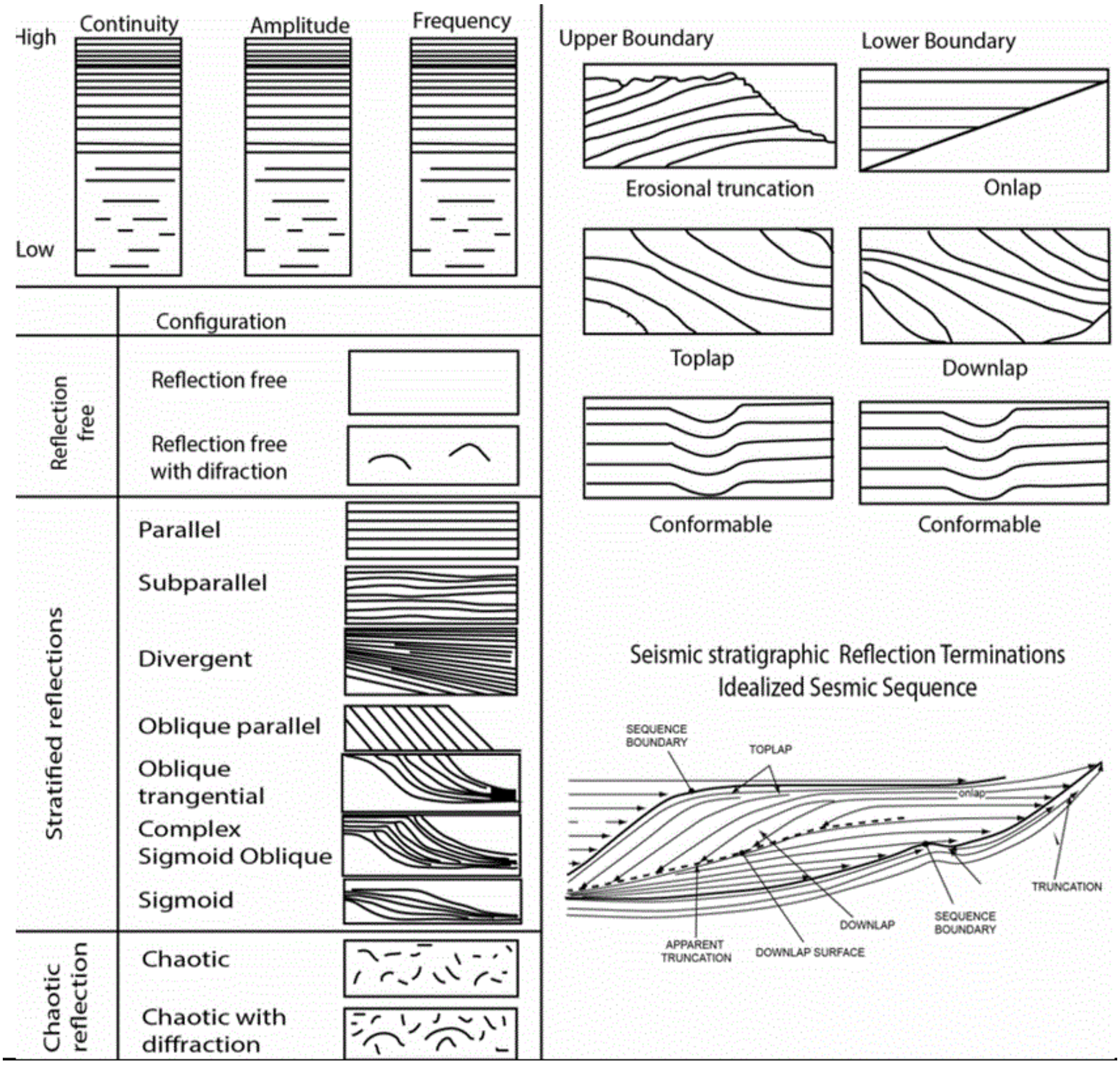

Figure 3.7 Represents the Seismic reflection can also lead to the identification of stratigraphic traps based on reflection geometry and configuration, geodynamics and synchronous filling of a rift type-basin evolved through compression tectonics (The western margin of the Levant Basin) (Doctoral dissertation, Université Pierre et Marie Curie-Paris VI).

3.5.1 Structural Analysis

In seismic structural analysis, the interpreter studies reflector geometry/shape based on the reflection time obtained as the result of seismic data acquisition, followed by seismic data processing. The main objective of seismic structural analysis is to search for traps that can hold the commercial hydrocarbon. The most common structural traps are four-way dip closure and fault-bonded structures (Sedki et al., 2025).

Following workflow is adopted for completion of structural seismic interpretation (Figure 3.8).

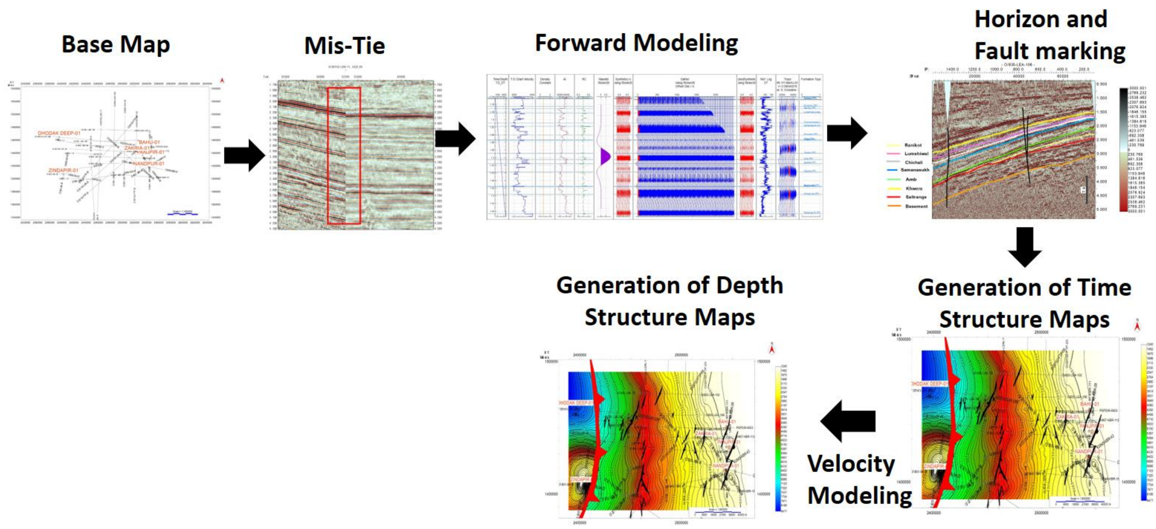

Figure 3.8 Workflow adopted for seismic structural interpretation. It started with loading of data, generation of base map followed with mis-tie analysis. Horizons were identified based on forward modeling. After identification of horizon, seismic interpretation followed. The time and depth maps were generated based on seismic interpretation.

3.5.2 Data Loading

2D seismic data up to PSTM processing was utilized for the current study. It is worth mentioning that no 3D data is acquired in the study area to date. The data was loaded in Kingdom software. The shot points, CDP, and trace were given in the header file, which was utilized for the loading. For this study, 765-line Km across the entire study area are utilized. The acquisition parameter of 2D seismic utilized for this study has a source and receiver interval of 50 m. The fold of the 2D seismic data is 100. The 2D seismic data quality in the region varied from fair to good. Well data comprising of digital LAS files, VSP and core data from six wells, namely Bahu-01, Panjpir-01, Nandpur-01, Zakria-01, Dhodhak-01, and Zindapir-01, were utilized from this study. The digital LAS files and well tops of six wells were loaded in Kingdom software.

3.5.3 Base Map

Base map generation started with the loading of seismic and well data. All the seismic lines were in SEG-Y format, loaded in Kingdom software by using data loading tool. The navigation of loaded seismic lines were QC. The seismic data is annotated in a manner that shot points do not overlap each other. The dip lines in the base map have east and west orientation, and strike lines are oriented north and south. In base map generation, special care regarding the seismic line selection was taken. Seismic lines were selected in a way that a regional east-west transect can be generated.

Also, the key well, Zakria-01, which was drilled up to the basement, was tied to the seismic lines. Similarly, the wells were loaded in the kingdom software. First the geographical coordinated were entered, which located the well at true location. After that the digital logs were imported. Total of six wells were loaded in the software. In well selection, the Bahu-01, Panjir-01, and Nanpur-01 wells lie in the eastern part of the study area, whereas the Zakria-01 well was selected as it lies in the western part. No well has been drilled to date in the further west of the Zakria-01 well in the Foredeep area. Two wells, namely Dhodhak Deep-01 and Zindapir-01, were selected in the Sulaiman Fold and Thrust belt.

3.5.4 Mis-tie Analysis

When interpreting seismic data, there are situations when the two different seismic sections did not match with each other. It shows the mismatch of interpreted horizons between two tie lines. Mistakes often happen when data with varying datum corrections or phases are connected, instead of uniformly zero-phase data being interpreted together. To correct the mis-tie, there are two approaches, one is dynamic and other is static shift. When data shifts in bulk, as happens when connecting seismic sections with various datum corrections, the mis-tie is referred to as static. When data migrates differentially, on the other hand, the mis-tie's magnitude changes over time, and this is referred to as dynamic shift. In some cases, when the utilized data has so many vintages, it is nearly impossible to adjust the shifts among 2D seismic lines. To avoid this scenario, the 2D seismic lines with most ambiguous shifts were excluded from the data set. If all the 2D seismic lines are important for mapping, the only approach to adjust the mis-tie is to re-process the 2D seismic data. During the reprocessing velocity picking, datum shift, phase and polarity issues can be resolved.

For this study, all the 2D seismic data was loaded in the Kingdom software and was analyzed to calculate the mis-tie. The bubble map technique was used to analyze the mis-tie among the 2D seismic data. In this technique the software analyzes the 2D seismic data for the shifts based on prominent markers on seismic. During mis-tie analysis the 2D seismic data showed mis-tie as the 2D seismic lines belong to different vintages, it has a mis-tie of 50 msec in the 2D seismic line O/20152-LDN-11 (Figure 3.9).

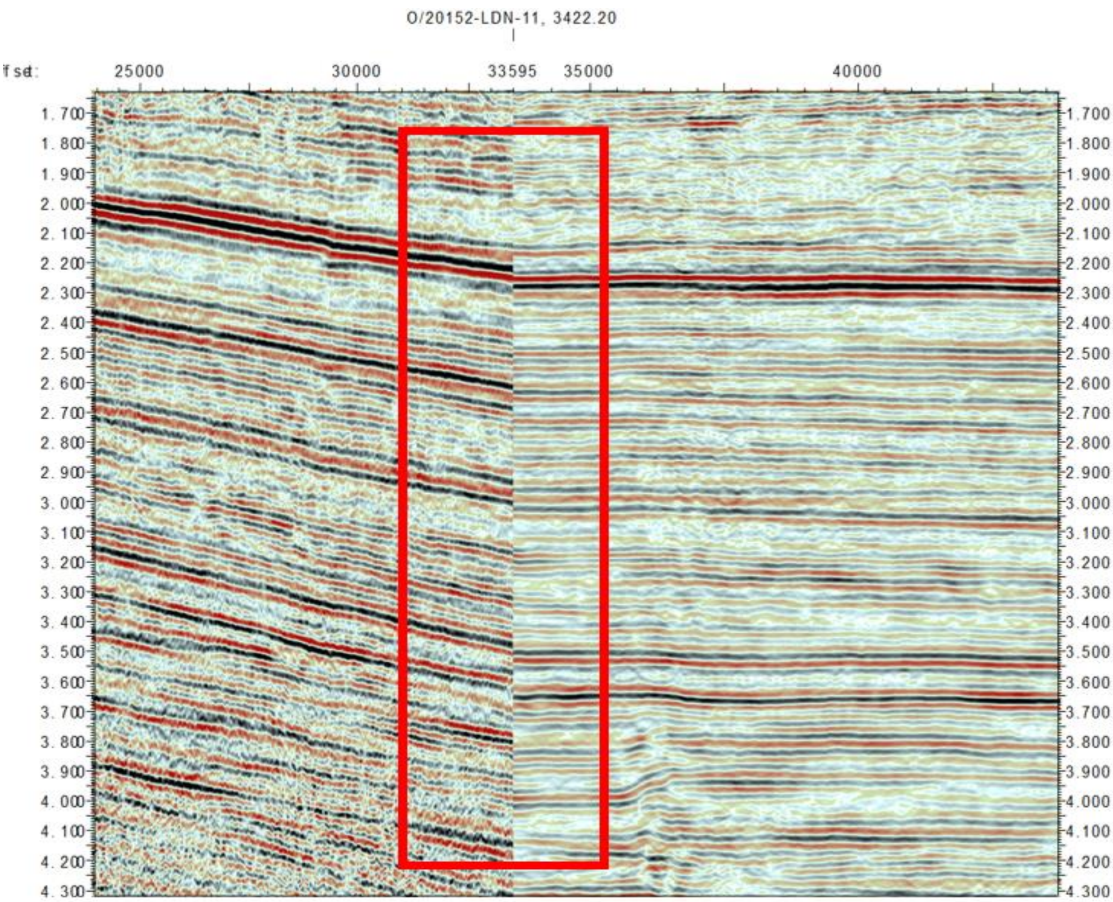

Figure 3.9 Represents the Composite line of two different vintage of seismic lines. It is clearly visible the mis-tie of about 50 m sec is evident between two different seismic vintages.

It is very important before the seismic interpretation to adjust the mis-tie among the 2D seismic lines. Bulk shift was applied based on the mis-tie analysis; the bulk shift was applied to the different seismic vintages to minimize the seismic datum effect. After the application of mis-tie on seismic data, the composite lines show no mismatch of seismic reflection (Figure 3.9).

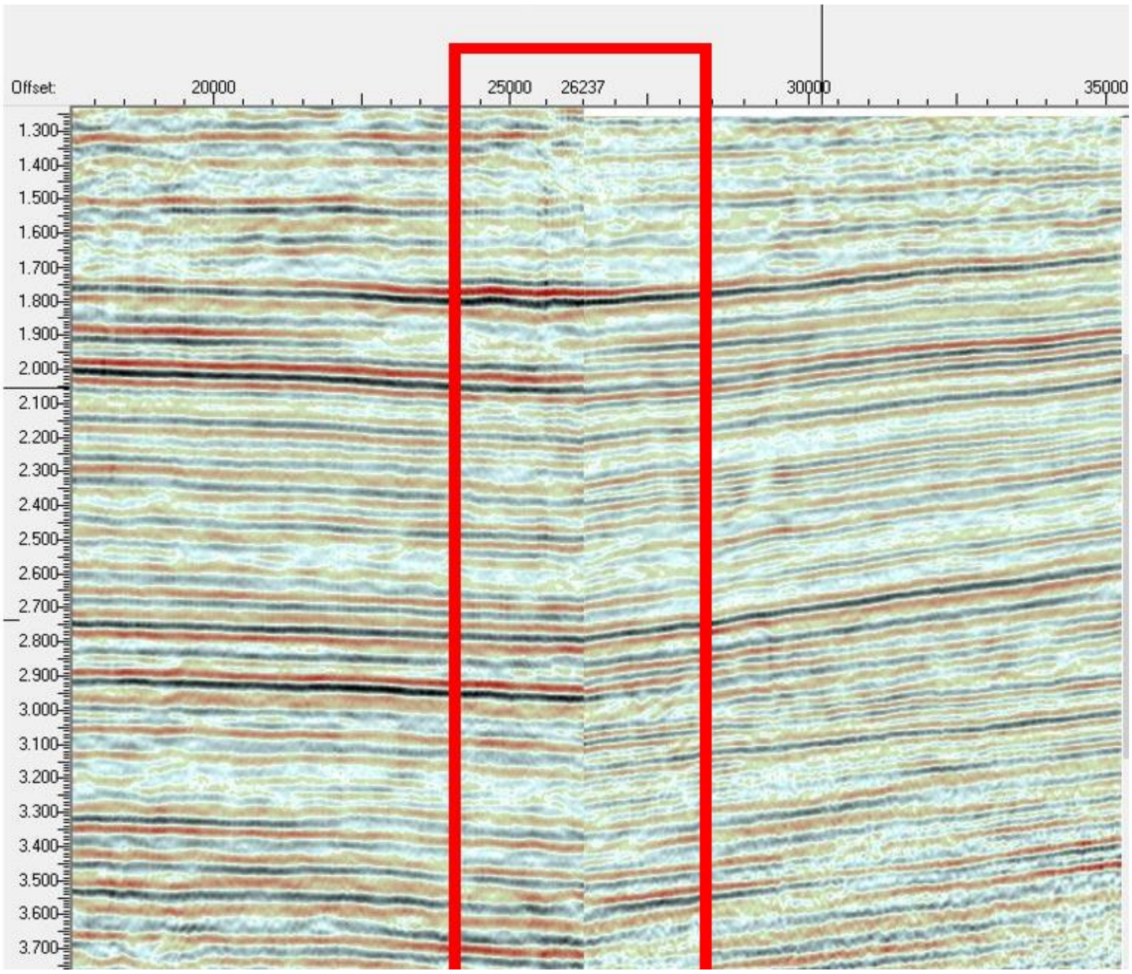

Figure 3.10 Bulk shift of 50 msec was applied on the 2D seismic data to remove the effect of seismic datum shifts among different vintage data. It is clearly visible the after the application of mis-tie the seismic data align and ready to use to further seismic interpretation.

3.5.5 Forward Modeling

Forward modeling is the first step before the start of seismic interpretation. In forward modeling a synthetic seismogram was generated. In a synthetic seismogram, the expected seismic response of the rock sequence encountered in the well can be calculated as a one-dimensional issue, i.e., as if the subsurface interfaces are horizontal and the ray routes are vertical. In this manner, rays are generally incident on the interfaces. The main purpose of the synthetic seismogram is to identify the polarity, phase, and seismic character of particular formation, that can be identified and later can be translated from key seismic line to all seismic data set. Its generation started with the digital logs and seismic data. Synthetic seismograms were created utilizing the sonic and density logs. Velocity is the inverse of DT and can be determined from sonic data and density data are obtained from the density log (Figure 3.11). The acoustic impedance can be obtained by multiplying density and velocity obtained from sonic and density log. The seismic wavelet is recovered from the 2D/3D seismic lines; it was the ricker wavelet. The zero-phase ricker wavelet was used. The frequency analysis of seismic data was performed. The dominant frequency of seismic data was 26 hertz. The 26 hertz frequency ricker wavelet was convolved with the reflection coefficient to get the seismic trace.

A seismogram is necessary to connect a well to a seismic source. As a result, sonic and density logs from the Bahu-01 and Zakria-01, as well as their GR records, are used as references for seismic correlation. The seismic data traces around the wellbore were utilized to create a wavelet, which was then convolved with the impedance log generated from the well's density and sonic logs to produce a final synthetic seismogram. Following that, the synthetic seismogram was compared to the 2D seismic line. Once the generated synthetic seismogram and original seismic were matched, the well-to-seismic relationship was accomplished and work proceeded on to the next step, which was horizon selection utilizing the time depth chart correlation created during the tie. The synthetic seismograms were developed from Bahu-01 well. The signatures of significant reflectors of the Samana Suk, Chichali and Lumshiwal Formations were found based on the Bahu-01 synthetic seismogram and translated into all 2D seismic data (Figure 3.11).

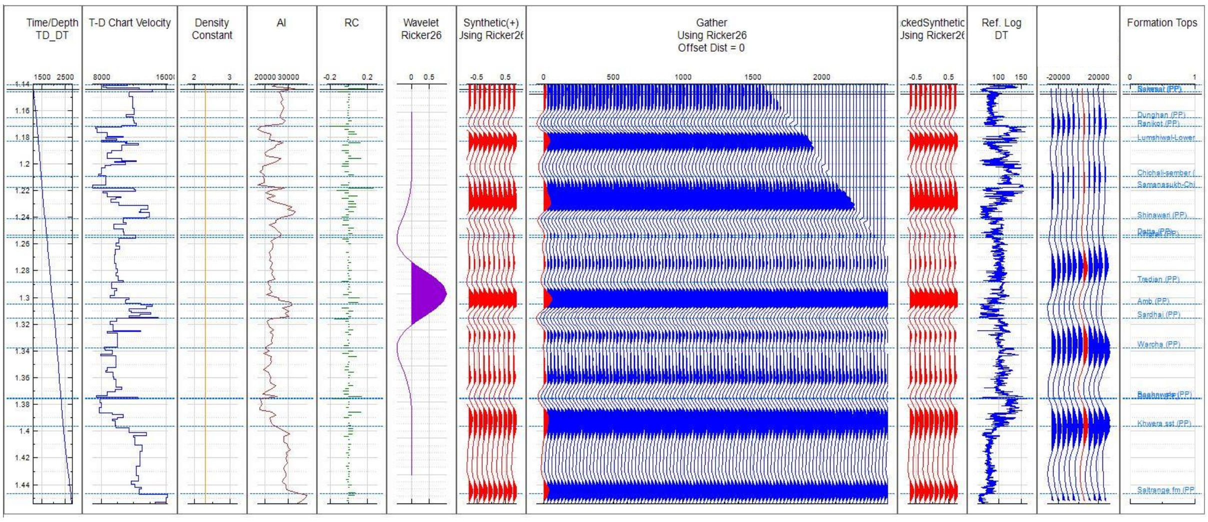

Figure 3.11 Shows the synthetic seismograms created using Bahu-01 well logs. The signature of prominent reflectors of the Samana Suk and Lumshiwal Formation were identified based on Bahu-01 synthetic seismogram and translated into all 2D seismic data.

The synthetic seismogram was developed at Zakria-01well. The sonic and density logs were used. The velocities were calculated from sonic log and densities were calculated from density log. The acoustic impedance was calculated by multiplying sonic and density log in fifth panel of (Figure 3.12). The signature of significant reflectors of Samanasuk Chichali and Lumshiwal were found based on Zakria-01 synthetic seismogram and translated into all 2D seismic data specially in western portion of Punjab Platform (Figure 3.12).

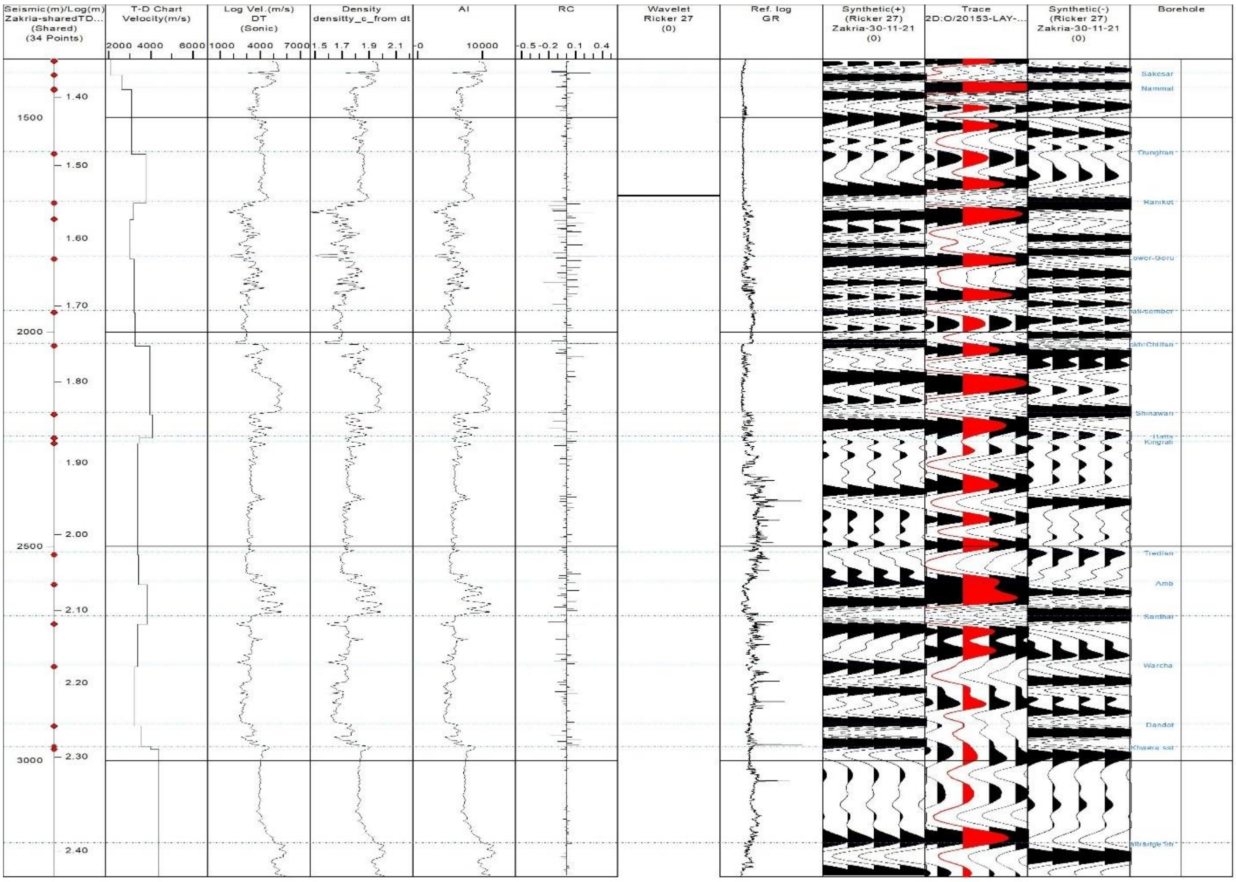

Figure 3.12 The synthetic seismograms generated at Zakria-01 well by using density and sonic logs. GR log is used as reference well. The signature of prominent reflectors of Samana Suk, Chichali and Lumshiwal were identified based on Zakria-01 synthetic seismogram and translated into all 2D seismic data.

3.5.6 Fault and Horizon Interpretation

The regional geology and tectonics of the area are the antecedents to correctly interpret geology and structure. Among these structural styles, the key is to appropriately designate faults according to the sense of their displacement as normal or thrust. Furthermore, after being designated, these faults are subjected to seal or trap analysis because when the reservoir horizon comes into contact with the sealing horizon, migration is prevented, and hydrocarbons can be preserved. Fault planes perceive displacements as vertical or horizontal movement along themselves (Ferrill et al., 2001).

On seismic sections, these faults are designated according to the geology and structural style of the area, but their degree of displacement aids in determining their nature. The sensation of displacement refers to movement along a fault line, which can be vertical or horizontal and occur separately or concurrently in nature. The displacement between the two fault blocks ranges from fractions of a meter to kilometres, and it is frequently dispersed throughout the fault zone rather than limited to a single fracture. The fault line becomes apparent as a fault trace or outcrop when the surface ruptures, but not before to this breakdown.

An oblique-slip fault is formed when horizontal and vertical movement along the fault line are roughly symmetrical. The entire horizontal movement along the fault plane results in strike slip faults, also known as lateral faults (Roche and Van, 2025). Of these lateral faults, the left lateral fault is called the sinistral faults and the faults with right lateral movements are called dextral faults. The active strike slip fault has offset shots running through it. These transform faults produce zones of lateral movement in which the feeling of displacement changes form and direction or simply pauses. The region of lateral displacement is between spreading centres; otherwise, no displacement occurs outside of them.

Dip-slip faults travel vertically along the fault plane and are further classed as normal and reverse faults. According to the miner's posture, the hanging wall is the package over his head, while the foot wall is the package underneath his feet. So, a fault is normal when the part of earth above the fracture travels downward in contrast to the section below the fracture, and a fault is reverse when a package of strata above the fracture slides upward in comparison to those beneath. The faults with dip angle less than 45° are classified as thrust faults (Zhao and Nissen, 2025). During thrust faulting, older rocks often lie on younger rocks; yet, younger rocks are frequently thrusted over older rocks.

These faults on seismic sections are identified when reflectors behave consistently over a seismic profile, i.e., the bed exhibits a vital feeling of displacement in a specific geological fashion. The fault correlation is performed concurrently with their marking on the seismic section. Faults are first marked with utilities in the Kingdom suite and then assigned. The process of awarding fault names is based on correlation, which is enabled by specific geological principles. The idea of their dip direction and angle of dip is taken into account for each individual defect when marking it on one line and then on other lines in a survey. This notion enables us to accurately assign a defect and correlate it across the entire survey.

As the study area lies in a less disturbed tectonically active zone, it is a gentle monocline dipping in the west direction. The normal faults were interpreted on the seismic section with very little throw. Most of the interpreted faults showed nearly vertical displacement. The interpreted faults had an orientation of NE-SW. For the horizon identification, the seismic horizons from the synthetic seismograms of the Bahu-01 and Zakkri-01 wells were translated into all 2D seismic lines. At first, the horizons were marked on a well line, and then loop correlation techniques were employed to translate the horizons from one seismic line to another. During seismic interpretation it was observed that the thickness of strata is increasing from east to west. The fault was interpreted on the seismic lines. The faults have normal sense of movement and has negligible throw. The throw of the faults is negligible, as the study Area lies in less deformed zone. The faults were interpreted on all seismic lines and on base map faults were joint together to form a polygon. The faults polygons were then used in the seismic mapping at different formation levels.

3.5.7 Contouring

In 2D seismic data, reflection lines are typically projected as horizontal distance vs two-way trip time, and this information, together with an interpreted time section and a geographic base map, may be used to construct a contour map of any geological structure. After all of the mis-ties associated with all of the seismic lines had been properly rectified, a final base map was constructed with updated two-way time values. It was assured that the contouring technique is devoid of ambiguities and mistakes, and that there is a proper contour interval. Furthermore, the base map created represents one's competence, as does the display of shot point data on the base map. This presentation needs a suitable interval that is smaller than the structure to be mapped.

Flex interpolation gridding method was used in Kingdom software. The flex gridding method uses different solution, the solution of which provides the values of grid nodes that satisfy the two criteria. The interpolated surface must either intersect or closely approximate the data inside the XYZ space. The surface must conform to a user selected mathematical criterion to the greatest extent feasible without contravening criterion 1. Due to the computational intractability of concurrently solving all equations, an iterative method is used. Each equation pertains to a single grid node and has terms that include only a limited number of its neighbouring nodes. Consequently, they are all interconnected; yet, the connections to remote nodes are tenuous and indirect. For this reason, each equation is solved to provide a grid value, assuming the nearby nodes remain constant. As the other nodes change, this procedure is repeated. With an unlimited number of iterations, the grid will converge to the desired answer, but in reality, a decent result was with considerably less iterations. Following are the different velocity methods for depth conversion.

3.5.8 Velocity Modeling for Depth Conversion

There are various techniques for the conversion of time structure maps into depth structure maps. Velocity is the bridge between time and depth domain. The following different velocity modeling techniques can be used for the generation of depth structure maps.

3.5.8.1 Average Velocity Method

In average velocity method, a particular formation can be converted into depth domain by using well velocities. The average velocity map can be generated by using the average velocity and the values can be used to generate the velocity map. The depth map can be generated by multiplying the average velocity to time map (Nanda et al., 2011).

Depth map = Time map/2*(avg velocity)

3.5.8.2 Interval Velocities Method

This method considers the individual formation velocity. It treats every layer with constant velocity. Derived from the depth thickness (isochore) the interval velocity divided by the time thickness (isochron). Interval velocity either from seismic or well data can be used to generate the average interval velocity map. The interval velocity maps multiplied by the time map to generate the depth map (Ogbamikhumi & Aderibigbe, 2019).

3.5.8.3 Velocity Function

Velocity functions are derived from time and depth relations. Values of time and depth preferably taken from well vertical seismic profile data. In sedimentary rocks, velocity usually increases with depth owing to sediment compression generated by burial. Functions may be deployed as separate layers or as part of a layering system. There are two major approaches for employing a velocity function:

a. A function having constant values. Because a standard value is utilized which cannot be applied on all available wells. This approach is very helpful in converting depth where limited well data.

b. The function that uses well data to interpolate a variable argument. This method functions well in areas with a high degree of well control and automatically fits the wells. Polynomial, exponential, and linear functions are all possible.

Depth conversion was done out by employing the polynomial function approach. Velocity study was done out by employing Zakria-01 well Two-way time (TWT) and True vertical depth sub-sea (TVDSS). It requires assessing the velocity data sets and the features of the subsurface layers for consistency. The polynomial function technique incorporates the application of the updated velocity function produced from seismic to well tie process that illustrates the velocity trend in the study area. A trend line was constructed using the plot of true vertical depth sub-sea (TVDSS) vs two-way travel time (TWT) of the updated velocity, and the required polynomial equation was calculated (Figure 3.13).

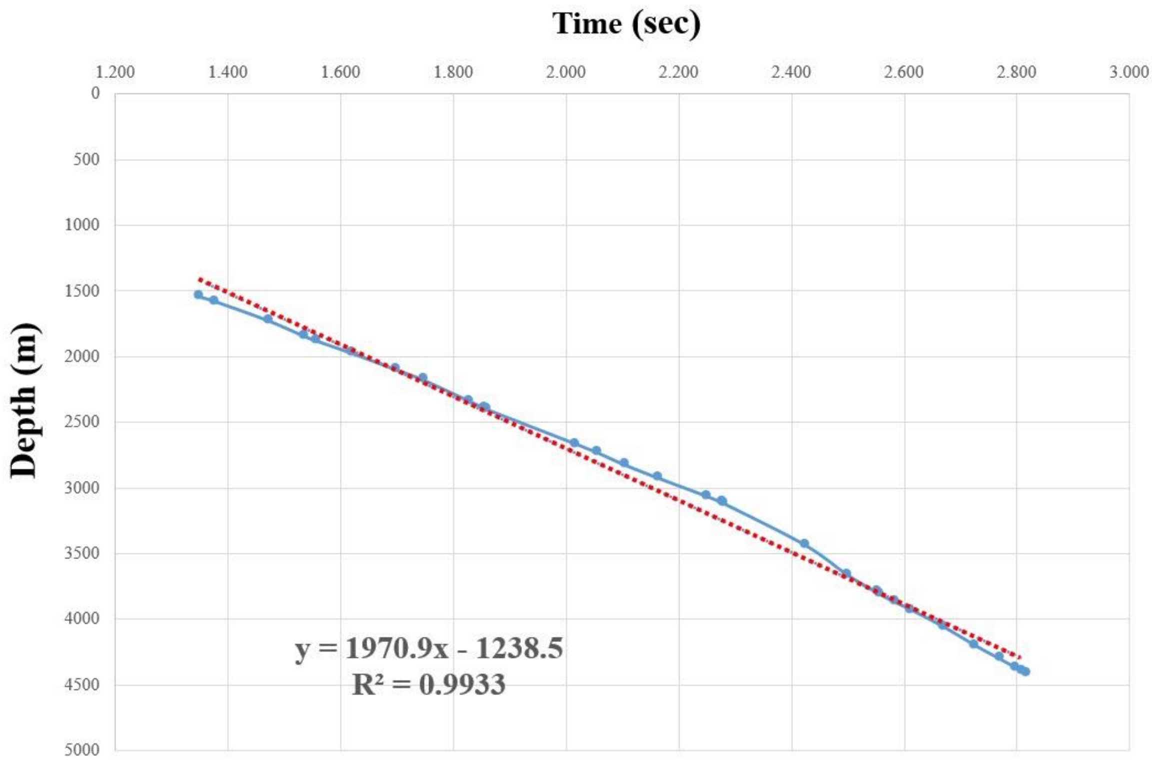

Figure 3.13 At Zakria-01 well, a trend line was constructed using the plot of true vertical depth sub-sea (TVDSS) vs two-way travel time (TWT) .The required polynomial equation was calculated.

