पेट्रोलियम एवं
प्राकृतिक गैस मंत्रालय
MINISTRY OF
PETROLEUM AND NATURAL GAS

सत्यमेव जयते

DIRECTORATE GENERAL OF HYDROCARBONS
(Ministry of Petroleum & Natural Gas,Government of India)

INFORMATION DOCKET

CONTRACT AREA
AA/ONDSF/ASSAM/2025 (A&AA)

DISCOVERED SMALL FIELD BID ROUND - IV

DISCLAIMER

This document, titled Information Docket, provides a consolidated overview of the Contract Area comprising the discoveries/fields offered under the Discovered Small Fields (DSF) Bid Round-IV. This docket has been prepared based on original inputs /information received from National Oil Companies, Private Operators/JV and available at National Data Repository (NDR).

Third Parties were engaged to independently assess the information and estimate the inplace volumes. In conducting these estimations, Third Parties used the available data/information and employed assumptions, procedures and methods deemed necessary given the timeframe available for evaluation.

The accuracy and clarity of the information presented herein, including the reported hydrocarbon resources, are thus limited to the data available at the time of analysis and the verifications performed by the Third Parties during the evaluation timeframe. The findings are subject to further review and validation by bidders upon receipt of additional and clarified data/information.

Given these limitations, all bidders are hereby advised to undertake their own independent technical and commercial due diligence and conduct thorough evaluations of the data and resource potential to support informed investment and bidding decisions.

Contents

INTRODUCTION

With the extension of the DSF policy 2015, DSF Bid Round IV offers 55 small-to-mid-size oil and gas discoveries through international competitive bidding. There are 9 Contract Areas under DSF-IV spread over Cambay, Assam & Assam Arakan, Gulf of Kutch, Mumbai Offshore, Krishna Godavari Basins. Out of 55 discoveries, there are 19 onshore discoveries in 3 Contract Areas, 26 shallow water discoveries in four Contract Areas and 10 Deepwater discoveries in two Contract Areas. The discoveries have been suitably clustered in order to leverage shared resources and operational flexibility.

In terms of hydrocarbon prospectivity, the fields-on-offer lie in 5 sedimentary basins which include 8 Contract Areas in Category I basins with hydrocarbon reserves and 1 Contract Area in Category II basins with contingent resources.

Each Contract Area on offer has multiple discoveries, comprehensively described in this Information Docket to bring in all relevant subsurface facts of geo-scientific and engineering information. This technical booklet will be useful if read while working with the Data Package which would be available on sale once the Data Room is set up for viewing.

1. CONTRACT AREA DESCRIPTION

The Contract Area, titled, AA/ONDSF/ASSAM/2025 is located in the onland area of India (**Figure 1-1**) within the Assam Shelf Basin and the Assam Arakan Fold Belt Basin (AAFB) segments of the composite Assam and Assam Arakan Basin (A&AA Basin). The Contract Area has an offered area of **709.85 Sq. Km**. under this DSF Bid Round IV. The Contract Area is made up of clusters with 8 discoveries/fields viz Laxmijan-1A (LXMJ-1A), Bihubar-1 (BHBR-1), Nahorhabi-1 (NAHB-1),Charaideo-1 (CRDO -1), Kherem-2 (KHM-2) in the Assam Shelf and Tukbai-2 (TUKB-2), Patharia-2 (PTRA-2) & Patharia-5 (PTRA-5) in the AAFB segment and 21 additional wells and 3 sidetracks included. In the map, enclosed with the NIO (Notice Inviting Offer) Document, the Contract Area is referred to as O-3. The following **Table 1-1** and **Figure 1-1** show the Contract Area details across the field(s) and/or cluster(s).

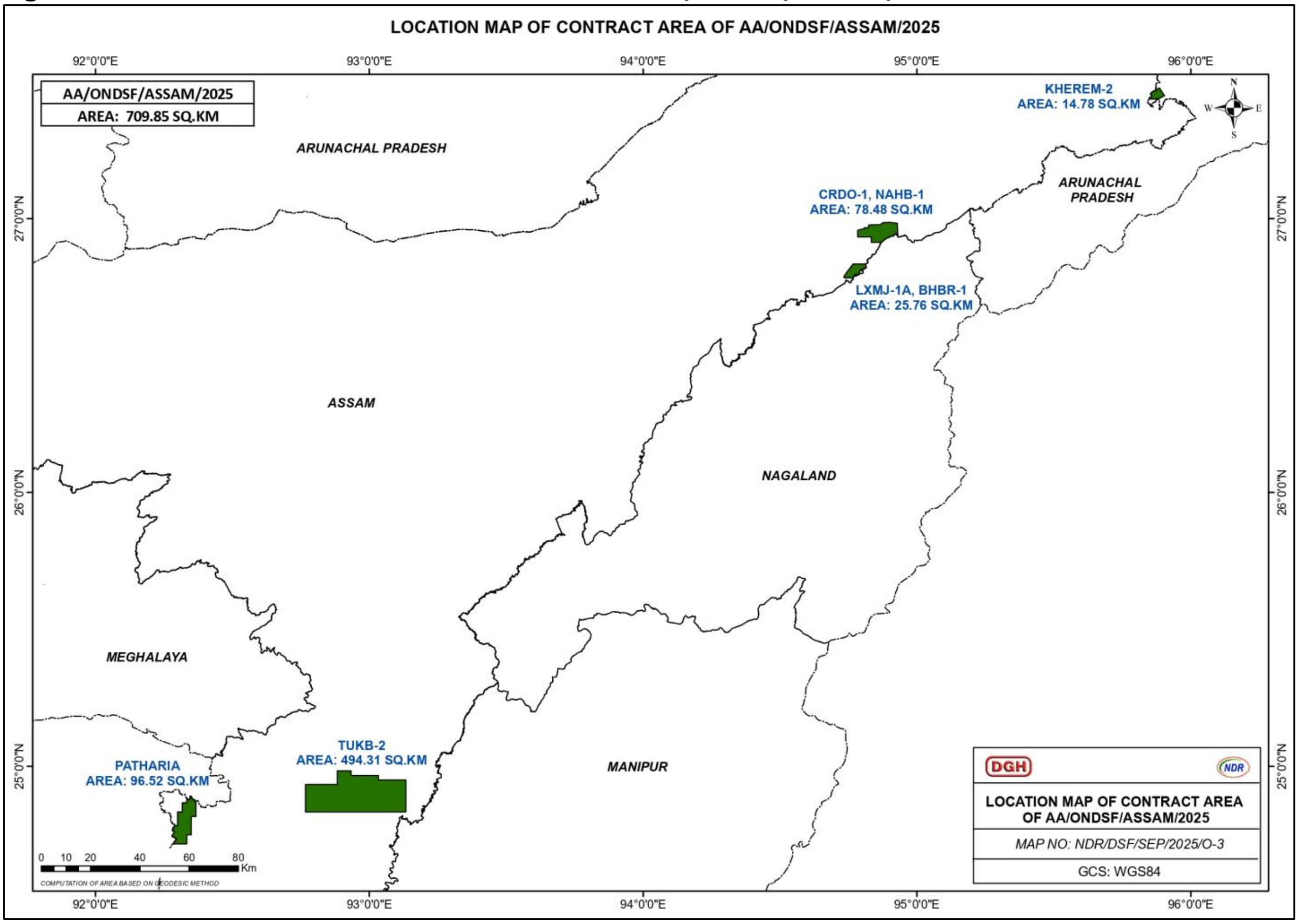
Table 1-1: Details of Contract Area AA/ONDSF/ASSAM/2025

Details of Contract Area AA/ONDSF/ASSAM/2025

Total Contract Area : **709.85** Sq Km
No. of Discovery Wells in Contract Area : **8**
Total No. of Wells in Contract Area : 32 (including Discovery wells)
No. of Polygons Covered in Contract Area : 5

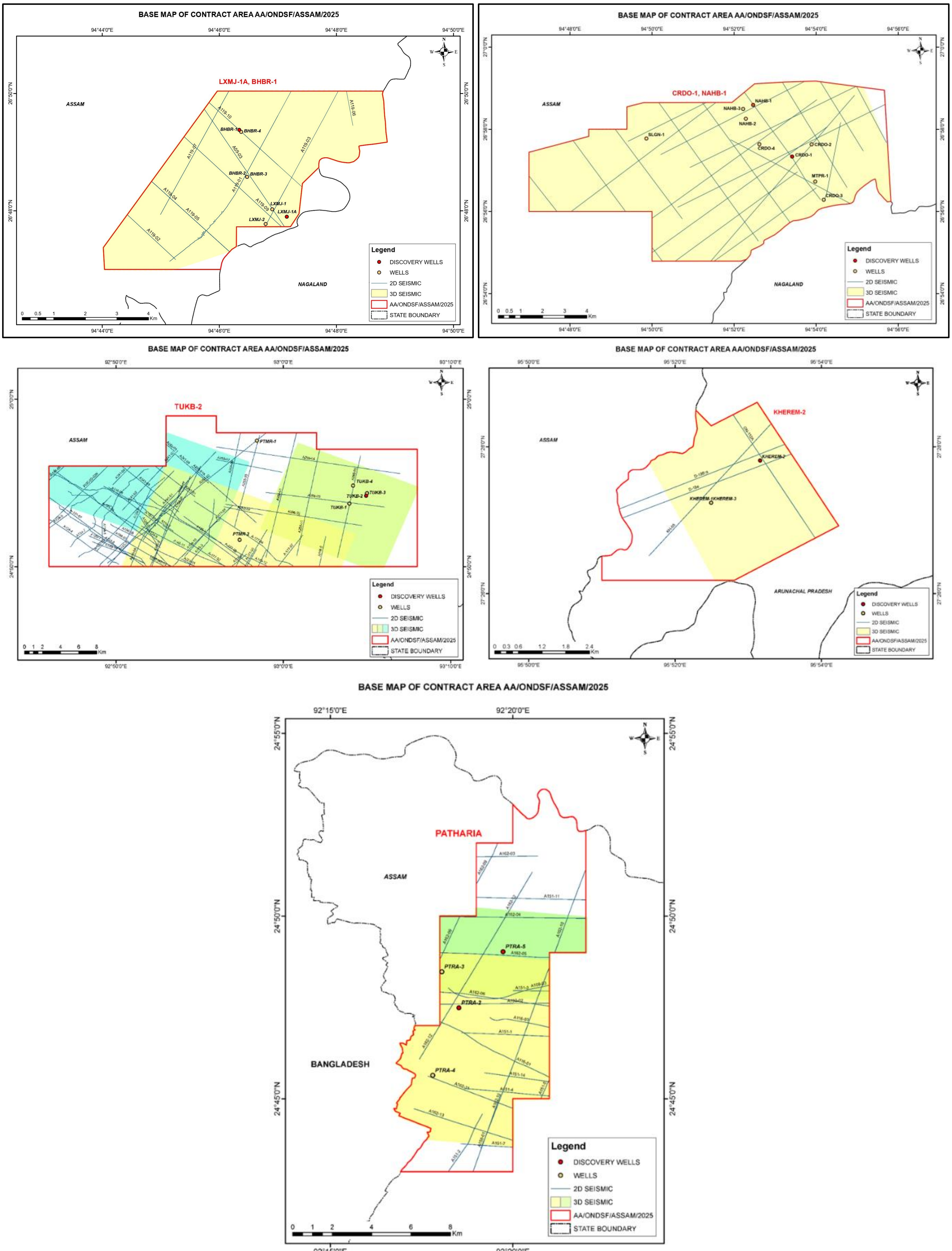
S. No.	Name of Polygon	Area, SqKm	No. of Discovery Wells	Total No. of Wells	O+OEG MMTOE	O+OEG (As per Erstwhile Operator) MMTOE
1	**Laxmijan**	25.76	1	3	0.96	0.15
2	**Bihubar**		1	5	0.70	
3	**Nahorhabi**	78.48	1	9	1.83	1.68
4	**Charaideo**		1		3.35	3.64
5	**Kherem**	14.78	1	3	1.34	0.89
6	**Tukbai**	494.31	1	8	0.17	0.03
7	**Patharia-2**	96.52	1	4	0.23	0.18
8	**Patharia-5**		1		0.19	0.14
Total		**709.85**	**8**	**32**	**8.77**	**6.71**

Figure 1-1 : LOCATION MAP OF CONTRACT AREA OF AA/ONDSF/ASSAM/2025



The area has information of **830.81 line km of 2D** seismic data and **532.64 sq km of 3D** seismic data. There are 32 wells in the Contract Area. The following **Figure 1-2** show(s) the coverage of available seismic 2D and 3D data along with wells drilled across field(s) and/or cluster(s).

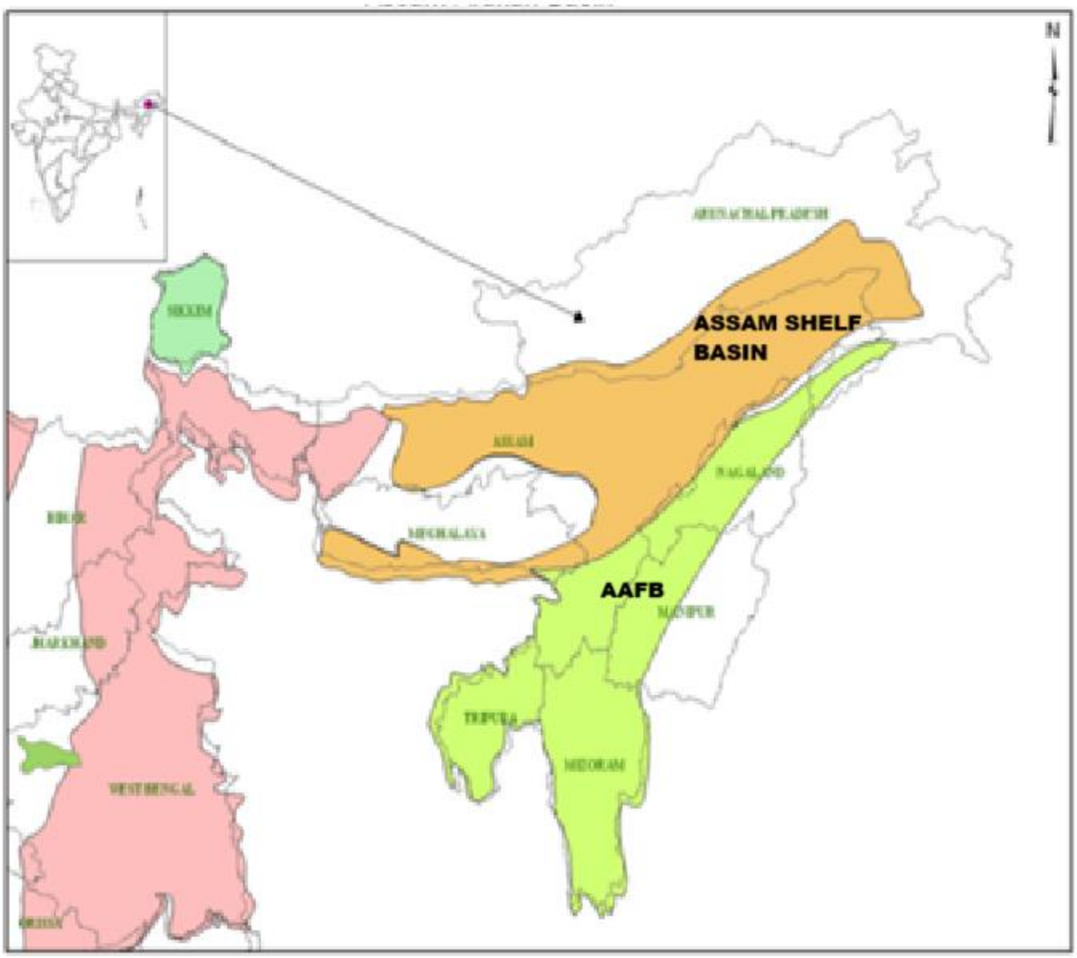
Figure 1-2 : COVERAGE OF AVAILABLE SEISMIC 2D AND 3D DATA IN AA/ONDSF/ASSAM/2025



2. PHYSIOGRAPHY AND ACCESSIBILITY OF THE AREA

The Contract Area is located in the states of Assam and Arunachal Pradesh within northeast India and encompasses discovered structures, both in the Category-I Assam Shelf Basin and the Assam Arakan Fold Belt (AAFB) Basin (**Figure 2-1)**. However, based on the tectonic history of the area the two Basins can be considered part of the composite Assam and Assam Arakan Basin (A&AA Basin). This part of India is located between the latitudes 22^{O}N and 29.5^{O}N. The Tropic of Cancer passes along the southern part of the Assam Arakan Fold Belt Basin through the states of Tripura and Mizoram. The Kherem, Laxmijan, Bihubar, Charaideo and Nahorhabi Fields are located in the Assam Shelf Basin while Tukbai and Patharia Fields are located in the Assam Arakan Fold Belt Basin.

Figure 2-1 : ASSAM & ASSAM ARAKAN (A&AA) BASIN



Though primarily in the plains area within the states of Assam and Arunachal Pradesh, the fields in the Assam Shelf Basin have uneven elevations ranging nearly 100m to 154m from Mean Sea Level and are mostly covered with alluvium. Being within the monsoon belt of South and South-East Asia, the region has essentially tropical climate, with high rainfall during summer (April-October) and relatively dry winter from November to March. But its location and topography, encircled on three sides by high mountain ranges and the presence of a precipitous plateau (Shillong Plateau), athwart the course of the incoming south west monsoon winds and have rendered its climate somewhat different from that of the other parts of India. The fields in the Assam Shelf Basin are well connected by motorable roads with national and state highways. The nearest railway station to the fields is Simaluguri Junction and the nearest airport is Jorhat for the Laxmijan, Bihubar, Charaideo and Nahorhabi Fields while for the Kherem Field, the nearest railway station is Tinsukia Junction and the nearest airport is at Dibrugarh.

The Patharia and the Tukbai Fields, falling in the state of Assam are located in the Cachar area of the Assam-Arakan Fold Belt Basin and which consists of, in the area of the fields, a series of long narrow anticlines and broad synclines in an almost N-S trend that swings north-eastward towards the northern margin. The N-S trending ridges are the northward extension of the Tripura hills running nearly up to the Barak River, which flows almost east to west parallel to the Barail Hill range. The average elevation of the Cachar Fold belt varies between 10 m and 1600 m because of the varied topography consisting of plains, hills, and valleys. Hilly terrains are present, particularly in the north and south, near the borders with the state of Mizoram and the Dima Hasao district of Assam. However, in the area of the discovered fields the ground level elevations are mostly in the range of 25 to 55 m.

This area has a humid tropical climate with annual rainfall ranging from 300-400 cm. The maximum temperature during the summer months of April-June ranges between 30°C-38°C. The monsoon lasts from May to September. Winter temperature (November, December and January) ranges from 12°C to 25°C. Guwahati is the nearest international airport while Silchar is the other connecting airport at a distance of around 60 Km. Karimganj is the nearest major town and railway station within a 10 KM radius. **Figure 2-2, Figure 2-3 and Figure 2-4** show locations of the blocks in satellite imagery.

Figure 2-2 : SATELLITE IMAGERY OF THE BLOCK AREAS:

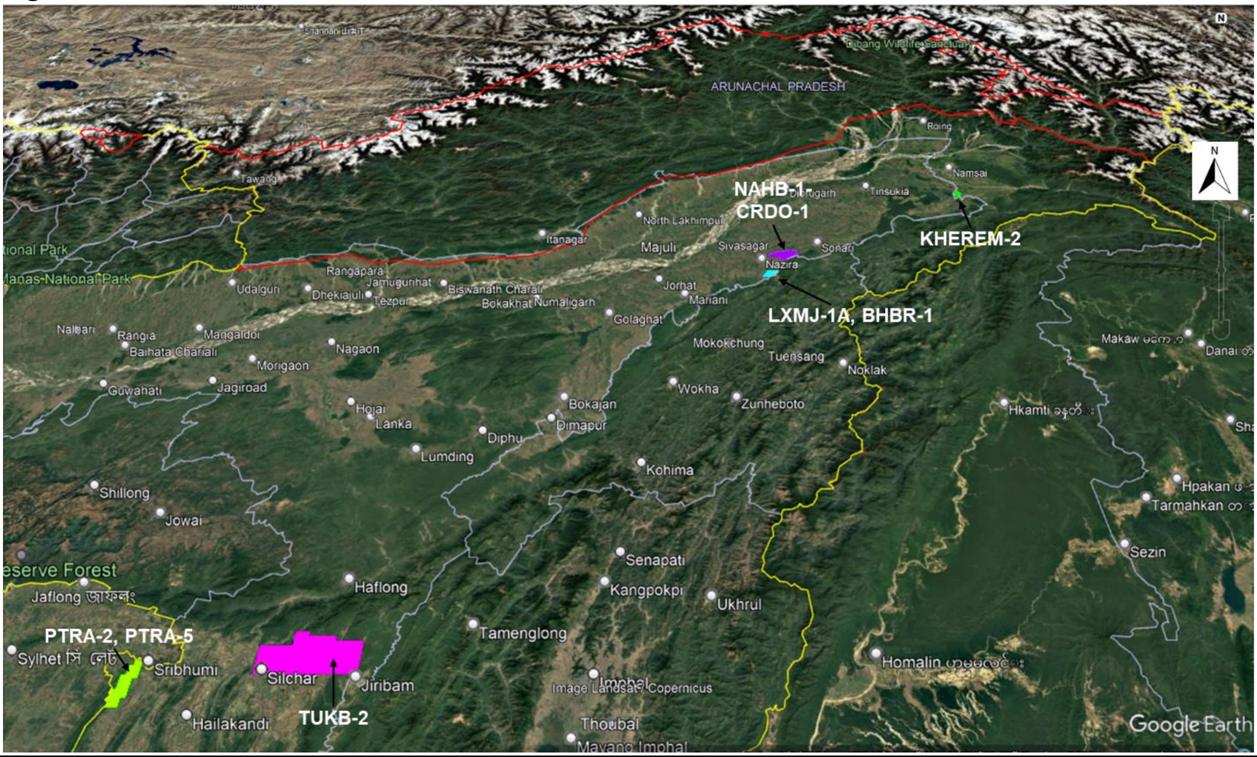


Figure 2-3 : SATELLITE IMAGERY OF THE NAHORHABI-CHARAIDEO AND LAXMIJAN-BIHUBAR AREA:

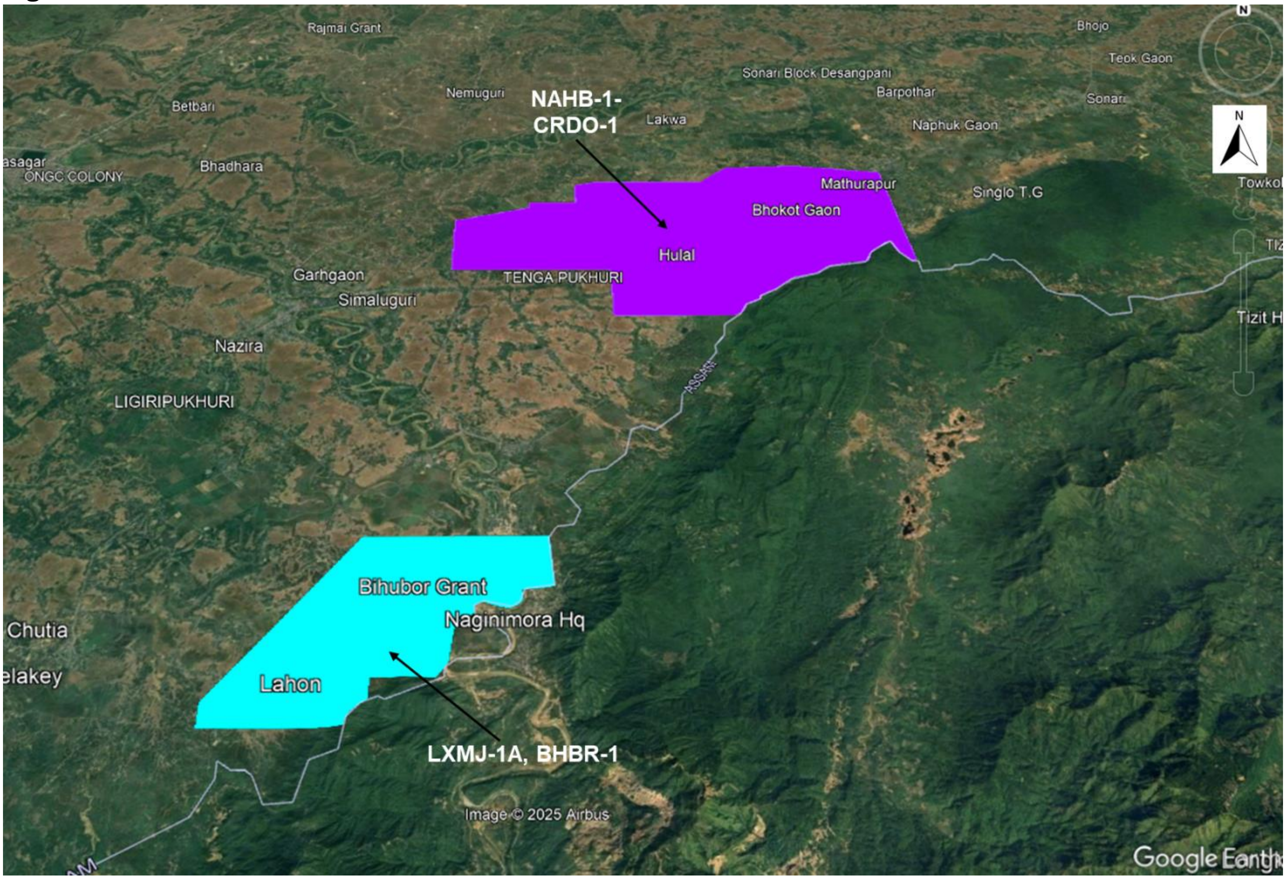
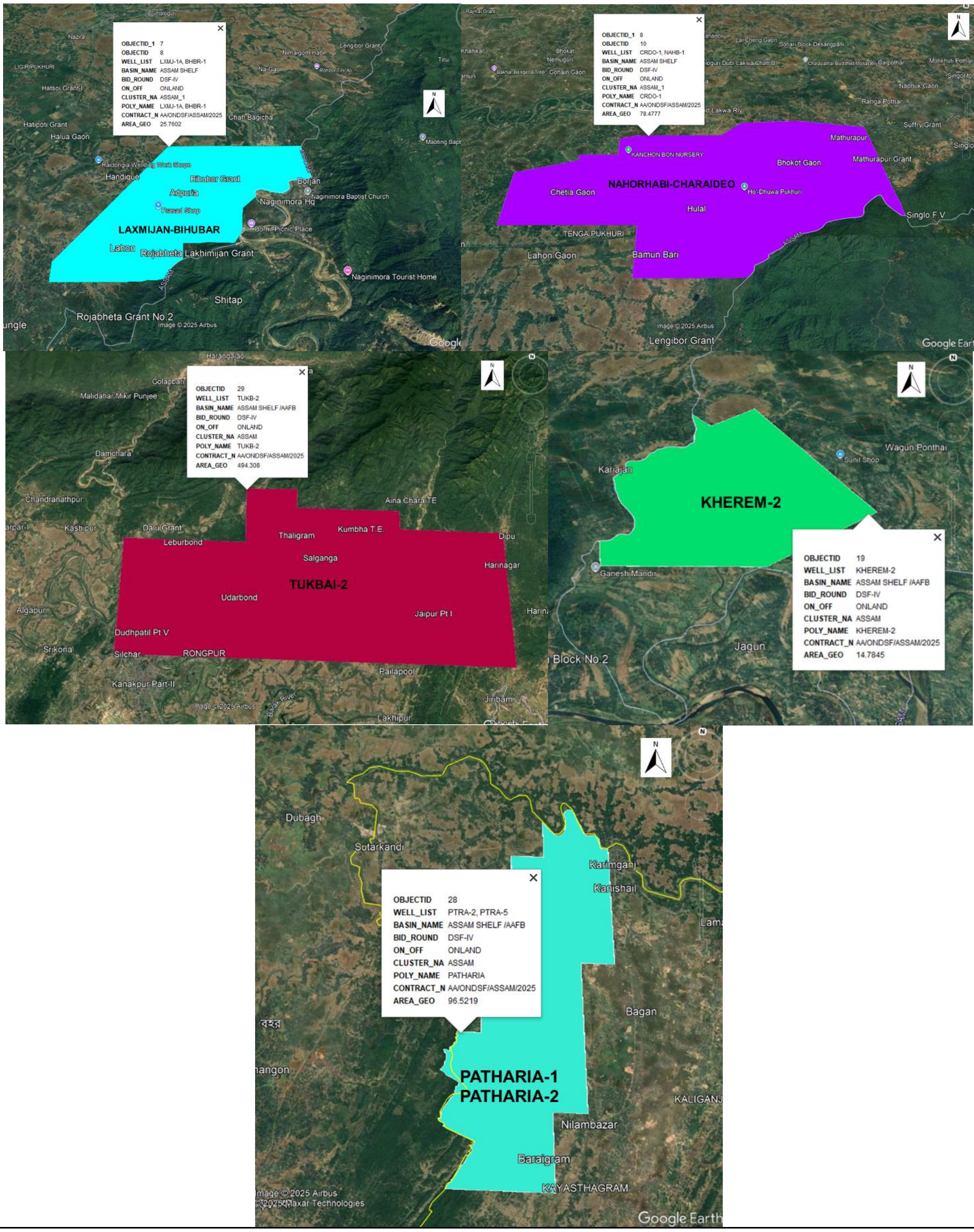


Figure 2-4 :SATELLITE IMAGERY OF THE BLOCKS SHOWN IN 5 CLUSTERS



3. RELEVANT SEDIMENTARY BASIN INFORMATION

3.1 ASSAM & ASSAM ARAKAN BASIN DESCRIPTION

The composite Assam and Assam Arakan Basin (A&AA Basin) is divided into two Category I basins viz. the Assam Shelf Basin and the Assam-Arakan Fold Belt (AAFB) Basin (**Figure 2-1**) The Assam Shelf Basin is a Category I Basin which is entirely onland, and the Basin has an area of 56,000 sq. km. containing about 7000 m thick sediments of mostly the Tertiary period. The Basin is a peri-cratonic, passive margin basin, with the signature of compressional tectonics as a result of the Himalayan orogeny. The Basin hosts a thick pile of mainly Tertiary sediments, ranging from Paleocene to Recent which overlies the Basement consisting of Granitic and Metamorphic complex. Gondwana sediments are exposed in the western extremity of Garo Hills (in the state of Meghalaya), consisting of gritty sandstones, carbonaceous shale and lenticles of coals. The Basin unconformably extends up to the northern bank of the River Brahmaputra into the foothills of the Eastern Himalayas. The Assam Shelf Basin is a petroliferous province, characterized primarily by siliciclastic deposits of the shelf margin, situated to the north-east region of Indian peninsula. and 8 plays are present within the Basement and Tertiary sedimentary section. Commercial hydrocarbon occurrences, besides in the Basement, is spread over different stratigraphic intervals ranging from the older sediments of Paleocene (Tura Sandstone) to the younger sediments of Pliocene (Girujan Formation). Several oil and gas fields have been discovered within structural, stratigraphic and strati-structural entrapment conditions. The hydrocarbon accumulations often indicate charging from multiple source sequences. The Assam Shelf Basin is still under active exploration stage.

The Assam-Arakan Fold Belt (AAFB) Basin is also a Category I Basin, implying that the Basin has significant commercial discovered in-place oil and gas. The Basin which is entirely onland has an area of 60,000 sq. km and contains a sedimentary column of more than 10,000 m thick sediments of mostly the Tertiary period. Assam Arakan Fold Belt Basin is a peri-cratonic, passive margin basin, with the signature of compressional tectonics during Himalayan Orogeny. The basin includes two distinct tectonic setting, viz. Tripura-Cachar Fold Belt and Naga- Schuppen belt. The Basin hosts a thick pile of Tertiary sediments, ranging from Paleocene to Recent which overlies the Archean Basement consisting of granitic and metamorphic rocks. The Basin is characterized primarily by siliciclastic deposits of fluvial to shelf margin setup, situated in the northeast region of Indian peninsula. It cuts through major states of the North-East region (NER) of India (Assam, Arunachal Pradesh, Nagaland, Manipur, Mizoram and Tripura). The Basin is currently under active exploration stage. In the Basin, 7 plays are present from the Eocenes to Pliocene. Commercial hydrocarbon occurrences have been mainly encountered and produced from within Miocene and Pliocene formations except for some small discoveries in Oligocene and Eocene sequences. Several gas pools have been discovered within structural closures while hydrocarbon accumulations often indicate charging from deeper sequence. The deepest Oligocene play (Renji) is yet to be thoroughly explored. All proven systems have significant risked resources

Though the Contract Area can be divided into the Assam Shelf Basin and the Assam Arakan Fold Belt (AAFB) Basin, based on the tectonic history of the area the two basins can be considered part of the composite Assam and Assam Arakan Basin (A&AA Basin). The major structural elements of the shelf–slope–basinal system of the composite Assam & Assam Arakan (A&AA) sedimentary basin is briefly described as following **(Figure 3-1).**

1. **Assam Shelf**

The salient features of the structural elements from north to south are as follows:

a) Southerly to southeasterly moving thrust sheets of younger (Miocene to Plio-Pleistocene) sedimentary rocks in the Eastern Himalayan foothills.

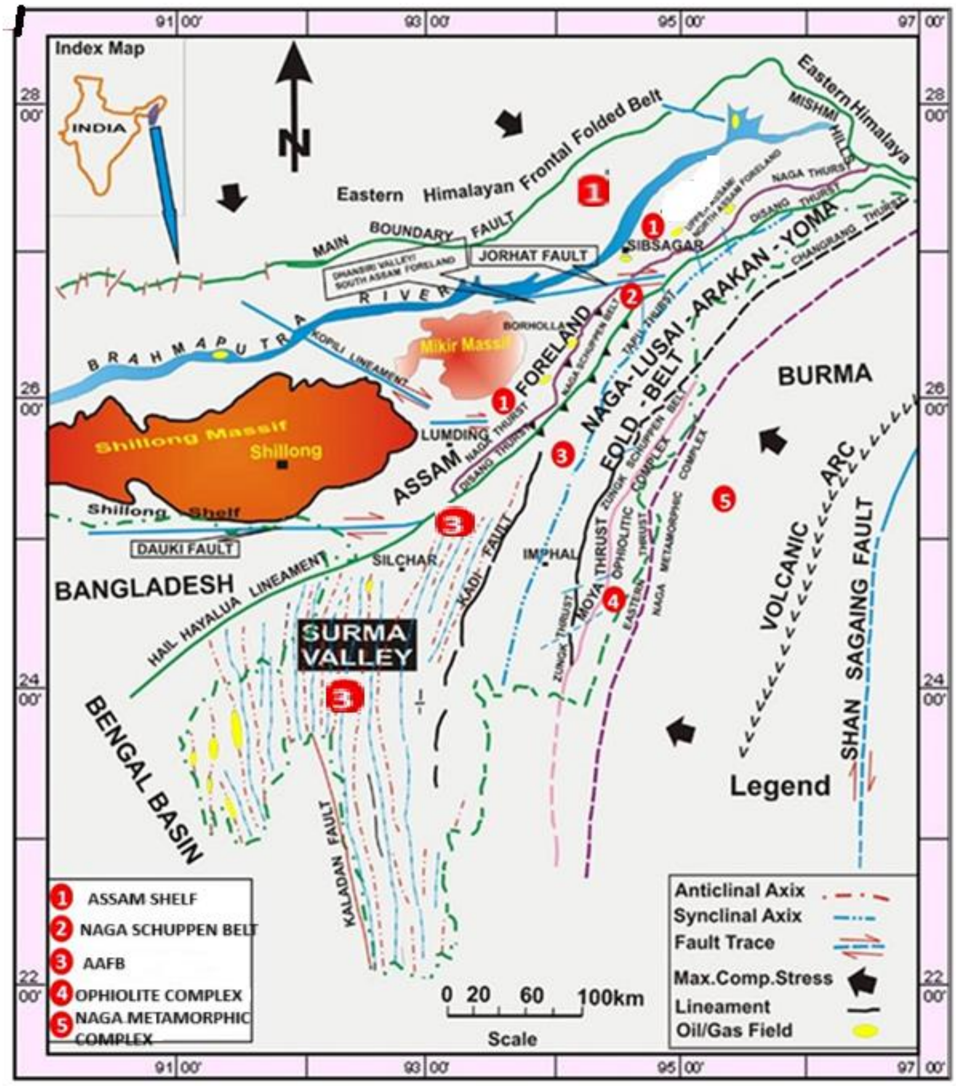
b) The Himalayan Foredeep zone, north of the River Brahmaputra, lies in the northern periphery of the foredeep and is overridden by the southerly moving thrust sheets of younger sedimentary rocks.

c) The subsurface Brahmaputra-Arch, running along the southeastern side of the River Brahmaputra in the eastern and northeastern part of the state of Assam.

d) The southeastern slope of the Assam Shelf, southeast of the Brahmaputra Arch, having local structural highs and lows, up to the Naga Thrust, and extending to beneath the Naga Schuppen belt. This element contains most of the oil fields of the Assam Shelf.

e) The Shillong Plateau and Mikir Massif, composed mostly of Precambrian granitic and metamorphic rocks. The southern slope of the Shillong Plateau exposes Gondwana, Cretaceous and Tertiary rocks.

Figure 3-1 :MAJOR STRUCTURAL ELEMENTS OF ASSAM & ASSAM-ARAKAN BASIN



2. The Naga Schuppen Zone

The Naga Schuppen Thrust Belt is a narrow, elongated zone of imbricate thrusts about 20 to 35 km wide, extending for about 200 km in a NE-SW direction. This morpho-tectonic unit which fringes the Assam-Arakan Fold Belt was formed as a result of subduction of the Indian Plate beneath the Burmese Plate. The main axis of compression is SE-NW, with the oldest Disang Thrust being of Late Eocene-Oligocene age. Thrusting continued up to Late Pliocene~~,~~ with the youngest emergent thrust, Naga Thrust, separating the foreland and the imbricate thrust zone.

3. **The Assam – Arakan Fold Belt**

This fold belt may be divided into two zones bounded by prominent thrusts, viz, (i) the Naga Fold Zone, lying in between the Disang and Tapu Thrusts and having exposures of Disang shales and Barail sediments, and (ii) the Central Flysch Zone, lying between the Tapu Thrust and Changrang – Zunki Thrust and having exposures of mainly Disang shales. The Tripura-Cachar Fold Belt and the Compressed Mizo Fold Belt are two more important zones of this structural element with the former hosting a number of hydrocarbon discoveries, primarily gas.

4. **The Zunki Schuppen belt,**

This zone contains mostly older Disang shales (Upper Cretaceous to Eocene) & occurring between the Zunki and Moya Thrusts.

5. **The Ophiolite Complex,**

Occurs in between the Moya and the Eastern Thrust. Disang shales, occurring in association with ophiolites, are somewhat metamorphosed here.

6. **The Naga Metamorphic Complex,**

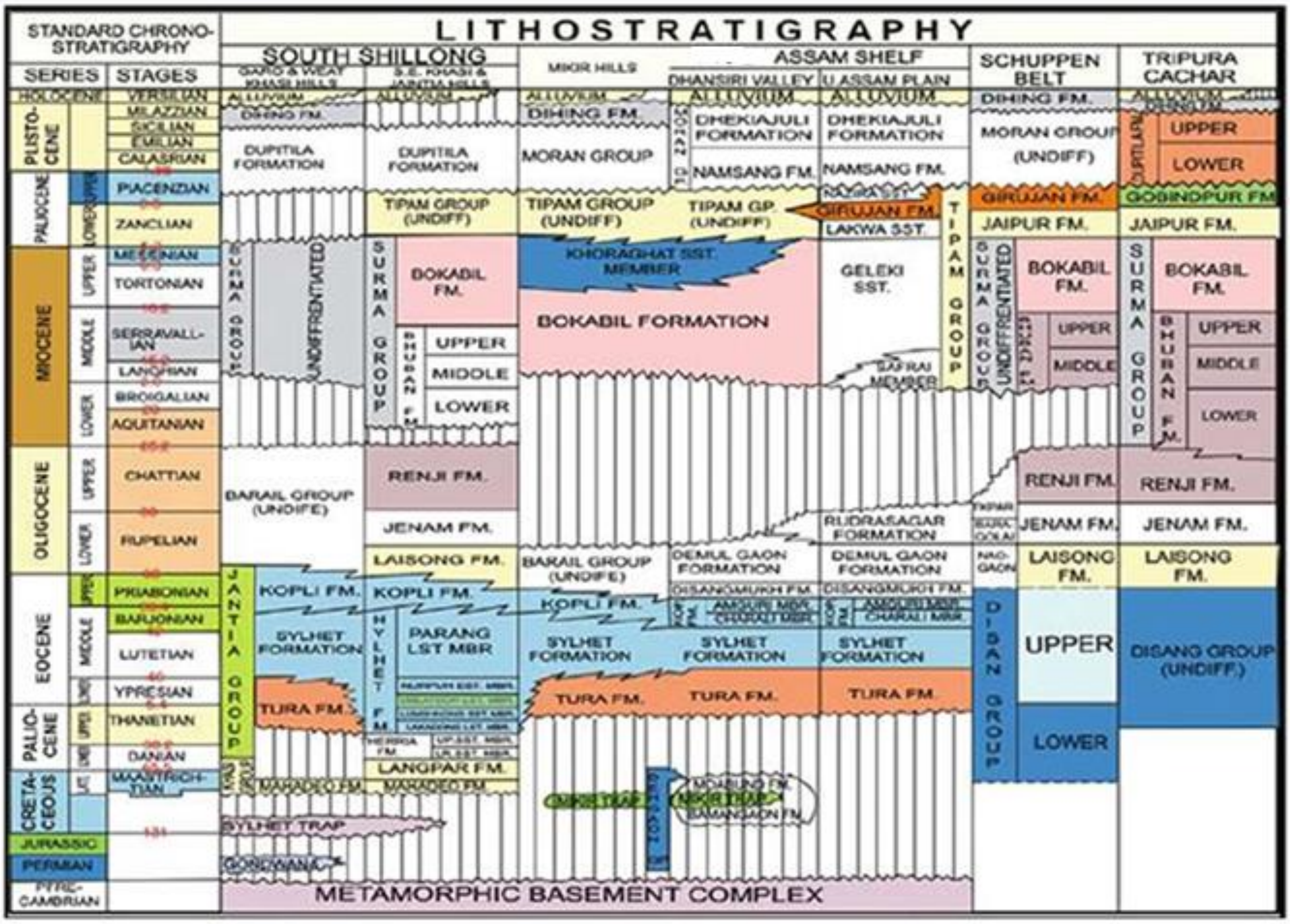
Located east of the Eastern Thrust the metamorphic complex occurs mostly to the east of the Indo-Myanmar international border.

The fields under this DSF round, located in the Assam Shelf, mostly lie close to or on the transition of the Naga Schuppen zone between the first two structural elements (please see above) of the composite Assam and Assam Arakan Basin. But the presence of Assam Shelf sediments has been established in the subsurface stratigraphic section of these fields.

3.2 ASSAM & ASSAM-ARAKAN BASIN STRATIGRAPHY

The stratigraphy of the Assam & Assam Arakan Basin (A&AA) at a few of Its structural elements is given in the **Figure 3-2.**

Figure 3-2: GENERALIZED STRATIGRAPHY OF THE BASIN



As earlier mentioned, the composite Assam and Assam Arakan Basin (A&AA Basin) consists of two basins viz. the Assam Shelf Basin and the Assam-Arakan Fold Belt (AAFB) Basin. The generalized stratigraphy of Assam Shelf Basin is as follows (**Figure 3-3 and Figure 3-4**):

Figure 3-3 GENERALIZED STRATIGRAPHY OF ASSAM SHELF BASIN

AGE	FORMATION / SAND		LITHOLOG	GROSS LITHOLOGY
Recent	Alluvium			Poorly consolidated coarse sand with sandy clays and clay.
Pliocene - Pleistocene	Namsang			Dominantly loose medium to fine grained sand with little mottled dominantly red color clay/claystone.
Pliocene - Pleistocene	Nazira Sandstone			Predominantly grey, medium grained sand with minor grey to brownish grey clay and occasionally siltstone, coal.
Miocene - Pliocene	Tipam	Girujan Clay		Mainly red, brown and greenish grey mottled clay with minor fine grained sand at the bottom.
Miocene - Pliocene	Lakwa Sst.	TS-1		Dominantly fine to medium grained grey sandstones with minor light grey soft clay/ claystone.
Miocene - Pliocene	Lakwa Sst.	TS-2		
Miocene - Pliocene	Lakwa Sst.	TS-3		
Miocene - Pliocene	Galeki Sst.	LCM+TS4		Dominantly clay/ claystone with occasional sand/ sandstones
Miocene - Pliocene	Galeki Sst.	TS-5		Intercalation of sand /sandstone with clay /claystone and siltstone.
Miocene - Pliocene	Galeki Sst.	TS-6		
Oligocene	Barails	Argillaceous / Rudrasagar (BCS)		Dominantly shale inter-bedded with coal and minor clay stone with Sand and siltstone
Oligocene	Barails	Arenaceous / Demulgaon (BMS)		Dominantly fine to medium grained grey sandstones with some inter-bedded clay and shale.
Late Eocene	Kopili			Mainly shale (splintery) alternating with fine grained sandstone and siltstone.
Middle Eocene	Sylhet			Mainly fossiliferous limestone with shales and thin sandstone bands.
Early Eocene	Tura			Dominantly sandstone with minor shales.
Pre - Cambrian	Basement			Leucocratic granite (weathered) with essential minerals e.g. quartz and pink feldspar.

The stratigraphy and gross lithology towards the northeast of the Basin particularly in the PEL/ ML areas bearing operated primarily by Oil India Limited (OIL) is as follows,

1. Alluvium/Dhekiajuli: Consists of medium to coarse grained unconsolidated sands with thin bands of clay.
2. Namsang: Comprised of medium to coarse grained sandstone with streaks of brownish clay. Coal and carbonized wood pebbles are also abundant.
3. Girujan: Made up of mottled, brown and bluish gray clay with bands of fine to medium grained sandstone and occasionally streaks of coal.
4. Tipam: Predominantly arenaceous range and is composed of salt and pepper coloured, medium grained sandstone with bands of blue and bluish gray shale. Some coal streaks are found in the middle and lower Tipams.
5. Barail: Commonly divided into two units viz. Argillaceous and Arenaceous. The argillaceous range of Barail consists of mostly bluish gray mudstone with thin bands of fine-grained sandstone and thin streaks of coal. In some areas well developed extra bands of fine-grained sandstone ranges are found.

The arenaceous range is comprised of mostly fine to medium grained sandstone with occasionally coal streaks, calcareous mudstone and bluish gray shale.

6. Kopili: Mainly composed of alternation of dark gray splintery shales and thin bands of fine grained sandstone with coal streaks and carbonaceous shale.
7. Prang: Consists of dark gray splintery shales with bands of creamy white, brownish gray and light ray limestone and calcareous sandstone.
8. Narpuh: Thin grayish white, light gray and thin bands of creamy white limestone, splintery shales, fine grained sandstone (often calcareous and glauconitic), and abundantly siltstone characterize the Narpuh stage.
9. Lakadong+Therria: Consists of carbonaceous shale with light gray to dark gray splintery shale, bluish gray shale, fine to coarse grained saccharoidal to calcareous, glauconitic sandstone. Thin stringers of coal, white and brownish charts are mostly present in middle and lower part.
10. Langpar: Composed of mostly medium to coarse grained arkosic sandstone along with bluish shale streaks.
11. Basement: Medium to coarse grained granite containing quartz, pinkish feldspar and biotite.

The generalized stratigraphy of AAFB Basin in the Tripura-Cachar Belt is as follows (**Table 3-1**):

Table 3-1: GENERALIZED STRATIGRAPHY OF TRIPURA-CACHAR FOLD BELT AREA

AGE	GROUP	FORMATION/ MEMBER	GENERALISED LITHOLOGY
Recent to Pliestocene		Alluvium	Loose sands, silts and clays
		Dihing	Pebble beds, conglomerates and sandstones with thin beds of clay
UNCONFORMITY			
Pliocene	Dupitala	Upper	Coarse pebbly sandstone and mottled clays
		Lower	
UNCONFORMITY			
Mio-Pliocene	Tipam	Gobindpur	Variegated soft and sticky clays often silty with Sandstone
		Jaipur	Mainly Sandstone with clays and claystone
Miocene	Surma	Bokabil	Fine grained sandstone, siltstone with intervening layers of claystone.
		Upper Bhuban	Sandstone and sandy claystone and shale layers
		Middle Bhuban	Shale and occasional fine grained sandstone
		Lower Bhuban	Alternations of Sandstone and shale
UNCONFORMITY			
Oligocene to Late Eocene	Barail	Renji	Dominantly sandstone with thin shale layers
		Jenam	Shale and occasional sandstone
		Laisong	Alternations of thin sandstone and shale beds
Eocene	Disang	**Disang**	Dark grey shale with thin beds of sandstone

Petroleum System:

All the oil and gas fields, discovered till date in the Assam Shelf, are situated mostly on the southeastern slope of the Brahmaputra Arch, and almost all the major oil fields like Nahorkatiya, Lakwa, Lakhmani, Geleki, Dikom, Kathaloni etc. lie in a belt bordering the Naga Thrust. In the Dhansiri valley also, oil fields like the Borholla, Khoraghat and Nambar lie in the same belt. Along the Naga Schuppen belt, oil accumulations in the Laxmijan and the Champang Oil fields occur in that zone of the Assam Shelf which is overridden by the Naga Thrust. In the Digboi and Kharsang Oil fields, oil occurs in Tipam Sandstone and Girujan formations, respectively, overlying the Naga Thrust.

Source Rock and Hydrocarbon Generation

The important source rock sequences occur within the argillaceous Kopili Formation and in the Coal-Shale Unit of the Barail Group. The average TOC of shales in the Kopili Formation is about 2.5% and in the Barail Coal-Shale Unit is about 3.8% while within the Sylhet Formation is about 0.60%, The average TOC ranges of different formations (shale samples) are as follows (**Table 3-2**):

Table 3-2: AVERAGE TOC RANGES WITHIN THE SEDIMENTARY COLUMN IN THE A&AA BASIN

Formation / Group	Average TOC Range	Remarks
Barail (shales)	2.5% to 4.5%	Excellent source potential
Kopili (shales)	1% to 3%	Excellent source potential
Sylhet Limestone	~ 0.61%	Poor source potential
Basal Sandstone	~ 0.62%	Poor source potential

Organic matter richness of shales increases towards the Naga Thrust. In both Kopilis and Barails, the organic matter is terrestrial Type-III with varying contributions of Type-II. Barail Coal-Shale Unit in the Naga Schuppen belt also form an important source rock sequence. In the Naga Schuppen belt, in addition to above, Disang shales also possess excellent source rock characteristics with TOC around 4% and VRo varying from 0.69% to 1.94%.

Geochemical analysis of exposed sediments from the Naga Schuppen belt show a TOC range of 0.64-1.20% for Barail shales. The dominant organic matter type is structured terrestrial. Presence of amorphous (upto 60%) and extractable organic matter (upto 55%) indicates a fairly good liquid hydrocarbon generating potential. Organic matter is mainly humic and sapropelic. TAI of 2.6 to 2.75 and VRo of 0.57 to 0.67% show that the sediments are thermally mature and within the oil window. In the subthrust, the source sequences occur at greater depths and, therefore, should be in a higher state of thermal maturity. It is expected that the source sequences within the Kopili Formation and Barail Group in the subthrust would be at the peak oil generating state.

Reservoir Facies

Hydrocarbon in the Assam Shelf and the Naga Schuppen Belt occurs in sandstone reservoirs ranging in age from Upper Paleocene-Lower Eocene to Mio-Pliocene. Major accumulations occur in Upper Paleocene + Lower Eocene, Oligocene (Barail Group) and Miocene (Tipam Group) sandstones. Borholla and Champang oil fields of the Dhansiri valley and in the adjacent Schuppen Zone oil also occurs in fractured granitic Basement rocks (Precambrian) and Tura sandstones (Upper Paleocene/ Lower Eocene). In the eastern and northeastern part of the Basin, prolific hydrocarbon fields are present in the Paleocene - Lower Eocene sandstone reservoirs viz. Tengakhat, Dikom, Kathaloni, Baghjan. In the Kumchai and Kharsang Fields of Arunachal Pradesh, oil occurs in the Girujan Formation of Mio-Pliocene age and prolific gas accumulations have been discovered in sandstone reservoirs of Dirok structure within Girujan Formation. In the Khoraghat oil field of Dhansiri Valley, oil occurs in sandstone reservoirs within the Bokabil Formation (Miocene). In the Tripura-Cachar belt, the Surma Group of rocks consisting of Bhuban and Bokabil Formations of Miocene age, which are primarily sandstones, constitute the major reservoir rocks.

Seal and Entrapment

There are three well developed regional cap rocks within the Tertiary sedimentary succession; the lower one, occurring in the Upper Eocene is the argillaceous Kopili Formation, the middle one is the Barail Coal-Shale Unit and the upper one, overlying the Tipam Sandstone is the Girujan Clay. Most of the oil accumulations, discovered till date in the Upper Paleocene-Lower Eocene, Oligocene (Barail) and Miocene (Tipam Sandstone) reservoirs, occur in structural combination (fold + fault) traps developed by compressive forces during Mio-Pliocene and later times.

Most of these hydrocarbon traps, particularly those developed in post- Barail sediments, orient parallel to the Naga Thrust. Faults associated with these traps in the southeasterly sloping shelf zone in the Brahmaputra and Dhansiri valleys have NE-SW to NNE-SSW orientation. Most of the prominent faults continue upwards into post-Tipam sediments, and the rest die out in the lower part of the Tipam Group. A few of the prominent faults, particularly those near the Naga Thrust, are reverse faults. It may be mentioned that oil, generated in the Kopili and Barail source beds, accumulated in post-Barail sediments by vertical migration through such prominent faults. Oil within the Kopili Formation (composed predominantly of shales with subordinate sandstone) occurs in strati-structural combination traps, as in the Geleki Field. Oil within the Girujan Clay Formation as in the Kumchai and Kharsang Fields also occurs in combination traps, but here the control of lithology on accumulation is more than that of structure. In the Borholla Field of the Dhansiri valley and Champang Field of the neighbouring Schuppen Belt, oil accumulations occur in structurally controlled subtle trap in fractured Basement rocks. Oil accumulations within the Bokabil Formation (Middle Miocene) in the Khoraghat and Nambar Fields of the Dhansiri valley, occur in structural combination traps.

In the Tripura-Cachar belt, anticlinal folds primarily serve as the traps for hydrocarbon and these structures have been forming since Miocene. Shaly facies within Bokabil, Upper Bhuban, Middle Bhuban and Lower Bhuban of the Surma Group with regional extent have acted as seals to prevent upward migration and create favourable entrapment conditions. Abnormal pressure regime in the deeper Bhubans has also created a barrier for the upward migration of hydrocarbon.

Figure 3-4 GENERALIZED STRATIGRAPHY DEPICTING PETROLEUM SYSTEM ELEMENTS OF ASSAM SHELF BASIN

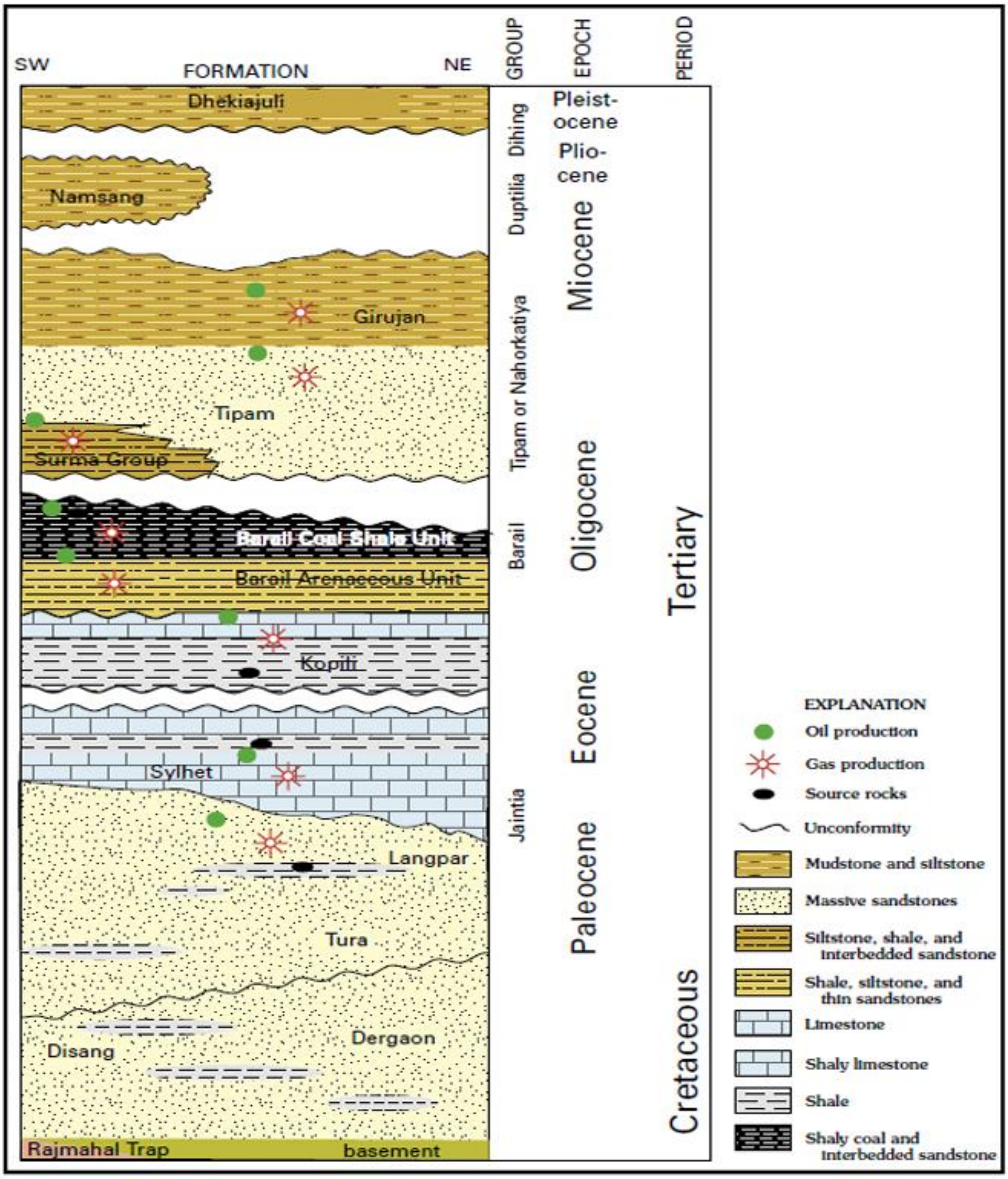
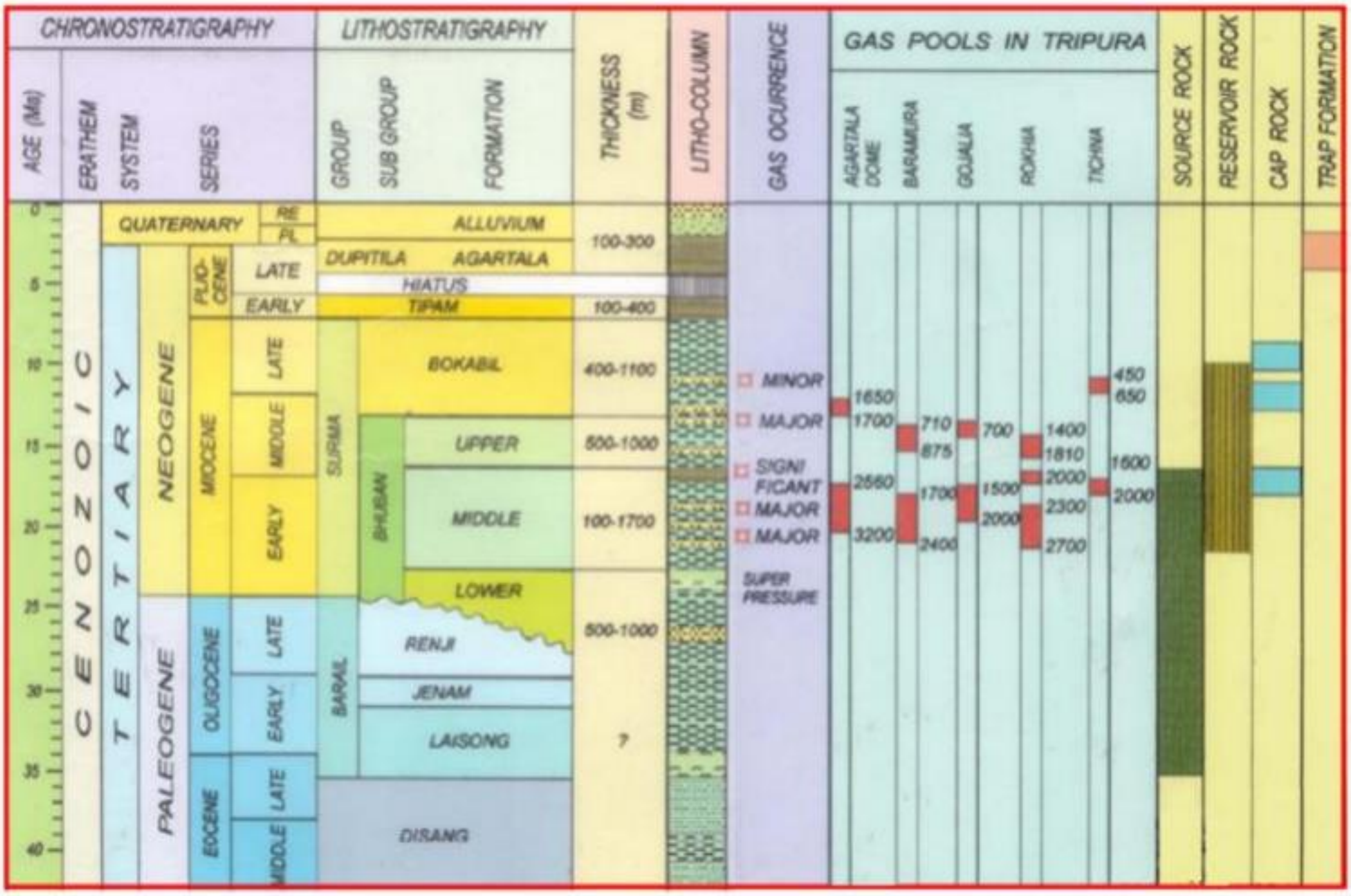


Figure 3-5 GENERALIZED STRATIGRAPHY DEPICTING PETROLEUM SYSTEM ELEMENTS OF THE AAFB BASIN



3.3 BASIN PROSPECTIVITY

The composite A&AA Basin is divided into two Category I Basins:

- The Assam Shelf Basin and
- The Assam-Arakan Fold Belt (AAFB) Basin.

The Assam Shelf Basin is spread over the state(s) of Arunachal Pradesh, Assam, Meghalaya, Nagaland and has a total hydrocarbon in-place of 2,705 MMTOE, out of which around 1,827 MMTOE has only been discovered, and this includes both commercial and sub-commercial in-place volume. The remaining 874 MMTOE, nearly 32% of total in-place is potential to be explored and discovered.

The Assam-Arakan Fold Belt (AAFB) basin has a total hydrocarbon in-place of 1,178 MMTOE, out of which around 178 MMTOE has been discovered, and it includes both commercial and sub-commercial in-place volume. The remaining 1,000 MMTOE, nearly 85% of total in-place is potential to be explored and discovered. The Basin is spread into the state(s) of Arunachal Pradesh, Assam, Manipur, Mizoram, Nagaland, Tripura.

The play-level undiscovered (risked) hydrocarbon in-place for Assam Shelf and Assam Arakan Fold Belt (AAFB) Basins is given in the Table below (**Table 3-3**):

Table 3-3: PLAY-LEVEL UNDISCOVERED (RISKED) HYDROCARBON IN-PLACE FOR ASSAM SHELF AND ASSAM ARAKAN FOLD BELT (AAFB) BASINS

PLAY	ASSAM SHELF	ASSAM ARAKAN FOLD BELT
	UNDISCOVERED (RISKED) HYDROCARBON IN-PLACE	
Cenozoic Pliocene (Girujan):	1 MMTOE	
Cenozoic Pliocene (Tipam):		124 MMTOE
Cenozoic Miocene (Tipam):	215 MMTOE	
Cenozoic Miocene (Bokabil):		191 MMTOE
Cenozoic Miocene (Upper Bhuban)		187 MMTOE
Cenozoic Miocene (Middle Bhuban)		292 MMTOE
Cenozoic Miocene (Lower Bhuban)		117 MMTOE
Cenozoic Oligocene (Barail Coal Shale):	192 MMTOE	
Cenozoic Oligocene (Barail Main Sands)	242 MMTOE	
Cenozoic Oligocene (Renji):		78 MMTOE
Cenozoic Eocene (Disang)		11 MMTOE
Cenozoic Eocene (Kopili)	46 MMTOE	
Cenozoic Eocene (Sylhet):	67 MMTOE	
Cenozoic Early Paleocene (Tura)	102 MMTOE	
Archean Basement:	9 MMTOE	

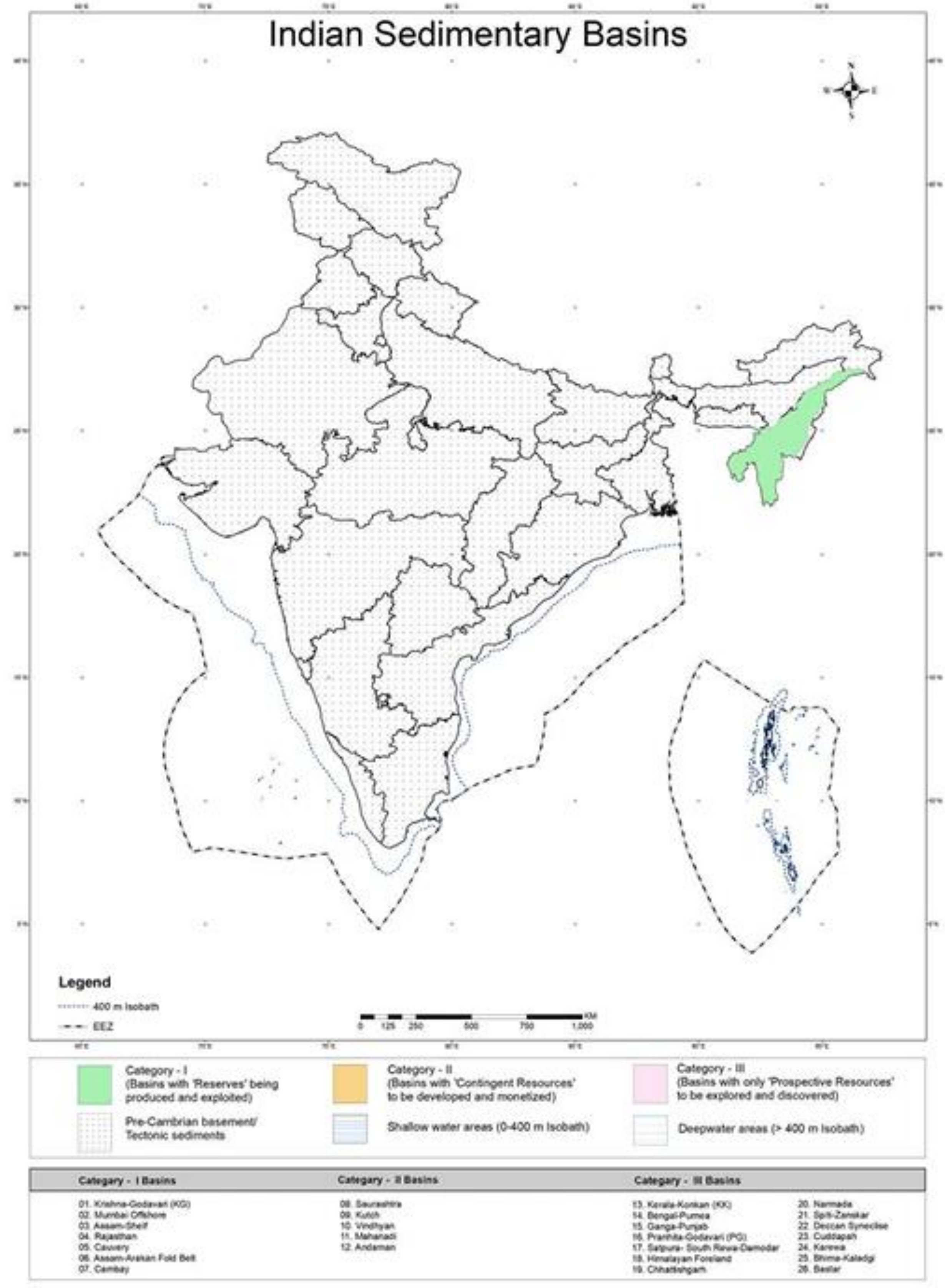
3.4 OPPORTUNITIES IN THE BASIN

The Assam Shelf and Assam Arakan Fold Belt (AAFB) Basins had been assessed earlier during a 1995-96 study under the aegis of the Directorate General of Hydrocarbons (DGH) along with 14 other sedimentary basins of India (**Figure 3-6**). In 2017, during a subsequent Hydrocarbon Resource Assessment Study, 3D PSM and Aerial Yield have been used based on the merit of adequate datasets. The 2017 resource reassessment study has incorporated 2,723 LKM of 2D seismic data, 10,995 SKM of 3D seismic data, 275 drilled well information from the Assam Shelf Basin and 15,000 LKM of 2D seismic data, 1,400 SKM of 3D seismic data, 317 drilled well information from the AAFB.

The Assam Shelf Basin is fairly explored with good seismic coverage. Geochemical, 2D/3D seismic, well data and reports are excellent while gravity data is good and magnetic data are fair. Reliability of results is excellent. 3D PSM and Trap Density method have been used to assess hydrocarbon resources due to good quality data existing throughout the basin. A major challenge is that mature source rocks lie below the thrust belt. Naga Thrust belt is the future focus for exploration. Shallow play near Naga-Schuppen belt are good targets for exploration

In the Assam Arakan Fold Belt basin gravity, well data and reports are good while magnetic, geochemical and 2D/3D seismic data are fair. Data availability is better in the Tripura-Cachar area while it is poor in rest of the basin. Reliability of results is good. 3D PSM and Trap Density method have been used in some parts to assess hydrocarbon resources due to fair data and conceptual information has been used in the rest of the basin. There is inadequate coverage of data in major part of the basin. The fact that structural traps primarily formed since Miocene, sequential restoration and migration of Thrusts is a focus area.

Figure 3-6 : REFERENCE SEDIMENTARY BASIN



4. DISCOVERY AND FIELD DESCRIPTION

The information docket is presented in a manner that each oil/gas discovery (i.e. the field) is described along with other wells, drilled and/or tested in the Contract Area. The available information of geo-scientific and engineering findings, studies and interpretations are sequentially showcased and in process, all subsurface and surface data from drilling, logging, testing and production data have been collated. Reservoir studies wherever available have been described with facts. Geological interpretations are suitably illustrated through correlations, sections and maps to bring in subsurface picture of the Contract Area. In the end, discovered hydrocarbon in-place and its recoverable contingent resources (wherever available) have been given with parameters and range of estimates.