The Figure 3.13 illustrates a linear connection at the target interval. There is no gap between the two-velocity data, which shows that there is no lateral variability in velocities. The equation that explains the velocity function may be stated using the equation of a straight line. For current study linear function of Zakria-01 well was used to translate the time map into depth map. This method is most robust, advance and reliable for depth conversion. The depth converted maps were tied at the wells for the QC purpose. The depth converted maps were checked at Zakria-01 and Bahu-01 wells.

3.5.9 Generation of Time and Depth Maps

The pre- or post-stack time migrating seismic image volumes give an appropriate technique to visualize time horizon. The current approach used post-stack time moved data, which can only improve imaging of contradicting dips with differing stacking velocities. While the pre-stack time migrating portions preserve true geological dip patterns of the bed by utilizing rms velocities (MacBeth et al., 2023).

When properly constructed, time contour maps provide an accurate trend of underlying geology. The contour maps were created using seismic time of all horizons independently. All seismic lines were used for this purpose. Time structure maps were generated from marked horizons namely, Lumshiwal Chichali, Samana Suk, Khewra Sandstone, and Salt Range Formation. The color palette depicts a rising trend of seismic time from south-east to north-west, which is also consistent with the trend of monocline growth on the Punjab Platform. Vertical and sub vertical faults were marked and translated to faults polygon during mapping phase.

Converting time domain to depth domain is very important step in seismic interpretation. The area covers the large are from Sulaiman Foredeep to Punjab Platform, having seismic time variation from east to west. The velocity was taken carefully to cover the different tectonic settings which are responsible to velocity change. The eastern portion Bahu-01, Panjpir-01 wells where analysed, similarly the Zakria-01 well velocities were plotted in parallel to eastern well. No well was drilled in western part of portion of study area. By analysing the velocity of all available well, an average velocity function was derived, which represents the change of velocity as the time changes. This velocity function was used to convert the time map into depth maps. This average function approach is most authentic approach for generating depth maps.

3.6 Migration Pathways

3.6.1 Introduction of Migration Pathways

Hydrocarbon migration may be divided into two categories. One is primary and other is secondary migration. Primary migration is the movement of hydrocarbon within the source rock upon maturity. Whereas the secondary migration refers to the movement of hydrocarbons from source rock to the carrier beds (Guan et al., 2025). Valid trap is necessary to the entrapment of hydrocarbon. Secondary migration hydrocarbon may start to in continuous fluid phase though porous sedimentary rocks. If the source and reservoir is placed near to each other the hydrocarbon from source can also move in reservoir. If the reservoir is far shallower than source rock, the faults act as the conduit from for the migration of hydrocarbon from source to reservoir rock. This movement of hydrocarbon from source to reservoir rock through faults referred as secondary migration (Guan et al., 1979). The fluid then concentrates in trapped accumulations of gas and oil. Several processes have been suggested to explain primary migration. Hydrodynamics and buoyancy are the primary processes for secondary migration that have been suggested.

Successful hydrocarbon exploration is dependent on the entrapment of hydrocarbon within the trap that were expelled from source rock. It is very important to understand the factors that affect the hydrocarbon migration tracing hydrocarbon migration paths, evaluating hydrocarbon displays, estimating seal capacity, developing found fields and generally comprehending the distribution of hydrocarbons in the subsurface is necessary to hydrocarbon exploration (Zhiliang et al., 2016).

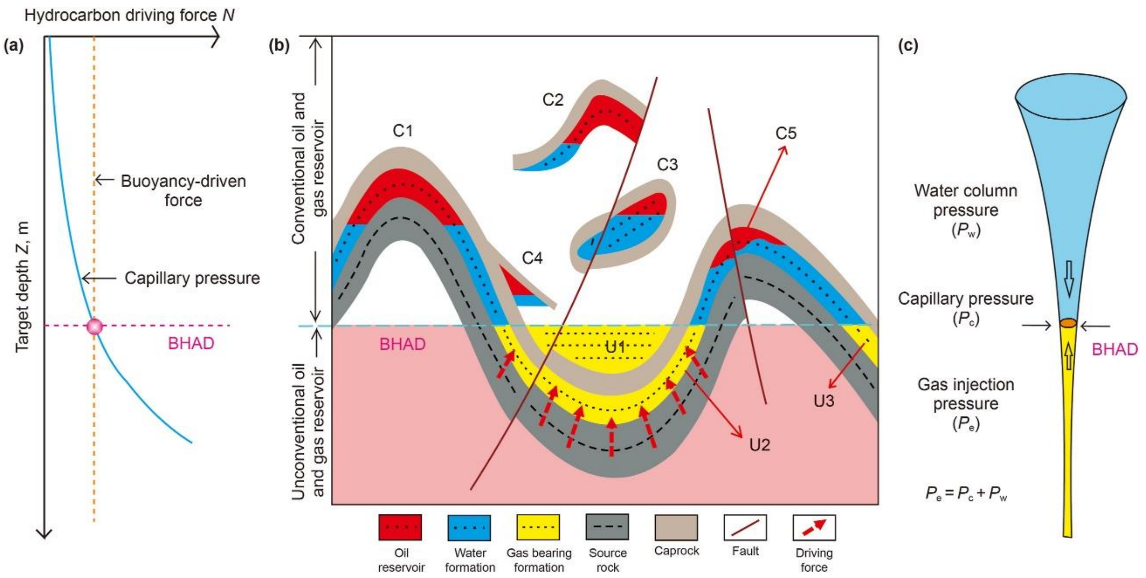

Figure 3.14 (a) Buoyance driven hydrocarbon accumulation depth is the primary factor behind continuous-phase secondary hydrocarbon migration under hydrostatic circumstances. (b) Model represents the migration and trapping of hydrocarbon. (c) Represents the pressure differential between the water and oil phases over a bent oil-water contact is known as capillary pressure. Reduced maximum pore throat radius causes hydrocarbon accumulation mechanisms to change from shallow to deep, sealed reservoir (modified after Pang et al., 2025).

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3.6.2 Mechanics of Secondary Hydrocarbon Migration

Oil has less density than water. Because of the density contrast oil and water cannot be mixed and are immiscible (Shi et al., 2025). Hydrocarbon release from the source rock, moves upward due to hydrodynamics or buoyancy. The phase of ascent is dependent on the density difference. Hence, buoyancy is the primary factor causing the oil to rise through sea water (Figure 3.14). The primary factor behind movement of hydrocarbon in water is dependent on buoyancy (Table 3.3). There is a resistive force that prevents hydrocarbons from migrating below the surface, where oil must pass through rock pores. This force did not exist in the simple case. The rock's pore throat radius, hydrocarbon water interfacial tension and wettability are the three parameters that control the strength of this resistance force. The collective term for these elements is "capillary pressure." The pressure differential between the water and oil phases over a bent oil-water contact is known as capillary pressure (Dolson et al., 1979).

Table 3.3 The primary factor behind the hydrocarbon migration through subsurface rock is buoyancy.

Migration mechanism	Migration rate
Buoyancy	meters per day (gas)
Hydrodynamic	0.1 to 100 m/year
Compaction	0.001 to 1m/year
Diffusion	1 to 10 m/ million years

3.6.3 Main Driving Forced for Hydrocarbon Secondary Migration

The hydrocarbon and water have different densities. A buoyancy is the main force for driving hydrocarbon is produced when the hydrocarbon and water, two immiscible fluids interacts (Al-Mimar et al., 2025). The hydrocarbon due to its low-density floats upward in a rock. The hydrocarbon column height, the driving force like buoyancy increases with increasing density differential (always measured vertically). Buoyancy is the primary factor behind continuous-phase secondary hydrocarbon migration under hydrostatic circumstances The buoyancy force rises through a static continuous hydrocarbon column in a vertical manner. There is a free water present in the pores of sedimentary rock. This free water in sedimentary pores is called free water. This is often referred to as the buoyant force's zero point (Huettel & Webster, 2001).

There is a point in sedimentary rock where there is less than hundred percentage water saturation. Depending on the fluid's density, each static fluid will have a different slope when its pressure is plotted versus depth. Static fluid pressure gradient or slope can be found by using fluid density. Height above free water level causes pressure to drop. The bouncy force is the pressure difference between water and hydrocarbon phase above the free water level. Above the free water level any location above the free water level, the buoyant force is the difference in pressure between the oil and water phases. The pressure gradients for water and oil (psi/ft) can be subtracted to calculate the buoyancy gradient or buoyance pressure change with height (Yusuf et al., 2012).

In order to determine buoyant driving variables in hydrocarbon entrapment and secondary migration, hydrocarbon and water phase subsurface densities are crucial. Because water density in subsurface normally range from 1.00 to 1.20 g/cc and SWP gradients are usually between 0.43 and 0.520 psi/ft. Static oil pressure gradients range from 0.220 to 0.430 due to the variety of oil density in subsurface, which are 0.50 to 1.00 psi/ft. Oil-water buoyancy gradients are often 0.1 psi/ft for the usual subsurface water and oil densities. However, the variety in water and oil densities discovered beneath the surface indicates the ability of hydrocarbon and eater to travel through the rocks or being trap under the seal rock. The methane las the lower density than the natural gas, it has the density of 0.00073 g/cc at atmospheric pressure, whereas common natural gas blends have a density of about 0.50 g/cc. For naturally existing gas, the subsurface static pressure gradients range from less than 0.001 to more than 0.220 psi/ft. The bouncy gradient of water and gas ranges from 0.2 to 0.5 psi/ft in the subsurface. The movement and trapment of hydrocarbon in the structural or stratigraphic trap are dependent on the hydrocarbon water system. Water gas systems are typically more potent as compared to water oil system (Hantschel et al., 2009).

Water and hydrocarbon densities are important for the calculation of bouncy. For the values of hydrocarbon and water densities to use in the work of petroleum explorationists, they must be derived from data that they usually have access to temperature and pressure and quantity of dissolved particles are the three primary factors influencing the density of subterranean water (Dahlberg et al., 2012).

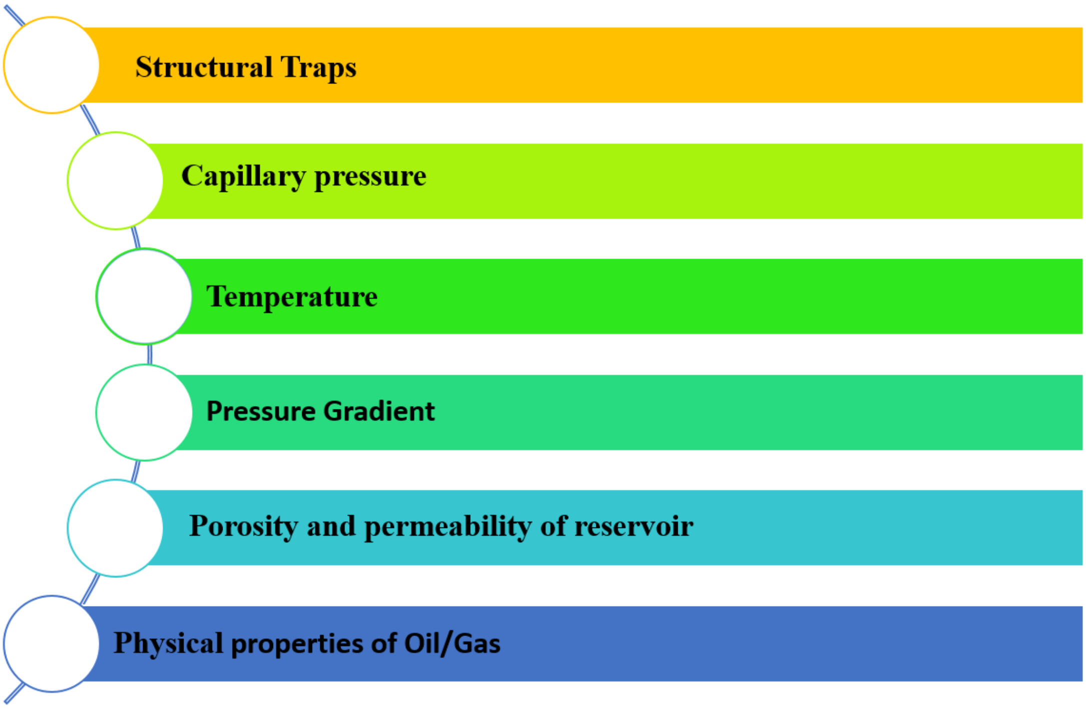

Figure 3.15 Shows the factors effecting the hydrocarbon migration. Temperature, pressure and composition of Hydrocarbon (hydrocarbon and gas) affect the density of oil below the surface. hydrocarbon and water phase and density play a significant role in identifying buoyant driving factors in hydrocarbon entrapment and secondary migration.

The scale of chloride ion may be used in circumstances when chloride is the predominant negative ion. It is recommended to use the higher scale for total dissolved solids for fluids that include noticeable concentrations of negative ions other than chloride. In most exploration scenarios, the total dissolved solids or chlorinity, together with the relevant pressure and temperature data, are provided. Although subsurface temperature and pressure should be translated first, direct measurements of water densities may also be used. The density of oil beneath the surface is influenced by temperature, pressure, and composition of hydrocarbon (oil or gas). The subsurface density of oil or condensate can be reasonably accurately calculated if solution gas-oil ratio and the stock tank API gravity are known (Hu et al., 2012).

Petroleum engineers sometimes take direct measurements of hydrocarbon properties known (Chaudhuri, et al., 2011). These pressure-volume-temperature (PVT) gives the most accurate estimations of sub surface oil dentistry when they are available (Figure 3.15). The subsurface density of a gas is determined by volume ratio technique. The apparent molecular weight of given quantity of gas is correlated with its mass. The apparent average molecular weight, temperature, and pressure all affect the volume that the gas occupies.

3.6.4 Factors Effecting the Hydrodynamics on Driving Forces

The water is the important factor for the movement of hydrocarbon. To analyze the secondary hydrocarbon migration and entrapment of hydrocarbon in structural or stratigraphic trap, it is important to know the hydrodynamic factors on bouncy for the driving of hydrocarbon in the subsurface. The hydrodynamics factors change in depth due to pressure and ultimately the bouncy force varies for the hydrocarbon migration in a particular column height (Wendebourg, et al., 2011). The force known as buoyancy for static oil filament is defined as the pressure changes that take place in the water phase for a certain hydrocarbon height that occurs above the free water level. The buoyant force and water pressure at any one time are different under hydrodynamic circumstances than they are under hydrostatic settings. The buoyant force and water pressure at any one time are different under hydrodynamic circumstances than they are under hydrostatic settings.

Hydrodynamic circumstances will cause a given oil column's buoyant pressure to vary. The potential water and oil pressure difference at the top of hydrocarbon column trapped in structure will be an upward movement of water within the reservoir than it would be for an oil column of the same height in the hydrostatic scenario. The difference in pressure between the hydrocarbon (oil and gas) and water at the top of a particular hydrocarbon column is lower in a reservoir experiencing downward water flow than it would be in a hydrostatic scenario for an oil column of the same height (Hantschel et al., 2009).

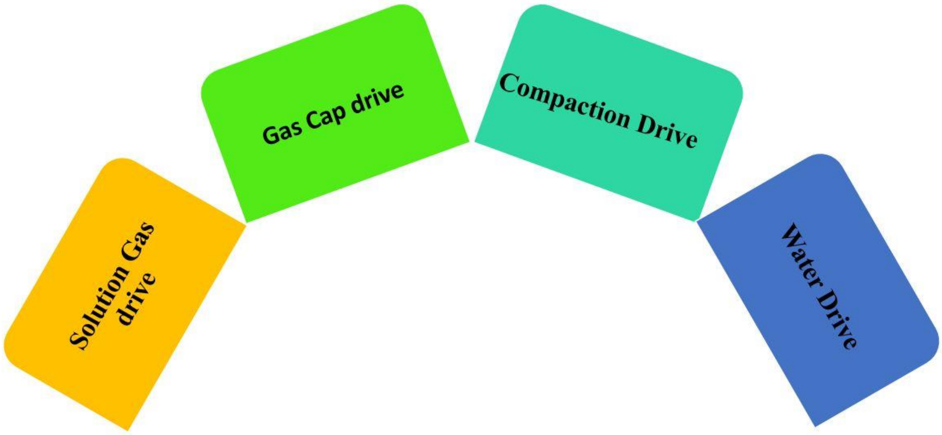

Figure 3.16 Represents the major driving force for secondary hydrocarbon migration. Solution Gas cap, Compaction and water drive are the major driving forces for secondary hydrocarbon migration.

The buoyancy force is responsible for the flow on hydrocarbon in upward direction. It can be applied to the stratigraphic entrapment of hydrocarbons. There is also downward movement of hydrocarbon, the downward movement of hydrocarbon increase the lateral seal capacity of rock as result of decrease in buoyancy pressure. For a specific hydrocarbon filament, up dip flow would increase the buoyant force from the hydrostatic, lowering the lateral seal capacity in that area (Dolson et al., 2009). It is easy to observe how important hydrodynamics is to the trapping of hydrocarbons while looking for small stratigraphic traps. Chengzao et al. (2021) demonstrated the advantages of a down dip hydrodynamic state, such as the capacity to capture commercial quantities of hydrocarbons and enhanced lateral seal capacity. The downward movement happens due to the either gravity or hydro-dynamics flow (Figure 3.16).

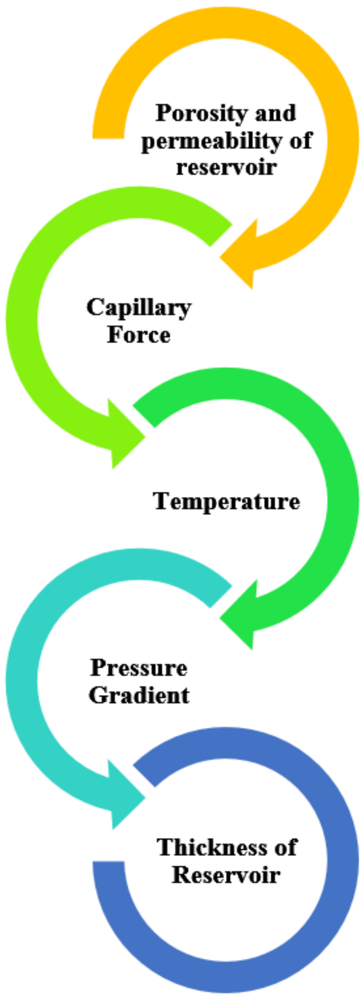

Figure 3.17 Factors effecting the flow of hydrocarbon during migration phase. The hydrocarbon movement will ease due to increase in porosity and permeability. Similarly, temperature and pressure gradient dictate the movement of hydrocarbon within reservoir.

The reservoir properties like porosity and permeability is very important for the flow of hydrocarbon in reservoir rock. The porosity is amount of free space available in the reservoir rock. The more sorted reservoir rocks have increase porosity. The clastic reservoirs have primary porosity whereas the carbonate rock has diagenetic or secondary fractures porosity. The more porosity means the more flow of hydrocarbon in the reservoir. Apart from the porosity the permeability is very important for the flow of hydrocarbon (McKinley et al., 2011). Permeability is the connection of pores in the reservoir. The well sorted grains with larger pore throat have increase permeability (Figure 3.17).

It is evident that hydrodynamics must be considered when attempting to evaluate the hydrocarbon entrapment after the secondary hydrocarbon migration. In the hydrocarbon exploratory phase, the seal rock capacity will be increase and hydrocarbon fill will not surpass hydrostatic conditions until the secondary hydrocarbon migration exceed the hydrodynamics conditions. Also, the seal rock capacity for the hydrocarbon entrapment will not get zero due to the upward movement of water flow. The hydrocarbon will be trap in the structure up to the spill point (Luo et al., 2016).

3.6.5 Forces that Resist the Secondary Hydrocarbon Migration

To move or travel the hydrocarbon through the reservoir rock, it must be squeezed through its pores. Practically, the pore size is to be large enough to facilitate the hydrocarbon migration through reservoir rock. Several resistive forces act to slow or stop the movement of hydrocarbon migration is in the rock. The movement of hydrocarbon in the rock is dependent on the pore size of the rock, the larger pore size will facilitate the more flow of hydrocarbon. Wettability is also another force involves in resistance of hydrocarbon. There is water hydrocarbon interfacial tension, the angle of contact between water and hydrocarbon along with solid pores wall. This resistance force is known as the capillary pressure (Zhang et al., 2019).

The secondary hydrocarbon will start when there is continuous movement of hydrocarbon through the pores of reservoir rock. The vertical hydrocarbon column displacement can be measure through the displacement pressure. This value's magnitude would dictate the least hydrocarbon column required to expulsion of hydrocarbon in particular rock for the sealing capacity of seal rock. Thus, in subsurface petroleum exploration, the resistance forces foe the hydrocarbon migration is important to understand (Allen et al., 2013).

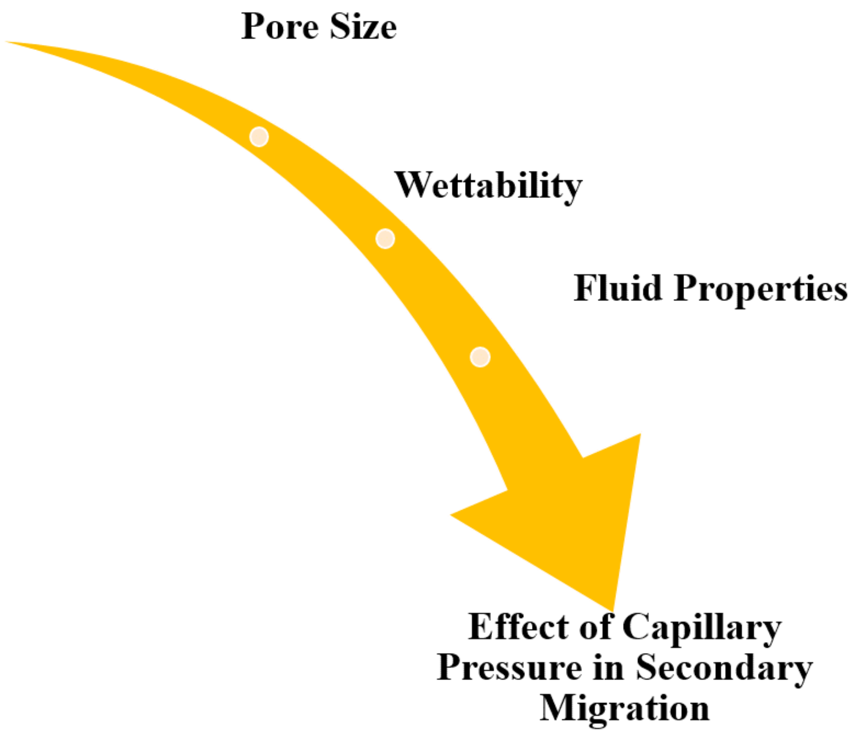

Figure 3.18 The major resistant forces during secondary migration. The mobility of hydrocarbons in the reservoir is influenced by the pore throat radius of the rock, interfacial tension pore throat and the degree of wettability. For the hydrocarbon to start moving it need to push due to pressure.

For the hydrocarbon migration in the rock, it is important to measure the displacement or breakthrough pressure, wettability, pore throats and hydrocarbon-water-interfacial tension must be measured or estimated (Figure 3.18).

3.6.6 Interfacial Tension

The amount of energy needed to increase the contact between two immiscible fluids (such as water and oil) by one-unit area is known as interfacial tension. Interfacial tension results from difference of same molecules with fluid and attraction between the molecules. The interfacial tension of water and oil is influenced by the composition of oil, type and number of chemical, concentration of gas, the water's pH, temperature and pressure. The interfacial tension between water and oil decrease as the result of increase in temperature (Miadonye et al., 2019).

Calculation of oil-water displacement pressure requires an estimate or measurement of subsurface interfacial tension between oil and water. Advanced laboratory equipment can be used to quantify the interfacial tension between oil and water within the reservoir. The interfacial tension between hydrocarbon (oil) and water is about 70 dynes/cm at atmospheric pressure and temperature. The interfacial tension between gas and water is influenced by pressure, temperature, the quantity of heavy hydrocarbons in solution in the gas and the quantity of surface-active materials in the water (Moeini et al., 2014). The interfacial tension between gas and water decreases by 5 to 10 dynes/cm. The interfacial tension between oil and water decrease as the subsurface temperature rises, reaching a subsurface range between 10-20 dynes/cm. The interfacial tension between gas and water are therefore greater than the interfacial tension between oil and water in both the surface and subsurface. As a result, the water and oil displacement pressure is greater than water gas displacement pressure. Thus, a gas water displacement pressure would be greater than an oil water displacement pressure. Ultimately, due to the high water gas interfacial tension compared to water and oil interfacial tension decreases the gas migration potential in the reservoir rock buried in sub-surface and water saturated (Xu et al., 2024).

3.6.7 Wettability

It is the force required to separate the solid from wetting fluid. While solid would be the calcite in limestone, the quartz grains in sandstone. Water is frequently thought of as the wetting fluid properties beneath the surface. There are adhesive forces in water oil rocks. The amount of cohesive force can be determined from the interfacial energy from the water, oil rock surfaces. Wettability can be measure from the oil and water contact angle against the solid rock wall (Siddiqui et al., 2018).

In rock-fluid systems, it is generally accepted that rocks having 0° to 90° contact angle referred as water wet, whereas the contact angle grater that ninety degrees is the oil wet rock. The water could be absorbing more easily in rock as compared to oil. When ingesting oil on rocks or surfaces that are wet with oil, water would not be the best option. Although it has been believed that the break over point in water and oil surfaces occurs at a contact angle of 90° (Mohammed et al., 2015).

Water laid sedimentary rocks are frequently thought of as preferring water-wet rocks because of the cohesive bond between the rock and water. Also, the early exposure of rock pore surface to water rather than oil in the phase of sedimentation and diagenesis make it more wet. Generally, it is thought that water is the best wetting fluid, and it has ability to cover the whole grain surface of rock. In this ideal scenario the contact angle between oil, water and rock would be zero. The wettability component in the displacement pressure equation would be unity since the cosine of zero is one. Rarely a subsurface rock completely saturated with oil; rather, they are partially saturated, with certain areas of the grain surfaces being wet with water and others with oil.

The organic matter in the source rock are the major underground outliers to the water wet cases. The major application of displacement pressure in hydrocarbon exploration industry is to assess the seal rock capacity. The lateral seal capacity also changes with facies that effect the hydrocarbon migration which mainly occurred in reservoir rock. The chance of having oil water wet rock is minimum in this case (Chengzao et al., 2021).

3.6.8 Radius of Pore Throats

Radius of greatest linked pore throat in the rock is the third important aspect to consider when evaluating the displacement pressure in water and oil saturated rocks. A closer look at the displacement pressure equation reveals that the displacement pressure changes, it increases with the increase in pore throat linked together. In comparison to a fine-grained shale, a reservoir-quality sandstone would have a much lower displacement pressure. To determine secondary migration and trapping, precise measurements of the pore-size distribution are required (Bagrezaie et al., 2021).

There are several different approaches to determining the radius of the biggest linked pore mouths. In thin slices, the size and distribution of the pores may be visually assessed. Since core analyses often provide porosity and permeability data. Capillary-pressure tests have been performed on reservoir core samples by petroleum labs for many years. The full capillary characteristics or distribution of pore size in rock may be ascertained, if the non-wetting fluid injection is prolonged gradually the required pressure, it creates a linked filament of non-wetting fluid throughout the sample (Schowalter et al., 1979).

3.6.9 Displacement Pressures

The pressure in the rock determines the least buoyancy pressure require for the secondary migration. For the secondary migration to happen, it is important to assess the displacement pressure of particular rock sample. For migration to occur, a continuous hydrocarbon flow must occur through the pores connected to each other in a water saturated rock. Hydrocarbon Column Height calculations is essential for evaluating secondary hydrocarbon and entrapment during the exploratory phase. These calculations determine the vertical hydrocarbon column that a specific rock pore system may trap or seal. The following may be achieved by using Smith's (1966) eq 3.1.

$$H = \frac{PdB - PdR}{(pw - ph) \times 0.433}$$

Also, the seal capacity estimates of different rock type may be helpful at various stage of the hydrocarbon exploration process. Knowing which cap rock seals are proximal to migratory hydrocarbons may help researchers study migration and reservoir changes in an exploratory basin. One of the important petroleum systems components is the seal of the reservoir. It is very important to know about the sealing capacity of seal rock that usually lies above the reservoir rock. The hydrocarbon column that traps in the structure depends upon the lateral seal capacity. In case of stratigraphic trap, the facies changes laterally, and it effect the lateral seal capacity (Gabrielsen et al., 2010).

Cap rock seals to moving hydrocarbons should be anticipated at the prospect or regional level based on all geological and geophysical dataset. The ideal seal rock can hold the massive hydrocarbon column. It should be ductile in nature so that the fracture cannot generate in the seal rock which could attribute the leakage of hydrocarbon from the seal rock. The perfect seal rock should be thick enough and has the lateral extent throughout the basin to hold hydrocarbon. The shale rock and salt are thought to be the best seal rock. The shales usually deposit in deep marine environment, the finer particles deposits in deep marine environment. If there are doubt about the seal rock presence in the basin, the more data in form of surface samples or wells would be required to assess the seal capacity which is necessary for the understanding and mapping of secondary hydrocarbon migration (Connolly, Brouwer & Walraven, 2008).

The mechanical characteristics of rocks may be physically evaluated in a lab or inferred empirically from published data. Seismic sections and subsurface mapping may be used to establish the structural setting. To ascertain if the rock layer in issue is susceptible to failing via brittle fracture, certain facts are required. Even while the rock's pore system may seal a sizable hydrocarbon column, it won't function as an efficient cap rock seal if brittle fracture predominates in the layer (Grimm et al., 2023).

3.6.10 Quantitative Hydrocarbon Show Interpretation

The mapping of hydrocarbon migration pathways is very critical in success hydrocarbon exploration. The linkage of source to reservoir and the entrapment of hydrocarbon the trap is important to understand. Also, the mapping of carrier beds at regional level is important. There are two models for the secondary hydrocarbon migration. In first model the hydrocarbon moves in continuous phase within the reservoir rock while in second model the hydrocarbon stains within the carrier beds. Usually, the reservoir samples having residual oil can indicate the flow of hydrocarbon. Also, the presence of gas in source and reservoir drilling also indicates the flow of hydrocarbon but it could not entrap in the structure or get leak as a result of non-presence of seal, seal failure or breach along the fault. The certain indications give the clue of hydrocarbon maturation and migration. These ideas of secondary hydrocarbon flow and entrapment to quantitatively forecast the potential area-wide spread of that accumulation (Kun et al., 2015).

3.6.11 Migration and Entrapment Model

The mechanical model for the hydrocarbon migration can help to understand the migration pathways. The hydrocarbon from the source expels and transport through the carrier beds and entrap in the valid structure. If the bouncy is the primary driving force then it displaces the water from the water saturated rocks.

The simple geological model can be used to construct the hydrocarbon migration pathways. Geological model consists of the uniform lateral extended seal rock over the reservoir rock. The source rock is placed below seal and reservoir rock. The hydrocarbon generated from the source rock accumulates in the reservoir rock. These concepts can be used anywhere expelled gas or oil is present in the rock as a continuous phase with sizes ranging from drops to larger interconnected filaments. Here, the primary migration method is not suggested. The movement of hydrocarbon in the reservoir cause by the bouncy force and it exceed the displacement pressure. At this point, the continuous hydrocarbon migration occurs. Upon reaching the cap rock seal above, the hydrocarbon phase will proceed to move vertically upward through the reservoir rock (Ahmed et al., 2019).

The hydrocarbon would migrate upward through carrier beds until it reaches the trap and have valid seal rock lies on top of it. More oil must accumulate in order for the hydrocarbon movement up dip in the carrier beds. The hydrocarbon would migrate in continuous form to

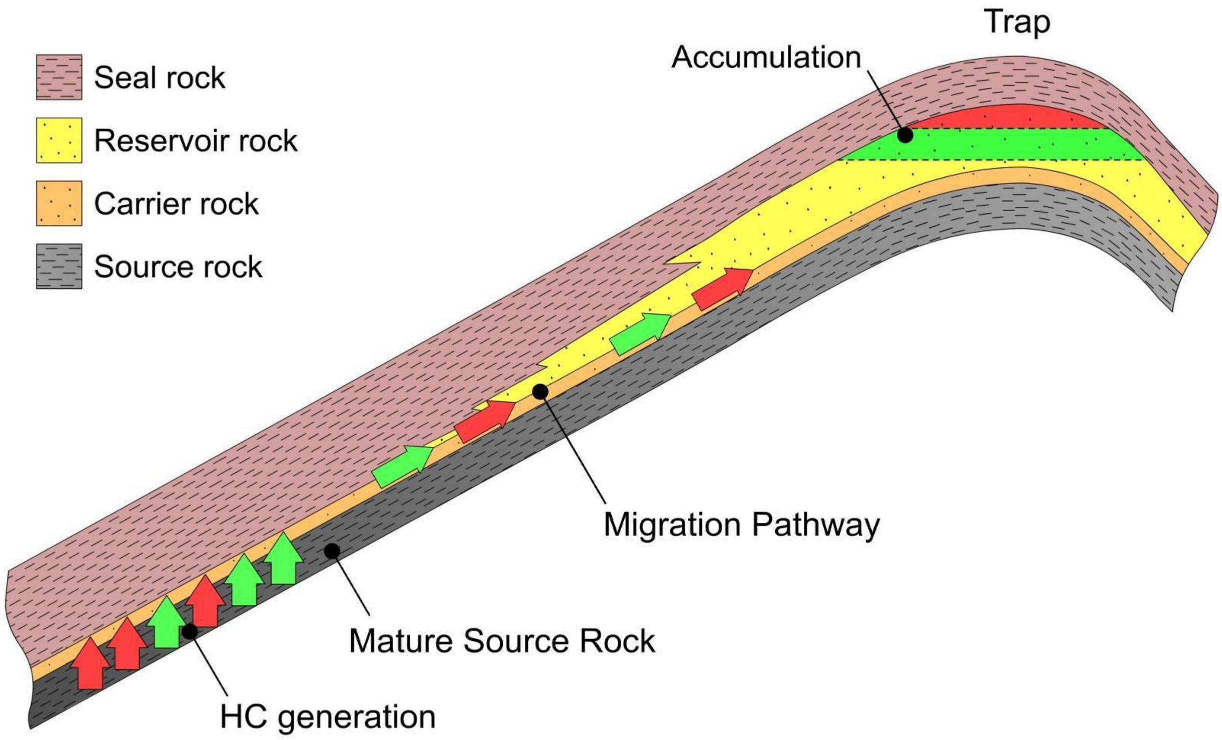

Figure 3.19 Secondary hydrocarbon migration occurs when hydrocarbon from the source rock expels and move within the carrier beds. The hydrocarbon entraps in the traps found in the path of secondary hydrocarbon migration pathways. The seal rock is one of the important factors for holding the hydrocarbon within the reservoir in trap (modified after Kovacs et al., 2018).

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form a vertical column; the height of column would depend upon the dip of the strata. The hydrocarbon vertical column increases as the result of increase in dip and vice versa (Figure 3.19).