For the sake of continuity in reading, domain contents like drilling, logging, testing, reservoir studies and geology, each field is described domain-wise into comprehensive illustration of all constituent wells and reservoirs in one go. For example, when a Contract Area has more than one discovery/field, each such discovery/field starts with a new page describing key information pertaining to drilling, logging, testing and other subsurface details.

Emphasis is given on factual presentation of data and available information on interpretations and results. Figures and pictures are extensively used for illustrations to establish a preliminary basis for field understanding and contents of data. As outlined under the disclaimer, all information contained in this report are made available by NOCs and Contractors through their specific submissions.

AA/ONDSF/ASSAM/2025 (A&AA) LAXMIJAN-BIHUBAR BLOCK

4.1 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) LAXMIJAN-BIHUBAR BLOCK

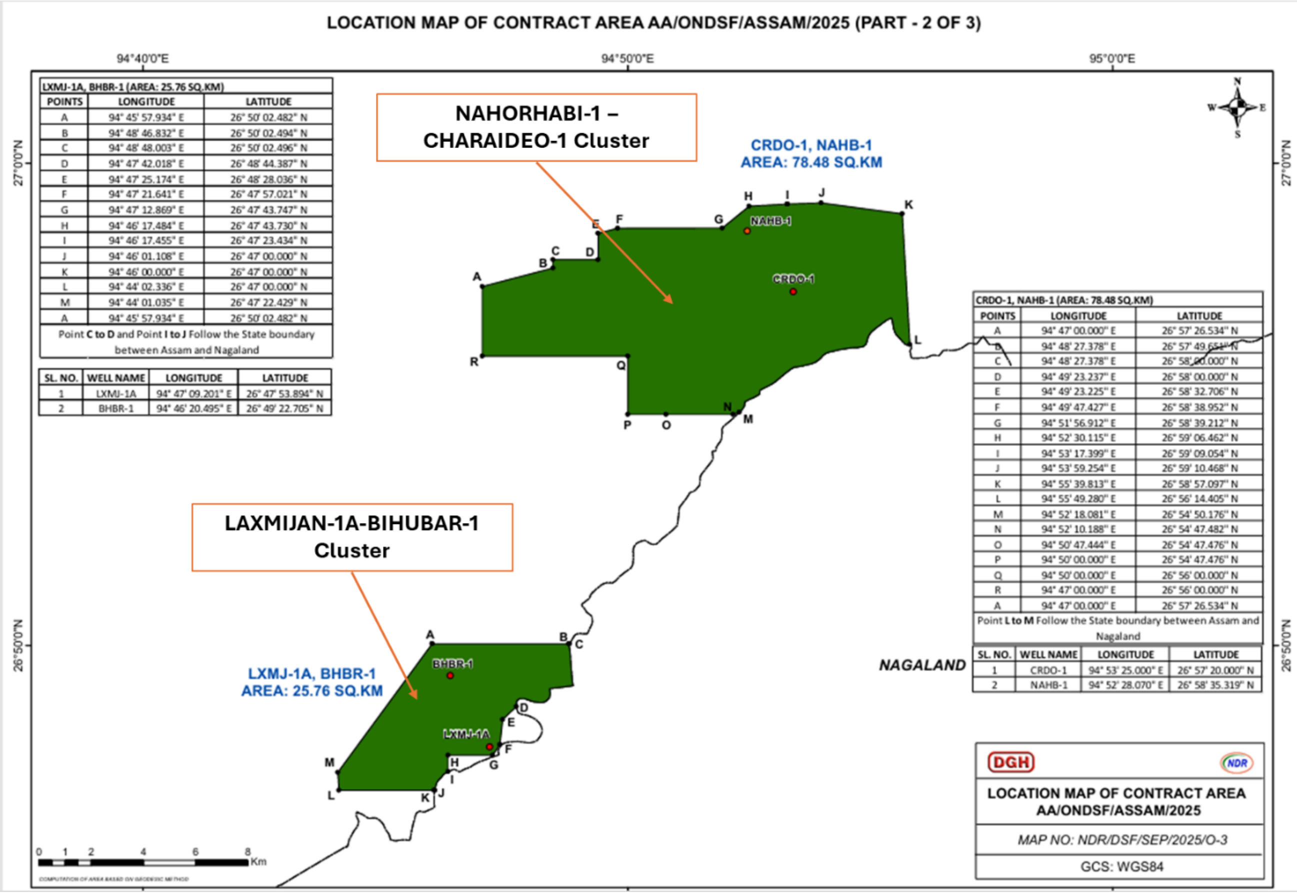
The Laxmijan-Bihubar block is located in the Assam Shelf area of the Category I composite Assam & Assam-Arakan Basin (A&AA Basin) at approximately 9-9.5 km E and ENE of the prolific onland Geleki Field within the state of Assam situated in the Assam Shelf area of the Assam & Assam Arakan Basin (A&AA Basin) in the northeast corner of India. The Bihubar Field is adjacent to the Laxmijan Field and lies to the north of it.

Laxmijan Field along with the neighbouring Bihubar Field together (**Figure 4-1**) covers an area of 25.76 sq. km under this DSF Bid Round IV. The co-ordinates of the endpoints defining the cluster boundary are tabulated below in **Table 4-1.** The area is a single area with 2 discoveries/fields (LXMJ-1A & BHBR-1) and 6 additional wells (including 1 S/T and 1 incomplete) have been drilled.

Table 4-1: COORDINATES OF THE BLOCK BOUNDARIES: LAXMIJAN-BIHUBAR CLUSTER

	Laxmijan-Bihubar Boundary Points		
	Area: 25.76 sq km		
	POINTS	**LONGITUDE**	**LATITUDE**
	A	94° 45′ 57.934″ E	26° 50′ 02.482″ N
	B	94° 48′ 46.832″ E	26° 50′ 02.494″ N
	C	94° 48′ 48.003″ E	26° 50′ 02.496″ N
	D	94° 47′ 42.018″ E	26° 48′ 44.387″ N
	E	94° 47′ 25.174″ E	26° 48′ 28.036″ N
	F	94° 47′ 21.641″ E	26° 47′ 57.021″ N
	G	94° 47′ 12.869″ E	26° 47′ 43.747″ N
	H	94° 46′ 17.484″ E	26° 47′ 43.730″ N
	I	94° 46′ 17.455″ E	26° 47′ 23.434″ N
	J	94° 46′ 01.108″ E	26° 47′ 00.000″ N
	K	94° 46′ 00.000″ E	26° 47′ 00.000″ N
	L	94° 44′ 02.336″ E	26° 47′ 00.000″ N
	M	94° 44′ 01.035″ E	26° 47′ 22.429″ N
	A	94° 45′ 57.934″ E	26° 50′ 02.482″ N
	Note: Point C → D and Point I→ J follows the state boundary between Assam & Nagaland		
SL. No.	**Well Name**	**Longitude**	**Latitude**
1	LXMJ-1A	94° 47' 09.201" E	26° 47' 53.894" N
2	BHBR-1	94° 46' 20.495" E	26° 49' 22.705" N

Figure 4-1: LOCATION MAP SHOWING THE LAXMIJAN-BIHUBAR BLOCK BOUNDARY.



A thin veneer of alluvium overlies sediments of the supra-Thrust Tipam Group and the area has an average elevation of around 120 m above MSL. The field is approachable by metalled road connected to National Highways NH 2 (erstwhile NH 37) and NH 702C. The nearest railway station is Simaluguri Junction and the nearest airport is Jorhat, about 70 kms from neighbouring Nazira Town.

The Laxmijan-Bihubar cluster Fields lie along the Naga Schuppen Zone of the Assam Shelf area in the Assam & Assam-Arakan Basin along which a number of prolific oil and gas fields are present (**Figure 4-2**).

The adjacent lying Laxmijan and Bihubar Fields have been covered by 2D seismic surveys of different vintages and part of 9 seismic lines amounting to 37.65 GLK cover both the areas. A 25.57 SKM of 3D seismic volume viz. GLKI_LAX_BIH_SAN_FMIG covering the area and was processed by merging multiple 3D datasets, is available for the area. A seismic grid map showing the 3D coverage and 2D lines across the Block is shown **Figure 4-3**

Figure 4-2: DISTRIBUTION OF THE OIL AND GAS FIELDS ALONG THE NAGA THRUST of ASSAM SHELF BASIN

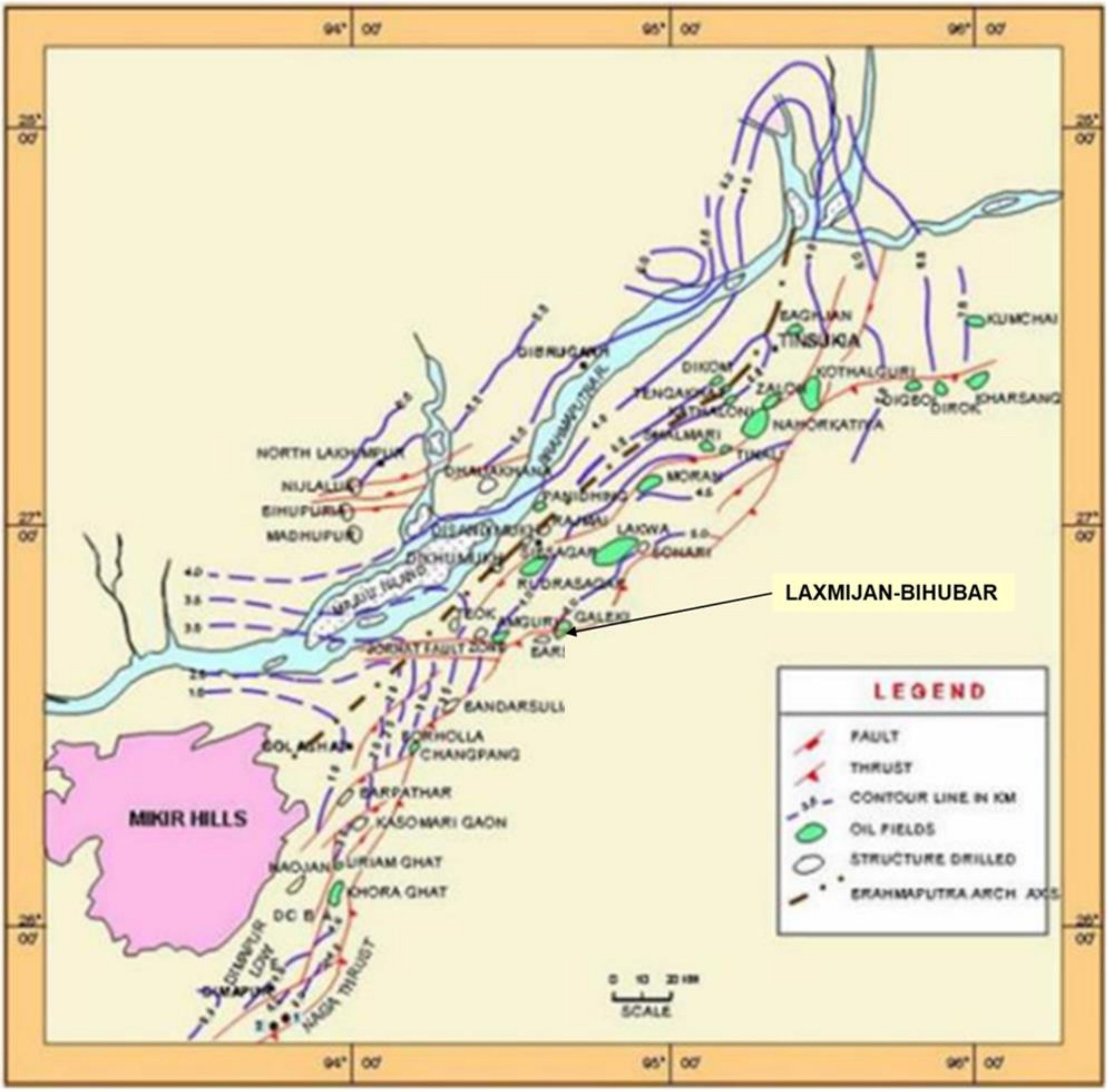
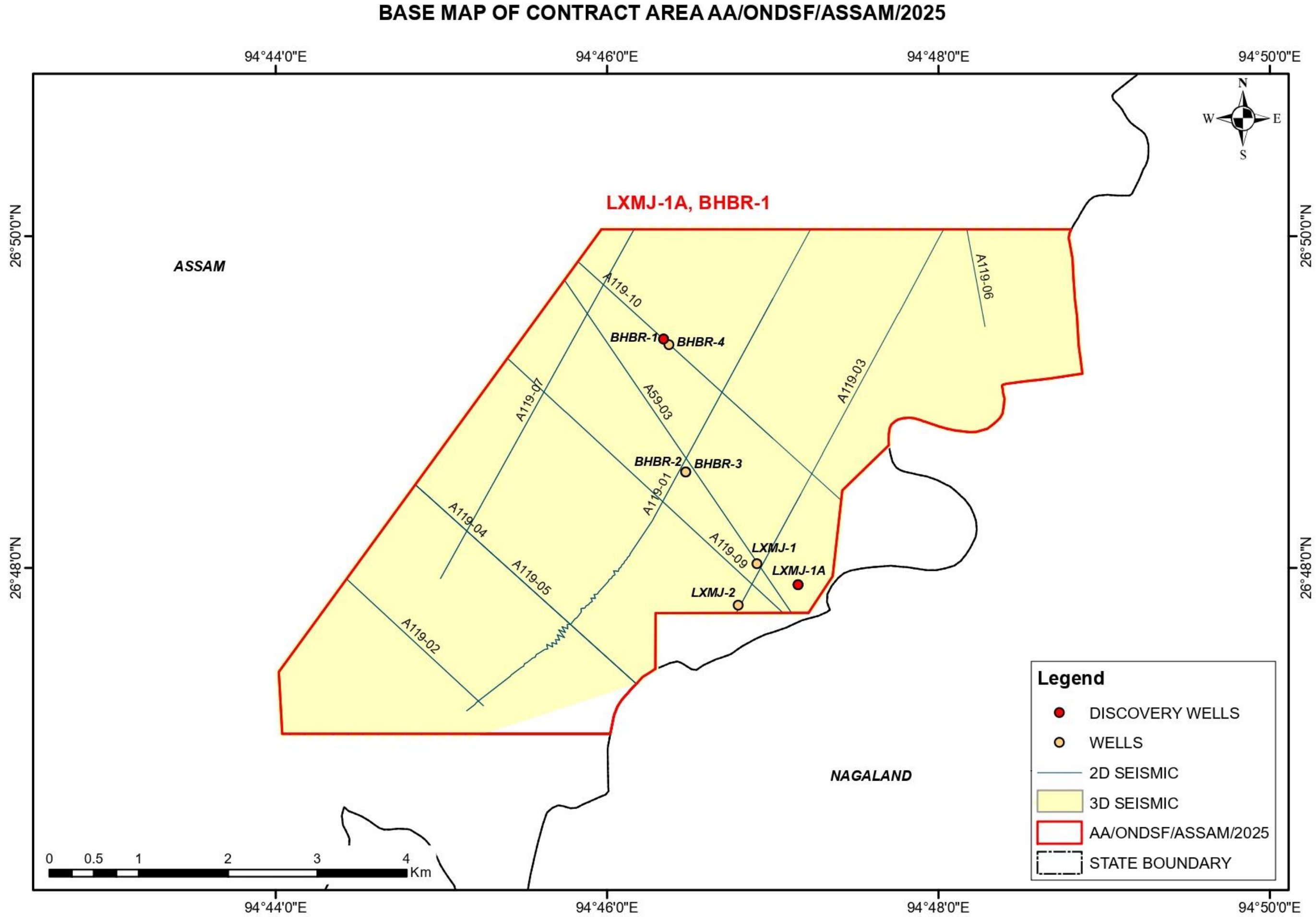


Figure 4-3: 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: LAXMIJAN-BIHUBAR



AA/ONDSF/ASSAM/2025 (A&AA) LAXMIJAN FIELD

4.2 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) LAXMIJAN FIELD

The Laxmijan Field was discovered by ONGC in 1985 with the drilling of well Laxmijan-1A (LXMJ-1A) which proved to be hydrocarbon bearing in the sub-Thrust Tipam Group of Miocene age. The well produced around 10 cum of oil from the TS-5A Sand during initial testing and produced around the same quantity of oil during a workover job in the year 2007. A total of 2 exploratory wells viz. Laxmijan-1A (LXMJ-1A) and Laxmijan-2 (LXMJ-2) were drilled and completed by ONGC in a drilling campaign between 1979 and 2000 in the Laxmijan Field of the Contract Area of which well LXMJ-1A was completed as a replacement well for the well Laxmijan-1 (LXMJ-1). The available details of the well Laxmijan-1 (LXMJ-1), which was an incomplete well with only the conductor stage being drilled, however are mentioned in the following paragraphs. Laxmijan Field has been recognized as a marginal field. The main pay are the TS-5A1, TS-5A2 and TS-5B sands of Miocene age.

4.2.1 Drilling and well completion

As stated earlier, two exploratory wells have been drilled in this field, viz., Laxmijan-1A and Laxmijan-2, along with a part well (Laxmijan-1) of which drilling had to be terminated at a shallow depth. Key information of the drilled wells has been collated and presented in the tables hereunder. The adjoining figures illustrate the Well Construction Diagram for key wells. Other well statics like kelly bush reference depth, drilled and logged depth including well coordinates are made available in Sections through various cross-references.

Well construction diagrams of wells, Laxmijan-1A and Laxmijan-2 are shown in **Figure 4-4**. General details of the drilled wells and their casing data are given in **Table 4-2 and Table 4-3** below:

Table 4-2: LAXMIJAN FIELD - GENERAL WELL DETAILS

Well	Laxmijan-1	Laxmijan-1A	Laxmijan-2
Area	Nazira, Assam		
Structure	Laxmijan		
Category	Exploratory	Exploratory	Exploratory
Co-ordinates	Lat: 26°47’40”	Lat:26°27’40”	Lat:26°47’44”
	Long: 94°46’30”	Long: 94°47’40”	Long: 94°47’00”
Rig	3DH	3DH-IV (Romanian type)	E-2000-IX & E-2000-VII
Target Depth	4500 m	4500 m	4850 m
Drilled Depth	1152.60 m	4479 m	4760 m
Objective	Tipam & Barail Sands	Tipam & Barail Sands	Barail Sands
Status	Abandoned due to unrecovered fish in hole (drillstring and BHA)	Discovery well. Could not be brought onto commercial production at that time due to poor cementation behind casing, nature of crude and lack of testing accessories in time. Well has been killed.	Abandoned as zones tested / interpreted to be water bearing with minor traces of oil.

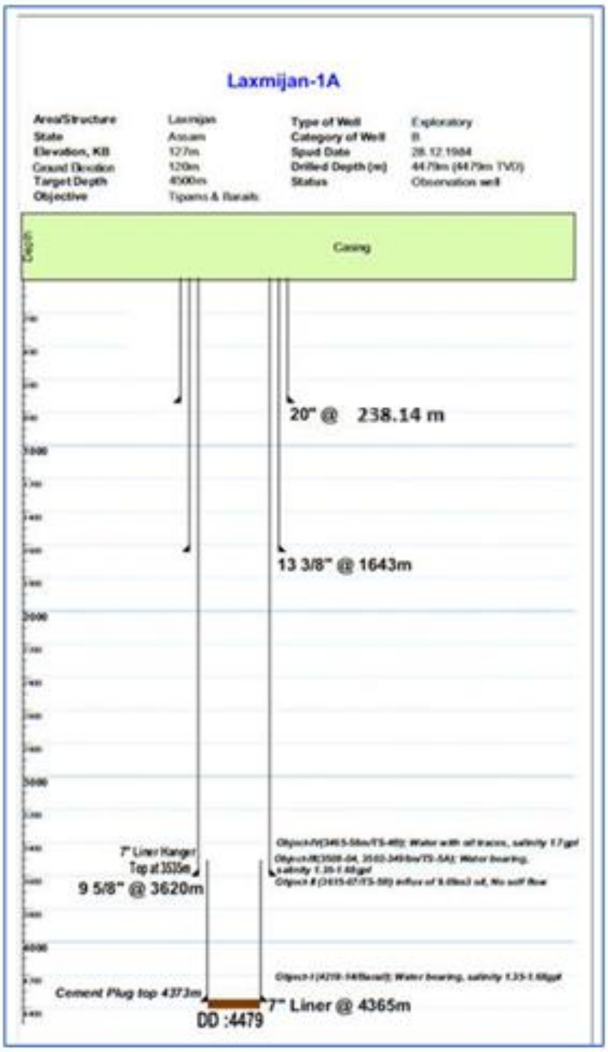
KB	126.70 m	127 m	128.0 m
Spud date	08-01-1979	20-12-1984	22-03-1997
Drilling Completion	16-03-1979	23-03-1986	11-10-2000
Production testing Completion	No production testing	25-08-1986	25-12-2000
Rig release	NA	25-08-1986	31-12-2000

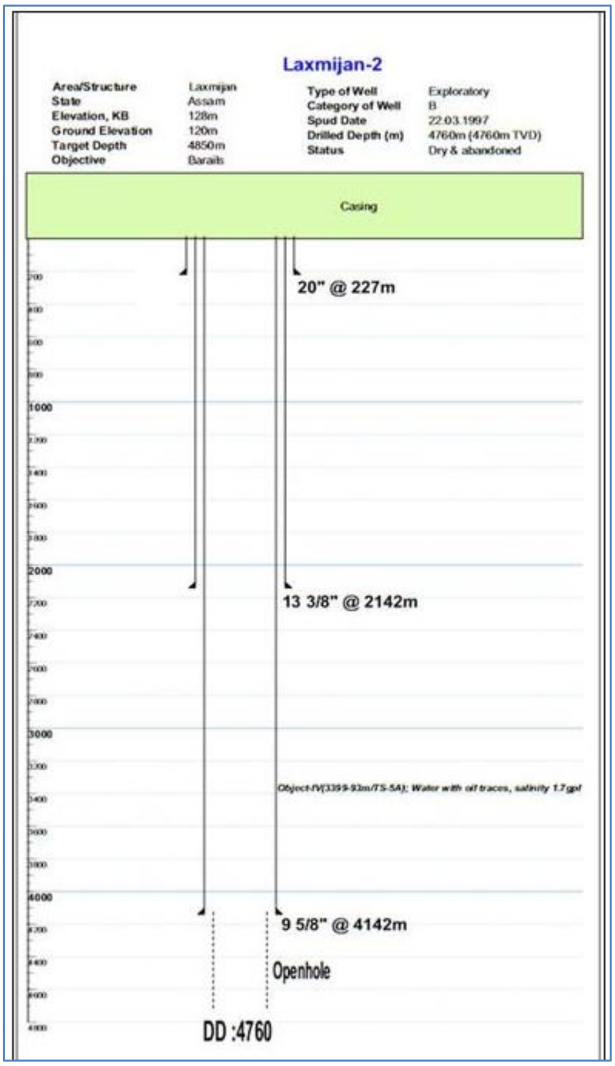
NA = Data not available

Table 4-3: LAXMIJAN FIELD - CASING DETAILS

Well	Hole Size	Casing Size	Cement Rise from Surface	Casing Shoe Depth (m)
Laxmijan-1	. 36 "	30"	Surface	21.16 m
	Other casings were not lowered due to repeated unsuccessful attempts at recovery of Fish (Drill string and BHA), following which the well was abandoned at a well depth of 1152.6 m			
Laxmijan-1A	36 "	30 "	NA	30 m
	26 "	20 "		238.4 m (short landed)
	18 ½ "	13 3/8 "		1643.4 m
	12 ¼ "	9 5/8 "		3620 m
	8 ½ "	7 "		4365 m
	6"	Casing not lowered		
Laxmijan-2	26 "	20 "	Surface	227
	17 ½ "	13 3/8 "	Not Logged	2142
	12 ¼ "	9 5/8 "	-	4142
	8.1/2"	Casing not lowered		

Figure 4-4: WELL CONSTRUCTION DIAGRAM OF WELLS LAXMIJAN-1A &2





4.2.2 Well logging and formation evaluation

The well logs of all discovery wells along with some key wells in the Contract Area have been reviewed. The logs recorded in various open-hole sections along with cased-hole logs and information of conventional and other wireline formation test data are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) have been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.2.2.1 Reports availability

The following reports are available for Laxmijan Field (**Table 4-4**).

Table 4-4: AVAILABILITY OF REPORTS

Well	KB	Spud Date	Drilled depth	WCR Available/ Not Available	FER Available/ Not Available
Laxmijan-1	126.7m	08-01-79	1152.60 m	Available	Not Available
Laxmijan-1A	127m	20.12.1984	4479 m	Available	Available
Laxmijan-2	128m	22.03.1987	4760 m	Available	Available

4.2.2.2 Well logs acquired (Laxmijan Field):

Log suites recorded in Laxmijan-wells are given in **Table 4-5 and Table 4-6.** Core data recorded in the wells are given in **Table 4-7**.

Table 4-5: LOG SUITES RECORDED

Well No.	Type of log	Interval (m)
Laxmijan-1	STANDARD Caliper-Induction	90-804
Laxmijan-1A	DIL-GR-SP	31-682.7, 650-724.5,
	Inclinometer	240-1070, 500-1379, 500-635
	DIL-GR-Inclinometer	650-1457
	DIL-SP-GR-Caliper-XY Inclinometer	500-1650
	LSS	240-1650
	DIL-BCS-CDL-CNS-GR-SP-CAL	1632.9-2704.7, 3623-4107.5
	DIL-BCS-GR-SP-CAL	2700 – 3652, 4000-4365
	MEL-GR	3390- 3640
	CAL	2700-3220
	DIPMETER	1000-2100, 2500-3080, 3470-3524, 3539-3651
	NGS-LSS	2700-3657
	CDL-CNS-GR-CAL	3422-3651, 3148-3216
	DIL-HDT	4090-4367, 3625-4365
	CBL-VDL-CCL-NEUTRON	3345-4360
Laxmijan-2	DLL-GR-SP	226-2147
	DLL-MSFL-CAL-GR-SP	2141 – 3597, 3590-4137
	BCS-GR	226-2140, 2141-3597, 3590-4144.8,
	SWC-GR	2197-3767
	DSLC(SDDB)-GR	4144-4757
	AIT-MCFL-GR-SP	4144 – 4646.5

	TLD-HGNS-GR	4144 - 4757
	CBL-VDL-CCL-GR	3098-3990

Table 4-6: WIRELINE LOGS ACQUIRED

Well	Hole Size	Details of Logs recorded
Laxmijan-1	18.1/2"	Standard logs, Induction and Caliper was recorded on 19/20.02.1979 at a well depth of 800 m
Laxmijan-1A	26"	DIL-GR-SP-CAL logs recorded on 12.02.1985 at well depth of 682.7 m
		DIL-GR logs recorded on 17.02.1985 at well depth of 724.7 m
	18.1/2"	Inclinometer Survey recorded on 08.03.1985 at a well depth of 1104.0 m
		Inclinometer Survey recorded on 18.03.1985 at a well depth of 1300.0 m
		DIL-GR and Inclinometer Survey recorded on 23.03.1985 at a well depth of 1457.0 m
		Inclinometer Survey recorded on 09.06.1985 at a well depth of 639.0 m
		DIL-SP-GR-CAL and Inclinometer survey recorded on 20/21.07.1985 at a well depth of 1650.0 m
		LSS-GR logs recorded on 21.07.1985 at well depth of 1650.0 m
	12. 1/4"	DIL-SP-CAL, BCS-GR and CDL-CNS logs recorded on 30/31.08.1985 at a well depth of 2801.5 m
		DIL-SP-CAL-BCS-GR, MEL-GR-CAL, Dipmeter and BCS-GR logs recorded on 10 to 14.10.1985 at a well depth of 3634.0 m
	8.1/2"	DIL-SP-BCS and CDL-CNS-GR logs recorded on 16.11.1985 at a well depth of 4100.0 m
		DIL-SP-CAL-BCS-GR logs recorded on 30/ 31.12.1985 at a well depth of 4362.0 m
		CNL-HDT logs recorded on 01.01.1986 at a well depth of 4362.0 m
		A cased hole CBL-VDL-CCL-Neutron-GR survey was recorded on 23.03.1986 for 7" Liner.
Laxmijan-2	17. 1/2"	17.5" | DLL-GR-SP and BHC-GR logs recorded on 20.05.1997 at a well depth of 2150 m
	12. 1/4"	DLL-MSFL-CAL-GR and BHC-GR logs were recorded on 18.07.1997 and 19.07.1997 respectively at a well depth of 3599 m
		DLL-MSFL-CAL-GR, BHC-GR logs and CST-GR (SWC) were recorded from 25.08.1997 to 26.08.1997 at a well depth of 4142 m
		MDT with Pretest in 30 points. A sample was collected at a well depth of 4152 m within the Barail BCS. 1/2 litre of muddy water was collected and the resistivity of the sample was found to be 0.626 ohm-rn, salinity of the sample was 4.5 gm/lit. Salinity of mud filtrate 14.62 grn/lit
	8.1/2"	AIT-MCFL-GR-SP and DSLC (SDDB)-GR logs recorded on 10.07.2000 at a well depth of 4650 m
		AIT-MCFL-GR-SP and TLD-HGNS-GR logs recorded from 13.10.2000 to 14.10.2000 at a well depth of 4760 m
	A cased hole CBL-VDL-CCL-GR log was recorded inside the 9.5/8" casing on 23.10.2000.	
	VSP survey carried out from 27.10.2000 to 31.10.2000	

Table 4-7: CONVENTIONAL CORES

Well no.	Core no.	Interval (m)	Recovery (%)	Gross Lithology
Lakshmijan-1	CC-1	777.57-783.57 m	32 %	Sandstone

Laxmijan-1A	CC-1	3464-3472 m	75 %	Mostly Sandstone

VSP DATA

Zero offset VSP was carried out from 27.10.2000 to 31.10.2000 in the well Laxmijan-2. Recording detail are given below in **Table 4-8.**

Table 4-8: VSP RECORDED IN WELL LAXMIJAN-2

Type of VSP	Offset distance in	Depth logged interval	Receiver Interval	No. of levels
ZVSP	70 m	4000-400	25	145

4.2.2.3 Well log evaluation and initial test results (LAXMIJAN FIELD):

A petrophysical study carried out on the well LXMJ-1A located within the Laxmijan Field indicate the Barail sands both in the supra-Thrust and sub-Thrust sections to have high water saturation (80-100%) with average porosity to be around 10%.(**Figure 4-5**) The Tipam sands, except for the TS-5 sand, mostly on an average show high water saturation (80-100%) but with better porosity in the average range of 15-20%. The TS-5 Tipam sand in the range 3485 – 3525 m show water saturation of 40-60% with porosity of 13 – 16% but gradually the saturation increases downwards to 75-100% with porosity being largely consistent.

Petrophysical study carried out in well LXMJ-2 indicated the supra-Thrust and sub-Thrust Barails to be water bearing. TS-1, TS-2, TS-3, TS-5, TS-6 and Safrai sands also have been interpreted to be water bearing. In the Girujans a few sand intervals were seen to be interesting from a hydrocarbon point of view. MDT survey conducted at 4228.5 – 4232.0 m of the well indicated the mobility in the range to be low (0.1 – 1.6 md/cp) and gradient plot showed more than 1.0 gm/cc indicating the presence of water. In the range 4300 – 4303 m, low mobility (0.1 to 0.2 md/cp) was also observed. The gradient plot indicated the presence of water.

The main pay of the Laxmijan structure is the, TS-5A1, TS-5A2 and TS-5B of Miocene age. Testing of the TS-5A zone in the ranges 3504-3508 m & 3498-3502 m with additional perforations in the ranges 3514-3520 m & 3492-3498 m produced around 10 cum of oil during initial testing in well LXMJ-1A in 1986 and produced almost the same quantity of oil during a workover job in 2007.

Figure 4-5: PETROPHYSICAL RESULTS OF PROSPECTIVE ZONES IDENTIFIED IN LAXMIJAN WELLS

Well	Object	Sand	Porosity %	Sw %
Laxmijan-1A	Obj-I	BCS	6-11	80-100
	Obj-II	TS-5	13	48-70
	Obj-III	TS-5	15	50-60
Laxmijan-2	Obj-I	TS-5	12	NR

Log motifs for tested Objects of Laxmijan-1A and Laxmijan-2 are shown in **Figure 4-6, Figure 4-7, Figure 4-8, Figure 4-9, Figure 4-10 and Figure 4-11.**

Figure 4-6: LOG MOTIF OF OBJECT-I (BCS) IN WELL LAXMIJAN-1A

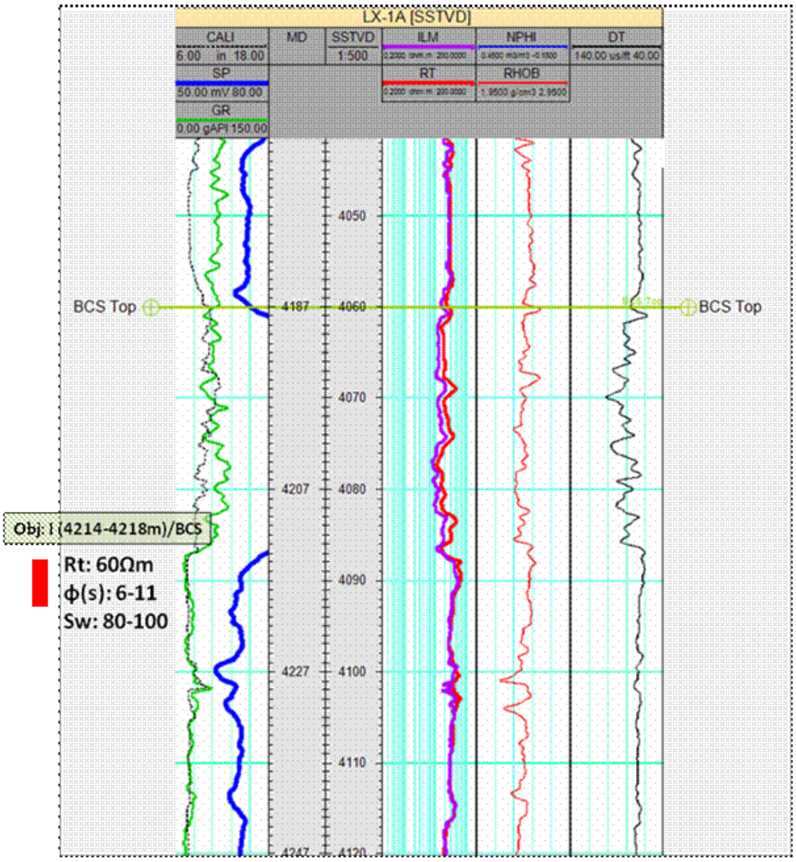


Figure 4-7: LOG MOTIF OF OBJECT-II (TS-5B) IN WELL LAXMIJAN-1A

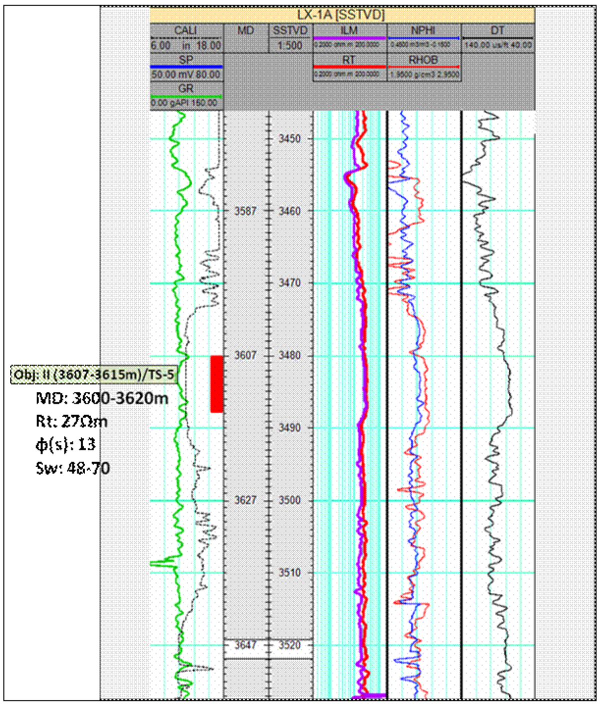


Figure 4-8: LOG MOTIF OF OBJECT-III (TS-5A) IN WELL LAXMIJAN-1A

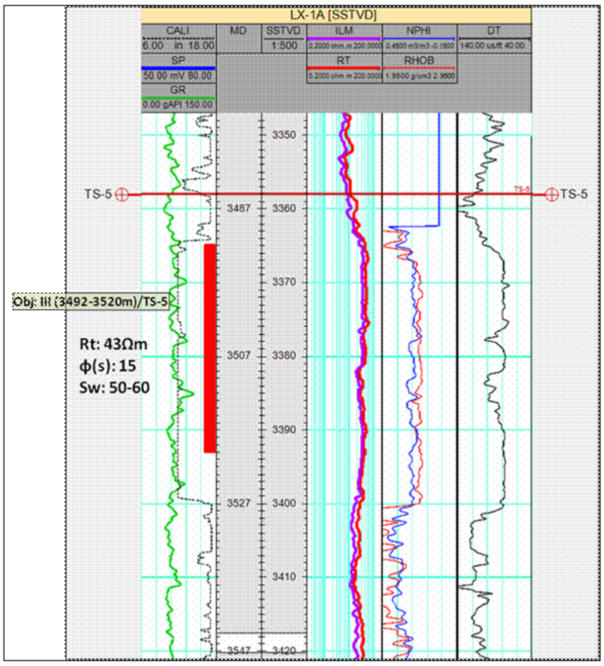


Figure 4-9: LOG MOTIF OF OBJECT-IV (TS-4B) IN WELL LAXMIJAN-1A

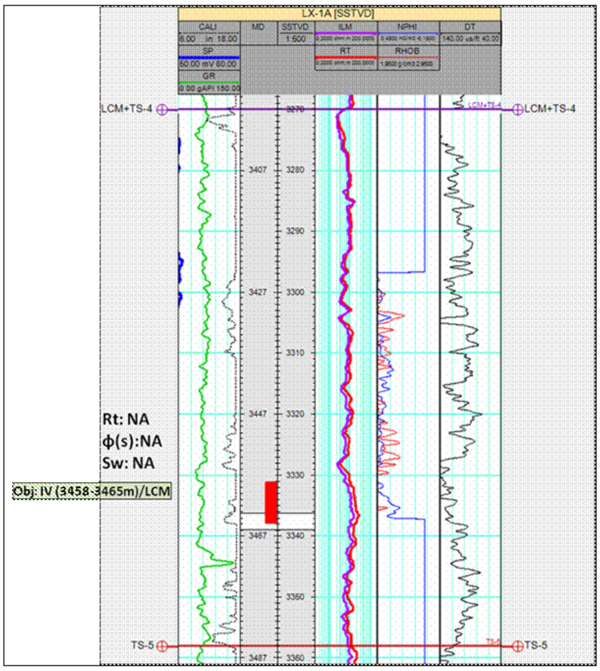


Figure 4-10: LOG MOTIF OF OBJECT-II, III & IV IN WELL LAXMIJAN-1A

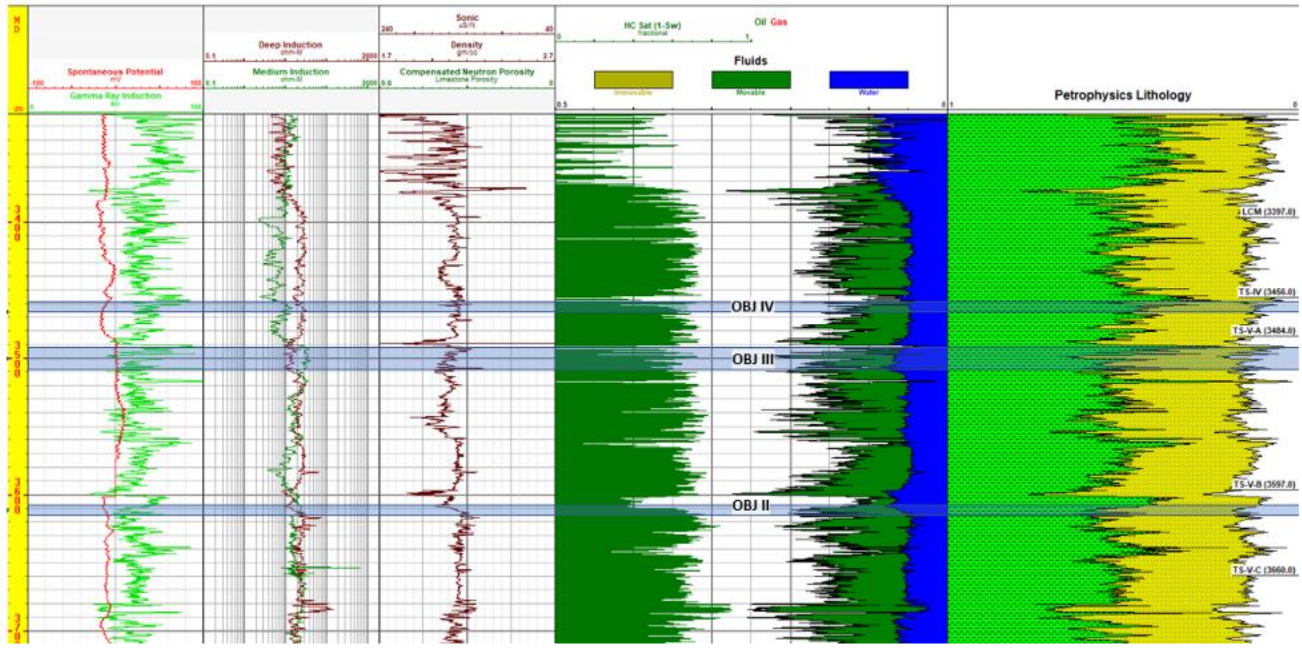
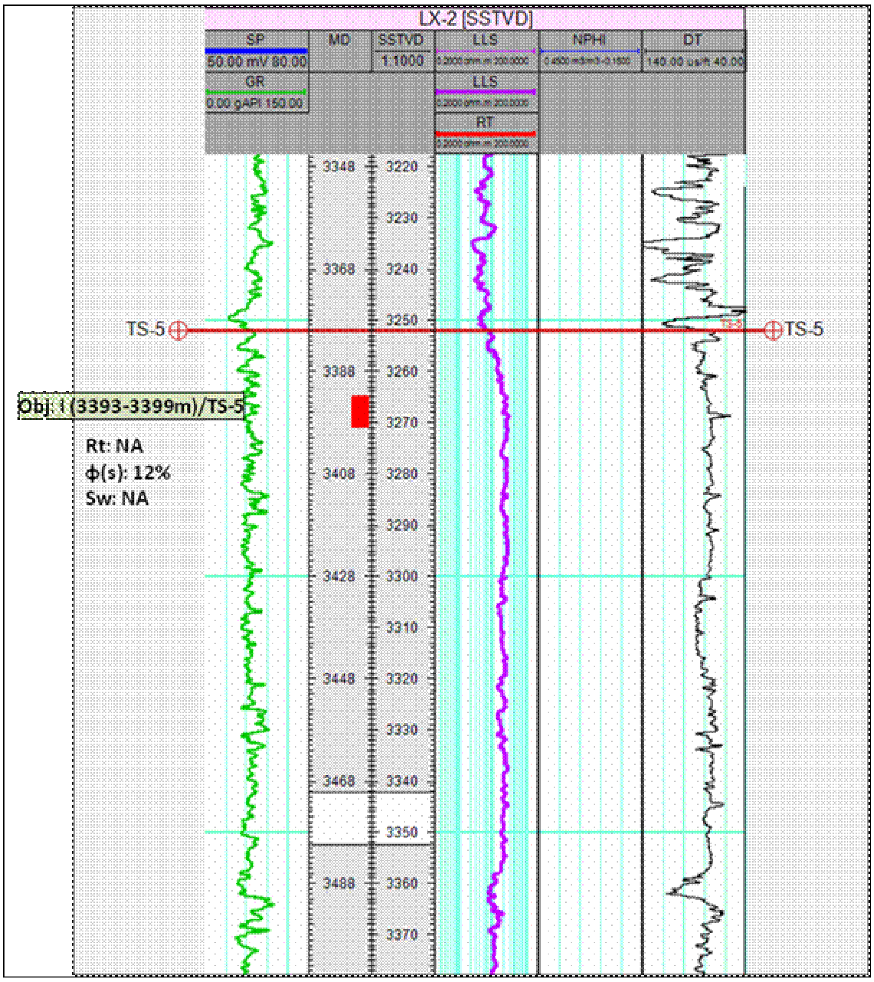


Figure 4-11: LOG MOTIF OF OBJECT-I (TS-5) IN WELL LAXMIJAN-2



4.2.3 Well testing and workover history

After the termination of drilling in well LXMJ-1 due to downhole complications, the replacement well LXMJ-1A was extensively tested.

Production testing has been carried out in wells LXMJ-1A and LXMJ-2. In well LXMJ-1A four zones have been tested, one zone in the Barail Group and three in Tipam sands of Miocene age whereas only one zone has been tested in well LXMJ-2. Detailed testing results are given in **Table 4-9.**

Table 4-9: DETAILED TESTING RESULTS OF LAXMIJAN WELLS

Well	Object	Sand	Perforation	Test Type	Flow Test Results	Status
Laxmijan-1	While drilling, drill-cuttings showed continuous golden yellow patchy fluorescence between 635 to 835 m. OH DST was carried out for the interval 793 – 797.7 m (supra-Thrust Tipam) and during which there was influx of 10 cum of water. The test was inconclusive as the chart appeared to show choking. Drilling continued but the well had to be abandoned due to unrecovered fish in hole. The well was abandoned at a depth of 1153.6 m.					
Laxmijan-1A	Obj-I	BMS	4214 – 4218 m using HSC charges @ 12 SPM	CHDST Packer set at 4174 m	No self-flow. Influx 9.27 cum of water with traces of hydrocarbon Salinity 1.35-1.68 gm/l. Final shut-in pressure = 392 ksc. ksc Plugged Back (CP).	Water bearing
	Obj-II	TS-5B	3607-3615 m using HSC charges @12 SPM	CHDST Packer set at 3535 m	No self-flow. Influx 9.16 cum of water. Salinity 1.07-1.35 gm/l. Final shut-in pressure = 361.6 ksc. Plugged Back (CP).	Water bearing
	Obj-III	TS-5A	3504-3508 m & 3498-3502 m using HSC charges @12 SPM Additional perforation 3514-3520 m &3492-3498 m using HSC charges @12 SPM (after cement job)	Conventional Testing	**No self-flow. Influx of 45m3 (10.0 cum crude oil of API gravity 31 deg** during subduing the well with mud of sp.gr 1.17 before cement repair job). Subsequently a gradient survey indicated oil upto 1060 m. Then a cement repair job was decided to be carried out. While subduing the well with mud of sp.gr 1.17 for the job, oil surfaced (10 cum crude oil of API gravity 31 degree) followed by water (salinity 2 gm/ l) After cement repair job and perforations 48 cum of influx was reported. Collected sample of oil / emulsion consisted of associated water (sal 1.92 gm/l) and oil of API gravity 28.6. While subduing the well for testing the next horizon, oil surfaced again.	Oil (Tested) Flow did not sustain possibly due to poor cementation behind casing that could not be repaired even after cement repair job. Well was subdued by placing a saline cushion of 300 m
	In 2007, Assam Company Limited carried out a Workover Operation wherein the TS-5 Sand was retested after a cement squeeze job. The test re-established the presence of oil and gas in the Sand with dominating quantity of water (~70%).					
	Obj-IV	TS-4B	3458-3465 m using PA-85	CHDST	No self-flow. Influx: 3.5 m^3 water (Sal 1.9-4.32 gm/l). However during	Water bearing

			charges @21 SPM		P/O influx of water with traces of oil was observed. Well was killed by placing a saline cushion of 300 m	
Laxmijan-2	Obj-I	TS-5A	3393-3399 m using 7" gun @ 18 SPM	CHDST	Conventionally tested in water. Poor influx. LL found at 700 m, salinity 1.17 gm/l (Technical water 0.39 gm/l) with **traces of oil** observed in sample. During the gradient survey the average gradient was 1.02 and formation pressure was recorded to be 271 ksc. The well was subdued with 1.15 sp. Gr. of mud	Water bearing with traces of oil

4.2.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study and PVT data/results.

Formation dynamic tests (LAXMIJAN FIELD)

MDT pressure tests recorded in LAXMIJAN wells are given in **Table 4-10 below.**

Table 4-10: AVAILABLE MDT PRESSURE DATA FROM WELL LAXMIJAN-2

Sl. No.	Horizon	Depth (m)	Hydrostatic Pressure (Psi)	Formation Pressure (Psi)	Test type
1	BCS	4151.48	8448.86	6066.42	Normal test
2	BCS	4152.00	8437.22	6066.78	Normal test
3	BCS	4152.01	8401.71	6067.02	Normal test
4	BCS	4153.00	8429.10 '	6067.69	Normal test
5	BCS	4154.00	8401.08	6068.82	Normal test
.6	BCS	4154.99	8400.37	351.67	Dry Test
7	BCS	4171.49	8428.34	15097.28	Normal test
8	BCS	4169.98	8420.40	15092.80	Normal test
9	BCS	4172.50	8422.20	6096.34	Norma! test
10	BCS	4173.98	8422.20	6091.39	Normal test
11	BCS ___	4175.01	8422.11	6092.82	Normal lest
12	BCS	4180.98	8431..86	6101.42	Normal test
13	BCS	4181.99	8430,37	6102.87	Normal test
14	BCS	4182.99	8426.11	6104.78	Normal test
15	BCS	4185.48	8429.35	6107.22	Normal test
16	BCS	4186.00	8426.36	6107.98	Normal test
17	BCS	4187.50	8427.10	6110.05	Normal test
18	BCS	4228.50	8516.08	6269.58	Normal test
19	BCS	4228.99	8510.05	6235.94	Normal test
20	BCS	4229.50	8508.17	3709.93	Dry Test
21	BCS	4230.50	8507.52	6219.77	Normal test
22	BCS	4231.00	8504.87	2845.57	Dry Test

No Pressure Transient and reservoir studies have been carried out in the field

PVT DATA INCLUDING CRUDE OIL AND GAS ANALYSIS

Analysis of oil/gas has not been carried out in Laxmijan Field. However, oil composition is available from the neighbouring Bihubar wells and is given in Table 4-11

Table 4-11: OIL COMPOSITION & RESERVOIR DATA FROM BIHUBAR WELLS.

Oil Composition & Reservoir data from Bihubar Wells

Reservoir Data

Reservoir Pr kg/cm^2	-	428
Oil saturation	-	50%
Formation vol. factor	-	1.8
Av. Porosity	-	11%
GOR m^3/t	-	280
API Gravity of oil	-	32.1
Density of Oil at 15°C gm/cc	-	0.8649
Pour Point °C	-	33

Oil Compositional characteristics

Bihubar # 2

	Int. 4300 – 4310 m (BCS)	3968 – 3970 m (BCS)
API Gr.	31.10	36.15
Pour Point	33°	27°
Water Content (v/v)	2.60	Traces
Salt Content mgm/l	13.16	10.00
Asphaltene % w/w	1.62	-
Resin % w/w	10.44	-
Wax % w/w	8.17	8.13
Initial BP °C	62	53

Distillation

1 BP to 150 °C % w/w	18.54	20.00
150 to 250 °C % w/w	19.20	19.00
250 to 300 °C % w/w	13.41	11.00

PRODUCTION HISTORY

Subsequent to the testing phases there has been no production from the wells

WORK-OVER HISTORY

Based on a study carried out by Assam Company Limited (ACL), a Workover Operation was carried out wherein the **TS-5 Sand in well Laxmijan-1A** was retested after a cement squeeze job during 2007. The test re-established the presence of oil and gas in the Sand with dominating quantity of water (~70%)

4.2.5 Geology and Reservoir Description of Laxmijan Field:

The geology of the area has been reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure and seismic attribute maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.2.5.1 Geological correlations, sections and maps (Laxmijan Field):

The Laxmijan-Bihubar area is situated to the south of River Brahmaputra and falls along the Naga Thrust area which is part of the Naga Schuppen Belt and flanks the Assam Shelf to the northwest. Geologically, Assam Shelf is defined as the Alluvium covered extension of the Shillong and Mikir Massifs to the ENE, and is a narrow belt of about 100 km width, bounded by two thrust belts to the north and the southeast viz. Eatern Himalayas and the Naga Schuppen Belt, respectively. This elongated shelf extends into the sub-thrust block of Naga Schuppen Belt in SE while the Naga Schuppen Belt is also a narrow linear belt of imbricate eight to nine major thrust slices along which Paleogenes of Indo-Myanmar mobile belt has moved north-westwards relative to buried Basement of the Assam Shelf.

The Namdang High is an anticlinal fold exposing topmost part of Barail in its core and plunging towards Laxmijan. It is an asymmetrical fold with a gentle southeastern limb and steep northwestern limb. Laxmijan-Bihubar Fields lie on the southeastern limb of the anticline and reservoir lithology are the sands within Tipam and Barail Groups trapped in this structural setting. The seismic data of the Laxmijan-Bihubar areas and correlation of drilled wells show the presence of the structural high which has been named Laxmijan-Bihubar High. This sub-thrusted Laxmijan-Bihubar High is separated from the Geleki High towards the west- northwest by a Low. A prominent arcuate transverse fault hading southwards separates Laxmijan area from the Bihubar area. The areas are further dissected by a number of faults trending NE-SW resulting in a number of discrete blocks and culminations. Geleki Oil field to the west-northwest is updip to the Bihubar and Laxmijan structures for Barail zones. Most of the in-place oil volumes in the area are confined within multi-cycle sandstone reservoirs belonging to the sandstones of Tipam Group and the Barail Group of sediments.

The Chalimsen and Naga thrusts are two major faults which pass through the well Laxmijan-1A at 955 m and 2043m respectively. The Chalimsen thrust brings the Barails over Namsang whereas the Naga thrust brings Tipam Sandstone (TS2) over the Girujans. In the well, the sequence below the Naga Thrust, starting from Girujan Clay is a normal succession (**Table: 4.12**). In general, the stratigraphy of the sequence at Laxmijan is about 250 m downdip as compared to the Bihubar structure which itself is a subthrust succession and in turn is about 300m lower to the Geleki structure. The well Laxmijan-2 is updip to well Laxmijan-1A at all stratigraphic levels and is also traversed by the two faults in the subsurface.

The primary prospective sands of the Laxmijan Field lie within the Tipam Group of Miocene age. The sands of the Tipam Group were deposited under fluvial depositional environment with high energy conditions as braided channels during Late Miocene to Early Pliocene. The Tipam sediments overlie the distributary channels which were formed by switching channels in associated environment. of sediments deposited within Rudrasagar Formation (Barail Coal Shale Unit) of the Barail Group of Oligocene age. After the deposition of Rudrasagar Formation there had been a prominent eustatic fall due to which the younger units of Rudrasagar Formation have been eroded to form an unconformity surface. After the close of Tipam times, positive movements resulted in the emergence of land form sand. Subsequent erosions are reflected in the unconformable relations between the Tipams and overlying sediments consisting of arenaceous unit with sub equal proportion of claystone, clay and silt of Moran Group during Pliocene-Pleistocene. The Recent Alluvium constitutes the youngest stratigraphic unit in the Basin.

Geological sections, depth contour maps on reservoir top and seismic sections/ slices of the Laxmijan Field are shown in **Figure 4-12, Figure 4-13, Figure 4-14, Figure 4-15, Figure 4-16, Figure 4-17, Figure 4-18, Figure 4-19, Figure 4-20, Figure 4-21, Figure 4-22** **and** **Figure 4-23. Figure 4-26**

Figure 4-24 **and Figure 4-25** show the results of enhancement of reflectors using AGC 800 ms window and depth to seismic tie of the well Laxmijan-2**.**

Figure 4-12: SCHEMATIC SECTION BETWEEN BIHUBAR AND LAXMIJAN WELLS

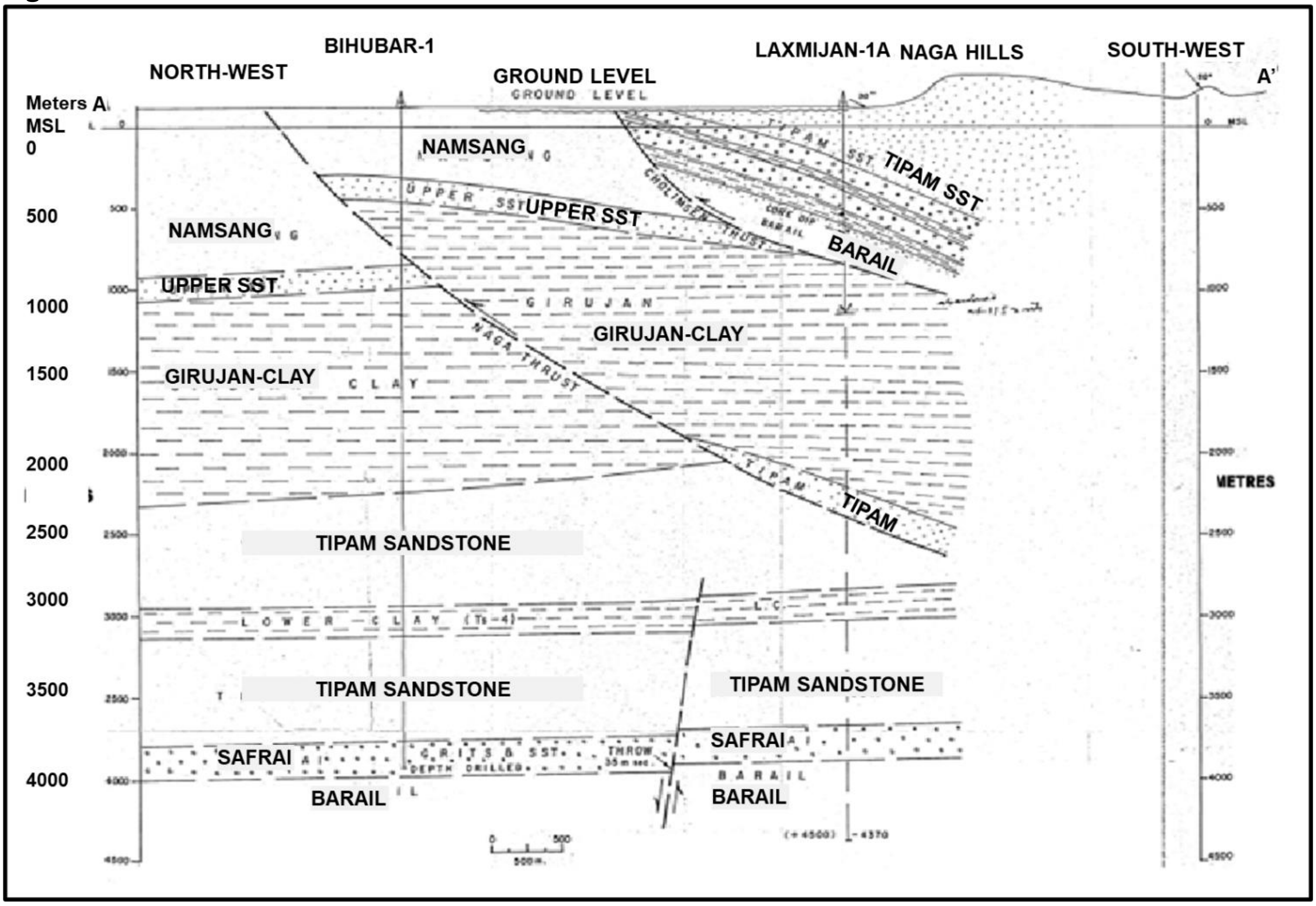


Table 4-12: STRATIGRAPHIC COLUMN ENCOUNTERED IN WELLS LAXMIJAN -1A AND LAXMIJAN-2

Formation/ Group	Sand	Well Laxmijan-1A		Well Laxmijan-2		Lithological Description
		MD (m)	BD (m)	MD (m)	BD (m)	
Alluvium		0 - 507	380			
Tipam				-409	-281	Mainly coarse unconsolidated sand stone with chert, free quartz Fe-Mg minerals White to grey shale, gritty sandstone, med gr, with abundant dark minerals with minor coal and claystone
	Safrai	507 - 634	380-507	409-534	281-406	
UNCONFORMITY						
Barail		634-955	507-828	534-819	406-691	Sandstone: Dark brown carbonaceous- shale occasionally clay stone and coal
CHOLIMSEN THRUST						
Namsang		955-980	828-853	819-921	691-793	Sandstone: Variegated with free quartz.
Upper Sandstone		980-1204	853-1077	921-1154	793-1026	Sandstone with clay and minor coal
Girujan Clay		1204-1913	1077-1786	1154-1870	1026-1742	Mostly variegated claystone with siltstone/ sandstone
Tipam	TS1 TS2	1913-1988 2017-2043	1786-1861 1890-1916	1870-1997	1742-1869	Sandstone with minor claystone
NAGA THRUST.						
Girujan Clay		2043-2666	1916-2539	1997-2610	1869-2482	Monotonous variegated clay/ claystone with sandstone, silt intercalations
Tipam	TS1	2666-2786	2539-2659	2610-2724	2482-2596	Sandstone with frequent intercalation of claystone.
	TS2	2786-3037	2659-2910	2724-2968	2596-2840	
	TS3	3050-3397	2910-3270	2968-3298	2840-3170	
	LCM TS4	3397-3484	3270-3357	3298-3383	3170-3255	
	TS5A	3484-3582	3357-3455	3383-3486	3255-3358	
	TS5B	3582-3702	3455-3575	3486-3598	3358-3470	
	TS5C	3702-3784	3585=3657	3598-3687	3470-3559	
	TS6	3784-4100	3657-3973	3687-4006	3559-3878	
	Safrai	4100-4187	3873-4060	4006-4112	3878-3984	Coarse grained sst with polygenetic conglomerates.
	UNCONFORMITY					
Barail	BCS	4187-4372	4060-4245	4112-4588	3984-4460	Dominantly shale with intercalation of sandstone and coal
	BMS			4588-4760+	4460-4632+	Dominantly sandstone with intercalation of shale and coal

Figure 4-13: SEISMIC SECTION ACROSS LAXMIJAN-BIHUBAR AND GELEKI FIELDS

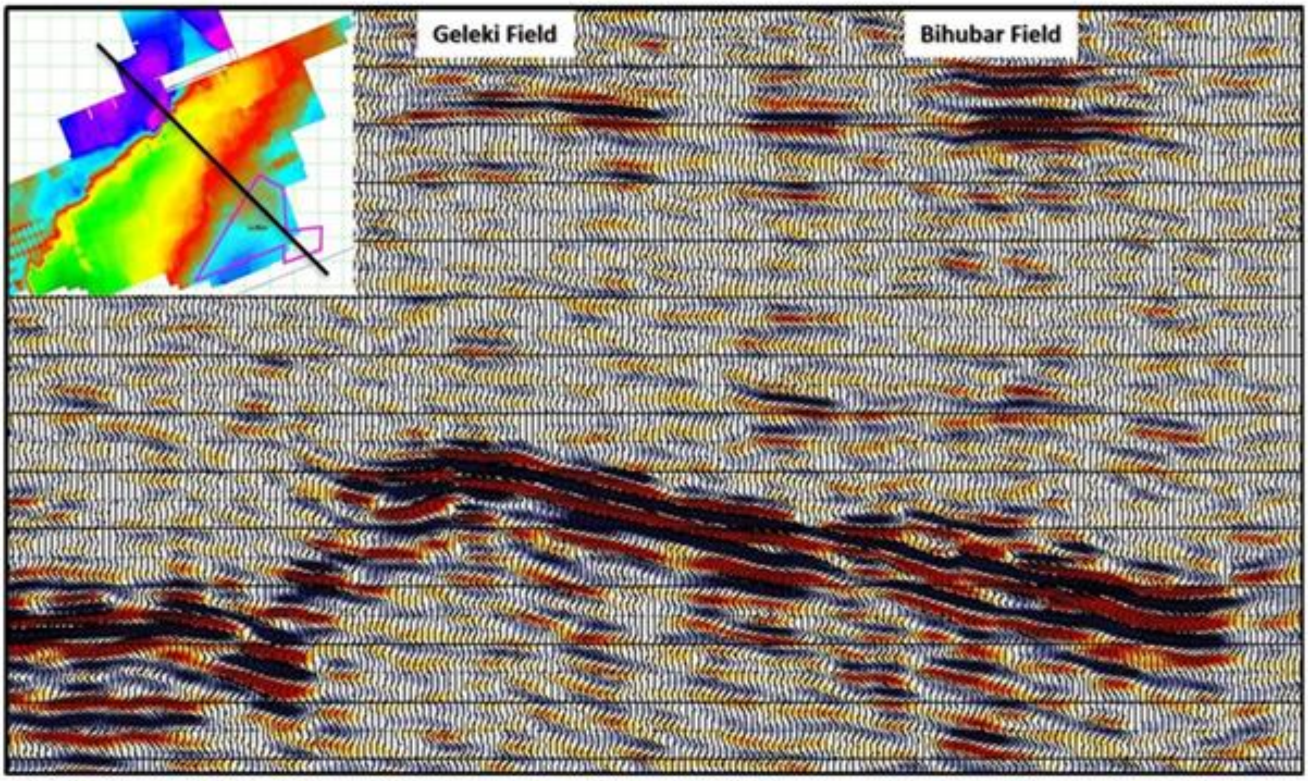
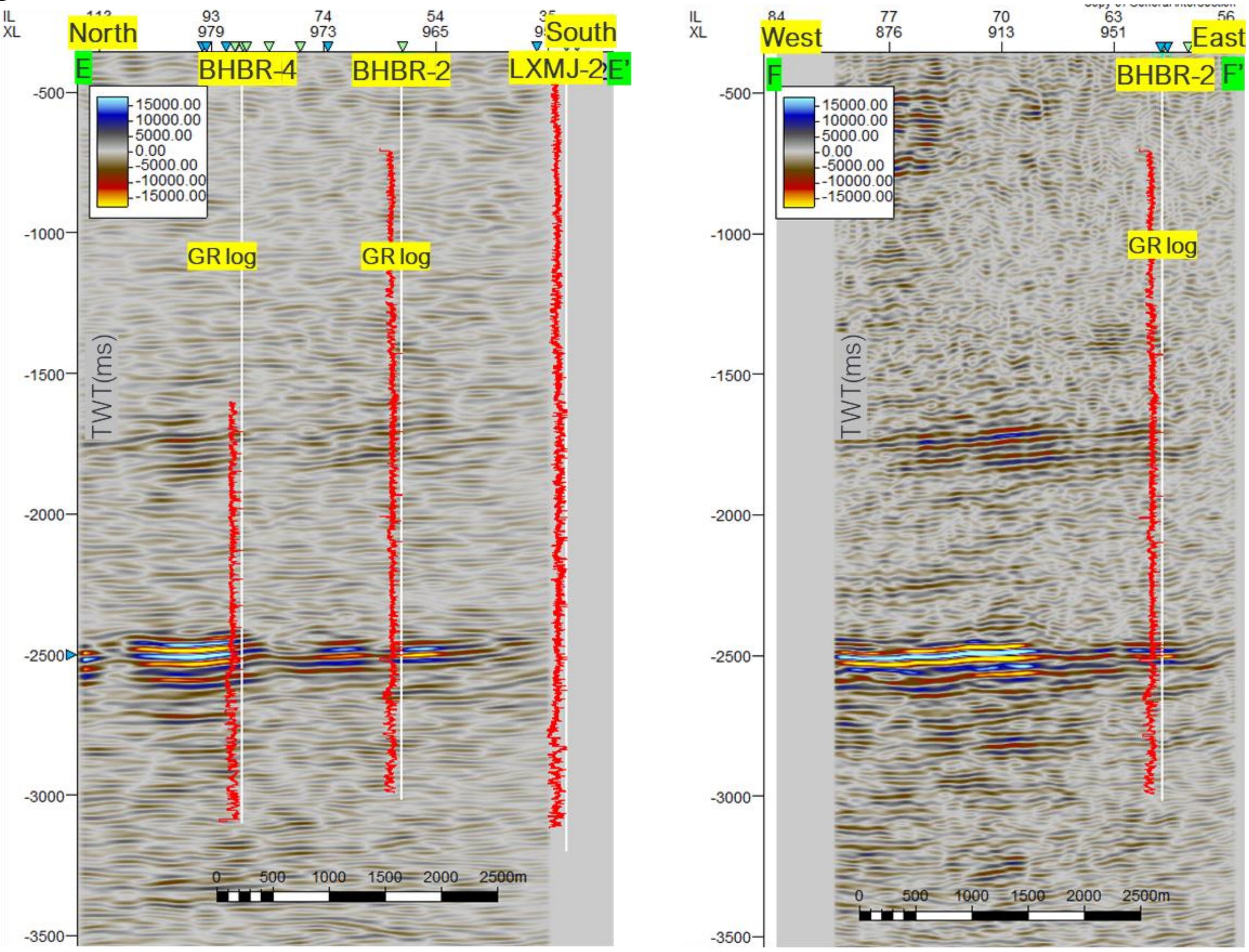


Figure 4-14: SEISMIC SECTION ACROSS WELLS LAXMIJAN-2, BIHUBAR-2 AND BIHUBAR-4



Vertical exaggeration: 2.5x
Seismic volume: 00001.GELEKI_PSDM_SCALE_TO_TIME_PSDM_SCALED_TO_TIME

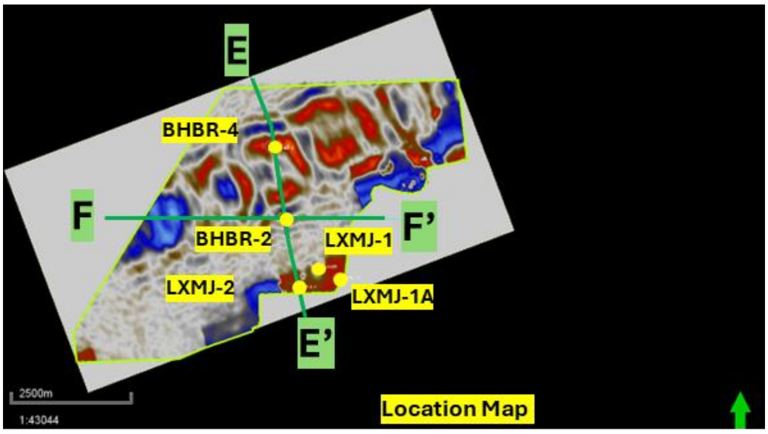


Figure 4-15: STRUCTURAL ELECTRO-LOG CORRELATION OF WELLS BIHUBAR 4, 2 AND LAXMIJAN 2, 1A

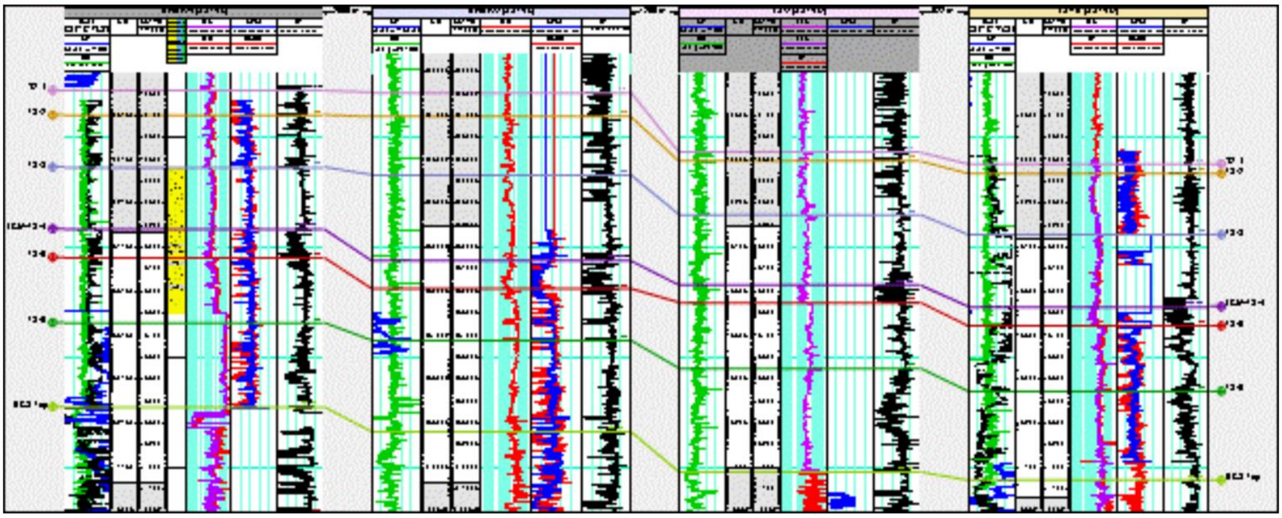


Figure 4-16: STRATIGRAPHIC (DATUM @ LCM) ELECTRO-LOG CORRELATION OF WELLS BIHUBAR 4, 2 AND LAXMIJAN 2, 1A

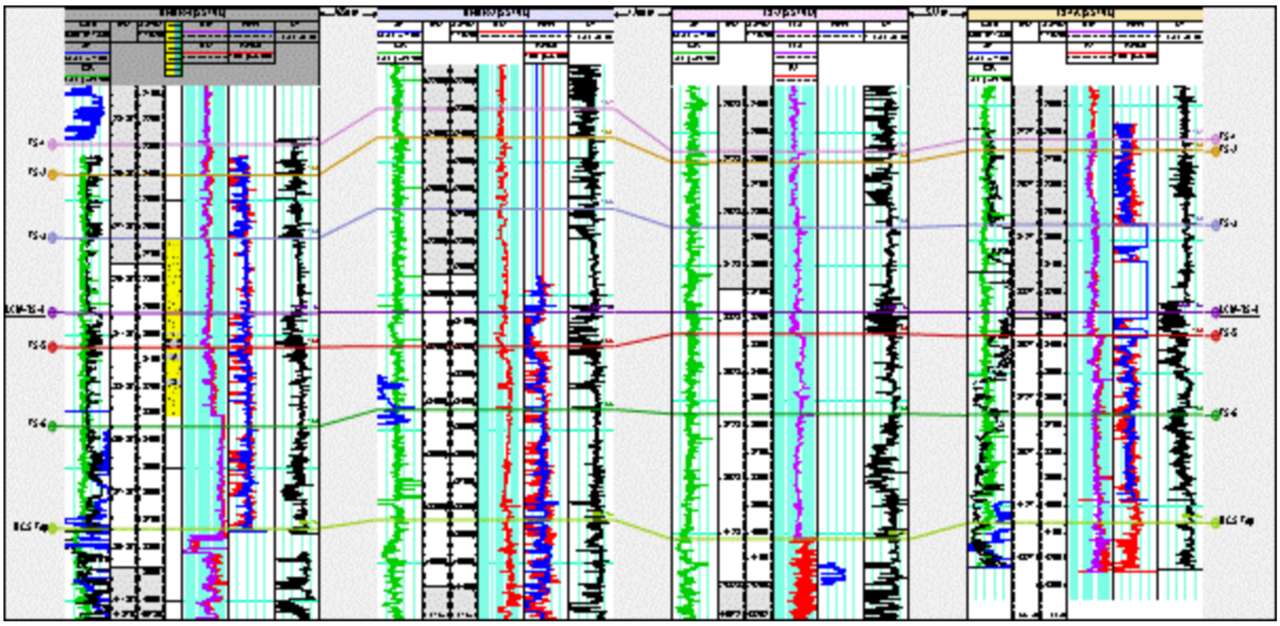


Figure 4-17: STRUCTURE MAP OF TS-II PICK SHOWING HIGHS AT WELLS LAXMIJAN 1A AND 2

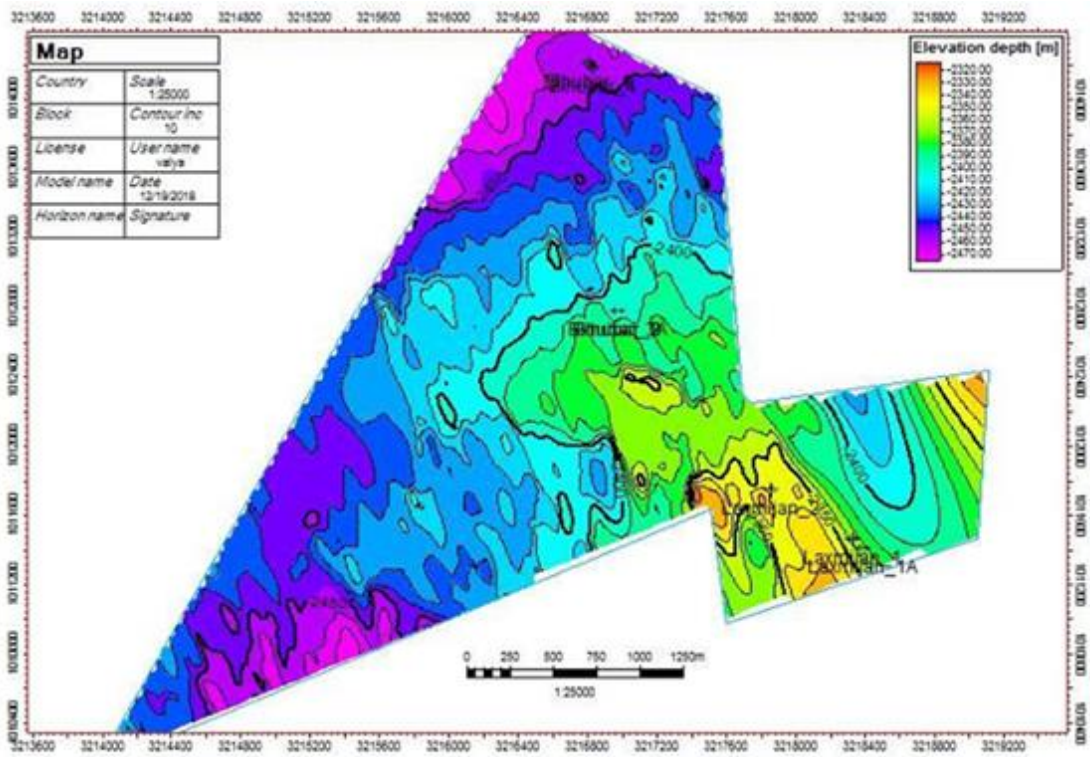


Figure 4-18: DEPTH STRUCTURE MAP AT THE TOP OF TS-5A

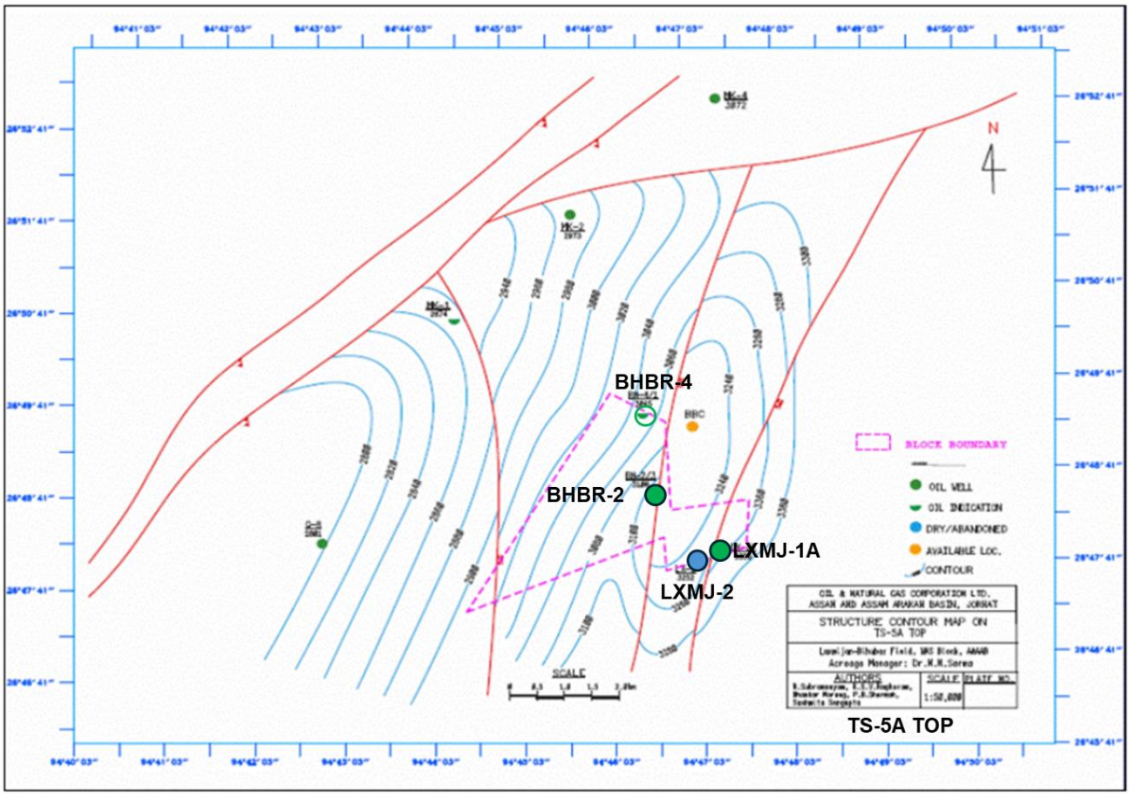


Figure 4-19: DEPTH CONTOUR MAP NEAR BARAIL BCS

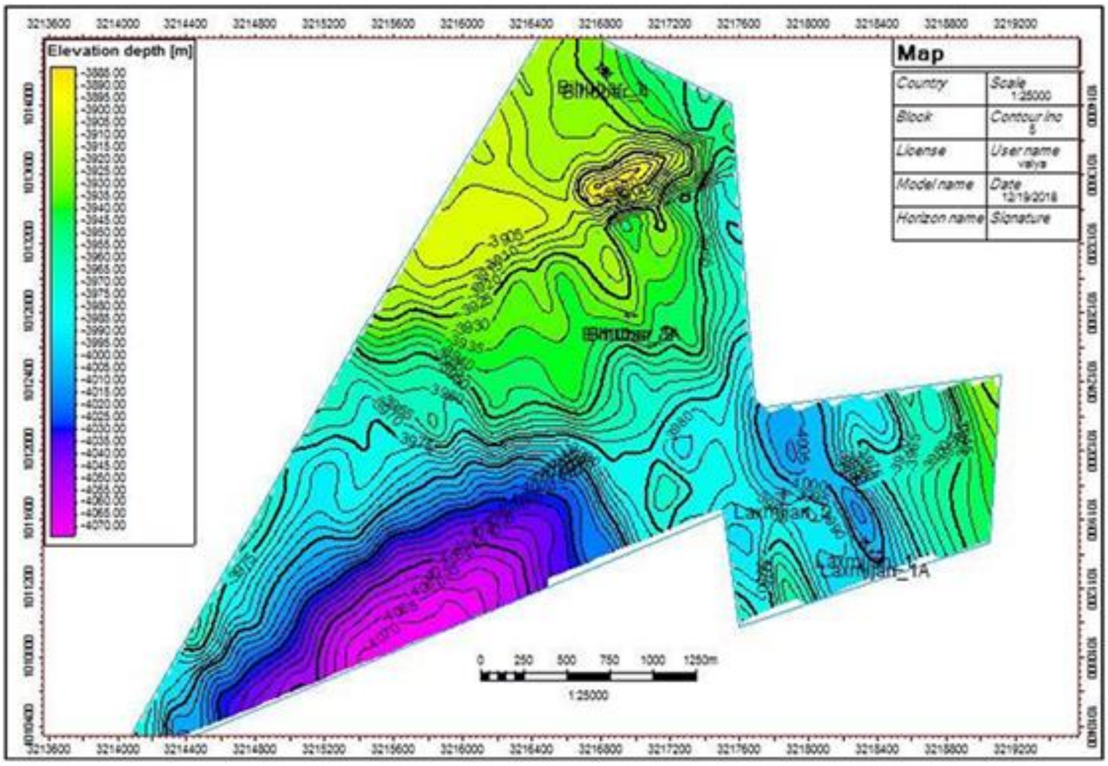


Figure 4-20: DEPTH STRUCTURE MAP AT THE TOP OF BARAIL BMS

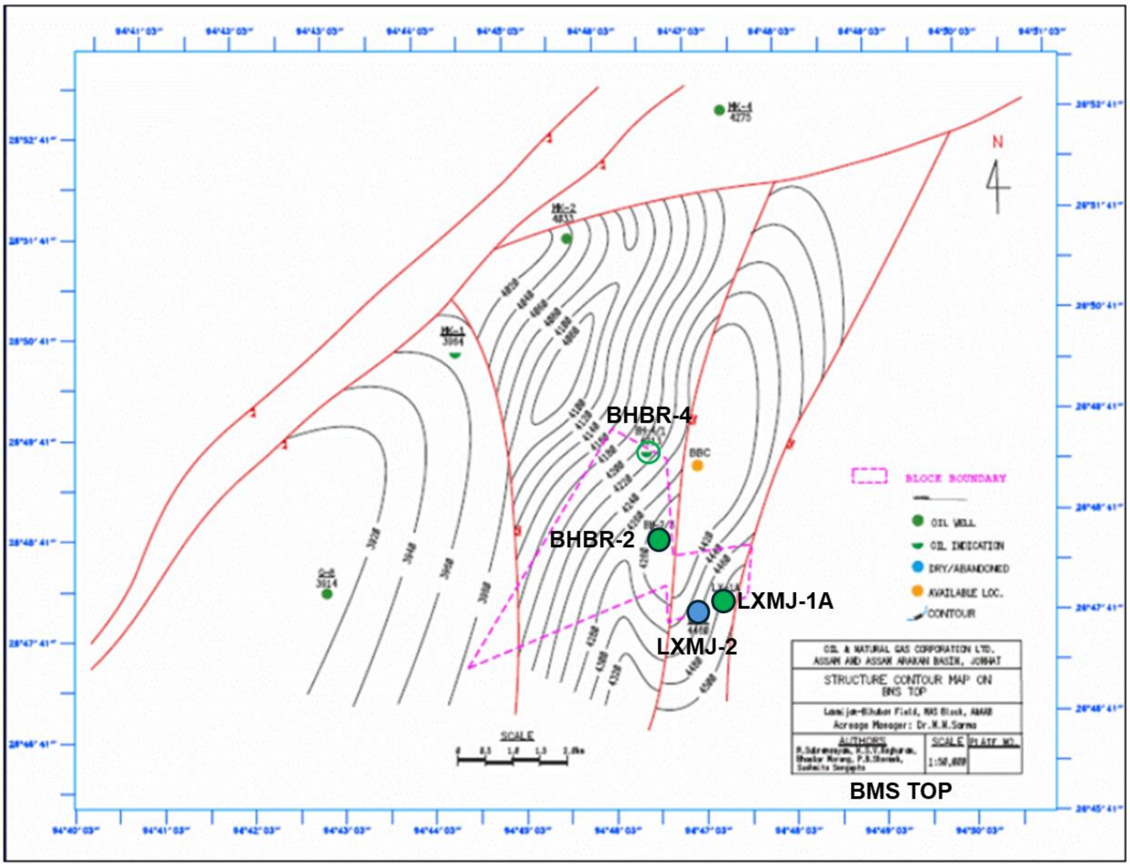


Figure 4-21: ISOPACH MAP BETWEEN TS-II AND BCS SHOWING INCREASED THICKNESS AT LAXMIJAN LEVEL TOP OF BMS

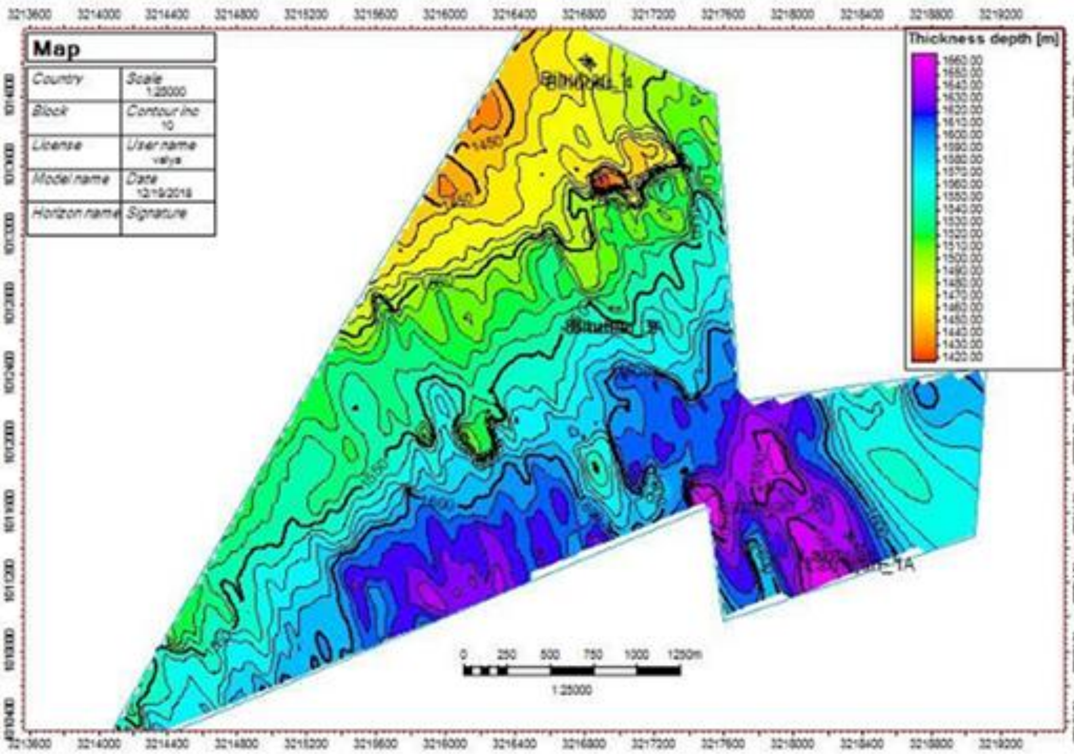


Figure 4-22: ARBITRARY LINE CONNECTING LAXMIJAN AND BIHUBAR WELLS IN THE TWO ADJACENT FIELDS

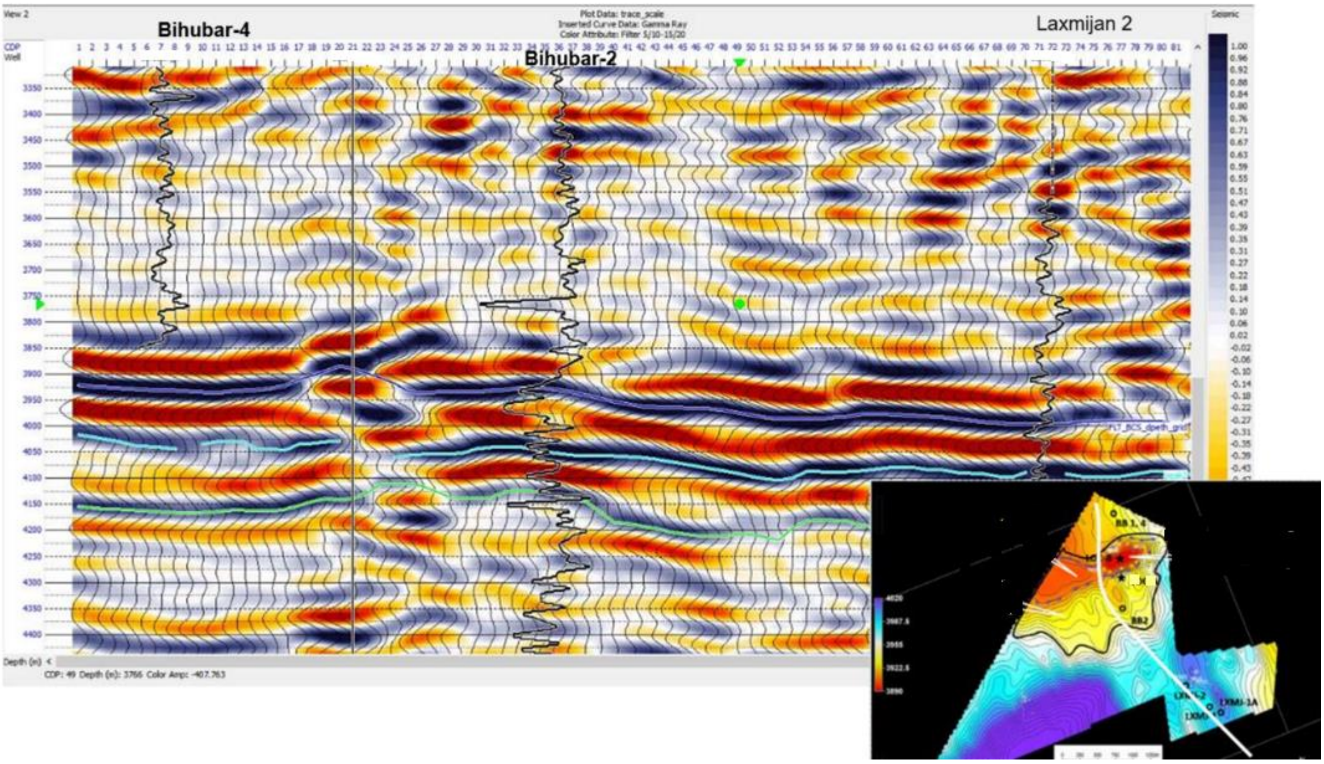


Figure 4-23: SWEETNESS ATTRIBUTE ON BCS HORIZON SHOWING INCREASED AMPLITUDE WITH DECREASED FREQUENCY

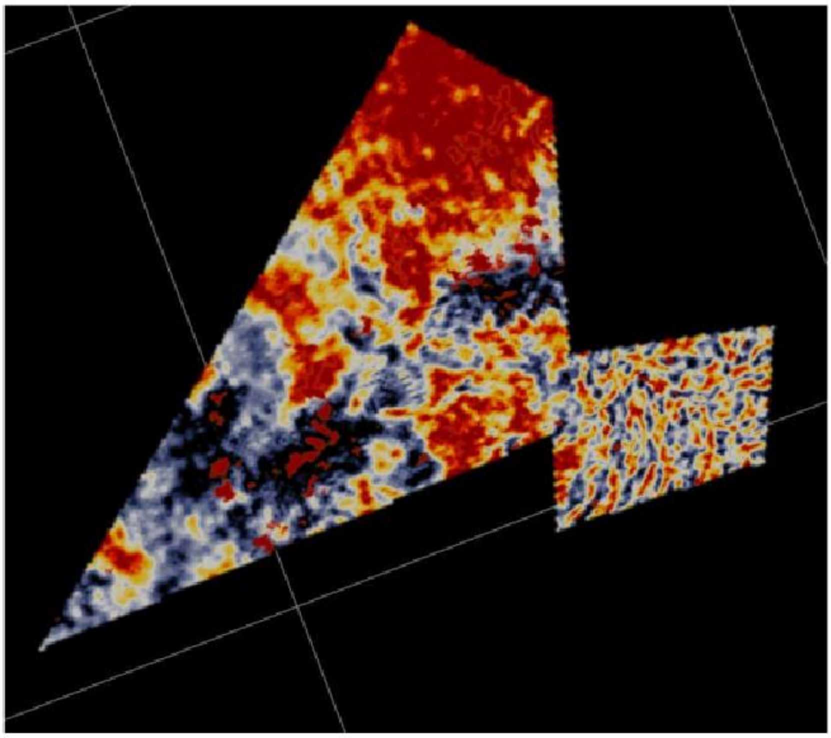


Figure 4-24: ARBITRARY LINE CONNECTING LAXMIJAN-AND BIHUBAR WELLS AND SHOWING THE INTERPRETATION OF BCS AND BMS

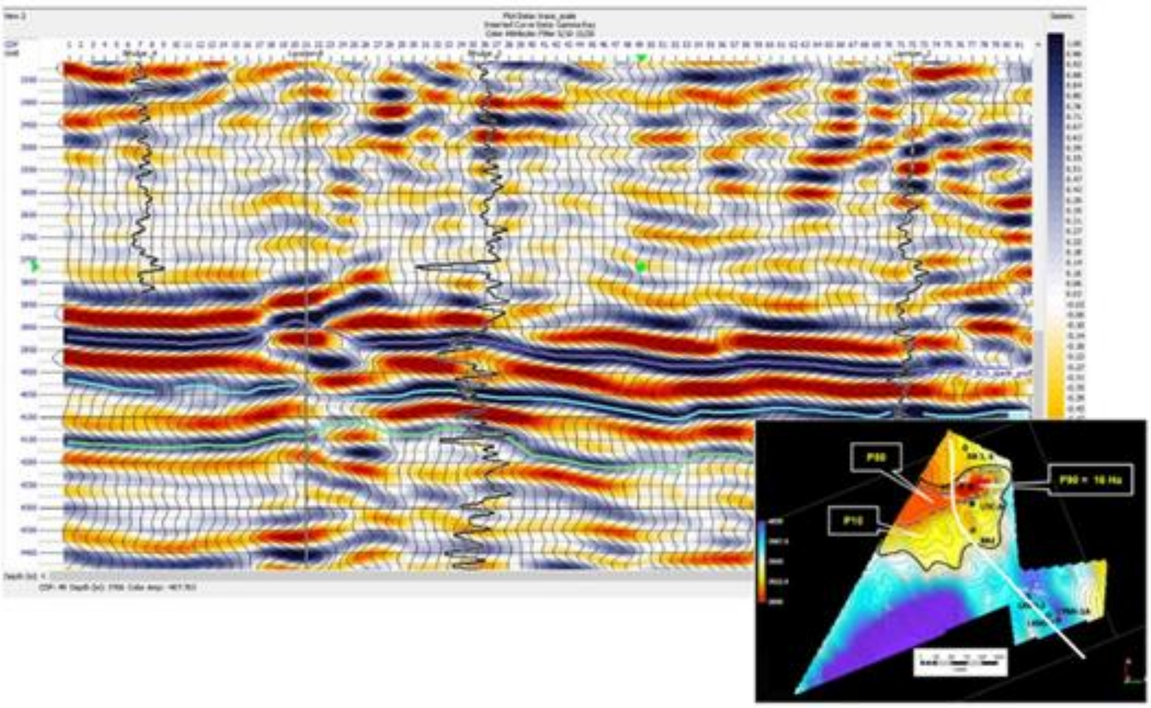


Figure 4-25: ENHANCEMENT OF REFLECTORS USING AGC 800 MS WINDOW

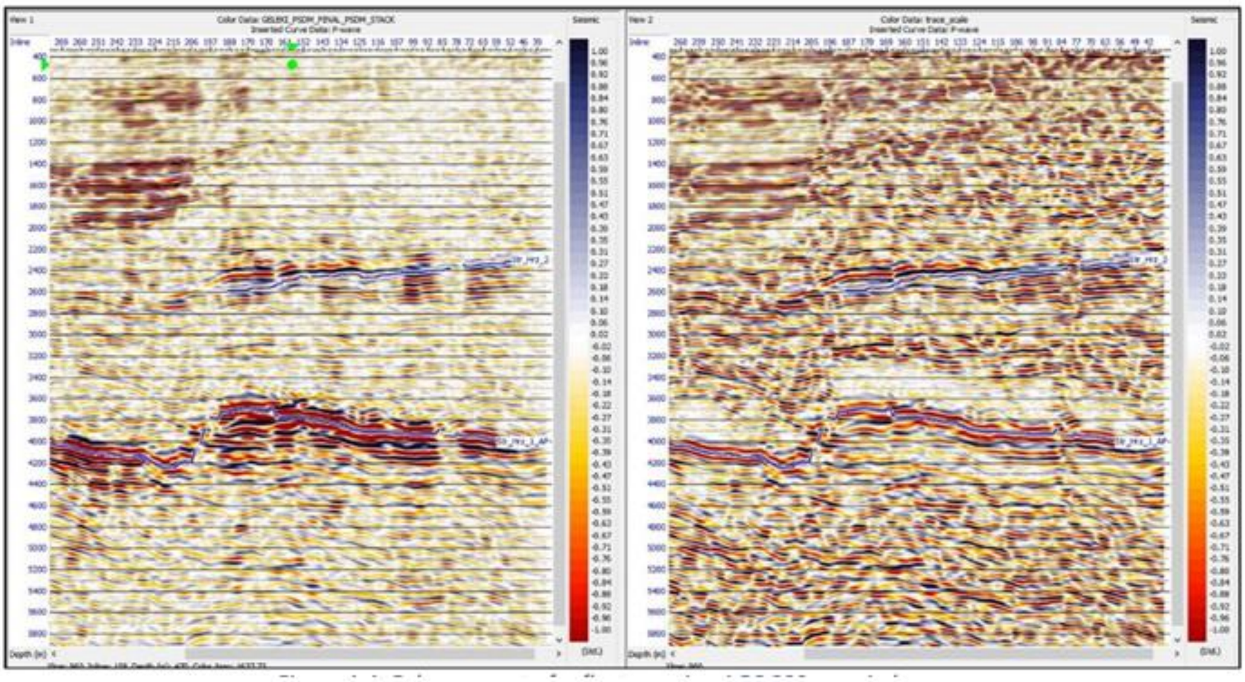
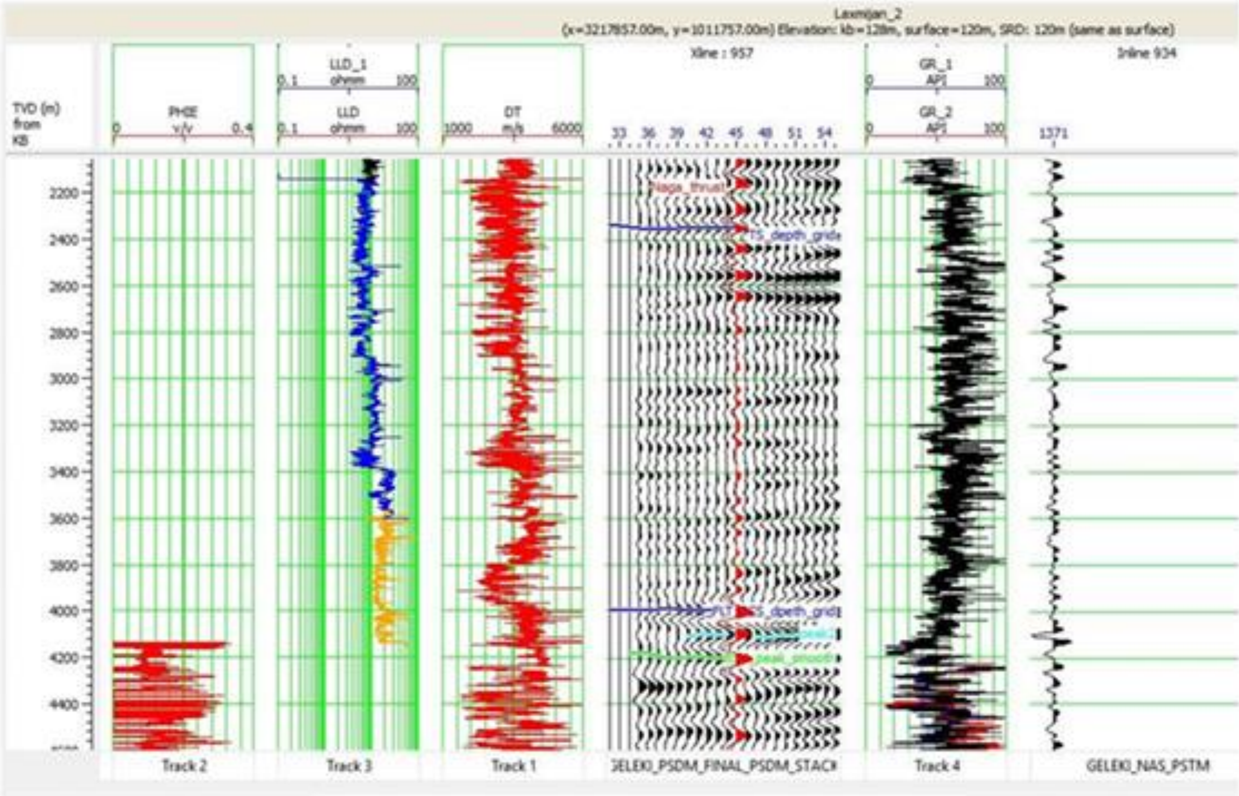


Figure 4-26: DEPTH TO SEISMIC TIE TO THE WELL LAXMIJAN-2



4.2.5.2 Reservoir parameters and hydrocarbon estimates (Laxmijan Field):

Petrophysical parameters and hydrocarbon estimates:

Table 4-13 gives the evaluation results of Laxmijan Field wells from the study

Table 4-13: DERIVED PARAMETERS FOR THE OBJECTS TESTED IN THE LAXMIJAN WELLS

Well	Object	Sand	Depth Range	Flow Test Type	Flow Test Results	Status	HC Sat	Porosity	Sw
LXM-1	Abandoned due to complications.								
LXM-1A	Obj-I	Barail	4218-4214	CHDST	Water bearing	Dry		0.07	
	Obj-II	TS-5B	3615-3607	CHDST	Water bearing	Dry		0.17	
	Obj-III	TS-5A	3508-3492	Convent-ional	Viscous Oil	Viscous Oil	57	0.15	43
	Obj-IV	TS-4B	3465-3458	CHDST	Water with traces of oil observed	Viscous Oil	57	0.13	43
LXM-2	Obj-I	TS-5A	3393-3399	Convent-ional	Water with traces of oil.	Dry			

Current hydrocarbons estimates

Initial hydrocarbons in-place have been estimated based on production testing result, reservoir parameter and Log motifs of wells Laxmijan 1A & 2. The reservoir parameters and in-place of Laxmijan Field are shown in **Table 4-14 and Table 4-15 below**.

Table 4-14: RESERVOIR PROPERTIES FOR VOLUMETRIC ESTIMATION OF LAXMIJAN FIELD

Field	Reservoir	Area	He	Phi					GOR	O+OEG
	Sand/ layer	Sq Km	m		So	Bo	API	Sp Gr	m3/ m3	MMTOE
Laxmija	TS4	0.126	5	0.168	0.43	1.47	31	0.8708	230	0.03
	TS5A1	1.004	20.2	0.142	0.43	1.48	31	0.8708	210	0.90
	TS5A2	0.282	4.8	0.142	0.25	1.48	31	0.8708	210	0.03
	TS5B	1.004	11.5	0.13	0.00	1.49	31	0.8708	125	-
										0.96

Table 4-15: HYDROCARBON IN-PLACE(2P) OF LAXMIJAN FIELD

Field	O+OEG MMTOE
LAXMIJAN	**0.96**

Erstwhile Operator-reported estimates on record:

The LAXMIJAN-BIHUBAR Cluster has a reported gas estimate of **0.15 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the currently reported estimates.

4.2.6 Production Facility for Oil and Gas Evacuation:

X-mass tree is available at well Laxmijan-1A
The nearest surface facility to the Field is **~ 10 km of Geleki Main Field**

Hydrocarbon transportation could be by tankers to the local consumers. The existing Geleki Field gathering system could serve as a good point for oil and gas delivery.

AA/ONDSF/ASSAM/2025 (A&AA) BIHUBAR FIELD

4.3 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) BIHUBAR FIELD

Well Bihubar-1 was the first well drilled on the Bihubar structure by ONGC as an exploratory well in 1975. The well was planned to be drilled to a depth of 4500 m with an objective to explore the Oligocene prospects in the Bihubar area. Though drilled to a depth of 4038 m, the well had to be sidetracked following repeated fishing in the well and the was finally abandoned at a depth of 3425m.

Of the five wells drilled on the structure, four wells viz. Bihubar -1, 3, 3A and 4 had to be abandoned either because flow tests have shown them to be mainly water bearing or due to drilling issues. Well Bihubar-1 is the discovery well in this field as during testing of the TS-5A sand of the Tipam Group of Miocene age, small quantity of oil was observed while changing over well fluid for testing a higher up sand though subsequently it showed poor influx. However, hydrocarbon, especially gas and viscous oil, was encountered in the well Bihubar-2 in the Miocene Tipam and the Oligocene Barail sands. The Bihubar Field has been recognized as a marginal field. The main pay is BMS and BCS within the Barail Group of Oligocene age. Structural entrapments are interpreted to be mainly fault closures.

4.3.1 Drilling and well completion

As stated earlier, five exploratory wells have been drilled in this field, viz. Bihubar-1 (GF), Bihubar-2 (BB-2), Bihubar-3 (BBA), Bihubar-3A and Bihubar-4 (BBD). The well Bihubar-3A was drilled as a Sidetrack well by kicking off at 755 m from the well Bihubar-3 as the testing of the sand TS1 could noy be carried out in the original well. Key information of the drilled wells have been collated and presented in the tables hereunder (**Table 4-16 and Table 4-17**). The adjoining figures illustrate the Well Construction Diagram (**Figure 4-27 and Figure 4-28**) for key wells. Other well statics like kelly bush reference depth, drilled and logged depth including well coordinates are made available in Sections through various cross-references.

Table 4-16: GENERAL INFORMATION OF THE WELLS DRILLED IN BIHUBAR FIELD

Well	Bihubar-1	Bihubar-2	Bihubar-3	Bihubar-3A	Bihubar-4
Area	Geleki				
Structure	Bihubar				
Well	Bihubar-1 (GF)	Bihubar-2 (BB-2)	Bihubar-3 (BBA)	BB-3A (BBA)	BB-4 (BBD)
Category	Exploratory	Exploratory	Exploratory (Directional)	Exploratory (Sidetrack)	Exploratory
Co-ordinates	X: 3216837.64	X: 3217070.59	X: 3217070.59	X: 3217070.59	3216868.34
	Y: 1014174.5	Y: 1012708.79	Y: 1012708.79	Y: 1012708.79	1014150.09
Rig	3D-7	3DH-III		3DH-III	E-2000-IV
Target Depth	4500 m	4300 m increased to 4600 m	2000 m + vertical shortening	2000 m KO from 618 m of BB-3	4600 m
Drilled Depth	4038.00 m Sidetracked depth 3425 m	4485 m	2080 m	2000 m	4600 m

Objective	Released for exploration of Barail prospects in Bihubar area.	To explore the hydrocarbon potentiality of sub-Thrust Tipam and Barails	To explore the hydrocarbon potentiality of Sub-Thrust Girujans	To explore the hydrocarbon potentiality of supra-Thrust Tipams	To explore hydrocarbons of Barails
Status	Discovery well with poor influx from tested zones Abandoned	Tested zones showed presence of oil/ viscous oil with water and gas. Flow did not Sustain. Abandoned.	Incomplete Testing with fish in hole. Abandoned	Tested zones produced water. Abandoned	One zone tested water with oil. Abandoned
KB	108.92 m	112.175 m	112.175 m	112.175 m	113.71 m
Spud date	20-11-1975	15-01-1985	14-03-1987	20-10-1990	07-07-1996
Drilling Completion	-14.12.1982	19.01.1986	14.03.1987	06-12-1990	22-03-1997
Rig release	06-04-1983	09-02-1987	Rig not released as same rig to drill a sidetrack from this well	19-01-1991	01-07-1997

Table 4-17: WELL WISE CASING DETAILS

Well	Hole Size	Casing Size	Cement Rise from Surface	Casing Shoe Depth (m)
Bihubar-1	18 ½ “	14 ¾ “	Did not surface	1200 m
	13 ¾ “	9 5/8 “	2930 m	3700.31 m
	8.1/2 “	5 ½ “	2510 m	3279.20 m
Bihubar-2	26 “	20 “	Surface	98.92 m
	17 ½ “	13 3/8 “	Surface	1919 m
	12 ¼ “	9 5/8 “	2700 m	3763 m
	8.1/2”	5 ½ “	3504 m	4461 m
Bihubar-3	17.1/2 “	13.3/8“	Surface	68.12 m
	12.1/4“	9. 5/8“	Surface	532.14 m
	8. 1/2“	5. 1/2“	1750 m	2063.91 m
Bihubar-3A (BB-3A)	17 ½ “	13 3/8 “	Surface	68.12 m
	12 ¼ “	9 5/8 “	Surface	532.14 m
	8 ½ “	5 ½ “	Ist Stage: 1630 m IInd Stage: 623 m	1973.0 m
Bihubar-4 (BBD)	26 “	20 “	Surface	387.76 m
	17. 1/2“	13 3/8 “	600 m	2389 m
	12 ¼ “	9 5/8 “	1700 m	3935.27 m
	8. 1/2“	5 ½ “	3875 m	4140.77 m

Figure 4-27 : WELL PROFILE OF BIHUBAR-2

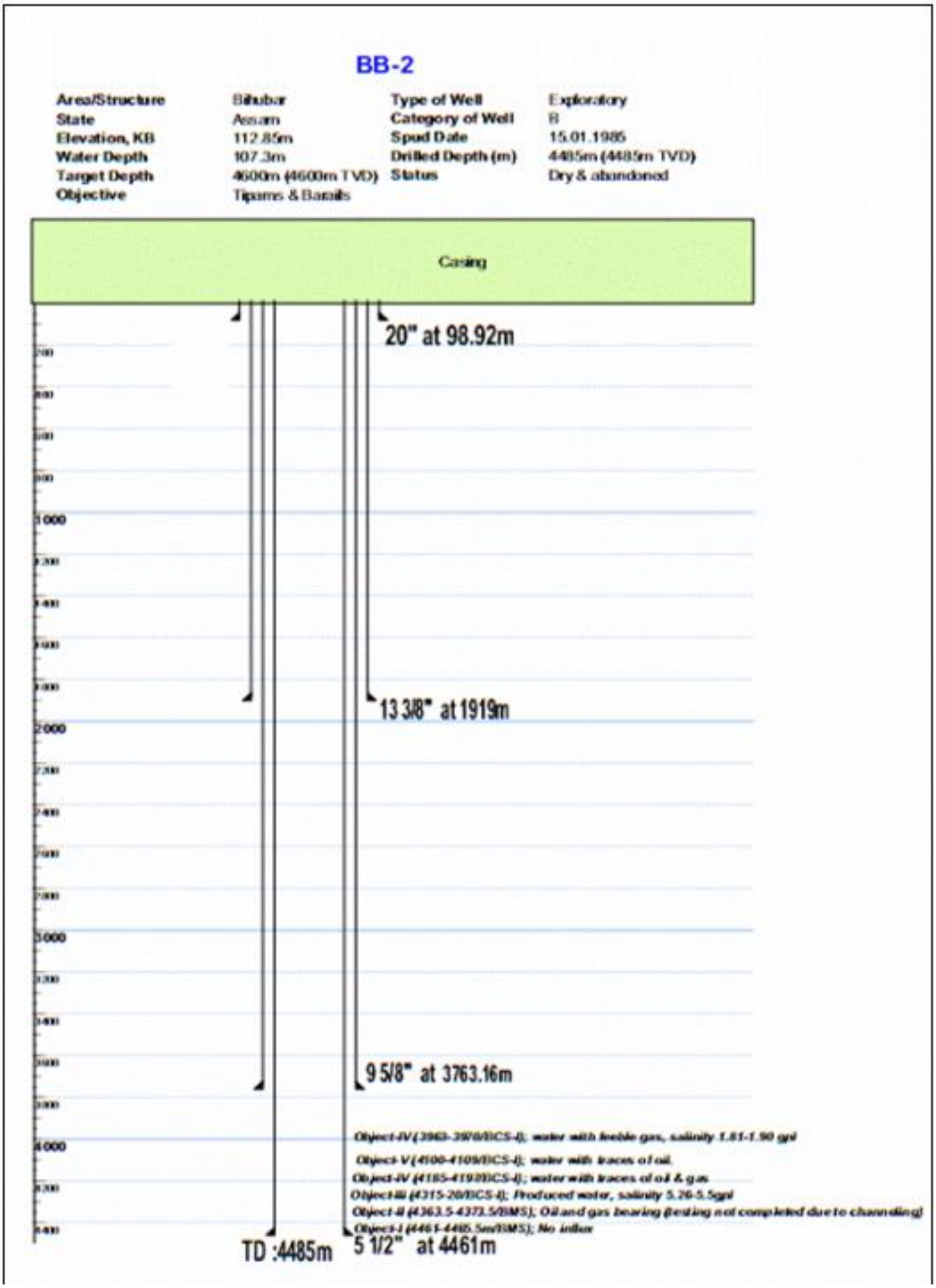
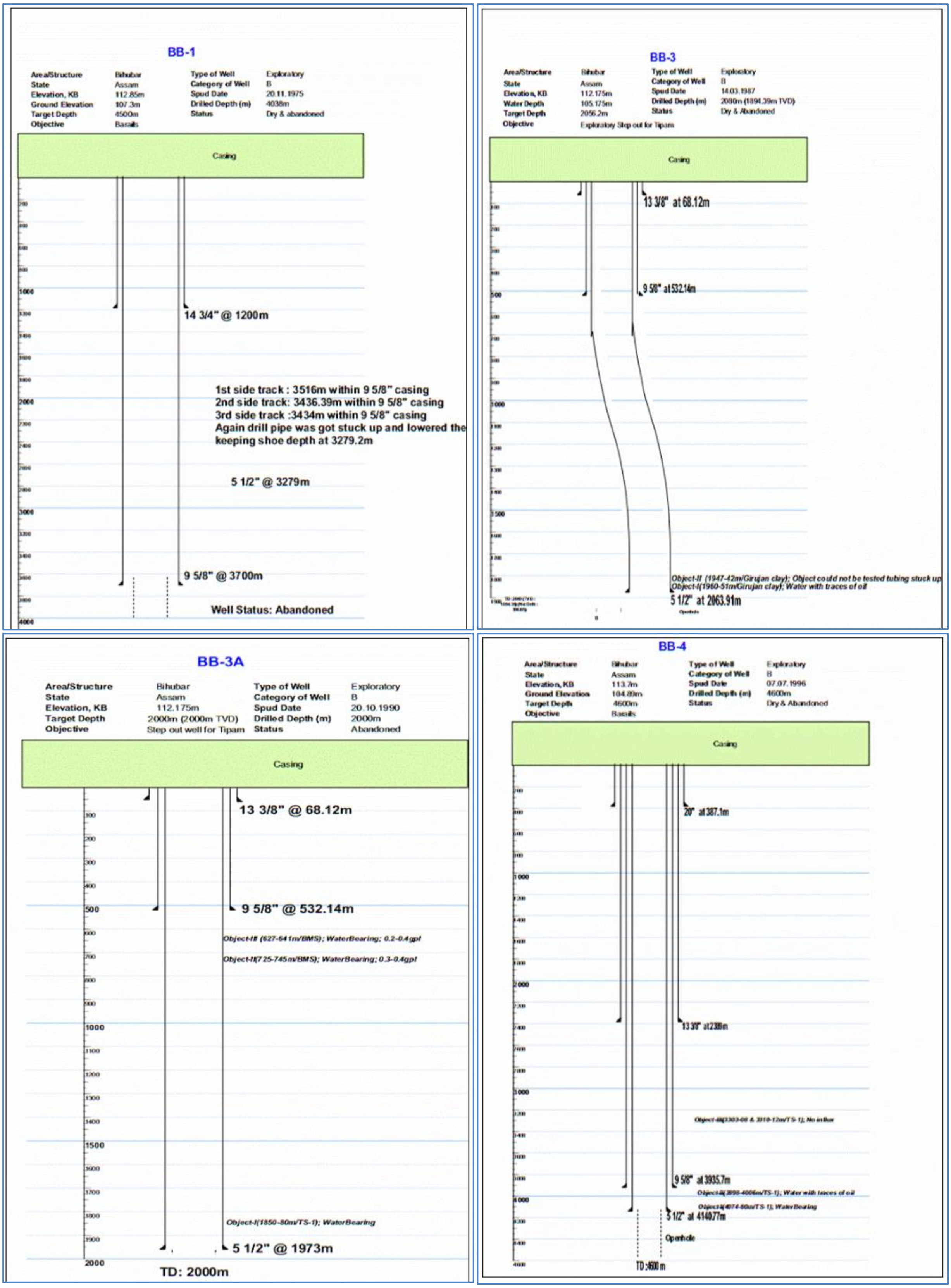


Figure 4-28: WELL PROFILE OF BIHUBAR-1, 3, 3A AND 4



4.3.2 Well logging and formation evaluation

The well logs of all discovery wells along with some key wells in the Contract Area have been reviewed. The logs recorded in various open-hole sections along with cased-hole logs and information of conventional and other wireline formation test data are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) have been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

Availability of reports, logs recorded and core data available in Bihubar wells are tabulated at **Table 4-18, Table 4-20 and TABLE 4-19.**

4.3.2.1 Availability of reports (BIHUBAR Field) :

Table 4-18: AVAILABILITY OF REPORTS

Well	KB	Spud Date	Drilled depth	WCR Available/ Not Available	FER Available/ Not Available
Bihubar-1	108.92 m	20-11-1975	4038 m	Available	Available
Bihubar-2	112.175 m	15-01-1985	4485 m	Available	Available
Bihubar-3	112.175 m	14-03-1987	2080 m	Available	Available
Bihubar-3A	112.175 m	20-10-1990	2000 m	Available	Available
Bihubar-4	113.71 m	07-07-1996	4600 m	Available	Not Available

4.3.2.2 Well logs acquired (BIHUBAR Field):

TABLE 4-19: LOG SUITES RECORDED IN DRILLED WELLS

Well No.	Type of log	Interval (m)
Bihubar-1	SP, Normal, Lateral,	25-1040, 900 -1185
	SP, Normal, BKZ	2855-1200, 2900-2600, 3150-3102, 3268-2900, 3696-3200, 4020-3700
	Caliper-Inclinometer	25-1040, 1200-2750, 2900-3268, 3350-3690
	Caliper	1200-2900, 1200-3698
	Induction, Sonic, CRN	2400-2735, 2700-3612
	Thermolog	After setting of 9.5/8” Csg. with shoe @3700.31
	CBL	2450-3175, 2400-3245
Bihubar-2	DIL-SP-GR	100-1923, 3753.0-4469.6
	LSS	100-1923
	X-Y CAL	100-1923, 2400-5-3050
	Inclinometer	100-1923, 1900-3048, 1920-2056
	SP-Caliper-DIL-BCS-GR	1919-3050, 1919-3781.5, 3751-4082, 3753-4335, 4337-4386
	CDL-CNS-GR-SP	2400.5-3050, 2910-3781.5, 3778-4323

	Caliper, GR, Dipmeter,	3190-3780, 3792-4120
	CBL-VDL-CCL-GR-IT3	3100-3722
	CBL-VDL-CCL-NEUTRON-GR	3444.8-4461
Bihubar-3	DIL-SP-GR	67-544
	GR-Cal-BCS	68-542
	CDL-CNS-GR	238-545, 532-1245.1860-2072.5
	DIPMETER	59.5-541.5, 532-930, 890-2058
	Inclinometer	532-1245, 890-2058
	SP-GR-Cal-DIL-BCS	497-637, 532-1245, 1168-2067, 1800-2067
	SFT	At well depth of 636 m in 8.1/2" hole
	SP-GR-Cal-MSFL-LLD-LLS	532-1245
	SWC	At well depth of 2080 m in 8.1/2" hole
	CBL-VDL-CNL-CCL	520-2040, 1400-2028.5
Bihubar-3A	DIL--SP-GR-CAL	1986-514
	BCS	1986-514
	CDL-CNS-GR-Caliper	1986-540
	SWC	At well depth of 1986 m in 8.1/2" hole
Bihubar-4	DIL-SP	387-2397, 3250-3870
	LL-3	1550-2397
	DIL-SP	2389-3420
	BCS-CAL	2389-3407, 3250-3870
	CDL-CNS-GR	2375-3870
	SWC	At well depth of 3911 m (12.1/4" hole)
	DLL-MSFL-GR-SP-CAL	3936.9-4595.5
	CBL-VDL-GR	2900-4140

Table 4-20: WELL WISE CORE DETAILS

Well no.	Core no.	Interval (m)	Recovery (%)	Gross Lithology
Bihubar-1	CC-1	2524-2532 m	75 %	Sandstone
	CC-2	3001-3008 m	Nil	-
	CC-3	3075.55-3083.55 m	100 %	Sandstone
	CC-4	3309-3317 m	62.5 %	Sandstone
Bihubar-2	CC-1	629-633.25 m	Poor recovery	Sandstone
	CC-2	3905-3913 m	91%	Sandstone
Bihubar-3	CC-1	541-546 m	35 %	Sandstone
	CC-2	636-641 m	40 %	Sandstone
Bihubar-3A	No Conventional Cores were cut in this well.			
Bihubar-4	No Conventional Cores were cut in this well.			

4.3.2.3 Well log evaluation and initial test results (BIHUBAR Field):

Petrophysical analysis was evaluated for the objectives tested in the wells drilled in the Bihubar Field and the derived parameters are shown in **Table 4-21**.

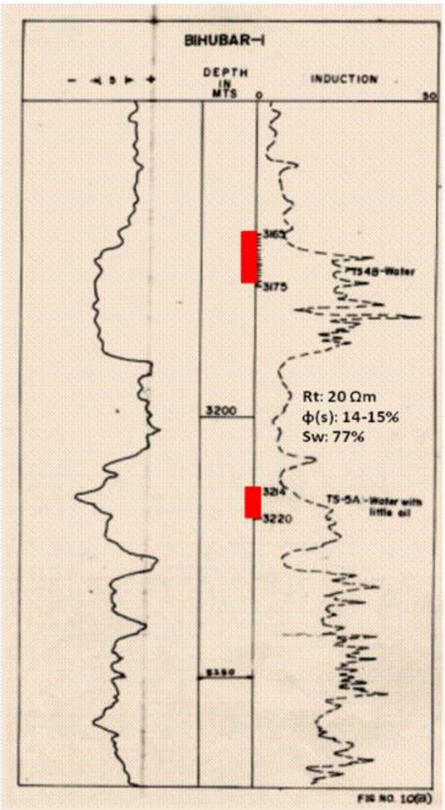
Table 4-21: PETROPHYSICAL RESULTS OF THE PROSPECTIVE ZONES IDENTIFIED IN BIHUBAR WELLS

Well	Object	Sand	Porosity %	Sw %
Bihubar-1	Obj-I	TS-5A	14-15	77
	Obj-II	TS-4B	13	80
	Obj-III	TS-2	19	86
Bihubar-2	Obj-I	BMS	Poor Hole condition	
	Obj-II	BMS	11	62
	Obj-III	BCS	11	67
	Obj-IV	BCS	11	80
	Obj-V	BCS	8	81
	Obj-VI	Barail	9-12	63
	SFT at 4102 m gave 1 litre of mud filtrate with traces of waxy crude oil.			
Bihubar-3	Obj-I	GC	12	65-100
	Obj-II	GC	25-30	70-100
	During SFT run several attempts were made to collect sample. But no influx was observed and in most places’ packer seat was not available.			
Bihubar-3A	Obj-I	TS-1	16-24	55
	Obj-II	BMS	9	76
	Obj-III	BMS	10	NR
Bihubar-4	Obj-I	BCS-III	18	NR
	Obj-II	BCS-IV	25	NR
	Obj-III	TS-5B	10	NR

NR = Not reliable

Log motifs for tested objects of wells Bihubar-1, Bihubar-2, Bihubar-3, Bihubar-3A and Bihubar-4 are shown in **Figure 4-29 through Figure 4-35**.

Figure 4-29: LOG MOTIF OF WELL BIHUBAR-1



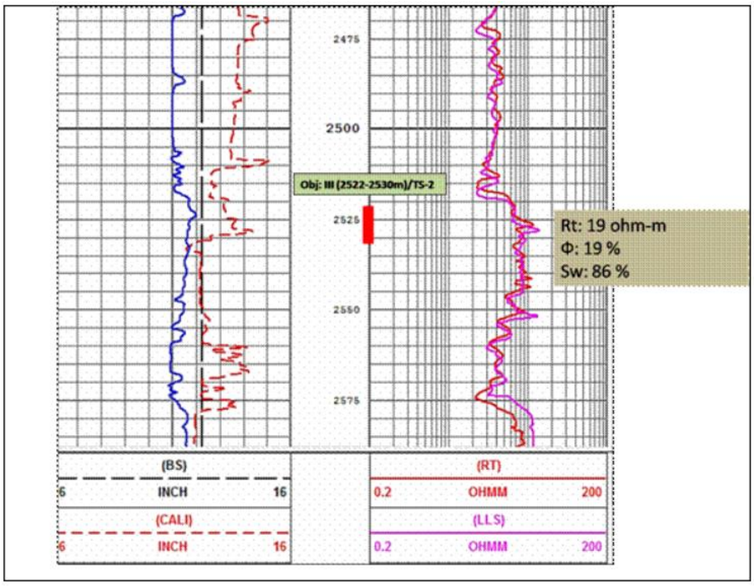


Figure 4-30: LOG MOTIF OF WELL BIHUBAR-2 (OBJECTS I, II, III & IV)

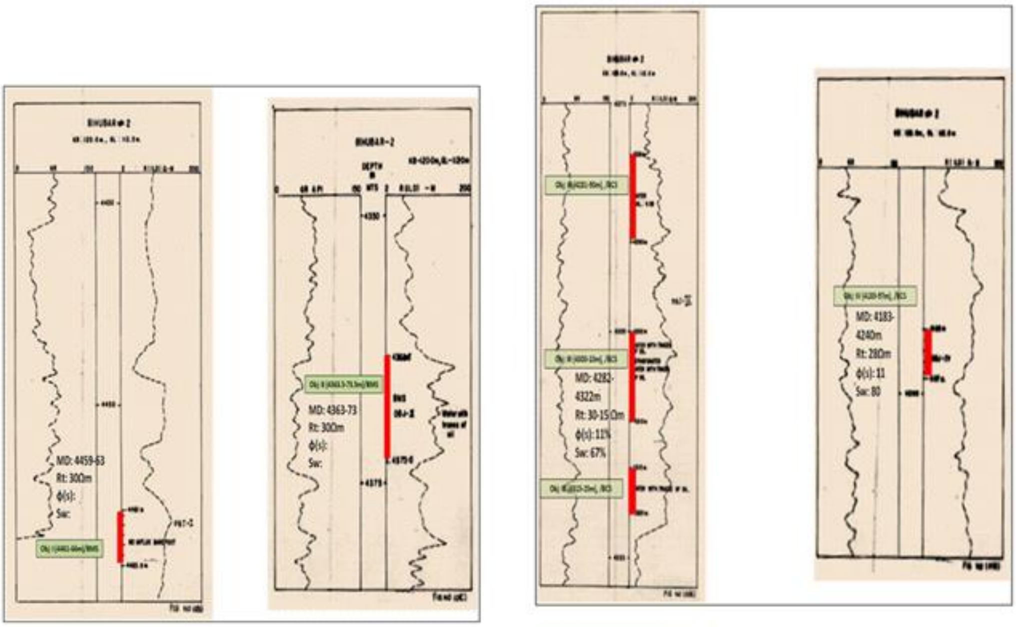


Figure 4-31: LOG MOTIF OF WELL BIHUBAR-2 (OBJECTS II & III)

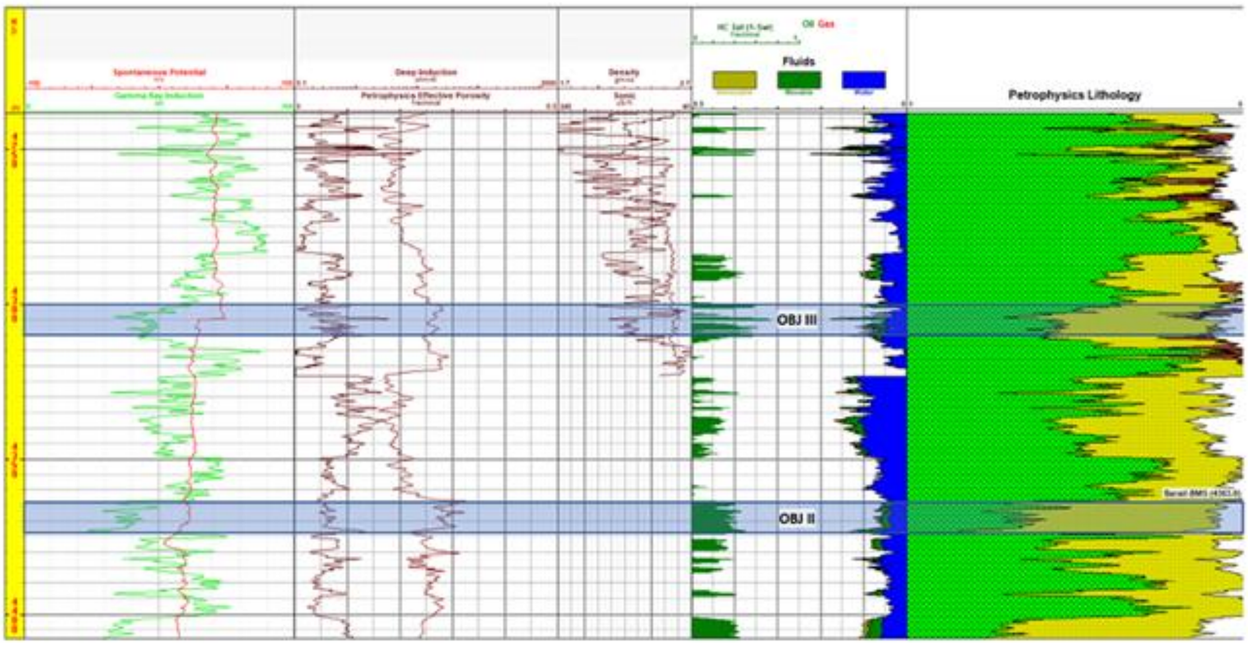
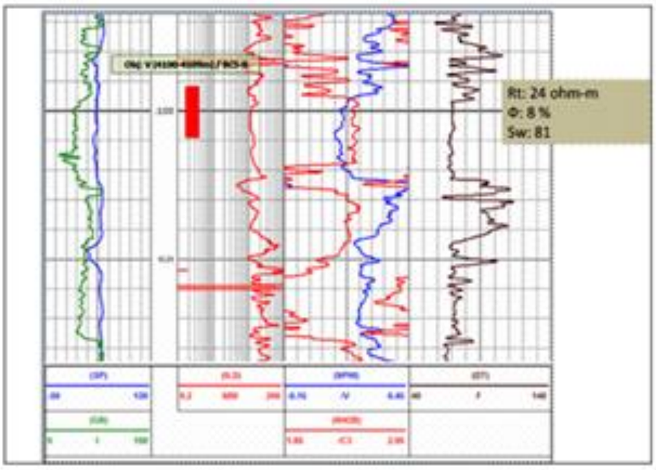
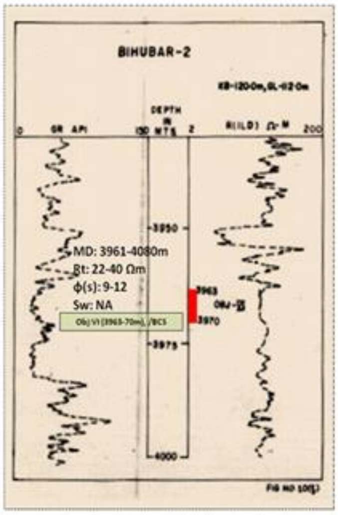


Figure 4-32: LOG MOTIF OF WELL BIHUBAR-2 (OBJECTS IV, V & VI)





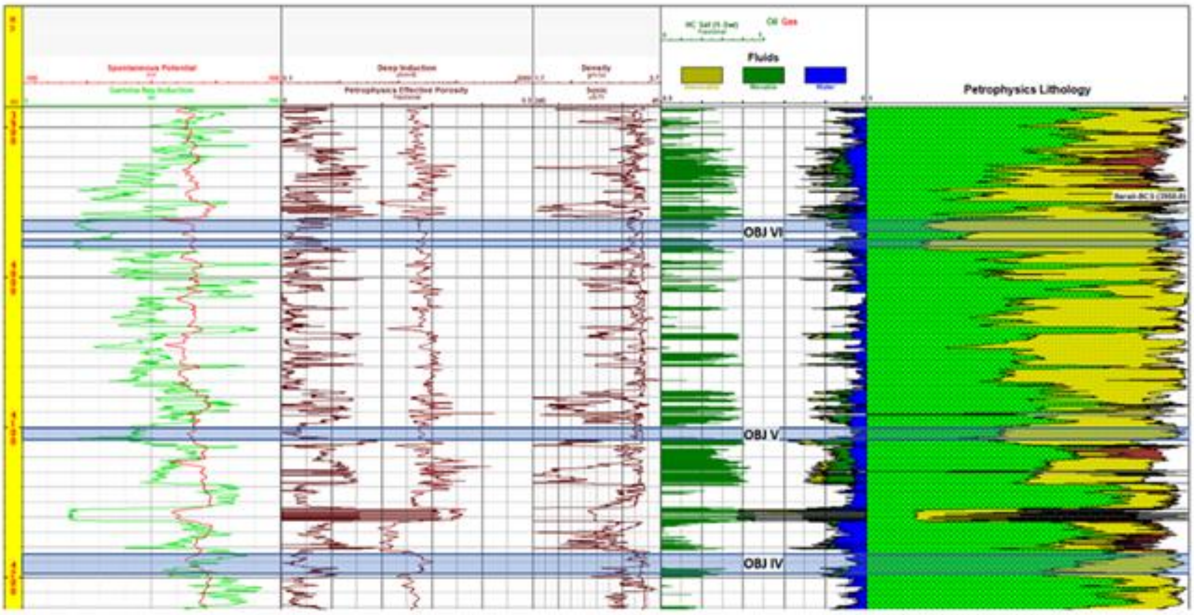
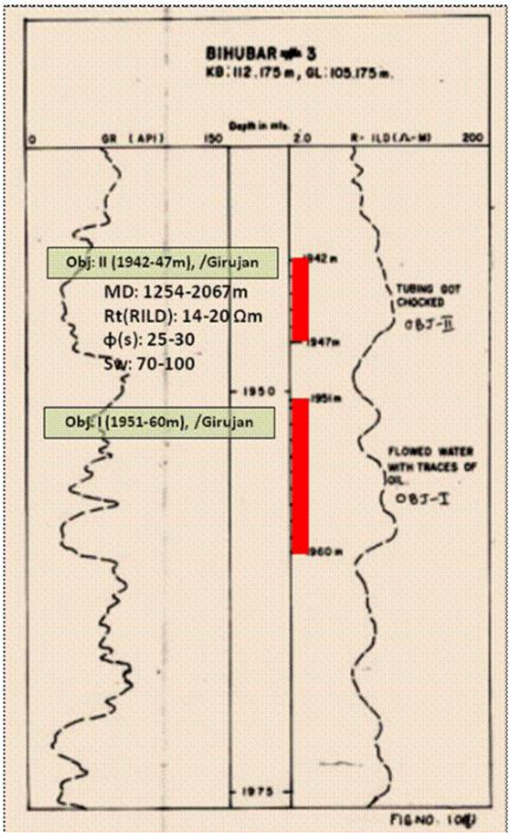


Figure 4-33: LOG MOTIF OF WELL BIHUBAR-3



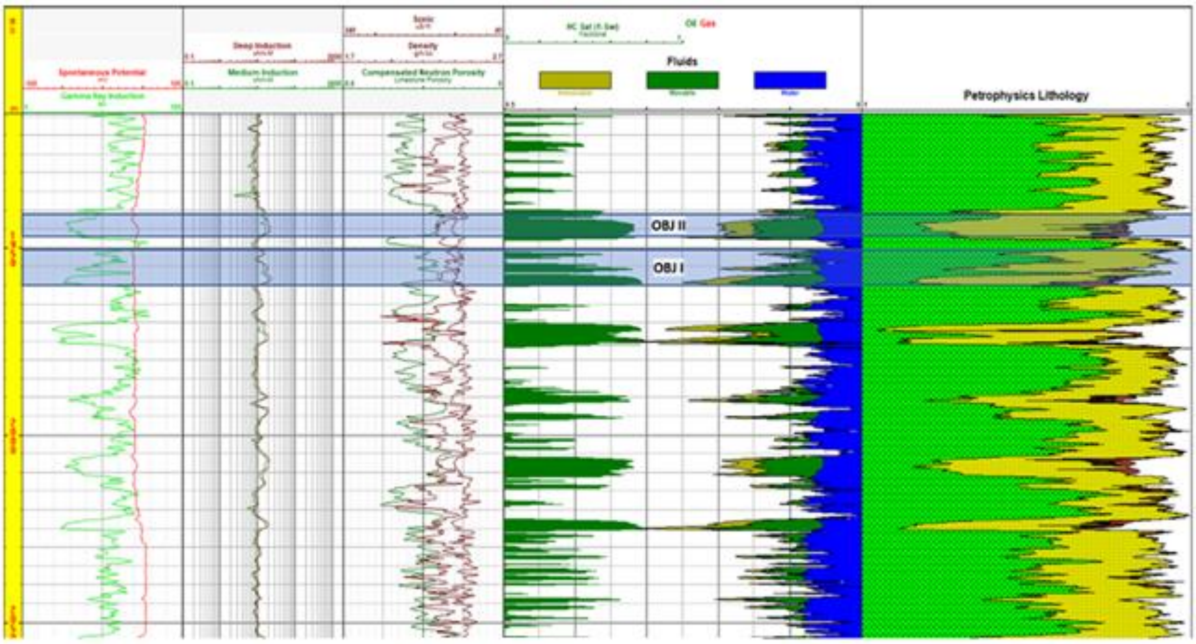


Figure 4-34: LOG MOTIF OF WELL BIHUBAR-3A

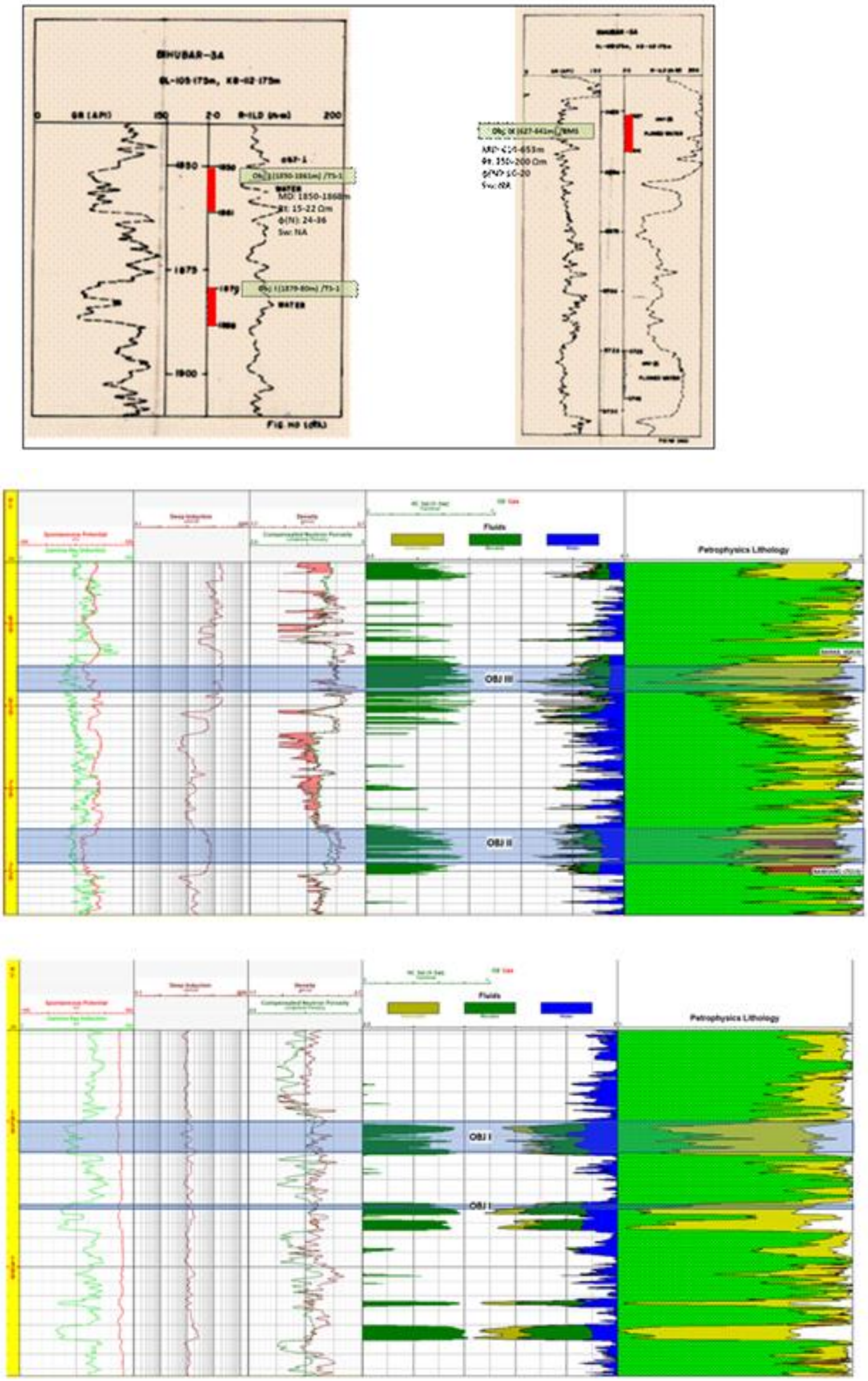
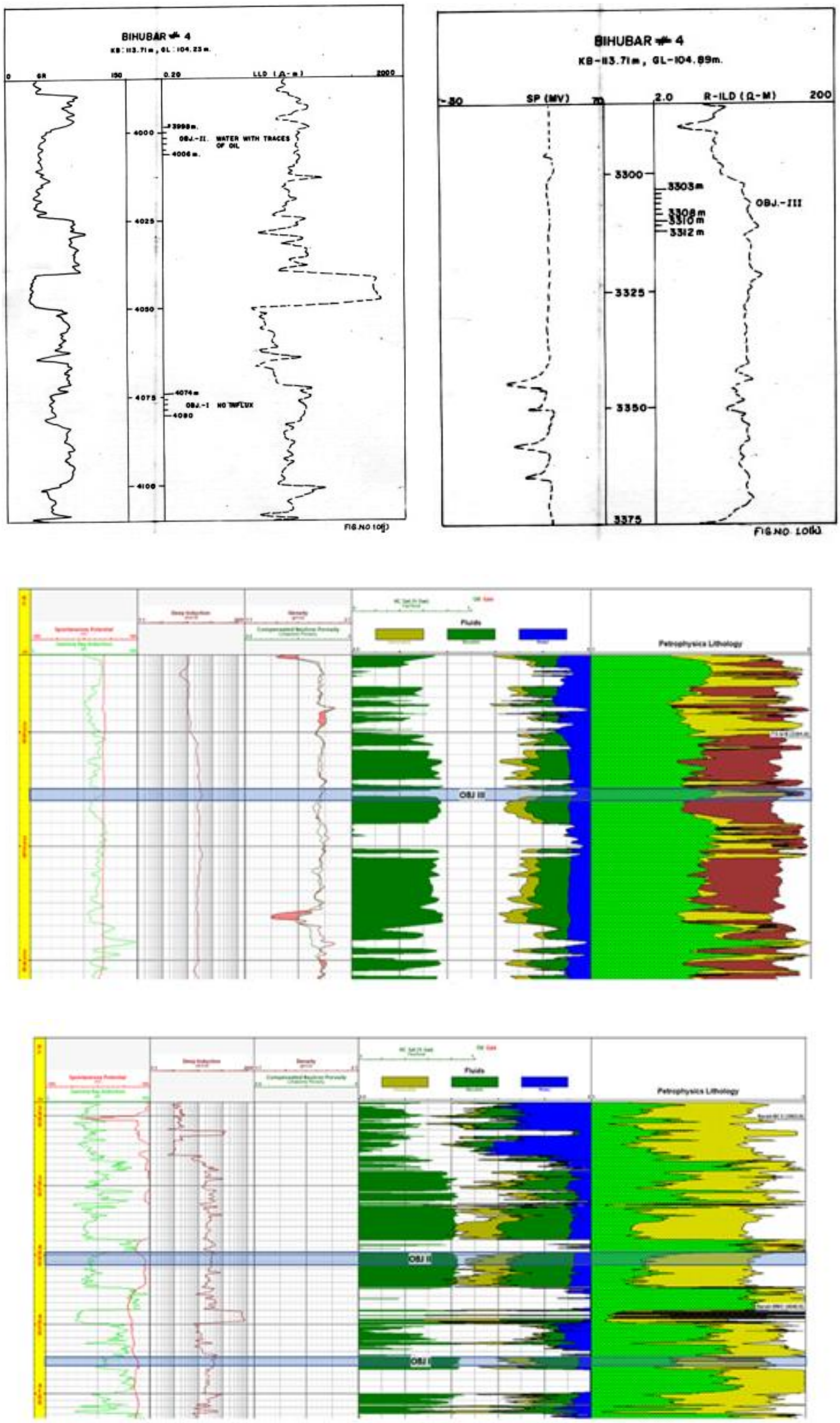


Figure 4-35: LOG MOTIF OF WELL BIHUBAR-4



4.3.3 Well testing and workover history

In Bihubar Field, 5 Exploratory wells have been drilled and tested. The well-wise/object wise testing details are given in **Table 4-22**.