Oil is continuously added to the reservoir as it migrates higher and vertically out of the source rock, producing an increased amount of oil. After the hydrocarbon column reaches its critical length, oil will move laterally and upward through the reservoir (Bjorlykke et al., 2015). Since the minimal saturation required for the hydrocarbon migration in the length of one inch. The oil saturation may be as low as 10% when migration occurs laterally up dip through the reservoir. The upper portion of carrier beds would be only saturated with oil or leaving other portion of reservoir filled with water (Schowalter et al., 2015). As the hydrocarbon filament migrates upward, isolated hydrocarbon droplets remain at the base on bed. These oil "migration-path shows" have the potential to provide valuable drilling data. The initial saturation will determine how much oil is left behind. The residual saturation increases with initial saturation. The hydrocarbon saturation during the journey of hydrocarbon migration ranges from 10 to 30 percentage, while residual hydrocarbon saturations along migratory pathways are estimated to be 20% or less.

Capillary pressures keep these leftover oil droplets permanently stuck. This remaining oil's soluble fraction may dissolve in the water. These residual hydrocarbon shows in the core sample and drilling data along the migration pathways. This migratory residual stain should be found just under the cap rock seal in a uniform reservoir, with visible oil showing only in the top few feet of the reservoir. For this reason, it may become difficult to identify oil migration pathways during drilling. The solubility of gas is high as compared to oil and it would not remain any residual gas in rock (He, Sun & Wang, 2022).

In order to find hydrocarbon migration pathways, the hydrocarbon must move upward laterally along the path of high dip start and with pores with large, connected pore throat or against lowest displacement pressure. When seen from a map perspective, this winding movement will result in some rocks having residual oil saturation where migration has taken place and totally oil-free strata right next to each other (Luo et al., 2012).

The hydrocarbon filament's length will shrink, and its buoyant force keep on decreasing as the result of hydrocarbon remain in residual oil and gas form in rock along the migration pathway (Baur and Katz, 2018). At certain point in the migration, the buoyant force will eventually diminish to the point where it is unable to overcome the effect of capillary resistance force in the carrier bed. The hydrocarbon migration will stop until a different hydrocarbon filament migrates up dip to the filament that has halted, at which time it will resume. To resume the hydrocarbon migration, the more hydrocarbon from the source rock must expel and migrate upward. In any segment of rock, as long as the buoyant force of the hydrocarbon column is higher than the resistive force of the carrier bed, oil or gas will be able to migrate laterally up dip or vertically through the rock. Consequently, in a given geologic setting, the vertical or lateral migration of oil or gas has no physical bounds.

Oil is released at the basin's mature spots and migrates via the carrier beds. The movement of hydrocarbon occur perpendicular to the strike of beds. Structures like as anticlinal axis that plunge into basins or facies changes in carrier beds may concentrate the migratory front of hydrocarbon in relatively narrow route in migration pathways. If there is a displacement pressure barrier or a closed anticlinal trap along the carrier bed, hydrocarbon would entrap along the migration path. Any size may be used for these traps. The vertical closure of the structural trap and the cap rock vertical sealing ability determine the size of structure-type traps. The displacement pressure barrier's size and shape, as well as its lateral-seal capability, will determine the size of stratigraphic traps (Dolson et al., 2016).

Until the trap is filled, oil or gas will keep migrating laterally up dip into it following a migration route. In the simplified model, any structural trap with a carrier bed lies just below the seal rock will be fill up to the spill point of structure (Figure 3.19). Afterward the hydrocarbon will be spill from the structure and move upward along the migration pathway until it trap along another structure. As long as gas or oil is moving up dip into the trap, oil will continue to migrate up dip until the trap will fill completely. In a structural trap, if the sealing capacity of the overlying seal rock is weak, at certain point the oil and gas will not up to the spill point, instead it migrates upward and leak through the seal rock (De Jager et al., 2020).

The migration model states that oil that migrates into a trap will stay there forever, as long as the geological conditions don't change. This implies that lateral seals in stratigraphic traps or cap rock seals in structural traps have breakthrough pressures or displacements that are independent of time and thus drops of gas and oil will not gradually leak (Tiab and Donaldson, 2024).

3.6.12 Differential Entrapment

The source usually buried beep in the basin, the trap in the deepest depth, close the source rock fill with hydrocarbon immediately after the hydrocarbon expulsion from the source rock. When the two phases are present in a structural trap lies parallel in line, that leak petroleum up dip, there is a possibility of differential trapping hydrocarbon (oil and gas). If both oil and gas will present in the structure gas will rise to the top of the structure above the. In some cases, if the gas continuous to rise in the structure, the oil rushed down from the spill point, it moves upward until it get trap in other structure. When the trap fills with gas and eventually runs out of space to hold oil, oil will flow up dip. Consequently, along a migratory route, the upper traps would be filled with oil and the lower traps with gas (Lijun et al., 2018).

The timing of hydrocarbon expulsion and depth of traps should be considered while assessing the distribution of hydrocarbon (oil and gas) in the basin. The shallow gas along the hydrocarbon migration appears to be due to the leakage along the seal, but also the biogenic gas may also be present in the shallow reservoir. Interpreting distribution patterns of oil and gas will become more challenging due to thermal production of these resources. According to models of thermal generation, oil is produced and ejected first, followed by gas. Gas might be spread down dip from oil due to this creation and migration process, which is comparable to structural spill differential trapping. The remigration of hydrocarbon along the migration pathways occurs if the structural dip along migration pathway alter or conditions changes in reservoir or source rock (Allen et al., 2013).

Physical mechanisms that are well known include secondary hydrocarbon migration and trapping. By adhering to a few fundamental guidelines and using data that is often accessible in petroleum exploration and production, the distribution of hydrocarbon in the subsurface may be investigated in a rational, quantitative manner. In every stage of the search for oil and gas, a comprehensive grasp of these procedures may be quite beneficial.

These recommendations provide the basic elements required to identify potential locations for trapped gas or oil along a migration path when searching for new gas and oil sources. The existence of the reservoir, the structure, and the seal are the three main components that cause hydrocarbon entrapment in structural traps. A tilt in the gas-water or oil-water contact may occur when there is a hydrodynamic situation. The hydrocarbon entrapment in stratigraphic structures depends on the top and base seal rock's seal ability. The density of the hydrocarbon and water phases, pore throat, hydrodynamic condition in the carrier bed, interfacial tension between the hydrocarbon and water phases, and wettability will all have an impact on the barrier's seal capacity with regard to the vertical hydrocarbon column. The reservoir's dip will alter the quantity of hydrocarbon trapped, but the seal capacity won't change (Hao et al., 2015).

After a commercial field has been found, field development may benefit from the ideas of secondary migration and entrapment (Demaison et al., 1994). The accumulation's up dip and down dip limitations can be quantitatively ascertained using routinely available well data. Development drilling can then be done with this knowledge. The secondary migration entrapment process should not be employed in isolation to produce useful data; rather, they should be used in concert with all available geologic information when predicting outcomes in the hunt for oil and gas.

Hydrocarbon migration is an important element of petroleum system. Secondary migration comprises of hydrocarbon migration from source rock to reservoir rocks. Generally, hydrocarbon migration occurs along conduits beds and faults. Following methods were adopted in this research to establish hydrocarbon migration pathways in Punjab Platform.

3.7 2D Basin Modeling

Critical geologic characteristics and processes must converge for any exploration attempt to be successful. Geoscientists can examine the dynamics of sedimentary basins and the fluids that surround them using models of basins and petroleum systems to determine whether past conditions were conducive to the filling and retention of hydrocarbons in potential reservoirs. Point sites, mostly wells, are included in 1-D burial history models. Direct entry of 2D data is made possible by maps and cross-sections, which depict geologic information in two dimensions (Burwicz et al., 2017).

Both 1-D requires only well (geological thickness, ages) and source rock data (TOC, HI, OI) (Peters et al., 2017). However, 2D model requires additionally seismic horizon in depth domain and faults to generate a 2D profile. It also requires the components of the petroleum system, such as reservoir, source, and seal rock intervals with matching lithologies, depositional ages, and erosional ages, are incorporated into it (Figure 3.20). The petroleum systems can be defined using the models. The stratigraphy is interpolated between wells in 2D models, which are frequently based on seismic sections. 2D models incorporate hydrocarbon migration along the line of section, as well as temperature and maturation level against depth (Tawfik et al., 2023).

In 2D basin modeling, maps and cross section in depth domain were used to reconstruct oil and gas migration from source rock and its accumulation. These can be used to analyze both conventional and unconventional resources. 2D modeling includes fault classification, salt flow, and igneous intrusions, among other variables. 2D models can be assigned facies and lithologies, as well as source rock properties, to simulate the creation of heavy oil, oil, wet gas and gas. Other variables accessible for computation include HI, TOC, and kinetic methods (Ghorbani et al., 2025).

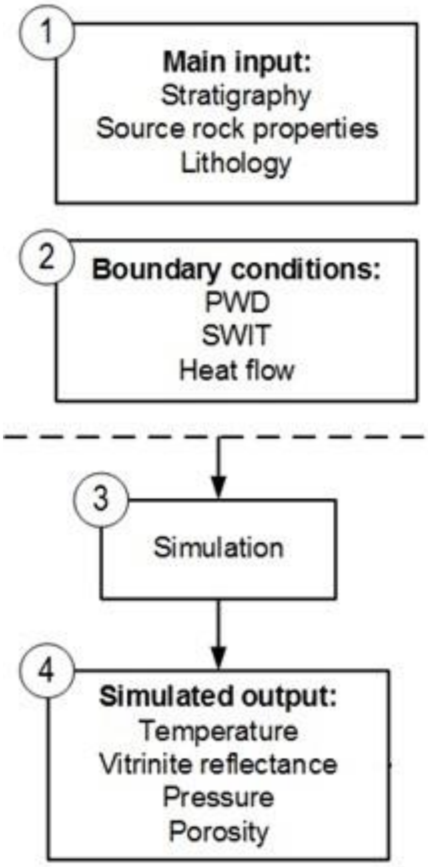

Figure 3.20 Shows the 1D basin modeling workflow. The formation depth, stratigraphic information, unconformities and source rock properties like TOC, HI and OI needs to be input in model. Also the Boundary conditions PWD, SWIT and HF are necessary to be incorporated. The source rock properties like Temperature, Vitrinite reflectance, Porosity need to include. After the inputs, temperature and Vitrinite are the mains inputs of Basin modeling.

3.7.1 Advantages of Using 2D Models

ID basin modeling is confined to one-point e.g well location. However, 2D basin modeling is the generation of cross-section or profile including multiple well location. Advantages of 2D basin modeling included profile generation which helps in identifying migration pathways, source transformation ratio and all hydrocarbon type.

3.7.2 Constrains of and Structural Model Generation of 2D Basin Model

The primary constraint of maps and cross-section profiles for hydrocarbon flow path models is their two-dimensional nature. Although appropriate for structurally trapped oil and gas, locations with stratigraphically imprisoned or continuous hydrocarbon accumulations may only indicate hydrocarbon migration. Combining 1D and 2D modeling offers more insight into the petroleum system history of a region or reservoir.

Several authors have used this technique for the predication of source rock maturity and migration model in the area. Bartha et al. (2018) have carried out 2D basin modeling in the Pannonian basin of Central Europe to investigate the tectonostratigraphic model of the area and its impacts on source rock maturity and maturation through historical time spans. According to Abdelwahhab et al. (2023), petroleum system elements, hydrocarbon migration is important to determine for successful hydrocarbon exploration. He carried out 1D and 2D basin modeling for source maturity and expulsion in the Abu Gharadig Basin (Western Desert, Egypt). Setyawan et al. (2023) carried out 2D basin modeling in the Tangguh field, Bintuni Basin, Papua, for a hydrocarbon charging model.

2D basin modeling was performed in the study area to evaluate source rock thermal maturity, timing, and expulsion of hydrocarbons. Geological, geophysical, and geochemical data were incorporated in the 2D basin modeling model. Forward modeling was performed to predict the thermal maturity of source rock based on basin tectonic evolution history and its implementations on source rock maturity and migration.

A regional E-W, 2D seismic section based on seismic was generated along the dip direction. This cross section extends from the full Sulaiman Foredeep to the Punjab Platform, passing through the Zindapir-01, Zakria-01, and Panjpir-01 wells (Figure 3.21). Geological, geophysical, and geochemical data were incorporated in the PetroMod software to build the

2D basin model. Input geological data comprises formation age, tops, thickness, and lithology. Number of formations ranging from Cretaceous to basement has been marked and mapped on seismic sections throughout the area. The variable velocity method was used to convert the horizons to the depth domain. Similarly, the faults that were identified on seismic were also converted into the depth domain. Mapped horizons were then converted to depth domain. Geophysical data includes the mapped depth structured maps and faults from seismic data. Geochemical data includes HI, TOC, temperature, maturity data, and erosion history. Also, already generated 1D basin models were incorporated into the 2D basin model to constrain the boundary conditions.

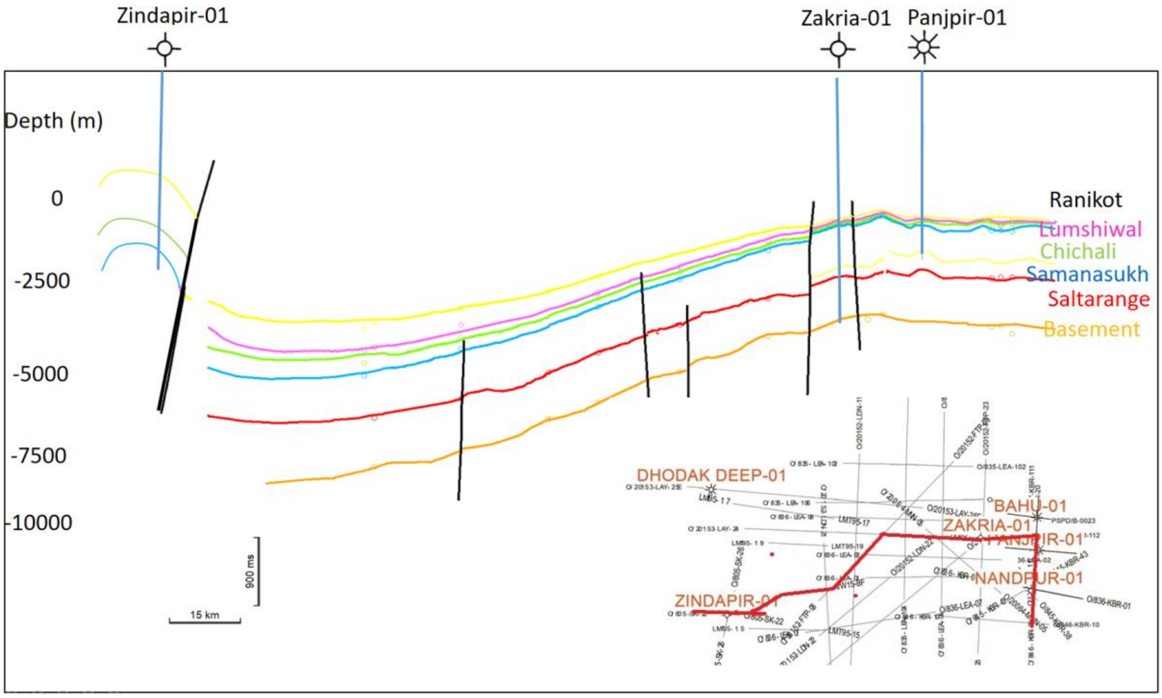

Figure 3.21 A Regional E-W, 2D seismic section has been generated along the dip direction. This cross section extends from Sulaiman Foredeep to the Punjab Platform passing through Zindapir-01, Zakria-01 and Panjpir-01 wells and shown with red line on base map. The structure framework for the 2D basin modeling generated which include the horizons and faults.

In 2D basin modeling, petroleum system elements were also incorporated in it. The Cretaceous Chichali Formation, which has excellent to good source rock potential in the Sulaiman Foredeep, was taken as a major source potential in the model. The Cretaceous Lumshiwal Formation was considered a reservoir in the area. Major faults were taken closed (sealing) based on fault seal analysis. The kinematic model was run and calibrated with already generated 1D basin models, temperature, and %Ro values calculated from core samples.

3.8 3D Hydrocarbon Charge Modeling

Geo scientists combine geophysical, geological and engineering data to generate a 3D sub-surface model that can be used to determine the presence of hydrocarbon entrap in structure. Petroleum system modeling are widely used in exploration phase in basin to predict the hydrocarbon migration pathways from source to reservoir, source properties, transformation ratio and hydrocarbon fill type. Good petroleum systems model also be used to detect and explain data inconsistencies. The generated models are also useful during for finding resource rich areas, such as sweet spots in unconventional plays like shale gas, and during field development and production for boosting completion efficiency. Petroleum systems modeling differs from reservoir simulation in that it operates on a broader scale, potentially encompassing many oil and gas fields, and takes into account geologic time frames of millions of years rather than production time frames of years or decades (Castro et al., 2025).

Petroleum system modeling combined all the element of petroleum system like source, reservoir, seal, timing and migration of hydrocarbon. The results of petroleum system are in the form of hydrocarbon generation, accumulation in traps, preservation and alteration in a trap. Petroleum system modeling key elements like reservoir, source, seal, charge results in generation of map that identifies the migration pathways from source rock to reservoir and identification of sweet spots that can hold hydrocarbons. Abdelwahhab, (2023) carried petroleum system analysis in western Egypt for the identification of Sweet spots that can entrap hydrocarbons.

3D petroleum system modeling is often created on reservoir rock to basin levels. A 3D petroleum system model allows for the visualization of potential migration pathways in three dimensions as well as the estimation of volumes of hydrocarbons that may have moved and been stuck. They simulate temperature and maturation level against depth, as well as hydrocarbon migration in three dimensions. Models can be created using time-stratigraphic intervals or by identifying common formations or facies. 3D petroleum system modeling program integrates and analyzes numerous variables. These data and interpretations help assess undiscovered oil and gas resources by analyzing the impact of changes in heat flow, PVT values, hydrodynamic and lithology in basin. 3D petroleum system modeling improves the assessment process by providing additional evidence for the assessment's results (Spacapan et al., 2025). Examples of support including excluding areas and petroleum system for assessments due to immature or over mature source rocks, including formations and areas with petroleum migration from mature source rock to trap through reservoir acts as carrier beds.

3.9 Requirements for 3D Hydrocarbon Charge Modeling

The 3D petroleum system modeling elements like source, reservoir and seal needs to assign against each stratigraphic age. Following data are required for the 3D hydrocarbon charge modeling.

1. Gather information on elevation and isopach data for stratigraphic intervals in petroleum systems.
2. Age ranges for stratigraphic and other intervals in the model, including tectonic, erosion, and non-deposition periods.
3. Paleo water depth, heat movement, and surface temperature with time.
4. Locations and ages of faulting; time of faults and segments opening and closing. Using maps, cross sections, and written descriptions, determine the lateral and vertical distribution of depositional facies/lithology.
5. Assess the quality and vertical and lateral distribution of elevation and (or) isopach data at stratigraphic and other intervals throughout the research region.

Dense data set is required for model generation. However, data quality might vary even within mature basins. Well logs are very helpful in identifying the lithological contacts, such as those between sandstone and shale, as well as major markers that determine proximity to the targeted reservoir formations. It is important to determine ages for all modeling intervals, tectonic events that influence hydrocarbon formation, movement, and accumulation, and non-deposition periods. The areal distribution and thickness of an eroded section can be approximated using existing estimates and maps, as well as by developing 1D models (Giunta et al., 2025).

TOC and HI is required for the model, which provide carbon and hydrogen for oil and gas production. These data can be represented with default values and analogs. % Ro data is used for external calibration of 3D models. The modeling program uses various techniques to calculate and calibrate thermal maturation over time. The model can also be calibrated using 1-D burial histories for wells and 1-D extractions of 3-D models.

The kinetics methods for modeling the timing of hydrocarbon production is very important. The program supports both default and user-defined kinetic parameters for primary and secondary cracking of oil and gas. The lateral and vertical distribution of source rocks contributing hydrocarbons to each petroleum system, as well as kerogen type, lithology, TOC, and HI, are all required (Badics et al., 2025).

3.9.1 Advantages of 3-D Hydrocarbon Charge Model

The primary advantages of 3D hydrocarbon charge modeling are:

1. Reconstructions of model at reservoir and basin scales that can reveal hydrocarbon migration pathways.
   Oil and gas generation, migration, and accumulation are predicted throughout time period.
2. Calculate and display the volumes of oil and gas in each petroleum system over time, including in place, generated, accumulated and lost hydrocarbons.

3D modeling can use Darcy (vertical), flow path (lateral), or hybrid Darcy (vertical and lateral) fluid flow. At the reservoir, interval, and basin scales, PetroMod calculates the volumetric and percentage contributions of gas and heavy oil from various source rocks. This lists the main source rocks and the contributions they have made throughout time, from accumulation to the provincial level. By comparing computed amounts to known volumes of in-place and recoverable oil and gas as well as estimates of undiscovered resources, mature basins enable more precise model assessment and calibration. Training models and using them as analogs for various reservoirs or basins is the aim of this investigation. Quantities of generated hydrocarbons can be calculated by the modeling tool, but they could not match the anticipated volumes of in-place, known, or undiscovered hydrocarbons. Due to (a) variations in the volumes of generated, migrated, and accumulated hydrocarbons; (b) the impact of grid resolution on the locations and volumes of accumulated hydrocarbons, particularly since grid cells can be much larger than the sizes of modeled and actual accumulations; and (c) insufficient geology, it is preferable to publish the percent contribution of each source rock rather than volumes of generated and accumulated hydrocarbons. The quality of the source rocks, which differ in organic content laterally and vertically, is a major influence. Although point sources inside study regions provide TOC, Ro, and other data, modeling necessitates extrapolation across significant vertical and lateral areas.

3.9.2 Limitation and Requirement of 3D modeling

The main disadvantage of 3-D modeling is the need for extensive data.

For this study petroleum migration pathways from source rock to reservoir was established and a generated the map that represents the migration pathways and identification of sweet spots which could serve the hydrocarbon entrapment. Also structural aspects of the top reservoir surface and its influence on hydrocarbon accumulation and migration was established. The workflow adopted for current research to map the hydrocarbon migration pathways along with outputs are shown in (Figure 3.22).

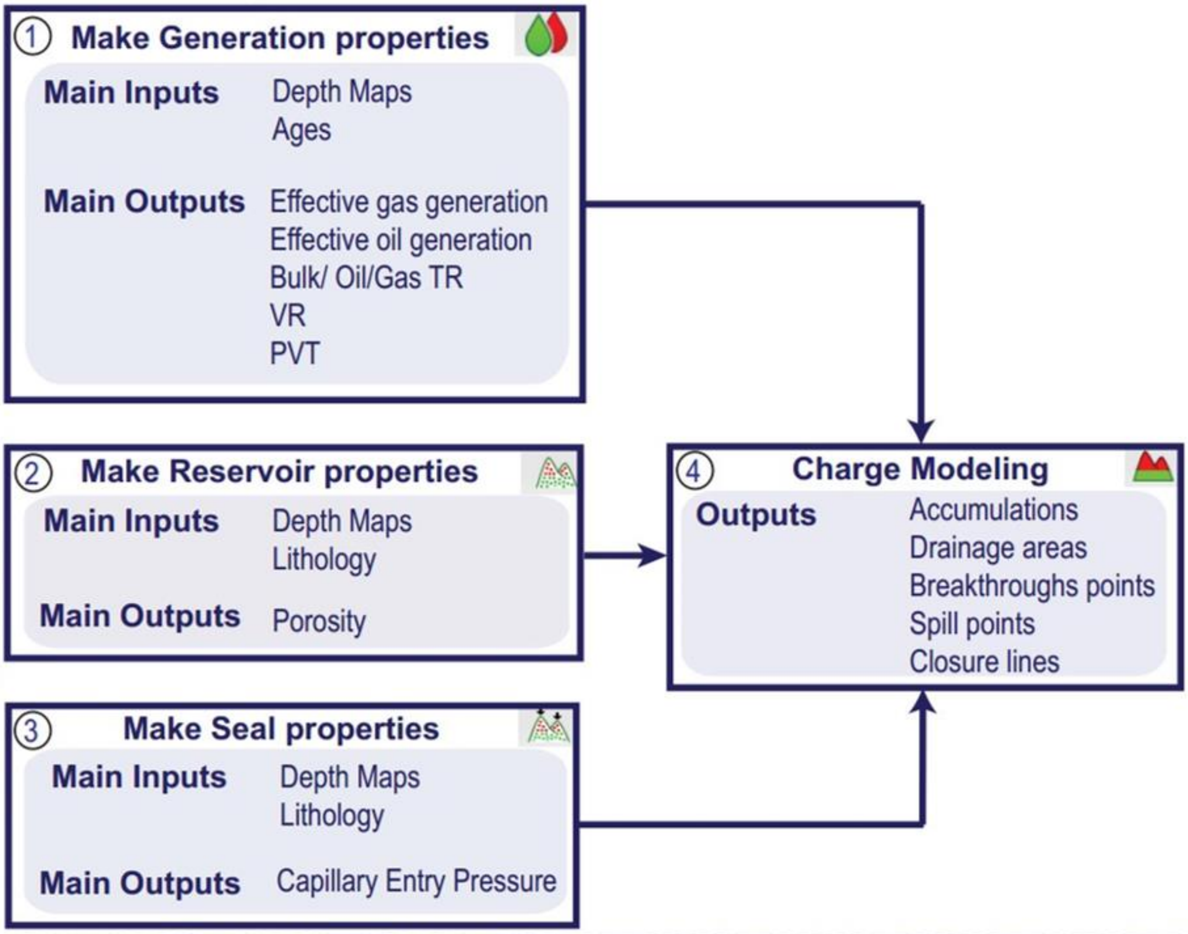

Figure 3.22 Comprehensive workflow of 3D petroleum System modeling. The ages and depth of formation were provided in model using well data. The source rock properties TOC, HI, TOC incorporated, the seal and reservoir depth included in model. The porosity and reservoir map were integrated in model. The accumulation, drainage area, Spill points and closure lines reflects the output for model.

Petrel software was used to generate the hydrocarbon charge model. The first step of petroleum system migration started with the generation and maturity modeling of the Chichali Formation as source rock by incorporating the geological, geophysical, and geochemical data. Geophysical data comprises a depth map of source rock and a thickness map of source rock.

Bathymetry information ranges from 10 m to 50 m depth was given in the model. Geochemical data comprises kerogen type, total organic carbon content, hydrogen index, sediment surface temperature, thermal gradient heat flow, thermal conductivity, and basal heat flow values.

Depth map of the Chichali Formation as source rock was incorporated in the model, and the thickness of source rock was given in the model as the average thickness of 78 meters, and the age of source rock in Early Cretaceous age, 145 million years, was incorporated in the model. Kerogen type III, TOC wt.% values Ranges from 0.52 to 2.5 percent and hydrogen index values range from 10 to 110 were included in the model. Thermal data was given in the model sediment surface. The surface temperature is 25°C, and heat flow thermal conductivity is 190 KJ, and basal heat flow values were incorporated in the model with an average thermal conductivity of 55 mw/m^2.

For the reservoir model, reservoir tops depth maps of the Lumshiwal and Samana Suk Formations, reservoir thickness maps, porosity, net to gross, water saturation (sw), and lithology information were given in the model. Porosities, net-to-gross ratios, and water saturation were calculated from the petrophysical logs interpretation of wireline logs. Lumshiwal Formation sandstones porosities range from 10% to 28%, Sw ranges from 30% to 50%, and the net-to-gross ratio is 0.5% and Samana Suk Formation porosities range from 5% to 18%. For seal rock (Lumshiwal shales) top depth map, Capillary pressure of 20 bars and open fault model along the lithology chart were incorporated.

Ultimately, a 3D hydrocarbon charge model was generated by incorporating all information from source maturation and generation, reservoir, and seal models. 3D hydrocarbon charge models created the accumulation closure polygons at the exact depth of the hydrocarbon contact for each accumulation and also successfully identified the migration pathways from source to reservoir. The establishment of hydrocarbon pathways will help in mitigating exploration risks, especially those related to source maturity and hydrocarbon migration and charging.

3.10 Direct Hydrocarbon Indicators (DHI's)

For a very long time, the goal of explorationists has been to develop a tool or method that would allow them to directly detect hydrocarbons buried deep beneath the surface of the earth. Direct hydrocarbon indicators (DHI's) are unusual seismic amplitudes that can occur when hydrocarbons are present. They occur as a result of changes in pore fluids, which affect the elastic characteristics of the bulk rock. DHI's are most abundant in relatively young, unconsolidated siliciclastic sediments with high impedance at lithologic borders. They exhibit a variety of features, as indicated by the link between depth and acoustic impedance. DHI's are employed in hydrocarbon exploration wells primarily to mitigate geological concerns (Meciani et al., 2025).

Acoustic impedance is the product of velocity and density. Change in impedance due to the presence of pores filled with either water, oil, or gas results in lower P-velocities while S-velocities remain the same (Sams et al., 2025). Therefore, its effects emerged on the reflection coefficient at the top of siliciclastic rocks. Acoustic impedance, which is additionally affected by mineralogy, porosity, pore fluids, temperature, and pressure. The impedance changes depending on the fluids in the pores, which might be filled with water, oil, or gas. As the pore space fills with gas, Vp decreases, but Vs remains constant; this changes the reflection coefficients at the top and bottom of a reservoir, known as DHI's.

Sands compact faster than shales because they have a larger impedance; nevertheless, water sands have almost the same impedance as shale, implying that the amplitude of reflections is lower. Oil sands have lower impedance than water sands and shales, whereas gas sands have lower impedance than oil sands. If embedded in shales, particularly gas sands, they would have a greater reflection amplitude due to the opposite polarities. These can be differentiated based on their amplitude response. Gas is compressible, but water is not. As a result, the presence of either will reduce the P wave velocity. The difference in impedance tends to decrease as we go deeper, since the amplitude response becomes less diagnostic. The higher the impedance between the sand and the shale, the greater the anomaly. DHI's consist of three types: bright spots, dim spots, and flat spots (Nanda et al., 2021). They are mainly used in hydrocarbon exploration to mitigate the exploration risks (Figure 3.23).

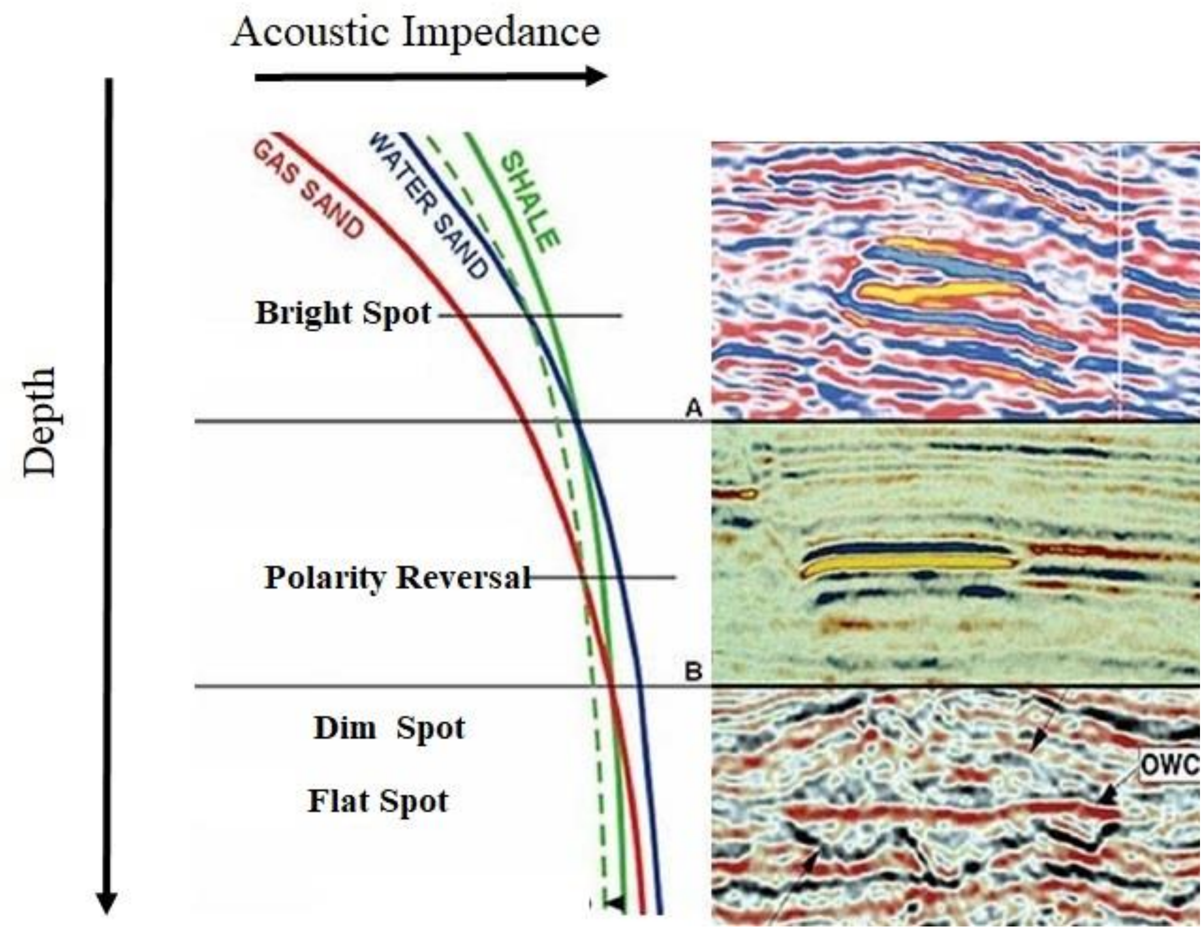

Figure 3.23 Bright spot, polarity reversal, Dim and flat spot are the main DHI's. A bright spot is defined as a spot with a local increase in amplitude due to hydrocarbon presence. Dim spots imaged on seismic data by strongly cemented sands with a substantially larger acoustic impedance than the overlying shale. Flat spots reflect a hydrocarbon contact based on seismic response (Nanda et al., 2021).

3.10.1 Bright Spot

A bright spot is characterized by a localized increase in amplitude brought on by hydrocarbon accumulation (Figure 3.23). Originally used to describe the amplitudes of the Common Mid-Point stack, the term is now used to describe pre-stack implementations (AVO). An increase in a gas's reflection coefficient in the pore space might cause these amplitude highs. Instead of detecting the presence of hydrocarbons, it is used to identify an increase in amplitude, and it is often higher in unconsolidated clastic rocks. Sands have a lower acoustic impedance than shales due to the water-filled pore space. The sand's density and velocity drop when hydrocarbons are added to the pore spaces. Because of the increased impedance contrast at the top of the sand, the reflection is stronger and more negative, giving the impression that it is "brighter" (Nanda et al., 2021).

3.10.2 Dim Spot

Dim spot is created by tightly cemented sands that have a significantly higher acoustic impedance than the shale that sits on top of them (Figure 3.23). At the top of the sandstone, there is a prominent peak. Adding hydrocarbons to the pore space may reduce the density and velocity of sandstone, but not enough to alter the polarity of the reflection coefficient. By lowering the acoustic impedance and reflection coefficient, the hydrocarbon produces a "dim spot" (Wojcik et al., 2016).

3.10.3 Flat Spot

Seismic response indicates that flat spots indicate a hydrocarbon contact (Figure 3.23). This type of interaction can occur between gas and water, oil and water, or gas and oil (Yahaya et al., 2022). Flat spots occur as the hydrocarbon reservoir must be thicker than the vertical resolution. Finding flat spot is frequently challenging; low-angle faults, processing artifacts, and the base or border of channels are frequently mistaken for flat patches. Low saturated gas in a reservoir can also produce flat spots.

3.10.4 Phase Reversal

Phase change, often referred to as polarity reversal, happens when the rock in the reservoir above moves more slowly than the reservoir below. The acoustic impedance rises somewhat over the shale layer above it. The weak positive reflection coefficient is correlated with the top of the sand. The sandstone's density and velocity diminish with the addition of hydrocarbons to the pore space; this also causes the acoustic impedance to drop until it is marginally lower than the shale layer above (Nixon et al., 2018). As seen in (Figure 3.23), the reflection at the top thereafter undergoes a phase shift, going from a peak to a mild trough. A phase change doesn't have any noticeable amplitude (Figure 3.23).

3.10.5 Gas Chimneys

Gas chimneys develop when gas seeps from a deeper level of the subsurface, typically along a fault plane, due to a hydrocarbon deposit that is improperly sealed. Usually, a cloud of gas is the outcome (Lehmann et al., 2025). The rocks above, mostly shale with porous zones, may move more slowly as a result of this gas. Gas chimneys are commonly noticed as regions of low-quality data or sags in seismic data. This may make precise structural mapping extremely challenging. These saturations are useful for identifying potential leak traps below, even though they frequently have no economic value.

3.10.6 Shadow Effects

The decrease of velocity in a hydrocarbon accumulation results in shadow effects. This leads to a reflection sink because it lengthens the travel durations in the deeper reflections. They frequently arise because of the high amplitude processing both above and below a bright spot. Khawaja, (2023) used DHI’s to the prove the existence of hydrocarbon presence and accumulation in Dujaila field, SE of Iraq. Nanda, (2021) used DHI’s for hydrocarbon exploration and production. (Rowi), 2020 utilized DHI’s for prospect evaluation and maturation.

2D seismic data was interpreted in the study area. Migration pathways were also established from the Sulaiman Foredeep to the Punjab Platform by using 3D hydrocarbon charge modeling. Accumulation polygons at already producing fields Bahu-01, Panjpir-01, and Nandpu-01 validate the migration pathways. However, to further confirm the hydrocarbon charge model, DHI’s were used. Bright spots at reservoir level (Lumshiwal sandstone) were identified at multiple 2D seismic lines. The identified bright spot in the Lumshiwal Formation emerged due to high amplitude on seismic and was interpreted at the trough on the seismic section. The abnormally high amplitude at the reservoir level indicates the presence of hydrocarbons (gas).

CHAPTER 4

INTERPRETATION AND RESULTS

4.1 Isopach Maps

The thicknesses of formations encountered in these wells were used to produce an isopach map utilizing Kingdom software. Isopach maps of the source Chichali Formation, reservoir the Chichali and Samana Suk Formation were generated by using thickness calculated from well logs correlation. The isopach map of was constructed using the thickness acquired from well log correlation. Six well thicknesses were utilized to construct the isopach maps.

Isopach maps also indicate the location of the depocenter. The Chiltan Formation is found in Bahu-01, Pajpir-01, and Nandpur-01; however, it is thinning further east and completely eroded in the eastern part of the Punjab Platform (Figure 4.1). The Chichali Formation of Cretaceous age is continuous in all wells, with maximal thickness in the western region of the Punjab Platform, which is referred to as its depocenter (Figure 4.2). The Lumshiwal Formation, which is of Cretaceous age has its thickest thickness in the west, which is the depocenter; hence, sediment movement would be from east to west (Figure 4.3).

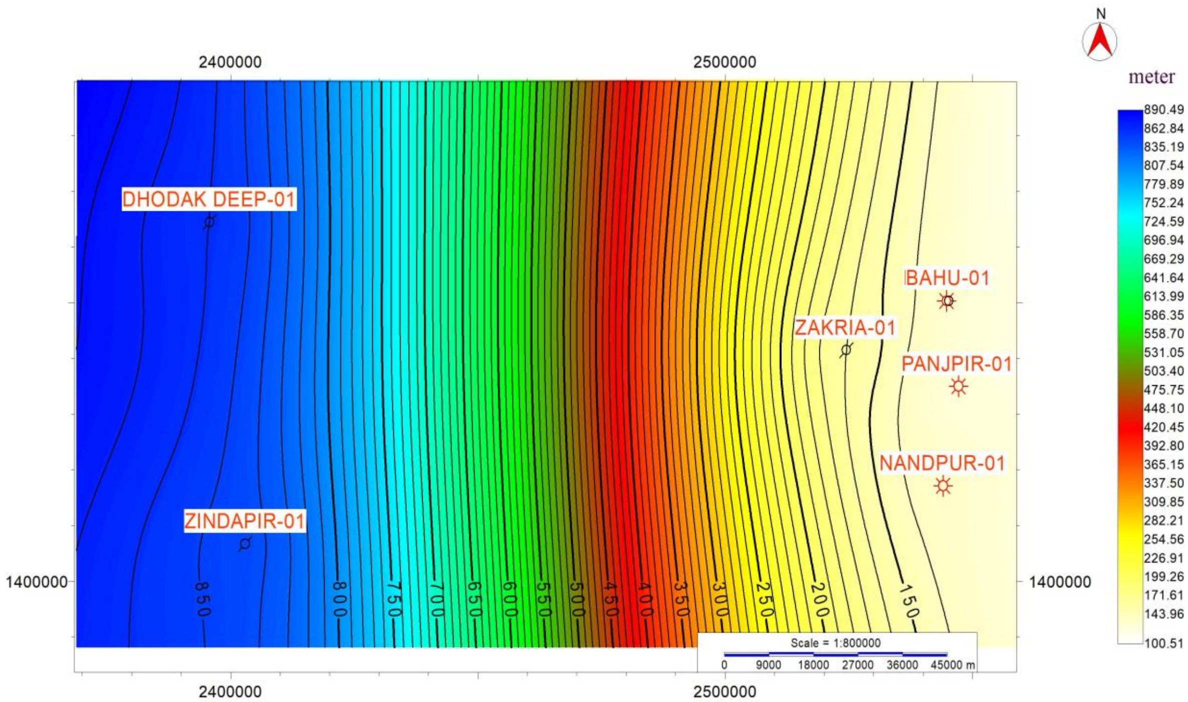

Figure 4.1 The isopach map of Chiltan Formation was generated using the thickness obtained from well log correlation. Six wells thickness were used to generate the isopach maps. It shows that the thickness of Jurassic Chiltan formation is increasing toward west.

The isopach map of the Chiltan Formation of Jurassic age was constructed using the thickness acquired from well log correlation. The drilled thicknesses in six wells were utilized to construct the isopach maps. It reveals that the thickness of Jurassic Chiltan Formation is increasing toward west (Figure 4.1).

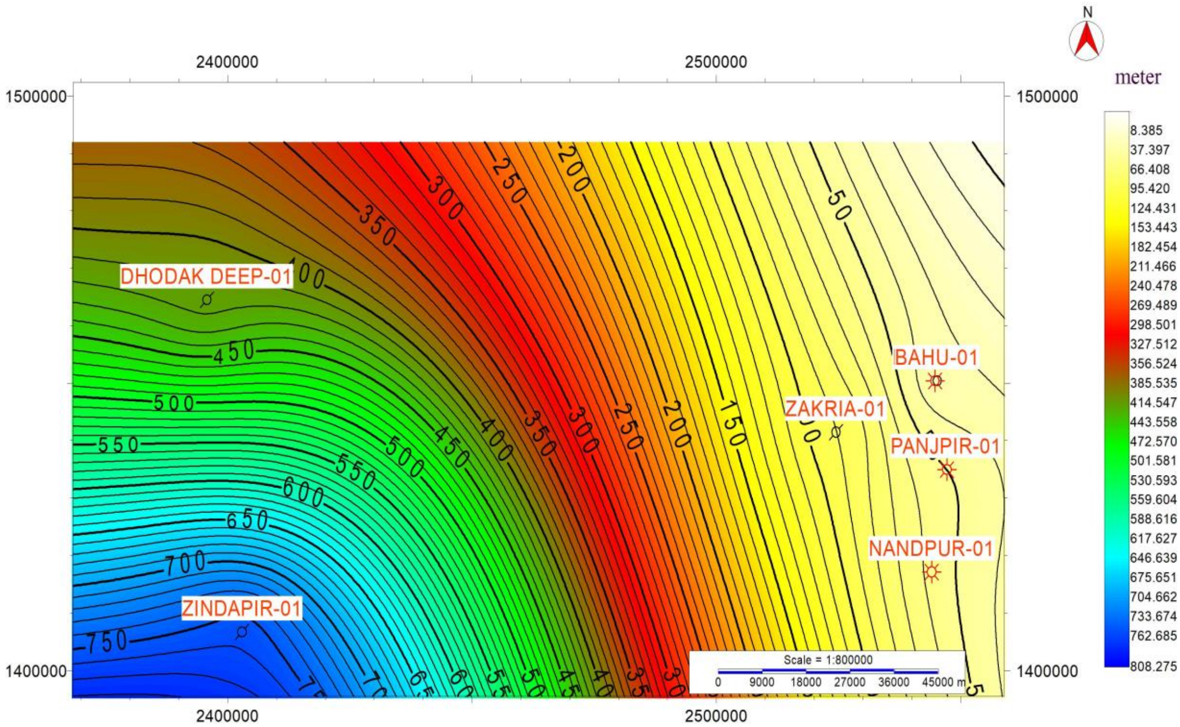

Figure 4.2 The isopach map of the Chichali Formation of Early Cretaceous age was generated using the thickness obtained from well log correlation. Six wells thickness were used to generate the isopach maps. It shows that the thickness of Chichali Formation is increasing toward west.

The isopach map of the Chichali Formation of Early Cretaceous age was constructed using the thickness acquired from well log correlation. The drilled thicknesses in six wells thickness was utilized to construct the isopach maps. It reveals that the thickness of Lumshiwal Formation is increasing toward southwest (Figure 4.2).

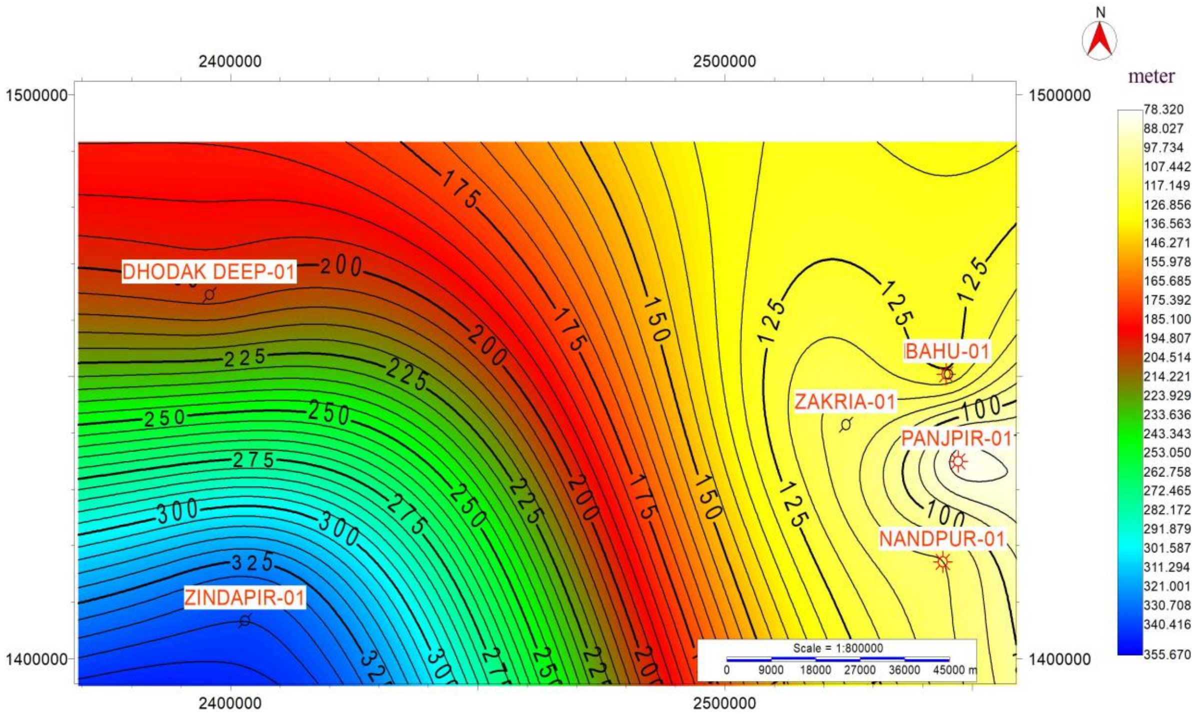

Figure 4.3 The isopach map of Cretaceous age reservoir rock of Lumshiwal Formation was generated using the thickness obtained from well log correlation. The drilled thicknesses in six wells were used to generate the isopach maps. It shows that the thickness of Lumshiwal Formation is increasing toward west.

4.2 Seismic Interpretation

The area's regional geology and tectonics serve as the foundation for accurately interpreting geology and structure. Of these, the structural style of a region is crucial for accurately classifying faults as either normal or thrust based on the sense of displacement. Additionally, these faults are chosen for seal or trap analysis after they have been marked because they stop migration and preserve hydrocarbons when they bring the reservoir horizon up against the sealing horizon. The displacements are seen as either vertical or horizontal movement along the fault plane (Alsadi et al., 2017).

These faults are identified on seismic sections according to the local geology and structural style. The movement along a fault plane, which can be either vertical or horizontal and can happen separately or concurrently in nature, is referred to as displacement. Instead of remaining in a single fracture, the displacement between the two fault blocks is frequently dispersed throughout the whole fault zone, ranging from fractions of meters to kilometers. When the surface ruptures, but not before this breakdown, the fault line becomes apparent as a fault trace or outcrop. An oblique-slip fault is created when the vertical and horizontal movements roughly opposite one another along the fault line. Strike slip faults, sometimes referred to as lateral faults, are caused by the general horizontal movement along the fault plane (Li et al., 2025). Of these lateral faults, the left lateral fault moves its left fault block in the opposite direction of the observer, while the right lateral fault moves its right fault block in the opposite direction. Offset streams run along the active strike slip fault. These transform faults offer the zones of lateral movement along which the sensation of displacement either abruptly stops or changes its form and direction. The only places where lateral displacement occurs are between spreading centers; outside of them, no displacement follows a path.

Dip-slip faults are further divided into normal and reverse faults based on their vertical movement along the fault plane (Oglesby et al., 2005). The normal and reverse fault blocks, which are on opposing sides of a vertical fault, were initially addressed by miners who were stuck along fault zones while conducting mining exploration. According to the miner's position, a foot wall is a package beneath his feet, and a hanging wall is a package above his head. A fault is therefore considered normal when the portion of earth above the fracture slides downward relative to the part below it, and it is reversed when the package of strata above the fracture slides upward relative to those below. Thrust faults occur when the reversal fault's dip angle is less than 45 degrees. During thrust faulting, older rocks typically rest on younger rocks, but younger rocks are frequently forced over older rocks as well.

Along with their marking on the seismic section, the fault correlation was completed. Faults are first identified by the use of Kingdom suite utilities, and then they are allocated. Certain geological principles allow for the association between faults, which is the basis for fault name assignment. When recording a fault on one line and then on other lines in a survey, the idea of its dip direction and angle of dip is taken into account for each individual fault.

Seismic interpretation is one of the most important steps in structure interpretation based on the modeling of the seismic horizons on seismic lines (Liner et al., 2019). The seismic horizons from Paleocene to basement show conformity of structural deformation; the three faults were marked in seismic lines. The fault has very little throw. The throw ranges from 5 msec to 10 msec. The faults show normal sense of movement and have strike-slip movements as well, especially in the western portion of the seismic line O/20152-FTP-08. The 2D data quality of the seismic line is fair-to-good. The horst structure is marked in the central portion of the seismic line. The eastern side of the horst is further rising toward the east.

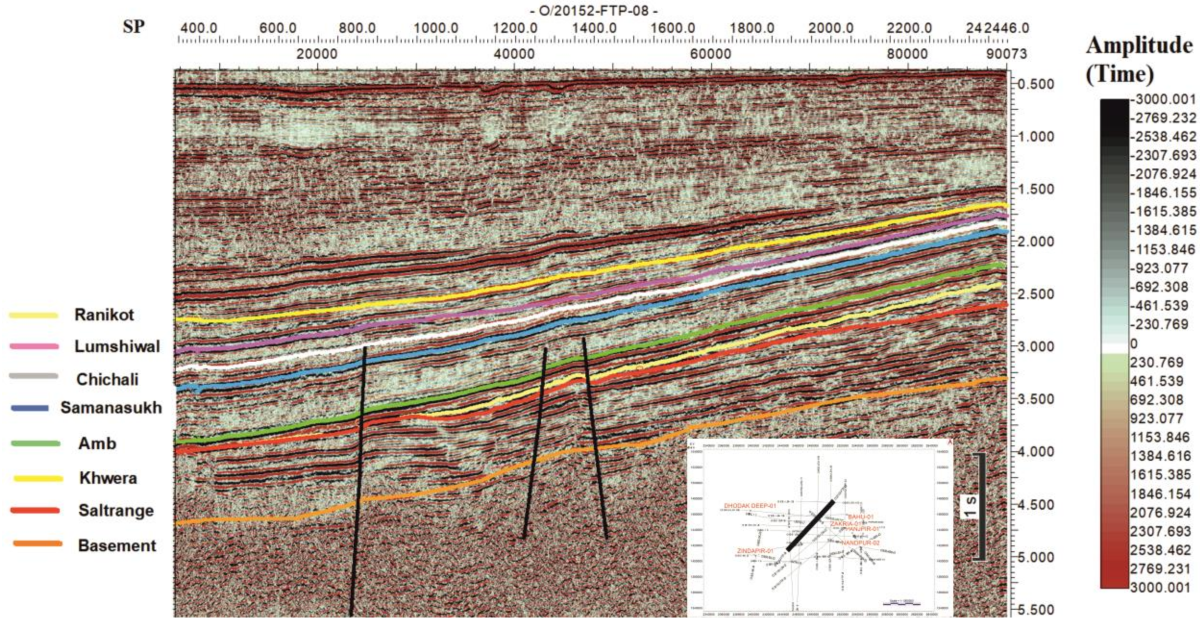

Figure 4.4 The seismic horizons from Paleocene to basement shows conformity of structural deformation on interpreted seismic line O/20152-FTP-08, the three faults were marked in seismic lines. Each fault has very less throw. The throw ranges from 5 to 10 msec. The faults show normal scenes of movement.

The seismic horizons extend from the Paleocene to the basement; there is evidence of structural deformation that is consistent, and three faults have been identified using seismic lines. Very little throw is present in the faults. Five milliseconds to one hundred milliseconds are the range of the throw. Not only the faults exhibit typical patterns of movement, but they also exhibit strike-slip movement, particularly in the western half of the seismic line. Seismic line data quality in two dimensions' ranges from good to excellent. Within the middle area of the seismic line, the horst structure is specifically noted. In the direction to the east, the strata are rising (Figure 4.4).

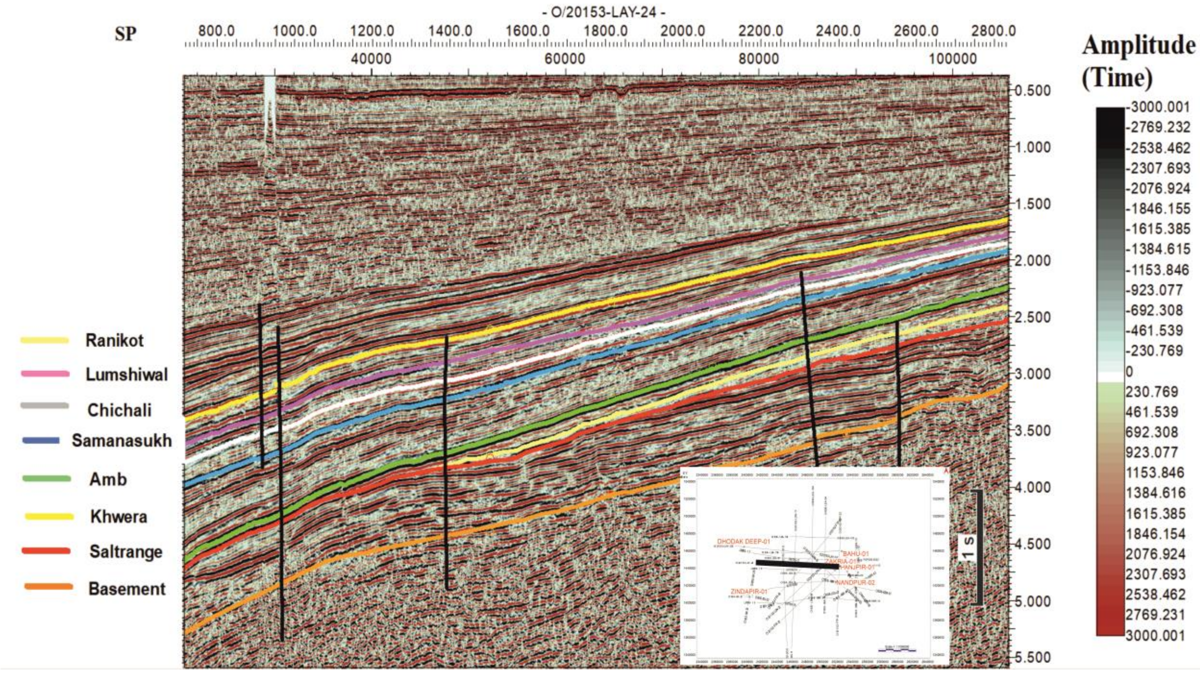

Figure 4.5 Eight significant and notable geological formations and horizons are highlighted on the interpreted time sections O/20153-LAY-24. Faults are directed NW-SE to N-S orientation. The throw of faults ranges from 3-5 millisecond. These faults have negligible throws as the study are lies in very less deformed tectonic zone. The strata are rising toward east, and the seismic interpretation represents a monocline trend with highs in the eastern direction.

Eight significant and notable geological formations and horizons are highlighted on the interpreted time section O/20153-LAY-24, which is a dip line. Data between SP 800 and 2800 and seismic reflections within time frames of 1.5 seconds to 3.2 seconds are shown via the E-W-oriented line sections O/20153-LAY-24. Four faults were marked by the dip lines. It is difficult to distinguish between these typical faults based on their sensation of displacement since they range from vertical to sub-vertical. Faults are directed NW-SE to N-S orientation. The throw of faults ranges from 3-5 milliseconds. These faults have negligible throws as the study lies in a very less deformed tectonic zone. The strata are rising toward the east, and the seismic interpretation represents a monocline trend with highs in the eastern direction. Interestingly, the overall thickness from the Ranikot Formation to the top basement is decreasing on the eastern side. In seismic line O/20153-LAY-24, the Cambrian and Precambrian sequences are pinching toward the west and the decrease in the thickness is the deposition trend. Overall, no lead is present in this line (Figure 4.5).

Seismic line O/835-LEA-102 is the dip line with E-W orientation. Eight prominent geological formations and horizons are highlighted on the interpreted time sections O/835-LEA-102 (Figure 4.6). These formations consist of basement rocks, source, reservoir, and cap rocks. The Chichali Formation is source rock, the Lumshiwal Formation is reservoir rock, and the Ranikot Formation is seal rock in this area. Data between SP 200 and 1200 and seismic reflections within time frames of 1.2 seconds to 3.5 seconds are shown via the NW-SE-oriented line sections O/835-LEA-102. Four faults were marked by the dip lines. It is difficult to distinguish between these typical faults based on their sensation of displacement since they range from vertical to sub-vertical. The fault is directed NW-SE and N-S oriented. The throw of fault ranges from 5-10 milliseconds. Interpreted faults have negligible throws as the study lies in a very less deformed tectonic zone. The strata are rising toward the east, and the seismic interpretation represents a monocline trend with highs in the eastern direction. Interestingly, the overall thickness from the Ranikot Formation to the top basement is decreasing on the eastern side. In his line, the Cambrian sequence is pinching toward the west, and the decrease in the thickness is the deposition trend. Overall, no lead is present in this line.

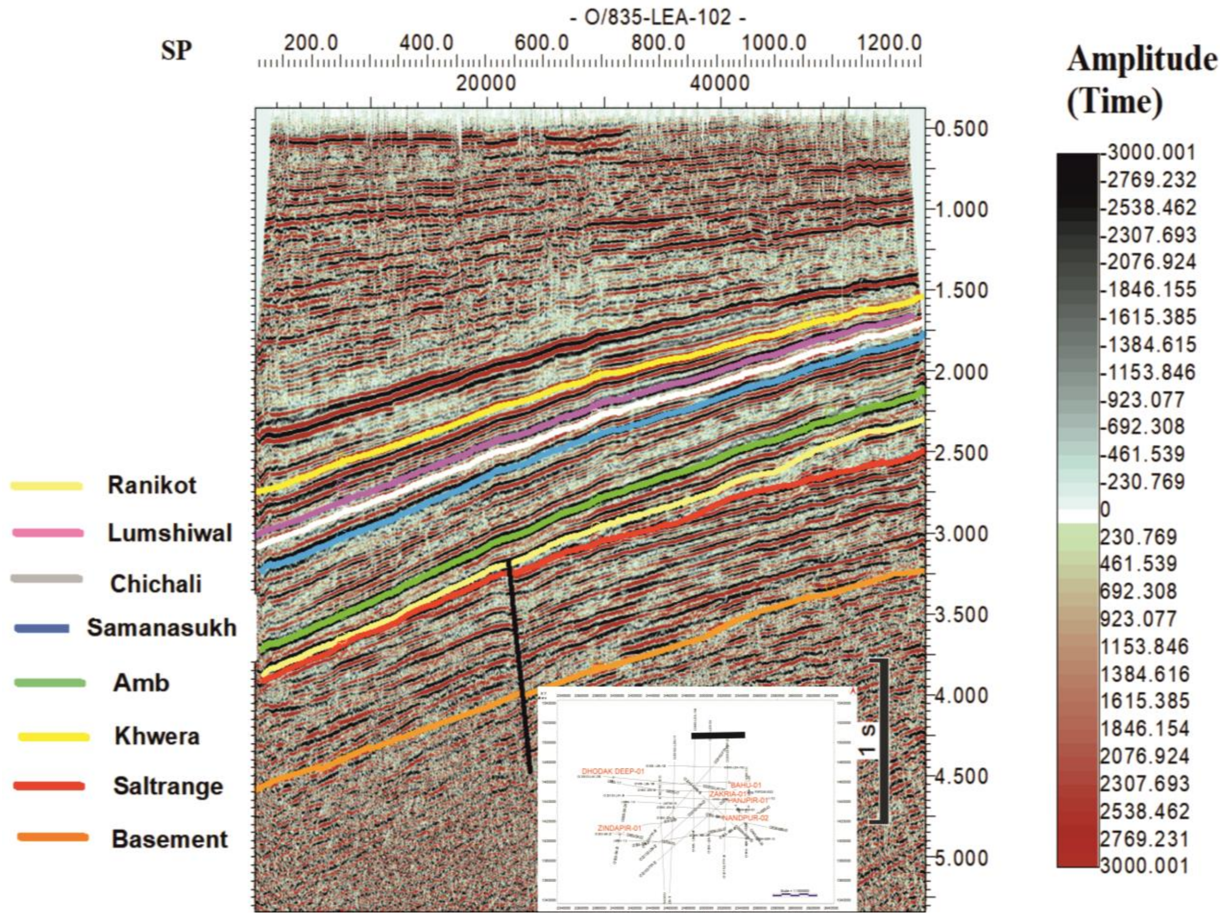

Figure 4.6 Seismic line O/835-LEA-102 is the dip line with E-W orientation. Eight prominent geological formations and horizons are highlighted on the interpreted time sections O/835-LEA-102.These formation consist of basement rocks, source, reservoir and cap rocks. The strata are rising toward east and the seismic interpretation represents a monocline trend with highs in the eastern direction.

Seismic line O/835-LEA-106 is an E-W dip line. The interpreted time sections O/835-LEA-106 emphasize eight major geological structures and horizons (Figure 4.7). These formations are composed of basement, source, reservoir, and cap rocks. In this area, the Chichali Formation serves as the source rock, the Lumshiwal Formation as the reservoir rock, and the Ranikot Formation as the seal rock. The NW-SE-oriented line sections O/835-LEA-106 display data between SP 200 and 1600, as well as seismic reflections within time frames ranging from 1.5 to 3.5 seconds. The dip lines indicated the main faults. The sense of displacement ranges from vertical to sub-vertical. The fault runs NW-SE and north-south. The fault throws ranges between 5 and 10 milliseconds. The eastern fault shows the splay and reflects the strike-slip movement. The interpreted fault has insignificant throws since the studied area is in a very little deformed tectonic zone. The strata are rising eastward, and the seismic interpretation shows a monocline trend with highs in the eastern direction. Interestingly, the entire thickness from the Ranikot Formation to the top basement is decreasing on the eastern side. In 2D seismic line O/835-LEA-106, the Cambrian sequence is squeezing toward the west, with a decrease in thickness representing the deposition tendency. There is one fault-bounded structure seen at the shot point number 700.

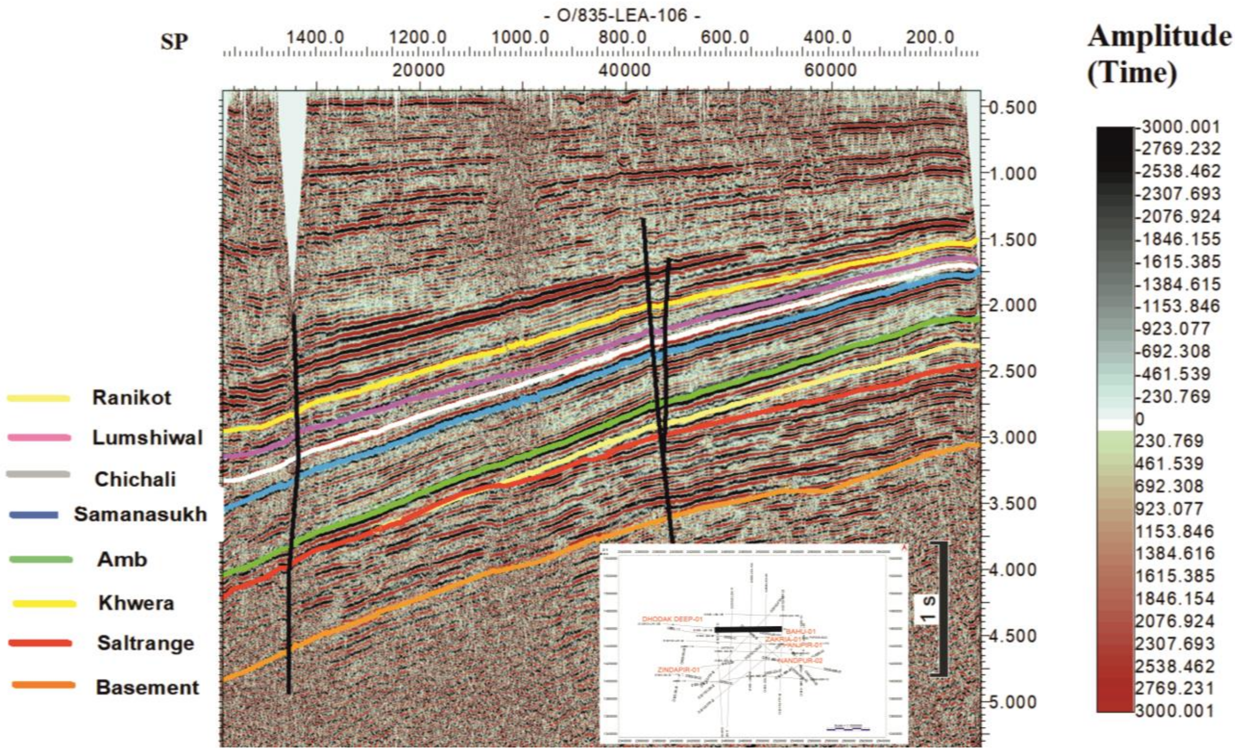

Figure 4.7 The NW-SE oriented line sections O/835-LEA-106 display data between SP 200 and 1600, as well as seismic reflections within time frames ranging from 1.5 to 3.5 seconds. The dip line indicated the main faults. In this line, the Cambrian and Precambrian sequences are squeezing toward the west, with a decrease in thickness representing the deposition tendency.

Properly constructed, time contour maps provide an accurate trend of underlying geology. The contour maps were created using seismic time of all horizons independently. All seismic lines were used for this purpose. So, time structure maps were created for the Ranikot, Lumshiwal and Chichali Formations, which are geologically dated as Paleocene, Cretaceous, and late Jurassic. The color palette depicts a rising tendency of seismic time from southeast to northwest, which is also consistent with the pattern of monocline growth on the Punjab Platform (Figure 4.8). Vertical and sub-vertical faults are highlighted.

A depth structure map for the Lumshiwal Formation reservoir was generated (Figure 4.8). The contour interval measures 100 m. The color bar indicates that the minimum time begins at 1245 m and concludes at about 8450 m. These time contours reveal a deepening of depth values from east to west, indicating a monocline structure descending westward into the Sulaiman depression. The deepest values of the Lumshiwal Formation lie at 7000m in the Sulaiman Foredeep area.

The main red fault is the thrust fault, which uplifted the Sulaiman Fold Belt area and all the structuration in the fold belt is the result of this main fault (Figure 4.8). It has immense throw ranges from 1500m to 4000m.The structures of Zindapir-01 and Dhodhak-01 were created as the result of these faults. The Zindapir is a fault-bounded structure with valid structure evident on the Top Lumshiwal map. The number of other faults was interpreted and shown in (Figure 4.8). The orientation of these faults is NE-SW direction. The cluster of faults is present in both the eastern and western parts of the study area. The throw of these faults is negligible, ranging from 6-15 meters calculated from depth structure map (Figure 4.8). The strata are rising in the east in the proximal part of the Indian shield. The trend of strata is aligning with the orientation of the west-dipping Indian shield.