Table 4-22: PRODUCTION TESTING RESULTS OF BIHUBAR WELLS

Well	Object	Sand	Perforation Range m	Flow Test Results	Status
Bihubar-1 Abandoned	Obj-I	TS-VA	3214-3220	Poor influx. While changing over from well fluid to KCl solution for testing higher up sand, **small quantity of oil was observed**. The sand was then retested with CHDST and at a drawdown of 100 ksc fluid started flowing @300 l/hr before ceasing to flow. 3.7 cum of formation water surfaced with a maximum salinity of 2.817gm/l.	Tight sand. Water bearing with oil in traces
	Obj-II	TS-IVB	3165-3175	Approx. 42.75 cum of water was knocked by compressor application **without any trace of oil and gas.**	Poor influx
	Obj-III	TS-II	2522-2530	Not tested due to poor cement bond	Not Tested
BHBR-2 Abandoned	Obj-I	BMS	4461-4466	Poor Influx. While conditioning the hole prior to CHDST, **Gas with traces of oil was observed in the mud.** Conventionally tested Barefoot formation but very poor Influx except very feeble gas . Plugged back (BP)	Tight Sand with **traces of Gas** Bad Hole Cond+Fish
	Obj-II	**BMS**	**4364-4374**	Produced **25-30m^3 of oil, 125-130m^3 of water & continuous flow of gas**, water salinity 5.148 gm/l. Could not be tested further due to suspected channelling Plugged back (CP)	**Presence of viscous oil with gas.** Flow did not sustain. **Oil content 15%-20%**
	Obj-III	BCS	4315-4320 4300-4310	Produced 41.5m^3 of water and **3.7m^3 of oil**, water salinity 5.26-5.5gpl.	3 zones tested with **flow/recovery of water, oil and gas observed**. Poor cementation, formation damage suspected.
			4281-4290	Produced 5.5m^3 of water **traces of oil and feeble gas**. Surfaced flow –nil total influx-3.80 m^3 (**60-100 lt of oil** rest water, silty mud slurry, **feeble gas** (tested both the intervals) water salinity 2.8-4.8 gm/ll.	

			4281-4290 (Repeat)	Repeat: **Surface flow-feeble gas total influx=2.3m^3,100-150 lt of oil,**1.2m^3 of silty slurry,1.1m^3 of muddy water, water salinity 3.2-4.09gpl, formation pressure-562.5 kg/cm^2 Plugged back (BP)	
	Obj-IV	BCS	4185-4197	Muddy Water Influx of 269 cum. Salinity 1.93 gms/l to 4.094 gms/l **with traces of floating oil.** Plugged back (CP)	Water bearing **with traces of oil & gas**
	Obj-V	**BCS**	**4100-4109**	Influx of water @, 2lt/min with **traces of oil, feeble gas**, Total influx-7.79 cum, water-7.74 cum, oil-50 lt, mild flow of gas with salinity:1.87gm/l, Formation pressure-422.5 ksc	Water bearing **with traces of oil & gas**
	Obj-VI	Barail	3963-3970, 3975-3980	Influx of water @, 2lt/min **with traces of oil, feeble gas**, Total influx-7.79 cum, water-7.74 cum, oil-50 lt, mild flow of gas with salinity:1.87gm/l, Formation pressure-422.5 ksc	Water with **feeble gas,** Well abandoned by placing two cement plugs.
BHBR-3	Obj-I	Girujan Clay	1951-1960	Only Water Influx with trace oil. + Heavy Sand cut. No sustained flow. Plugged back (BP)	Water bearing
	Obj-II	Girujan Clay	1942-1947	The tubing string got choked during activation (2nd compressor application) and circulation could not be established. The tubing got stuck and could not be released (heavy formation sand cut was suspected) so the object could not be tested completely.	Unstable hole. Inconclusive Testing
BHBR-3A Abandoned	Obj-I	TS-1	1879-1880, 1850-1861	1.83m^3 of formation water with fine sand. Plugged back (BP)	Water bearing.
	Obj-II	BMS	725-745	Water bearing, sal 0.3-0.4 gpl Plugged back (BP)	Water bearing.
	Obj-III	BMS	627-641	Water bearing; sal 0.2-0.3 gpl Plugged back (CP)	Water bearing.
BHBR-4 Abandoned	Obj-I	BCS-III	4074-4080	Poor influx. Plugged back (BP)	Tight formation
	Obj-II	BCS-IV	3998-4006	Water bearing with **traces of oil.** On opening annulus to subdue the well **flow of oil up to 0.25 cum was observed which subsequently ceased**. Plugged back (BP)	Water bearing with traces of oil
	Obj-III	TS-5B	3310-3312	Poor influx; Water bearing	Water bearing

4.3.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study and PVT data/ results.

Formation dynamics tests (Well BIHUBAR-1)

No MDT/RFT/SFT has recorded in the Bihubar wells.

4.3.5 Geology and Reservoir Description of BIHUBAR Field:

The geology of the area has been comprehensively reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.3.5.1 Geological correlations, sections and maps (BIHUBAR Field):

The Laxmijan-Bihubar area, situated to the south of River Brahmaputra, lies along the Naga Schuppen belt which is a narrow linear imbricated thrusted zone of eight to nine major thrust slices along which Paleogenes of Indo-Myanmar mobile belt has moved north-westwards relative to buried Basement of the Assam Shelf. The Naga Schuppen Zone flanks the Assam Shelf which is to the northwest. However, extension of the Shelf sediments in the subsurface is also established further southeast with such sediments being encountered in all the Bihubar wells. Geologically, Assam Shelf is defined as the Alluvium covered extension of the Shillong and Mikir Massifs to the ENE, and is a narrow belt of sediments about 100 km wide and bounded by two thrust belts to the north in the Eastern Himalayas and the southeast viz. Naga Schuppen Belt, respectively. The imbricate thrusted zone viz. Naga Schuppen belt exposes Tertiary sediments (Tipams in the Laxmijan-Bihubar area) along different thrust slices. The belt is bounded by Naga Thrust in the north west and Disang Thrust in the southeast. The overthrusts bifurcate and rejoin either with the Naga Thrust or Disang Thrust.

The Namdang High is an anticlinal fold exposing topmost part of Barail in its core and plunging towards Bihubar and Laxmijan. It is an asymmetrical fold with a gentle southeastern limb and steep northwestern limb. Laxmijan-Bihubar Fields lie on the southeastern limb of the anticline and reservoir lithology are the sands within Tipam and Barail Groups trapped in this structural setting. The seismic data of the Laxmijan-Bihubar areas and correlation of drilled wells show the presence of the structural high which has been named Laxmijan-Bihubar High. This sub-thrusted Laxmijan-Bihubar High is separated from the Geleki High towards the west- northwest by a Low. A prominent arcuate transverse fault hading southwards separates Laxmijan area from the Bihubar area. The areas are further dissected by a number of faults trending NE-SW resulting in a number of discrete blocks and culminations. Geleki oil field to the west-northwest is updip to the Bihubar and Laxmijan structures for Barail zones. Most of the in-place oil volumes in the area are confined within multi-cycle sandstone reservoirs belonging to the sandstones of Tipam Group and the Barali Group of sediments.

The Chalimsen and Naga thrusts are two major faults which pass through the Bihubar wells. The Chalimsen thrust brings the Barails over Namsang whereas the Naga thrust brings the Tipam Sandstones over the Girujans. The sequence below the Naga Thrust, starting from Girujan Clay is a normal succession. In general, the stratigraphy of the sequence at Bihubar structure is about 250 m updip as compared to Laxmijan but is about 300m lower to the Geleki structure.

The hydrocarbon reservoirs of this field occur in the sand–shale sequence of the Barail (Oligocene) section (both BCS and BMS) and Tipam sandstones. The reservoirs are defined by heterogeneous lithology of medium to fine grained tight sandstone, finely interlaminated with siltstone/shale(occasionally carbonaceous) within the Barail. The entrapment has been interpreted to be strati-structural. The Barail sediments in the area are primarily deltaic in origin where the distributary channels of the overlying Rudrasagar Formation consisting of Coal-Shale Sequence prograded over the delta front environment of the Demulgaon Formation which is also known as the Barail Main Sand (BMS) The sediments unconformably overlying the Barails belong to the Tipam Group of Miocene age which were deposited under fluvial depositional conditions in mostly high energy environment as braided channels. After the close of Tipam times, positive movements resulted in the emergence of landform sand subsequent erosion are reflected in the unconformable relations between the Tipams and overlying sediments consisting of arenaceous units with sub equal proportion of claystone, clay and silt of Moran Group during Pliocene-Pleistocene. The Recent Alluvium constitutes the youngest stratigraphic unit in the Basin. The stratigraphic column of Bihubar area is presented in a tabular form.

Seismic sections in Laxmijan-Bihubar-Geleki Fields are given in **Figure 4-36 and Figure 4-37.**

Figure 4-36: SEISMIC SECTION ACROSS LAXMIJAN-BIHUBAR AND GELEKI FIELDS

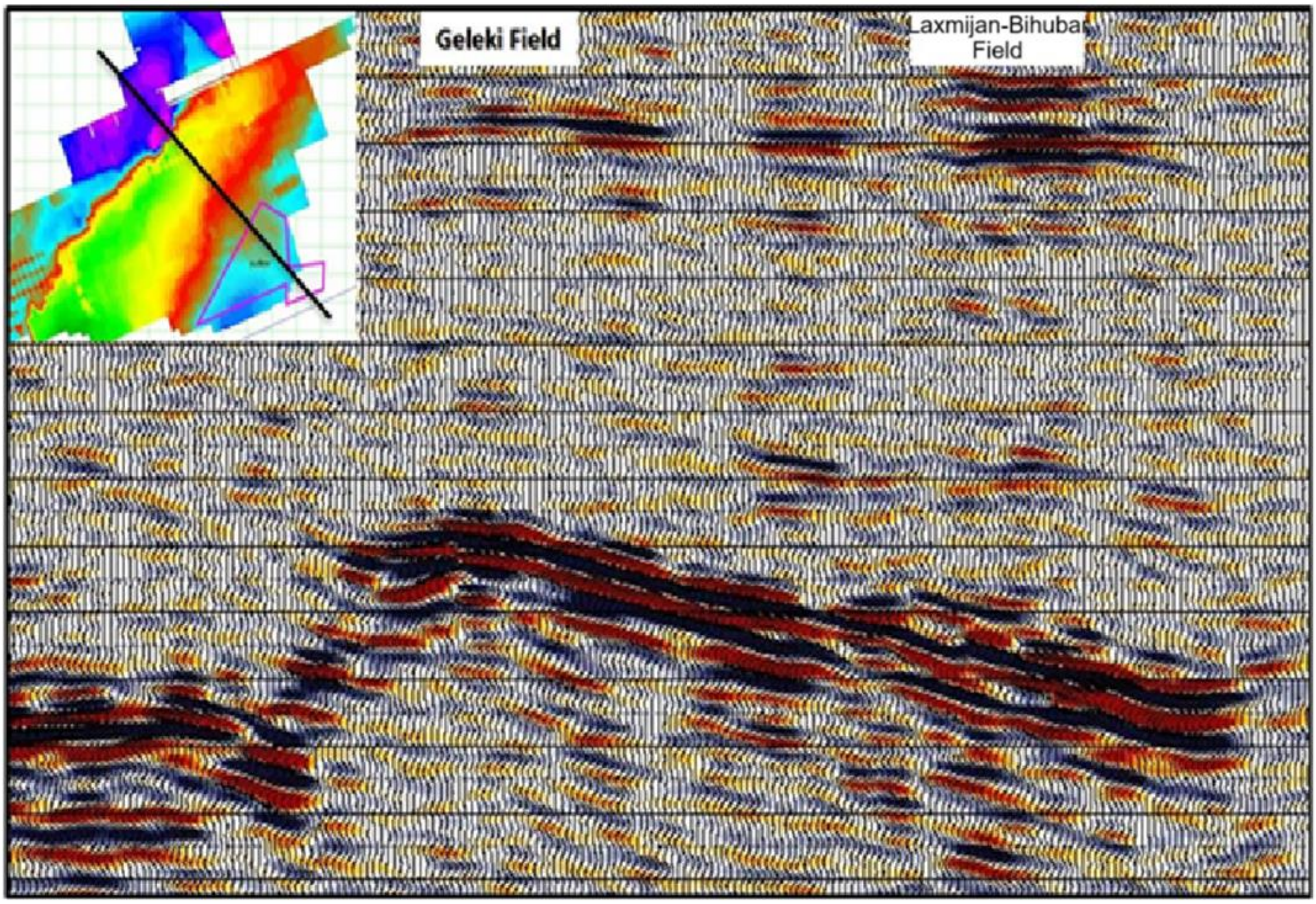
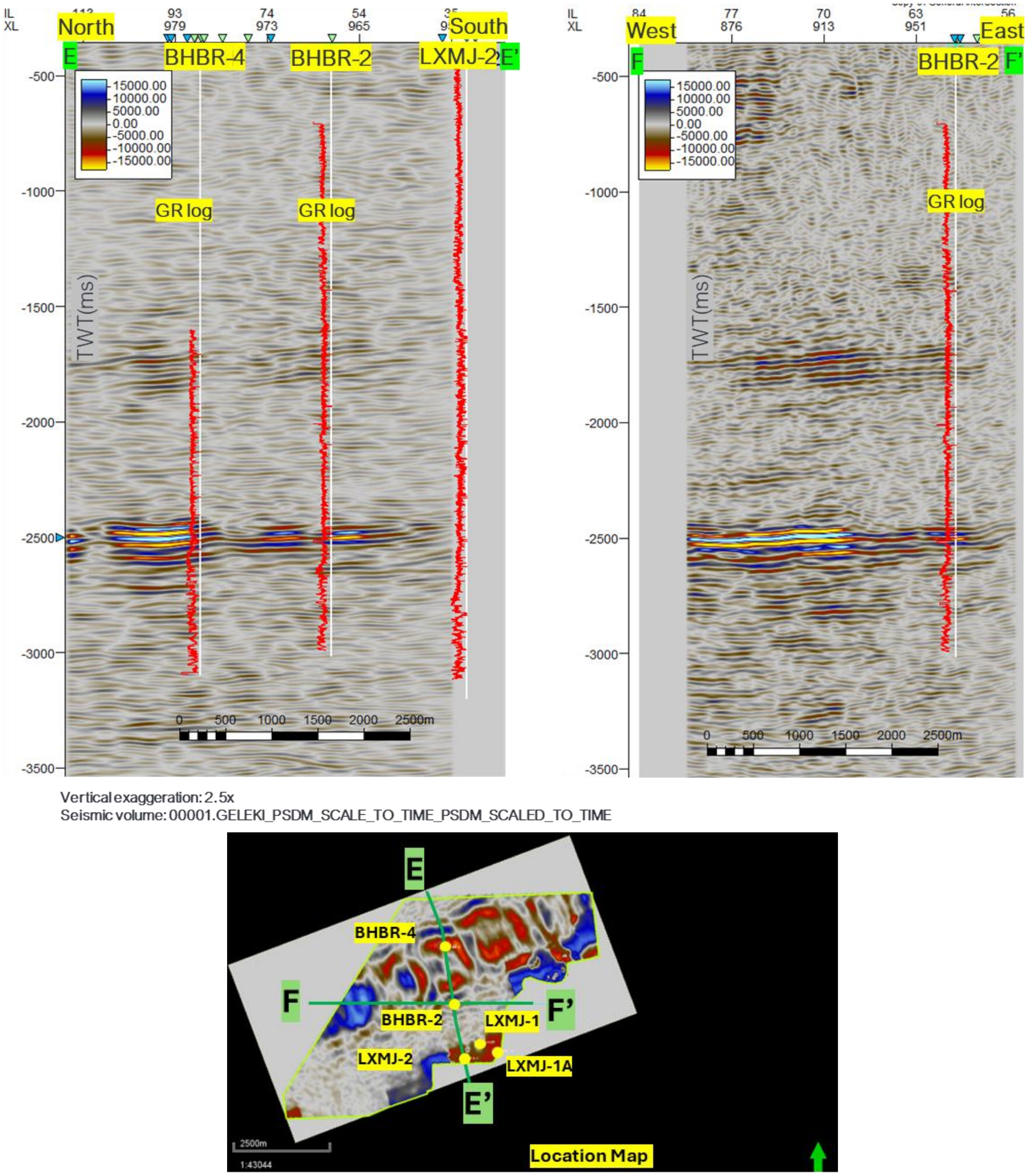


Figure 4-37: SEISMIC SECTION ACROSS WELLS BIHUBAR-2, BIHUBAR-4 AND LAXMIJAN-2



A) <u>STRUCTURE (BIHUBAR Field):</u>

Bihubar structure falls on eastern side of Geleki oil field. Available seismic data indicates that Bihubar structure up to the Tipam level is a northern plunging structure influenced by the Naga Thrust. The structural disposition is depicted in the depth structure contour map on top of TS-5A and BMS shown in **Figure 4-38 and Figure 4-39** respectively.

Figure 4-38: DEPTH STRUCTURE MAP ON TOP OF TS 5A

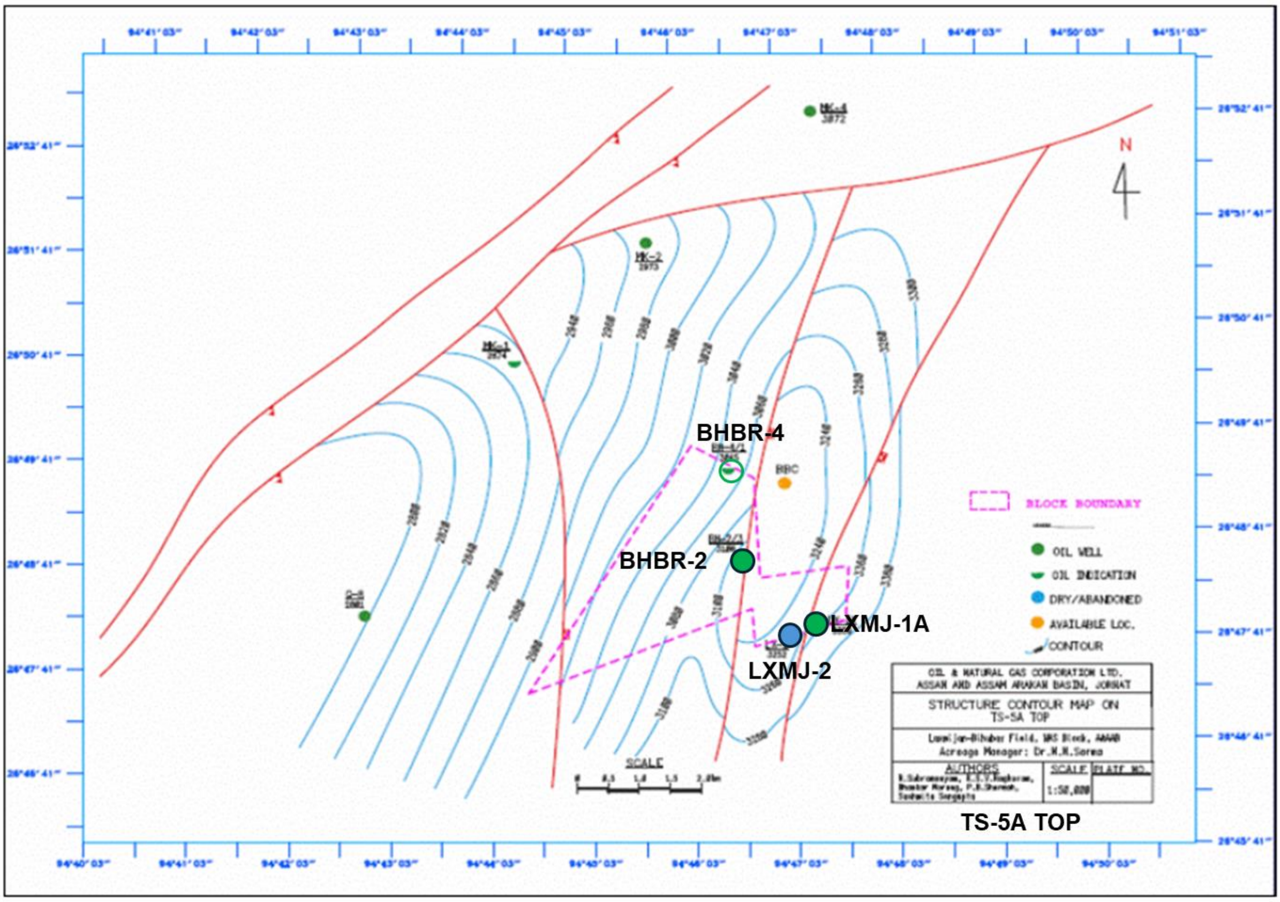
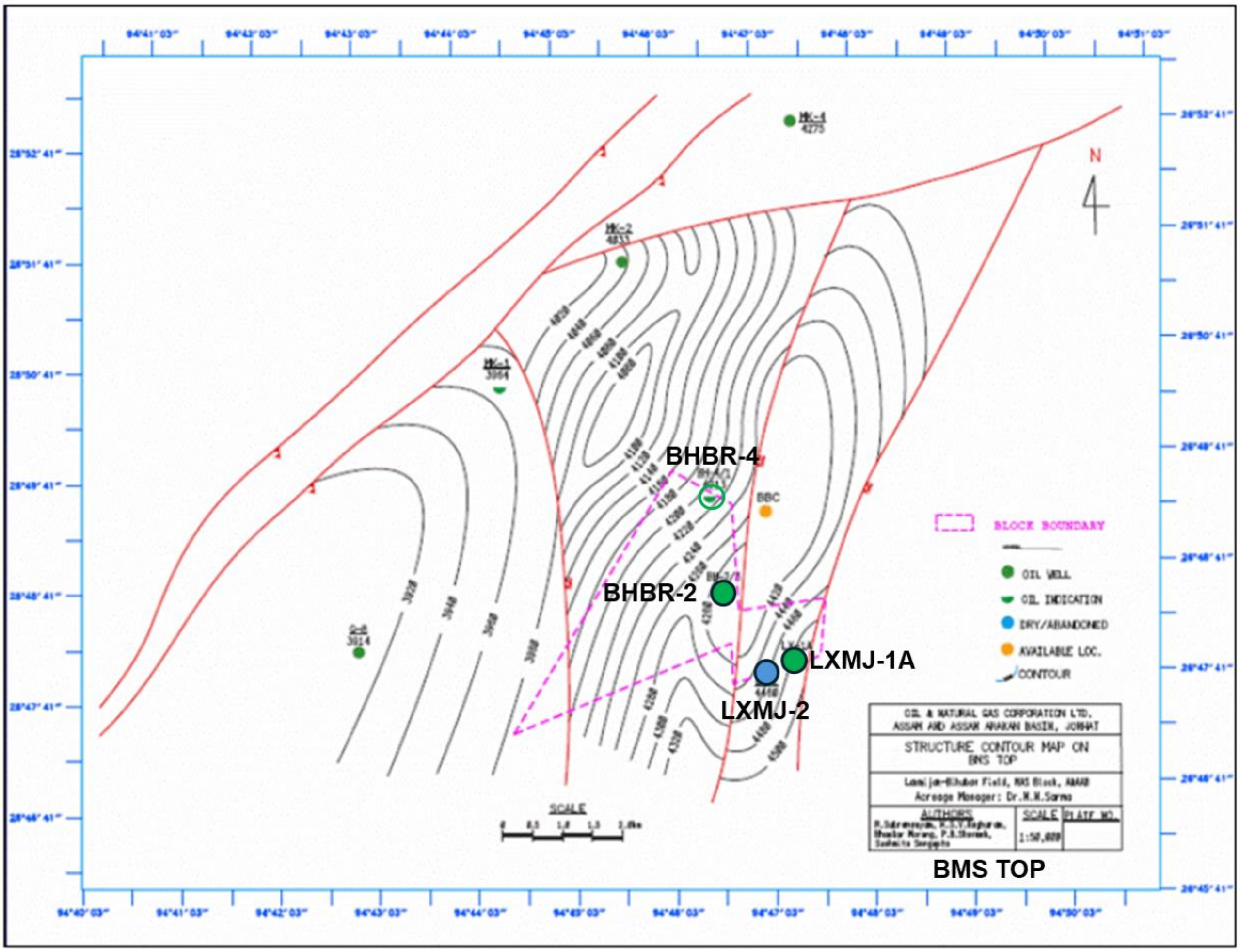


Figure 4-39: DEPTH STRUCTURE MAP ON TOP OF BMS



The NW-SE electro-log correlation profile, both stratigraphic and structural, in the Bihubar-Laxmijan area, along wells Bihubar-4, Bihubar-2, Laxmijan-2 and Laxmijan -1A is shown in **Figure 4-40 and Figure 4-41.**

Figure 4-40: STRATIGRAPHIC ELECTRO LOG CORRELATION OF WELLS BIHUBAR -4, 2 AND LAXMIJAN-2, 1A

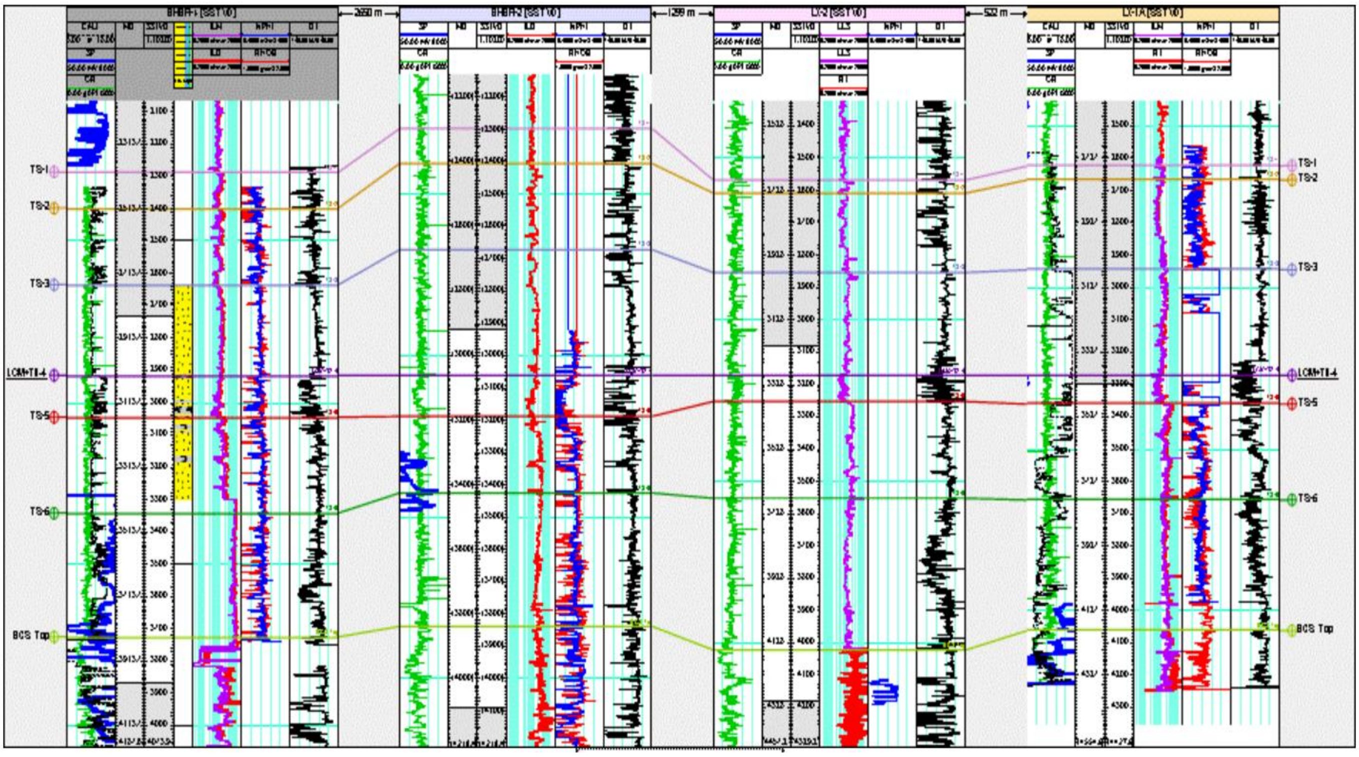
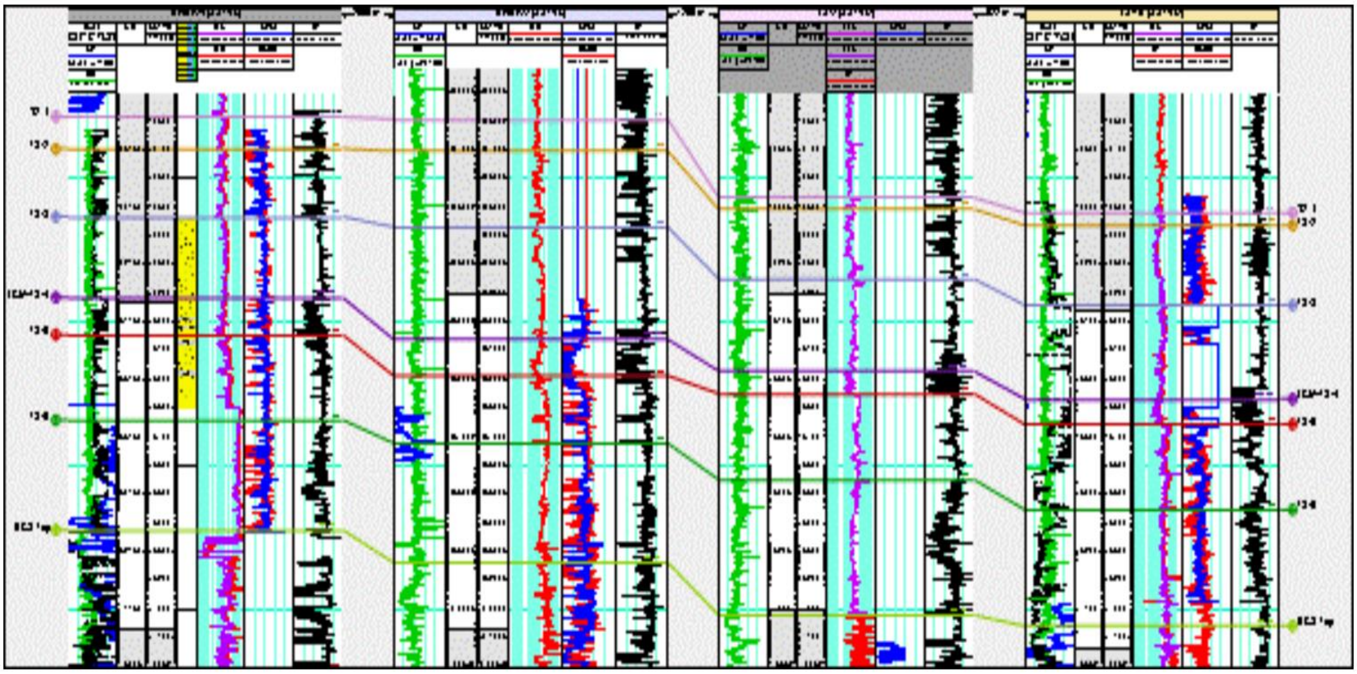


Figure 4-41: STRUCTURAL ELECTRO-LOG CORRELATION OF WELLS BIHUBAR -4, 2 AND LAXMIJAN-2, 1A



Stratigraphic column of Bihubar area based on well data is depicted in **Table 4-23 below**.

Table 4-23: STRATIGRAPHIC COLUMN OF BIHUBAR AREA

GE	FORMATION/ GROUP	THICKNESS (M)	LITHOLOGICAL DESCRIPTION
Recent-Pleistocene	Alluvium	100	Unconsolidated sands with gravel, silt and minor clays
Miocene	Tipam	280	Mainly coarse unconsolidated sand with minor soft clay
	Safrai	85	Sandstone : Coarse grained Polymeric Conglomerate / coarse Sandstone
Oligocene	Barails	155	Carbonaceous shale and coal with alternations of sand & shale.
Thrust			
Plio-Miocene	Namsang	235	Sandstone / Claystone
	Upper SSt Girujan clay Tipam Sandstones	1500	Sandstone / Claystone
Thrust			
Plio-Miocene	Girujan Clay Tipam	1326	Claystone and Dominantly sandstone with intercalations of minor shale
Oligocene	Barails	690+	Sandstone, Shale, Coal

4.3.5.2 Reservoir parameters and hydrocarbon estimates (BIHUBAR Field):

4.3.6 Studies on Bihubar-Laxmijan Area

A Field development plan (FDP) for the combined Bihubar-Laxmijan cluster was prepared by Megha Engineering & Infrastructure Ltd (MEIL) in the year 2019. Two major parts in this study were recognized. The first part is geological and geophysical interpretation of the Block to better understand the petroleum system including extensive petrophysical work and to be a feeder for the second part, which is the reservoir engineering and economic reserve evaluation.

Table 4-24 shows the derived parameters for the objectives tested in the wells drilled so far. The table follows with the individual interpretation of each zone carried out by MEIL.

Table 4-24: DERIVED PARAMETERS FOR THE OBJECTS TESTED IN THE DRILLED BIHUBAR WELLS

Well	Object	Sand	Depth Range	FlowTest Type	Flow Test Results	Status	HC Sat	Porosity	Sw
BHBR-1	Obj-I	TS-VA	3214-3220	CHDST	Injectivity NIL	Dry			
	Obj-I	TS-IVB	3165-3175	CHDST	Injectivity NIL	Dry			
	Obj-III	TS-II	2522-2530	CHDST	Not tested due to poor cement bond	Not Tested			
BHBR-2	Obj-I	BMS	4461-4466	CHDST	Gas Traces. No Influx.	Bad Hole Cond+ Fish			
	Obj-II	BMS	4364-4374	CHDST	Presence of viscous crude oil with gas. Capable of self-flow oil content 15%-20%	Oil may be highly viscous. No sustained flow	38	0.11	77
	Obj-III	Barail Ch.	4310-4300	CHDST	100-150ltr of oil influx. Continuous flow of feeble gas	Oil may be highly viscous. No sustained	22	0.11	67

Well	Object	Sand	Depth Range	FlowTest Type	Flow Test Results	Status	HC Sat	Porosity	Sw
						flow			
	Obj-IV	Barail	4185-4197	CHDST	Muddy Water Influx	Dry	11	0.06	89
	Obj-V	Barail	4100-4109	CHDST	Traces of oil and feeble gas	Trace HC	19	0.08	81
	Obj-VI	Barail	3963-70, 75-80	CHDST	Traces of gas	Trace Gas	37	0.07	63
BHBR-3	Obj-I	GC	1960-1951	OHDST	Only Water Influx with trace oil. + Heavy Sandcut. No sustained flow	Dry	35	0.12	65
	Obj-II	GC	1947-1942	OHDST	Unstable hole. Test Inconclusiv e.	N/A	55	0.19	45
BHBR-3A	Obj-I	TS-1	1880-79, 61-50	CHDST	Water bearing	Dry	45	0.22	55
	Obj-II	BMS	745-25	CHDST	Water bearing	Dry	45	0.09	55
	Obj-III	BMS	641-627	CHDST	Water bearing	Dry	59	0.1	41
BHBR-4	Obj-I	BCS-III	4074-4080	Convent ional	Water bearing	Dry	82	0.18	18
	Obj-II	BCS-IV	3998-4006	Convent ional	Water bearing with traces of oil	Dry	82	0.25	18
	Obj-III	TS-5B	3312-3310	Convent ional with DST packer	Water bearing	Dry	50	0.1	50

Current Oil and Gas Volumes In-Place

Initial hydrocarbon resources have been estimated based on the production testing results, reservoir parameters and log motifs of the drilled wells. The reservoir parameters and hydrocarbon resources of Bihubar Field are tabulated in **Table 4-25 and Table 4-26 respectively**.

Table 4-25: RESERVOIR PARAMETERS & VOLUMETRIC ESTIMATION OF BIHUBAR FIELD

Field	Reservoir	Area	He	Phi	Hydrocarbon saturation		FVF		API	SPGR	GOR Sm3/m3	O+OEG
	Sand/ layer	SKM	m		So	Sg	Bo	Z/Bg				MMTOE
Bihubar	BCS Obj-III	0.600	10	0.11	0.55	-	1.1800	-	32.1	0.8649	280	0.35
	BCS Obj-V	0.495	4.97	0.08	0.70	-	1.1800	-	32.1	0.8649	280	0.13
	BMS	0.450	7.5	0.11	0.60	-	1.1800	-	32.1	0.8649	280	0.22
												0.70

Table 4-26: HYDROCARBON IN-PLACE(2P) OF BIHUBAR FIELD

Field	O+OEG MMTOE
BIHUBAR	**0.7**

Erstwhile Operator-reported estimates on record:

A gas estimate of **0.15 MMTOE** had earlier been reported for the LAXMIJAN-BIHUBAR Cluster

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the currently reported estimates.

4.3.7 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Bihubar Field is the **Geleki GGS** at a distance of **25 KM**

Well heads are available at wells Bihubar-2 and Bihubar-4 (abandoned).

AA/ONDSF/ASSAM/2025 (A&AA) NAHORHABI – CHARAIDEO - BLOCK

4.4 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) NAHORHABI- CHARAIDEO BLOCK

The Charaideo – Nahorhabi block is located in the Assam Shelf area of the Category I composite Assam & Assam-Arakan Basin (A&AA Basin) at approximately 6 Km South of prolific onland Lakwa Field within the state of Assam situated in the Assam Shelf area of the Assam & Assam Arakan Basin (A&AA Basin) in the northeast corner of India. The Nahorhabi Field is situated north of Charaideo Field.

Charaideo Field along with the neighboring Nahorhabi Field together covers an area of 78.48 sq. km under this DSF Bid Round IV. The co-ordinates of the endpoints defining the cluster boundary are tabulated below in **Table 4-27**. The area is a single area with 2 discoveries/fields (Charaideo-1 & Nahorhabi-1) and 7 additional wells have been drilled.

The Nahorhabi Field is located at a distance of approximately 3 km South of the prolific onland Lakwa Field and 25 Km NE of Nazira Town. The Nahorhabi Field alone covers an area of around 30 sq. km. The coordinates of the end points defining the block boundaries are tabulated in the table below, (**Table 4-27**) and its location map is shown in **Figure 4-42**: Also, its location with respect to various oil and gas fields in Assam Shelf is shown on **Figure 4-43.**

Table 4-27: COORDINATES OF THE BLOCK BOUNDARIES: NAHORHABI-CHARAIDEO BLOCK

CRDO-1 - NAHB-1 Boundary Points		
Area: 78.48 sq km		
Point	**Longitude**	**Latitude**
A	94° 47′ 00.000″ E	26° 57′ 26.534″ N
B	94° 48′ 27.378″ E	26° 57′ 49.651″ N
C	94° 48′ 27.378″ E	26° 58′ 00.000″ N
D	94° 49′ 23.237″ E	26° 58′ 00.000″ N
E	94° 49′ 23.225″ E	26° 58′ 32.706″ N
F	94° 49′ 47.427″ E	26° 58′ 38.952″ N
G	94° 51′ 56.912″ E	26° 58′ 39.212″ N
H	94° 52′ 30.115″ E	26° 59′ 06.462″ N
I	94° 53′ 17.399″ E	26° 59′ 09.054″ N
J	94° 53′ 59.254″ E	26° 59′ 10.468″ N
K	94° 55′ 39.813″ E	26° 58′ 57.097″ N
L	94° 55′ 49.280″ E	26° 56′ 14.405″ N
M	94° 52′ 18.081″ E	26° 54′ 50.176″ N
N	94° 52′ 10.188″ E	26° 54′ 47.482″ N
O	94° 50′ 47.444″ E	26° 54′ 47.476″ N
P	94° 50′ 00.000″ E	26° 54′ 47.476″ N
Q	94° 50′ 00.000″ E	26° 56′ 00.000″ N
R	94° 47′ 00.000″ E	26° 56′ 00.000″ N
A	94° 47′ 00.000″ E	26° 57′ 26.534″ N
Note: Point L → M follows the state boundary between Assam & Nagaland		

SL. No.	Well Name	Longitude	Latitude
1	CRDO-1	94° 53′ 25.000″ E	26° 57′ 20.000″ N
2	NAHB-1	94° 52′ 28.070″ E	26° 58′ 35.319″ N

Figure 4-42: LOCATION MAP SHOWING THE NAHORHABI-CHARAIDEO BLOCK BOUNDARY.

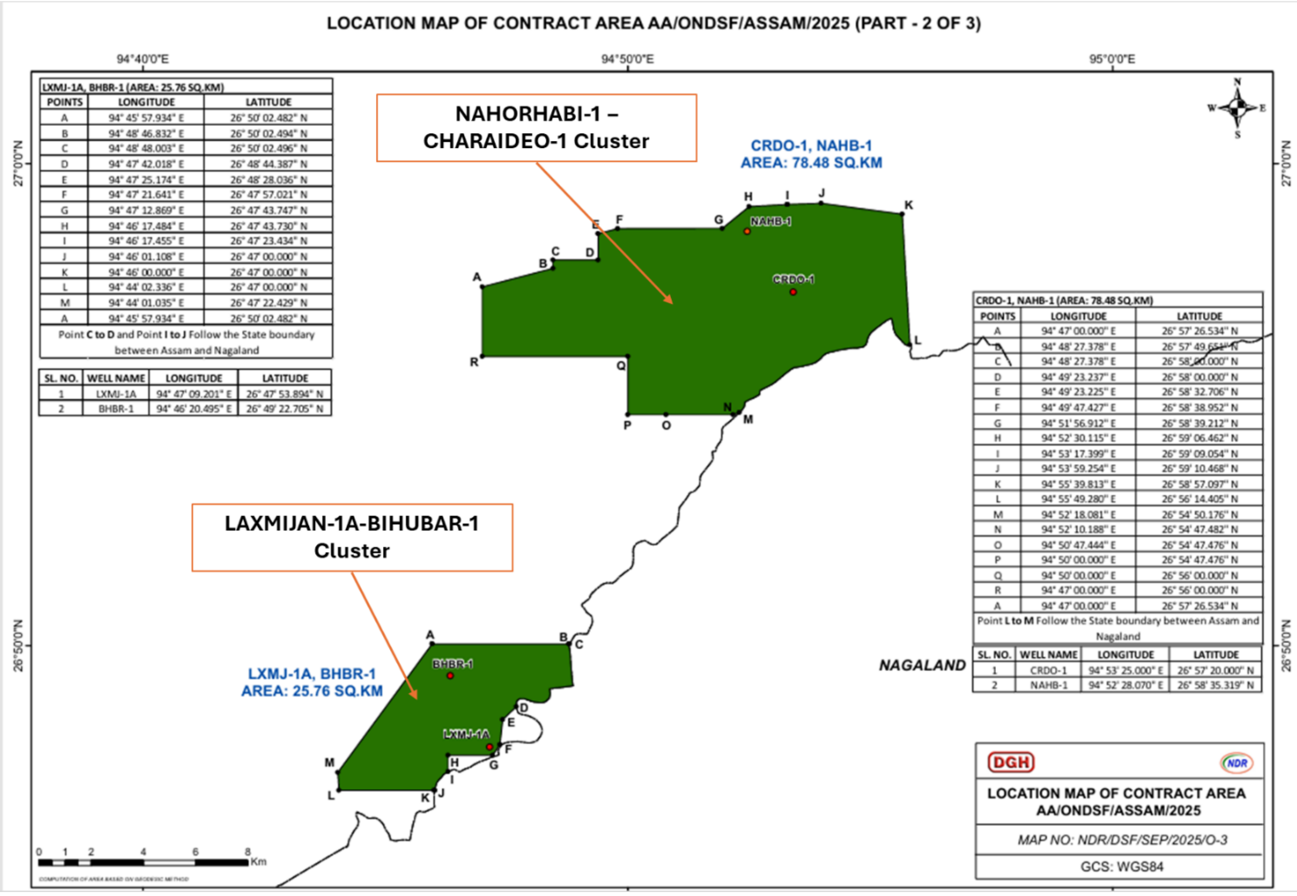
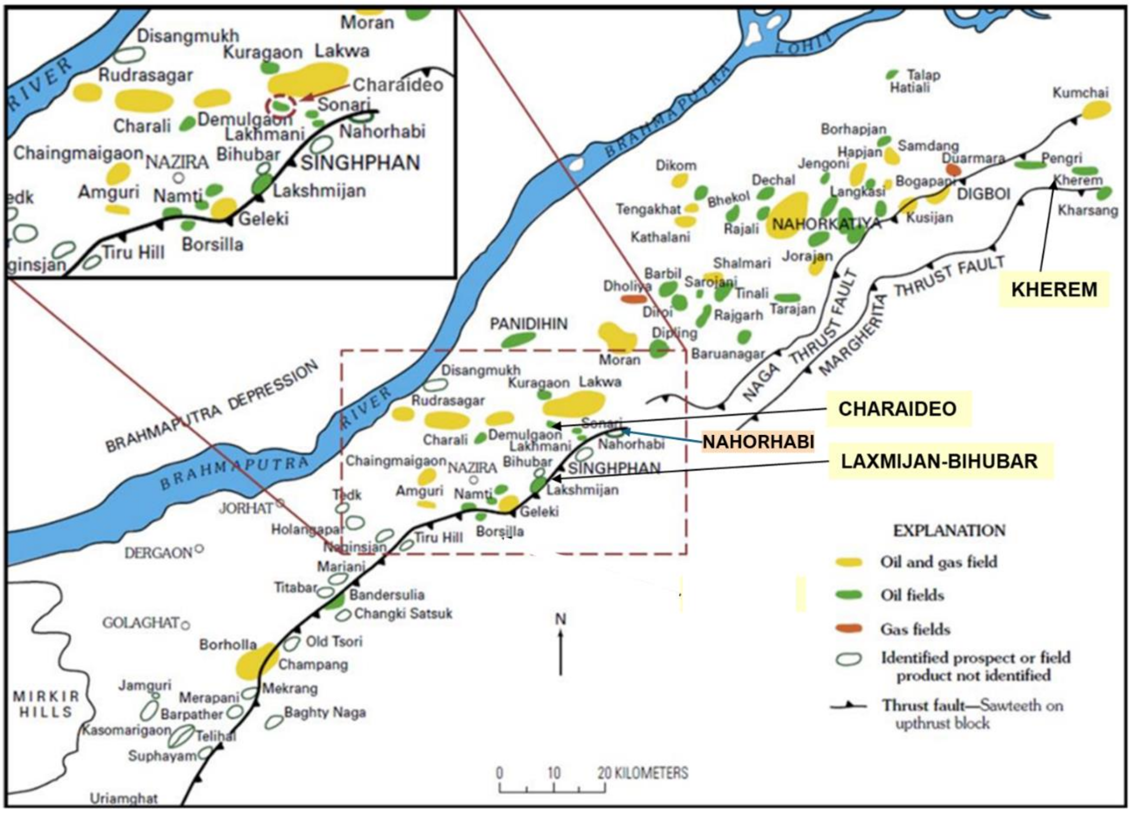
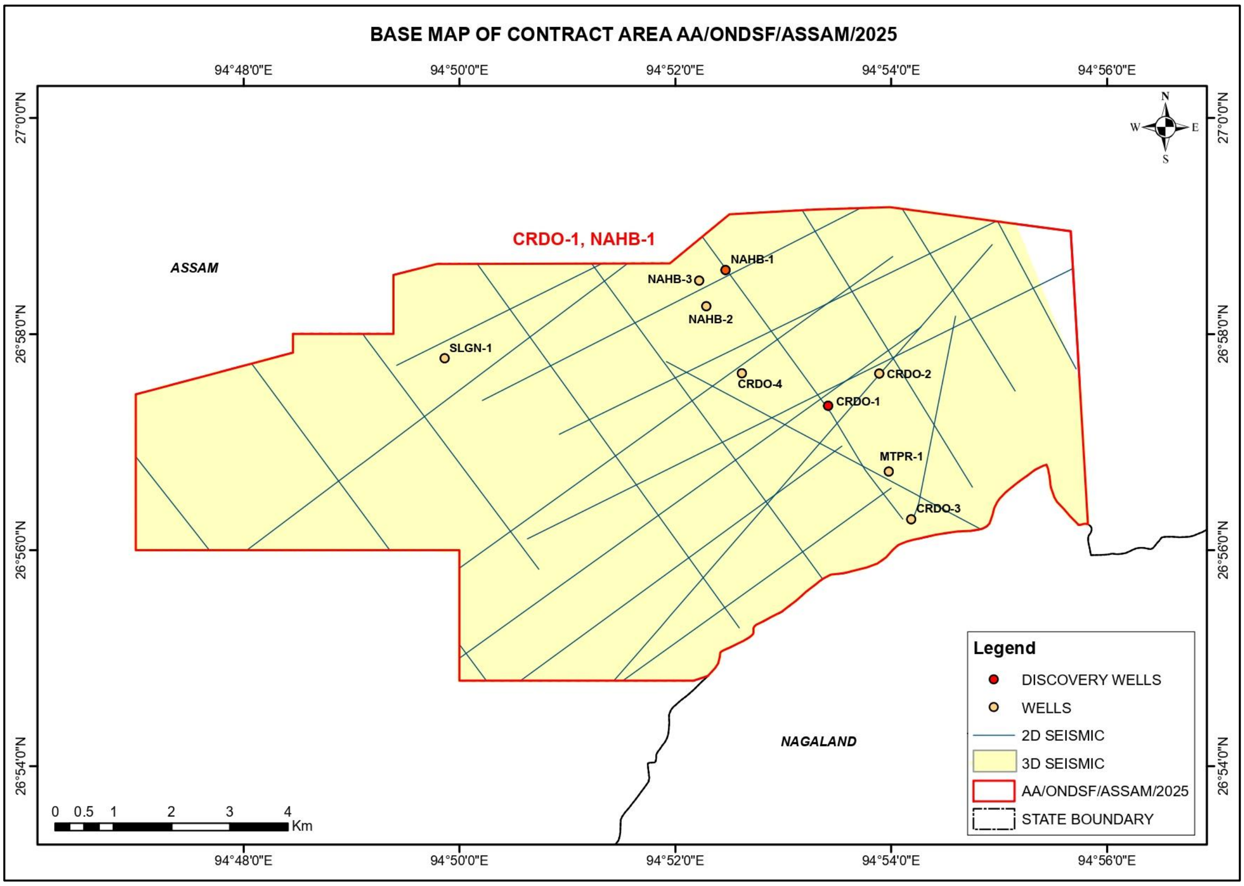


Figure 4-43: LOCATION MAP OF NAHORHABI - CHARAIDEO STRUCTURE WITH RESPECT TO PRODUCING OILFIELDS IN THE ASSAM SHELF BASIN



The available details of seismic coverage of the block are shown in **Figure 4-44**.

Figure 4-44: 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: NAHORHABI- CHARAIDEO BLOCK



AA/ONDSF/ASSAM/2025 (A&AA) NAHORHABI FIELD

4.5 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) NAHORHABI FIELD

The Nahorhabi Field is located at a distance of 3 km South of the prolific onland Lakwa Field and 25 Km NE of Nazira Town in the Assam Shelf area of the composite Assam & Assam-Arakan Basin (A&AA Basin) in the state of Assam situated in the northeast corner of India. The Nahorhabi Field covers an area of around 30 sq. km. The structure is confined between 26° 56' 06" to 26° 59' 20"latitudes and 94° 50' 00" to 94° 55' 00" Longitudes. The Nahorhabi fault closure was identified by conventional reflector seismic surveys carried out in 1973-1974 and the closure was confirmed by the subsequent survey in 1974-1975. Geophysical surveys in Assam Shelf were started in 1957 which led to major discoveries like Rudrasagar, Lakwa, Gelelki in 1960, 1963 & 1968 respectively. The Northeast-Southwest trending structure indicated two independent closures separated by a saddle. The area was further delineated by CDP Survey carried out during 1977-1978.

Nahorhabi-1 was drilled south of Lakwa in 1982 to a depth of 4505m (Barail Main Sand) and produced oil from Lower Barail Sand (LBS). During initial testing, Object-2 (4303-4309m, 4291-4299m m) in Lower Barail Sand indicated presence of OIl, Gas & Water. Nahorhabi-2 was drilled in the year 2003 and was drilled upto 4550m and in total seven objects were tested and indication of Oil & water was observed at different levels. Nahorhabi-3 was drilled in 2009 to explore further hydrocarbon bearing layers encountered in Nahorhabi-1 and 2. This well was drilled upto 4705m and four objects were tested. There were indications of presence of hydrocarbons.

The well Nahorhabi-1 has cumulatively produced around 2500 Tons of Oil.

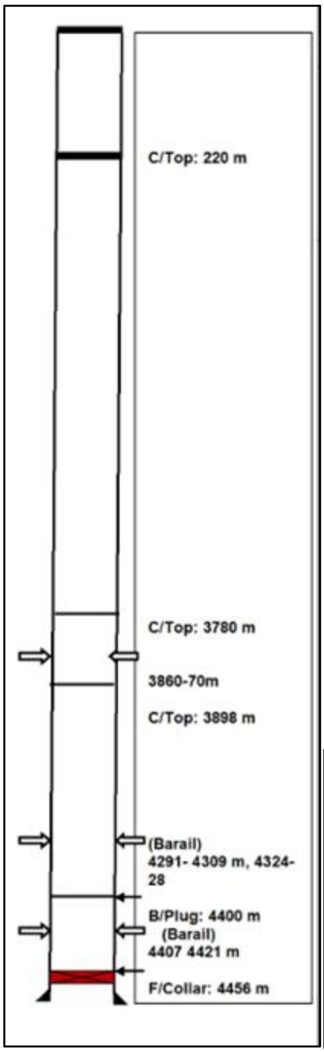
4.5.1 Drilling and well completion

Key information of drilled wells has been collated and presented hereunder. The adjoining figures wherever shown illustrate the Well Construction Diagram for key wells. Other well details like kelly bush reference depth, drilled and logged depths including well coordinates are made available in Sections through various cross-references.

In Nahorhabi structure, three exploratory wells (NAHB-1, 2 and 3) have been drilled so far. The well construction diagrams of wells Nahorhab-1, 2 & 3 are shown in **Figure 4-45, Figure 4-46 and Figure 4-47** respectively.

The general well data, casing details in Nahorhabi wells are given in **TABLE 4-28.**

Figure 4-45: WELL CONSTRUCTION DIAGRAM OF WELL NAHORHABI - 1



GENERAL INFORMATION:

Drilled Depth : 4505 m — G.L: 98.126 m
Float Collar : 4456 m — K.B: 104.82 m

CASING & CEMENTATION POLICY: 4 CP X 1O

SIZE & GRADE	DEPTH IN MTS	CEMENT RISE
20"	175	Surface
13 3/8"	1664	Surface
9 5/8"	3788	3175 m from surface
5 ½, P-110, 23 ppf	0 –2790 m	3790 m from surface
N – 80, 20 ppf	2790 – 3800 m	
P – 110, 23 ppf	3800 – 4481 m	

Figure 4-46: WELL CONSTRUCTION DIAGRAM OF WELL NAHORHABI - 2

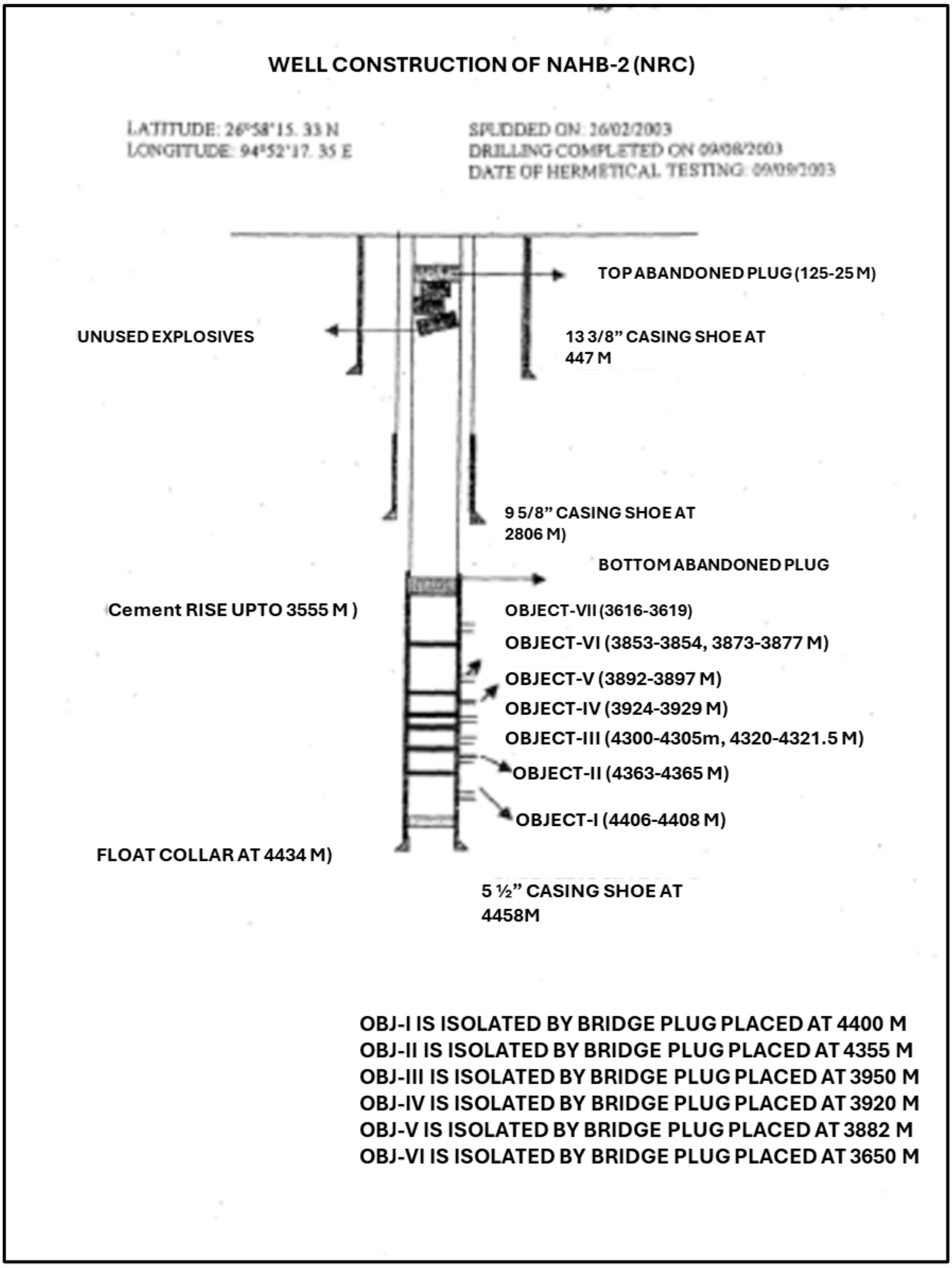


Figure 4-47: WELL CONSTRUCTION DIAGRAM OF WELL NAHORHABI - 3

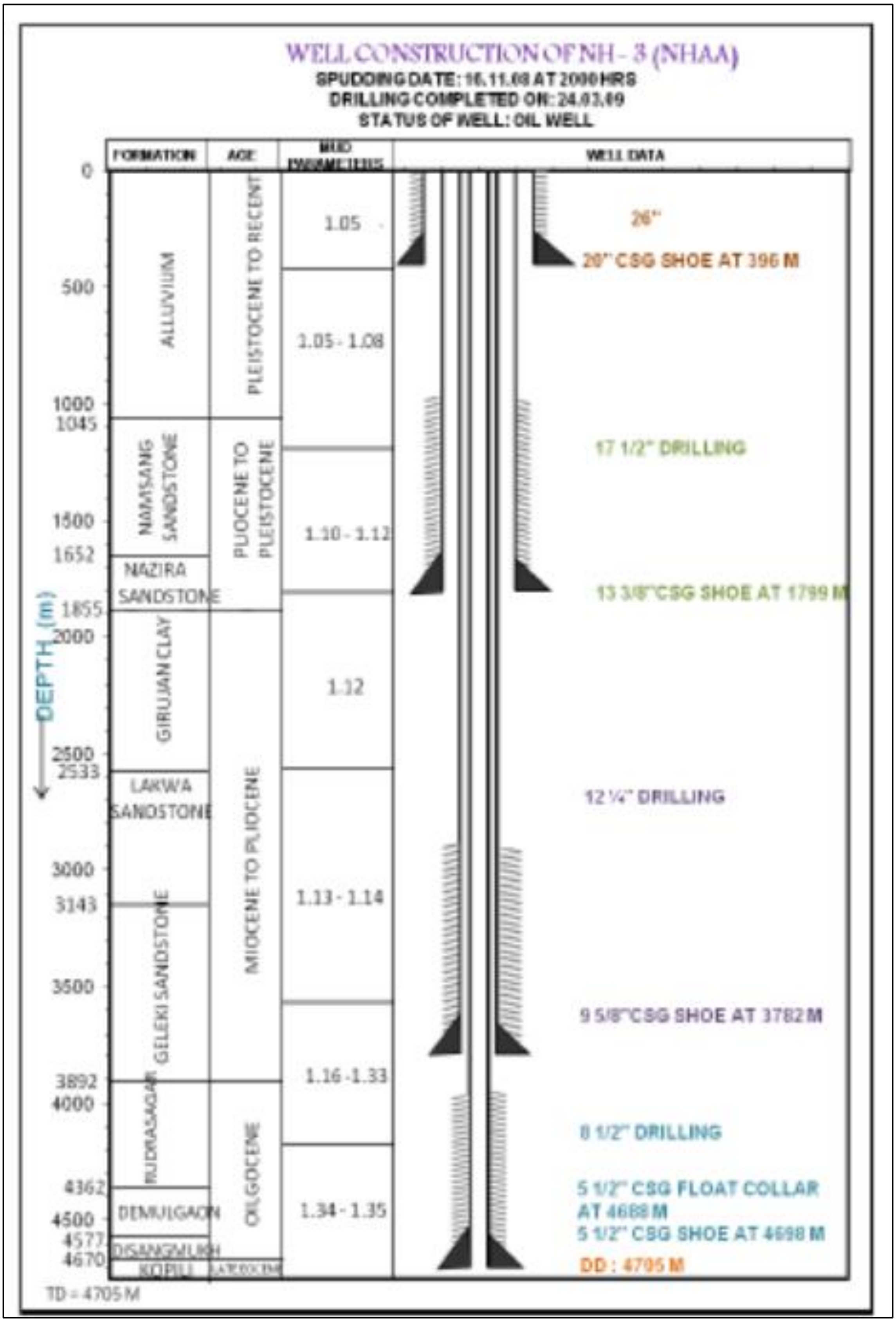


TABLE 4-28: NAHORHABI FIELD - GENERAL WELL DATA

	Nahrohabi-1	Nahorhabi-2	Nahorhabi-3
Area	Nazira, Assam		
Structure	Nahorhabi		
Well	**Nahorhabi-1**	**Nahorhabi-2**	**Nahorhabi-3**
Category	Exploratory	Exploratory	Exploratory
Co-ordinates	Lat: 26^{0} 58' 55" N	Lat: : 26^{0} 58' 15.33" N	Lat: : 26^{0} 58' 30.652" N
	Long: 94^{0} 52' 48" E	Long: 94^{0} 52' 17.35" E	Long: 94^{0} 52' 15.63" E
Rig	3DH-I	E-1400-VI	F-4900
Target Depth	4500 m	4450 m	4705 m
Drilled Depth	4505 m	4451 m	4705 m
Objective	To explore Hydrocarbon Potential of Tipams and Barails sands.	To explore Hydrocarbon Potential of Tipams and Barails sands.	To explore hydrocarbon prospects in BMS, LBS-1 & SAFRAI
Initial Testing Results	Produced Oil, Gas & Water from 4408-4421m. Testing inconclusive. Other objects were tested later through workover	Seven objects tested. Oil Indication	Four objects were tested. One object flowed Oil, Gas & Water.
KB	104.826 m	105.0 m	105.0 m
Spud date	23-02-1981	26-02-2003	16-11-2008
Drilling Completion	17-12-1981	09-08-2003	25-03-2009
Hermitical testing on	23-01-1982	10-09-2003	13-04-2009
Rig release	19-02-1982	29-04-2004	06-07-2009

4.5.2 Well logging and formation evaluation

The well logs of all discovery wells along with some key wells in the Contract Area have been reviewed. The logs recorded in various open-hole sections along with cased-hole logs and information of conventional and other wireline formation test data are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) have been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.5.2.1 Well completion and log evaluation reports availability (NAHORHABI Field):

Data and reports availability as well as logs acquired list are given in **Table 4-29, Table 4-30, Table 4-31.**

Table 4-29: REPORTS AVAILABLE FOR NAHORHABI WELLS

Well	WCR/ FER availability	Spud date	KB	Drilled Depth
Nahorhabi-1	Both available	23-02-1981	104.826 m	4505 m
Nahorhabi-2	Both available	26.02.2003	105.0 m	4551 m
Nahorhabi-3	Both available	16-11-2008	105.0 m	4705 m

Table 4-30: DATA AVAILABILITY IN NAHORHABI WELLS

Sl. No.	Data/Report	NAHB -1	NAHB-2	NAHB-3	Remarks
1	Formation Evaluation Report	✓	✓	✓	Available for all three wells
2	Well Completion Report	✓	✓	✓	Available for all three wells
3	Delineation Report of Nahorhabi Field		Available under WCR of NAHB-2		
4	Production Data	✓	✗	✗	Production data available for NAHB-1 only
5	Core Analysis	✗	✓	✓	Core analysis report available for NAHB-2 & 3
6	Bottom Hole Pressure Data	✓	✗	✗	SBHP available of NAHB-1
7	Oil and water Analysis	✓	✓	✓	Available in all the wells
9	Workover	✓	✓	✓	Testing and servicing of NAHB-1
10	Surface Facility	✓	✗	✗	Well NAHB-1 Produced Oil, Gas & Water
11	Heavy Mineral Report	✓	✗	✗	NAHB-1 only