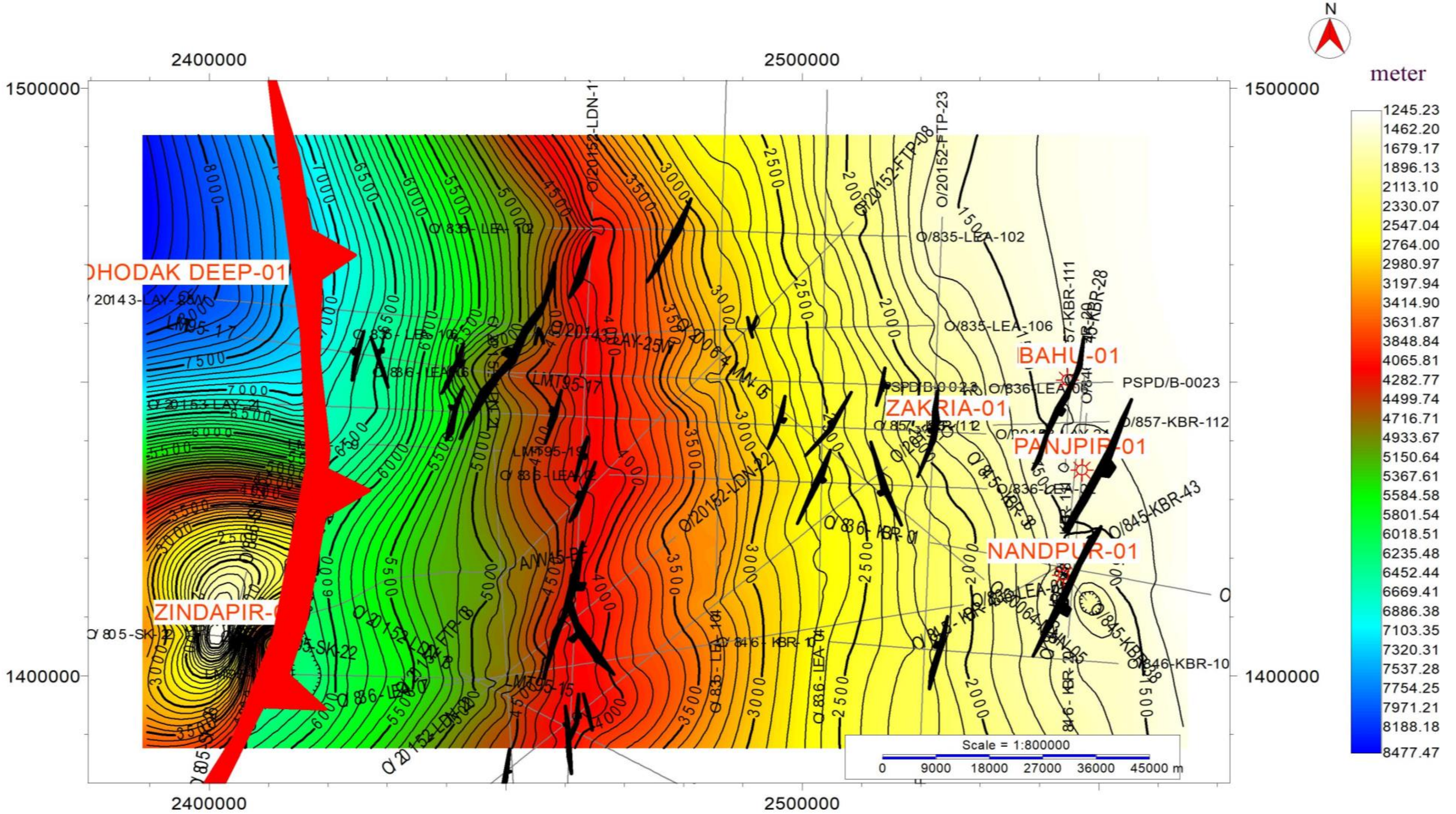

Figure 4.8 Depth structure map for the reservoir Lumshiwal Formation. The contour interval measures 100 m. The color bar indicates that the minimum time begins at 1245 m and concludes at about 8450 m. These time contours reveal a deepening of depth values from east to west, indicating a monocline structure descending westward into the Sulaiman depression. The deepest values of depth of Lumshiwal Formation lies at 7000m in Sulaiman Foredeep area.

The Chichali Formation depth map (Figure 4.9) follows the same color bar trend from minimum to maximum depth contour ranges. The depth structure has a contour interval of 100 m. The contours follow the monocline structure of the Punjab Platform, which decreases from east to west (Figure 4.9). The depth structure map shows a drop in contour values from east to west as follows: 1600 m in the Punjab Platform area to 7800 m in the western Sulaiman Foredeep area. It is important to mention that the deepest burial of source rock Chichali Formation lies in the Sulaiman Foredeep area. This decrease in contours corresponds to the dip of the Punjab monocline. The cluster of faults is present in both the eastern and western parts of the study area (Figure 4.9). The throw of these faults is negligible, ranging from 6-15 meter calculated from depth structure map (Figure 4.9). The strata are rising in the east in the proximal part of the Indian shield. The trend of strata is aligning with the orientation of the west-dipping Indian Shield.

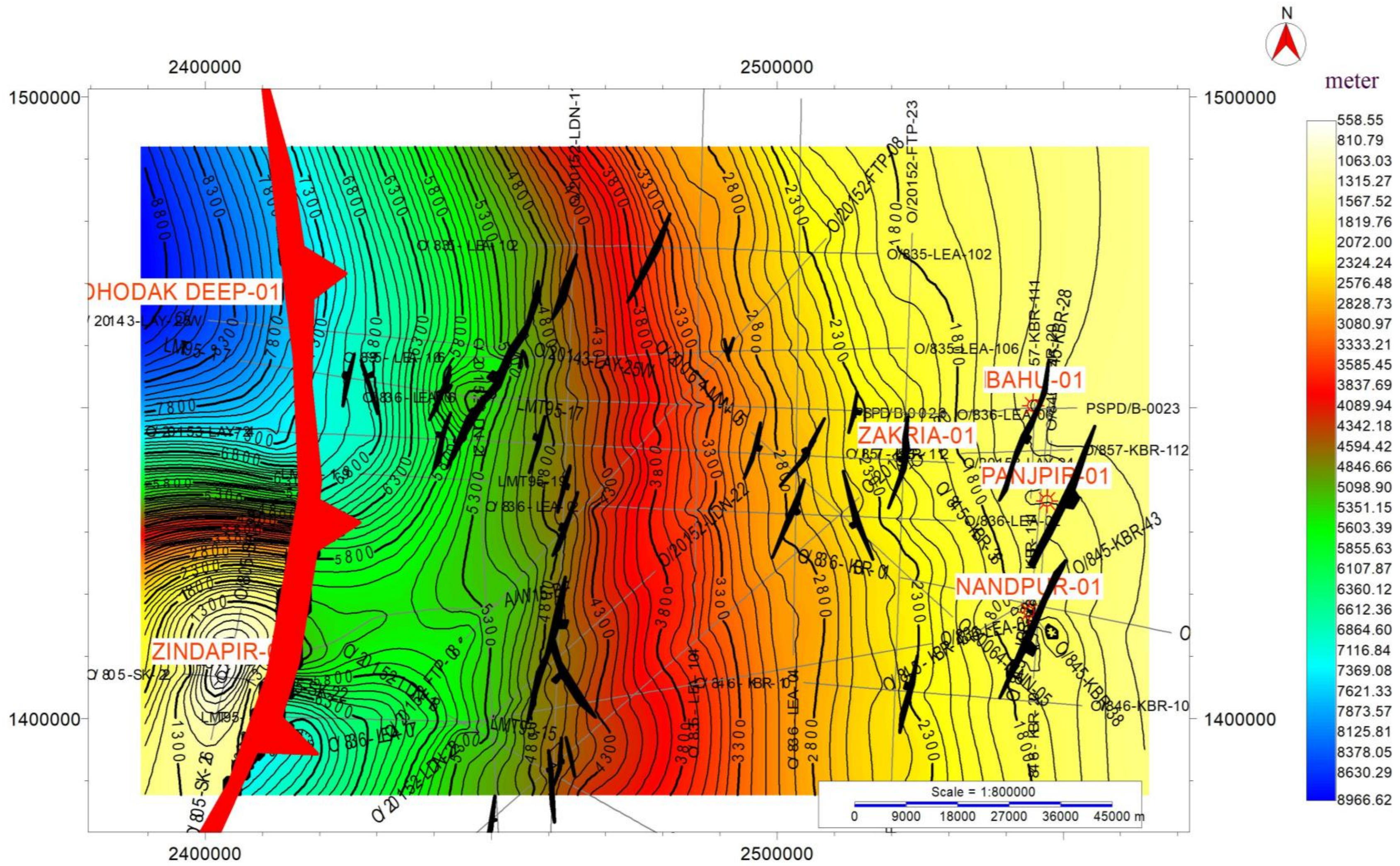

Figure 4.9 The Source rock Chichali Formation depth map generated as the result of seismic interpretation and mapping. The contours follow the monocline structure of the Punjab Platform, which decreases from east to west. The depth structure map shows a decrease in contour values from east to west as follows: 1600 m in the Punjab Platform area to 7800 m in western Sulaiman Foredeep area.

The depth structure generated at Jurassic age Samana Suk formation with contour interval of 100 m (Figure 4.10). These time contours reveal an increase of depth values from east to west, indicating a monocline structure descending westward into the Sulaiman depression. The deepest values of depth of the Jurassic age Samana Suk formation lie at 7750 m in the Sulaiman Foredeep area (Figure 4.10).

The main red fault is the thrust fault, which uplifted the Sulaiman fold belt area and all the structuration in the fold belt is the result of this main fault. It has immense throw ranges from 1500m to 4000m.The structures of Zindapir-01 and Dhodhak-01 were generated as result of this faults. The Zindapir is a fault-bounded structure with valid structure evident on the Top Samana Suk formation map (Figure 4.10). The number of other faults were interpreted and shown in (Figure 4.10).

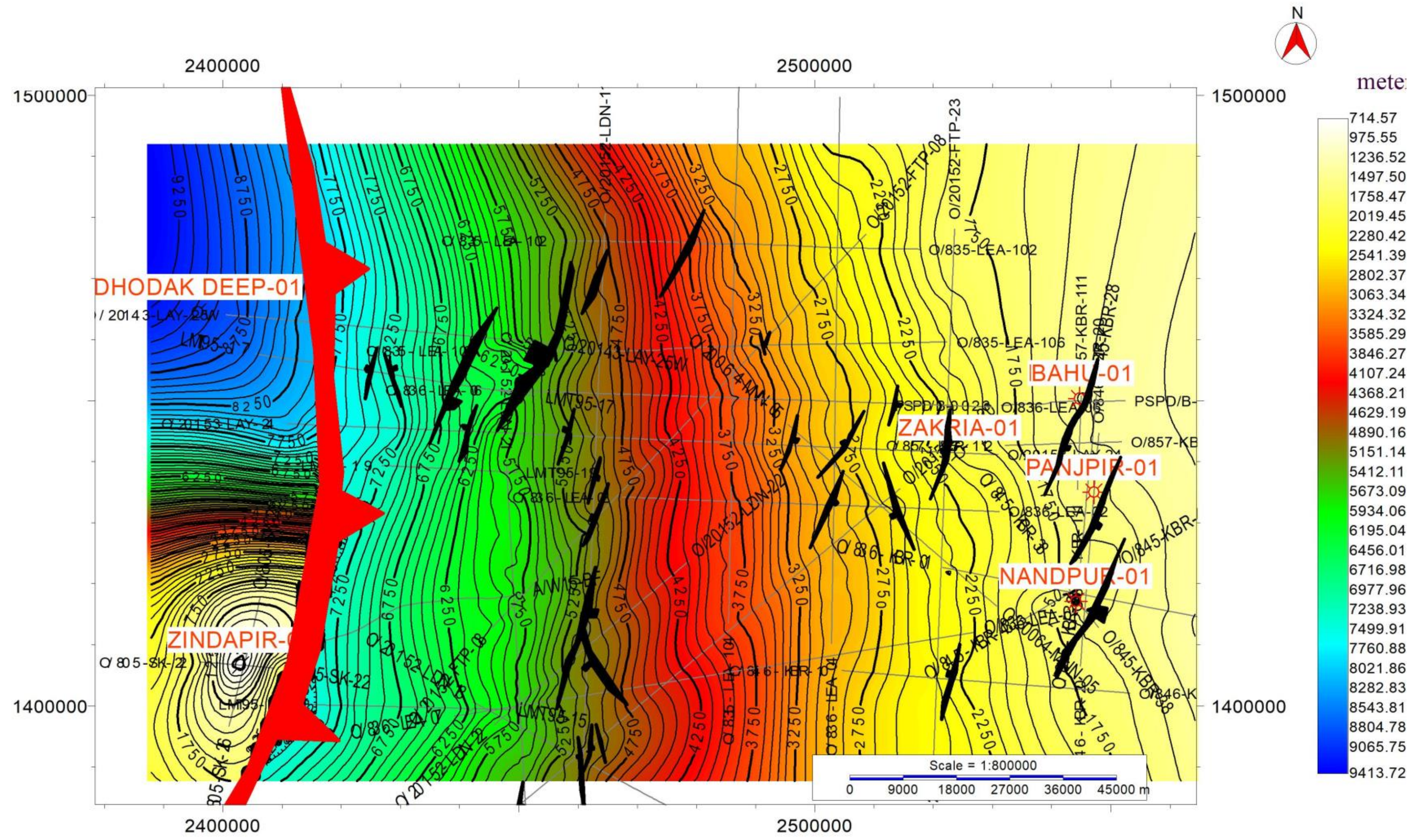

Figure 4.10 Represents the depth structure map for the Jurassic age Samana Suk Formation. The main red fault is the thrust fault which uplifted the Sulaiman Fold Belt area and the all the structuration in the fold belt the result of this main fault. It has immense throw ranges from 1500m to 4000m.The structures of Zindapir-01 and Dhodhak-01 were created as the result of main bounding fault in red colour. The Zindapir is fault bounded structure with valid structure evident on Top Samana Suk Formation depth map.

4.3 TOC

The average TOC values were calculated from core samples. Calculated TOC values at Bahu-01, Panjpir-01, Nandpur-01 and Zakria-01wells are 0.34%, 1.25%, 1.36%, and 0.72% respectively. Based on these values, an average TOC map was generated for the Cretaceous source rock (Figure 4.11). Bahu-01, with its TOC of 0.34%, exhibits a poor source rock potential. In contrast, Panjpir-01 and Nandpur-01, with TOC values of 1.25% and 1.36%, respectively, signify moderate to good organic richness. Zakria-01 well, with a TOC of 0.72%, demonstrates fair organic richness.

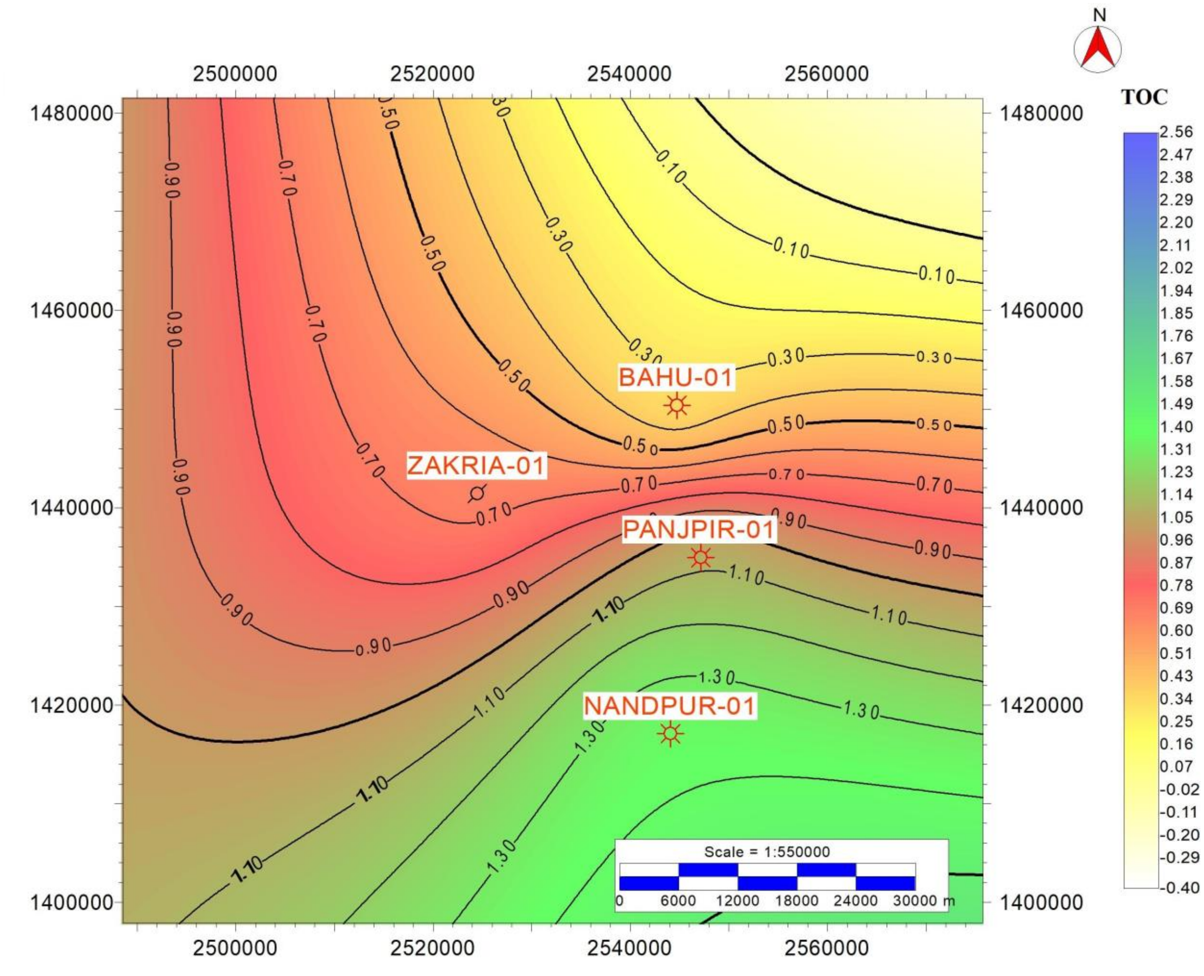

Figure 4.11 Average TOC map of the Cretaceous Chichali Formation showing the TOC distribution in study area. The TOC values are increasing from east to west direction.

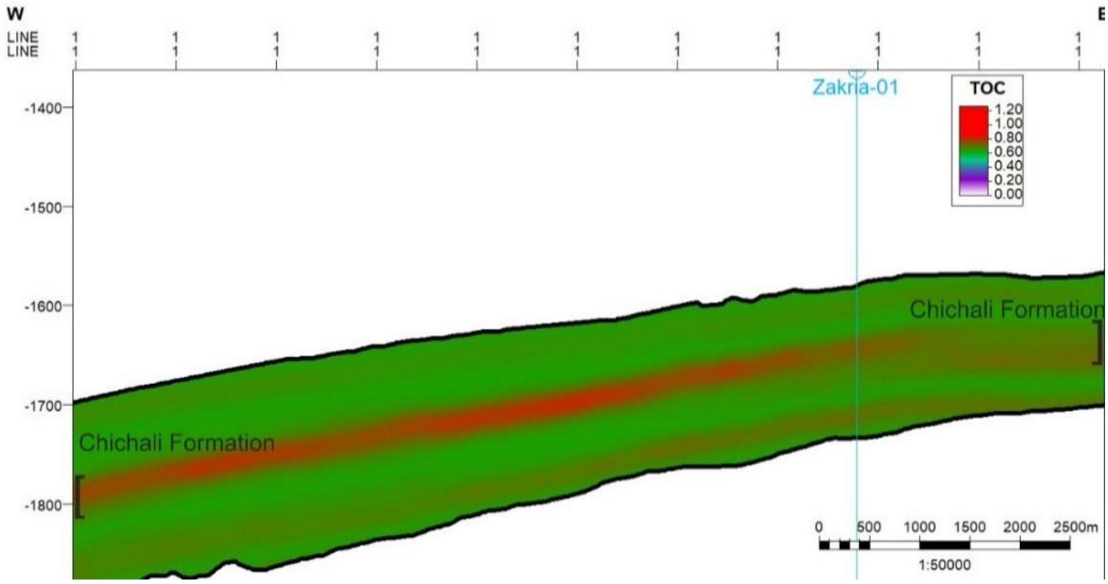

Figure 4.12 2D seismic profile showing the TOC variation of Chichali Formation, TOC is further increasing toward the west as a result of deep marine setting. TOC values were derived at Zakria-01 well from P-impedance by using linear equation Y = -0.000466368 * X + 1.37812 with R2=0.95.

Also, the average Zakria-01 TOC was calculated from seismic inversion at the Zakria-01 well location. TOC at Zakria-01 well is 0.77%, closely matching the actual average TOC of 0.72% obtained from lab analysis. The main purpose of calculating the TOC from seismic inversion was to calculate the TOC in the western part of the study area where no wells have been drilled. Calculating TOC from the seismic inversion approach is novel in the study area. The seismic inversion reveals that TOC is increasing from east to west and has a good TOC of 1.50% in most western parts (Figure 4.12). The TOC variation in the area is also supported by the tectonic setting and stratigraphy of the source rock, which indicates that sediments deposited from proximal sedimentary settings in the east to distal sedimentary settings in the west. The comparison between TOC values derived from core samples and those calculated from seismic inversion shows a strong correlation (R= 0.9774) for assessing the organic richness of the Chichali Formation in the Punjab Platform area (Figure 4.13).

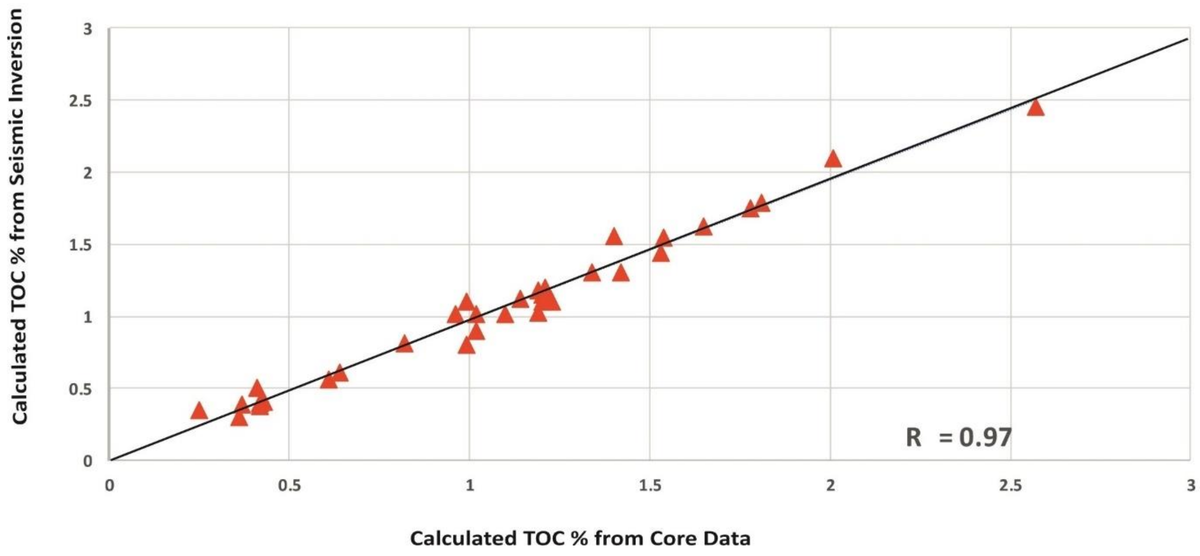

Figure 4.13 The coefficient of determination was calculated by plotting calculated TOC from core samples from Zakria-01 well versus calculated TOC from seismic inversion at Zakria-01 well. It is showing an excellent correlation coefficient of (R= 0.97).

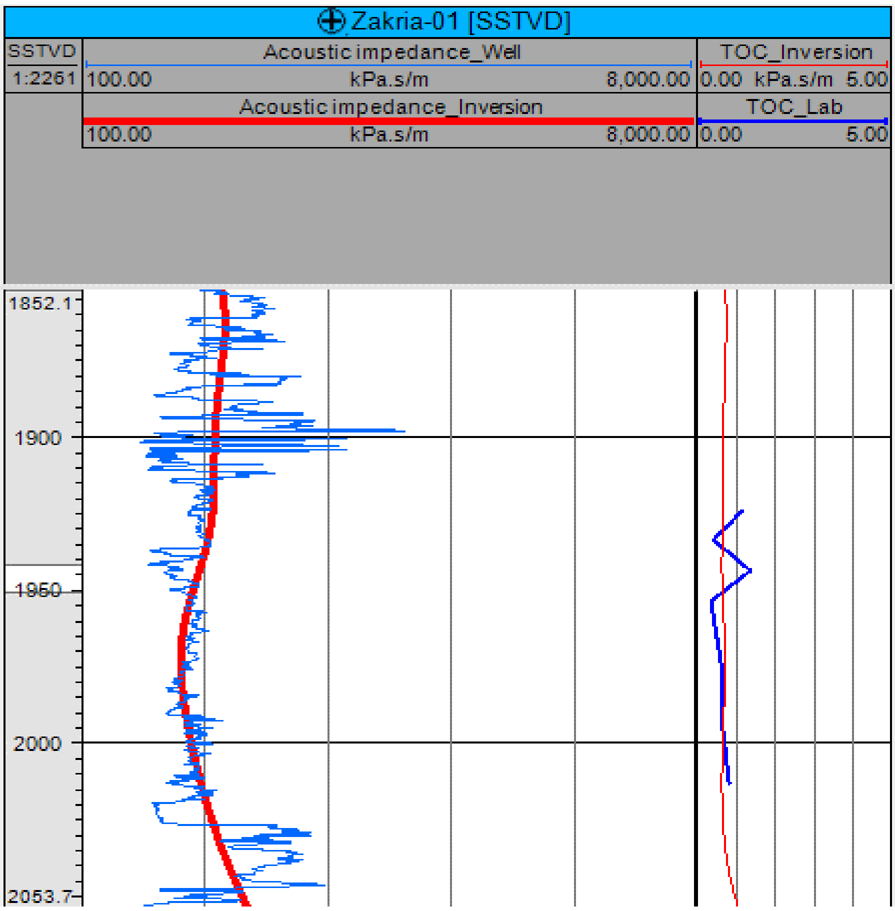

Figure 4.14 Shows the comparison of calculated acoustic impedance from seismic (red curves) versus well (blue curves). Also calculated TOC from seismic inversion is compared with TOC, calculated from core. Acoustic impedance and TOC calculated from core and seismic data represent same trend. At Zakria-01 well, the calculated TOC from seismic inversion is 0.78, aligning closely with the TOC of 0.72 obtained through lab analysis from core samples.

The TOC results obtained from core and seismic are compared and this highlights the effectiveness of the seismic inversion technique for TOC estimation, particularly in situations where core data is unavailable. Calculated acoustic impedance from seismic inversion (red curves) plotted versus core data from well (blue curves) (Figure 4.14). Also calculated TOC from seismic inversion is compared with TOC calculated from the core. Acoustic impedance and TOC calculated from core and seismic data represent the same trend. At Zakria-01 well, the calculated TOC from seismic inversion is 0.78%, aligning closely with the TOC of 0.72% obtained through lab analysis from core samples. The main goal achieved from seismic inversion is to evaluate the organic richness of source rock, especially in the western portion of Punjab Platform, where no wells were drilled, and source rock potential was never addressed before.

Shah et al. (2021) conducted a source rock potential assessment of the Cretaceous Chichali Formation in the Panjpir field within the Punjab Platform, using solely core data. In their analysis, they found that the Chichali Formation had an average TOC (wt.%) value of 1.41%, indicating moderate to good total organic richness. Similarly, Gakkhar et al. (2011) assessed the potential of Cretaceous rocks in the Punjab Platform and reported average TOC (wt.%) values ranging from 1.29%. According to Raza et al. (2008), the shales of the Cretaceous Chichali Formation in the Panjpir-01 well showed fair organic richness, with an average TOC (wt.%) value of 1.35%. Additionally, geochemical analysis of samples from the Nandpur-01 field indicated poor to fair organic carbon content, with an average value of 1.12%. The consistency in results between our research and those of earlier authors confirms the credibility of our work. The uniqueness of this research is the calculation of TOC from seismic data which was not carried by earlies authors.

4.4 Kerogen Type

For the determination of kerogen type, Rock eval data, HI and OI were utilized. Rock eval data HI verses OI are plotted at the Bahu-01, Panjpir-01, Nandpur-01, and Zakria-01 wells. Based on these Van Krevelen diagram (Modified) graphs all the samples taken from Bahu-01, Nandpur-01, and Zakria-01 wells falls in Kerogen type-III. Samples from Panjpir-01 well falls in kerogen type-II-III (Figure 4.15). Based on these results, it is concluded that Panjpir-01 well dominates kerogen t type-III and has gas generation potential. In exploration phase, this better understanding about kerogen type and hydrocarbon generation potential will help to add more resources in the Punjab Platform.

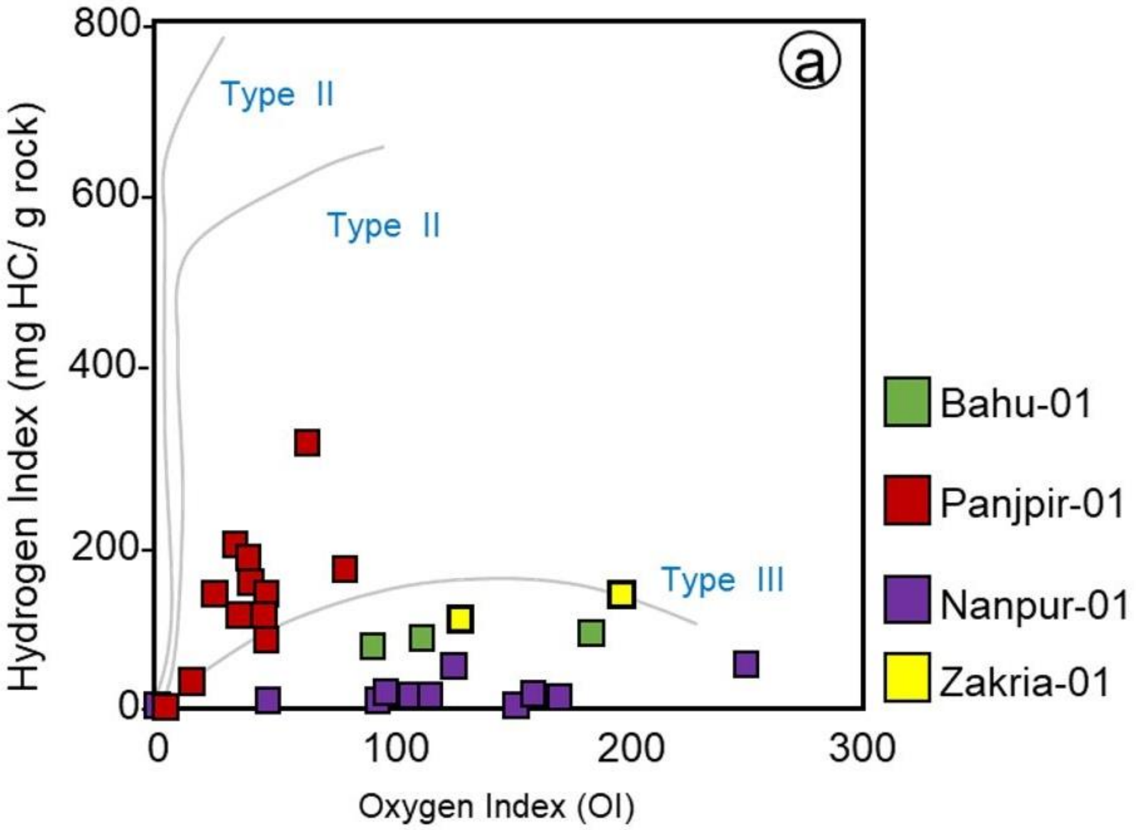

Figure 4.15 Source rock Kerogen Type was identified by using Van Krevelen diagram. Rock eval data HI was plotted against OI. Bahu-01, Nandpur-01 and Zakria-01 wells falls in kerogen type III, whereas samples from the Panjpir-01 well falls within kerogen types II to III.

4.5 Maturity

In addition to source rock richness, source rock maturity plays an equally vital role in source rock evaluation. Rock eval analysis can be used to determine thermal maturity based on T_{max} parameters. Peter and Cassa (1994) source rock classification were used for this research. This approach relies on the thermal decomposition of organic matter in an inert atmosphere, yielding a T_{max} value at which the maximum hydrocarbon generation occurs (Chen et al., 2023). Rock eval pyrolysis, T_{max} data was used for this study for estimating essential geochemical parameters in source rock geochemical assessment. T_{max} values less than 435°C indicates the immaturity of source rock whereas T_{max} range from 435-470°C represents the maturity of source rock. Over maturity of source rock attains at greater than 470°C. Rock eval pyrolysis data was utilized to generate an average T_{max} map.

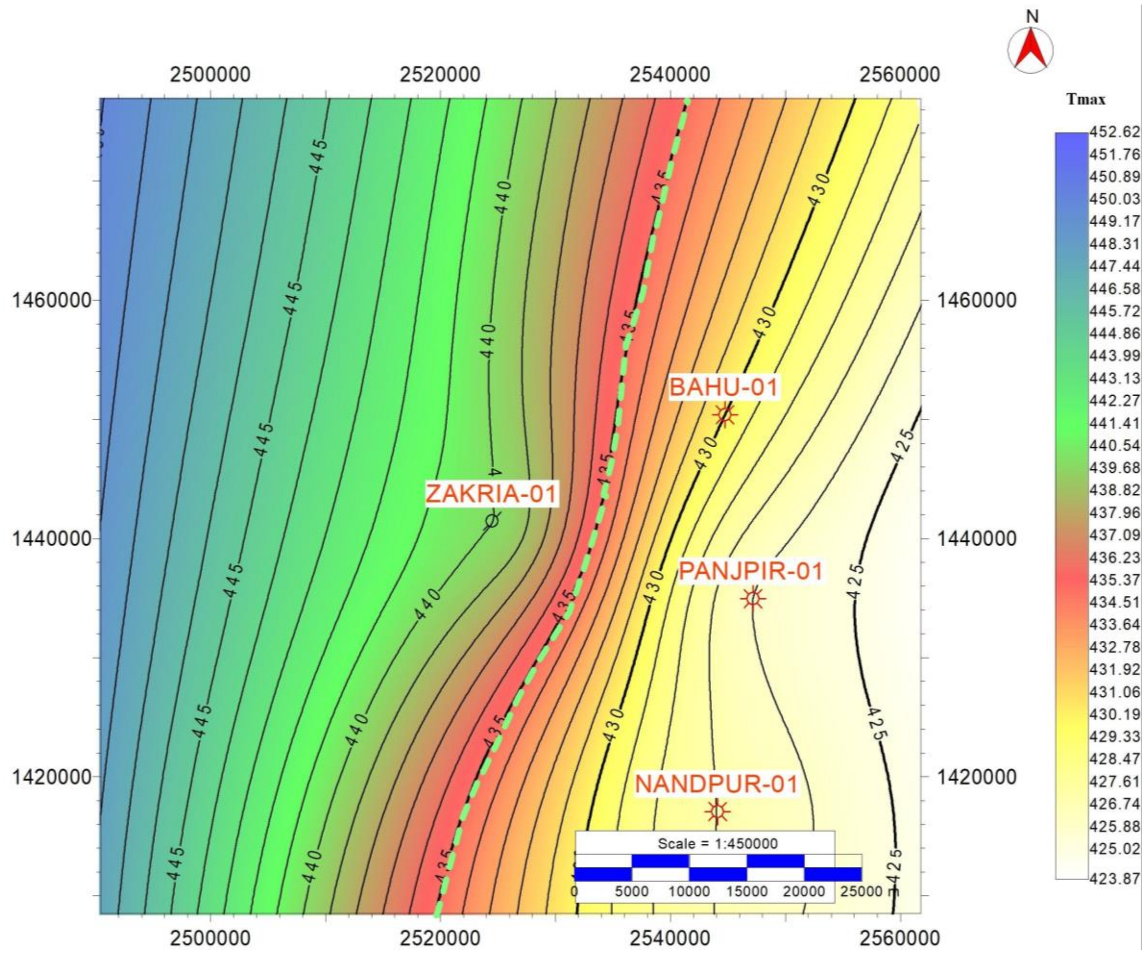

Figure 4.16 Rock eval pyrolysis and T_{max} data was also utilized for source rock maturity. Average T_{max} map of Cretaceous Chichali Shale was generated. Dotted green line separates source rock immature eastern zone from mature western zone. Source rock in Bahu-01, Panjpir-01 and Nanpur-01wells falls in immature zone. However, it is mature in Zakria-01 well.