4.5.2.2 Well logs acquired (NAHORHABI Field) :

Table 4-31: WELL LOGS ACQUIRED (NAHORHABI FIELD) :

Well	Type of Logs	Interval m
NAHB-1	Standard and Inclinometer (Russian)	180-1701, 1665-2820
	Sonic, Induction and FDC, standard, BKZ	2600-3788
	Caliper	1600-3788
	Inclinometer	1600-2700, 3800-4000, 3800-4300
	Standard, BKZ, and Latro Caliper,	3781.5-4481
	Induction, Sonic (by GOI unit)	3781-4492
	Standard	2600-3788, 3781.5-4250
	BKZ	2600-3788
NAHB- 2	HRI-BCS-CAL-GR	447-2812.3
	SPECTRAL DENSITY-DUAL SPACE NEUTRON	1750-2814.2
	AIT-NCFL-SP-HCAL-GR	4300-4395,2810.6-4024
	TLD-CNL-HCAL-GR, SONIC-GR, SONIC(SDDB)-GR	4300-4375, 2810.6-4220
	SONIC(SDDB)-GR	2810.6-4191.66
	AIT-NCFL-SP-HCAL-GR	4150-4464
	SONIC(SDDB)-GR	4150-4458
	TLD-CNL-GR-CAL	3950-4435
	CBL-VDL	3526.62-4417.5,3517-4421
	USIT	3600-4406.8,4150-4429.5,4300-4432.2
NAHB-3	HRI-BCS-SP-GR-IS	372-1801
	DLL-MSFL-GR-SP-CAL	1788-3785
	LDL-CNL-GR-CAL	1997-3785
	SDDB-GR	1788-3779
	NGT Ratios	1720-3770
	IS-GR	1788-3775
	DLL-MSFL-GR-SP-CAL	3726-4684
	LDL-CNL-GR-CAL	3770-4451
	NGT Ratios	3726-4680
	IS-GR	3782-4678
	CBL-VDL-GR-CCL	3000-3782
	LDL-CNL-GR-CAL	4451-4694
	SDDB-GR	3782-4694
	CBL-VDL-GR-CCL	3845-4698

4.5.2.3 Well log evaluation and initial test results (NAHORHABI Field):

The petrophysical properties of the sands in the discovery well viz. Nahorhabi-1 is given in **Table 4-32**

Table 4-32: PETROPHYSICAL PROPERTIES OF WELLS NAHORHABI-1

Well	Sands	Top(m)	Bottom(m)	Av Phi %	Av Sw %
Nahorhabi 1	Barail (BMS)	4408	4421	13.5	38
	Barail (BMS)	4380	4390	13.5	41
	Barail (LBS-1)	4300	4315	11.5	56
	Barail (LBS-1)	4291	4300	12.0	58
	Barail (BCS)	3860	3872	11.5	43
	Tipam (TS-6)	3429	3450	20.0	52

Log motifs of the tested Objects of Nahorhabi-1, Nahorhabi-2 & Nahorhabi-3 are shown in **Figure 4-48** through **Figure 4-62.**

Figure 4-48: LOG MOTIFS OF OBJECT-I AND II OF WELL NAHORHABI-1 (BMS/LBS-1)

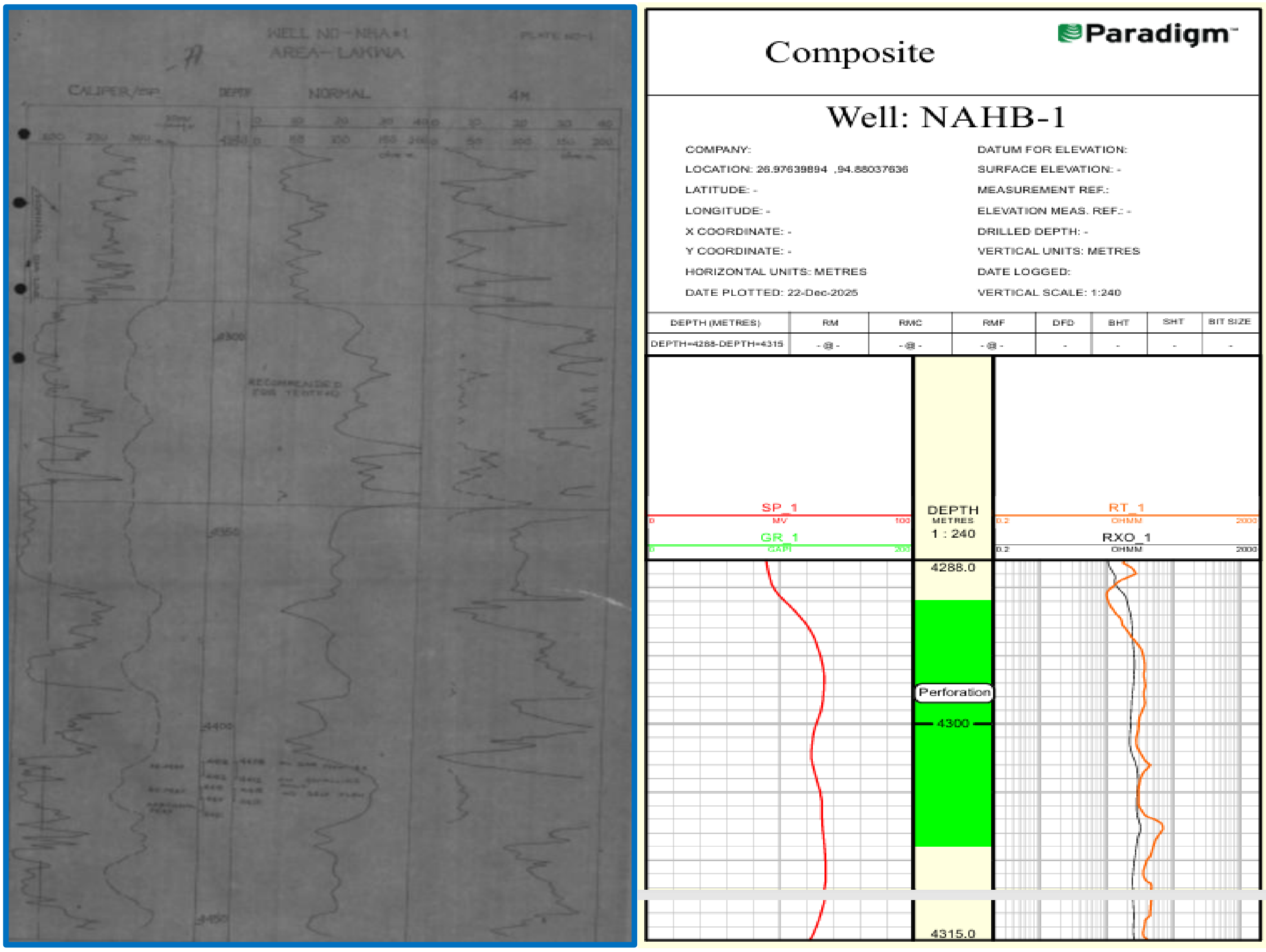


Figure 4-49: LOG MOTIFS OF OBJECT-I (BMS) OF WELL NAHORHABI-2

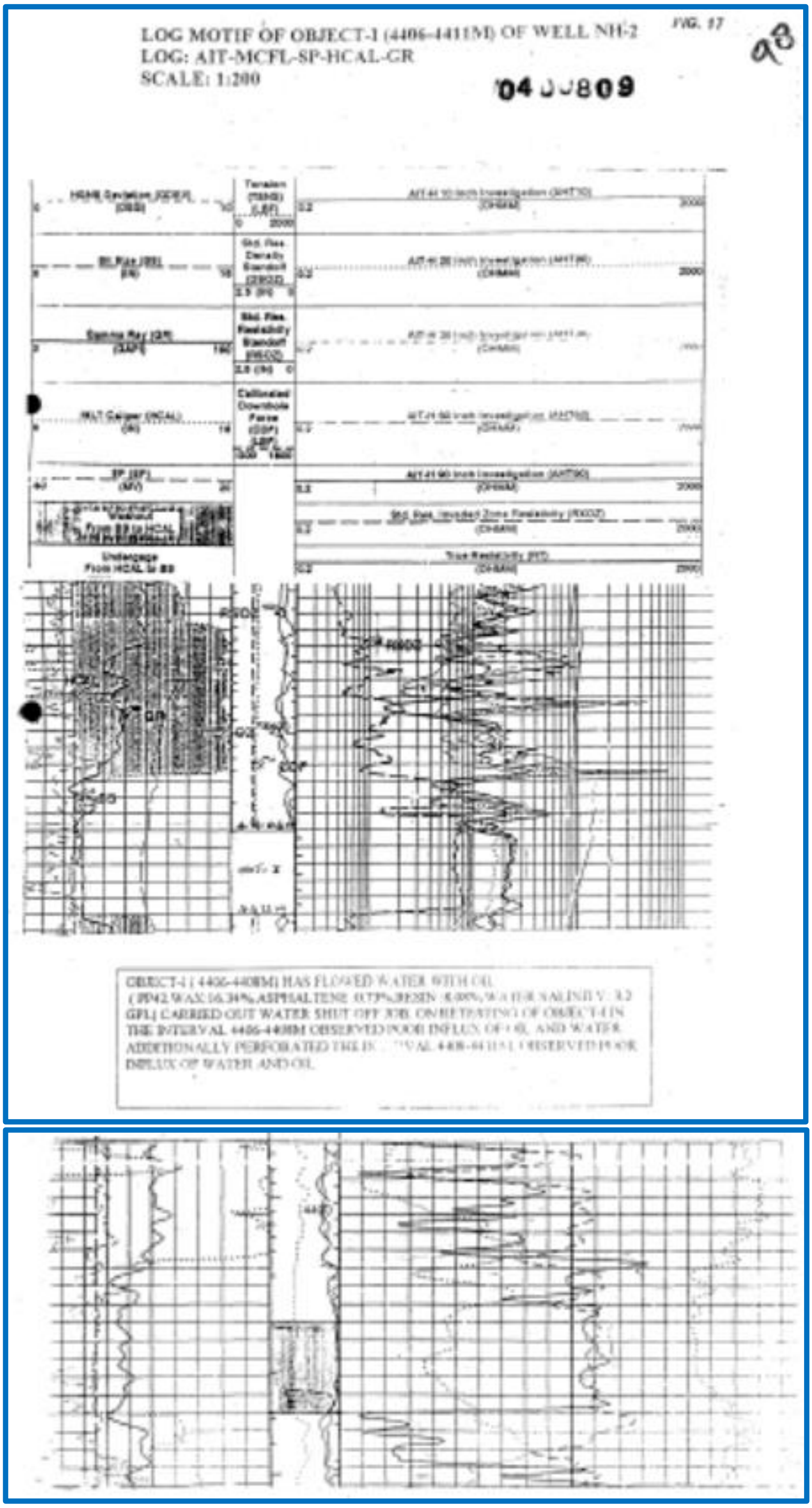


Figure 4-50: LOG MOTIFS OF OBJECT-II (BCS) OF WELL NAHORHABI-2

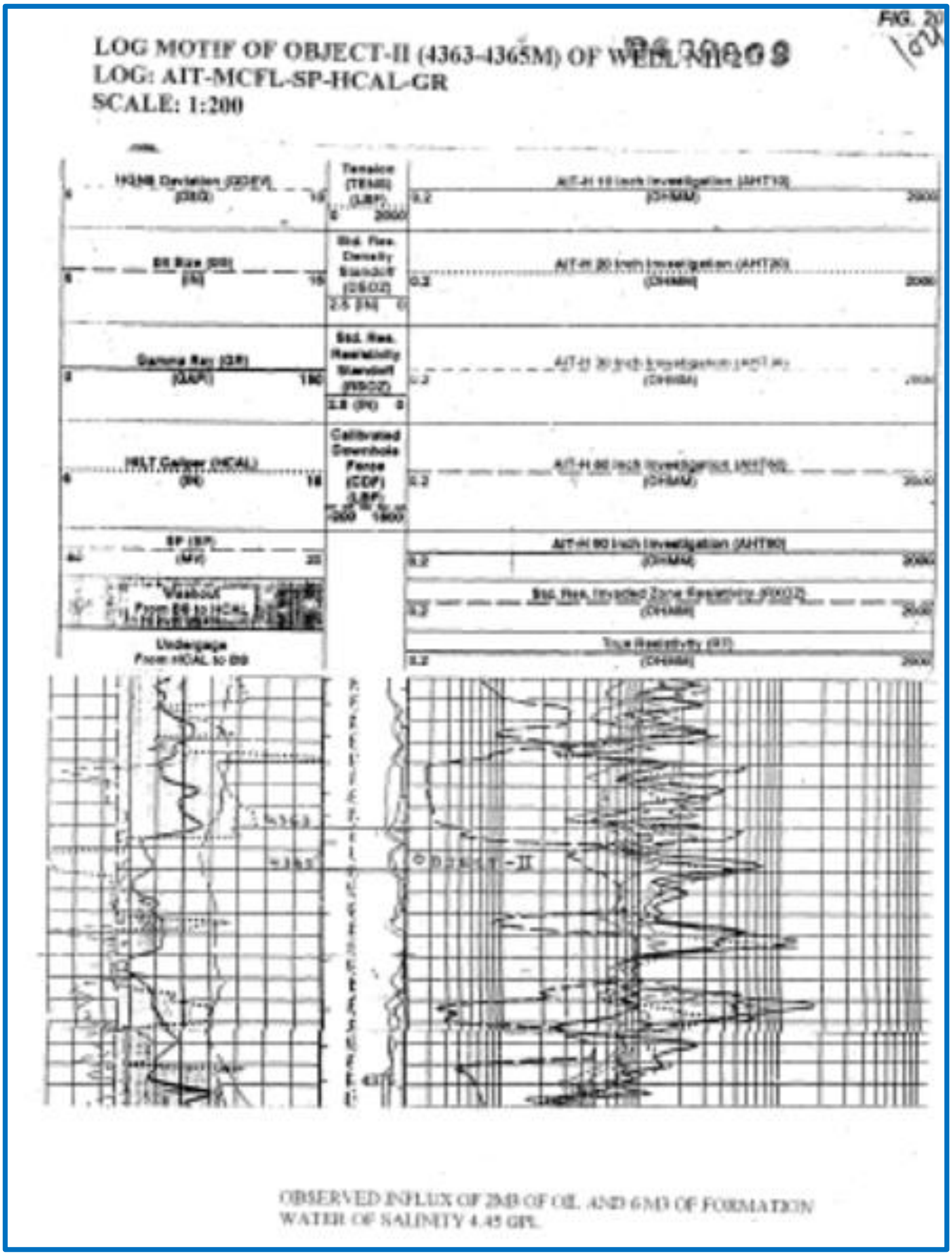


Figure 4-51: LOG MOTIFS OF OBJECT-III (BCS) OF WELL NAHORHABI-2

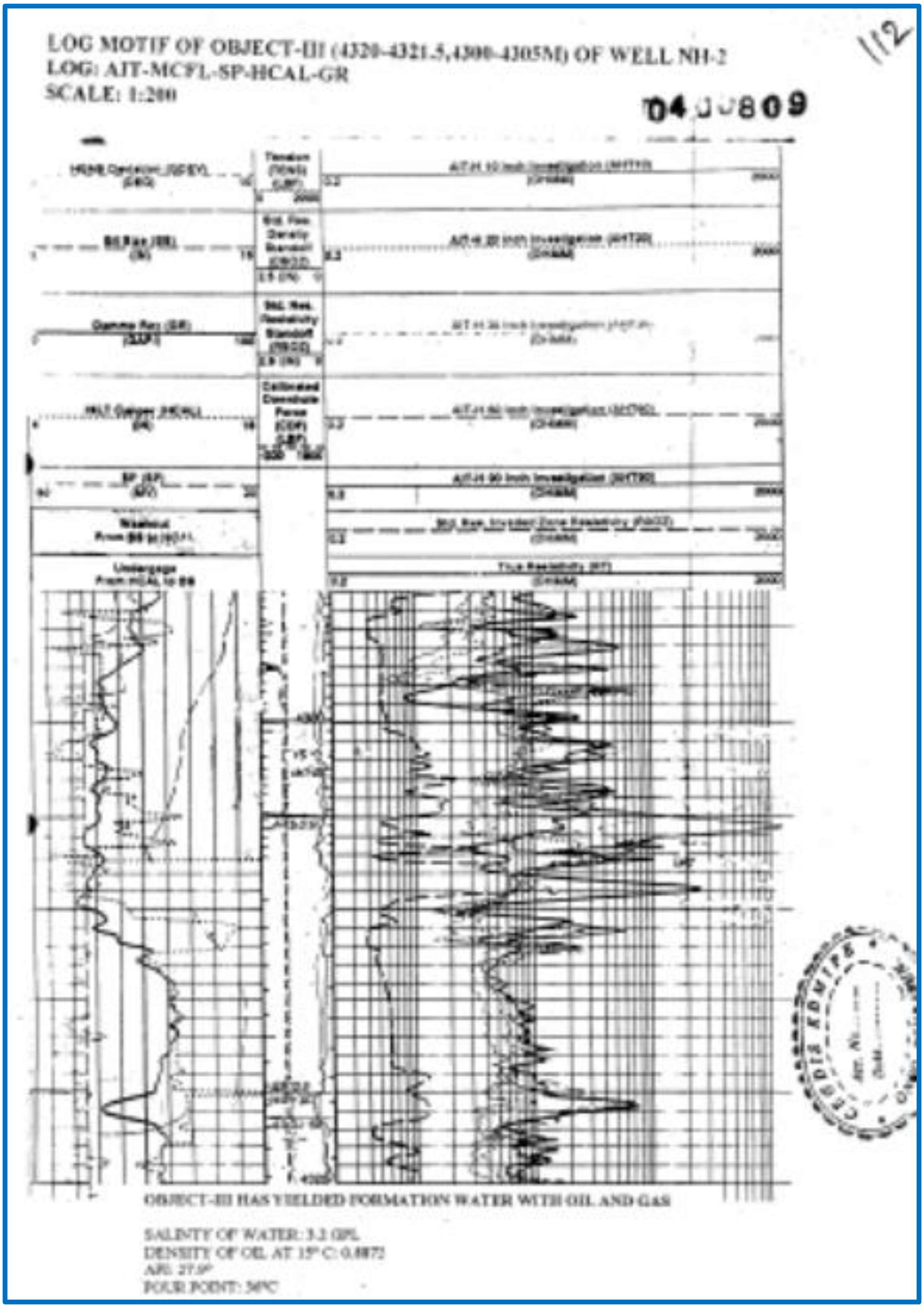


Figure 4-52: LOG MOTIFS OF OBJECT-IV (BCS) OF WELL NAHORHABI-2

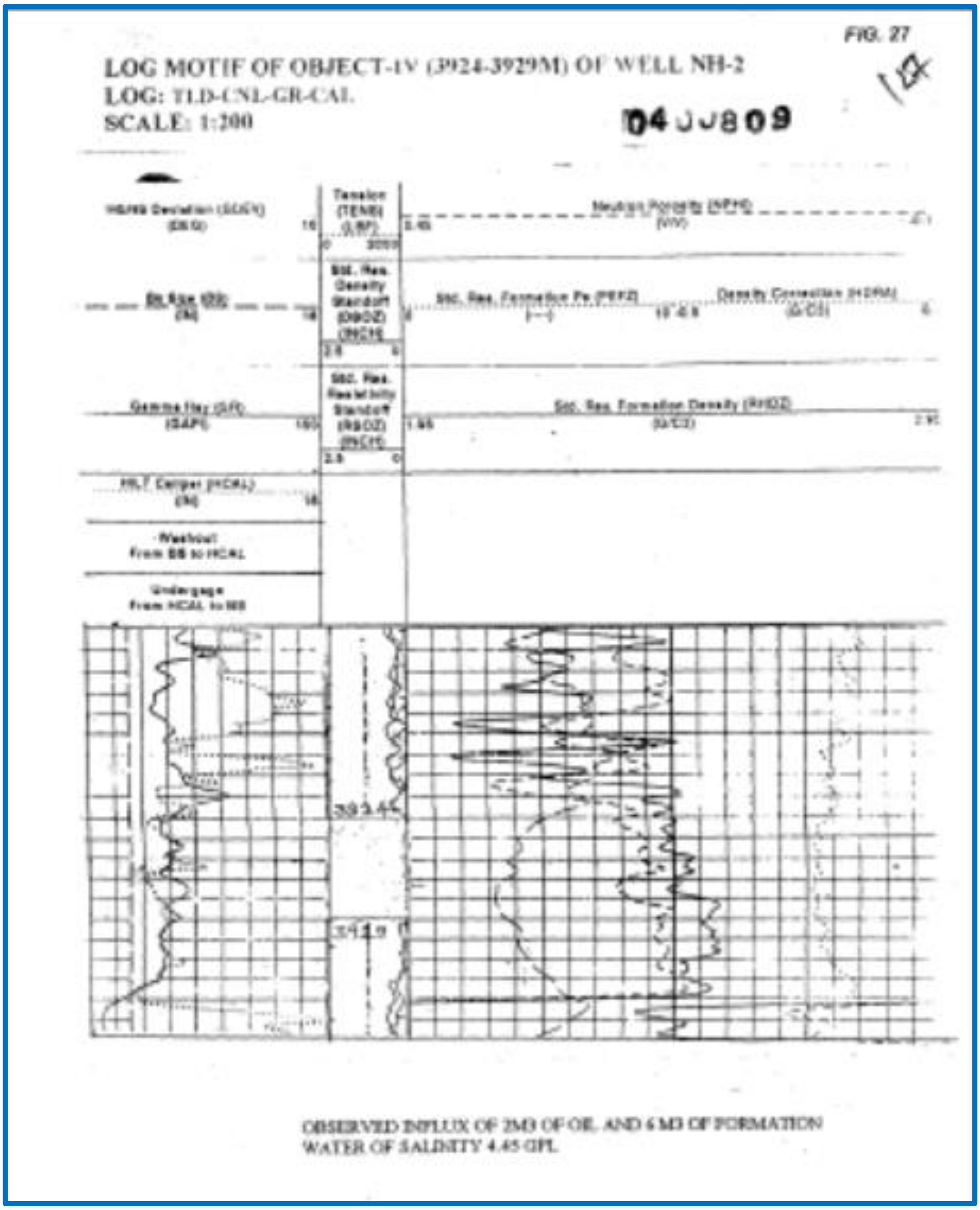


Figure 4-53: LOG MOTIFS OF OBJECT-V (SAFRAI) OF WELL NAHORHABI-2

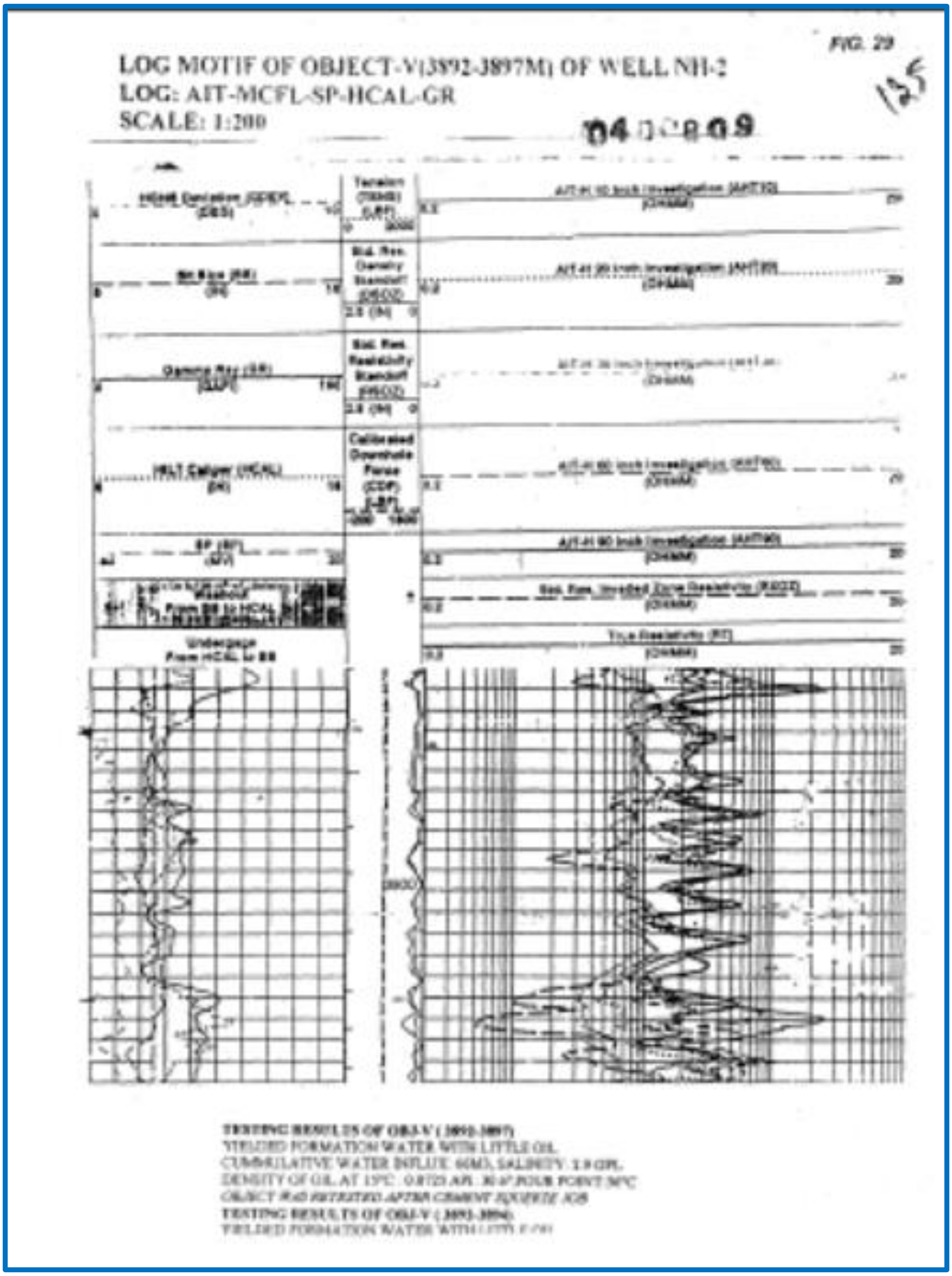


Figure 4-54: LOG MOTIFS OF OBJECT-VI (SAFRAI) OF WELL NAHORHABI-2

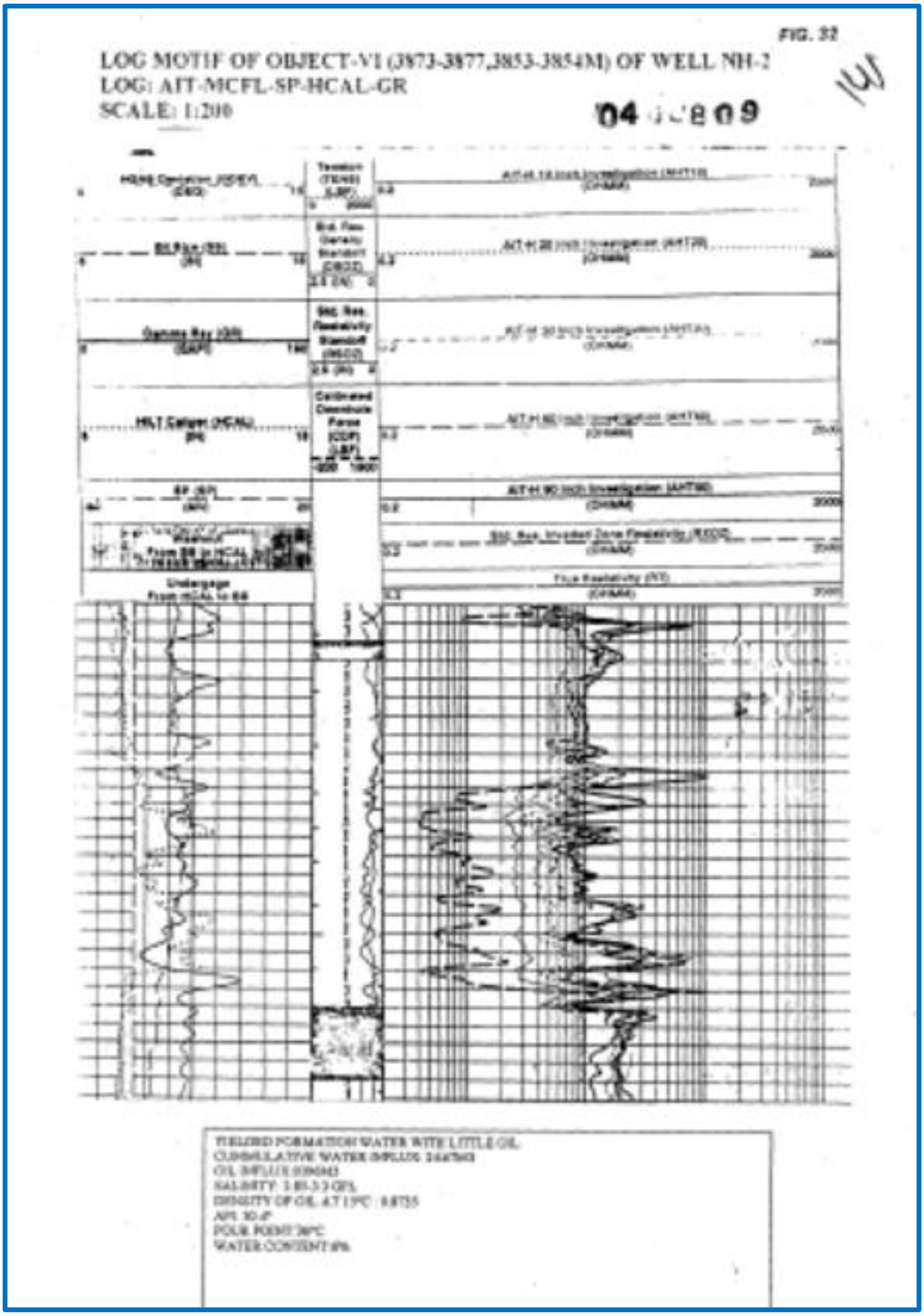


Figure 4-55: LOG MOTIFS OF OBJECT-VII (TS-6) OF WELL NAHORHABI-2

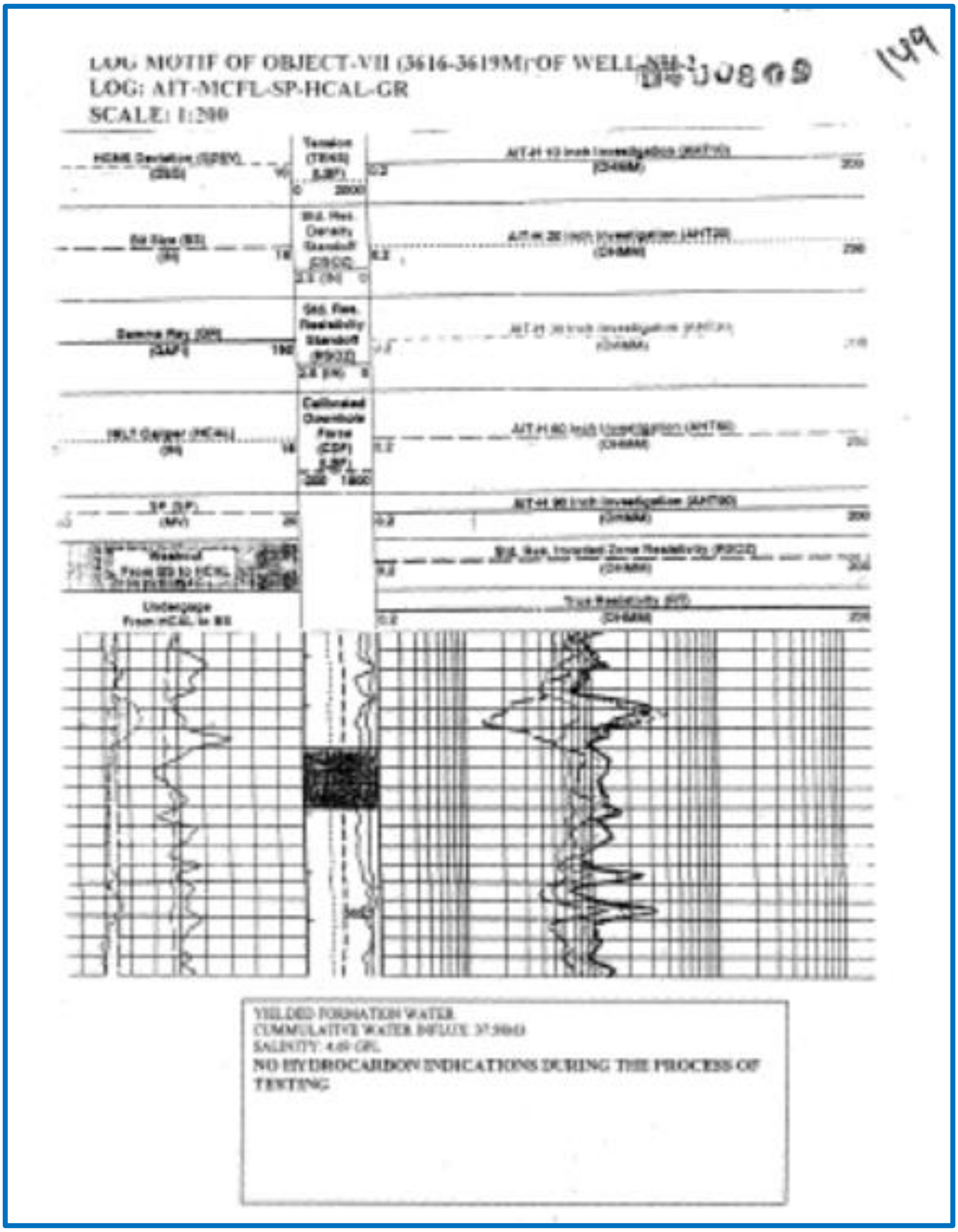


Figure 4-56: LOG MOTIFS OF OBJECT-I (KOPLI) OF WELL NAHORHABI-3

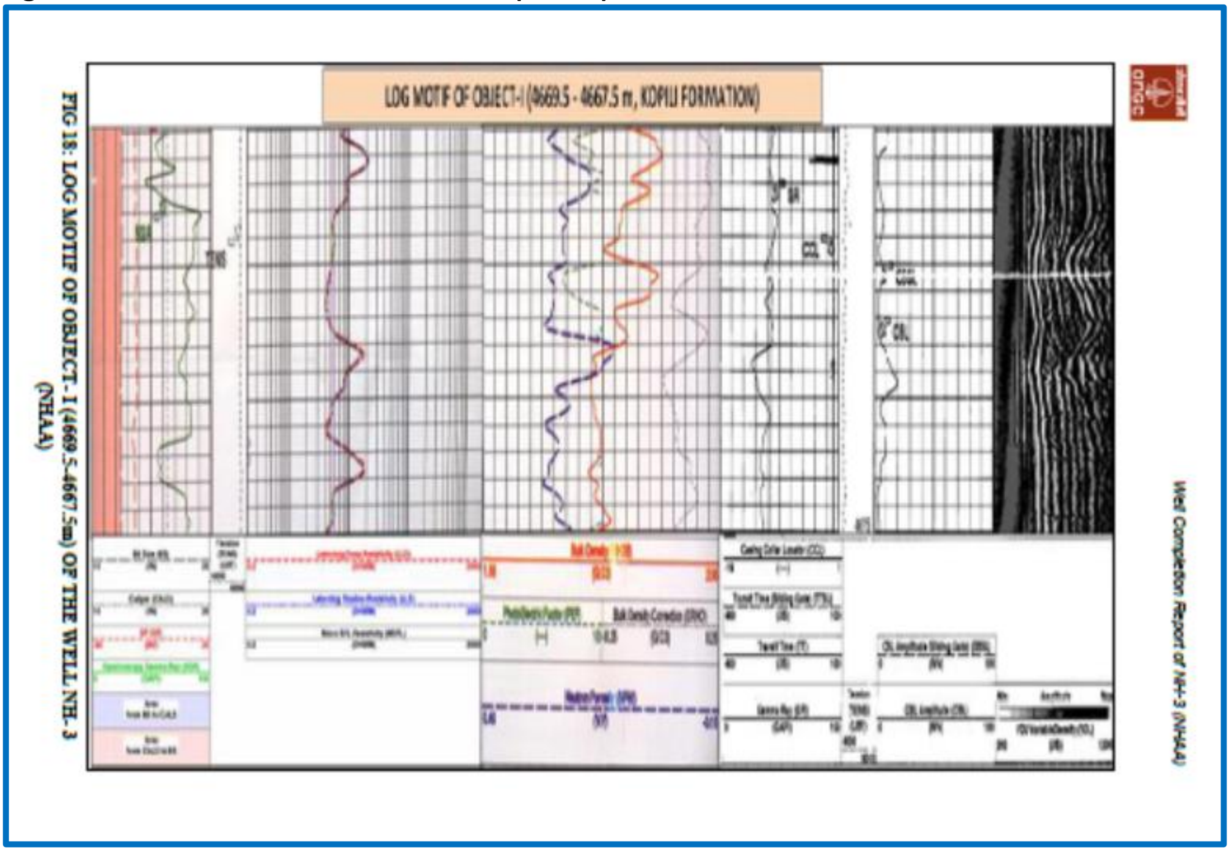


Figure 4-57: LOG MOTIFS OF OBJECT-II (KOPLI) OF WELL NAHORHABI-3

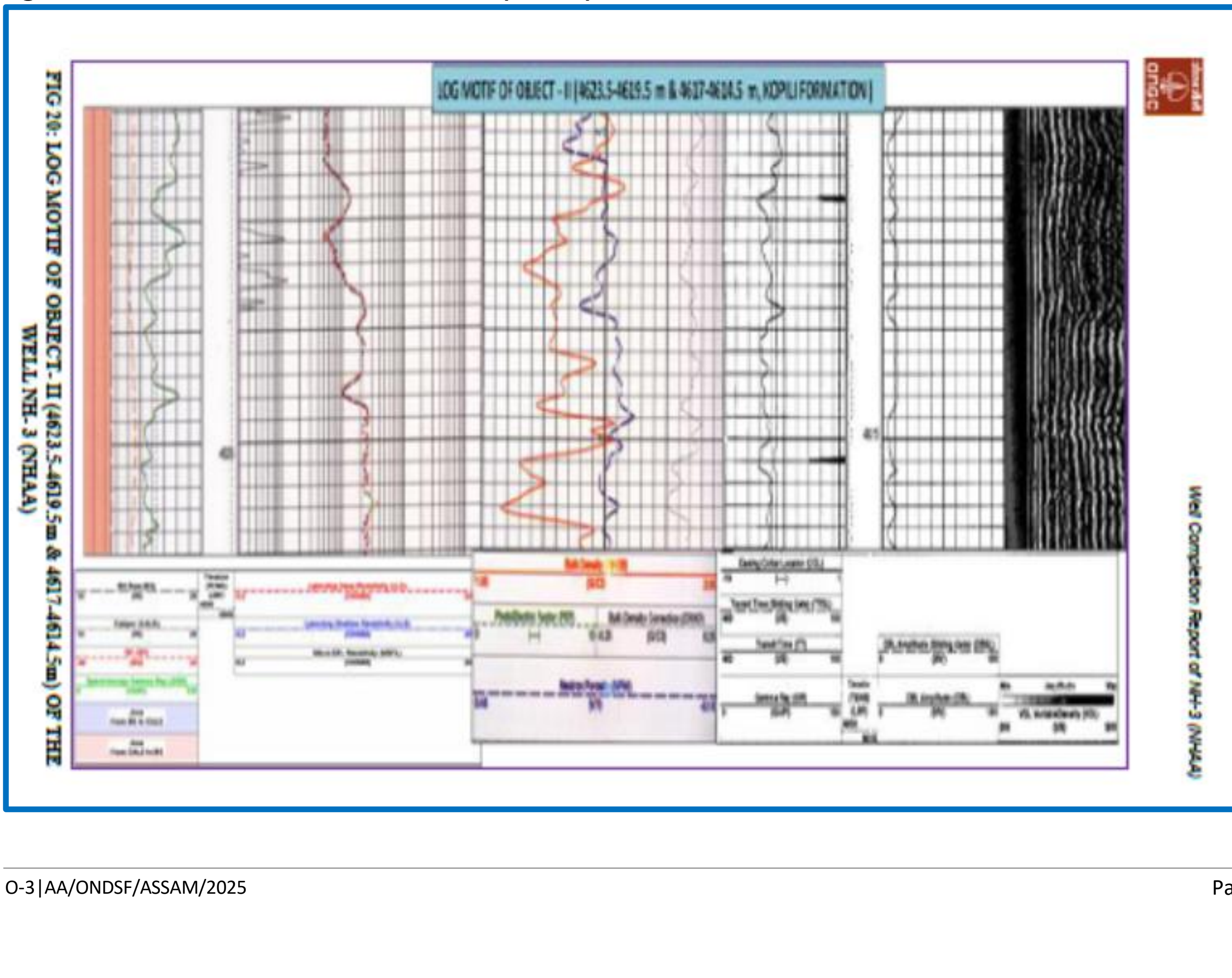


Figure 4-58: LOG MOTIFS OF OBJECT-III (BMS) OF WELL NAHORHABI-3

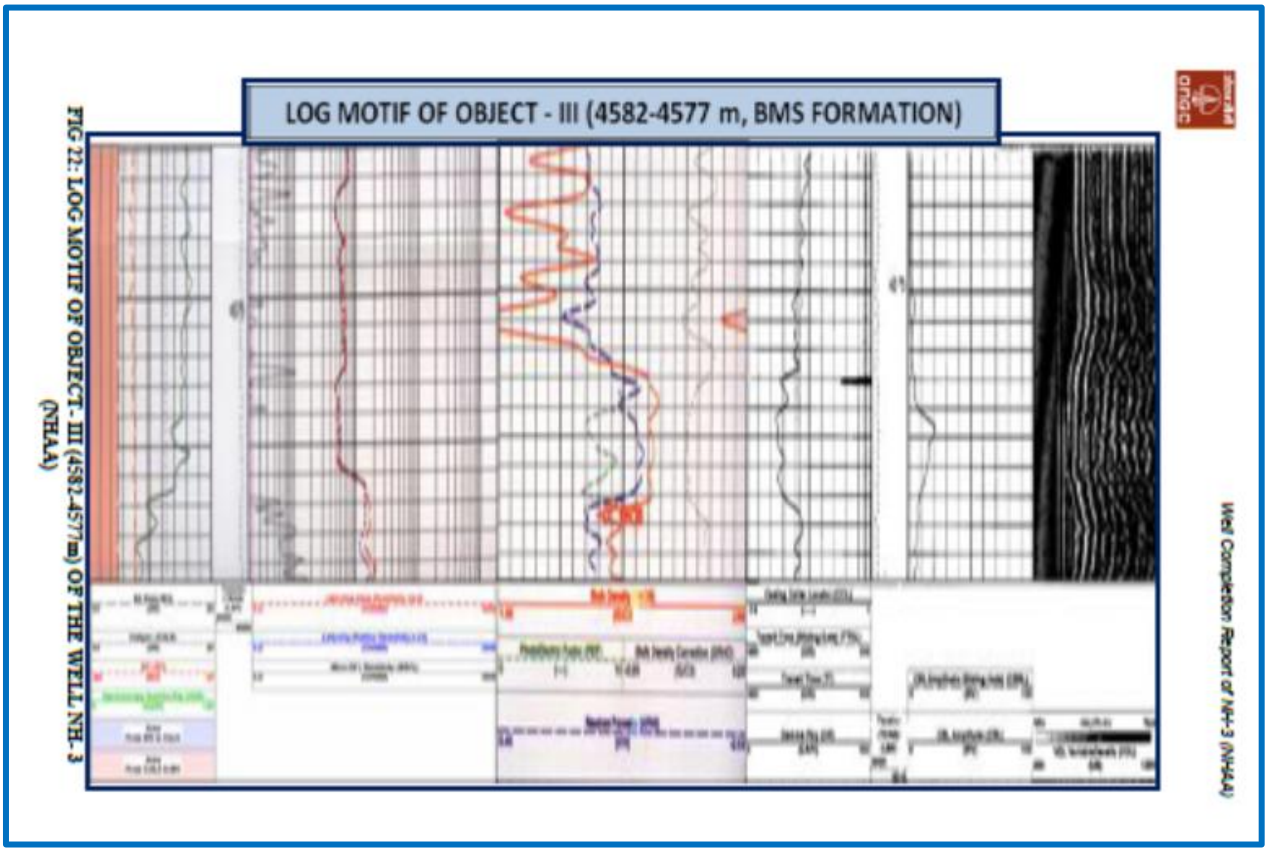


Figure 4-59: LOG MOTIFS OF OBJECT-IV (BMS) OF WELL NAHORHABI-3

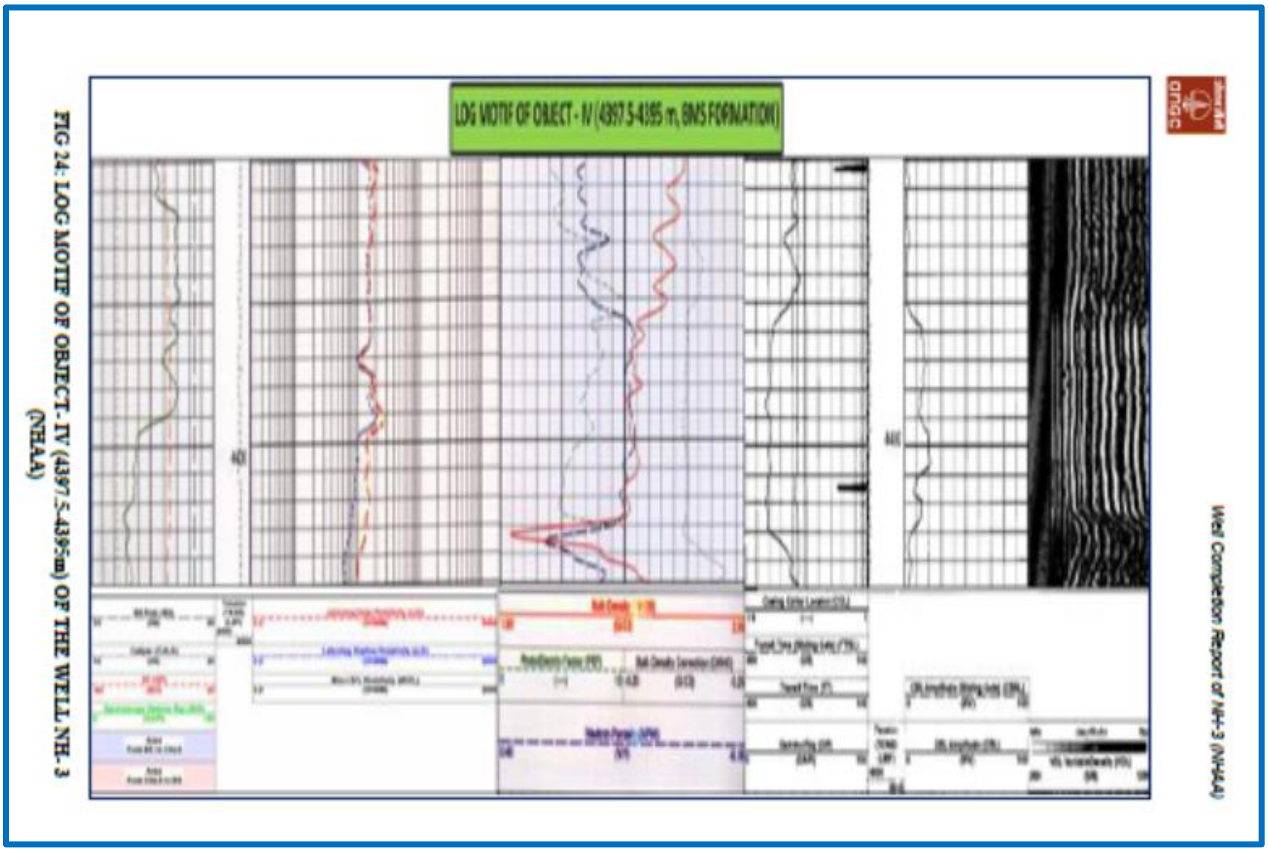


Figure 4-60: LOG MOTIFS OF OBJECT-V (LBS-1) OF WELL NAHORHABI-3

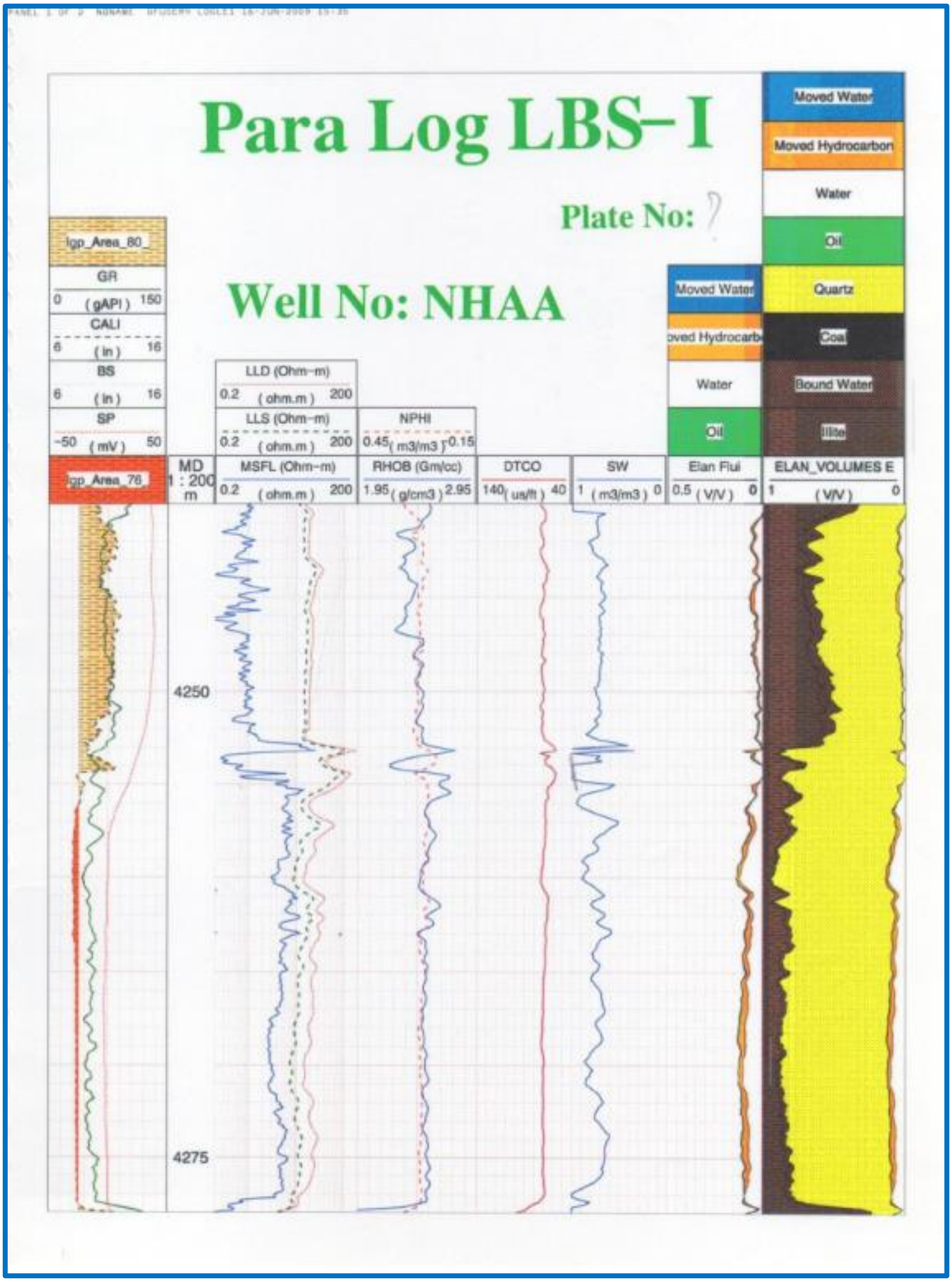


Figure 4-61: LOG MOTIFS OF OBJECT-VI (BCS) OF WELL NAHORHABI-3

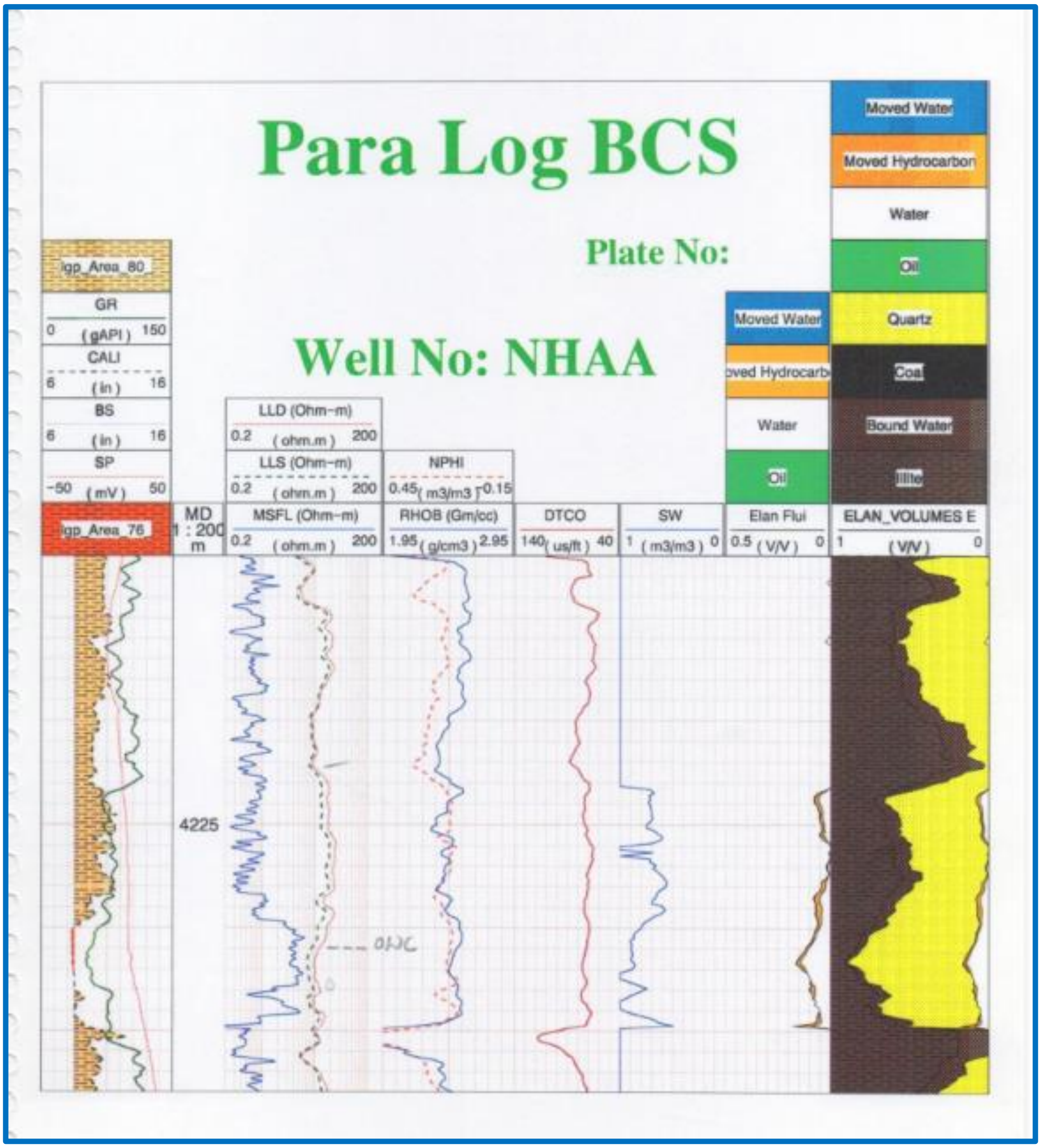
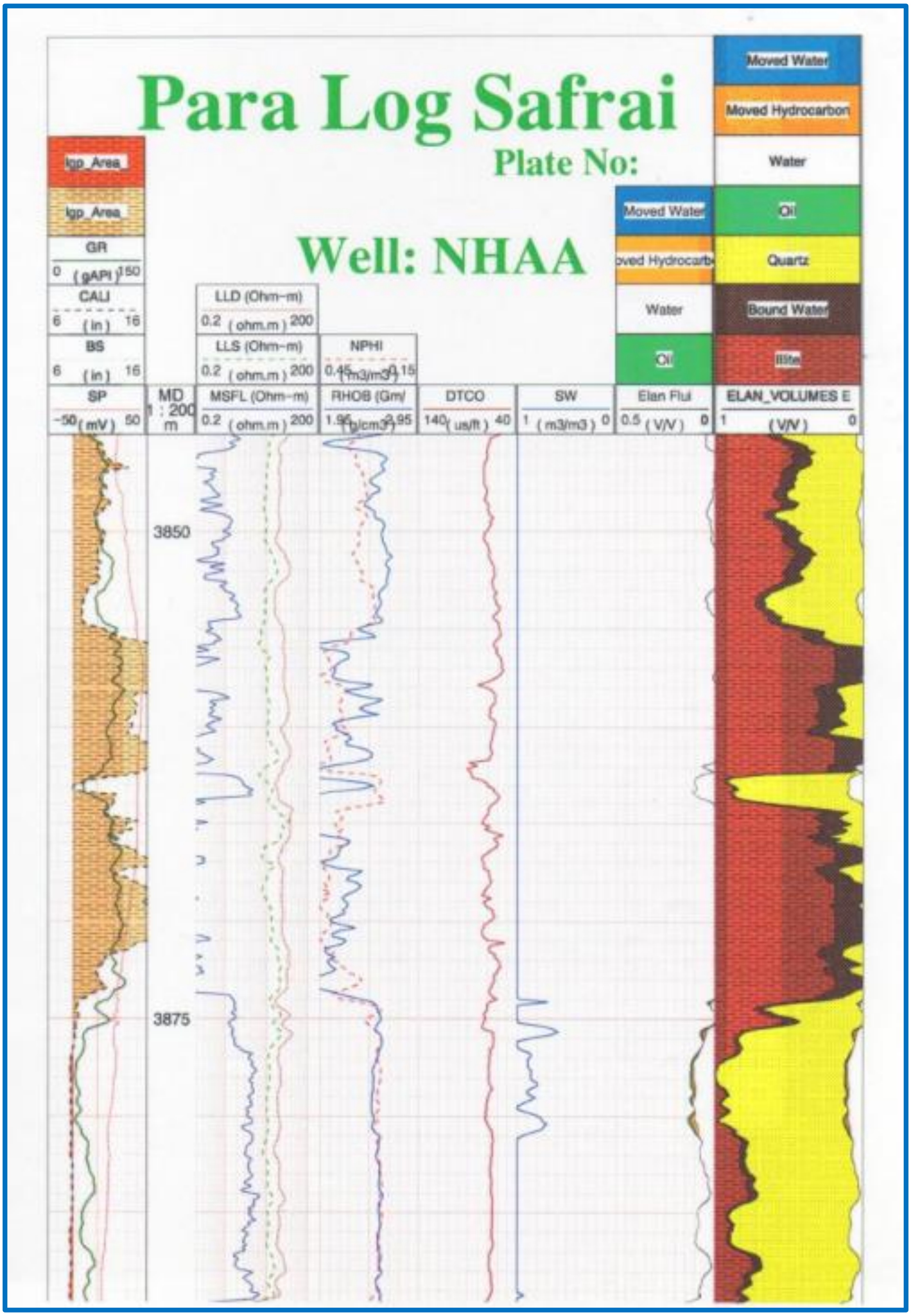


Figure 4-62: LOG MOTIFS OF OBJECT-VII (SAFRAI) OF WELL NAHORHABI-3



4.5.3 Well testing and workover history

Well testing and workover history of **Nahorhabi-1, Nahorhabi-2 & Nahorhabi-3** is given below.

Well testing of NAHORHABI-1

NAHB-1 was tested with rig in the interval **4408- 4412 m & 4415- 4421 m**, **Barail Main Sand as Object-1** and it flowed Oil, Gas and water. Remaining objects of NAHB-1 were tested subsequently with Workover rig.

Object-I (4408-4412 & 4415-4421) - With Rig

After perforation, well was opened but the well could not be activated with compressor application. On swabbing, Oil, Water and little gas was recovered. Interval. 4417-4421 was reperforated. Well could not be activated after repeated swabbing. Testing remained inconclusive.

WOR-1, U–36 (9/1986):

Object-I was retested by compressor & N2 but observed only gas flow. The intervals 4408- 4412 m & 4415-4421 m were reperforated. Compressor was applied 08 times and acid job was carried out but observed no flow. Re-perforated 4408- 4412 m & additionally perforated 4407- 4408 m, 4412- 4415 m @12 spm by 4” gun. Activated by compressor but observed no flow. Tested & found injectivity nil at 250 ksc. Carried out acid job. On activation, the well produced mainly water with feeble gas & very little oil. So, it was called off.

Object- II (4303-4309m, 4291-4299m) Barails

B/P was set at 4400 m and interval **4303- 4309 m (Barails)** was perforated with HSC gun @ 12spm & **4291-4299 m** @13 spm. The interval of **4303- 4309 m @13 spm** was reperforated by gun, activated by repeated compressor application. Observed gas and little Oil & water. Acid job was carried out, but no improvement was observed. Reperforated 4291- 4299 **m** & additionally perforated **4299- 4303 m** @18 spm (TTP) under reduced head. Activated & C/O influx study on 26/9/86. Productivity Index (PI) = 0.206 m3/d/ksc. Well became active on same day.

In 1999, flow studies were carried out & it was observed that the rate varied from 48 m3/d to nil. Initial THP= 125 ksc, CHP= 130 ksc.

Reservoir studies were carried out on 20.8.99. SBHP= 454.5 ksc, Gradient survey indicated Oil observed from surface to 3400 m, and remaining water.

Reservoir studies were again carried out on 2.11.99; SBHP= 260 KSC at 4200 m, Oil= 1300 to 3700 m and remaining was water.

WOR-2, CW-III (27/03/04- 18.05.04):

Interval **4291- 4309 m** was reperforated @ 12 spm by 3 3/8” gun. Activated with open-end tubing with GLV. Recorded BHS but observed poor influx. Acid job was carried out and observed no injectivity. Activation was done with N2 & well closed for build-up. Observed SCHP of 35 KSC. Lowered activation GLV with packer & activated. Reservoir studies were carried out which indicate Liquid level at 920 m, Oil Water Interface at 1200 m, SBHP= 297 KSC at 4000 m. The well was completed on SRP.

WOR-3, IR-XI (19/01/10- 14/02/10, SRP SERVICING):

The well was cleared up to 4350 m and Xylene job was carried out with injectivity of 300 LPM at 2000 psi. Activated the well and the well was completed with SRP.

WOR-4, SEALL-50-I (01/11/2010- 11/11/2010, SRP SERVICING):

The well was cleared up to 4350 m and Xylene job was done and N2 was pumped up to 185 KSC, drilled down up to 2400 m & K/O= 12 m3 water. Observed Liquid level at 1197 m in annulus & 1303 m in tubing. Finally, the well was completed on SRP with P/Barrel at 1999.78 m & a Tailpipe of 36.30 m.

WOJ-5 (IR-500-XI; 01.10.17 - 05.11.17) PLAN:

The well was cleared up to 4335 m and injectivity was found to be 60 lpm at 1500 psi. Recorded CBL-VDL between 4292 – 3448 m and found hole cleared up to 4292 m. RIH s/e up to 4400 m. Scraped the well up to 4400 m. Perforated in the interval of **4328 - 4324 m, 4327 - 4325 m, 4309 - 4304 m and 4296 - 4291 m** (with stim gun) @ 18 spm. Completed the well on SRP with pump barrel and gas anchor. Kept gas anchor at 2350 m and pump barrel at 2000 m. Tested p/barrel at 70 ksc, found ok. Then RIH plunger with sucker rod and tested pump by a/lift. Found ok at 70 ksc.

Testing of Interval3859-3860m, Safrai

WOJ-6 (IR-500-XI; 08.07.19 – 20.10.19) PLAN - Testing of Safrai-Sand & Recompletion on SRP

Carried out perforation in the interval of **3859-3860 m** @ 18 spm. Placed 0.8 m3 cement slurry & WOC. Scraped well up to 3880 m; recorded CBL-VDL & GR-CCL in the interval of 3403.2-3880.6 m. Carried out perforation in the interval of **3860-3865 m**. Applied compressor followed by N2. Carried out BHS and recorded SBHP gradient study from 3800 m. BHS result indicated Liquid Level at 3480 m & SBHP 30.95 KSC at 3800 m. Fishing was observed and it was pushed down 3880 m and well was cleared up to 3898 m. Carried out additional perforation in the interval of **3865-3870 m @ 18 spm**. Applied compressor followed by N2 up to 260 KSC. Observed return from 255 KSC with traces of oil. Knock-out 40 m3 oil & water. Recorded BHS by lowering BHS tool up to 3750 m and found Liquid level at 2794 m & SBHP- 91.66 KSC at 2794 m, W/C- 90% & Water Salinity as 2.574 GPL. Observed no activity. Carried out re-perforation in the interval of 3861- 3865 m @ 18 spm and tested injectivity & found nil at 3500 psi. Carried out acid job by spotting acid against perforation @ 3500 psi & kept for soaking for 30 minutes but acid could not be squeezed up to 3500 psi. Reverse washed. Applied compressor (02) followed by N2 up to 275 KSC; knock-out= 42.3 m3 water. Recorded BHS by lowering BHS tool up to 3800 m. Rate of influx-1.5 m3, PI-0.14 m3/day/KSC.

Carried out BHS job, but manometer could not be lowered below 1966 m due to obstruction; SBHP-64.39 KSC at 1966 m. LL-1476 m. RIH 52 mm GC tool & got held up at 1960 m. Again RIH 42 mm GC tool & got held up at 2008 m. On POOH string, observed heavy mud in return. RIH s/edge up to 3898 m, on circulation observed heavy mud in return. Pumped 85 m3 (02 times of well volume) water, observed no fresh water in return. The well was temporarily abandoned.

The results of production testing in the wells of Nahorhabi –1, 2 & 3 are summarized in **Table 4-33**.

Table 4-33: TESTING RESULTS OF NAHORHABI WELLS

NAHOHABI field:	
Nahorhabi-1	In this well, Object-II was tested between interval **(4303-4309m, 4291-4299 m) in Lower Barail Sand** and produced Oil, Water and Gas through Swabbing . Further testing of Nahorhabi-1 was done through Workover Rig as has been discussed in detail above. Object-II and Object-III were also tested through Workover and details has already been explained above.
Nahorhabi-2	Seven objects were identfied for testing. Object-I(4406-4408m) of BMS flowed water with little oil even with additional perforation of 4408-4411m . Object-II(4363-4365m) of BCS gave influx 2m3 of Oil and 6 m3 of formation water (Salinity 4.45 gpl). Onject-III 4300-4305m, 4320-4321.5m) yielded water salinity of 3.2 gpl with oil and gas. Object-IV (3924-3929m) gave water of salinity 2.56 gpl. Object-V(3892-3897m), Safrai formation gave water of salinity 2.9 gpl with traces of oil. Object-VI(3853-3854, 3873-3877m) of Safrai formtion flowed water of salinity 2.85 gpl with tracesof oil. Object-VII (3616-3619m) of Geleki formation yielded water of salinity 4.69 gpl. Testing results indicated presence of Hydrocarbons at BMS, BCS and Safrai levels. The well was abandoned.
Nahorhabi-3	Four objects were tested out of seven objects identified for testing. First two Objects (Object-I & II) in Kopili sand showed no encouraging result. The third Object 4582-4577m showed no influx on activation. The fourth object 4397.5-4395m in BMS attained self flow of oil, gas with high water cut (85%).

4.5.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, Formation Dynamics Tests, reservoir pressure build-up study and PVT data/ results.

The influx studies carried out in Nahorhabi-1 indicated the Productivity Index (PI) as 0.206 m3/d/Kg/cm2. The well Nahorhabi-1 had intermittently produced Oil, Gas and Water during 2003-2020 as depicted in the following graphs. (**Figure 4-63 and Figure 4-64)**

Figure 4-63: OIL PRODUCTION DATA OF WELL NAHORHIBA-1

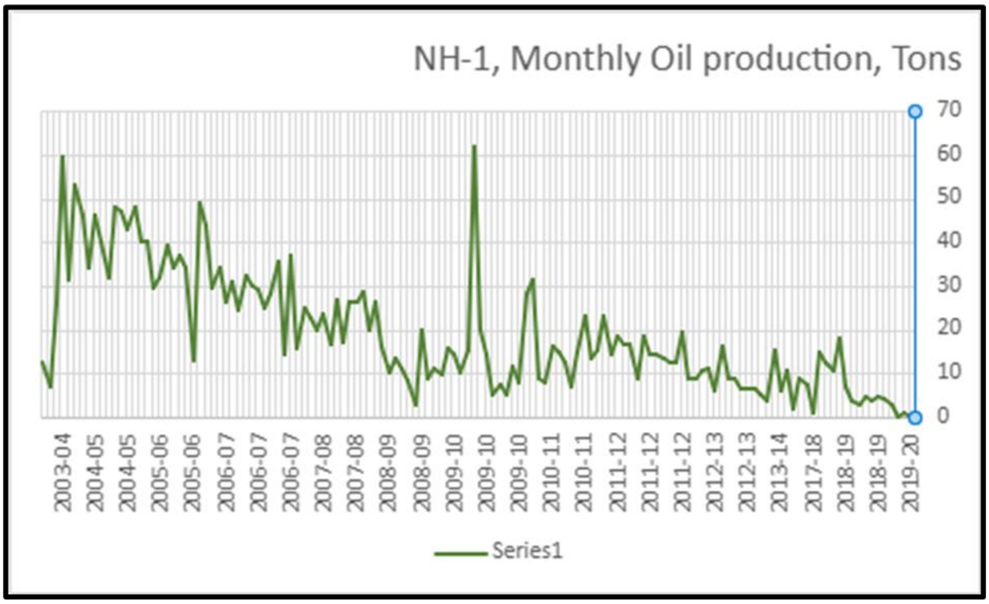
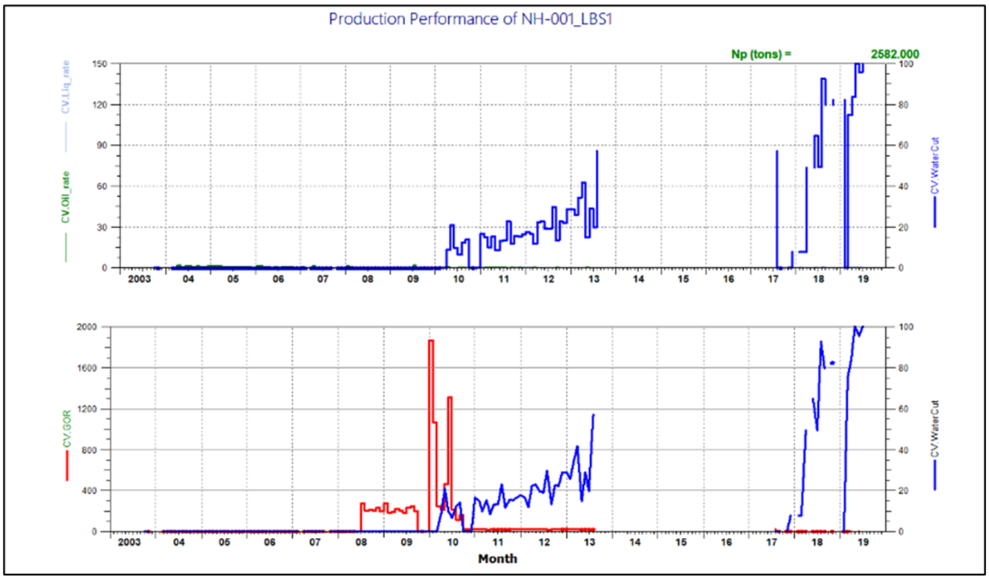


Figure 4-64: Production Performance Graph of NAHORHIBA-1, GOR & Water Cut Vs Time



Bottom Hole Pressure studies including SBHP & Influx study have been done in well **Nahorhabi-1** which indicated an **Initial pressure of 473.6 Kg/cm2** at datum of 4208m and gradient survey indicated presence of Oil & Water in the tubing. The well produced intermittently between 2004 to 2019.