Average T_{max} values below 435°C at Bahu-01, Panjpir-01, and Nandpur-01 indicate immaturity, while a T_{max} value exceeding 435°C at Zakria-01 confirms maturity of source rock. It clearly divides the western source mature zone from eastern immature zone (Figure 4.16). The source generation potential based on T_{max} values indicates the early to mature source potential. The %Ro calculation is most crucial and authentic approach for the evaluation of source rock maturity. Senftle and Landis (1991) classification was used in this research for the source rock maturity. Also %Ro values calculated through organic petrography are analyzed. The %Ro values calculated from core samples are plotted against depth to reveal the maturity of the Cretaceous source rock (Figure 4.17). Source rock samples having %Ro values less than 0.5 lies in immature zone with no hydrocarbon generation potential. The onset of oil generation is correlated with %Ro of 0.5 and termination of oil generation at %Ro of 1.1. The gas generation ranges lie between %Ro values of 1.1-1.5.

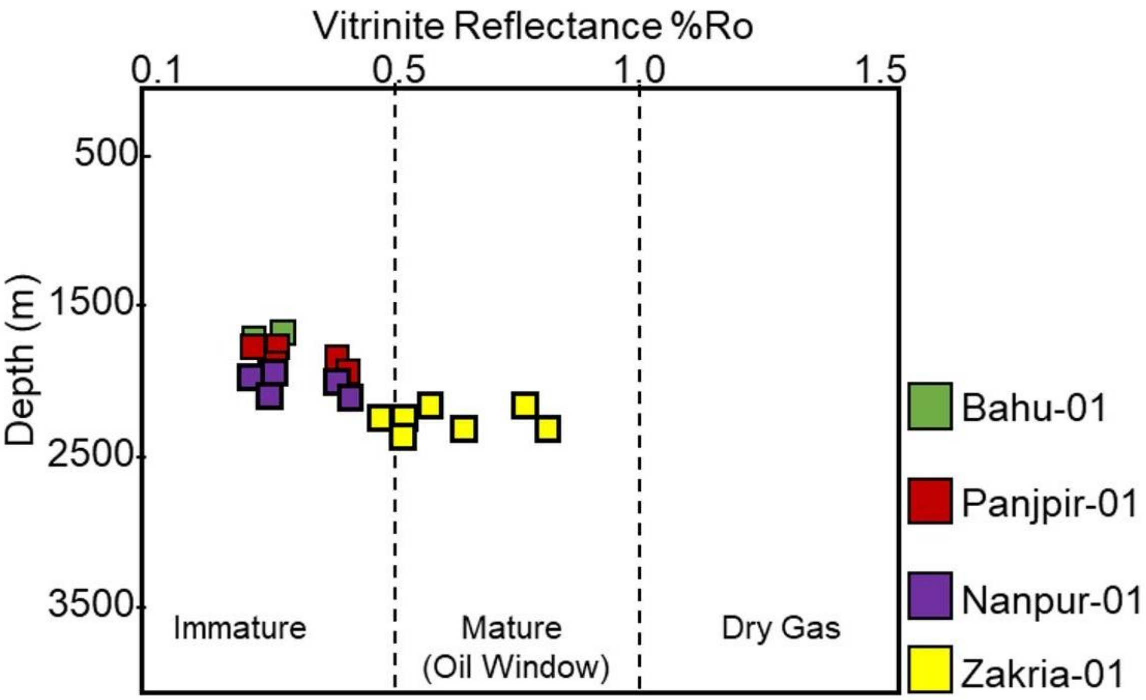

Figure 4.17 Represents the calculated %Ro from core samples plotted against depth. Source rock samples in Bahu-01 Panjpir-01 and Nanpur-01 wells falls in immature window. Immature source rock represents no hydrocarbon generation potential in these wells. Samples from Zakria-01 well lies in source mature window representing early oil generation potential. Senftle and Landis (1991) classification was used in this research for the source rock maturity.

This %Ro plotted versus depth graph shows that the %Ro values at Bahu-01, Panjpir-01, and Nandpur-01 are all less than 0.5%, signifying immature source rock. Immature source rock represents no hydrocarbon generation potential in these wells. In contrast, Zakria-01 well displayed an average %Ro of 0.63%, revealing that the Cretaceous source rock is within the oil window (Figure 4.17). This corresponds to the geological basin setting. Bahu-01, Panjpir-01 and Nandur-01 lie in eastern proximal margin of Punjab Platform, source rock is not buried deep in term of depth to attain maturity. However, Zakria-01 well is situated toward the western, basin side of Punjab Platform. The source rock has attained maturity due to the adequate overburden and deep burial in terms of depth.

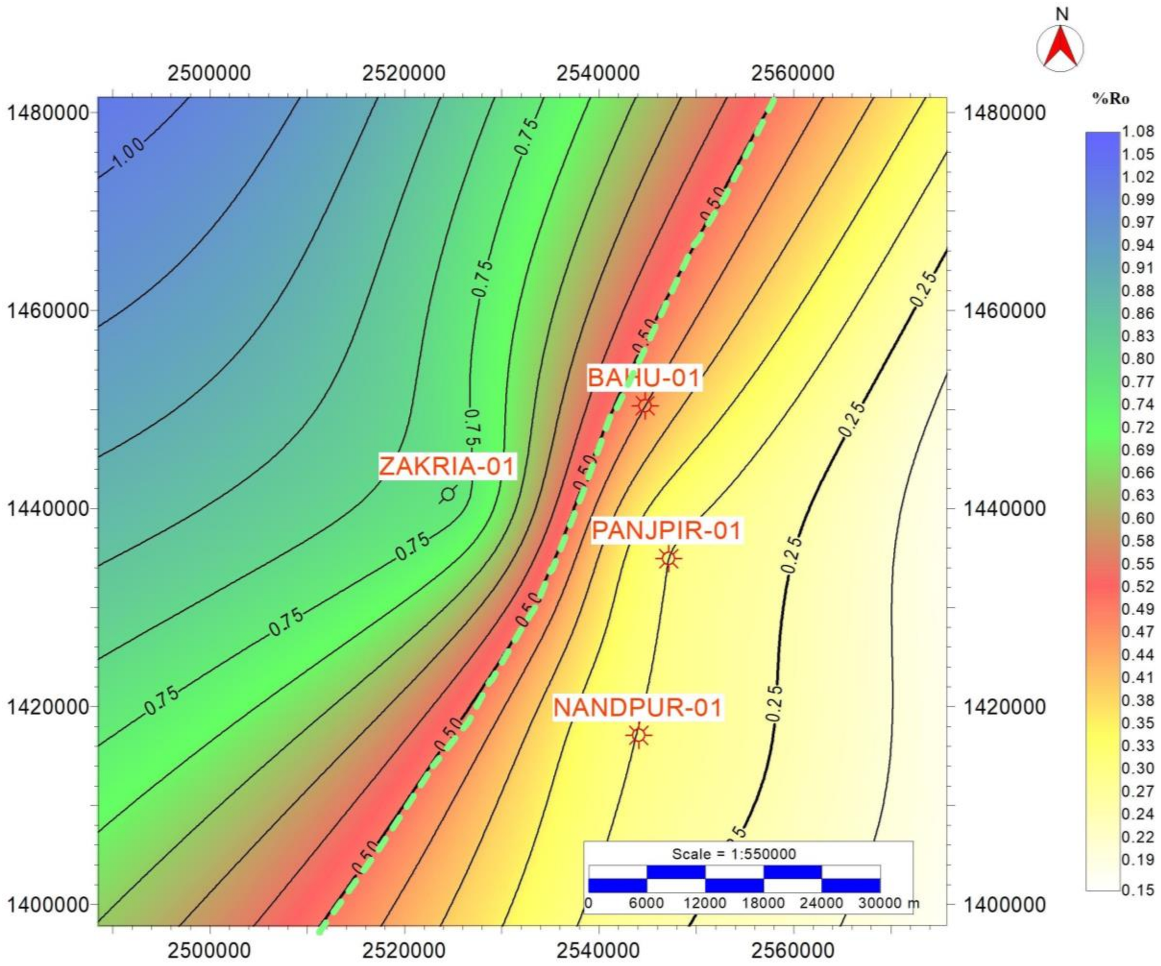

Figure 4.18 Shows average %Ro map of Cretaceous Chichali Formation. Dotted green line separates source rock immature eastern zone from mature western zone. Bahu-01, Panjpir-01 and Nandpur-01 wells lies in source rock immature zone while Zakria-01 well falls in source mature zone.

An %Ro map is generated to assess the maturity of the source rock based on Vitrinite values (Figure 4.18). The onset of oil generation is correlated with %Ro of 0.5 and the termination of oil generation at %Ro of 1.1. The gas generation ranges between %Ro of 1.1-1.5. The average %Ro values in Bahu-01, Panjpir-01, and Nandpur-01 wells are all below 0.5%, confirming the immaturity of the source rock in these wells. In contrast, Zakria-01 well showed an average %Ro value of 0.63, indicating source rock maturity. Based on maturity results a clear boundary was marked to separate mature western portion of Punjab Platform from the immature area in eastern side (Figure 4.18).

4.5.1 Calculation of Source Rock Maturity through Basin Modeling

The source rock maturity and its timing of expulsion were calculated from ID basin modeling approach. The results of Multi 1D basin modeling provide insights into the paleo-water depth and temperature conditions in different geological intervals. Surface water interference temperature remains close to 28 °C. In the Mesozoic interval, the PWD from 0 to 200 meters, while in the Late Paleogene, it varied from 0 to 50 meters (Fig. 15).

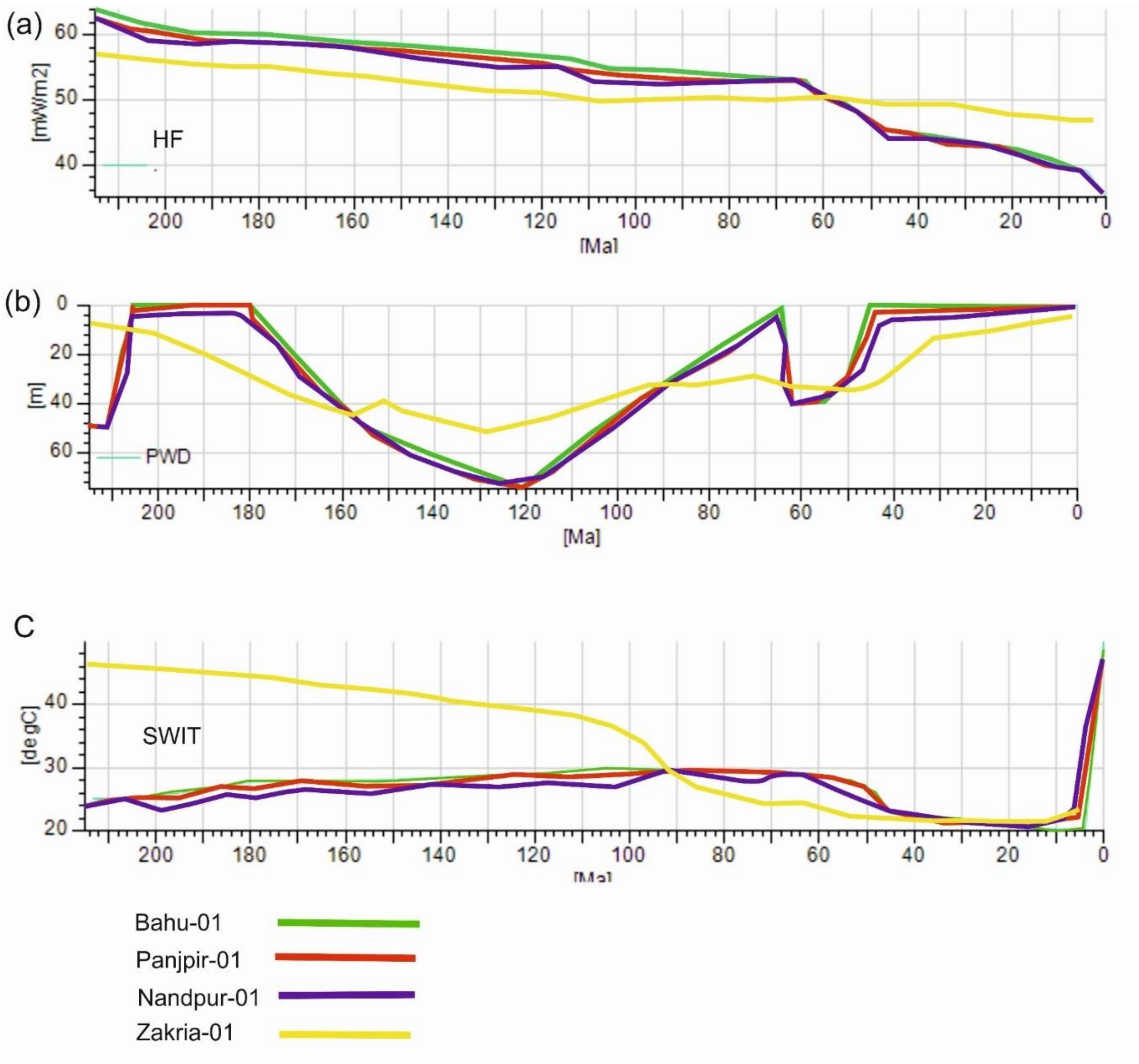

Figure 4.19 (a) Shows the heat flow (mW/m^2) curve plotted against age. It is showing high heat flow values from 250 (Ma) to 65(Ma) due to rifting phase (b) Showing the PWD (m) curve plotted against age (Ma). Water depth decreases after 65 (Ma) due to the uplifting phase (c) Surface water interface temperature in ^{o}C, plotted against age in (Ma), SWIT remains close to 28 °C.

The source rock properties, like kerogen type, vitrinite reflectance, HI, and OI, calculated through rock pyrolysis and spectroscopy, were incorporated. These source rock properties are necessary to incorporate in petroleum system modeling for the hydrocarbon generation expansion and migration. The TOC (wt.%) on the eastern side ranges from 0.35 to 1.5.

However, the TOC (wt.%) on the western side increased at ranges from 1.5 to 3. The calculated HI (mg/g) values range from 2 to 125, and OI mg/g range from 30 to 120 in the eastern side of the study area. The simulated paleo heat flows were adjusted to match the actual %Ro values with the modeled values. An average heat flow ranging from 50 mW/m² to 60 mW/m² provided the best match for actual %Ro. ID basin modelling results are shown in (Figure 4.20). The maturity of the source rock of the Chichali Formation shows a variation of %Ro over the entire area (Figure 4.20). In the eastern part of the study area, where the Bahu-01, Pnjpir-01, and Nandpur-01 wells were drilled, the %Ro ranges from 0.3% to 0.45%, showing the immaturity of the source in the eastern area. In the central part of the study area, close to the Zakria-01 well, there is a %Ro of 0.75%, which shows the maturity of the source rock. It is worth mentioning that the eastern part of the study area did not contribute to the bulk generation potential of the hydrocarbon, and it remained barren throughout the era (Figure 4.20). Zakria-01 well represents the value 0.55% of %Ro obtained from basin modeling, suggesting that the source rock maturity lies in the early maturity stage (Figure 4.20d).

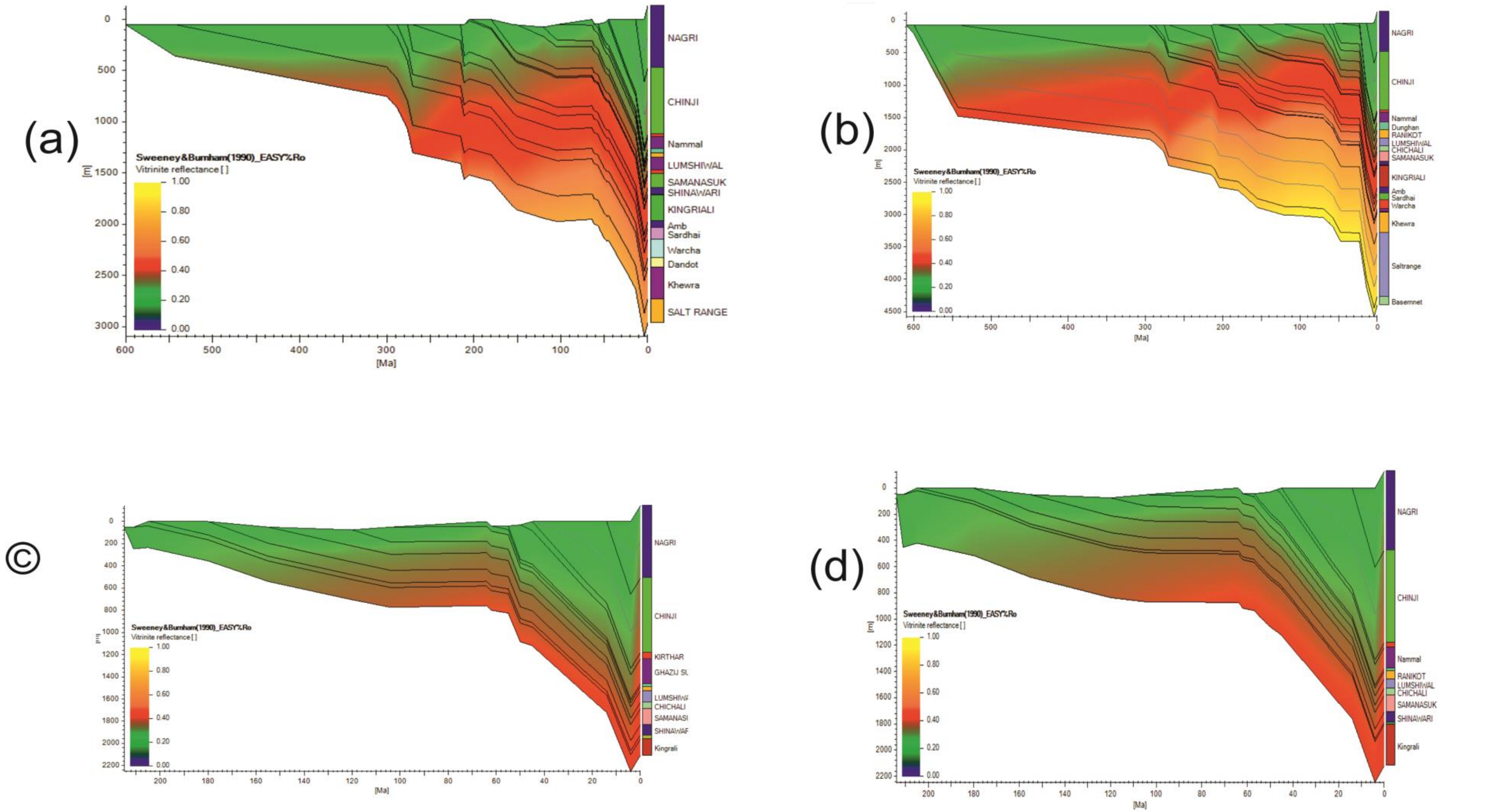

Figure 4.20 ID basin Modeling was carried at (a) Bahu-01, (b) Panjpir and (c) Nandpur-01 wells. Source rock is immature at (a, b & c) wells because of modeled % Ro less than 0.5 (d) Source rock is mature at Zakria-01 well because of modeled % Ro greater than 0.5 % and having oil generation potential and maturity attained at Eocene time.

Furthermore, the %Ro calculated from the direct lab-based approach (petrography) and the indirect method (Basin Modeling) are compared, and it showed a strong correlation coefficient value of R= 0.92 (Figure 4.21). This compressive source rock evaluation approach for the Chichali Formation Maturity is novel in the study area and the best match between results derived from diverse methodologies reflects that an integrated approach can be adopted in other basins of the world for enhanced hydrocarbon exploration.

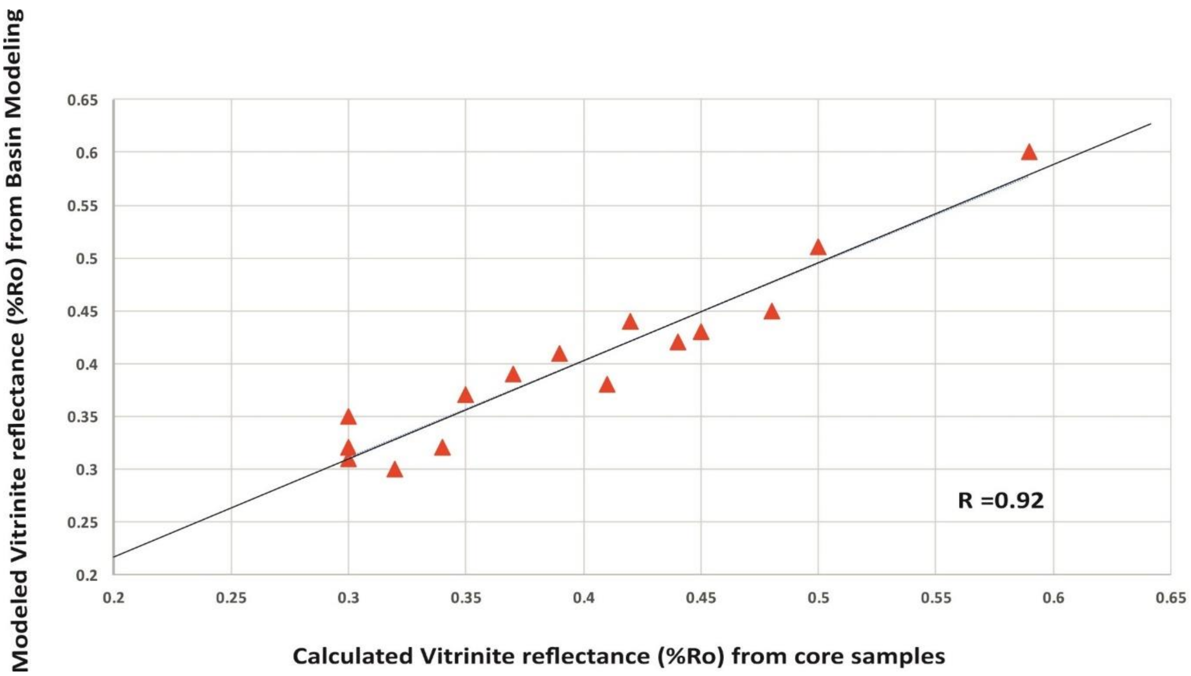

Figure 4.21 The coefficient of determination was obtained by comparing %Ro calculated from organic petrography in the lab from core samples versus predicted %Ro from basin modeling. It is having good correlation value of (R= 0.92).

The results of Multi 1D basin modeling provide insights into the paleo-water depth and temperature conditions in different geological intervals. In the Mesozoic interval, the paleo-water depth ranged from 0 to 200 meters, while in the Late Paleogene, it varied from 0 to 50 meters. The simulated paleo-heat flows were adjusted to match the actual %Ro values with the modeled values. An average heat flow ranging from 50 m W/m² to 60 m W/m² provided the best match for actual %Ro.

The 1D basin modeling results for each well are as follows:

1. Bahu-01 Well (Figure 4.20a): The modeled %Ro for the Cretaceous source rock was 0.33%, indicating immature source rock.

2. Panjpir-01 Well (Figure 4.20a): The modeled %Ro was 0.38%, also suggesting immature source rock.
3. Nandpur-01 Well (Figure 4.20a): The modeling indicated a (%Ro) value of 0.4% for the Cretaceous source rock, confirming its immaturity.
4. Zakria-01 Well: The (%Ro) value from basin modeling was 0.55%, suggesting that the Cretaceous source rock in Zakria-01 well is in the early maturity stage.
5. Zindapir-01 Well: The (%Ro) value from basin modeling was 0.99%, suggesting that the Cretaceous source rock in Zindapir-01 well is in the main maturity stage.
6. Dhodak Deep-01 Well: The (%Ro) value from basin modeling was 0.9%, suggesting that the Cretaceous source rock in Dhodak Deep-01 well is in the main maturity stage.

4.6 2D Basin Modeling

The East-west direction profile was selected to perform the 2D basin modeling. The E-W direction was selected because the deposition dip of strata is in E-W direction. The eastern side represents the proximal direction and western side is the basinal part. The East-West 2D section was generated to construct the 2D basin modeling profile which include the stratigraphy from Pre-Cambrian rocks to Recent. All the horizons were in depth domain also the faults were included in the profile in depth domain. The most western faults have reverse sense of movement and it is interpreted as the regional faults that is separating the Punjab Platform from Sulaiman Fold Belt. The interpreted faults have normal sense of movement in Sulaiman Foredeep and Punjab Platform area. However, the throw of these normal faults has negligible throw. The constructed 2D profile consists of three 2D seismic lines. The three 2D seismic lines represents the cross section that covers the Punjab Platform, Sulaiman Foredeep, and Sulaiman Fold Belt (Figure 4.22). The interpreted horizons show that the Lumshiwal Formation acts as reservoir rock and the Chichali Formation is source rock in the area. 2D basin modeling results at present age shows that, the source in the Sulaiman Foredeep area has a (%Ro) range of 1 to 1.5, which represents the source rock maturity in the late oil to wet gas window. In most western parts (Sulaiman Fold Belt), the %Ro ranges from 1 to 1.3, which represents source rock maturity in the wet gas window. However, the eastern side (Punjab Platform), where three producing fields are present, shows the (%Ro) ranges from 0.4 to 0.48%, which confirms the source rock maturity in the Punjab Platform. The 1D basin modeling results also validate the 2D basin modeling results. Also, the 2D basin modeling results in terms of maturity vlues (%Ro) match with (%Ro) calculated from core samples.

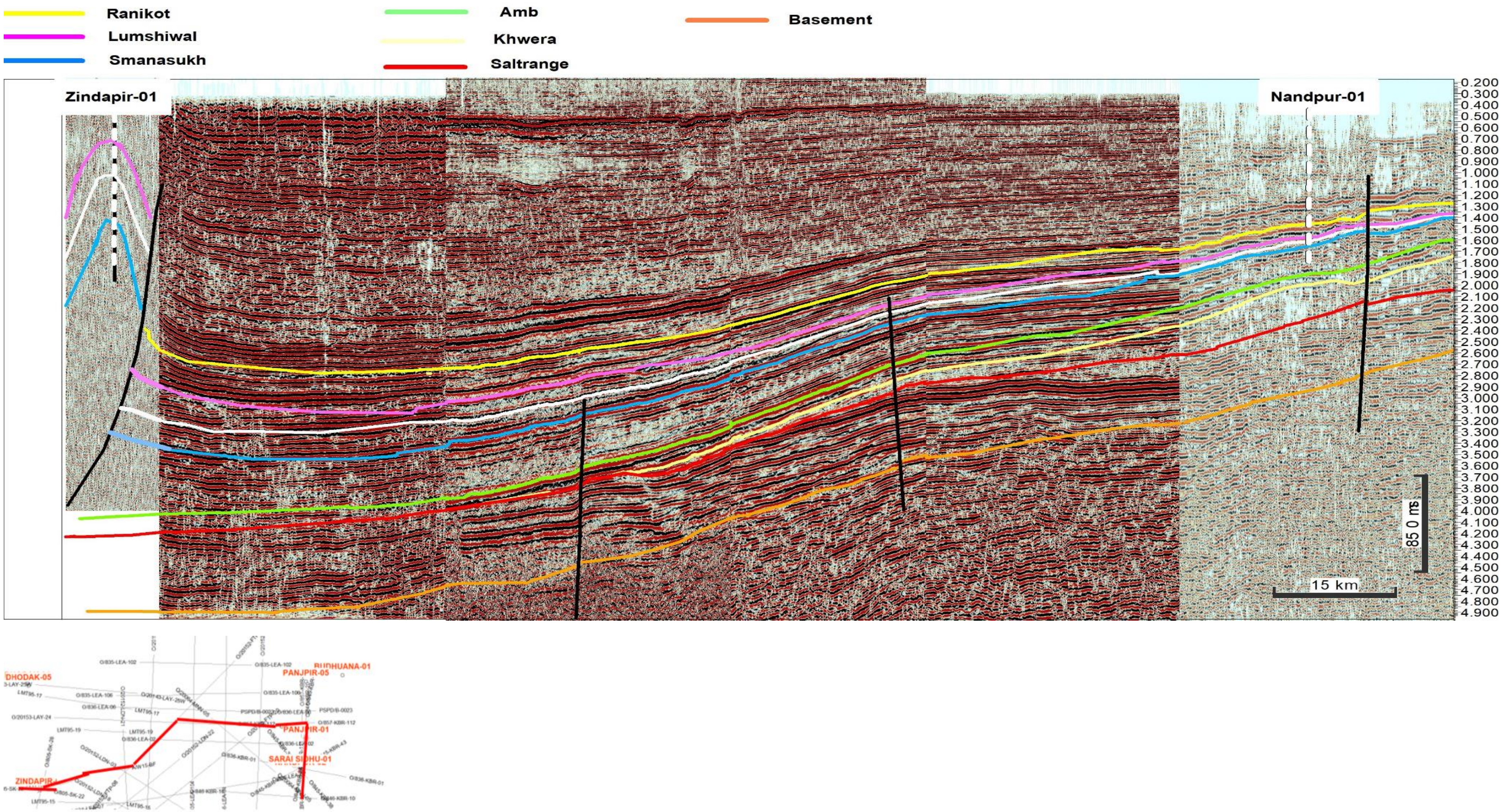

Figure 4.22 The East-West, 2D section was generated to construct the 2D basin modeling profile. It represents the cross section that covers the Punjab Platform, Sulaiman Foredeep, and Sulaiman Fold Belt. Number of formations ranges from Cretaceous to basement have been marked and mapped on seismic section throughout the area. Mapped horizons were then converted to depth domain. Variable velocity method was used to convert the horizons to depth domain. Similarly, the faults which were identified on seismic were also converted into depth domain.

After confirming the source rock maturity, source and reservoir characteristics were mapped. The Cretaceous Chichali Formation source rock lies between 6000 m and 5000 m in the Sulaiman Foredeep, and it gets shallower toward the east. In producing the Bahu-01, Panjpir-01, and Nandpur-01 wells, it was between 1600 and 2000 m. The reservoir Lumshiwal Formation is lying on top of the source Chichali Formation. The interpreted porosity of reservoir rock in Foredeep is ranging from 1-4%. However, porosity gets better in the proximal eastern side, where it is producing from the Bahu-01, Panjpir-01, and Nandpur-01 wells. In these gas-producing fields, porosity ranges from 18 to 25%. The source rock pore pressure in the Sulaiman Foredeep lies between 12,000 and 16,000 PSI. High pore pressure is due to the deep burial of source rock. Similarly, the reservoir pore pressure lies between 9,000 and 11,000 PSI. Both source and reservoir pore pressure decrease in the eastern side of the study area due to a decrease in burial depth. Also, the reservoir has good permeability (4–7 mD) in the Sulaiman Foredeep area and 2–5 mD in the Punjab Platform area (Figure 4.23).

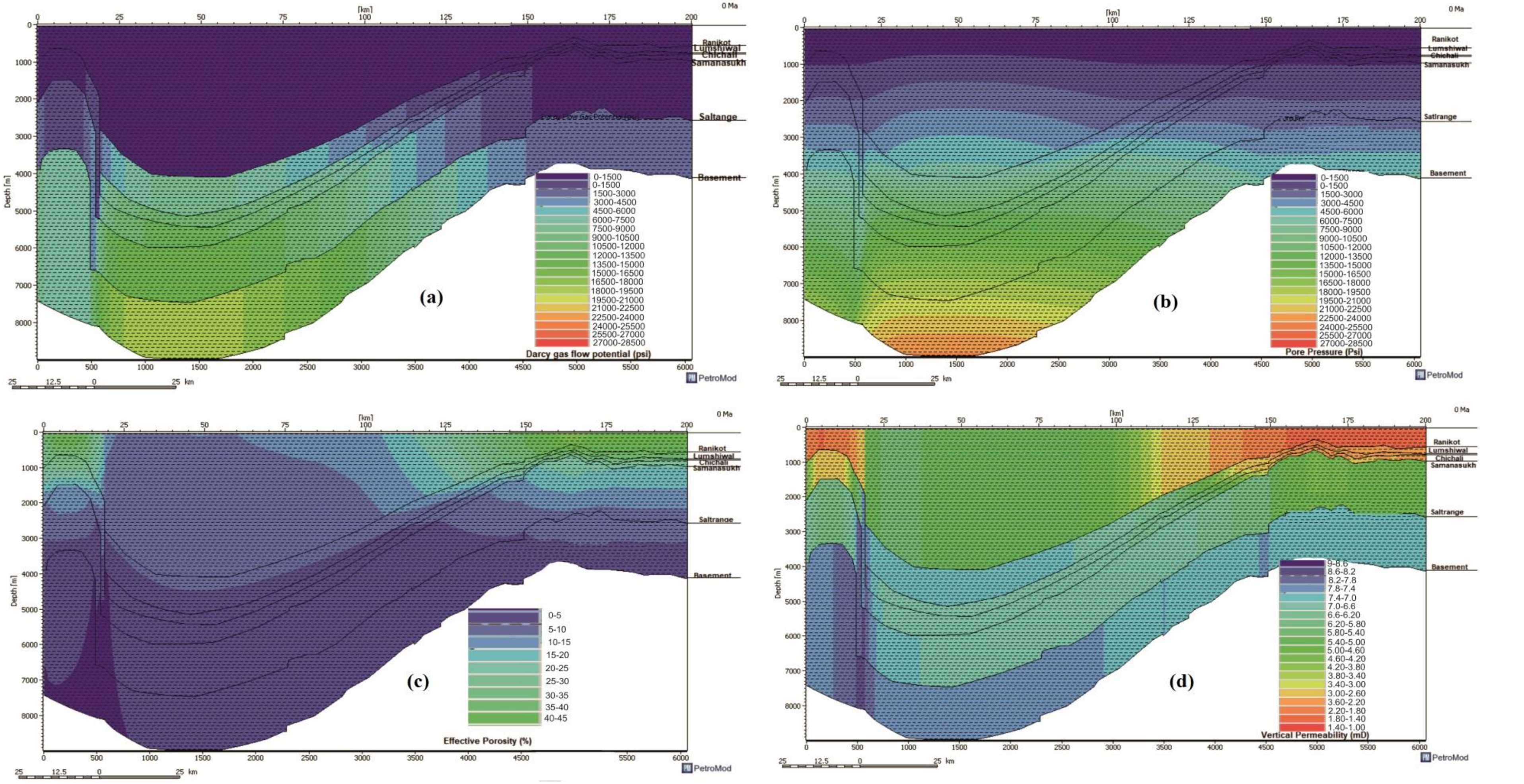

Figure 4.23 (a)It shows the variation in reservoir properties (a) darcy gas flow potential (b) pore pressure (c) effective porosity and (d) vertical permeability. Both source and reservoir pore pressure decrease in the eastern side of the study area due to a decrease in burial depth. Also, the reservoir has good permeability (4–7 mD) in the Sulaiman Foredeep area and 2–5 mD in the Punjab Platform area.