Oil, Gas & Water analysis (NAHORHABI FIELD)

Oil and Water Analysis of NAHB-1 & 2 are given in following tables (**Table 4-34, Table 4-35 and Table 4-36**).

Table 4-34: OIL SAMPLE ANALYSIS & WATER ANALYSIS (NAHB-1)

Oil Sample analysis & Water Analysis (NAHB-1), BMS	
Date & Time of Collection	17.2.82 at 0800 hrs
Density at 15°C	0.8923
A.P.I. Gravity	27.0
Water Content	21.2%
B.S. & W.	26%
Salinity	37.6 mg/lit.
Pour Point	33°C

Table 4-35: OIL ANALYSIS REPORT, WELL NAHB-2

Oil Analysis Report, Well NAHB-2						
Interval, m	Object/Zone	Density at 15oC	Specific Gravity	oAPI	Pour Point oC	Plastic Viscosity at 36oC
4365-4363	BMS	0.8968	0.8970	26.2	36	12
4406-4411	BCS	0.8934	0.8939	26.8	36	21
4406-4411	BCS	0.9071	0.9078	24.4	39	9

Table 4-36: WATER ANALYSIS REPORT – WELL NAHB-2

Water Analysis Report – Well NAHB-2			
Interval, m	Zone/Object	Date	Water Salinity as NaCl in gm/litre
4406-4408	Object-I/BMS	30.09.2003	2.78 – 2.90
4406-4408	Object-I/BMS	24.11.2003	0.13 -1.00
4406-4411	Object-II/BMS	8.12.2003	1.17-1.80
4406-4411	Object-II/BMS	11.12.2003	1.17-3.40
4363-4365	Object-III/BCS	26.12.2003	4.45
4363-4365	Object-III/BCS	23.12.2003	0.60
4321.5-4320 4305-4300	Object-III/BCS	23.12.2003	0.12
4028-4024	Object-III/BCS	23.01.2004	3.8
3924-3929	Object-IV	04.02.2004	2.56-2.63

3924-3929	Object-IV	10.02.2004	2.63
3897-3892	Object-V/Safrai	16.02.2004	2.78-2.90
3873-3877 3853-3854	Object-VI/Safrai	23.03.2004	0.047-0.06
3873-3877 3853-3854	Object-VI/Safrai	27.03.2004	2.85
3916-3919	Object-VII	05.04.2004	1.17
3916-3919	Object-VII	06.04.2004	1.17

4.5.5 Geology and Reservoir Description of NAHORHABI Field:

The geology of the area has been comprehensively reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.5.5.1 Geological correlations, sections and maps (NAHORHABI Field):

Litho-column and stratigraphy in Nahorhabi wells are presented in **Table 4-37.**

Table 4-37: STRATIGRAPHY OF NAHORHABI AREA

Age	Formation	Unit	Depth Interval (m)	Thickness (m)	Lithological Description
1.	2.	3.	4.	5.	6.
Recent & Plio-Pleistocene	Alluvium	Surface-	Surface – 1047	1047	Mainly coarse unconsolidated sand with minor soft clay
Unconformity					
Mio-Pliocene	Namsang	-	1047 – 1486	439	Alternation of loose sand with grey mottled clay
Unconformity					
Miocene	Girujan	Upper Sandstone	1486 – 1864	1206	Mainly brown to brick-red mottled clay with sand bands
		Girujan Clay	1864 – 2692		
	Tipam	Tipam Sandstone	2692 – 3875	1183	Mainly grey coloured fine to coarse grained sands with clay bands
Unconformity					
Oligocene	Barail	Coal Shale	3875 – 4290	415	Mainly grey to dark grey shale and carbonaceous shale with coal and occasional sands
		Main Sand	4290 – 4505+	215+	Mainly very fine to fine-grained sandstone with minor shales and coals

The stratigraphic sequence encountered in in wells of Nahorhabi and generalized stratigraphic succession of the Nahorhabi Field are shown in **Table 4-38 and Table 4-39.**

Table 4-38: STRATIGRAPHIC SEQUENCE ENCOUNTERED IN NAHORHABI WELLS

WELLS	NAHB-1		NAHB-3		NAHB-2		Structural Pos wrt	
Formation Tops	KB 104.8	Thickness	KB 105	Thickness	KB 105	Thickness	NAHB-1	NAHB-2
Girijan Clay	**1863** *1758.2*	717	**1855** *1750*	678	**1860** *1755*	703	8 ↑	5 ↑
TS-1	**2580** *2475.2*	109	**2533** *2428*	94	**2563** *2458*	104	47 ↑	30 ↑
TS-2	**2689** *2584.2*	170	**2627** *2522*	201	**2667** *2562*	186	62 ↑	40 ↑
TS-3	**2859** *2754.2*	328	**2828** *2723*	315	**2853** *2748*	334	31 ↑	25 ↑
LCM	**3187** *3082.2*	83	**3143** *3038*	87	**3187** *3082*	70	44 ↑	44 ↑
TS-5	**3270** *3165.2*	295	**3230** *3125*	284	**3257** *3152*	298	40 ↑	27 ↑
TS-6	**3565** *3460.2*	202	**3514** *3409*	315	**3555** *3450*	288	51 ↑	41 ↑
Safrai	**3767** *3662.2*	110	**3805** *3700*	87	**3843** *3738*	70	38 ↓	38 ↑
Radrangar	**3877** *3772.2*	416	**3892** *3787*	470	**3913** *3808*	488	15 ↓	21 ↑
Dumlegon	**4293** *4188.2*	98+	**4362** *4257*	215	**4401** *4296*	50+	69 ↓	39 ↑
Disangmukh	Not drilled	-	**4577** *4472*	93	Not drilled	-	-	-
Kopili	Not drilled	-	**4670** *4565*	35+	Not drilled	-	-	-
DD	4500	-	**4705**	-	4450	-	-	-

Figure 4-65: WELL CORRELATION BETWEEN NAHB-1, NAHB-2 & NAHB-3

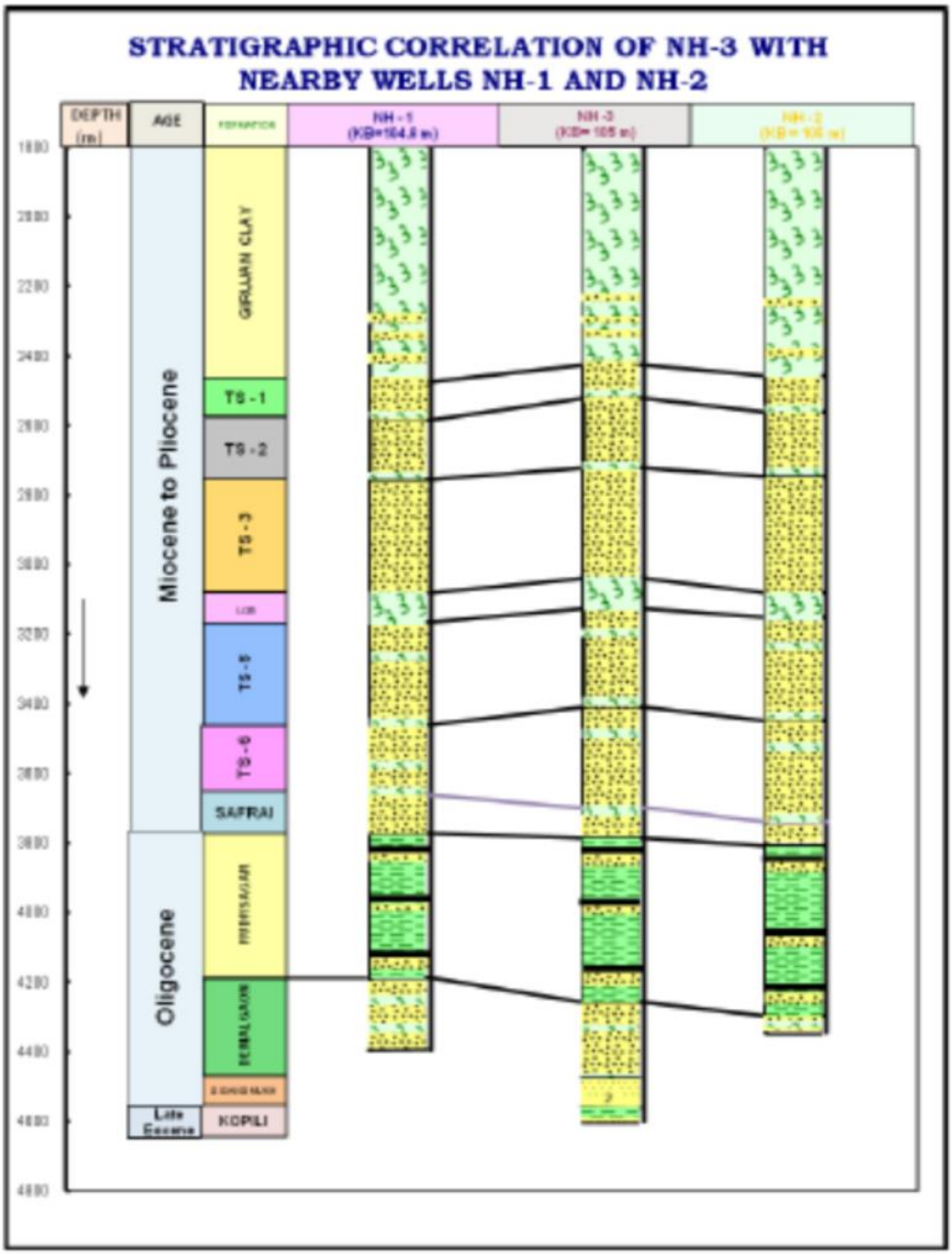


FIG 15: STRATIGRAPHIC CORRELATION OF THE WELL NH-3 (NHAA) WITH NEARBY WELLS, NH-1 & NH-2

Figure 4-66: SEISMO-GEOLOGICAL SECTION PASSING THROUGH NAHORHABI WELLS

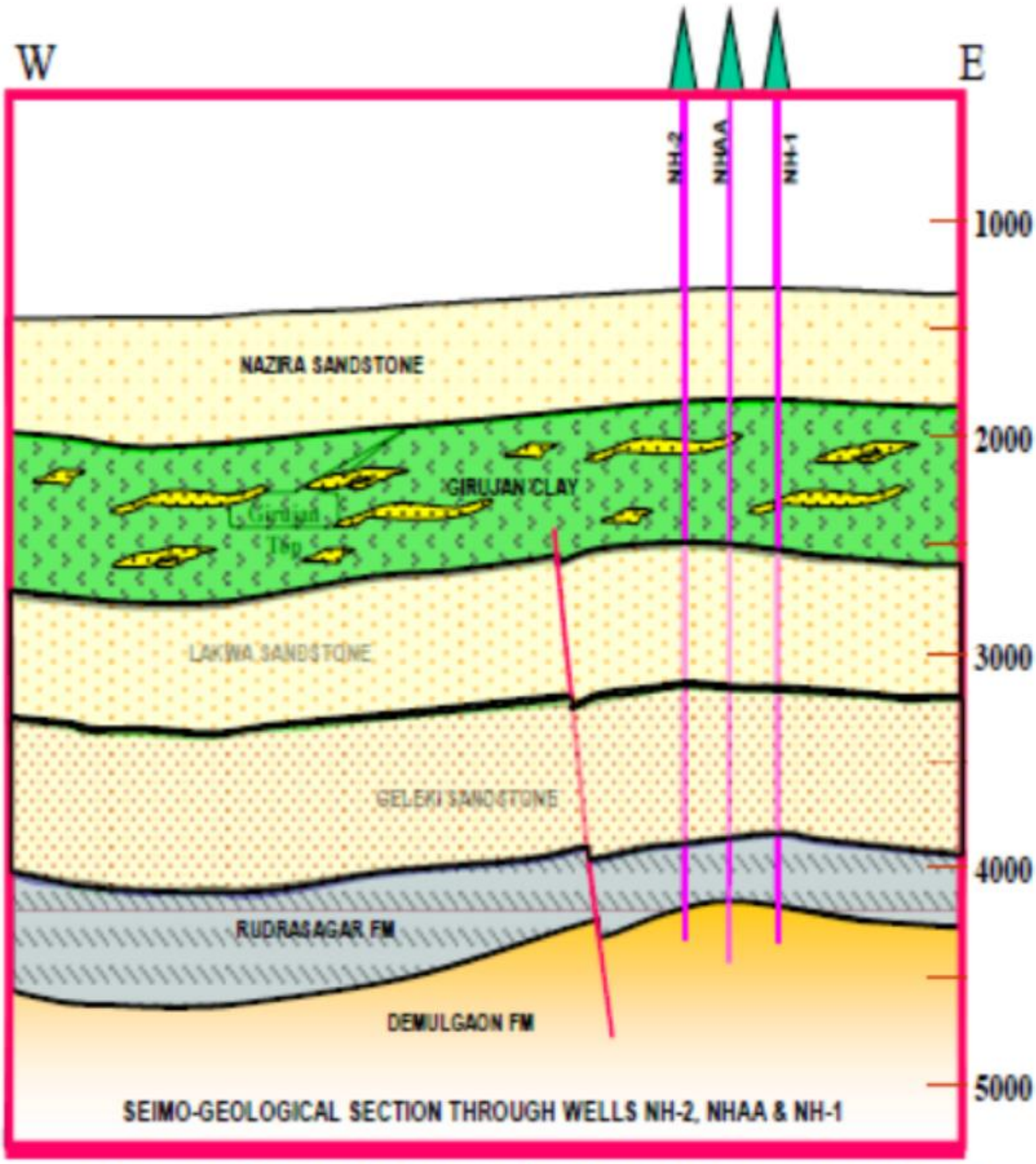


FIG 16: SEISMO-GEOLOGICAL SECTION THROUGH THE WELL NH-3 (NHAA), NH-1 & NH-2

A seismic section showing wells CRDO-1, CRDO-2, CRDO-3, CRDO-4, NAHB-1 and MTPR-1 is shown in **Figure 4-67.**

Figure 4-67: SEISMIC SECTION OF WELLS CRDO-1, CRDO-2, CRDO-3, CRDO-4, NAHB-1 and MTPR-1

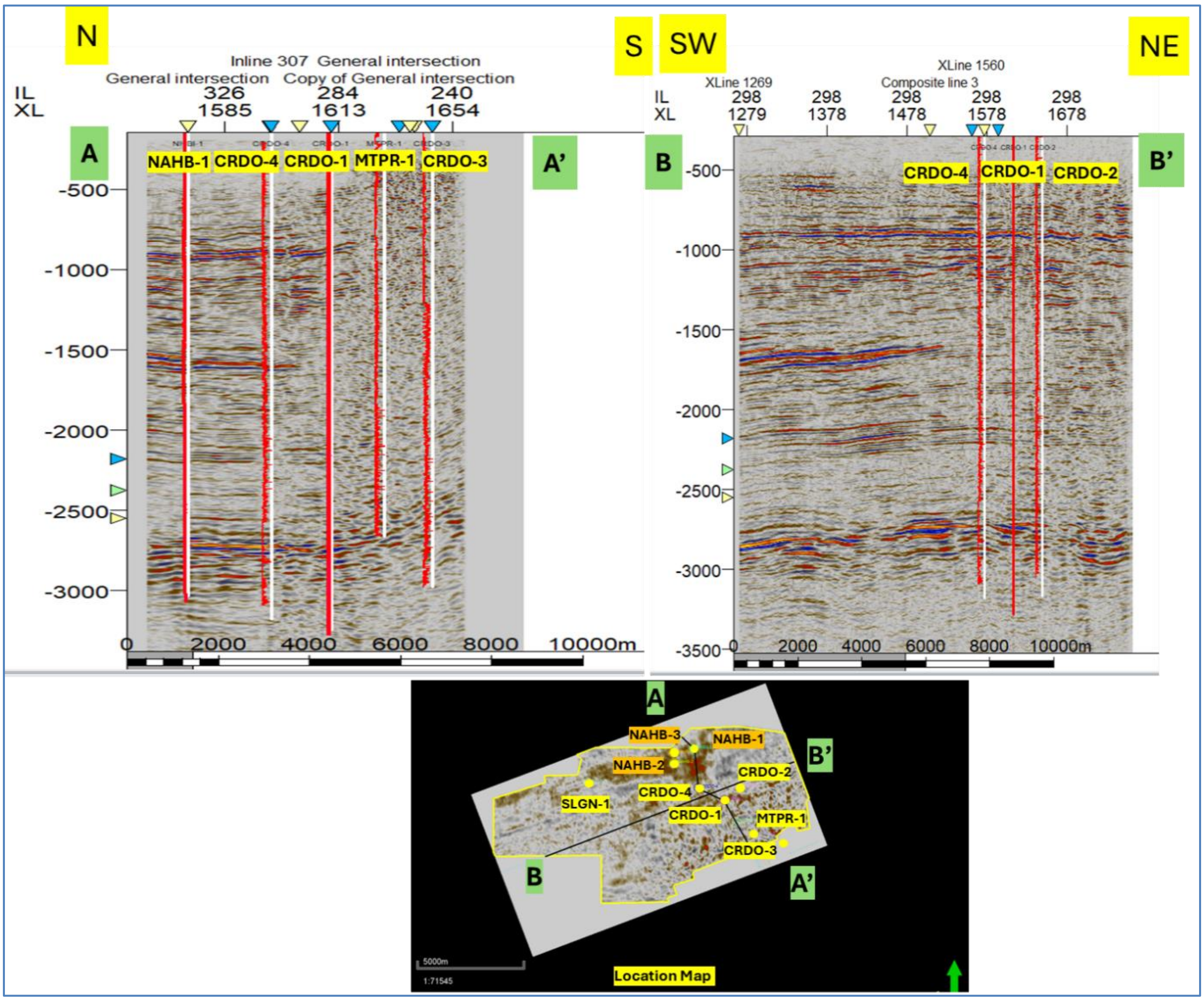


Table 4-39: CORRELATION OF NAHORHABI WELLS WITH NEARBY WELLS

Formation	Charaideo #1	Nahorhabi #1	Rajabari #1	L-22	L-17	L-16
Alluvium & Older Alluvium	Surface-1010 m.	Surface-1047 m.	Surface-1043 m.	Surface-985 m.	Surface-915 m.	Surface-1037 m
Namsang	1010-1550 m.	1047-1486 m.	1043-1464 m.	985-1666 m.	915-1682 m.	-
Upper Sandstone	1550-1875 m.	1486-1864 m.	1464-1902 m.	1666-1827 m.	1682-1871 m.	-
Girujan Clay	1875-2806 m.	1864-2692 m.	1902-2495 m.	1827-2585 m.	1871-2825 m.	1863-2452 m.
Tipam Sandstone	2806-4034 m.	2692-3875 m.	2495-3757 m.	2585-3860 m.	2825-3797 m.	2452-3553 m.
Barail Coal-Shale	4034-4607 m.	3875-4290 m.	3757-3985 m.	3860-3980-(+)	3797-3920 m.	3553-3786 m.
Barail Main Sand	4607-4805 m.	4290-4550 m.	3985-4175 m.		3920-3932 m. (+)	3786-3991 (+)
TS-I	-	-	2495-2547 m.	-	-	2451-2481 m.
TS-II	2806-2864 m.	2692-2813 m.	2588-2760 m.	2585-2662 m.	-	2537-2706 m.
TS-III	2974-3305 m.	2858-3187 m.	2770-3075 m.	2772-3095 m.	2825-3103 m.	2711-2995 m.
TS-IV	-	-	-	3159-3167.5 m.	3200-3221.5 m.	3005-3030 m.
TS-V	3410-3632 m.	3269-3503 m.	3135-3420 m.	3186-3444 m.	3235-3490 m.	3067-3299 m.
TS-VI	3687-4034 m.	3569-3875 m.	3425-3757 m.	3494-3860 m.	3485-3797 m.	3320-3553 m.
BS-D	-	4002-4023 m.	3853-3885 m.	-	-	3618-3648 m.
BS-C	-	4037-4075 m.	3904-3916 m.	-	-	3653-3700 m.
BS-B	-	-	-	-	-	-
BS-A	4550-4586 m.	-	-	-	-	-
Barail Main Pay Sand	4607-4650 m.	4290-4390 m.	3985-4050 m.	-	3920-3932 m. (+)	3786-3822 m.
Barail Main Sand	4670-4805 m. (+)	4405-4505 m. (+)	4081-4175 m. (+)	- Logs recorded upto 3750 m.	-	3845-3991 m. (+)

The well NAHB-2 has been correlated with Nahorhabi-1 (NAHB-1) and Charaideo-1 (CRDO-1), which are located at a distance of 1.1 to 2.5 kms towards NorthEast and SouthEast direction from the well NAHB-2. The well NAHB-2 is found to be structurally up by 19.18 m and 136 m with respect to NAHB-1 and CRDO-1 at the top of TS-2, whereas at the level corresponding to LCM the present well is shallower by 0.18 m and 114 m with respect to the above mentioned wells. At the level corresponding to the top of Safrai Formation, the well NAHB-2 was found to be deeper by 39.82 m and shallower by 101 m with respect to NAHB-1 and CRDO-1 respectively.

Seismic Section showing Inline passing through the well NAHORHABI-1 & Nearby wells (NAHB-2 & NAHB-3)

Figure 4-68: INLINE PASSING THROUGH NAHORHABI WELLS

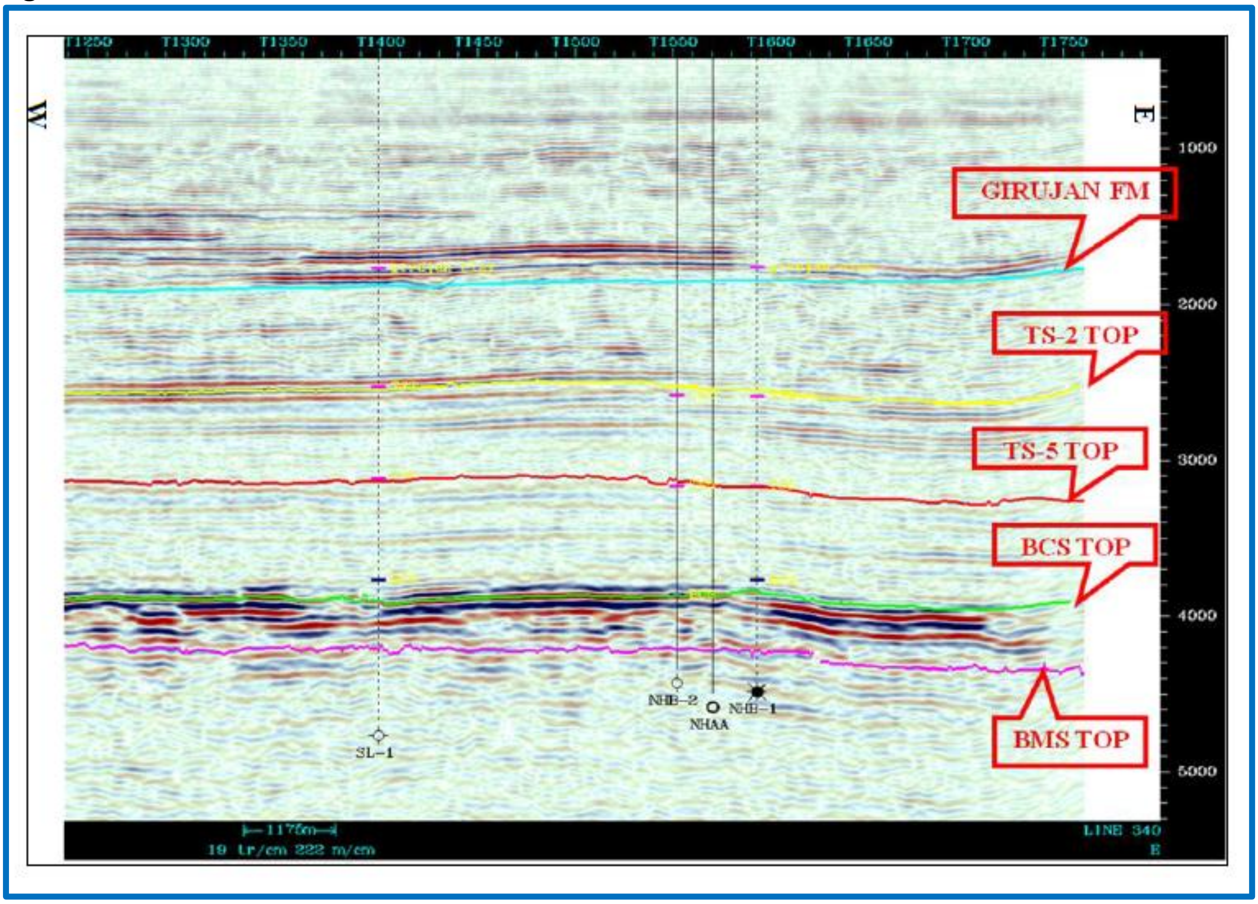
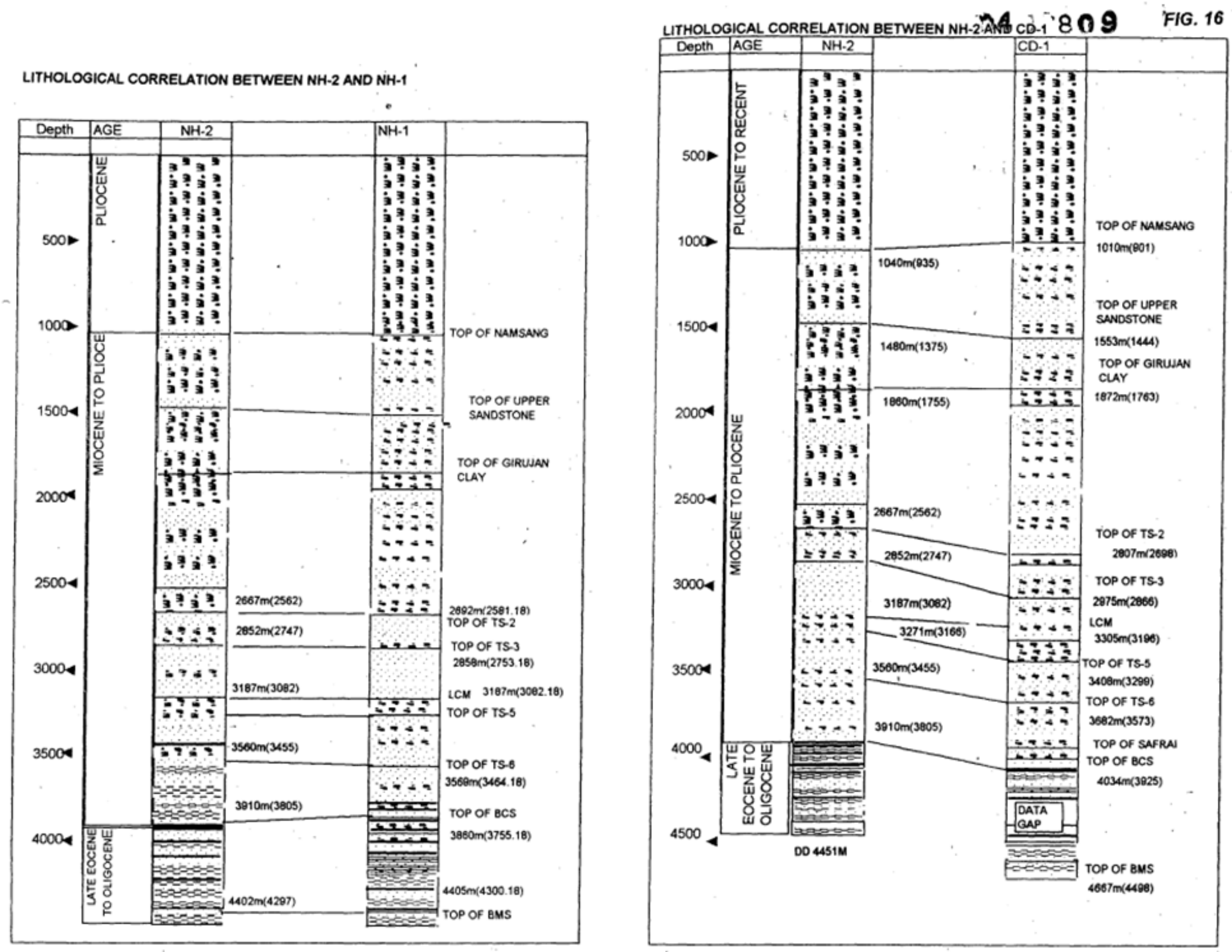


Figure 4-69: LITHOLOGICAL CORRELATION BETWEEN NAHB-2 & NAHB-1 AND NAHB-2 & CRDO-1



Nahorhabi-1 was drilled up to 4500 m. Cutting samples from 2400 m down to 4500 m were analysed in the laboratory. In total, 104 cutting samples at intervals of 20 m and two cores CC 1 (2294-3302 m) and CC 2 (4014.94-4020.94 m) were processed for heavy minerals and studied. The heavy mineral data assists in classifying the drilled sequence as follows:

<u>Heavy Mineral Zone-V (3880-4500 m) Barail Sequence</u>

30 cutting and 2 core samples (CC 2) were examined. It is characterized by predominance of ore minerals and impoverishment of non-opaques.

The heavy mineral assemblage consists of ore minerals (87.37%-100%, av. 93.69%) and garnet (0-15.90%, av. 1.57%). Epidote (0-15.38%, av. 0.51%), hornblende (0-1.49%, av. 0.86%), tourmaline, zoisite, muscovite, chlorite, biotite etc. are rare and sporadic.

<u>Heavy Mineral Zone-IV (2860-3860 m) Tipam Sandstone</u>

51 cutting and 2 core samples (CC 1) were examined for their heavy mineral content. The heavy mineral assemblage consists of low ore minerals (20.60%-85.71%, av. 48.67%), garnet (6.66%-40.31%, av. 22.00%), very high epidote (0-40.90%, av. 20.45%) and hornblende (0-4.80%, av. 1.60%). Zoisite and chlorite are rare but persistent. Tourmaline, kyanite, zircon, staurolite, amphibole, chloritoid.

Heavy Mineral Zone-III (2400–2860 m) Girujan Clay

23 cutting samples were examined for their heavy mineral content. The heavy mineral assemblage of this sequence includes ore minerals (35.33%–97.71%, av. 76.156%), garnet (0–15.90%, av. 4.61%), epidote (0–15.38%, av. 5.21%) and hornblende (0–18.72%, av. 4.43%). Zoisite and chlorite are almost persistent in small quantities whereas tourmaline, staurolite, kyanite, zircon, amphibole etc. is sporadically present in small quantities.

Core Studies in NAHORHABI-1 Well

The results of core analysis carried out in well Nahorhabi-1 are given in **Table 4-40.**

Table 4-40: NAHORHABI FIELD - CORE DATA

Field	NAHORHABI
Well No.	Nahorhabi-1
Core No.	-
Interval (m)	4014.94–4070.94 m.
Portion for Testing (From Top) (m)	4015.50–4015.77 m.
Lithology of Portion	-
Type of Core	-
Sample Received On	24.02.81
DETAILS OF CORE ANALYSIS	
1) Effective Porosity % (v/v)	11.83
2) Gas Permeability (mD)	
a) Horizontal (mD)	57.4896
b) Vertical (mD)	54.2141
3) Liquid Perm (Horizontal)	
a) Fresh Water (mD)	Very low
b) 5% Salt Water (mD)	Very low
4) Fluid Content % (w/w)	
a) Water	2.339
b) Oil	0.2448
5) Residual Saturation % (v/v)	
a) Water	46.06
b) Oil	5.4176
6) Pore Volume (per 1/100 g)	5.077
7) Chloride Content (g per 100 g)	0.02542

Structure contour maps and Oil Iso pay maps for the zones TS-6, BCS, LBS-1 & BMS were prepared as on 01.04.1995 as shown in **Figure 4-70** through **Figure 4-77**.

Figure 4-70: STRUCTURE CONTOUR MAP ON TOP OF TS-6 (1.4.1995) WITH DRILLED WELL LOCATIONS OF NAHORHABI

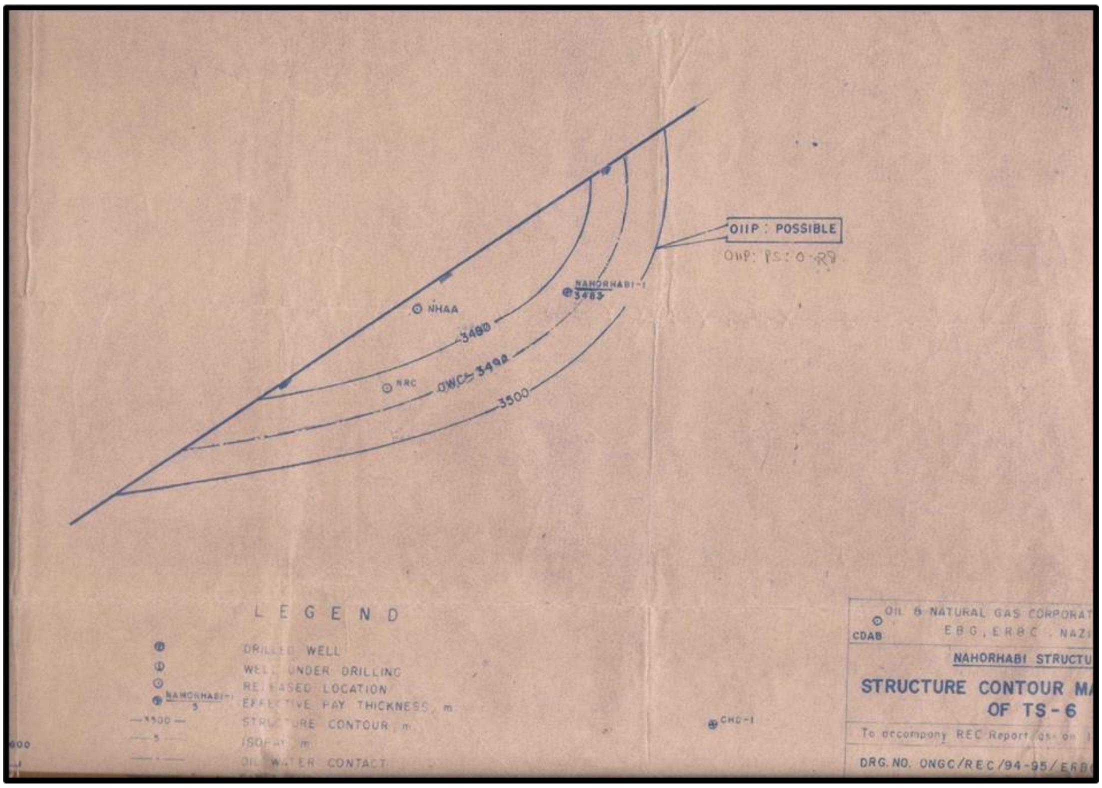


Figure 4-71: OIL ISOPAY MAP OF TS-6 (1.4.1995) WITH DRILLED WELL LOCATIONS OF NAHORHABI

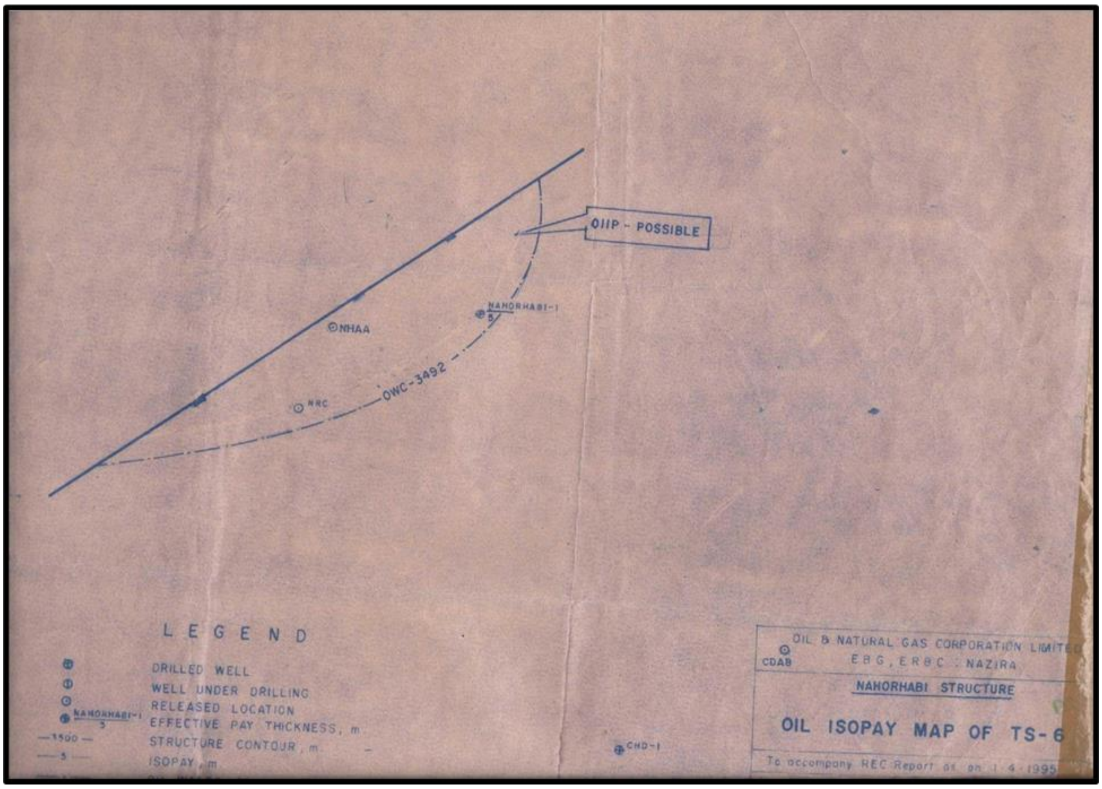


Figure 4-72: STRUCTURE CONTOUR MAP OF BCS (1.4.1995) WITH DRILLED WELL LOCATIONS OF NAHORHABI

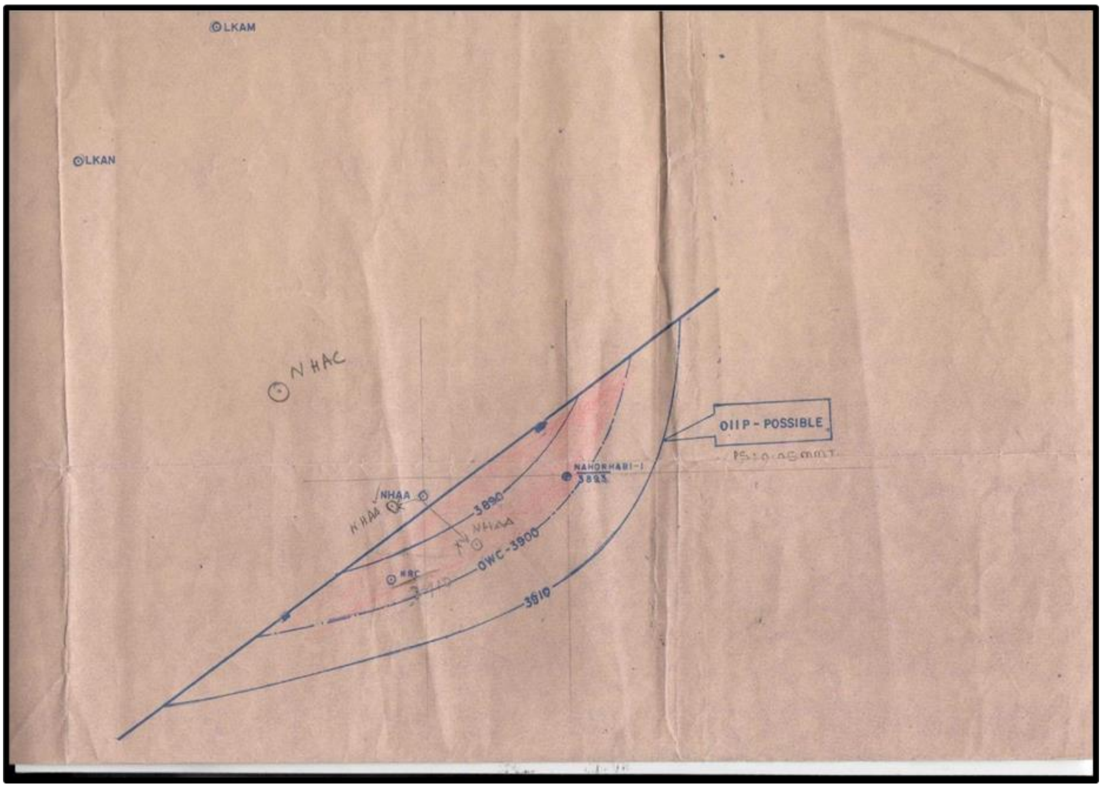


Figure 4-73: OIL ISOPAY MAP OF BCS (1.4.1995) WITH DRILLED WELL LOCATIONS OF NAHORHABI

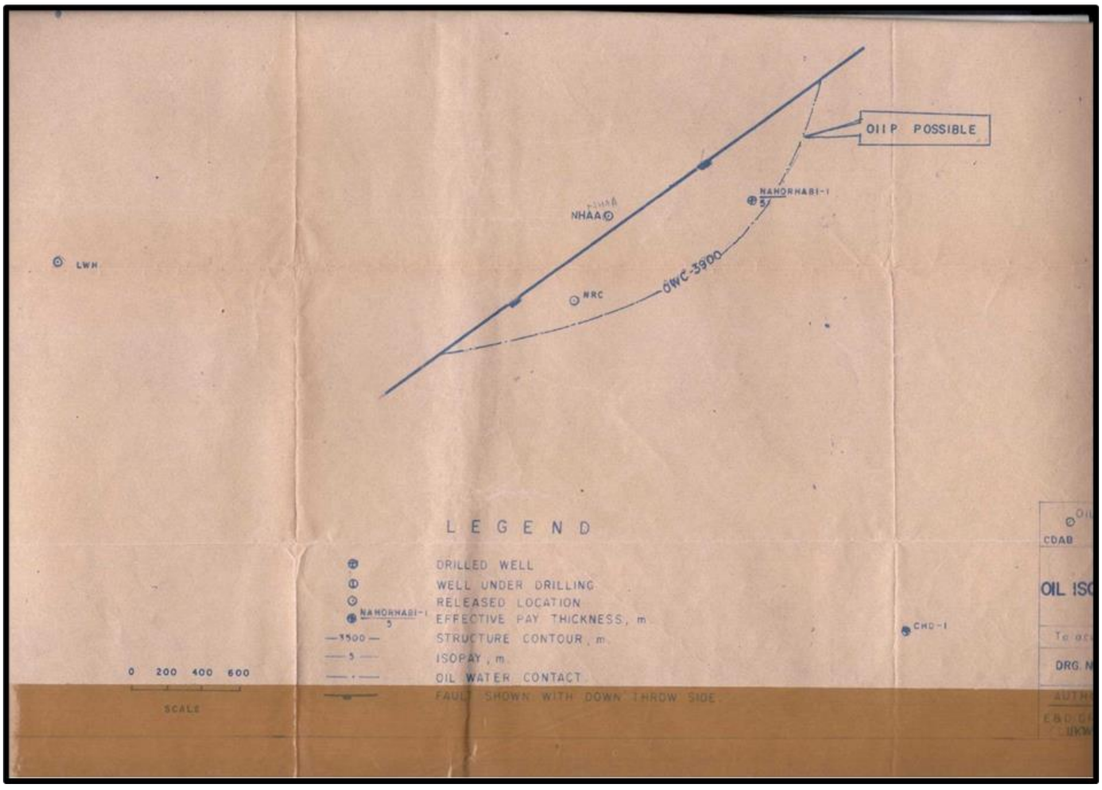


Figure 4-74: STRUCTURE CONTOUR MAP OF BMS (1.4.1995) WITH DRILLED WELL LOCATIONS OF NAHORHABI

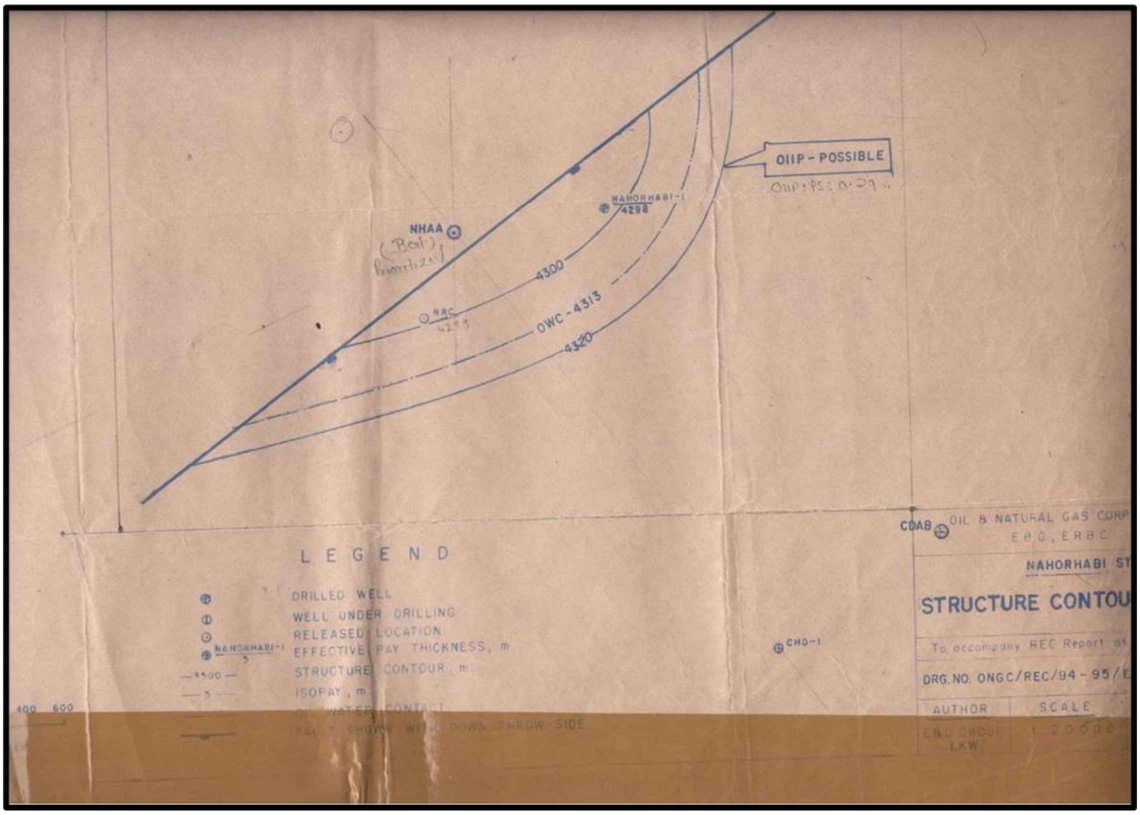


Figure 4-75: OIL ISOPAY MAP OF BMS (1.4.1995) WITH DRILLED WELL LOCATIONS OF NAHORHABI

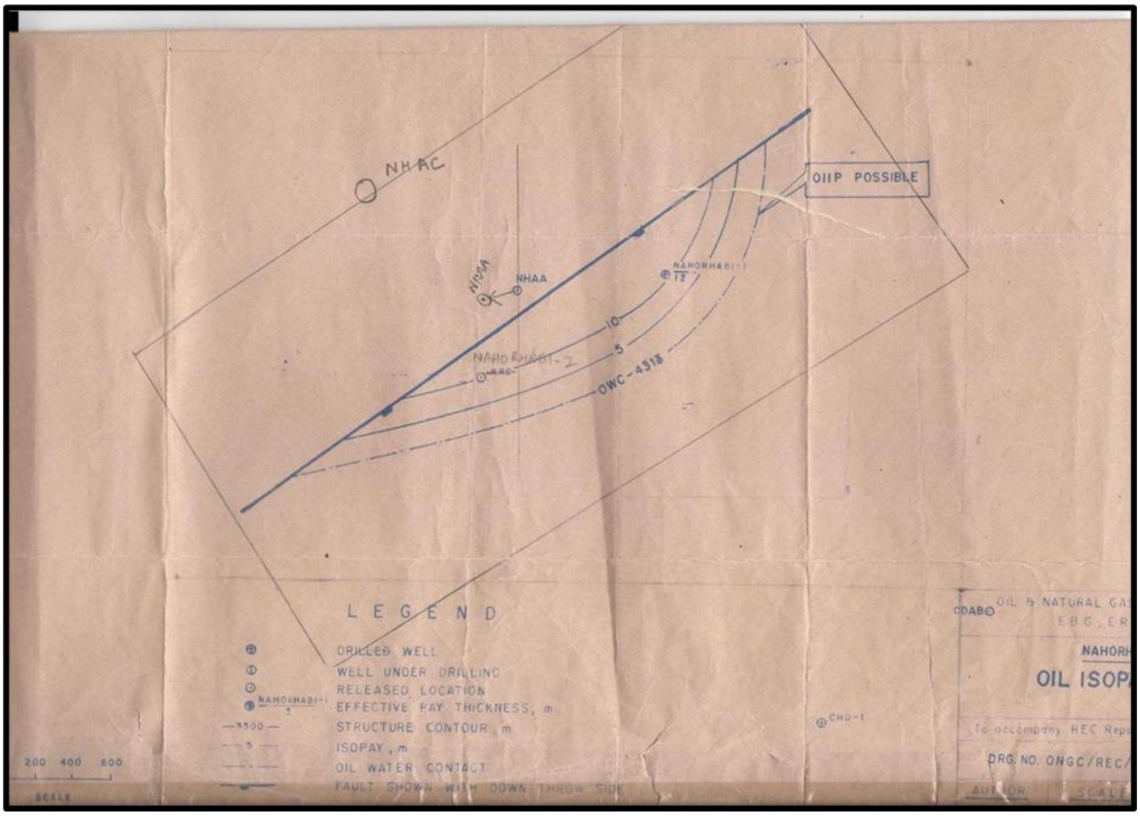


Figure 4-76: STRUCTURE CONTOUR MAP OF LBS-1 (1.4.1995) WITH DRILLED WELL LOCATIONS OF NAHORHABI

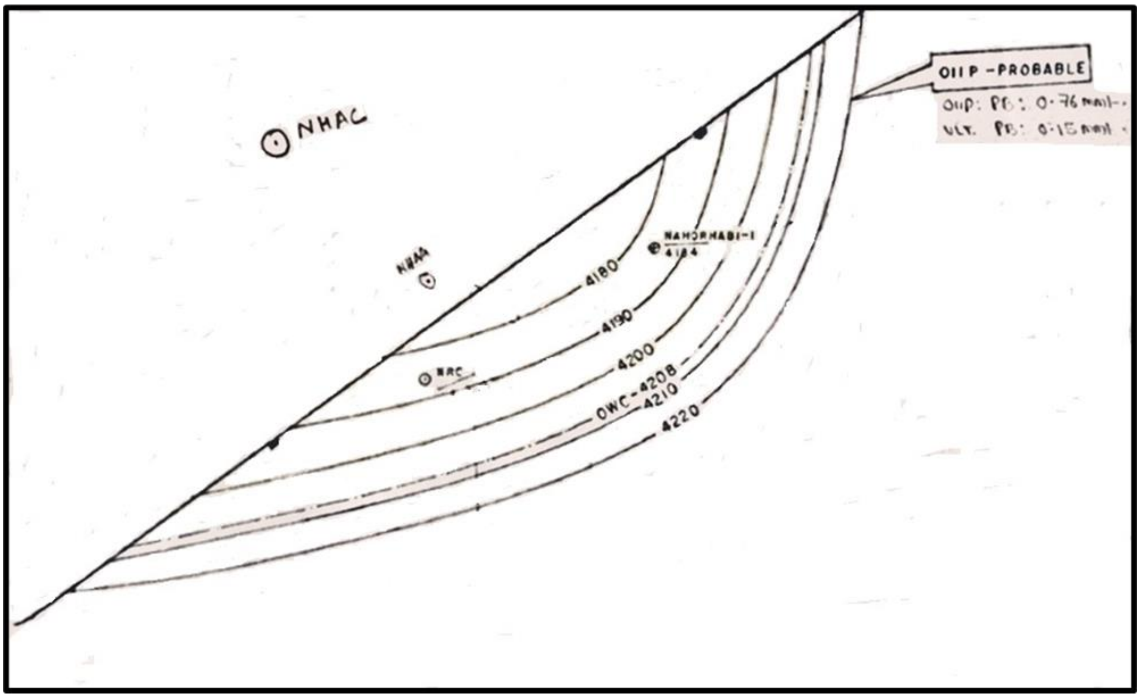
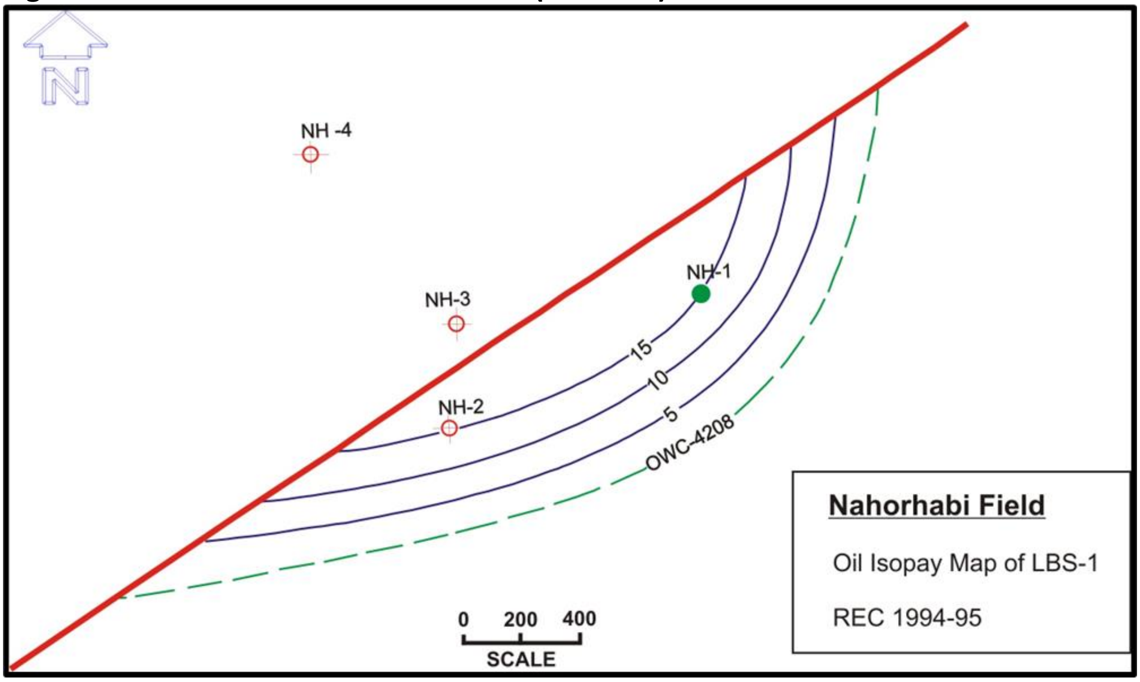


Figure 4-77: OIL ISOPAY MAP OF LBS-1 (1.4.1995) WITH DRILLED WELL LOCATIONS OF NAHORHABI



4.5.5.2 Reservoir parameters and hydrocarbon estimates (NAHORHABI Field):

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

After the discovery of Nahorhabi-1, earlier operator estimated the reserves for the first time as on 1.1.1982 in C2 Category. On testing the Barail Main pay sand with workover rig during 1986, the reserves for BMS (LBS-1) were upgraded to C1 category reserves as on 1.1.87. The details of the reserves as on **1.1.1987** for all the pay zones are given in the table below (**Table 4-41**) as per Russian Classification System.

Table 4-41: NAHORHABI OIIP AND RESERVES AS ON 1.1.1987 AS PER RUSSIAN CLASSIFICATION SYSTEM

Zone	Avg. Depth	Avg. Thickness	Category	OIIP, MMt	Soln Gas, MMm3	Free Gas, MMM3	Recoverable OIIP, MMT	Recoverable SG, MMm3	Free Gas, MMm3
TS6	3483	4.47	C2	0.28	55.3	-	-	-	-
BCS	3893	2.50	C2	0.05	13.0	-	-	-	-
BMS	4184	8.86	C1	0.76	189.7	-	0.114	23.386	
BMS	4298	6.60	C2	0.29	73.2	-	-	-	-
Total				**1.38**	**331.1**	**-**	**0.114**	**23.386**	

Reserves estimates as on **01.04.1995** are summarized at **Table 4-42**.

Table 4-42: NAHORHABI OIIP AND RESERVES AS ON 01.04.1995

Zone	Top of Reservoir	OWC, m	Thickness	Category	OIIP, MMT	EUR, MMt
TS-6	3483	3492	5	Possible	0.28	
BCS	3893	3900	5	Possible	0.05	
LBS-1	4184	4208	15	Probable	0.76	0.15
BMS	4298	4313	12	Possible	0.29	
Total					**1.38**	**0.15**

Current Oil/ Gas In-Place estimation

The reservoir parameters and in-place estimated for various sands of Nahorhabi Field in the current study are given in **Table 4-43 and Table 4-44** respectively**.**

Table 4-43: RESERVOIR PARAMETERS FOR VOLUMETRIC ESTIMATION OF NAHORHABI FIELD

Reservoir	Top of Reservoir	Area	Avg He	Phi	H/C Saturation	FVF	oAPI	Sp. Gr	GOR	OIIP	GIIP
		Sq Km	m		So	v/v			M3/m3	MMt	MMm3
TS-6	3483	0.86	5	0.20	0.48	1.75	26.8	0.8934	300	0.22	74
BCS	3893	0.53	5	0.12	0.57	1.75	26.8	0.8934	300	0.10	32
LBS-1	4184	0.96	12	0.12	0.50	1.75	27.0	0.8923	300	0.45	152
BMS	4298	1.20	10	0.14	0.60	1.75	27.0	0.8923	300	0.60	200
										1.37	**458**

Table 4-44: HYDROCARBON IN-PLACE (2P) OF NAHORHABI FIELD

	O+OEG
Field	**MMTOE**
NAHORHABI	**1.83**

Erstwhile Operator-reported estimates on record:

The Nahorhabi Field has a reported Oil estimate of **1.68 MMTOE.**

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the currently reported estimates.

Other Prospective Resource Candidates

In addition to the objects tested in Nahorhabi –1, one zone in the interval 3860-3872 has also been estimated as Oil Bearing based on Log Characters with porosity of around 11.5 % and Oil Saturation of 57%. (Refer Page 60 & 61 of WCR of NAHB-1)

Further, as per WCR of NAHB-3, Object-V & VI in BCS and VII were not tested and planned to be tested later with Workover Rig. This could also be an upside if not tested yet

4.5.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Nahorhabi Field is 21 km. NE of main Geleki field and approx. 3 km. south of Lakwa field**.**

AA/ONDSF/ASSAM/2025 (A&AA) CHARAIDEO FIELD

4.6 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) CHARAIDEO FIELD

Charaideo Field was discovered by ONGC in 1981. ONGC has drilled 4 exploratory wells viz. Charaideo-1 (CRDO-1), Charaideo-2 (CRDO-2), Charaideo-3 (CRDO-3) and Charaideo-4 (CRDO-4) in the Charaideo area of which wells CRDO-1, CRDO-2 and CRDO-4 fall within the present Contract Area whereas well CRDO-3 falls outside the Contract Area. Well CRDO-1 was found to be oil bearing in Barail Coal Shale (BCS) unit of the Barail Group (Oligocene age) while wells CRDO-2 and CRDO-4 witnessed inflow of oil in Barail Main Sand (BMS) unit of Barail Group (Oligocene age).

The discovery well Charaideo-1 (CRDO-1) is situated about 6 km south of Lakwa Field and was drilled during the year 1981 by ONGC to explore the hydrocarbon prospects in Tipam and Barail Groups and in this well there was minor inflow of oil for a little while from the BCS unit before the flow ceased.

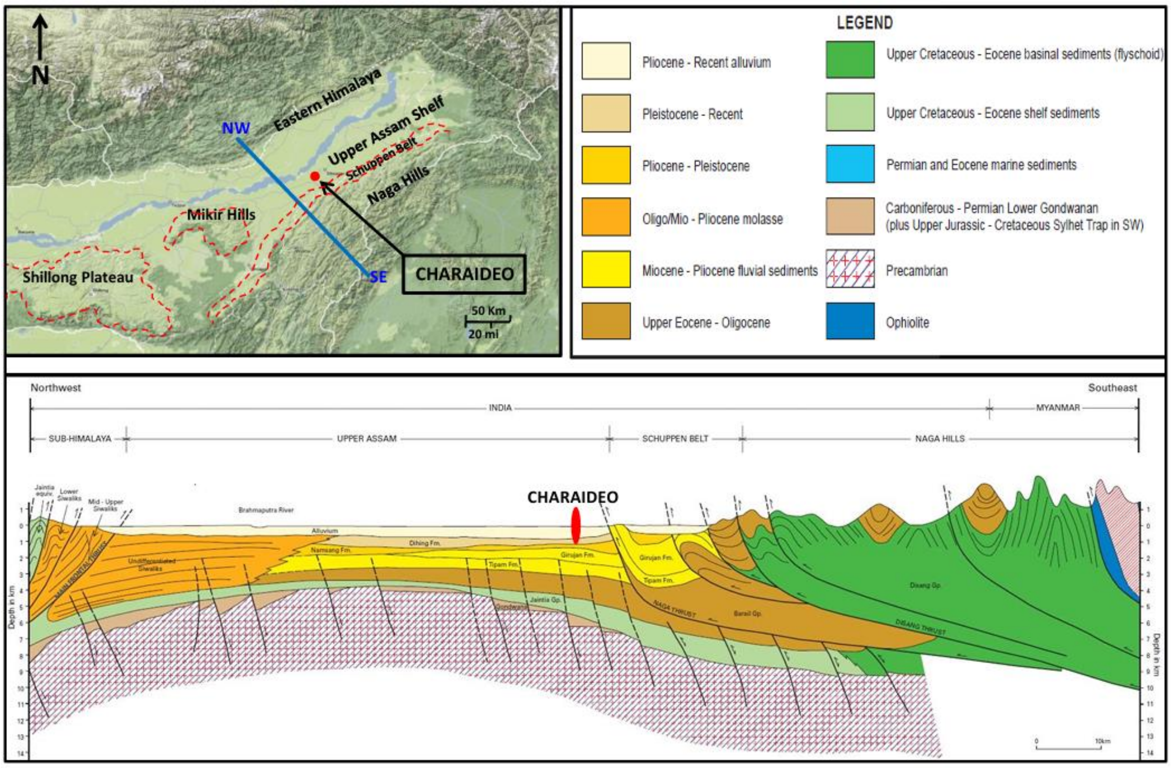
The well CRDO-2 was drilled in the year 2001 to a target depth of 4700 m and bottomed in BMS. The well is correlatable at all levels with the well CRDO-1. A number of hydrocarbon shows were observed during drilling in sands of the Tipam Group and Rudrasagar Formation (BCS unit of Barail Group). Conventional core recovered from Barail Coal Shale unit also indicated the presence of hydrocarbon. Subsequently, nitrogen application caused the flow of little oil and gas from the 4612 m - 4642 m zone of BMS. Other zones remain untested due to fish in hole.

The well CRDO-4 was drilled in the year 2009 as an exploratory vertical well for exploring the hydrocarbon potential of Barails (BCS & BMS). This location was proposed on the highest part of the Charaideo structure to probe its true potential. The well has been drilled down to a depth of 4708 m. The well was terminated within the BMS Formation and was sidetracked three times due to drilling complications.

On testing well CRDO-4, Object-I (4558-66m/BMS) gave poor influx of oil and the well witnessed poor influx of water. On subduing the well with mud, flow of 300 litres of oil was observed. Re-perforation of the zone again produced only 100 litres of oil during reversing out with water. It was thus concluded that the zone requires further activation by hydrofracturing. Object II (4506-02m/ BCS) tested dry with poor fluid influx. Based on results of Object-II, testing of Object III (3932-28.5m/Safrai, lying behind double casing) was cancelled. Due to poor influx, it was recommended to retest the Object-I and improve the influx after hydro-fracturing.

The area Charaideo is located onland within the Assam Shelf area and has an offered area of 14.86 sq. km. under the DSF Bid Round IV. A NW-SE cross section from the Eastern Himalayan foothills to Naga Hills is shown in **Figure 4-78.**

Figure 4-78: NW-SE CROSS SECTION FROM THE EASTERN HIMALAYAN FOOTHILLS TO NAGA HILLS



The Charaideo area is covered with alluvium and has an average elevation of 100 m above MSL. The field is well connected with National Highway 2 (erstwhile NH 37) and National Highway 702C. The nearest railway station is Simaluguri Junction and the nearest airport is Jorhat which is about 70 kms from the neighbouring Nazira Town.

In the adjoining areas, although extensive exploration has been carried out in and around Lakwa-Lakhmani area, a well-known oil field in the Assam Shelf, few exploratory locations have been drilled to the north of Santak area, i.e. south of Lakwa Field. A few structural/ stratigraphic prospects have been probed in Rajabari, Nahorhabi and Charaideo areas and are found to be hydrocarbon bearing / with indications of hydrocarbon. Apart from the Charaideo structure, one well each drilled on the Rajabari and Nahorhabi structures had indicated the presence of oil at different levels in the Barail Group of sediments.

The area has also been covered from time to time by several seismic surveys (both 2D and 3D) which include series of different vintages viz. A-42, A-44, A-57, A-117, A-120, A-131, A-185, A-186 and A-202. The earliest subsurface mapping of the area was carried out with the help of seismic investigations A-42 and A-47 based on which two exploratory locations Nahorhabi-1 and Charaideo-1 were drilled during 1981. The Chariadeo Field area is also covered with 3D seismic by the NAS (North Assam Shelf) Mega-merge volume.

4.6.1 Drilling and well completion

Key information of drilled wells has been collated and presented hereunder. The adjoining figures wherever shown illustrate the Well Construction Diagram for key wells. Other well statics like kelly bush reference depth, drilled and logged depth including well coordinates are made available in Sections through various cross-references.

As stated earlier, of the four exploratory wells drilled in this field viz. Charaideo–1 (CRDO-1), Charaideo–2 (CRDO -2), Charaideo–3 (CRDO -3) and Charaideo–4 (CRDO -4), three wells, i.e. CRDO -1, CRDO -2 and CRDO -4 fall in the block.

Well construction diagrams of wells Charaideo-1, Charaideo-2 and Charaideo-4 are shown in **Figure 4-79, Figure 4-80 and Figure 4-81** respectively.

General details of the drilled wells and casing data, recorded are given in **Table 4-45 and Table 4-46.** Litho section of the Charaideo wells is shown in **Figure 4-82 and Figure 4-83.**

Figure 4-79: WELL CONSTRUCTION DIAGRAM OF WELL CHARAIDEO-1

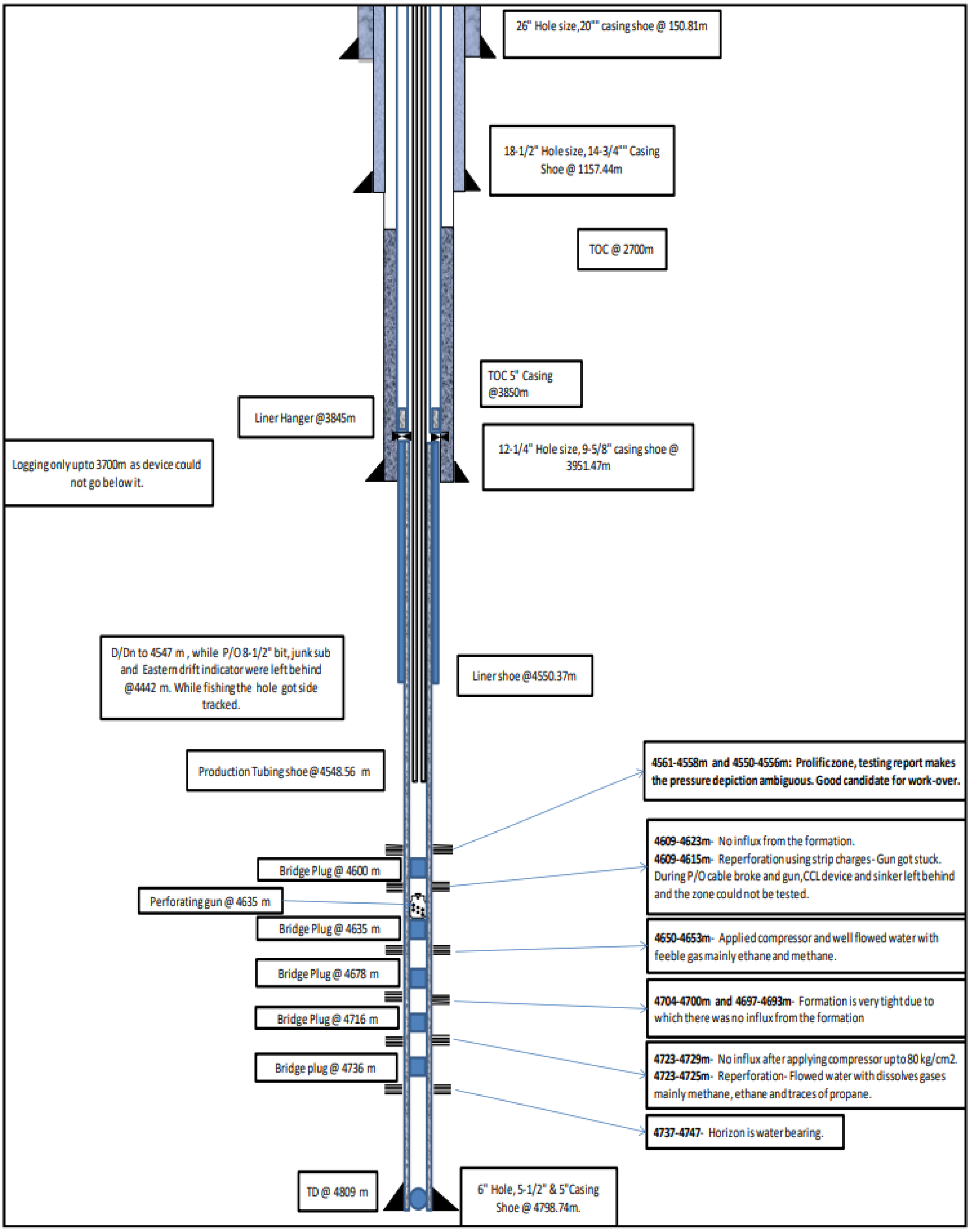


Figure 4-80 : WELL CONSTRUCTION DIAGRAM OF WELL CHARAIDEO-2

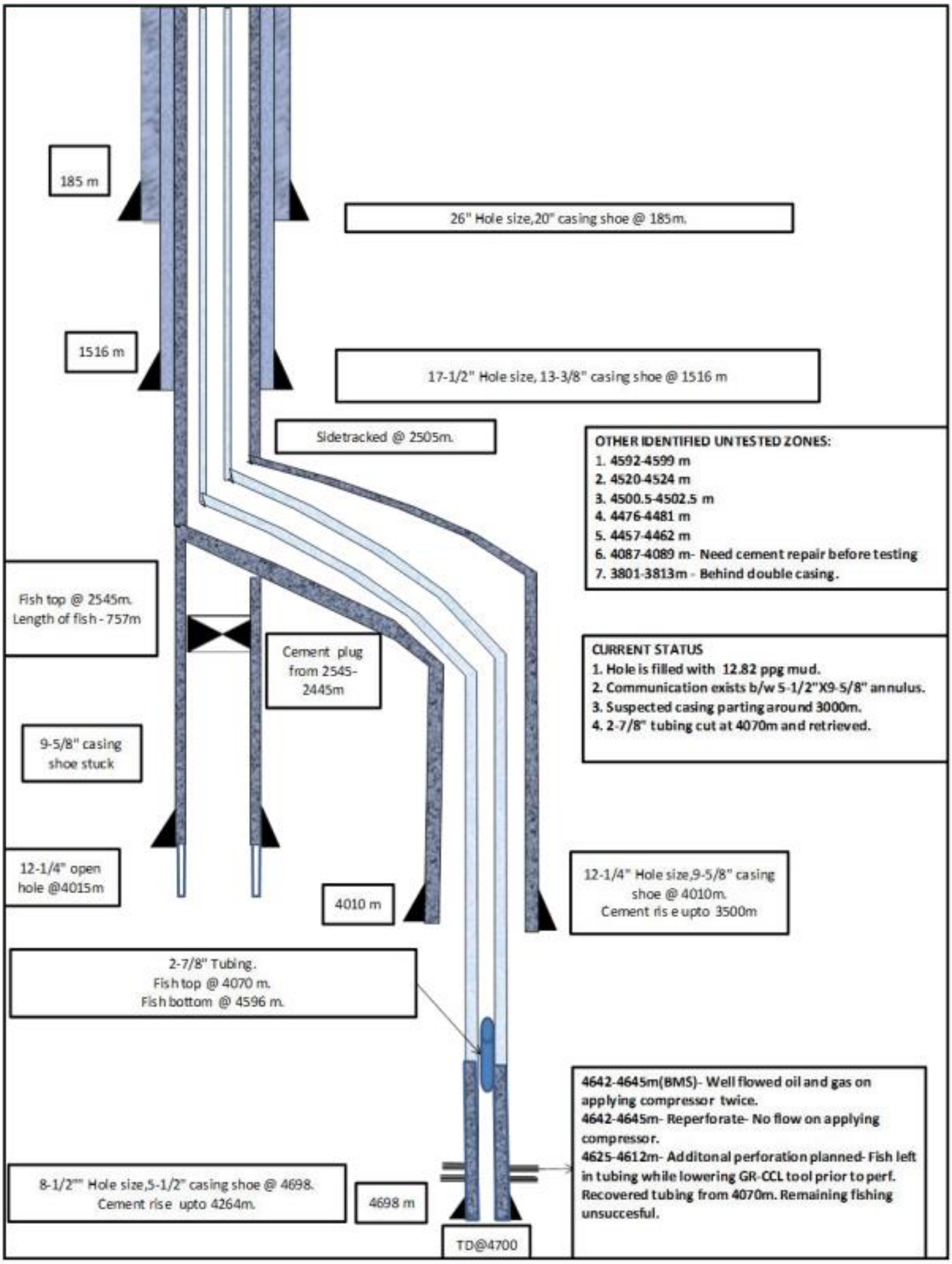


Figure 4-81: WELL CONSTRUCTION DIAGRAM OF WELL CHARAIDEO-4

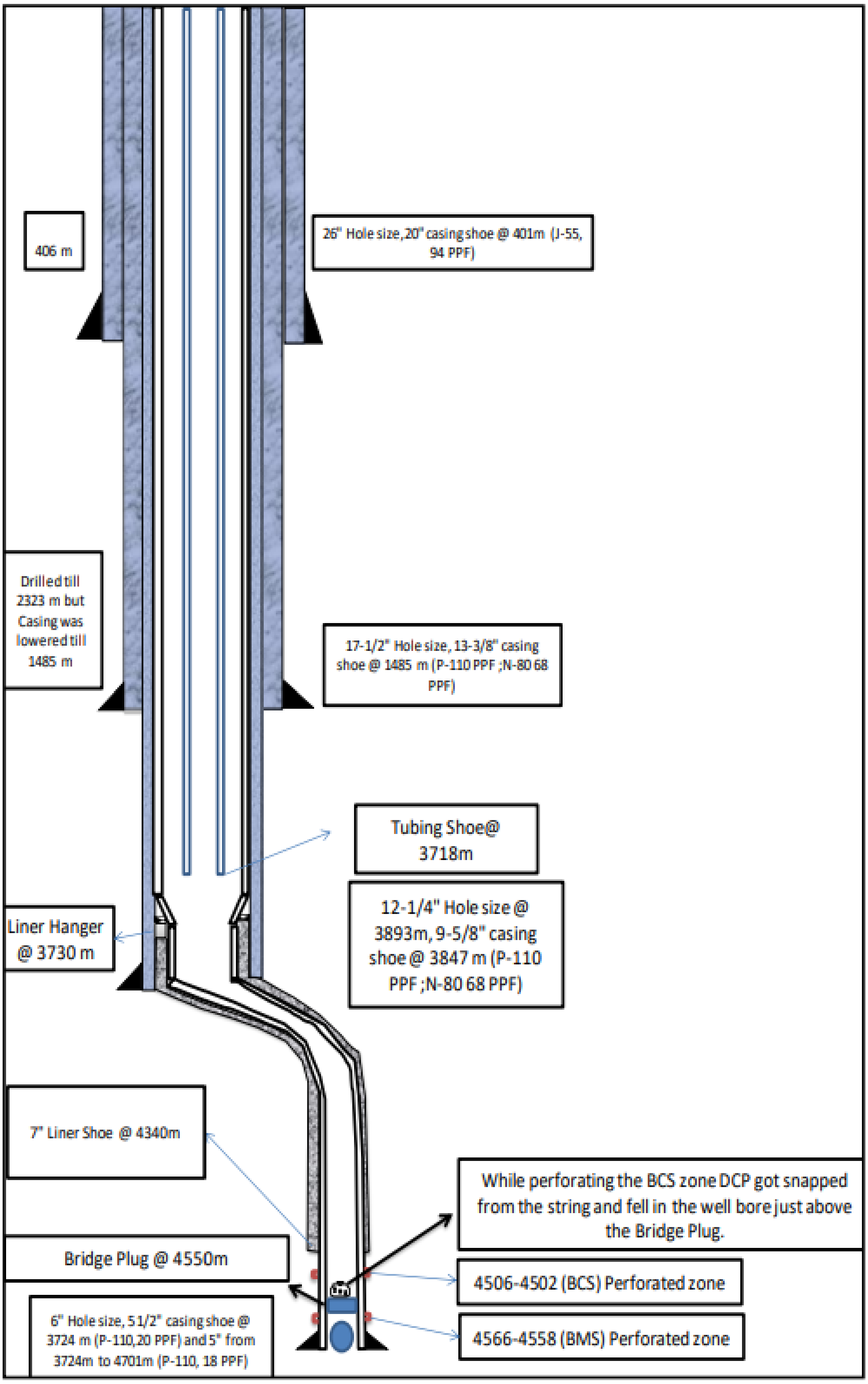


Table 4-45: GENERAL WELL DETAILS

	Charaideo-1	Charaideo-2	Charaideo-3	Charaideo-4
Area	Nazira - Assam			
Structure	Charaideo			
Well	Charaideo-1	Charaideo-2	Charaideo-3	Charaideo-4
Category	Exploratory	Exploratory	Exploratory	Exploratory
Co-ordinates	Latitude: 26°57’20”N	Latitude: 26°57’379”N	Latitude: 26°56’15.153”N	Latitude: 26°57’38.10”N
	Longitude:94°53’25”E	Longitude:94°53’53.52”E	Longitude:94°54’24.171”E	Longitude:94°52’37.14”E
Rig	H-2500	E-2000-IX	E-1400-VI	E-2000-IX
Target Depth	4800 m	4900 m	4500 m	4700 m
Drilled Depth	4805 m	4700 m	4334 m	4708 m
Objective	Tipam and Barail Prospects	Barail BCS Formation	Tipam and Barail Prospects	Barail Prospects
Status	Testing incomplete. **Flow of Oil and gas** with water for some time from BCS	Incomplete Testing due to technical reasons.	Well producer from Safrai Formation (Object-II) with SRP	Indication of oil with negligible influx in Object-I.
KB	108.60 m	110.0 m	121.005	104.5 m
Spud date	13.08.1979	29.07.2001	23.11.2007	24.06.2009
Drilling Completion	05.01.1982	18.10.2002	11.12.2008	22.08.2010
Production testing Completion	August, 1982	April, 2003	July 2009	November 2010
Rig release	25.08.1982	01.05.2003	20.08.2009	18.11.2010

Table 4-46: CASING DATA

Well	Hole Size	Casing Size	Cement Rise from Surface (m)	Casing Shoe Depth (m)
Charaideo-1	36 “	30 “	Surface	30.15 m
	26 “	20 “	Surface	150.81 m
	18.½ “	14. ¾ “	Surface	1157.40 m
	12. ¼ “	9.5/8 “	2700 m	3951.47 m
	8. ½ “	7 “ (liner)	-	4550.37 to 3845.0 m
	6 “	5 “& 5 ½ “ 5.1/2”= 0 to 3741.48m 5”=3741.48 to 4798.74m	3850 m	4798.74 m
Charaideo-2	26 “	20 “	Upto Surface	185 m
	17.½ “	13. 3/8 “	-	1516 m
	12.¼ “	9. 5/8 “	-	4010 m
	8.½ “	5. ½ “	-	4698 m
Charaideo-3	26 “	20 “	Surface	249 m
	17.½ “	13. 3/8 “	-	1760 m
	12.¼ “	9. 5/8 “	-	3724 m
	8 ½ “	5½ “	604 m	4327m
	8 ½ “	5½ “ (S/T)	993 m	4160 m
Charaideo-4	**26 “**	20 “	Surface	401 m
	17.½ “	13. 3/8 “	600 m	1485 m (Short Landed)
	12.¼ “	9. 5/8 “	No CBL	3847 m

	8 ½ "	7 " Liner	465 m	4340 m to 3740 m
	4. "	5½ "& 5" 5.1/2"= 0 to 3724m 5" = 3724 to 4707m	925 m	4707 m

Figure 4-82 : LITHO-SECTION INFORMATION OF THE CHARAIDEO WELLS

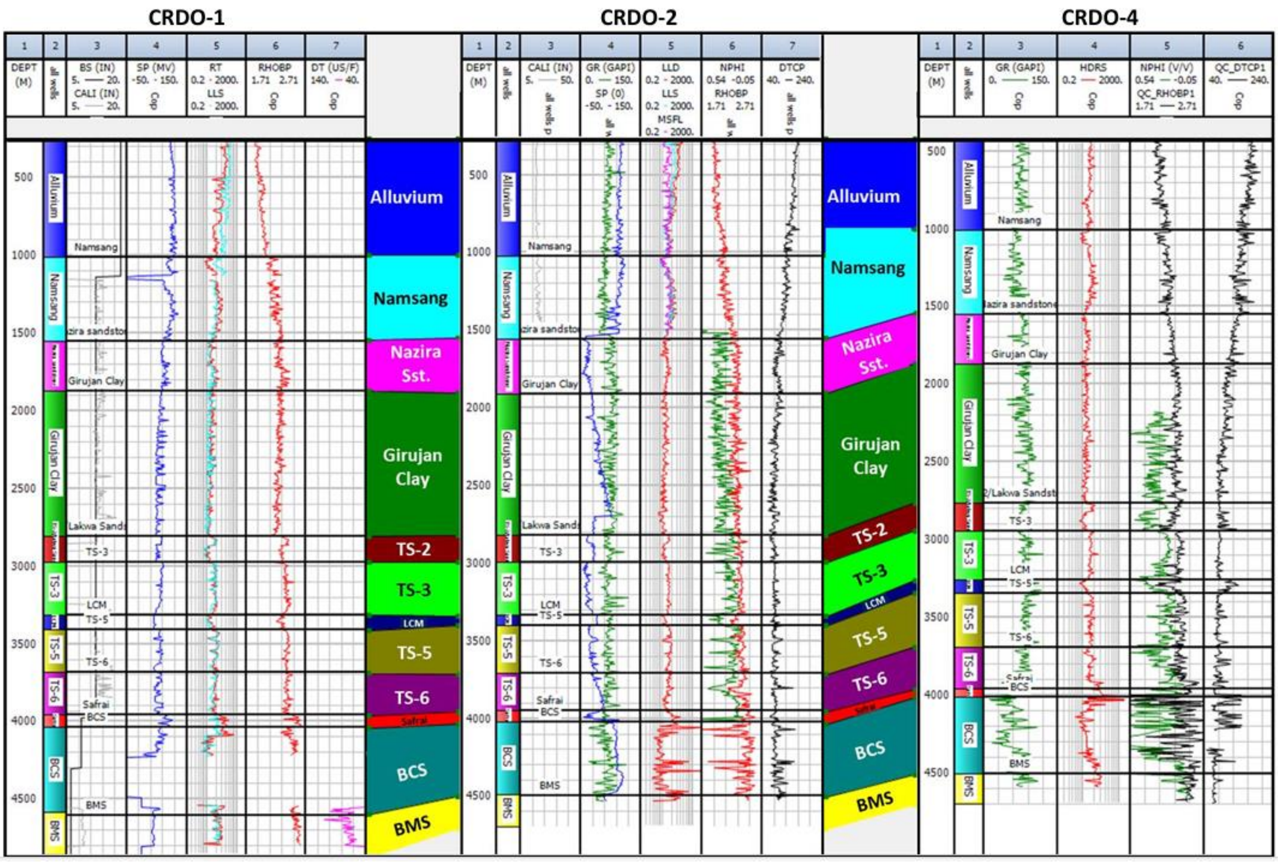
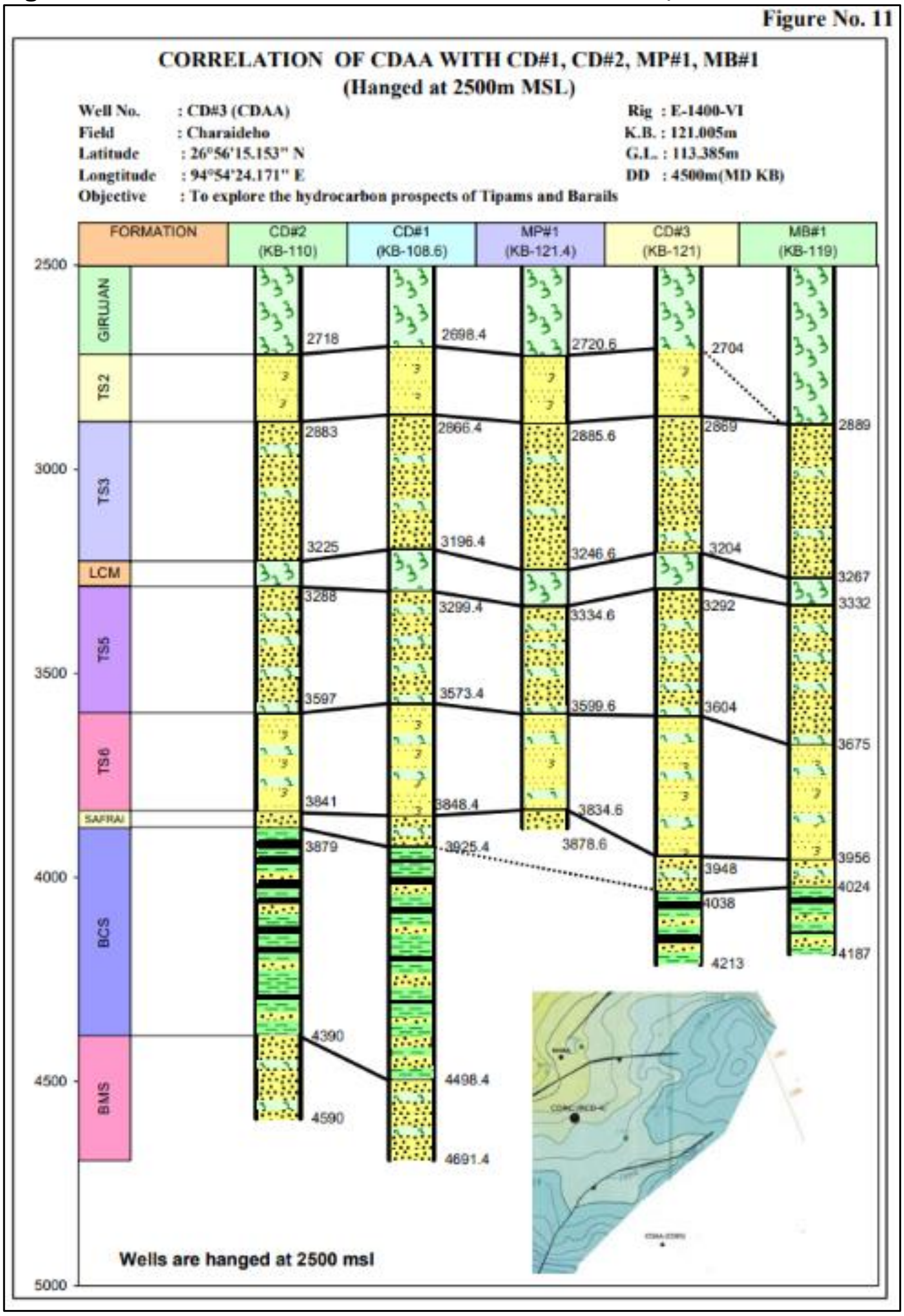


Figure 4-83 : CORRELATION BETWEEN WELLS CRDO-1, CRDO-2 & CRDO-3 AND OTHER NEARBY WELLS



4.6.2 Well logging and formation evaluation

The well logs of all discovery wells along with some key wells in the Contract Area have been reviewed. The logs recorded in various open-hole sections along with cased-hole logs and information of conventional and other wireline formation test data are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) have been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.6.2.1 Well completion and log evaluation reports availability in Charaideo Field:

	WCR/ FER availability	Spud date	KB	Drilled depth
CRDO-1	Both available	13.08.1979	108.60 m	4805 m
CRDO-3	Both available	23.11.2007	121.005 m	4334 m
CRDO-4	Both available	24.06.2009	104.5 m	4708 m

Lists of availability of reports , list of log suites recorded for the wells CRDO-1, CRDO-2 and CRDO-4 are given **Table 4-47, Table 4-48, Table 4-49 and Table 4-50.**

4.6.2.2 Well logs acquired Charaideo Field:

Table 4-47: CHARAIDEO-1 FIELD: AVAILABILITY OF REPORTS

Well	KB	Spud Date	Drilled depth	WCR Available/ Not Available	FER Available/ Not Available
Charaideo 1	108.60 m	13.08.1979	4805 m	Available	Available
Charaideo 2	110.0 m	29.07.2001	4700 m	Not Available	Not Available
Charaideo-3	121.005 m	23.11.2007	4334 m	Available	Available
Charaideo 4	104.5 m	24.06.2009	4708 m	Available	Available

Table 4-48: LOG SUITES RECORDED

Well No.	Type of log	Interval (m)
Charaideo-1	Std. log & BKZ	151-1137, 1158-2879, 2800-3340, 1158-3440, 3952—4228,
	Caliper	151-1175.5, 1158-2870
	Inclinometer	200-1150, 1158-2850
	Sonic, Induction, SP-Normal-4M-BKZ, Inclinometer, Caliper	3952-4782
	Temperature	700-upwards, Surface to 4752
	CBL-Neutron (CH), GR	3952-4752
Charaideo-2	HRI-SP-GR-CAL-SONIC	2713-4023
	LDL-CNL-GR-CALI	1500-4020

Charaideo-4	INDUCTION–GR-SONIC	400-2315
	HRI-BCS-SP-GR-CAL- INCL	1477-2988
	SDL-DSN-GR-CAL	2174-2988
	HRI-SDLT-DSNT-GR-SP-INCL-CAL SDL-DSN-GR-CAL	2876-3838
	HRI-GR-SP-CAL	3770-3861
	SDL-DSN-GR-CAL	3800-3861
	BCDT-GR	2850-3861
	FMI-GR SWC	1520-3847
	PEX-HRLA	3847-4233
	CNL-GR	4150-4310
	CBL-VDL-GR-CAL	3741-4316, 3700-4667.8
	HRLA-MCFL-BHC-TLD-HGNS-GR-HCAL	4344.5-4407
	HRLA-MCFL-BHC-GR	4344.5-4703
	HRLA-Sonic	4344.5-4703
	CNL CH)-GR-CCL	4300-4667.8

Table 4-49: WELL CHARAIDEO-1:WELL LOGS RECORDED

Hole Size	Wireline Log Operations
18.1/2”	Standard, BKZ (Full Set) logs (Soviet Resistivity) recorded on 11/12.09.1979 at 1139.87 m
13.3/4”	Caliper and Inclinometer Surveys carried out on 11.10.1979 at well depth of 1175.5 m
12.1/2”	Standard, Caliper and inclinometer survey were recorded on 21.08.1980 at a well depth of 2890.47 m
	Standard logs recorded on 18/19.09.1980 at a well depth of 3381 m
	Standard, BKZ (full set) and Caliper survey were recorded on 17/18.10.1980 at a well depth of 3975 m
	Thermo log was recorded at a well depth of 3975 m
8.1/2”	Attempted to log the well at a depth of 4198.67 m but the tool could not be lowered below 3984 m
	Standard Logs (SP, Normal and 4 m Lateral) were recorded on 26.02.1981 at a well depth of 4220 m. Tool could not be lowered below 4200 m
	On 04.07.1981 an attempt was made to log the hole at a well depth of 4541 m but the tool could not be lowered below 4180 m.
	On 15.09.1981 an attempt was made to log the hole upto Fish Top (below 4547 m instead of calculated depth of 4442 m) but tool could not be lowered beyond 4230 m.
	On 02.11.1981 and 08.11.1981 attempts were made to log the hole at a well depth of 4547 m but the tool could not be lowered below 4228 m.
6”	Russian and GOI logs were recorded on 06/07.01 1982 at a well depth of 4809 m
	Attempt to record CBL and Neutron Gamma logs against the 7” Liner was unsuccessful on 6/7.01.1982 as the tool could not be lowered below 3700 m.

Table 4-50: WELL CHARAIDEO-4: WELL LOGS RECORDED

Hole Size	Wireline Log Operations
17.1/2”	INDUCTION-GR-SONIC logs recorded on 10.08.2009 at a well depth of 2323 m.
	HRI-RCS-SP-GR-CAL- INCLINOMETER survey carried out on 29.08.2009 at well depth of 2993 m
12.1/4”	SDL-DISN-GR-CAL survey were recorded on 29.08.2009 at a well depth of 2454 m m
	HRI-SDLT-DSNT-GR-SP, INCLINOMETER-CAL, SDL-DSN-GR-CAL logs recorded on

	23.09.2009 at a well depth of 3875 m
	HRI-GR-SP-CAL-SOL-DSN GR—CAL, BCDT-GR surveys were recorded on 26.09.2009 at a well depth of 3893 m
	FMI-GR log, SWC was recorded on 27.09.2009 at a well depth of 3893 m
8.1/2”	COMPOSITE Log (PEX HRLA) logs were recorded in the ranges 4233-3847 m and 4231-3847 m on 04.01.2010 and 23.05.2010 at a well depth of 4233 m and 4245 m
	CNL-GR (Cased Hole) and CBL-VDL-GR-CCL logs were recorded on 29.07.2010 at a well depth of 4407 m.
6”	HRLA-MCFL-BHC-TLD-HGNS-GR-HCAL logs recorded on 24.08.2010 at a well depth of 4595 m
	HRIA-MCFL-BHC-GR logs were recorded on 26.08.2010 at a well depth of 4809 m
	HRLA - Sonic logs were recorded on 29.08.2010 at a well depth of 4708 m
5.1/2” Casing	CH-CNL and CBL-VDL-GR-CCL logs were recorded on 15.09.2010 at a well depth of 4708 m

Conventional & Sidewall Core Data

Conventional and Sidewall cores were recovered from well Charaideo-2 (13 cores–1 CC and 12 SWC) and well Charaideo-4 (18 cores – 1 CC and 12 SWC) from the TS-6, BCS and BMS levels (**Table 4-51**).

Table 4-51: CONVENTIONAL CORE DATA OF CHARAIDEO FIELD

Well no.	Core no.	Interval (m)	Recovery (%)	Gross Lithology
Charaideo-1	Not attempted in this well			
Charaideo-2	CC-1	4090.63-4093.4 m	61.75 %	Mainly Sandstone – The core has indicated presence of hydrocarbon. It showed GYF and +ve cut.
Charaideo-4	CC-1	3781-3790 m	Nil	-
	CC-2	4501-4508 m	67%	Sandstone with silty claystone showing fluorescence and +ve cut.

4.6.2.3 Well log evaluation and initial test results (Charaideo Field):

Petrophysical parameters obtained in the reservoir zones of Charaideo Field in the best case using the average parameter of the three wells and parameters obtained in the reservoir zones of key wells are as follows (**Table 4-52 and Table 4-53**).

Table 4-52: AVERAGE PARAMETERS OBTAINED IN THE RESERVOIR ZONES OF CHARAIDEO

Best Case - P50						
Zones	Thickness Gross (m)	Sand Net (m)	Silty Sand Net (m)	Total Net (m)	Avg. Porosity (Frac)	Avg. Sw (Frac)
TS-5	347	0.3	0.3	0.6	0.183	0.496
TS-6	271	0.5	1.2	1.6	0.146	0.507
Safrai	51	1.3	0.7	1.9	0.178	0.533
BCS	492	8.8	7.6	16.4	0.161	0.472

BMS	194	4.4	4.1	8.5	0.167	0.456

Table 4-53: PETROPHYSICAL PARAMETERS OBTAINED IN THE TESTED ZONES OF CHARAIDEO WELLS

	Charaideo-1		Charaideo-2		Charaideo-4	
Zones	**Avg. Porosity %**	**Avg. Sw %**	**Avg. Porosity %**	**Avg. Sw %**	**Avg. Porosity%**	**Avg. Sw %**
TS-5					12-16	49.6
TS-6					11-16	85-100
Safrai					10-11	90-100
BCS	12	37	9-10	48	9-10	85-100
BMS	9-11	46	9-14	58-68	7-10	65

Hydrocarbon indications were seen in drill cuttings and core samples. Formation tops were obtained from well log data while horizons were obtained from seismic data. All these were combined to correlate the wells in the field.

Well, log motif of CHARAIDEO Wells:

Log motifs for tested Objects of wells Charaideo-1 are shown in **Figure 4-84, Figure 4-85, Figure 4-86, Figure 4-87, Figure 4-88 and Figure 4-89.**

Log motifs for tested Objects of wells Charaideo-2 are shown in **Figure 4-90** through **Figure 4-95**,

Log motifs for tested Objects of wells Charaideo-4 are shown in **Figure 4-96 and Figure 4-97** .

Figure 4-84: LOG MOTIFS OF OBJECT-I (BMS) IN WELL CHARAIDEO-1

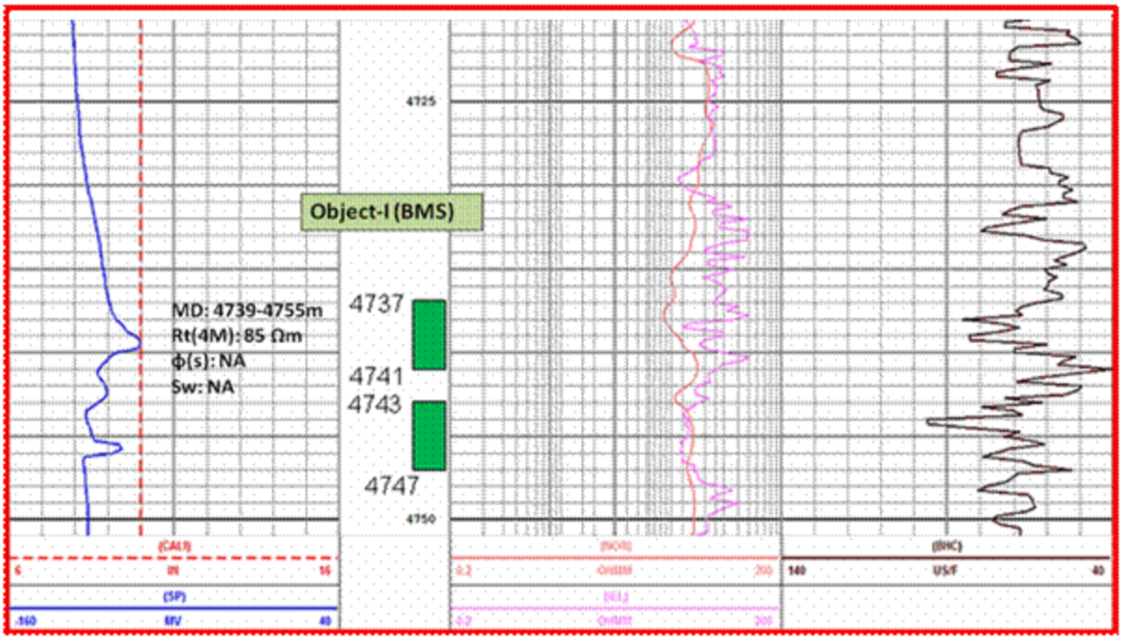


Figure 4-85: LOG MOTIFS OF OBJECT-II (BMS) IN WELL CHARAIDEO-1

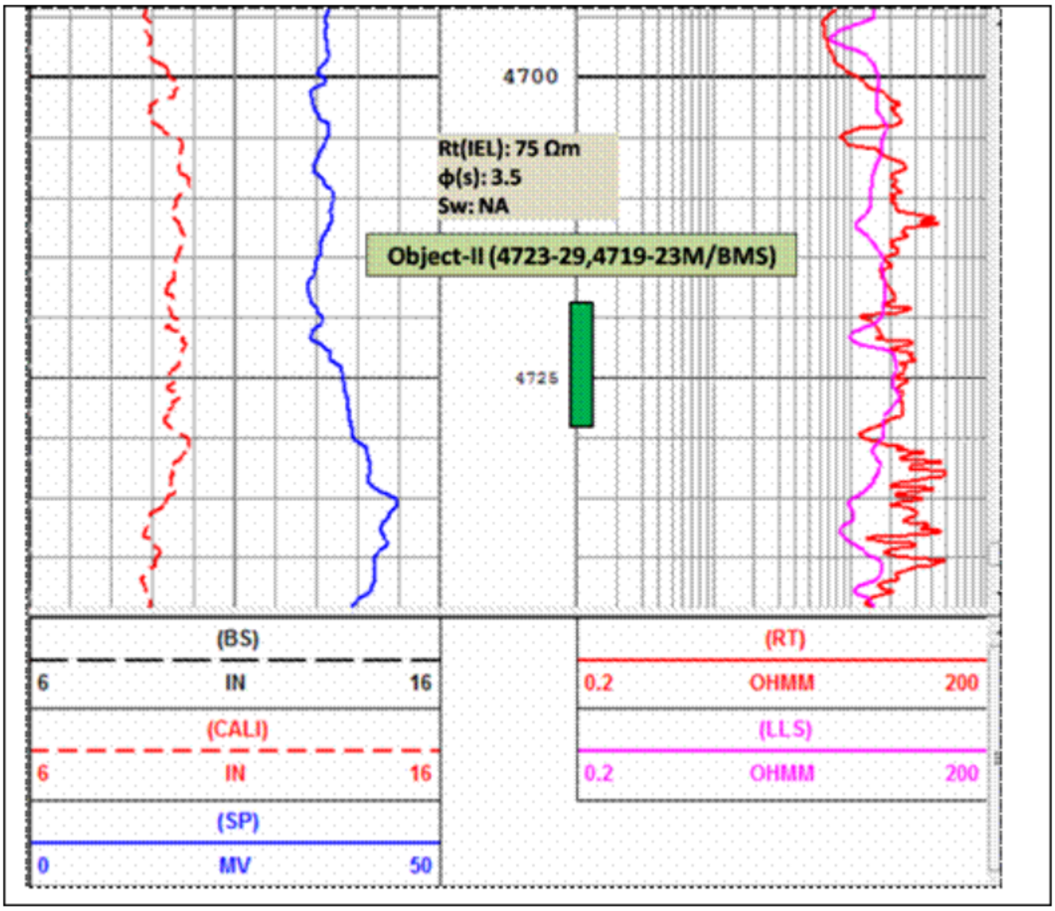


Figure 4-86: LOG MOTIFS OF OBJECT-III (BMS) IN WELL CHARAIDEO-1

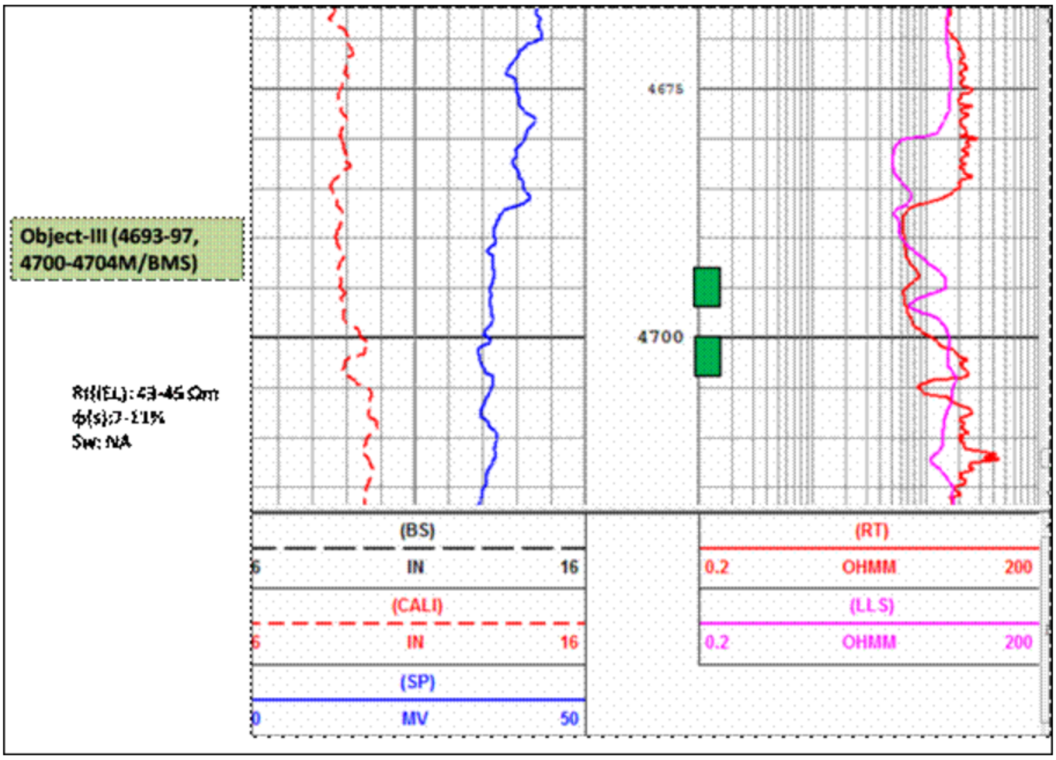


Figure 4-87: LOG MOTIFS OF OBJECT-IV (BMS) IN WELL CHARAIDEO-1

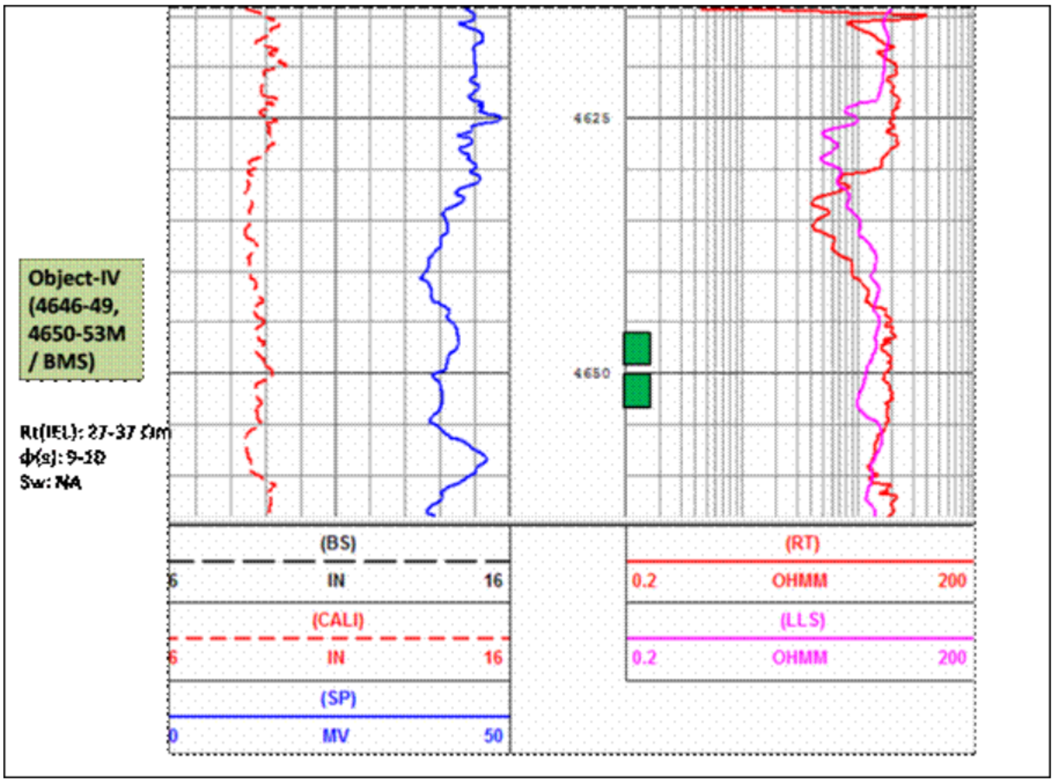


Figure 4-88: LOG MOTIFS OF OBJECT-V (BMS) IN WELL CHARAIDEO-1

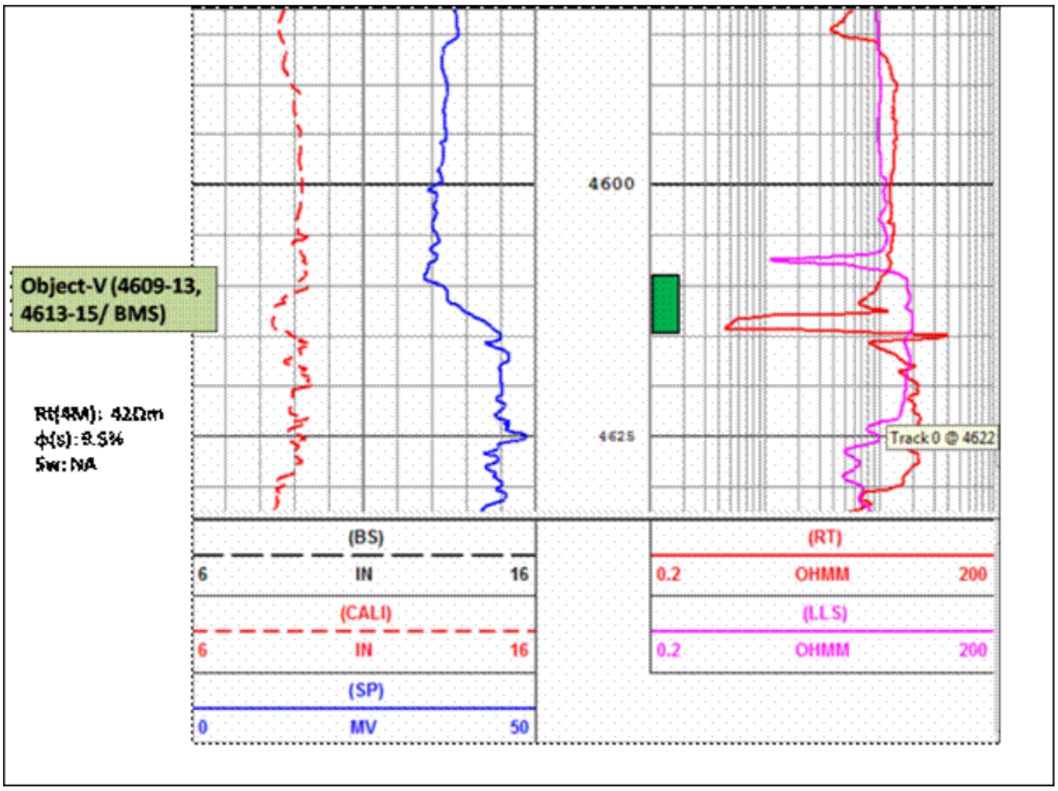


Figure 4-89: LOG MOTIFS OF OBJECT-VI (BCS) IN WELL CHARAIDEO-1

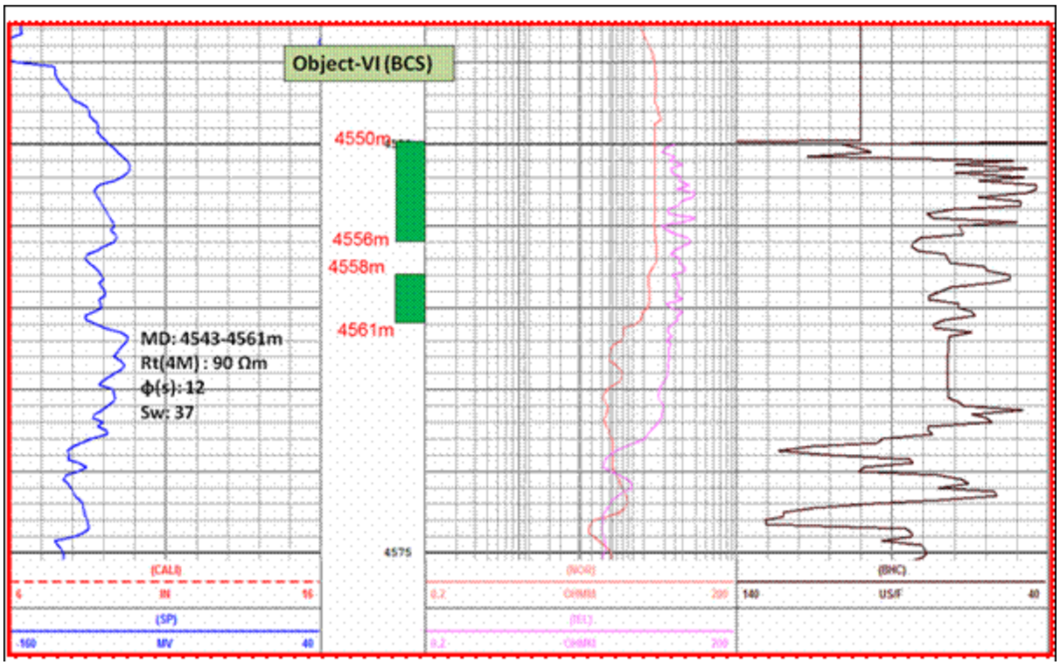


Figure 4-90: LOG MOTIF OF OBJECT-III (BMS) IN WELL CHARAIDEO-2 (Not Tested)

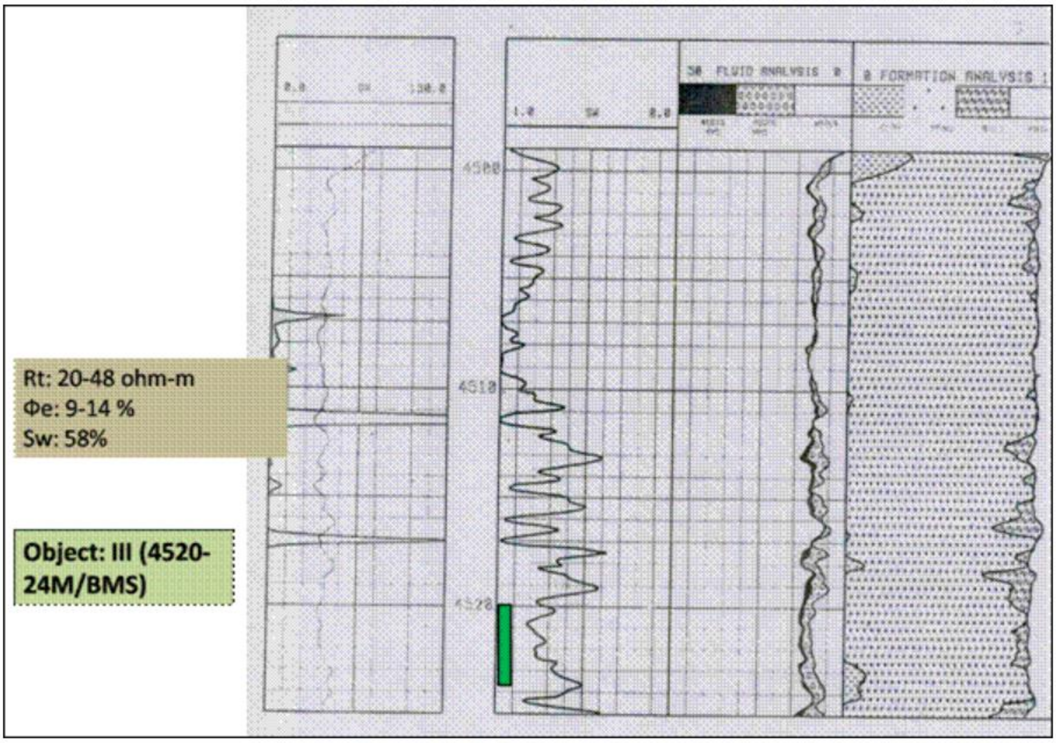


Figure 4-91: LOG MOTIF OF OBJECT-IV (BMS) IN WELL CHARAIDEO-2 (Not Tested)

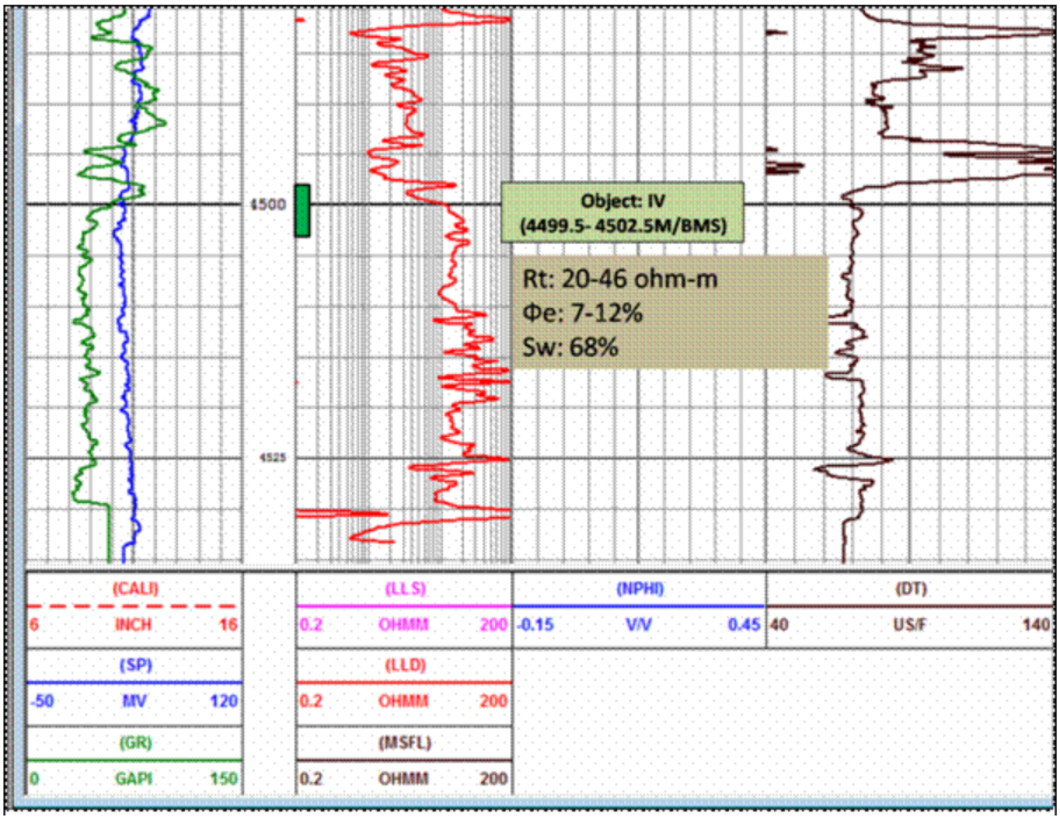


Figure 4-92: 93LOG MOTIF OF OBJECT-V (BCS) IN WELL CHARAIDEO-2 (Not Tested)

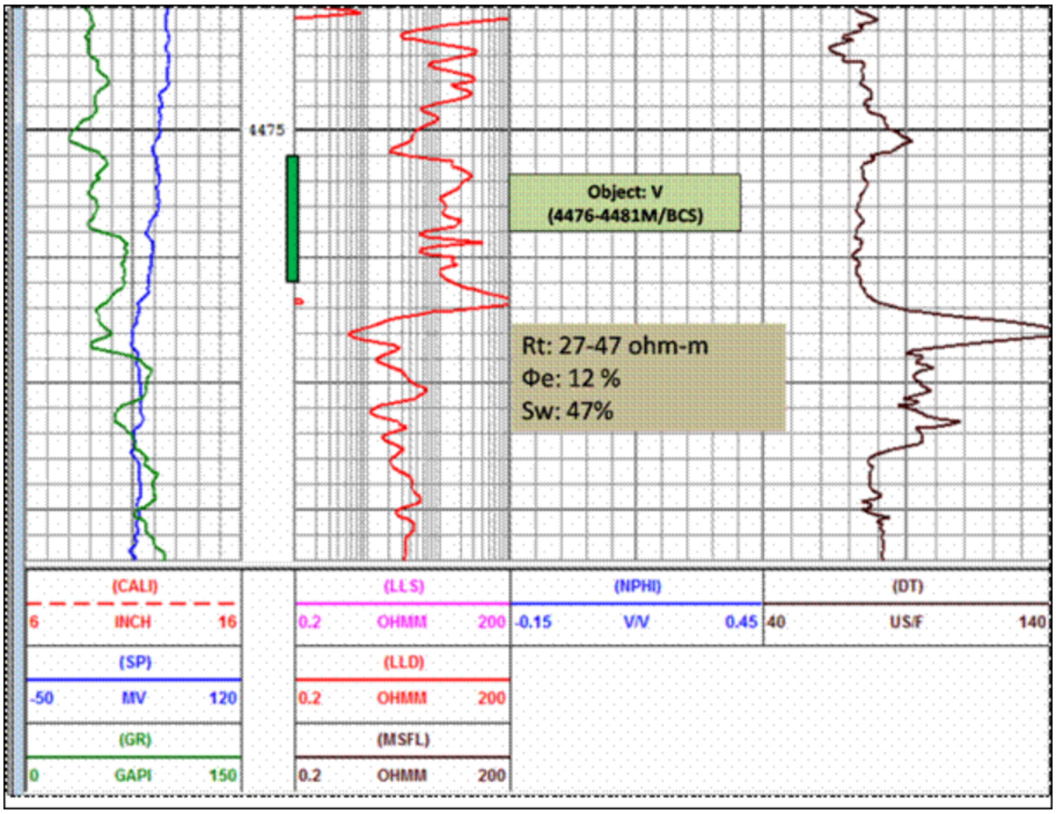


Figure 4-94: LOG MOTIF OF OBJECT-VI (BCS) IN WELL CHARAIDEO-2 (Not Tested)

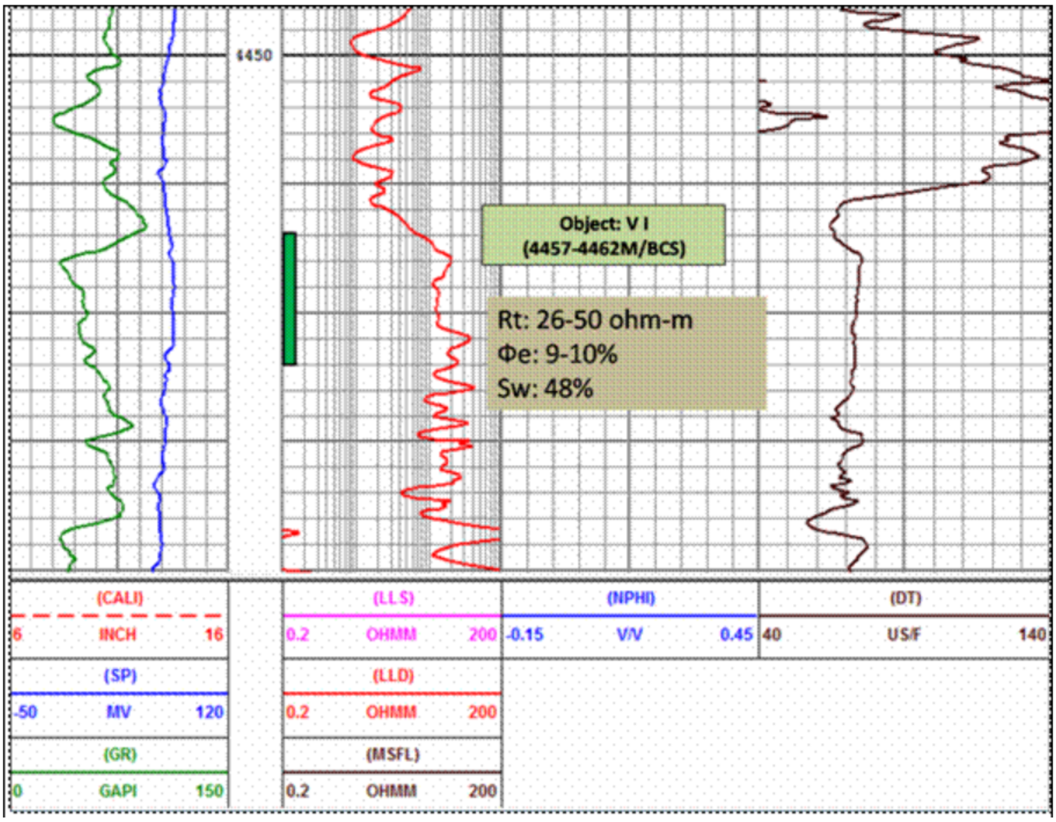


Figure 4-95: LOG MOTIF OF OBJECT-VII (BCS) IN WELL CHARAIDEO-2 (Not Tested)

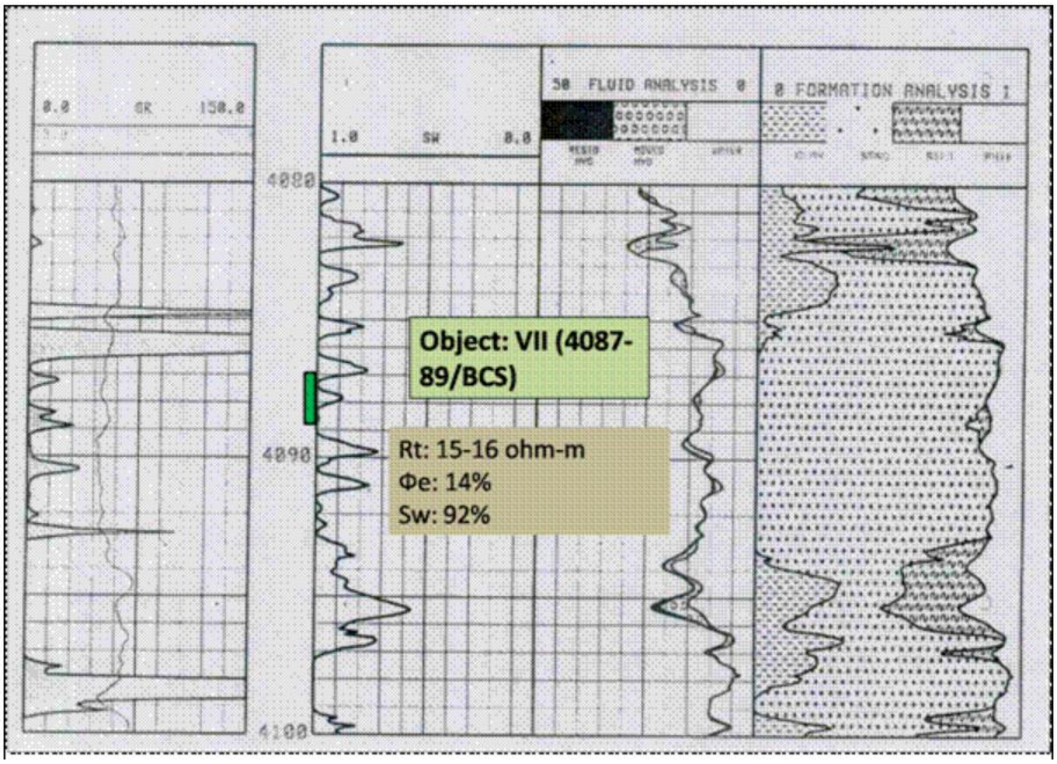


Figure 4-96: LOG MOTIF OF OBJECT-I (BMS) IN WELL CHARAIDEO-4

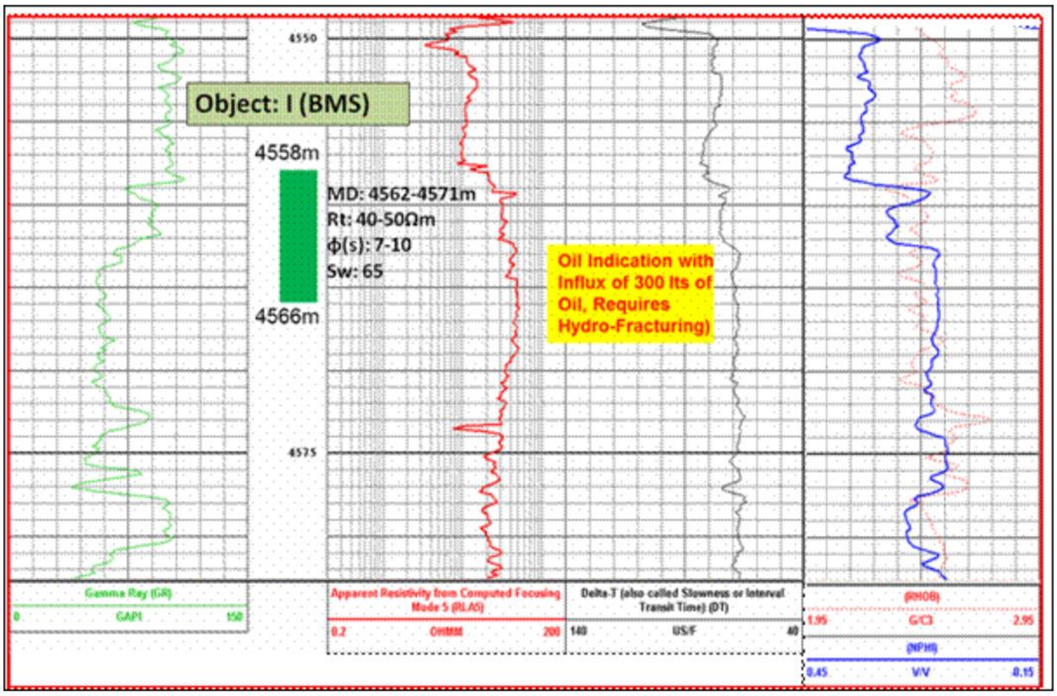
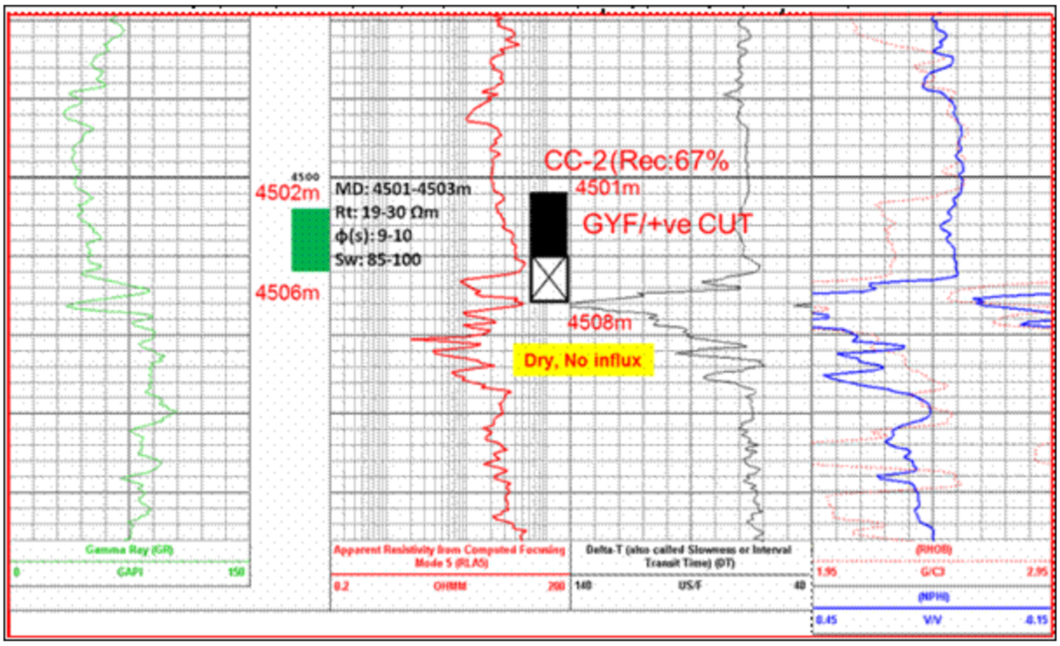


Figure 4-97: LOG MOTIF OF OBJECT-II (BCS) IN WELL CHARAIDEO-4



4.6.3 Well testing and workover history

In Charaideo Field four exploratory wells have been drilled. Out of these four wells three wells CRDO-1, CRDO-2 and CRDO-4 fall within the present block whereas well CRDO-3 falls outside the Block. The object wise detail testing results of three wells are given in **Table 4-54.** Reservoir depths of each reservoir are given in **Table 4-55.**

Table 4-54: TESTING RESULTS OF CHARAIDEO WELLS

WELL	OBJECT	INTERVAL (M)	RESULT	STATUS
CRDO#1	I, BMS	4737-4741M 4743-4747M	Chromatography on DST fluid sample showed indications of ethane and methane. No flow at surface. Plugged back (BP).	Water bearing
	II, BMS	4723-4729M 4719-23M (Addl.) 4723-25M (Reperf.)	Initially poor inflow. After reperforation self flow of water with dissolved gas @7 liters/ min Sal 3.05 gpl was observed. Plugged back (BP)	Water with dissolved gas
	III, BMS	4693-4697M 4700-4704M	Poor influx Plugged back (BP)	Tight sand with poor influx
	IV, BMS	4646-4649M 4650-4653M	Self flow of water with feeble gas. Sal 2.4 gpl. Plugged back (BP)	Water bearing with dissolved gas
	V, BMS	4609-4613M 4613-4615M (Addl Perf)	Poor influx even on additional perforation and on testing Injectivity was found to be nil. On trying to reperforate the entire range a Fish was left in hole which could not be recovered. Plugged Back (BP) after pushing down Fish to bottom	Poor influx.
	VI, BCS	4550-4556M 4558-4561M	On application of Compressor after changeover of well fluid to water poor influx was observed. However later pressure buildup was observed in the annulus. On opening the well through tubing, it flowed water **but on opening through annulus observed flow of oil/gas for few minutes. There was also a gradual increase in pressure. Subsequently the well flowed oil/ gas for 3 minutes, followed by water and then ceased.** **The well fluid was then subjected to swabbing for activation. The well flowed only gas. On further swabbing the well showed poor influx with sluggish rise in fluid level with minor oil in the swabbed fluid.**	**Oil and gas indication in BCS with poor influx**
CRDO-2	I, BMS	4642-4645M 4612-4625M (ADDL PERF)	Flowed **oil and gas** on application of compressor twice. Additional perforation was planned but while lowering GR-CCL tool prior to perforation fish was left in tubing. Recovered tubing from 4070m. Further Fishing operations unsuccessful.	Testing incomplete. **Oil indication in BMS**.
	II, BMS	4592-4599M	-Not tested due to fish-	

	III, BMS	4520-4524M	-Not tested due to fish-	
	IV, BMS	4499.5-4502.5M	-Not tested due to fish-	
	V, BCS	4476-4481M	-Not tested due to fish-	
	VI, BCS	4457-4462M	-Not tested due to fish-	
	VII, BCS	4087-4089M	-Not tested due to fish-	
CRDO-3	II BCS	4304-4300 m	No influx and injectivity even after reperforation	
	II, Safrai	4097 –4103 m	Intermittent Producer of Oil & Gas. Requires Artificial Lift	
	III, Safrai	4087-4083.5 m & 4079-4074.5 m	Influx of water salinity 4.4 gpl as NaCl	
CRDO-4	I, BMS	4558-4566M	While subduing the well with mud (of sp. gr.1.42), return of **300 lits of oil** followed by water was observed. After re-perforation, observed 100 lts of oil during reversing out with water. Plugged back (BP)	The object was concluded as oil bearing with poor influx. Requires hydrofracturing
	II, BCS	4502-4506M	Poor influx	Poor influx

Table 4-55: RESERVOIR SAND DEPTHS IN CHARAIDEO WELLS

Well	KB(m)	DD(m)	TS-1	TS-2	TS-3	LCM	TS-5	TS-6	Safrai	BCS	BMS
CRDO-1	108.6	4805	ND	2806	2974	3314	3410	3682	3957	4035	4585
	TVDSS		ND	2697	2865	3205	3301	3573	3848	3926	4476
CRDO-2	110	4700	ND	2819	2992	3335	3399	3708	3951	4025.7	4492
	TVDSS		ND	2708	2882	3225	3289	3597	3840	3915.7	4382
CRDO-4	104.5	4708	ND	2765	2932	3264	3345	3692	3964	4014	4507
	TVDSS		ND	2661	2828	3160	3241	3588	3960	3911	4403

4.6.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study and PVT data/ results.

No routine/Special core analysis data available

No Pressure Transient and Reservoir studies have been carried out

No analysis of oil/gas has been carried out

No Production has been taken.

No work over job has been carried out

Well Heads are available at well CRDO-1 and CRDO-2 and X-Mass tree at CRDO-4

FDP is available for the field.

HC was encountered in the Safrai, BCS and BMS levels and their PVT data collected are as follows (**Table 4-56**):

Table 4-56: PVT DATA FOR RESERVOIR ZONES IN CHARAIDEO WELLS

SAFRAI ZONE					
DEPTH (M)					3995
TEMP (F)					265.73
PRESSURE (Psia)					5804.7
sp gr					0.824
API GRAVITY					40.2
Black-Oil Fluid Properties Correlations This Black-oil model is consistent with Eclipse 100/200 (use field units here)					
BO model results					
API gravity of oil	API	40.22		40.22	
solution gas-oil ratio of saturated oil	Rs	1563.36	scf / stb	278.43	m3 / m3
bubble point pressure	Pb	5308.4	psia	3.660E+07	Pa
oil compressibility	Co	1.691E-05	1 / psi	2.453E-09	1 / Pa
oil formation volume factor	Bo	1.840	rb / stb	1.840	m3 / sm3
oil viscosity	Viso	0.230	cp	2.305E-04	Pas
oil density	Deno	35.43	lb / ft3	567.5	kg / m3
gas pseudo-critical pressure	Ppc	668.4	psia	4.608E+06	Pa
gas pseudo-critical temperature	Tpc	395.5	R	219.7	K
gas pseudo-reduced pressure	Ppr	8.685		8.685	
gas pseudo-reduced temperature	Tpr	1.835		1.835	
gas Z-factor	Z	1.0687		1.0687	
gas formation volume factor	Bg	3.777E-03	rcf / scb	3.777E-03	m3 / sm3
gas density	Deng	14.553	lbs / ft3	233.118	kg / m3
gas viscosity	Visg	0.0283	cp	2.826E-05	Pas
water formation volume factor	Bw	1.049		1.049	
water viscosity	Visw	0.217	cp	2.171E-04	Pas
oil-gas interfacial tension	STog	0.63	dyn / cm	6.280E-04	N / m
water-gas interfacial tension	STwg	58.68	dyn / cm	5.868E-02	N / m

BCS-I&II ZONE					
DEPTH (M)					4320
TEMP (F)					283.28
PRESSURE (Psia)					6203.1
sp gr					0.86
API GRAVITY					31.1
Black-Oil Fluid Properties Correlations This Black-oil model is consistent with Eclipse 100/200 (use field units here)					
BO model results					
API gravity of oil	API	31.14		31.14	
solution gas-oil ratio of saturated oil	Rs	1215.41	scf / stb	216.46	m3 / m3
bubble point pressure	Pb	6991.2	psia	4.820E+07	Pa
oil compressibility	Co	1.609E-05	1 / psi	2.333E-09	1 / Pa
oil formation volume factor	Bo	1.749	rb / stb	1.749	m3 / sm3
oil viscosity	Viso	0.297	cp	2.966E-04	Pas
oil density	Deno	38.04	lb / ft3	609.3	kg / m3
gas pseudo-critical pressure	Ppc	667.6	psia	4.603E+06	Pa
gas pseudo-critical temperature	Tpc	401.7	R	223.1	K
gas pseudo-reduced pressure	Ppr	9.292		9.292	
gas pseudo-reduced temperature	Tpr	1.851		1.851	
gas Z-factor	Z	1.1008		1.1008	
gas formation volume factor	Bg	3.729E-03	rcf / scb	3.729E-03	m3 / sm3
gas density	Deng	15.152	lbs / ft3	242.713	kg / m3
gas viscosity	Visg	0.0296	cp	2.958E-05	Pas
water formation volume factor	Bw	1.057		1.057	
water viscosity	Visw	0.203	cp	2.027E-04	Pas
oil-gas interfacial tension	STog	0.91	dyn / cm	9.067E-04	N / m
water-gas interfacial tension	STwg	57.79	dyn / cm	5.779E-02	N / m

BMS ZONE

DEPTH (M)	4450
TEMP (F)	290.3
PRESSURE (Psia)	6389.7
sp gr	0.86
API GRAVITY	29.4

Black-Oil Fluid Properties Correlations

This Black-oil model is consistent with Eclipse 100/200

(use field units here)

BO model results

API gravity of oil	API	29.41		29.41	
solution gas-oil ratio of saturated oil	Rs	1173.52	scf / stb	209.00	m3 / m3
bubble point pressure	Pb	7413.9	psia	5.112E+07	Pa
oil compressibility	Co	1.576E-05	1 / psi	2.286E-09	1 / Pa
oil formation volume factor	Bo	1.730	rb / stb	1.730	m3 / sm3
oil viscosity	Viso	0.313	cp	3.134E-04	Pas
oil density	Deno	38.61	lb / ft3	618.5	kg / m3
gas pseudo-critical pressure	Ppc	667.3	psia	4.601E+06	Pa
gas pseudo-critical temperature	Tpc	403.3	R	224.1	K
gas pseudo-reduced pressure	Ppr	9.575		9.575	
gas pseudo-reduced temperature	Tpr	1.860		1.860	
gas Z-factor	Z	1.1159		1.1159	
gas formation volume factor	Bg	3.704E-03	rcf / scb	3.704E-03	m3 / sm3
gas density	Deng	15.364	lbs / ft3	246.105	kg / m3
gas viscosity	Visg	0.0301	cp	3.008E-05	Pas
water formation volume factor	Bw	1.061		1.061	
water viscosity	Visw	0.198	cp	1.979E-04	Pas
oil-gas interfacial tension	STog	0.97	dyn / cm	9.659E-04	N / m
water-gas interfacial tension	STwg	57.46	dyn / cm	5.746E-02	N / m

Formation Dynamics Tests (CHARAIDEO FIELD)

RFT/SFT/MDT:

No RFT/SFT/MDT sampling done due to severe downhole complications.