All these parameters proved that the source rock is mature in the Sulaiman Foredeep and Sulaiman Fold Belt area. However, it is immature in the Punjab Platform area. At present, the source in the Sulaiman Foredeep area has a (%Ro) range of 1 to 1.5, which represents the source rock maturity in the late oil to wet gas window. In most western parts (Sulaiman Fold Belt), the %Ro ranges from 1 to 1.3, which represents source rock maturity in the wet gas window (Figure 4.24). However, the eastern side (Punjab Platform), where three producing fields are present, shows the (%Ro) ranges from 0.4 to 0.48%, which confirms the source rock immaturity in the Punjab Platform. Hydrocarbon has been expelled from the source Chichali Formation in the Sulaiman Foredeep to the overlaying reservoir Lumshiwal Sandstone.

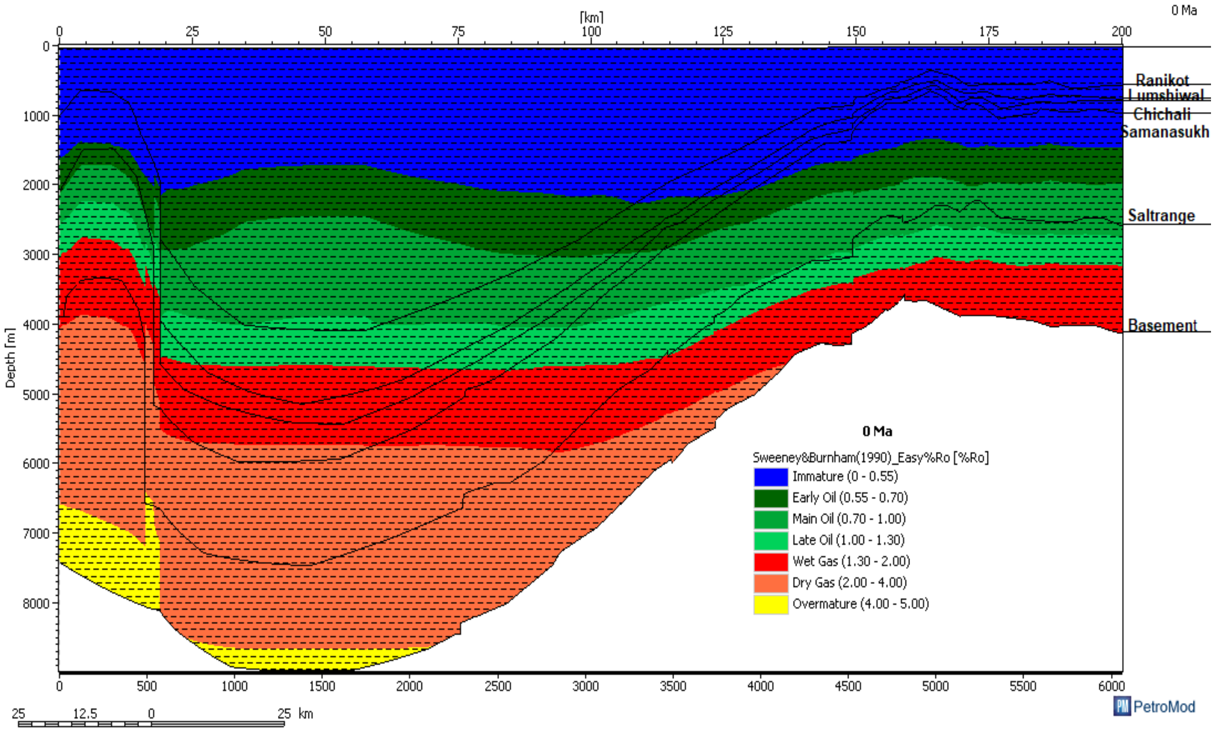

Figure 4.24 It shows the (%Ro) of source maturity, calculated from of 2D basin Modeling. At present age the source in the Sulaiman Foredeep area has a (%Ro) range of 1 to 1.5, which represents the source rock maturity in the late oil to wet gas window. In most western parts (Sulaiman Fold Belt), the %Ro ranges from 1 to 1.3, which represents source rock maturity in the wet gas window. However, the eastern side (Punjab Platform), where three producing fields are present, shows the (%Ro) ranges from 0.4 to 0.48%, which confirms the source rock maturity in the Punjab Platform.

4.7 3D Charge Model

4.7.1 Seal

3D hydrocarbon charge models/3D petroleum system models consist of source, reservoir, seal, trap, and migration elements. Petroleum system modeling was performed in Petrel software. Horizons were marked on the whole study for the identification of the top and bottom parts of the seal; it was also calibrated through wells, and the top and bottom parts of the seal was marked and extended all over the study area in the petroleum system modeling. The shales of the Ranikot Formation are the seal rock for the Cretaceous-age Lumshiwal sands. The lithology of source rock was identified based on well log interpretation. The lithology of the source rock was identified based on well log interpretation. The volume of shale in seal rock increases toward the western side, which is the Sulaiman Foredeep area. Also, the thickness of shale increases westward (Figure 4.25a).

The reservoir rock Lumshiwal Formation and the source rock Chichali Formation were interpreted throughout the area. The thickness map of seal rock was generated. The thickness map of the seal rock indicates that the thickness of the seal is increasing toward the west as compared to the eastern part where Bahu-01, Panjpir-01, Nandpur-01, and Zakria-01 wells were drilled (Figure 4.25). The thickness of seal rock ranges from 50 m to 150 m, where we go toward the western part in the Sulaiman Foredeep part. The thickness of the source rock is around 200 m even in the most western part (Sulaiman Foredeep).

One of the important factors for the seal rock is to hold how much pressure for the entrapment of hydrocarbons; the more the pressure it holds, the more the hydrocarbons it can entrap in the structure, so it is very important to calculate the pressure that the seal rock can hold. The pressures of the seal rock were modeled in petroleum system modeling by using Petrel software. The transformation function was derived from the porosity calculation based on the hydrostatic pressures. Porosity was derived from the well data that were incorporated, and depth versus porosity functions were derived. Ultimately, pressure was calculated based on the porosity derived from the well data.

The porosity in the Bahu-01, Panjpir-01, and Nandpur-01 wells ranges from 28% to 25%. Porosity ranges reflect excellent porosity in reservoir rock. The porosity deteriorates in the western Sulaiman Foredeep to 10 to 15%. It reflects that porosity is decreasing from east to west. The eastern side of the study lies in the proximal setting of the basin, and the western part of the area lies in a distal basinal setting. The porosity variation in the study is in accordance with geological and stratigraphic settings.

A pressure map was generated from porosity, it reveals that the pressure in the eastern part of the study area is around 5 to 50 bars, whereas the pressure in the western side, which is Sulaiman Foredeep ranges from 1600 to 1800 bars. It reflects that the thickness and pressure map in the western part is most likely to hold the hydrocarbons, as the thickness of the source rock is around 200m and the pressure is ranging between 16000 and 18000 bars, which is sufficient to hold the appreciable amount of hydrocarbon (Figure 4.25).

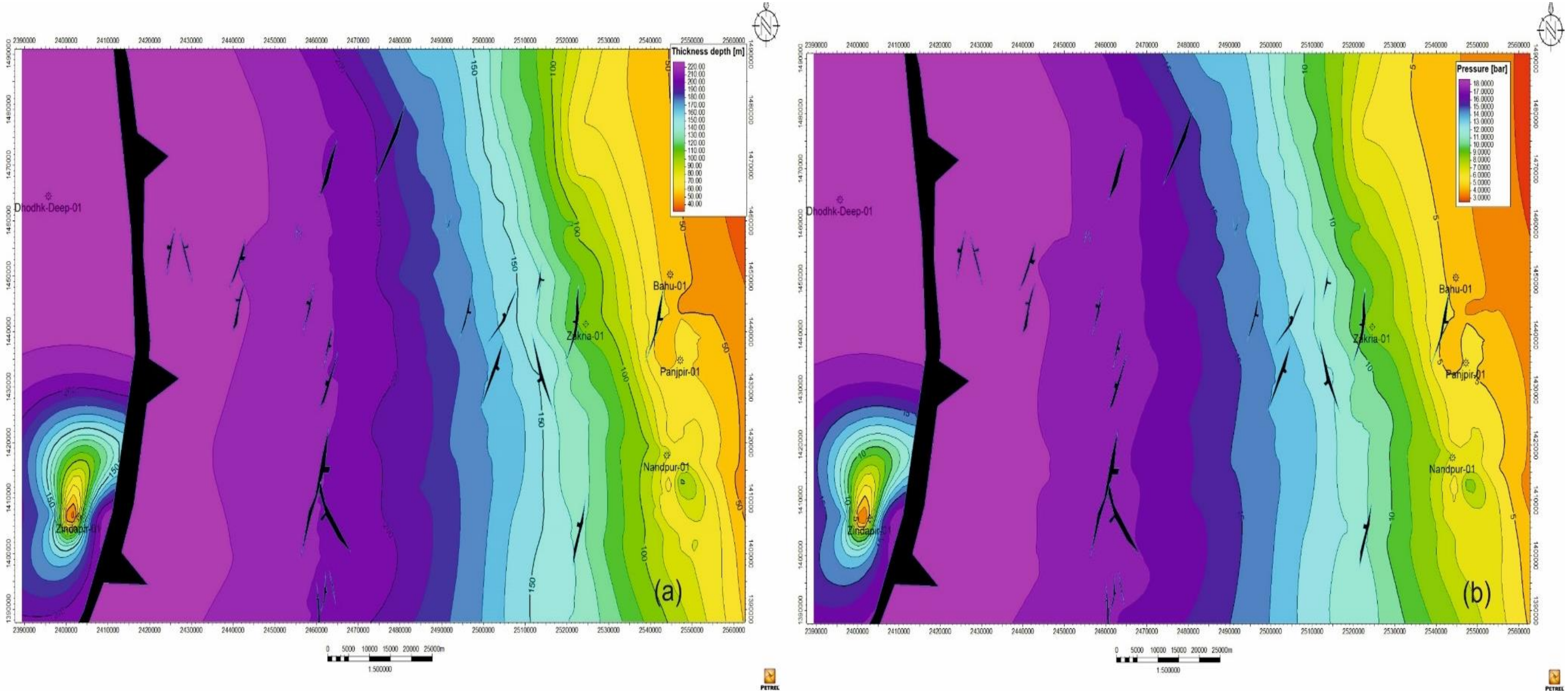

Figure 4.25 (a) It reflects that thickness and pressure map in the western part is most likely to hold the hydrocarbons as the thickness of the rock is around 200 m and the pressure is ranging between 16000 to 18000 bars which is sufficient to hold the appreciable amount of hydrocarbon (b) Pressure map of Ranikot Formation seal rock was generated from porosity reveals that the pressure in the eastern part of the study area is around 5 to 50 bars whereas the pressure in the western side which is Sulaiman Foredeep ranges from16000-18000 bars.

4.7.2 Reservoir

Reservoir is an important element of petroleum system modeling. Reservoir property in terms of porosity and reservoir lithology was incorporated in petroleum system modeling. The reservoir properties were taken from the log interpretation, as well as the lithology of the reservoir, which was taken from the well logs, namely Bahu-01, Panjpir-01, and Nandpur-01.

The reservoir properties of formation were evaluated in terms of porosity. The eastern portion, where the wells, namely Bahu-01, Panjpir-01, and Nandpur-01, were drilled, has greater porosities as compared to the well drilled in the central portion of the study area. In the eastern portion, the property ranges from 30% to 20%, whereas in the western part, the porosity ranges from 15% to 5%. This map honours the geological setting and depositional model of the area, which shows that the eastern part is in the proximal setting and the western part lies in the distal part of the basin. It reflects that the area in the eastern part has more porosity as compared to the western part, and the reservoir is more favourable in the eastern part for the movement of hydrocarbons laterally with Lumshiwal Formation. The central and the western parts, where we are having the porosity ranges from 20 to 5%, are also favourable for the hydrocarbon movement due to good porosity ranges.

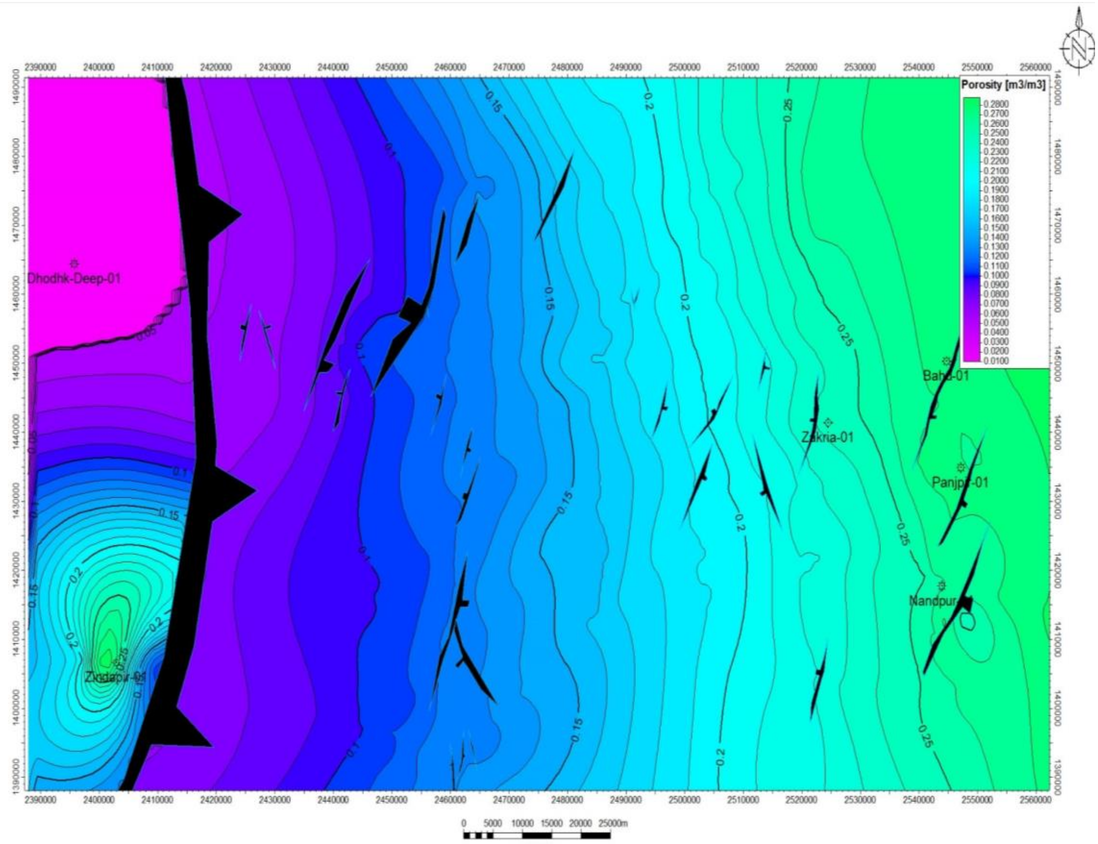

Figure 4.26 It reflects the variation of porosity of reservoir Lumshiwal Formation. The eastern part has more porosity as compared to the western part and the reservoir is more favorable in the eastern part for the movement of hydrocarbon laterally with Lumshiwal Formation. The central and the western part.

4.7.3 Source

Source is the equally important element of the petroleum system modeling. For Chichali, source rock depth was generated at the top and base of the source rock. The source rock properties, like kerogen type, vitrinite reflectance, HI, and OI, calculated through rock pyrolysis and spectroscopy, were incorporated. These source rock properties are necessary to incorporate in petroleum system modeling for the hydrocarbon generation expansion and migration. The TOC (wt.%) on the eastern side ranges from 0.35 to 1.5. However, the TOC (wt.%) on the western side increased at ranges from 1.5 to 3. The calculated HI (mg/g) values range from 2 to 125, and OI mg/g range from 30 to 120 in the eastern side of the study area. The heat flow values in the eastern parts range from 45 to 50 mw/m2, whereas in the western part, they range from 50 to 60 mw/m2. For heat flow, the Mckenzie method was adopted. Inputs for the rift phase, post-rift phase, depth of crust, and mantle were incorporated. To validate the source rock maturity results, modeled (%Ro) values calculated by using EASY% Ro algorithm

(Sweeney & Burnham, 1990) were compared with (%Ro), obtained through organic petrography in the laboratory.

Based on these source rock properties, a hydrocarbon generation map was generated (Figure 4.27). It reveals that entrance in early oil window occurred in 65 to 50 (ma) in the western part. It shows the transformation of source into early oil window occurred between 65 to 50 (ma), whereas in the central part of the study area, it enters into early oil window between 15 to 20 (ma) (Figure 4.27b). The eastern part of the study area remains barren, and source did not transform into hydrocarbon. (Figure 4.27b) represents the entrance in the main oil window, where the part of Sulaiman Foredeep enters in the main oil window in 65 to 35 (ma), whereas the central part of the study area enters in the main oil window in 50 to 25 (ma). The eastern part of the study area, where three main gas discoveries are present, remains barren.

(Figure 4.26c) represents the entrance in late oil window in the western part of the study area; the Sulaiman Foredeep entered in the late oil window during 50 to 15 (ma), whereas the central part of the study area highlighted in the yellow color (Figure 4.27c) enters in the late oil window in 10 (ma). It reflects that the source in the eastern part of the study area was not converted to any hydrocarbon and remained immature. (Figure 4.27d) represents the entrance in the wet gas window, the westernmost part of the Sulaiman Foredeep area entered in the wet gas window during 50 to 35 (ma); however, the central part of the study area remains barren, and also the eastern part of the study area will not charge by hydrocarbon. (Figure 4.27e) represents the entrance in the dry gas window; the source rock of the Chichali Formation enters in the dry gas window in a small part of the western study area that lies in the Sulaiman Foredeep around 10 (ma), with most of the study area, the central and the eastern part, remaining barren, and the Chichali Formation did not transform into dry gas in these areas.

It is concluded from (Figure 4.27) that the source of the Chichali Formation was transformed into hydrocarbons in the western and central parts of the study area; the western part of the study area was charged with hydrocarbons from 150 to 35 (ma). The peak amount of the hydrocarbons generated during 20 to 10 (ma) in the central part of the study area, while the eastern part of the study area remained barren and the source did not generate any sort of hydrocarbons in this area. The western part, source, had generated the hydrocarbon, and these expelled hydrocarbons have charged the traps in the eastern part, namely Bahu, Panjpir and Nandpur. In the petroleum system, modeling the total gas generation from a source is equally important for the hydrocarbon migration and the entrapment of structural traps.

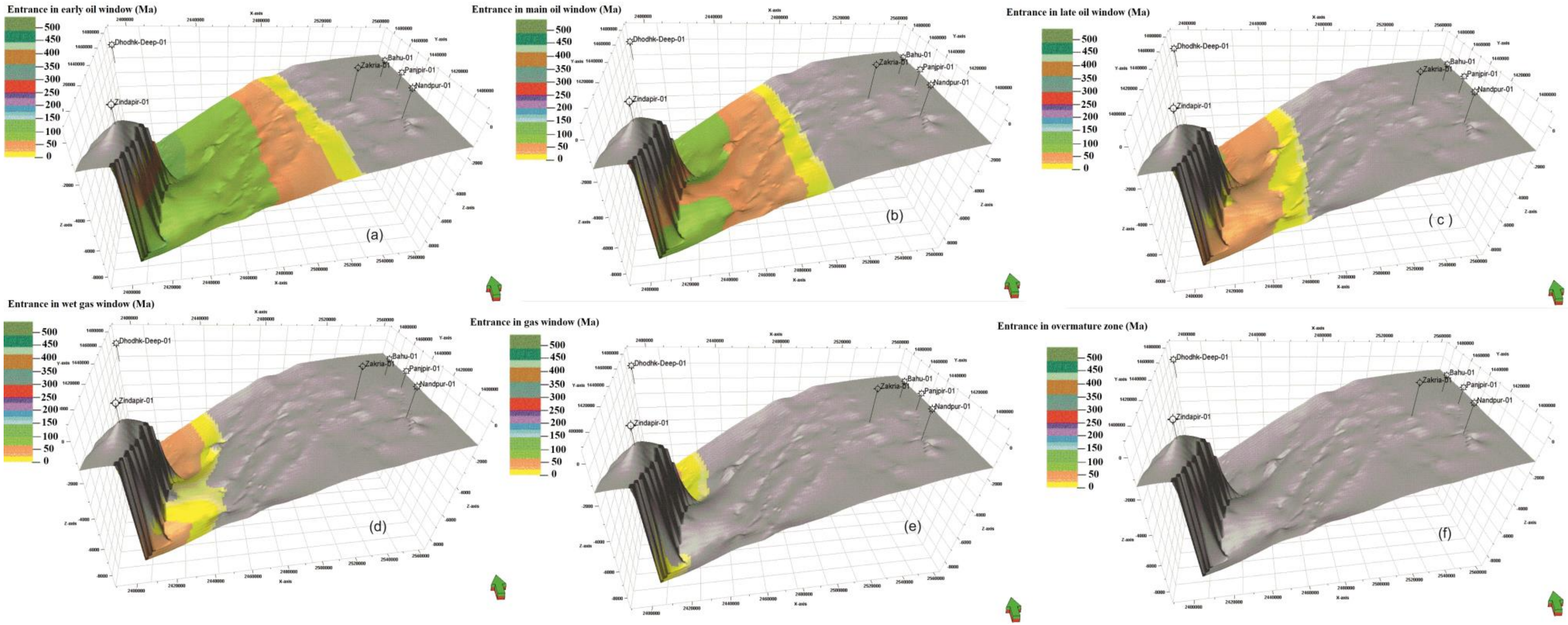

Figure 4.27 Represents the different stages of Source rock maturity. (a) It reveals that entrance in early oil window occurred in 65 to 50 (ma) in the western part. It shows transformation of source into early oil window occurred between 65 to 50 (ma), whereas is in the central part of the study area it enters into early all window between 15 to 20 (ma). (b) representing the entrance in main oil window the part of Sulaiman Foredeep enters in the main all window in 65 to 35 (ma) (c) the entrance in late oil window the western part of the study area the Sulaiman Foredeep entered in the oil late oil window during 50 to 15 (ma) whereas the central part of the study area highlighted in the yellow colour (d) entrance in wet gas window, the western most part of the Sulaiman Foredeep area entered in the wet gas window during 50 to 35 (ma), however the central part of the study area remains barren and also the eastern part of the study area will not charge by hydrocarbon (e) the Chichali Formation enters in the dry gas window in only small part of the western study area that lies in the Sulaiman Foredeep around 10 (ma) with most part of the study area, the central and the Eastern part remains barren (f) Show the over maturity map. No portion gets over mature in entire study area.

4.7.4 Maturity

The maturity of the source rock of the Chichali Formation shows a variation of %Ro over the entire area (Figure 4.28). In the eastern part of the study area, where the Bahu-01, Pnjpir-01, and Nandpur-01 wells were drilled, the %Ro ranges from 0.3% to 0.45%, showing the immaturity of the source in the eastern area. In the central part of the study area, close to the Zakria-01 well, there is a %Ro of 0.75%, which shows the maturity of the source rock. As we move toward the western part of the study area, especially in the Sulaiman Foredeep area, the %Ro values are in the range of 0.9 to 1.3%, indicating the maturity of the source, and it is in the early gas window of the source rock. Based on the %Ro map (Figure 4.28), it clearly shows that only the western Sulaiman Foredeep part has a source mature area, where part of the central part of the study area is partially mature. The source rock of Chichali Formation is immature in the eastern part of the Punjab Platform.

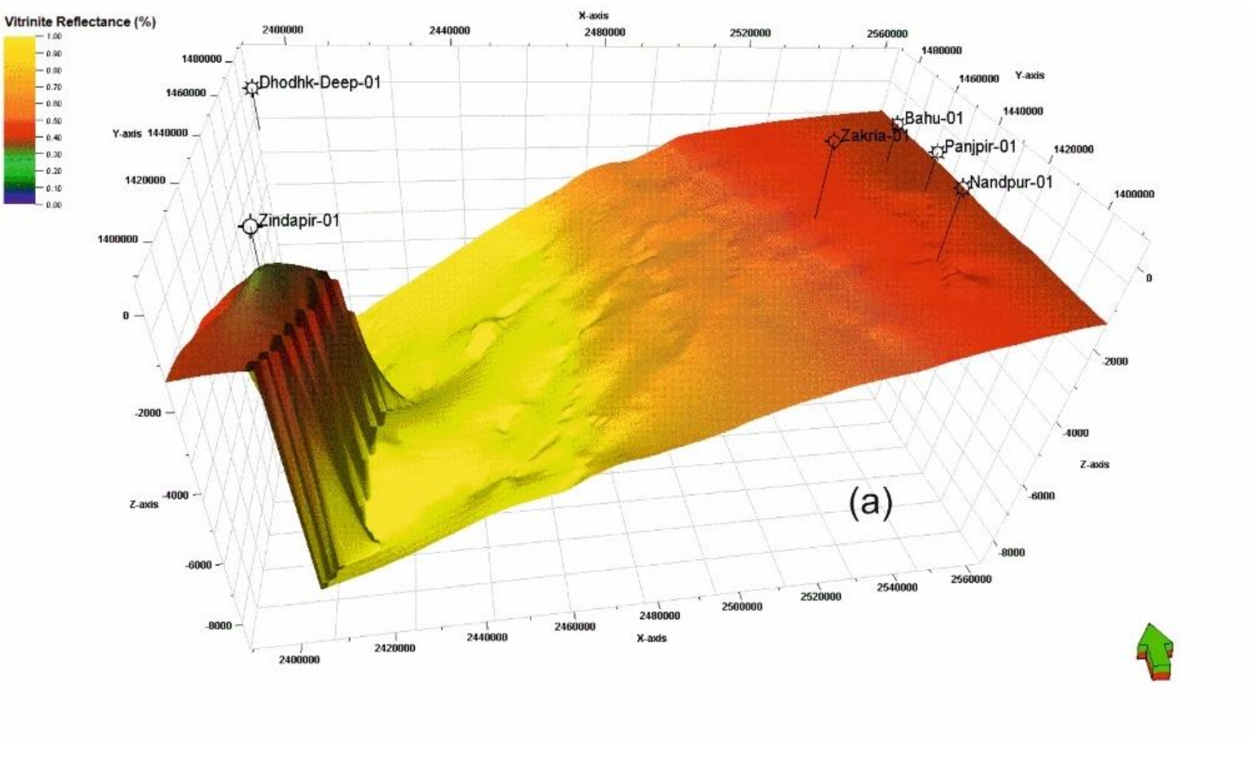

Figure 4.28 The maturity of the source rock of Chichali Formation shows a variation of %Ro over the entire area. In the eastern part of the study area where Bahu-01, Panjpir-01 and Nandpur-01 wells were drilled has %Ro ranges from 0.3% to 0.45% showing the immaturity of the source of in the eastern area. In the central part of study area close Zakria-01 well has %Ro of 0.75% it shows the maturity of the source Rock. As we move toward the western part of the study area especially in the Sulaiman Foredeep area the %Ro values are in the range of 0.9 to 1.3% indicating the maturity of the source of and it is in early gas window of the source rock. Based on %Ro map.

4.7.5 Generation and Transformation

In the petroleum system modeling, the total gas generation from a source is equally important for the hydrocarbon migration and the entrapment of structural traps. Total gas generation mass (kg/m) in the western part of the study area, especially in Sulaiman Foredeep, ranges from 70 to 100 kg/m of gas generation mass, whereas in the central part it had produced 40 to 100 kg/m of gas generation mass. In the east part of the central part, it was decreased to 25 to 30 kg/m of gas generation mass. In the eastern part of the study area, there is a minimum total gas generation mass because of the immaturity of the source. It proved that total gas generation mass was primarily generated in the western part of the study area, especially in the Sulaiman Foredeep area. The bulk amount of gas generation mass produced from Sulaiman Foredeep acts as the main source kitchen area for the Punjab Platform, where the three main gas discoveries are present (Figure 4.29).

The transformation ratio is the amount of source rock converted into gas or oil during the maturation phase; it shows the gas transformation ratio in percentage. From the gas transformation map, it is evident that the sources mature in the western part of the study area indicates the transformation of source rock from 90 to 100%. The source transformation ratio in the western to central part has 35 to 80% of the gas transformation ratio, whereas the central part of the study area has 5 to 10% of the gas transformation ratio. The eastern part of the study area, where we have three discoveries, namely Bahu, Panjpir, and Nandpur, has no source for gas transformation. It proves that the western part has only contributed to the maturation and transformation of gas in the Punjab Platform.

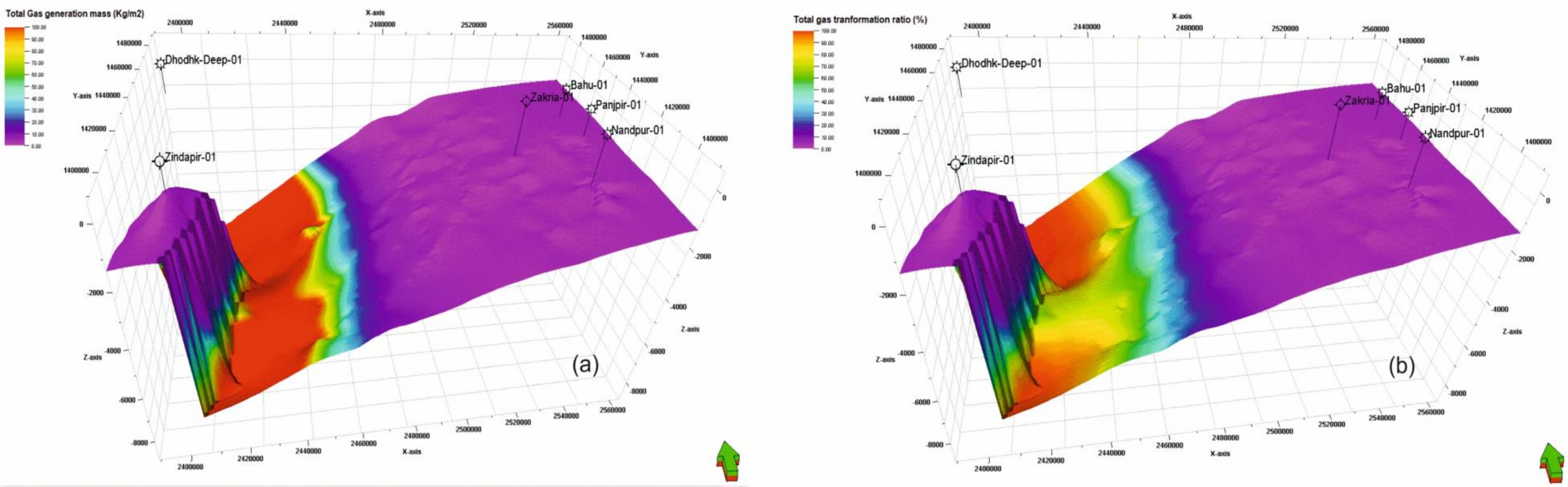

Figure 4.29 (a) Total gas generation mass kg/m in the western part of the study area, especially in Sulaiman Foredeep, ranges from 70 to 100 kg/m of gas generation mass, whereas in the central part it had produced 40 to 100 kg/m of gas generation mass. Whereas just east of the central part, it was decreased to 25 to 30 kg/m of gas generation mass. (b) From the gas transformation map, it is evident that the sources mature in the western part of the study area due to the transformation of source rock from 90 to 100%. The source transformation ratio in the western to central part has 35 to 80% of the gas transformation ratio, whereas the central part of the study area has 5 to 10% of the gas transformation ratio.

Bulk generation potential in (ma) reflects that in the western part of the study area, which lies in the Sulaiman Foredeep, the total gas generation potential for the source occurred during 65 (ma), whereas in the western and central parts of the study area, the bulk generation potential occurred during 25 to 40 (ma), and it was fully exhausted up to 10 (ma). It is worth mentioning that the eastern part of the study area did not contribute to the bulk generation potential of the hydrocarbon, and it remained barren throughout the era (Figure 4.30).

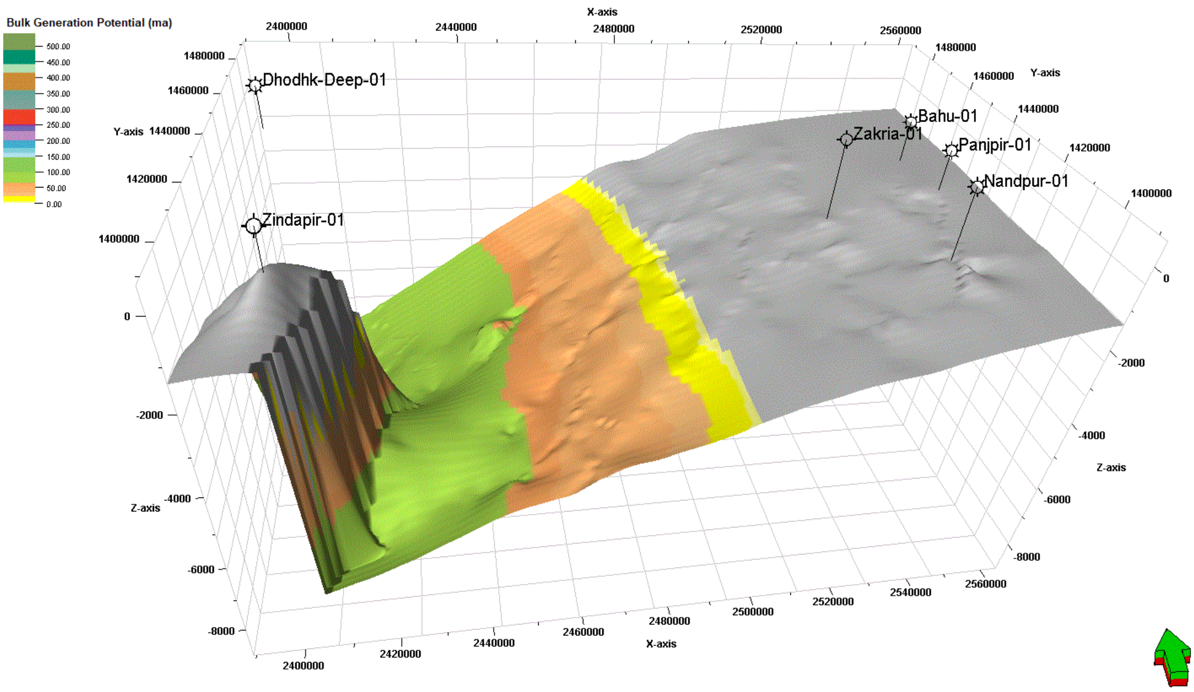

Figure 4.30 Bulk generation potential in (ma) reflects that in the western part of the study area, which lies in Sulaiman Foredeep, the total gas generation potential for the source occurred during 65 (ma), whereas in the western and central parts of the study area.

4.7.6 Accumulation

In petroleum system modeling hydrocarbon trapment is very important element. To map the accumulation spots, the source, reservoir and seal rocks map were incorporated in the 3D charge model. Also the structural depth map at top reservoir was included in model. The Lumshiwal Formation sands have good porosity ranges from 5 to 25%, which contributed to lateral hydrocarbon migration from the source kitchen area in the Sulaiman Foredeep to the central and eastern part of the Punjab Platform (Figure 4.31). The 3D charge model revealed that the hydrocarbon has moved upward from the source rock mainly due to bouncy. The hydrocarbon migration occurred horizontally in the reservoir rocks; the faults in the hydrocarbon migration pathways have very minimal throw and the hydrocarbons from these faults did not significantly contributed in the hydrocarbon migration.

The lateral migration occurred mainly due to the tilt of the Indian Plate; it is a monocline rising toward the east. The hydrocarbon, due to buoyancy and pressure difference, migrated from the western side (Sulaiman Foredeep) to the eastern Punjab Platform area. The Zakria-01 well, which was drilled in the central portion of the Punjab Platform, did not produce hydrocarbons due to the lack of a structural trap.

The Zakria structure is rising toward the east, and the structure is opening toward the eastern side. It clearly shows the accumulation of hydrocarbons, mainly gas, occurred in the promising area of the Punjab Platform, namely the Bahu and Nandpur gas fields, due to migration pathways. The source maturity data indicate that the eastern area did not contribute to the hydrocarbon generation.

(Figure 4.31) clearly resolves the issue of hydrocarbon migration and accumulation from the source kitchen area to the prospective area in the east direction. To prove the authenticity of hydrocarbon migration pathways, DHI's analysis was performed. Direct hydrocarbon indicators show the presence of the hydrocarbon. The direct hydrocarbon indicators were marked on the multiple seismic lines. It clearly shows the bright spot in the reservoir Lumshiwal Formation on 2D seismic line LEA-24. Similarly, another bright spot is identified on the 2D line KBR-111 in the Lumshiwal Formation. This bright spot is present in the incised valley in the Lumshiwal Formation. These identified DHI's are present in the mapped hydrocarbon migration pathways. Also, the presence of hydrocarbons in Bahu, Panjpir, and Nandpur proved our mapping and accumulation model of long-path migration from the Sulaiman Foredeep to the Punjab Platform area.

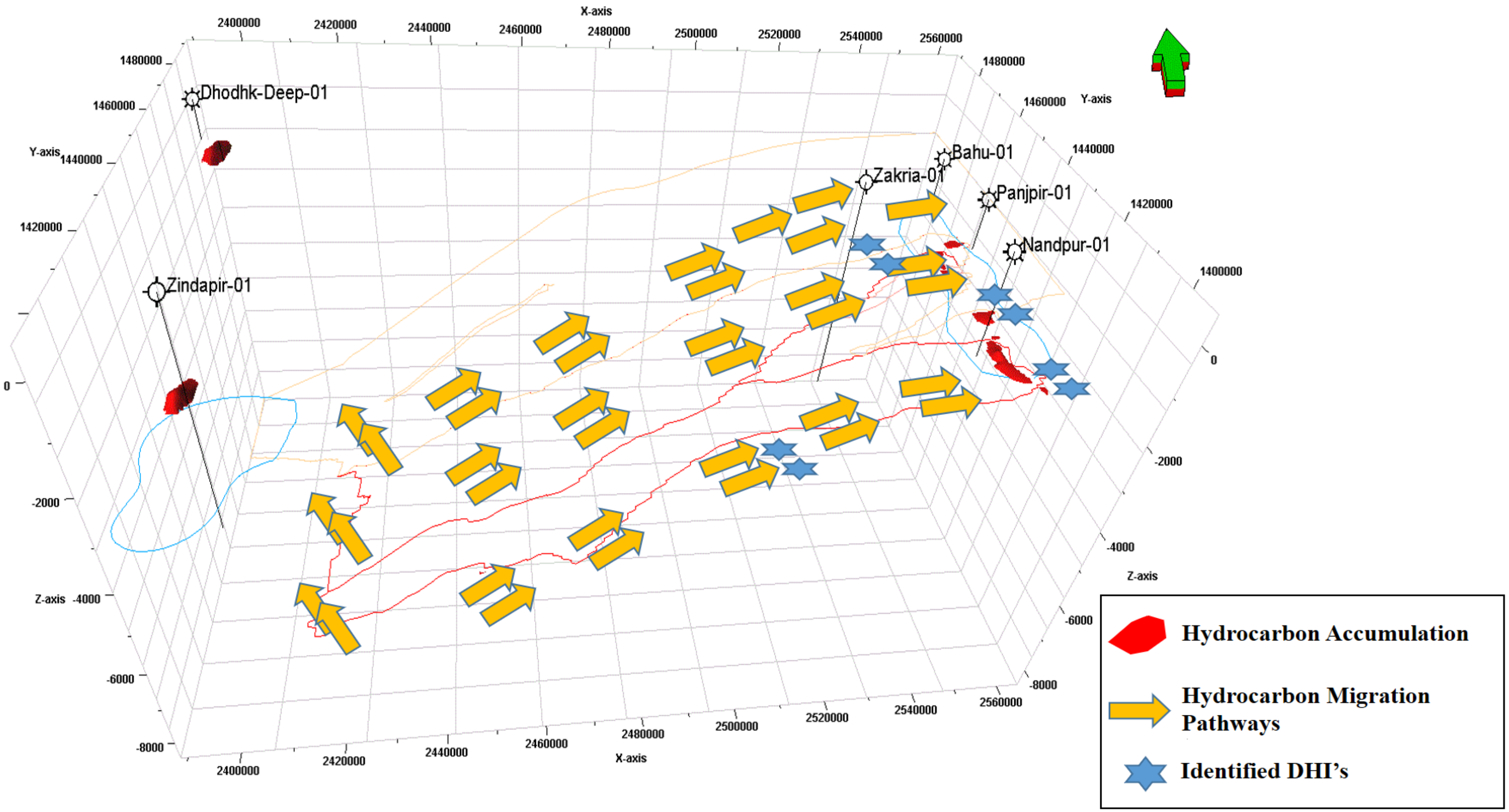

Figure 4.31 3D petroleum system map shows hydrocarbon accumulation fill and migration pathways. The hydrocarbon, due to buoyancy and pressure difference, migrated from the western side (Sulaiman Foredeep) to the eastern Punjab Platform area. The structure is rising toward the east, and the structure is opening toward the eastern side. The orange and red color polygons are representing the migration pathways. The solid red color polygons are showing the accumulation of gas in the valid structural traps. Hence, it proved the accumulation of hydrocarbons, mainly gas, occurred in the promising area of the Punjab Platform, namely the Bahu and Nandpur gas fields, due to migration pathways.

4.8 Direct hydrocarbon indicators (DHI's)

DHI's are anomalous seismic amplitudes that can occur when hydrocarbons exist. They occur as a result of changes in pore fluids, which alter the elastic properties of the bulk rock. DHI's analysis was performed, and direct hydrocarbon indicators indicated the presence of hydrocarbons on seismic lines. It clearly reveals the bright point in the Reservoir Lumshiwal Formation. A bright spot with a local increase in amplitude due to hydrocarbon build up in lines LEA-02 (Figure 4.32c). Similarly, another bright spot was identified on seismic lines LEA-106 (Figure 4.32a). Lumshiwal Formation also indicate the presence of hydrocarbon; the bright spot is present in the stratigraphic trap marked on seismic line (Figure 4.32b). It represents the incised valley in Lumshiwal Formation. The incised valley is filled with gas, and it shows the negative amplitude on the seismic lines (Figure 4.32b). (Figure 4.32d) shows the Lumshiwal Formation indicates the presence of hydrocarbon, the bright spot is present in the structural trap marked on seismic line LEA-24. Within Lumshiwal Formation these bright spots are validating the hydrocarbon migration pathways. These DHI's confirms the presence of hydrocarbon particularity gas and the authenticates our working of establishment of migration pathways that are communicating the source buried deep in Sulaiman Foredeep to the traps which are present about 200 Km away from the source rock. It is now proved that the fields Bahu, Panjpir and Nandpur fields were changed from the deep buried Chichali Formation source rock in Sulaiman Foredeep and the secondary migration occurred horizontally within Lumshiwal Formation.

Overall, long-path migration pathways established in this area are novel, and integrated approaches were adopted to address this issue, which was never addressed before. This establishment of long-path pathways will help the exploration companies further explore hydrocarbons within established migration pathways. This will not only enhance the likelihood of successful hydrocarbon exploration but also contribute to meeting the country's energy demands. Previous research used a single method for the evaluation; the limitation of ID and 2D basins restricts them from fully addressing the issue and establishment of migration pathways. The 3D petroleum system modeling is a robust and reliable approach for the mapping of migration pathways. The deficiency of mapping migration pathways was addressed in this study by adopting a 3D migration pathway model. The integrated approach using source rock richness, maturity, ID, 2D basin modeling, and 3D charge modeling/3D petroleum system modeling will be adopted in other basins of the world for successful full hydrocarbon exploration.

The study focuses on the development of long-path migration pathways in a new area, addressing a previously unresolved issue. The integrated approach, which includes source rock richness, maturity, ID, 2D basin modeling, and 3D charge modeling, is aimed at enhancing the likelihood of successful hydrocarbon exploration and meeting the country's energy demands. Previous research used a single method for evaluation, but the 3D petroleum system modeling offers a robust and reliable method for mapping migration pathways. This integrated approach, which should be adopted in other basins worldwide, is expected to contribute to successful hydrocarbon exploration.

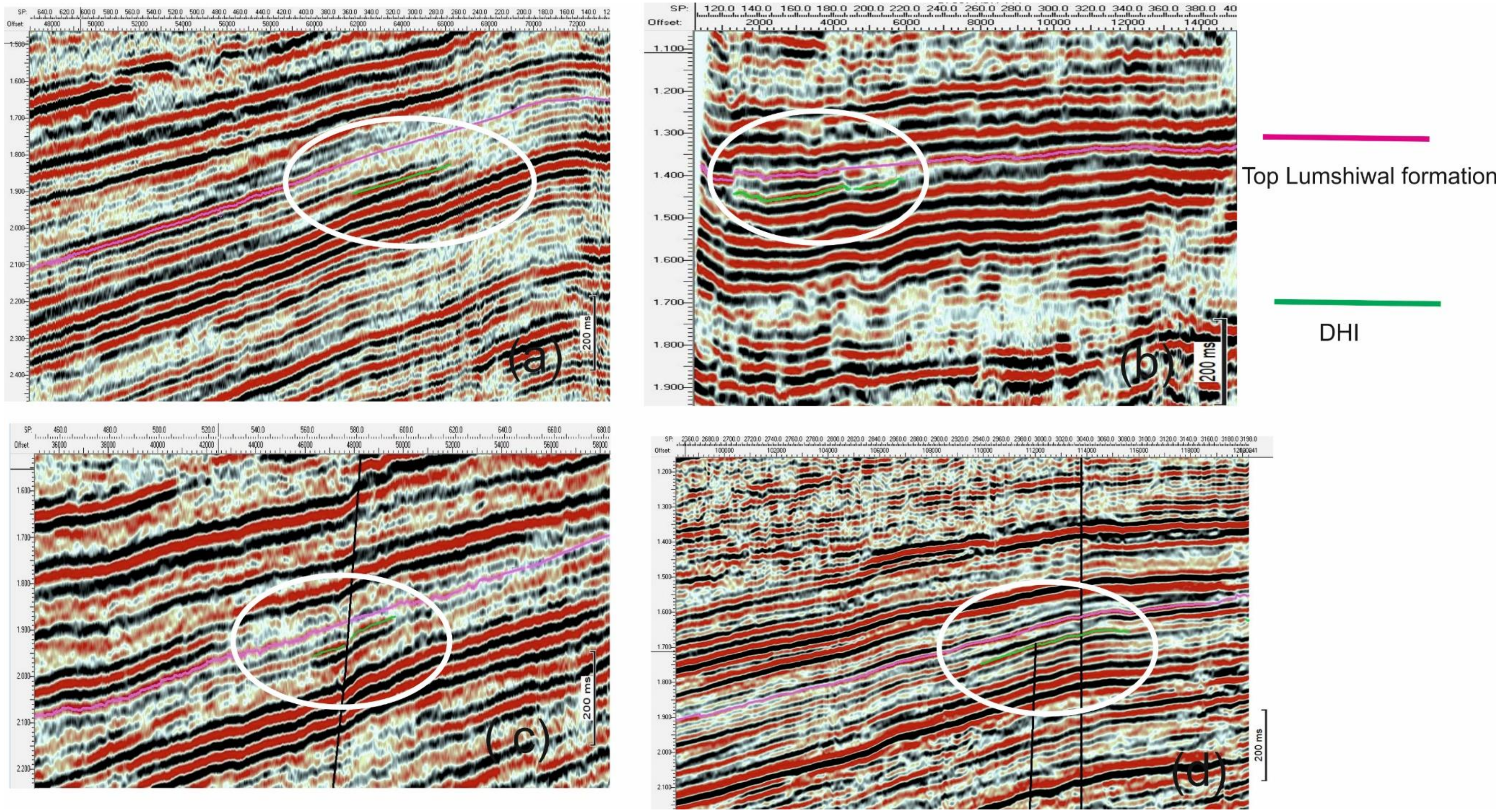

Figure 4.32 DHI's analysis was performed, and direct hydrocarbon indicators indicated the presence of hydrocarbons on multiple seismic lines.(a) Lumshiwal Formation indicates the presence of hydrocarbon, the bright spot is present in the stratigraphic trap marked on seismic line LEA-106 (b) The incised valley is fill with gas and it show the negative amplitude on the seismic lines KBR-111 within Lumshiwal Formation. (c) the Lumshiwal Formation indicates the presence of hydrocarbon; the bright spot is present in the trap marked on seismic line LEA-02. (d) Lumshiwal Formation indicates the presence of hydrocarbon; the bright spot is present in the stratigraphic trap marked on seismic line LEA-24.

CHAPTER 5

DISCUSSION AND CONCLUSION

5.1 Discussion

The Punjab Platform is the most eastern part of the Indian Plate. It is the part of Indus Basin. The Indus Basin is divided into (Upper Indus Basin) UIB, MIB (Middle Indus Basin) and (Lower Indus Basin) LIB. Punjab Platform lie in CIB. The MIB has three distinct elements namely Punjab Platform, Sulaiman Foredeep and Sulaiman Fold Belt. The Punjab Platform is bounded by Indian Shield in east, Sargodha High in north, Mari Kandkot High in south and Sulaiman Foredeep in west. It is fully covered by the alluvium strata. Tectonically it is a west dipping monoclonal structure, and it undergoes extension tectonics with minor fault throw (Raza et al. 2008; Kadri 1995).

About thirty exploratory wells have gone dry in the Punjab Platform. Only three fields, Bahu, Panjpir, and Nandpur, are producing gas. The possible source rock Chichali Formation of Cretaceous age is buried in the western part of the Punjab Platform. The reservoir rocks range from Cretaceous to Cambrian and Infra-Cambrian. The Lumshiwal and Samana Suk Formations are producing in the fields in Punjab Platform. Major structures besides valid traps have failed to produce hydrocarbons.

Despite intensive exploration efforts, the Punjab Platform has yet to unlock significant hydrocarbon reserves due to variability in source rock properties. The complexities regarding the source rock evaluation can be resolved by an integrated approach using various methodologies, including organic geochemistry, petrography, and basin modeling. Xiao et al. (2024) evaluated the organic richness by using an organic geochemistry approach. The variation of source rock characteristics is resolved in the Punjab Platform, which is located in the Central Indus sub-basin, Pakistan. In the study area, limited hydrocarbons have been explored despite aggressive exploration activities. Notably, this region also boasts of exploring the hydrocarbons in the vicinity of the Bahu, Panjpir, and Nandpur gas fields (Shah, 2023). The possible source rock, shales of Chichali Formation, is buried deep in the western part of the Punjab Platform. The organic richness of shale plays a crucial role in deciphering their quality and productivity.

The petroleum system in this location predominantly comprises the Cretaceous Chichali Formation as potential source rock. Uncertainties related to source rock richness and maturation are the main hindrances to substantial hydrocarbon exploration, which could add sizable reserves. The assessment of source rock potential, including the elucidation of organic richness, kerogen type, and thermal maturation, can be done through various methodologies, including organic geochemistry, petrography, and basin modeling (Cappuccio et al., 2021).

Rock eval pyrolysis is widely recognized as one of the most effective geochemical techniques for source rock evaluation, especially regarding the determination of kerogen type (Espitalié et al., 1977; Behar et al., 2001). This technique is extensively used to assess source rock organic matter type, generation potential, and maturity level (El Diasty et al., 2022). In this study, 100 mg of each sample were subjected to Rock eval measurements using the Rock eval 6 machine. The analysis provided results for S_1, S_2, S_3, and Tmax values (Peters and Cassa, 1994).

Researchers in various global basins, such as Riqingwei, Nangu Sag (Sichuan Basin, China), Indus Basin (Pakistan), and Pletmos Sub-Basin (South Africa), have typically used singular methods for source rock evaluation. For instance, Roth et al. (2023) used organic geochemistry to assess source rock, emphasizing the calculation of total organic content (TOC wt.%) from core data as a highly reliable method for TOC assessment.

Nazeer, (2018) studied possible origins of inert gases in the Sulaiman Foldbelt and Punjab Platform. According to the authors, exploratory wells drilled in the study area contain inert gases (mostly CO_2 and N_2) in varying percentages. The amount of nitrogen in the Punjab Platform is significant. The authors concluded that inert gases do not have an igneous origin and probably formed during the production, expulsion, and migration of hydrocarbons. Shah and Ahmed (2018) investigated the source rock potential of three rocks, namely Ranikot Formation (Paleocene) and Samana Suk Formation (Jurassic) in the Panjpir field by using TOC and Rock eval pyrolysis analysis measurements. The research concluded that all source rock samples have kerogen type III and have poor generation potential.

In the past, several authors, including Gakkhar et al. (2011), Nazeer et al. (2018), and Shah et al. (2021), evaluated the source rock potential predominantly by using a single technique. It restricted them to completely evaluate the source rock potential for enhanced hydrocarbon exploration, especially in the western part of the Punjab Platform, where limited data is available. Regions with high TOC content often yield the best results (Khalil Khan et al., 2022).

TOC can also be calculated from the seismic inversion technique by using seismic data (Atarita et al., 2017). Organic material within shale has specific density, radioactivity, and electrical resistivity characteristics that affect both seismic and wireline log responses (Zhu et al., 2011). Hence, seismic inversion can be used reliably to quantify the organic richness in shale (Broadhead et al., 2016; Ehsan et al., 2018; Tomski et al., 2022). Earth reflectivity was obtained from seismic traces using deconvolution algorithms. For seismic inversion, seismic data was used as input and well data was used as a control in the subsurface modeling approach (Bashir et al., 2024). The stochastic inversion technique was used to model the small-scale variability seen on the well log data but cannot be identified from seismic data. Multiple realizations that were compatible with the well and seismic data were performed to solve the non-uniqueness problem. There were a great number of potential outcomes that can be produced using stochastic procedures. Importantly, Khalid et al. (2019) showed that in organic-rich intervals, there exists an inverse relationship between P-wave seismic velocities and TOC. TOC generally exhibits a linear relationship with impedance values (Ouadfeul & Aliouane, 2016). (Mahmood et al., 2021) also elaborated on the true dependency of TOC on impedance data. In this study, we applied seismic stochastic inversion to post-stack seismic data to calculate the TOC. Seismic inversion was performed on these source rock top and base seismic horizon units that were located within the study area. Seismic inversion involves the extraction of an appropriate seismic wavelet (Bashir et al., 2021).

Besides seismic, well logs are very useful for calculating TOC, present in potential source rocks. It is possible to detect source rocks with wireline logs, which may also be utilized as an indicator of the potential of the source rocks. By correlating sonic logs with seismic data, it is possible to gain a better understanding of the lithology, structure, and stratigraphy of the subsurface (Ali et al., 2023). Ullah et al. (2023) examined the distribution of minerals and their thermal properties. The natural radiation emitted from the minerals within the geological formations is quite beneficial in detecting the lithological variations through the gamma ray (GR) log (Ali et al., 2024).

Petrography is one of the most accurate and dependable methods for determining the age of source rocks (Wilkins et al., 2018). To ascertain the thermal maturity of the source rock, %Ro values for core samples were computed (Hakimi et al., 2023). The 1D basin modeling, which includes the building of burial history and source rock maturation levels, was also used to compute the maturity and time of source maturation. To determine the modeled %Ro, this technique takes into account a number of factors, such as HI, OI, Tmax, TOC, HF, PWD, SWIT, formation depth, and formation thickness (Aziz et al., 2020). It is well acknowledged that one of the best geochemical methods for evaluating source rocks is rock eval pyrolysis, particularly when it comes to identifying the kerogen type (Espitalié et al., 1977). This method is widely used to evaluate the maturity level, generation potential, and organic matter type of source rocks (El Diasty et al., 2022). The Rock Eval 6 equipment was used to perform Rock Eval measurements on 100 mg of each sample used in this investigation. Results for S1, S2, S3, and Tmax values were obtained from the analysis (Peters & Cassa, 1994).

When S2 has several peaks or exhibits weak intensity, maturity estimate using Tmax may sometimes provide questionable findings (Snowdon et al., 1995). When facies influence affect the Tmax, organic petrography provides a more accurate and superior maturity assessment by measuring the vitrinite reflectance, which may provide more accurate findings (Sadeghtabaghi et al., 2021). The most used metric for determining the maturity of source rocks is %Ro (Burnaz et al., 2023; Ola et al., 2018). When evaluating source rocks, it is equally important to ascertain when the rocks will mature and to comprehend their burial history (Dembicki Jr & Production, 2017). A reliable method for building the burial history and determining the degree of source rock maturation is the 1D basin modeling methodology (Abdelwahhab et al., 2020). Yasin et al. (2021) used the 1D basin modeling technique to assess the age and burial history of source rocks (Elatrash et al., 2021).

The explorationists' primary obstacle in locating substantial resources is the variation in source rock richness and maturation. The primary goal of this study is to fully understand the source rock variation in terms of organic richness, maturity, and timing of hydrocarbon expulsion for enhanced hydrocarbon exploration. To address this challenge, comprehensive source rock evaluation of Chichali Formation is adopted by using different techniques such as seismic inversion, rock eval pyrolysis, organic petrography, and basin modeling. As a result, a source rock mature area is mapped.

2D basin modeling is a commonly utilized approach for evaluating source rock and hydrocarbon migration paths, particularly for determining the maturity and timing of hydrocarbon expulsion from source rock. 2D basin modeling necessitates the use of seismic, well, geochemical, and source rock data to evaluate source rocks. Several writers have used a 2D basin modeling approach to estimate thermal maturity and migratory patterns in the region. Zeng, (2025) did 2D basin modeling in a rift basin (lacustrine) for hydrocarbon distribution. Bandics, (2025) mapped the petroleum system in the Hungarian Pannonian Basin using 2D basin modeling. The petroleum system aspect states that hydrocarbon migration is essential to the success of hydrocarbon exploration (Abdul Wahab et al., 2023). He modeled the Abu Gharadig Basin (Western Desert, Egypt) in both 1D and 2D for source maturity and expulsion. Setyawan, (2023) carried a 2D basin modeling for a hydrocarbon charging model at Tangguh Field in the Bintuni Basin, Papua. Bartha, (2018) conducted 2D basin modeling in the Central European Pannonian basin to investigate the region's tectono-stratigraphic model and its effects on source rock maturation throughout time.

Badics, (2025) conducted source rock and petroleum system modeling in the Zala North Basin, Hungary, using 3D seismic data. In the Sorvestsnaget Basin in the SW Barent Sea, Asvald, (2025) investigated fluid motion and build up using 3D seismic data. To map the structures that govern the migration routes, Lee, (2025) employed 3D seismic data. Spacapan, (2025) used 3D basin modeling to map the 3D petroleum system in the Asutral and Malvinas basins. In the South-eastern Ordos Basin, Chen, (2025) examined the Permian Shanxi Formation's history, source rock assessment, and maturity. Additionally, hydrocarbon maturation, migration, and acculturation can be studied using 3D geological analysis (Ahmed et al., 2024). Castro Vera, (2024) performed basin modelling of the hill’s syncline in Germany for the reconstruction of burial and thermal history and implications for petro physical properties for the Mesozoic shales. 3D basin and petroleum system modeling of early cretaceous play in NW Persian Gulf carried by (Shabani et al., 2023). Badejo (2021) used a three-dimensional petroleum system model to locate undrilled Tertiary sandstone prospects on the western border of the Central North Sea via basin modeling. Abubakar et al., (2020) used a multidisciplinary approach to discover hydrocarbon charge spots and migration in the Wessex Basin, southern England. Arfai (2018) used 3D basin and petroleum system modeling in the NW German North Sea (Entenschnabel) to investigate the thermal history, maturity, and petroleum generation of three probable source rocks.

Explorationists have long attempted to establish a technique that would enable them to directly find hydrocarbons buried far below the earth's surface. Unusual seismic amplitudes known as "direct hydrocarbon indicators" (DHIs) could develop when hydrocarbons are present. They emerge from changes in pore fluids, which have an impact on the bulk rock's elastic characteristics. Lee, (2025) evaluated the influence of structural limits on hydrocarbon migration under the neotectonic regime at the southern margin of the Ulleung Basin in the East Sea. In the Indonesian oil field of Banyubang, Priyono (2024) exploited low-frequency passive seismic as a direct hydrocarbon indicator. Handoyo, (2024) employed the DHI's to analyze the carbonate reservoir potential in the Salawati Basin, West Papua. Dim spots, flat patches, and polarity reversals are signals of hydrocarbon potential, according to DHI's forecast of the hydrocarbon indicator. Khawaja, (2023) exploited DHI's to illustrate the occurrence and development of hydrocarbons in the Dujaila field in southeast Iraq. Nanda et al. (2021) effectively carried out DHI's analysis for hydrocarbon exploration and production. Rowi et al. (2020) employed DHI's for prospect appraisal and maturation. Foschi et al., (2014) highlighted those seismic reactions, such as DHI's may be connected to the presence of hydrocarbons and will assist in hydrocarbon migration modeling. It may also evaluate their habitat and pathways in relation to the basin's architecture.

For this study, petroleum migration pathways from source rock to reservoir were established and a map that represents the migration pathways and identification of sweet spots that had served to fill the hydrocarbon traps was generated. Also, structural aspects of the top reservoir surface and their influence on hydrocarbon migration and accumulation were established. Source rock uncertainty and establishment of hydrocarbon migration pathways will help the mitigation of risks associated with hydrocarbon exploration. This will lead the exploration companies to add sizeable reserves in the near future.

5.2 Conclusions

- Bahu-01 well indicates poor source rock potential with an average TOC of 0.34%. In contrast, the Panjpir-01 and Nandpur-01 wells displays moderate to good organic richness, with average TOC of 1.25% and 1.36%, respectively. The Zakria-01 well exhibits fair organic richness, with an average TOC value of 0.78%.
- The organic richness results obtained from both direct lab-based geochemistry and indirect seismic inversion methods are compared, and it displays an excellent correlation coefficient of (R= 0.97).
- Bahu-01, Nandpur-01, and Zakria-01 wells has kerogen Type-III, while Panjpir-01 has a kerogen Type-II-III.

- Average T_{max} in lies below 435°C at Bahu-01, Panjpir-01, and Nandpur-01 confirms immaturity of source rock, while in western side T_{max} value exceeds 435°C at Zakria-01 confirms the maturity of source rock.
- Based on 1D basin modeling results, modeled %Ro for the Chichali Formation at Bahu-01, Nandpur-01 and Panjpir-01 indicates immaturity of source rock with values of 0.33%, 0.40% and 0.38%, respectively. At Zakria-01, the %Ro value of 0.55% suggests early oil window with peak hydrocarbon expulsion occurred in Eocene age.
- The comparison of %Ro values from petrography and ID basin modeling approaches yields a good correlation coefficient of R= 0.92.
- The Cretaceous age Chichali Formation source rock is immature in-situ in eastern Punjab Platform, where three gas fields were discovered, while the source is mature in Sulaiman Foredeep.
- Integrated source rock evaluation using seismic inversion, rock eval pyrolysis, organic petrography and basin modeling techniques is novel, and it has enhanced our understanding of the variation of source rock characteristics.
- 2D Basin modeling indicates that the Sulaiman Foredeep area has a (%Ro) range of 1-1.5, indicating source rock maturity in the late oil to wet gas window. Western parts have a range of 1-1.3, while the Punjab Platform, with three producing fields, has a range of 0.4 to 0.48%%, which confirms the source rock immaturity.
- The Cretaceous Chichali Formation source rock lies between 6000 m and 5000 m in Sulaiman Foredeep, and it gets shallower toward the east. In producing the Bahu-01, Panjpir-01, and Nandpur-01 wells, it was between 1600 and 2000 m.
- The reservoir rock in Foredeep has a porosity of 1-4%, with better porosity in the eastern side from Bahu-01, Panjpir-01, and Nandpur-01 wells, producing gas from 18 to 25%, and good permeability. Also, the reservoir has good permeability (4–7 mD) in the Sulaiman Foredeep area and 2–5 mD in the Punjab Platform area.
- The source rock pore pressure in Sulaiman Foredeep lies between 12,000 to 16,000 PSI. High pore pressure is due to deep burial of source rock. Similarly, the reservoir pore pressure lies between 9,000 to 11,000 PSI. Both source and reservoir pore pressure decrease in eastern side of study area due to decrease in burial depth.
- The DHI's confirms the presence of hydrocarbon particularity gas and authenticates our work about the establishment of migration pathways that are connecting the source buried

deep in Sulaiman Foredeep to the traps, which are present about 200 km away from the source rock.

- Pressure map reveals that the pressure in the eastern part of the study area is around 5 to 50 bars, whereas the pressure in the western side, which is Sulaiman Foredeep, ranges from 1600 to 1800 bars. It reflects that the thickness and pressure map in the western part is most likely to hold the hydrocarbons, as the thickness of the sock is around 200 m and the pressure is ranging between 16000 and 18000 bars, which is sufficient to hold the appreciable amount of hydrocarbon.
- The hydrocarbon generation map in Sulaiman Foredeep indicates that the early oil window opened between 65-50 Ma, the main oil window from 65-35 Ma, and the wet gas window from 50-35 Ma. The central part of the study area opened between 50-25 Ma, while the east part, where three main gas discoveries are present, remains barren.
- Total gas generation mass kg/m in the western part of the study area, especially in Sulaiman Foredeep, ranges from 70 to 100 kg/m of gas generation mass, whereas in the central part it had produced 40 to 100 kg/m of gas generation mass. Whereas just east of the central part, it was decreased to 25 to 30 kg/m of gas generation mass.
- The western part of the Punjab Platform has transformation of source rock from 90 to 100%. The western to central part has a source transformation ratio of 35 to 80%, while the central part has a ratio of 5 to 10%. The eastern part, including Bahu, Panjpir, and Nandpur, has no gas transformation source.
- The hydrocarbon migration occurred horizontally in the reservoir rocks. Lumshiwal Formation sands' good porosity ranges from 5 to 25% contributed to lateral migration from Sulaiman Foredeep source kitchen area to central and eastern Punjab Platform.
- Faults are NW-SE and N-S oriented, with a throw of 10-15 meters. The faults in the hydrocarbon migration pathways have very minimal effect on lateral hydrocarbon migration.
- The Indian Plate's tilt causes lateral migration of hydrocarbons from the western side to the eastern Punjab Platform area. Buoyancy is the main driving force for the hydrocarbon movement. The Zakria-01 well failed due to a lack of structural trap.
- DHI's analysis authenticates hydrocarbon migration pathways in the Lumshiwal Formation, identifying bright spots on a 2D line in the incised valley, confirming the presence of these pathways.

- It is now proved that the fields Bahu-01, Panjpir, and Nandpur-01 were charged from the deep buried the Chichali Formation source rock in Sulaiman Foredeep.
- These hydrocarbon migration pathways will enhance the chances of successful hydrocarbon exploration for exploration companies, contributing to meeting energy demands.
- The integrated approach using source rock richness, maturity, ID, 2D basin modeling, and 3D charge modeling/3D petroleum system modeling should be adopted in other basins of the world for successful full hydrocarbon exploration.

5.3 Future Recommendations

This research area, the Punjab Platform has only been covered by 2D seismic data to date. Acquiring 3D seismic data would enhance the mapping of leads and prospects for future drilling. Additionally, 3D data would support the refinement of direct hydrocarbon indicator (DHI). Furthermore, the future exploration activities should be focused toward zones where hydrocarbon migration has been identified through this study.

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APPENDICES-PUBLICATIONS

Appendices-A

Journal of Petroleum Exploration and Production Technology
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ORIGINAL PAPER - EXPLORATION GEOLOGY

Organic richness and maturity modeling of cretaceous age Chichali shales for enhanced hydrocarbon exploration in Punjab platform, Pakistan

Qadeer Ahmad[1] · Muhammad Iqbal Hajana[1] · Shamshad Akhtar[2]

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Abstract
This study employs comprehensive source rock evaluation using seismic inversion, rock-eval pyrolysis, organic petrography and basin modeling techniques. The kerogen type is determined by using the Van Krevelen diagram, confirming Bahu-01, Nandpur-01 and Zakria-01 wells have kerogen type III, whereas Panjpir-01 well exhibits kerogen type II to III. The TOC was calculated using core data from (34) samples by employing organic geochemistry technique and post stack seismic inversion, applied on 2D seismic data. Bahu-01 well indicates poor source rock potential, with an average TOC value of 0.34%. In contrast, Panjpir-01 and Nandpur-01 wells represent moderate to good organic richness, with average TOC values of 1.25% and 1.36%, respectively. However, Zakria-01 well with a TOC of 0.72%, exhibits fair organic richness. The Maturity estimation from organic petrography and basin modeling reveals that the Bahu-01, Panjpir-01, and Nandpur-01 wells have average vitrinite reflectance (%Ro) values below 0.50, indicating immature source rock. In contrast, the average %Ro value for the Zakria-01 well is 0.63, confirming the source maturity in the early oil window, with peak generation occurring during Eocene age. Finally, the source rock evaluation proves the source is mature in the western part only and future hydrocarbon exploration should be focused in the western area. The integrated source rock evaluation approach is novel in Punjab Platform. The diverse methodologies enhanced our understanding about source rock characteristics for pursuing hydrocarbon resources. An integrated approach will also provide valuable insights for hydrocarbon exploration in numerous other basins worldwide.

Keywords Punjab platform · Organic richness · Thermal maturity · Seismic inversion · Basin modeling

Introduction

The continuous instability of the global energy market, coupled with increased consumption has led to a significant rise in the worldwide demand for oil and gas (Ayorinde et al. 2024). The demand for energy is projected to rise at a rate of 41% between 2012 and 2035 (Sohail et al. 2024). Meeting the gap between production and consumption requires aggressive exploration activities (Latief and Lefen 2019). For carrying aggressive hydrocarbon exploration for reservoir quality prediction and identification of sweet spots, it is important to understand the economic importance of the petroleum system (Ashraf et al. 2020, 2024). The petroleum system includes the accumulation, conversion and migration of hydrocarbon into a reservoir from source rock over sufficient geologic time. These processes occurred under adequate burial depth and temperature pressure conditions. Now within the petroleum system, source rock evaluation represents a critical step that demands meticulous attention. The assessment of source rock potential includes the elucidation of organic richness, kerogen type, and thermal maturation (Cappuccio et al. 2021; Ehsan et al. 2024).

The complexities regarding the source rock evaluation can be resolved by integrated approach using various methodologies including organic geochemistry, petrography and basin modeling. Xiao et al. (2024) evaluated the organic

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