VSP Survey:

VSP survey has been carried out in well Charaideo-2

Gas Composition Analysis (CHARAIDEO FIELD) Condensate Composition:

While the composition of the condensate from Charaideo is unknown, for any basis of design, the composition of the condensate from the nearby Amguri Field may be assumed. (**Table 4-57**).

Table 4-57: ESTIMATED COMPOSITION OF HYDROCARBONS

Charaideo Condensate (Initial) Composition	
Component	**Mole%**
Methane	0.13
Ethane	0.5
Propane	2.2
I-Butane	2.2
N-Butane	3.6
Pentanes	8.4
Hexane	9.2
Heptane	15
Octane	16.7
Nonane and higher	42.03

4.6.5 Geology and Reservoir Description of Charaideo Field:

The geology of the area has been comprehensively reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.6.5.1 Geological correlations, sections and maps (Charaideo Field):

STRUCTURE

The Charaideo area is an integral part of the Assam Shelf in the A & AA Basin and is located in the fringe between two distinctive tectono-geological domains, the Assam Shelf and the Naga Schuppen Belt. Geologically, the Assam Shelf is defined as the Alluvium covered extension of the Shillong and Mikir Massifs to the ENE and is a narrow belt of about 100 km wide and bounded by two thrust belts to the north in the Eastern Himalayas & south-east viz. the Naga Schuppen Belt. In the southeast the elongated Assam Shelf extends into the sub-thrust block of Naga Schuppen Belt. The Naga Schuppen Belt is also a narrow linear belt of imbricate eight to nine thrust slices along which Paleogenes of Indo-Myanmar mobile belt has moved north-westwards relative to buried Basement of the Assam Shelf.

The Charaideo structure is a High located in the Nazira Graben, about 6 km SE of the main Lakwa High. The Naga Thrust has affected the southern part of the structure. To the west of the structure, along the strike direction, is the Rajabari Fault closure and to the East is the Mathurapur Low. About 3 km north of Charaideo structure is the Nahorhabi Fault closure. Charaideo is structurally lower at Tipam and Barail levels with respect to the Nahorhabi structure.

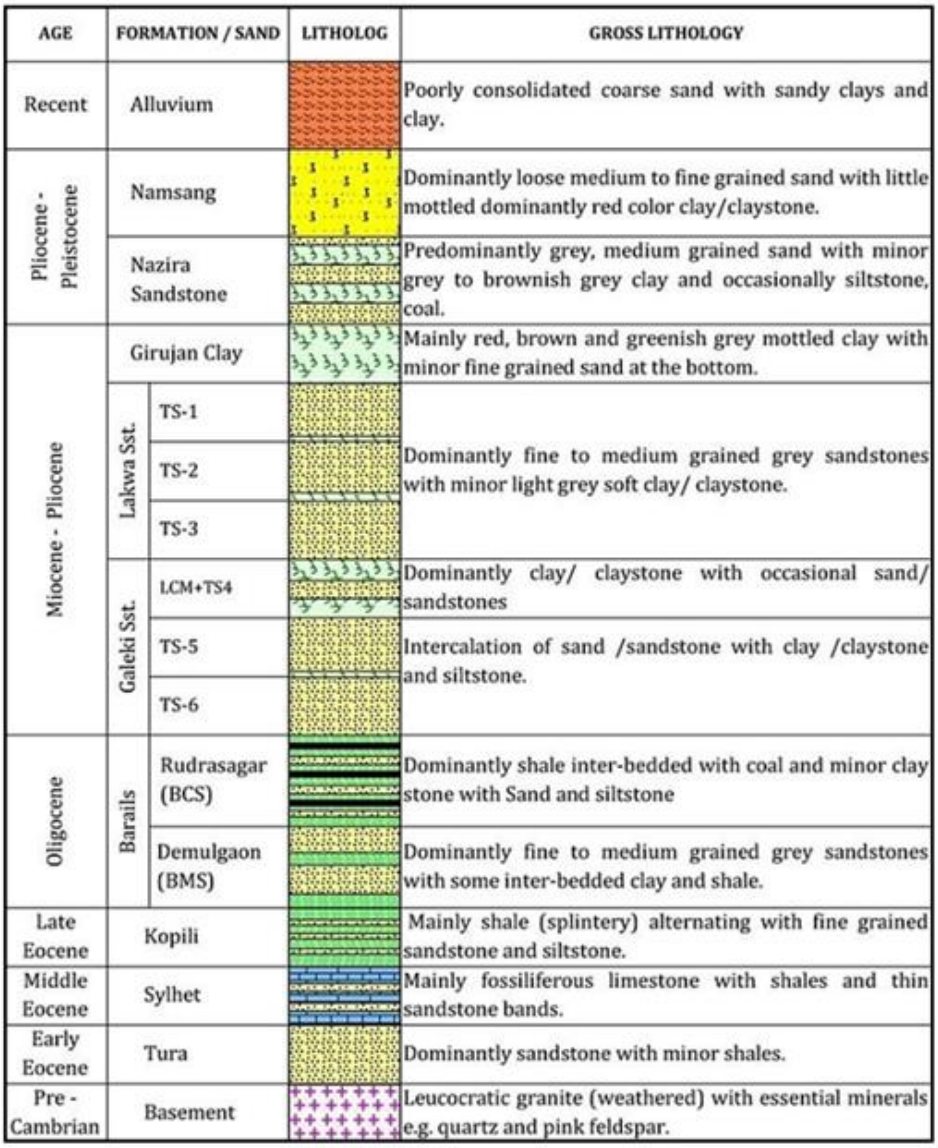
STRATIGRAPHY

The deepest sedimentary section encountered in the Charaideo area is the BMS section of the Barail Group of Oligocene age. A regressive phase had advanced in the area during this period when fine grained sand and shale alternations of this Formation gave way to lagoonal coal-shale alternations of the BCS unit of the Barail Group. The lower fine-grained sand and shale alternations which comprise the Barail Main Sand (BMS) was deposited in a distal delta-front environment. The overlying Barail Coal Shale (BCS) consisting of the coal-shale sequence of lagoonal facies prograded over the BMS. Distributary channels within the BCS (LBS-1, LBS-2 and LBS-3) were deposited by switching channels in associated environment. Subsequently, there was a prominent eustatic fall in the Lower Miocene due to which the younger units of BCS section were eroded to form an unconformity surface. In the Assam Shelf area, a major hiatus is observed after the deposition of the Barails as a result of block adjustment in the basin. Hiatus continued till the end of the Lower Miocene. During Upper Miocene – Lower Pliocene, Tipam Group was deposited under high energy conditions as interlaced braided channel deposits when the shelf area was tilted as a result of upliftment in the Arakan-Chin axial belt. A major transgression over the entre basin led to deposition of the Girujan Clay Formation. Post deposition of Girujans, positive movements resulting in the emergence of landforms and subsequent erosion are reflected in the unconformable relations between the Tipam Group and the overlying sediments. Lacustrine to fluvial deposits of Nazira & Namsang Formations were deposited as a result of episodic tectono-sedimentary events. The Recent Alluvium constitutes the youngest stratigraphic unit in the field. The stratigraphic column of Charaideo area is given in in **Figure 4-98 and Table 4-58**.

Table 4-58: STRATIGRAPHIC COLUMN IN CHARAIDEO WELLS

AGE	GROUP	FORMATION	AVERAGE THICKNESS (M)	LITHOLOGICAL DESCRIPTION
Recent-Pleistocene		Alluvium	900	Unconsolidated sands with gravel, silt and minor clays
Pleistocene to Pliocene	Moran	Namsang	550	Intercalated sands and mottled clay
Pliocene – Miocene	Tipam	Nazira Sandstone	350	Predominantly sandstone with minor clays
		Girujan Clay	700	Mottled and variegated clays with intercalations of silt/sandstone beds
		Lakwa Sandstone	550	Massive sandstone with clay/shale alternations
		Geleki Sandstone	650	Massive sandstone with clay/shale alternations with minor calcareous matter in the lower part.
		Safrai	80	Conglomerate/ grit topped by sandstone shale alternations.
Oligocene – Late Eocene	Barail	Barail Coal Shale Unit	550	Carbonaceous shale and coal with alternations of sandstone & shale.
		Barail Main Sand Unit	150	Dominantly sandstone with intercalations of minor shale

Figure 4-98: LITHOSTRATIGRAPHY OF CHARAIDEO AREA



AGE	FORMATION / SAND		LITHOLOG	GROSS LITHOLOGY
Recent	Alluvium			Poorly consolidated coarse sand with sandy clays and clay.
Pliocene - Pleistocene	Namsang			Dominantly loose medium to fine grained sand with little mottled dominantly red color clay/claystone.
Pliocene - Pleistocene	Nazira Sandstone			Predominantly grey, medium grained sand with minor grey to brownish grey clay and occasionally siltstone, coal.
Miocene - Pliocene	Girujan Clay			Mainly red, brown and greenish grey mottled clay with minor fine grained sand at the bottom.
Miocene - Pliocene	Lakwa Sst.	TS-1		Dominantly fine to medium grained grey sandstones with minor light grey soft clay/ claystone.
Miocene - Pliocene	Lakwa Sst.	TS-2		
Miocene - Pliocene	Lakwa Sst.	TS-3		
Miocene - Pliocene	Galeki Sst.	LCM+TS4		Dominantly clay/ claystone with occasional sand/ sandstones
Miocene - Pliocene	Galeki Sst.	TS-5		Intercalation of sand /sandstone with clay /claystone and siltstone.
Miocene - Pliocene	Galeki Sst.	TS-6		
Oligocene	Barails	Rudrasagar (BCS)		Dominantly shale inter-bedded with coal and minor clay stone with Sand and siltstone
Oligocene	Barails	Demulgaon (BMS)		Dominantly fine to medium grained grey sandstones with some inter-bedded clay and shale.
Late Eocene	Kopili			Mainly shale (splintery) alternating with fine grained sandstone and siltstone.
Middle Eocene	Sylhet			Mainly fossiliferous limestone with shales and thin sandstone bands.
Early Eocene	Tura			Dominantly sandstone with minor shales.
Pre - Cambrian	Basement			Leucocratic granite (weathered) with essential minerals e.g. quartz and pink feldspar.

The structural disposition of the Charaideo-1 Field is depicted in the depth structure maps presented on tops of TS-2, TS-5 and BCS (**Figure 4-99, Figure 4-100 and Figure 4-101.**).The roughly NW-SE electro-log correlation profiles, both structural and stratigraphic, along all the wells of the Charaideo structure, viz. CRDO-1, CRDO-2 and CRDO-4 are shown in **Figure 4-102 and Figure 4-103** respectively. Formation tops (**Table 4-59**) were obtained from well log data while horizons were obtained using seismic data. All these were combined to correlate the wells in the field. Lithological correlation between wells CRDO-1, CRDO-2 and CRDO-4 is given in **Figure 4-104 and Figure 4-105.**

The hydrocarbon reservoirs of this field occur in the Barail section (both BCS and BMS) and Tipam section. The reservoirs are defined by heterogeneous lithology of medium to fine grained tight sandstone, finely interlaminated with siltstone /shale (occasionally carbonaceous) within the Barails. However, the Tipam reservoir is comparatively more arenaceous. The entrapment is strati-structural and capturing reservoir heterogeneity is the major challenge in the field.

Table 4-59: FORMATION TOPS ENCOUNTERED IN WELLS CRDO-1, CRDO-2, CRDO-3 & CRDO-4

Formation/ Group	Zone				
		CRDO-1 (m MD)	**CRDO-2 (m MD)**	**CRDO-3 (mMD)**	**CRDO-4 (m MD)**
Alluvium	–	0	0	0	0
Namsang	–	1010	1025	978	1010
Nazira Sandstone	–	1550	1556	1484	1550
Girujan Clay	–	1875	1910	1770	1874
Tipam	Lakwa Sandstone / TS-2	2806	2819.8	2825	2765
	TS-3	2974	2992	2990	297.568
	LCM	3314	3335	3325	3264
	Geleki Sandstone / TS-5	3410	3399	3413	3346
	TS-6	3682	3708	3725	3692
	Safrai	3957	3951	4069	3964
Barail	BCS	4035	4025.7		4014
	BMS	4585	4492		4507
TD	–	4805	4700		4708

Figure 4-99: DEPTH STRUCTURE MAP ON TOP OF TS-2

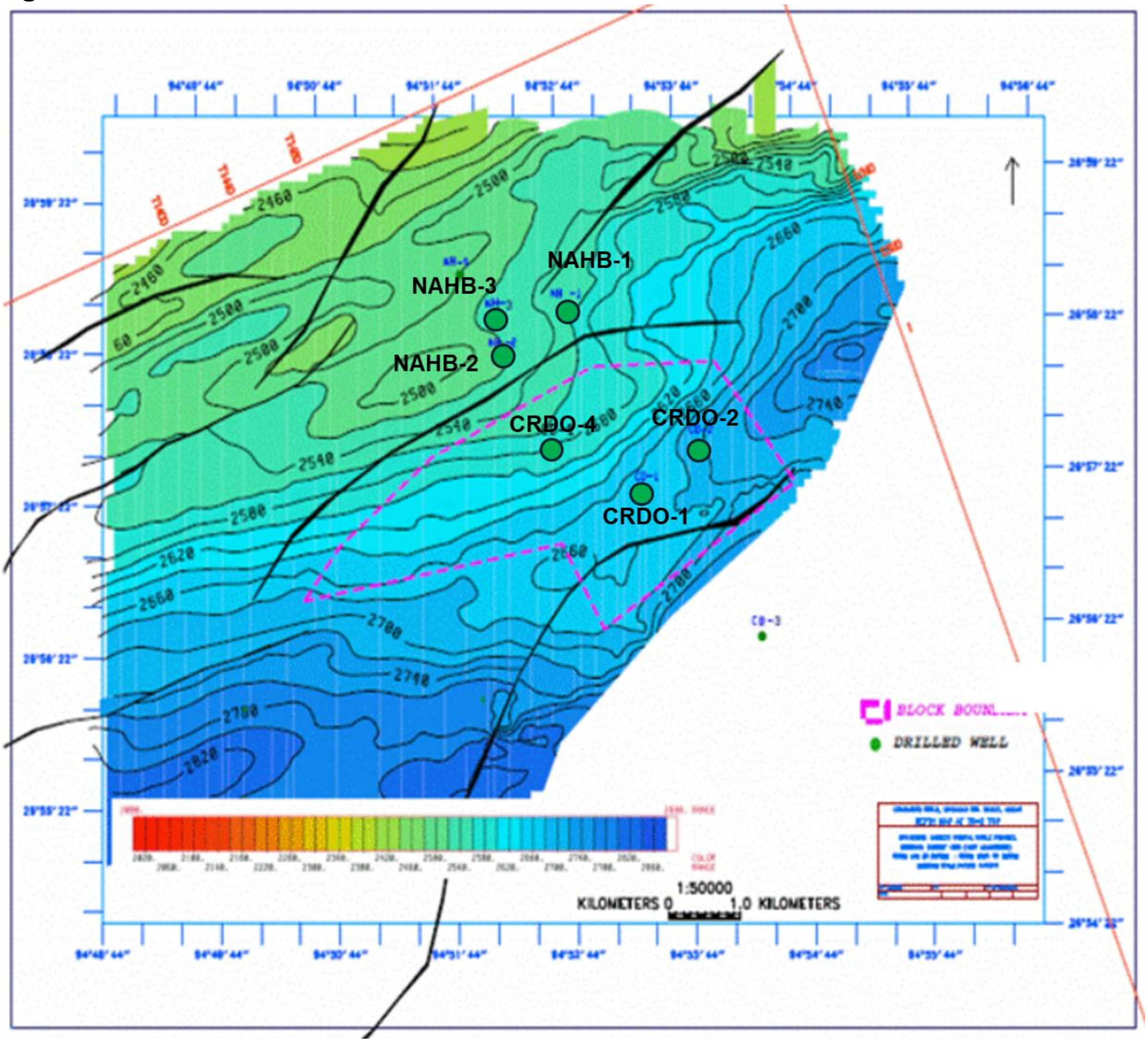


Figure 4-100: DEPTH STRUCTURE MAP ON TOP OF TS-5

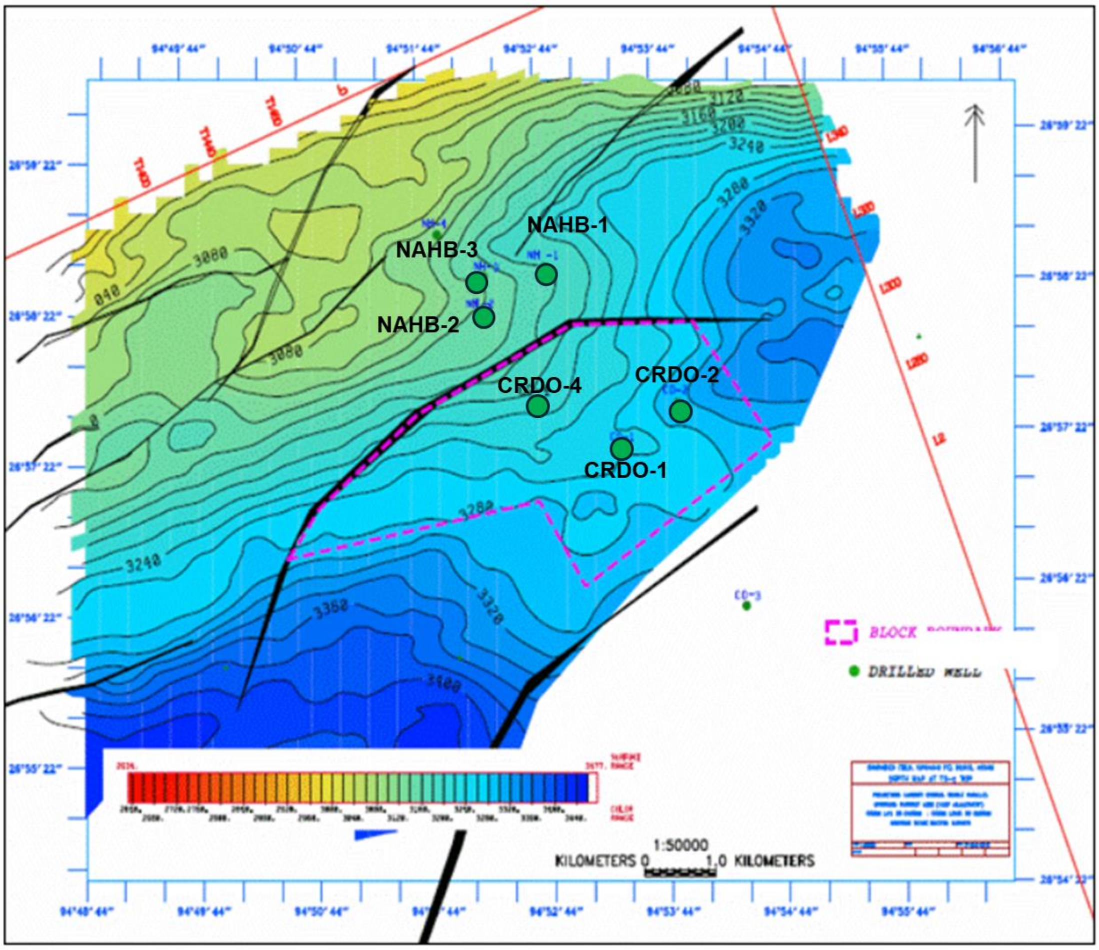


Figure 4-101: DEPTH STRUCTURE MAP ON TOP OF BCS

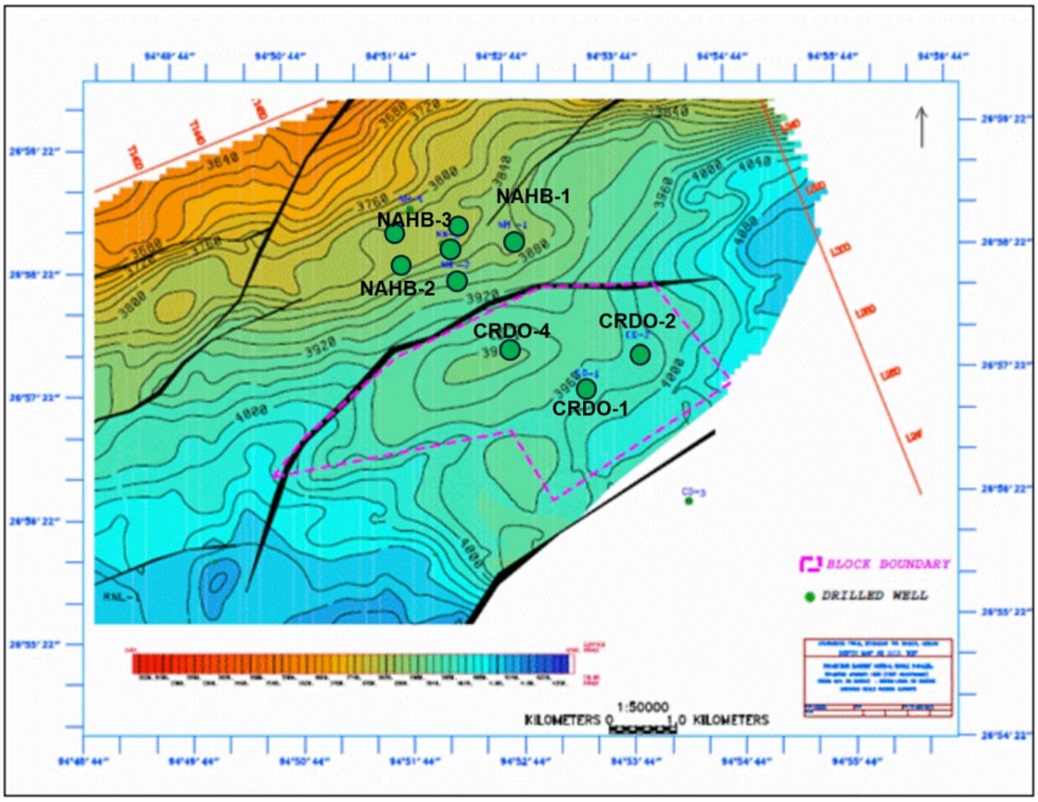


Figure 4-102: STRUCTURAL ELECTRO-LOG CORRELATION OF WELLS CHARAIDEO-4, 2 AND 1

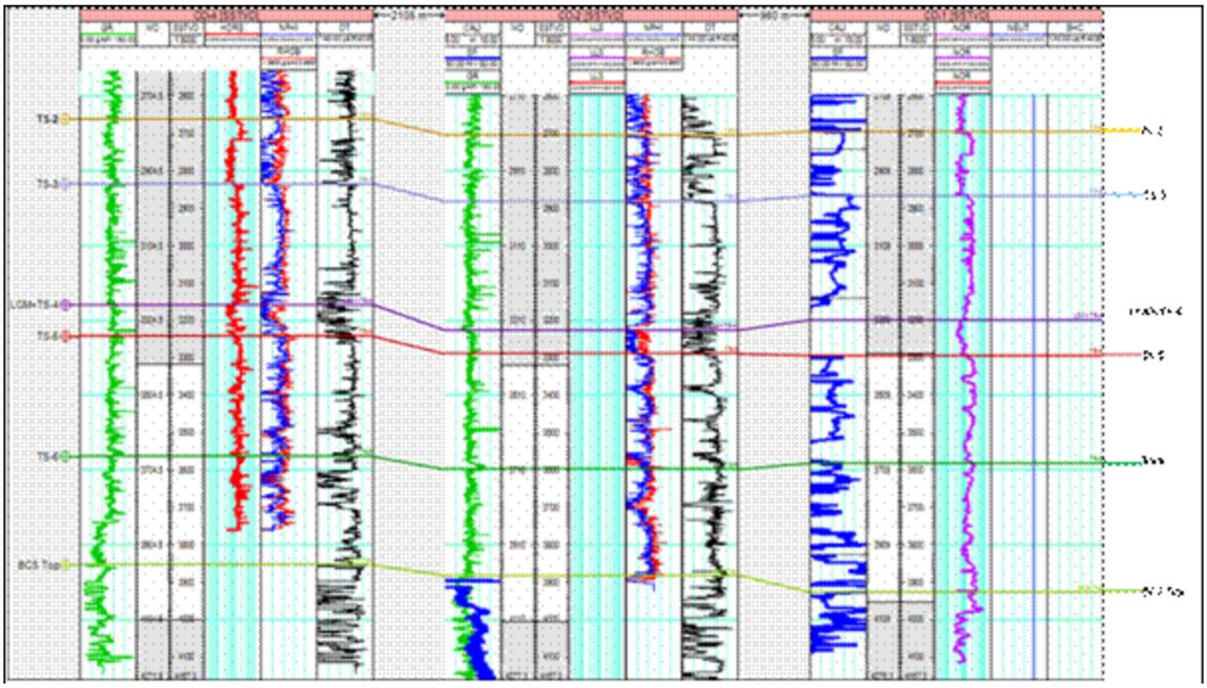


Figure 4-103: STRATIGRAPHIC ELECTRO-LOG CORRELATION (DATUM@LCM) OF WELLS CHARAIDEO-4, 2 AND 1

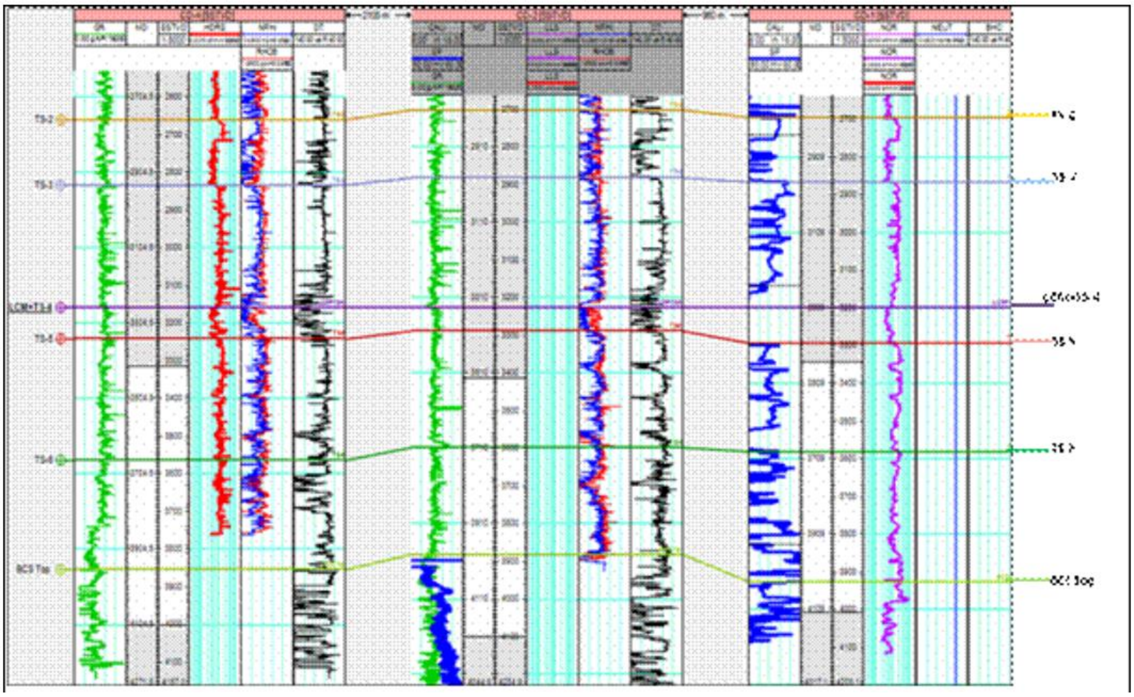
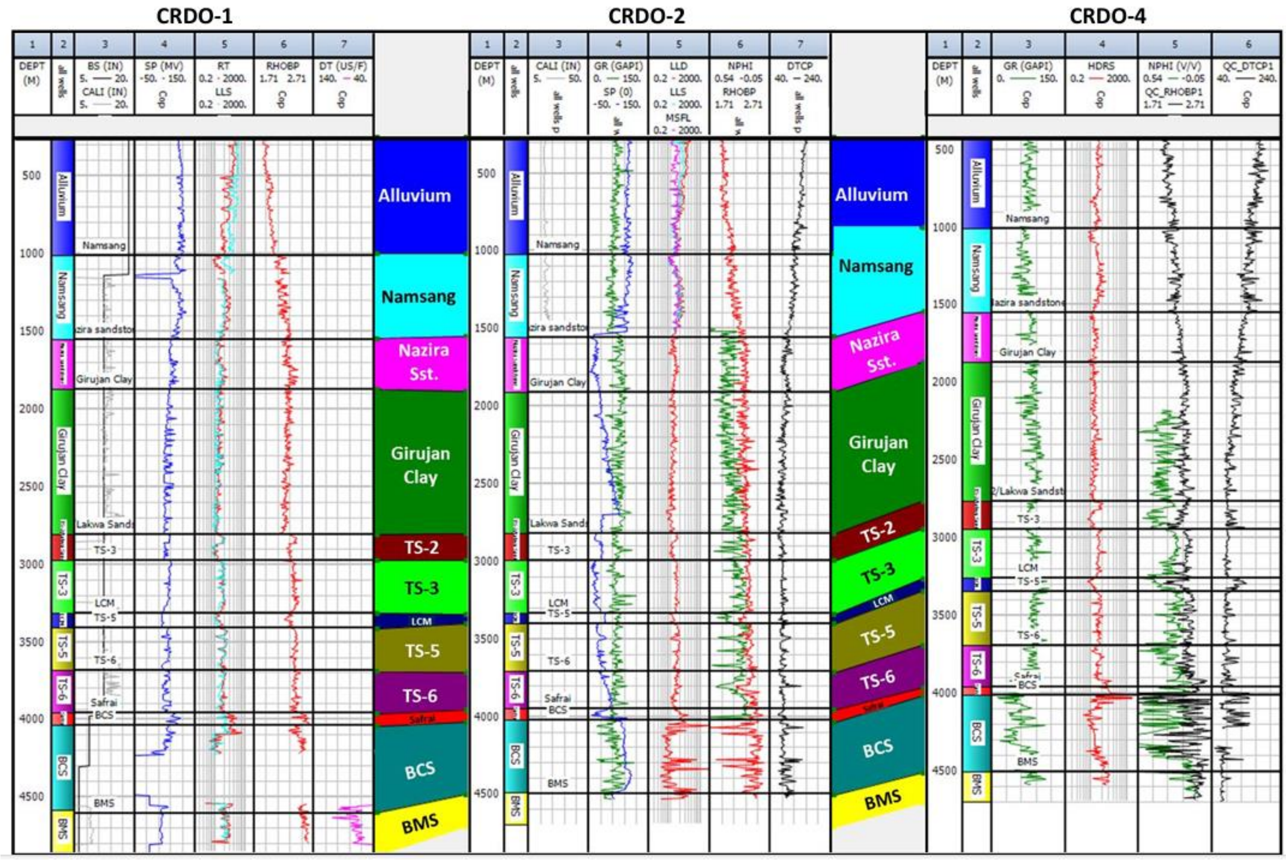


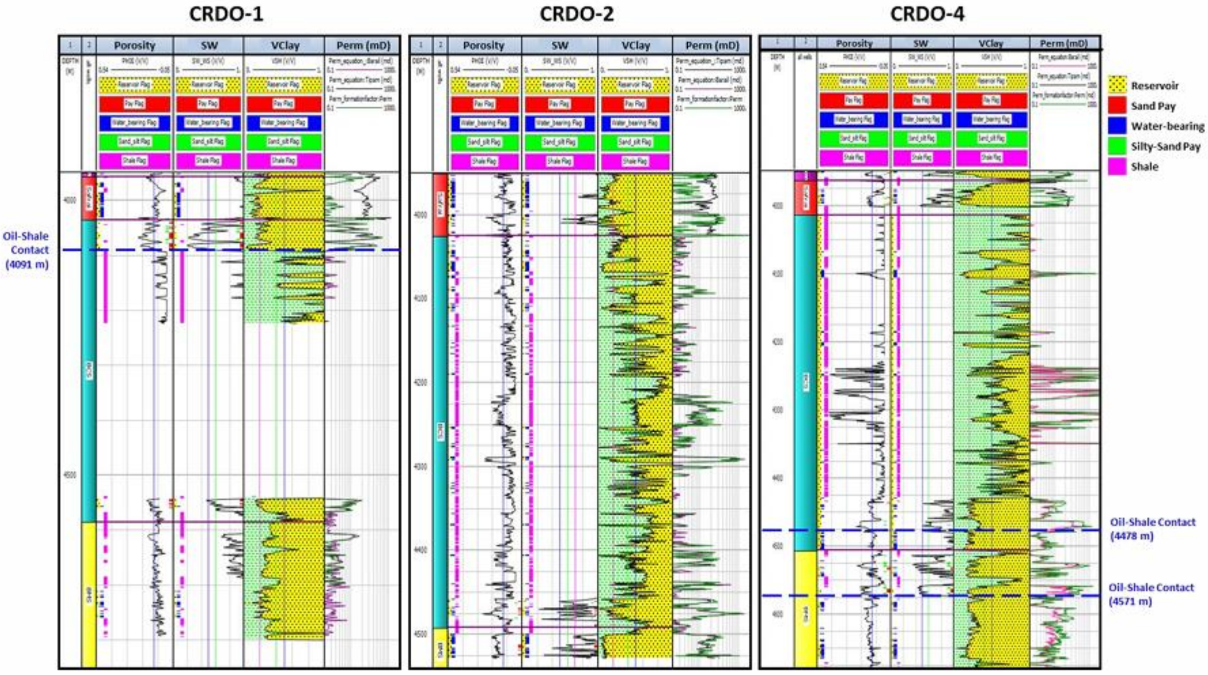
Figure 4-104: LITHOLOGICAL CORRELATION OF WELLS CRDO-1, CRDO-2 AND CRDO-4



Litho-classification and Fluid Contacts

During the well log analysis, lithology classification and net pay delineation were done in wells CRDO-1, CRDO-2 and CRDO-4. The fluid contacts for volumetric estimations were marked in the Barail sands (**Figure 4-105**)

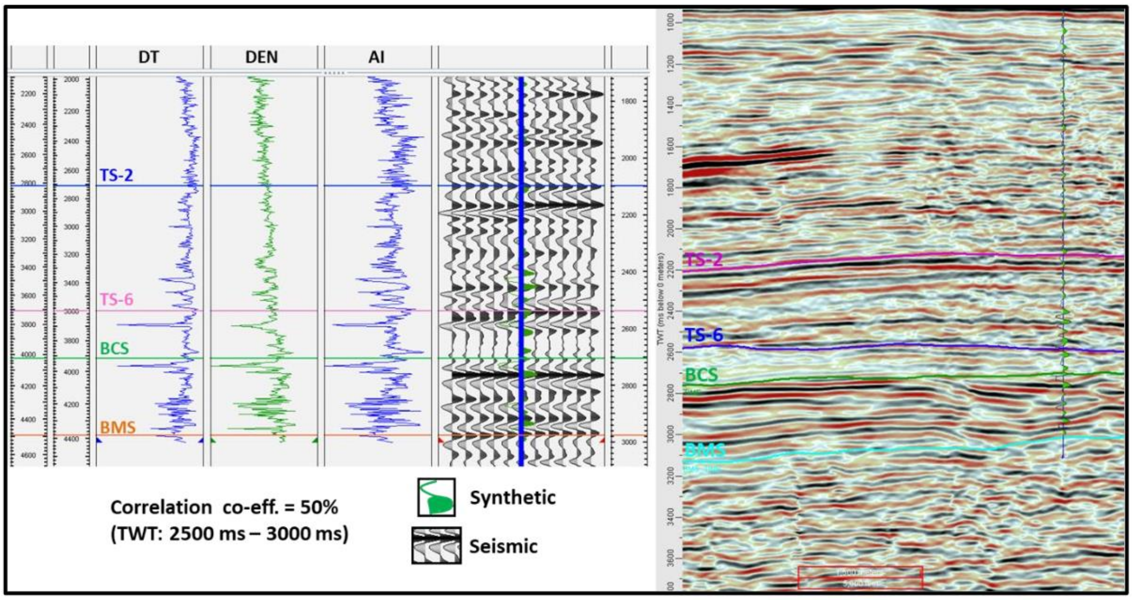
Figure 4-105: LITHO-CLASSIFICATION AND FLUID CONTACTS (BARAIL SANDS) IN WELLS CRDO-1, CRDO-2 & CRDO-4



Seismic Studies:

The area has also been covered by several seismic surveys (both 2D and 3D) from time to time which include series A-42, A44, A-57, A-117, A-120, A-131, A-185, A-186 and A-202. The earliest subsurface mapping of the area was carried out with the help of seismic investigations A-42, A-47 based on which two exploratory locations Nahorhabi-1 and Charaideo-1 were drilled in 1981. The entire area of 14.86 km^2 is covered by 3D seismic in the NAS Megamerge volume re-processed in RCC, Jorhat as shown in **Figure 4-44**.VSP was recorded in well CRDO-2 and the data is shown in **Figure 4-106.**

Figure 4-106: VSP DATA FOR WELL CRDO-2



A seismic section showing wells CRDO-1, CRDO-2, CRDO-3, CRDO-4, NAHB-1 and MTPR-1 is shown in **Figure 4-107.** An arbitrary seismic line passing through wells CRDO-4, CRDO-1 & CRDO-2 showing the trends in the seismic data in the area is shown in **Figure 4-108**. Also, seismic transects (IL & XL) passing through the wells CRDO-1, CRDO-2 &CRDO-4 are shown in **Figure 4-109, Figure 4-110 and Figure 4-111**.

Time and Depth Structure Maps

The following time and depth structure maps of Charaideo area are shown:

- Tipam S-2 (TS-2) (**Figure 4-112**)
- Tipam S-6 (TS-6) (**Figure 4-113**)
- Barail Coal Shale (BCS) (**Figure 4-114**)
- Barail Main Sand (BMS) (**Figure 4-115)**

Acoustic impedance maps within BCS and BMS are shown in **Figure 4-116 and Figure 4-117** respectively**.** Acoustic impedance section for well CRDO-2 is shown in **Figure 4-118.**

Figure 4-107: SEISMIC SECTION OF WELLS CRDO-1, CRDO-2, CRDO-3, CRDO-4, NAHB-1 and MTPR-1

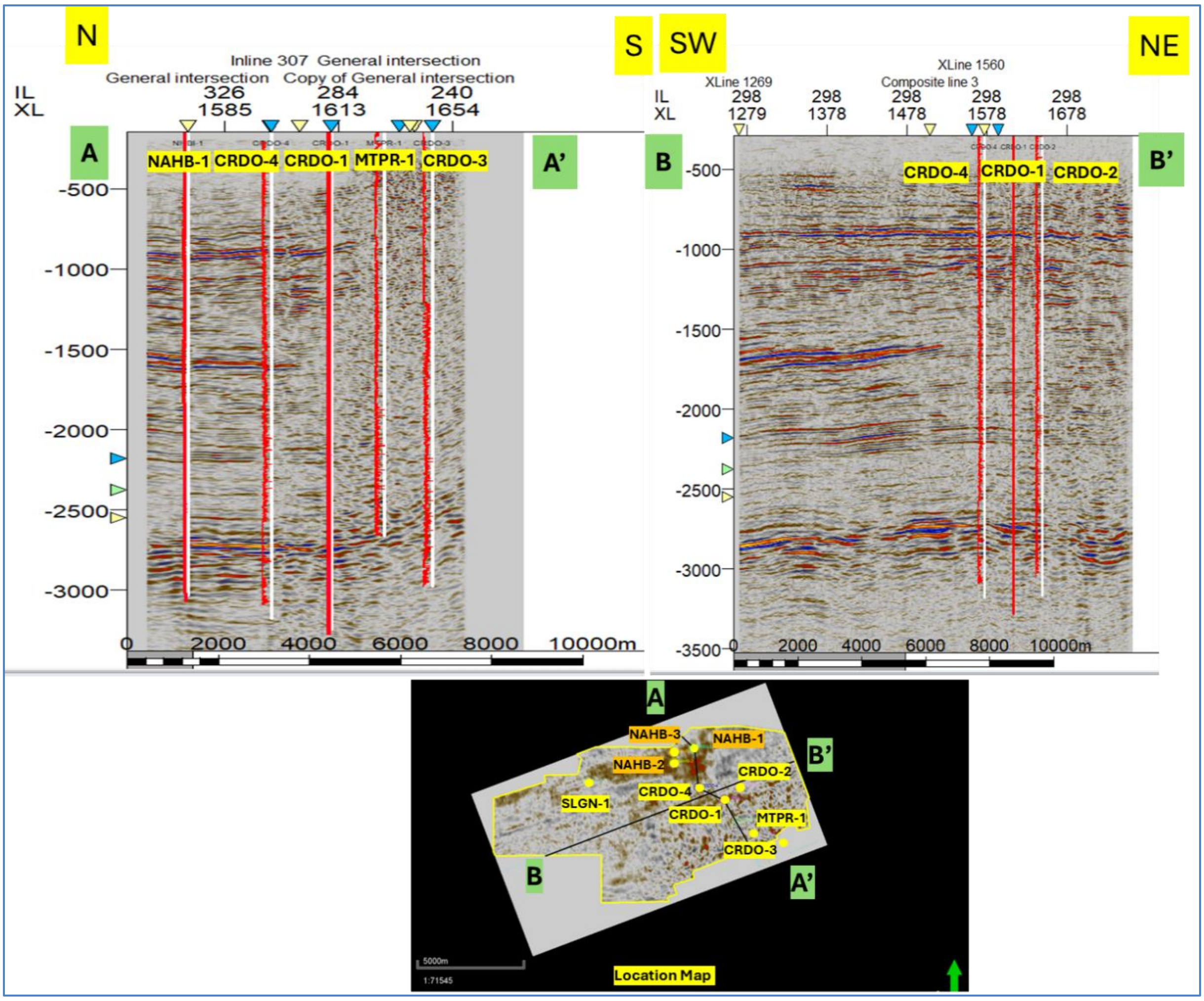


Figure 4-108: COMPOSITE LINE PASSING THROUGH WELLS CHARAIDEO 1, 2 AND 4

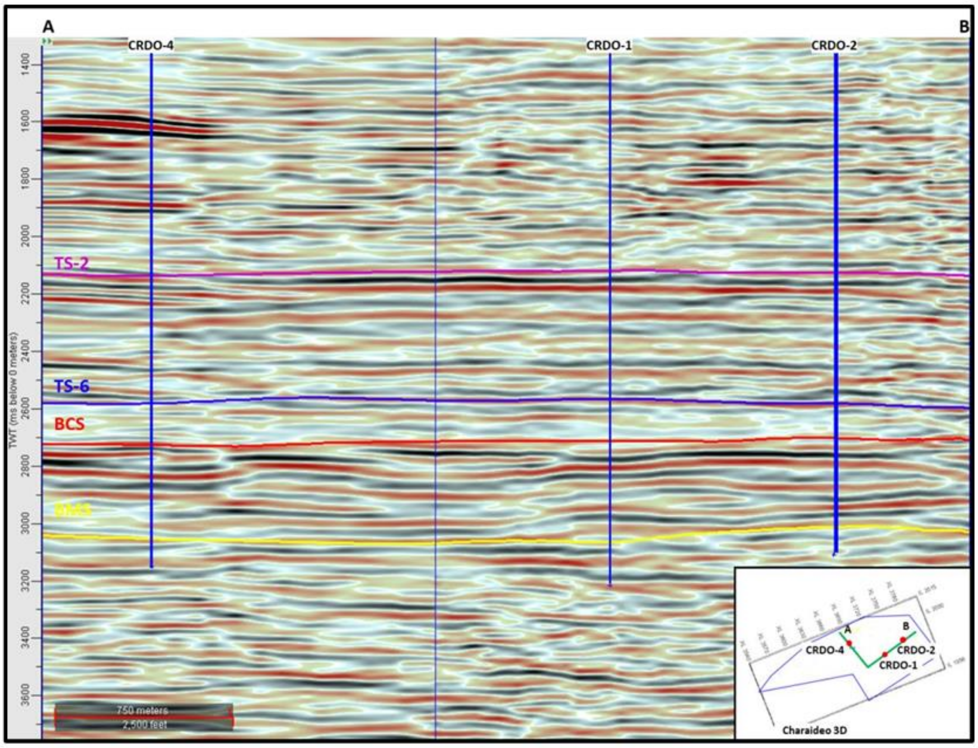


Figure 4-109: INLINE 1983 AND XLINE3728 PASSING THROUGH WELL CRDO-1

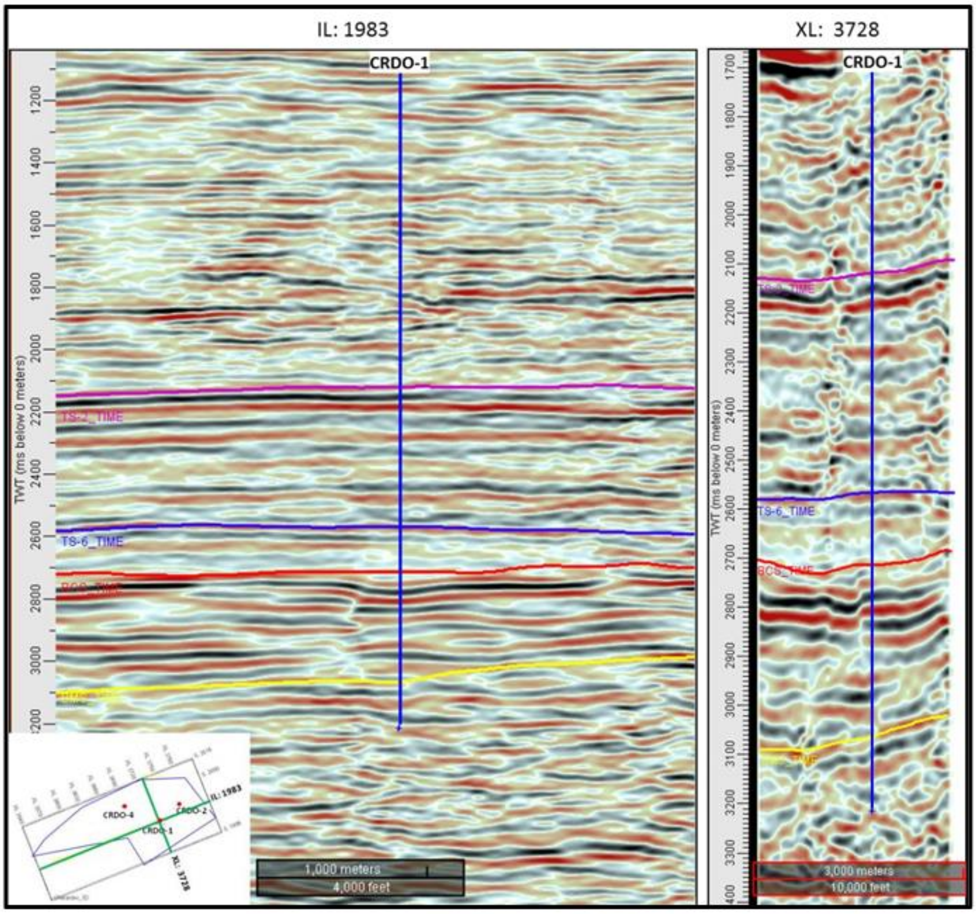


Figure 4-110: INLINE 1988 AND XLINE 3765 PASSING THROUGH WELL CRDO-2

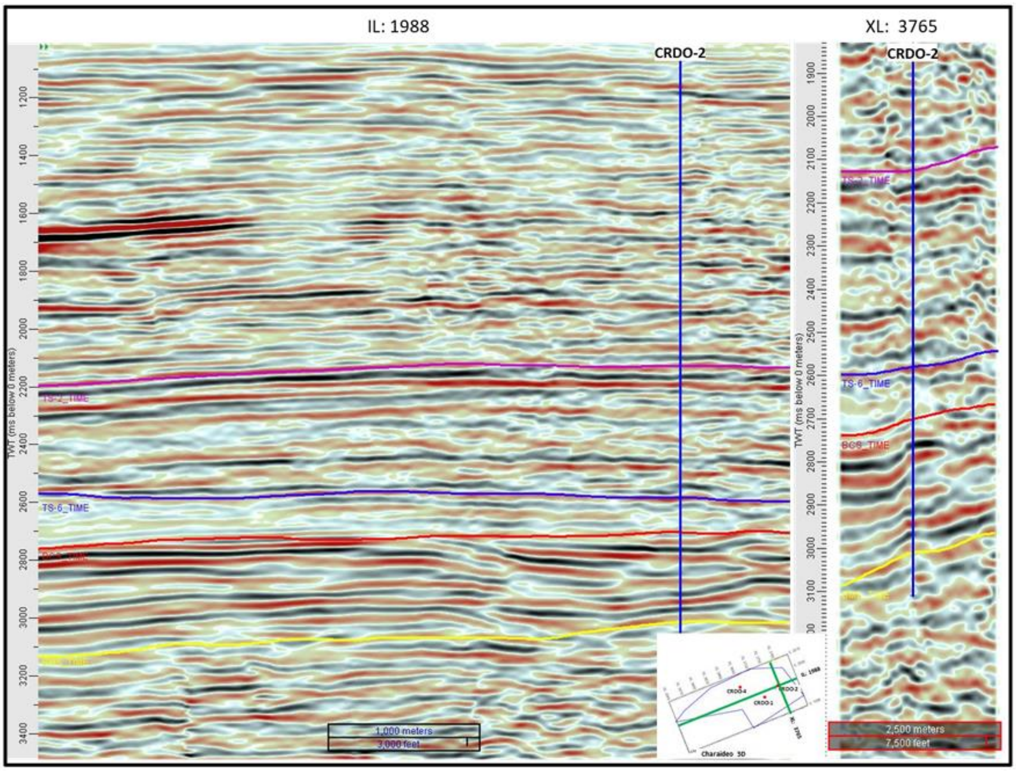


Figure 4-111: INLINE 2002 AND XLINE 3686 PASSING THROUGH WELL CRDO-4

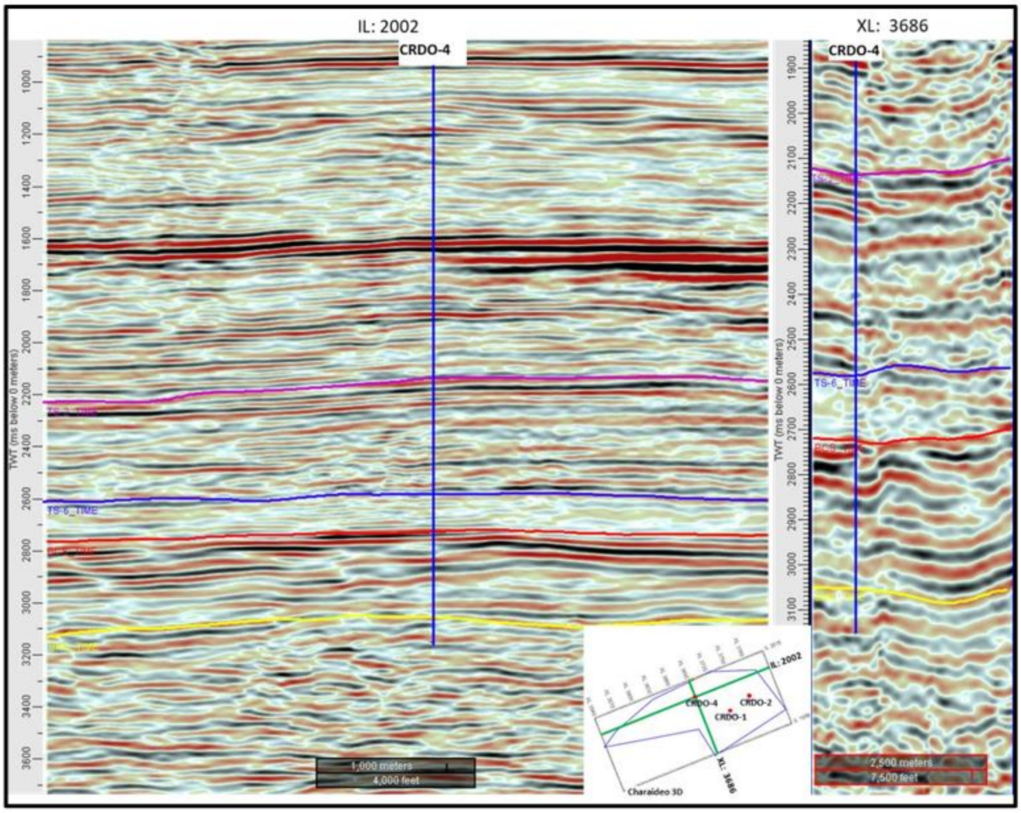


Figure 4-112: TIME AND DEPTH STRUCTURE MAP ON TOP OF TS-2

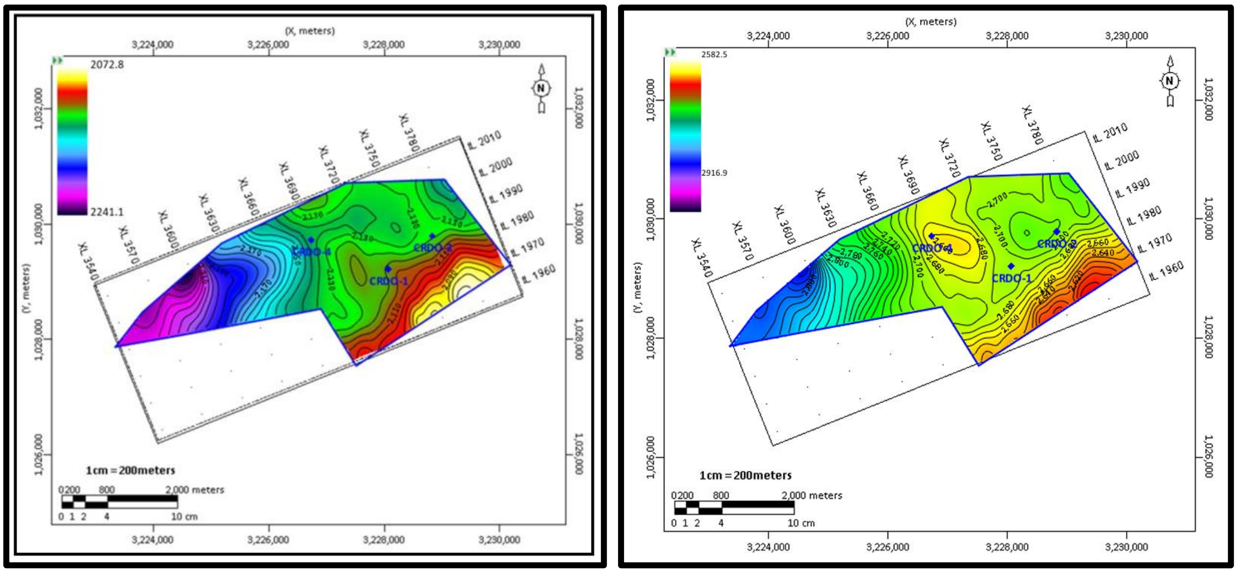


Figure 4-113: TIME AND DEPTH STRUCTURE MAP ON TOP OF TS-6

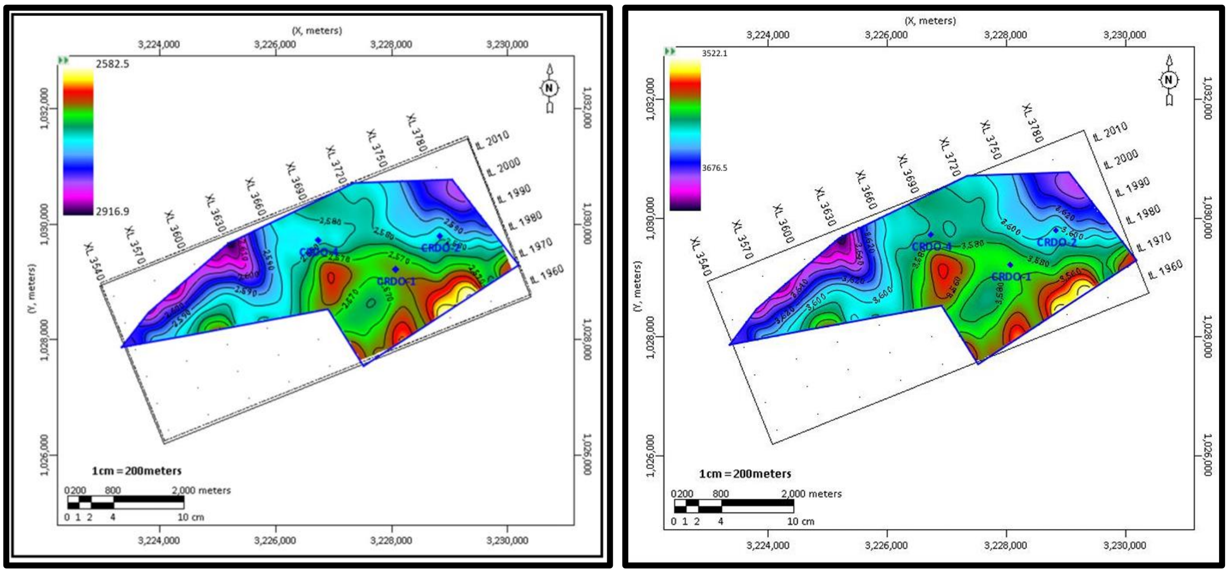


Figure 4-114: DEPTH AND TIME STRUCTURE MAP ON TOP OF BCS

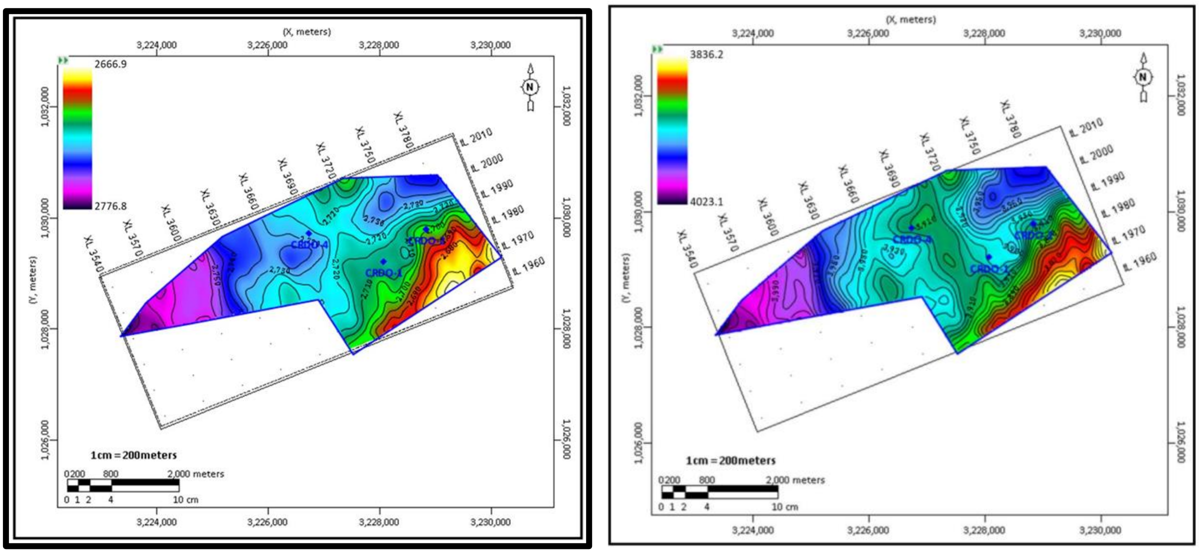


Figure 4-115: TIME AND DEPTH STRUCTURE MAP ON TOP OF BMS

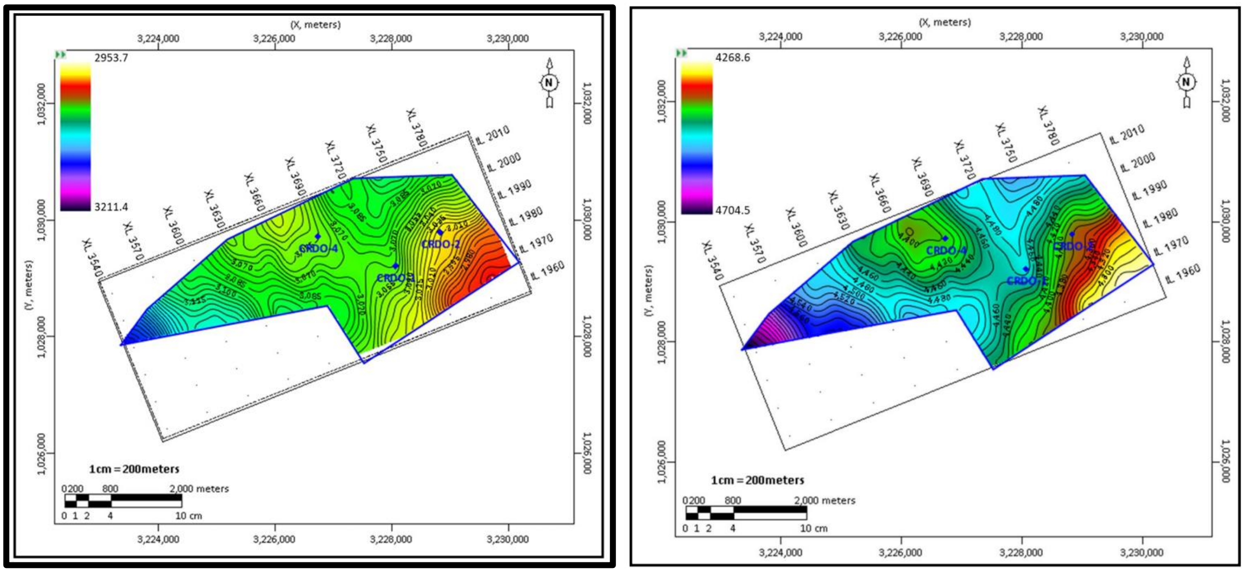


Figure 4-116: ACOUSTIC IMPEDANCE MAP WITHIN BARAIL COAL SHALE (BCS)

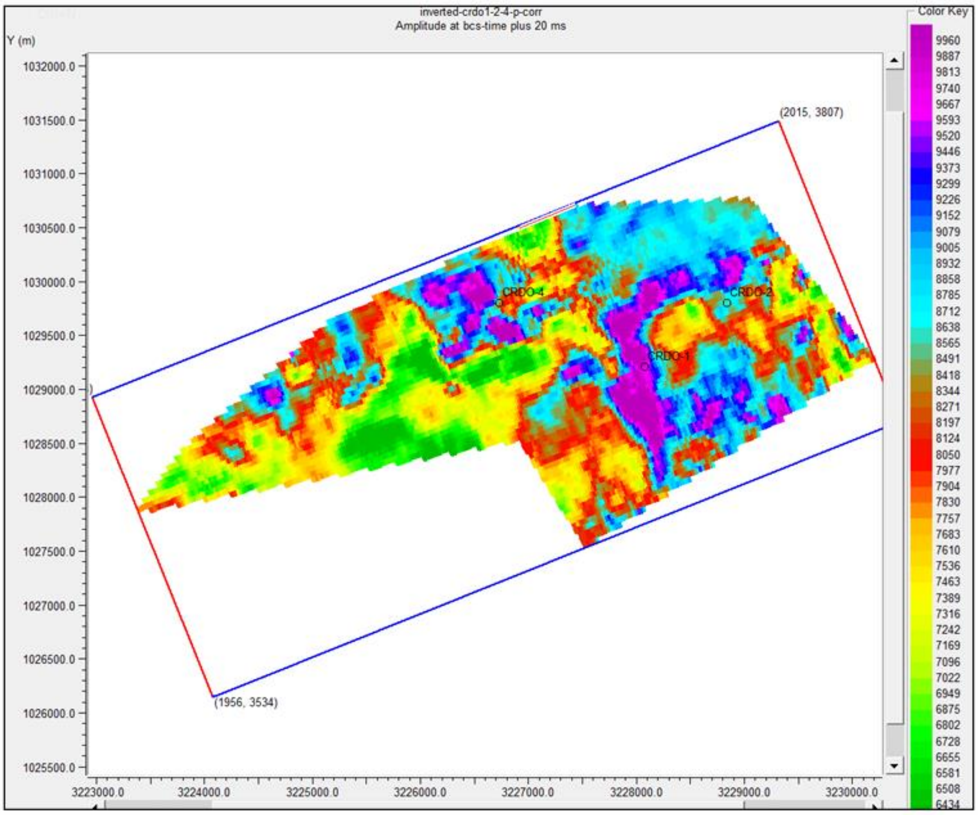


Figure 4-117: ACOUSTIC IMPEDANCE MAP WITHIN BARAIL MAIN SAND (BMS)

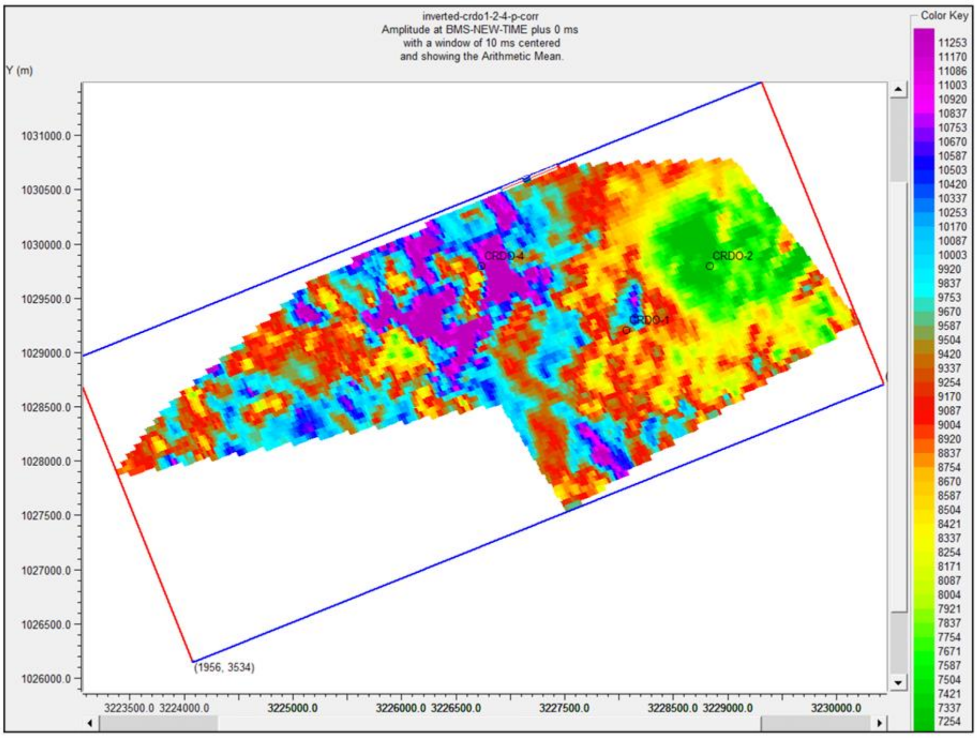
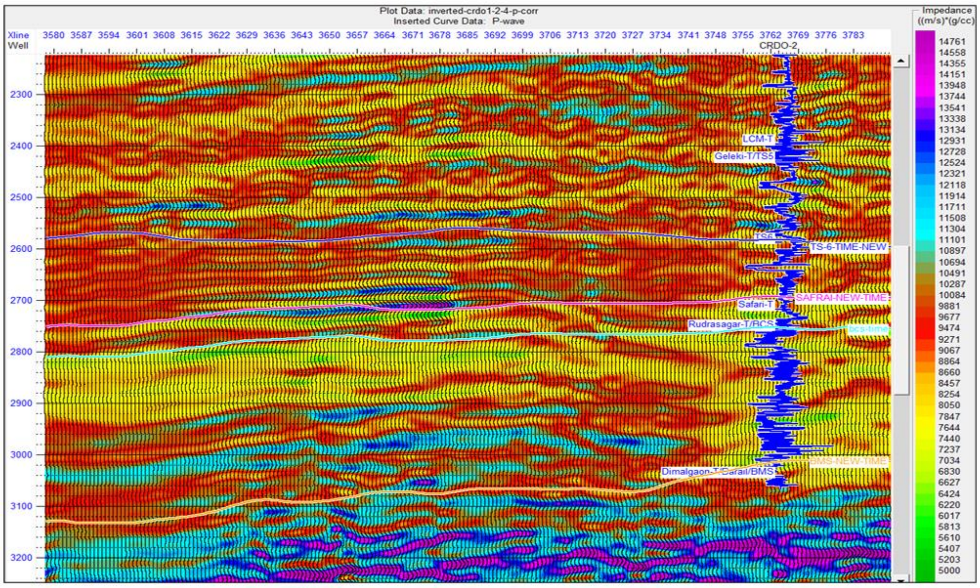


Figure 4-118: ACOUSTIC IMPEDANCE SECTION PASSING THROUGH WELL CRDO-2



4.6.5.2 Reservoir parameters and hydrocarbon estimates (CHARAIDEO Field):

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

Initial oil/gas volumes have been estimated in PS category-based testing data, reservoir parameters and log motifs of drilled wells CRDO-1, 2, 4.

Petrophysical parameters and hydrocarbon estimates:

Petrophysical Studies of conventional cores from well CRDO-4, CC-2, Sample ID: 104 is given in **Table 4-60.**

Table 4-60: PETROPHYSICAL STUDIES OF CORE SAMPLE OF WELL CRDO-4,

Petrophysical Studies of CDAC, CC-2, Sample ID: 104	**Date of Receipt of Sample: 16.02.2010**
Source of collection:	**Core Library, RGL; Sibsagar**
Well No./Area	CDAC
UWI	E-CRDO-4
Core No.	CC-2
Core interval (m)	4501-4508 m
Core Recovery	67 %
Formation/ Group	Barail
Lithology	Sandstone (Fine grained)

Test Results

Sl. No.	**Plug No.**	**Bulk Density (g/cc)**	**Effective Porosity (%)**	**Grain Density (g/cc)**	**Bulk Density (g/cc)**	**Permeability K gas (md)**	**K∞ (md)**
1	1H	4501.05	11.1	2.8	2.49	0.693	0.573
2	2H	4501.26	9.3	2.68	2.43	0.916	0.858
3	3H	4501.52	12.2	2.78	2.44	0.933	0.847
4	4H	4501.7	6.2	2.72	2.56	0.185	0.114
5	5H	4501.94	8.9	2.74	2.5	0.860	0.790
6	6H	4502.34	9.8	2.76	2.48	0.486	0.337

The Lowest Known Hydrocarbon (LKH) depths encountered as per FDP in each reservoir zone for each well are given in **Table 4-61**. The reservoir parameters for BCS (shallow and deep), and BMS to calculate In-place volumes were obtained using the average values of the 3 wells (**Table 4-62, Table 4-63 and Table 4-64).** The areas for the calculations were used from the maps shown in the following figures. (**Figure 4-119, Figure 4-120 and Figure 4-121**). Corresponding Net Pay maps of BCS Shallow, BCS Deep, BMS in CRDO-2 and BMS in CRDO-4 are shown in (**Figure 4-122, Figure 4-123, Figure 4-124 and Figure 4-125**) respectively.

Table 4-61: LOWEST KNOWN HYDROCARBON (LKH) DEPTHS ENCOUNTERED IN CHARAIDEO WELLS

Zones	CRDO-1			CRDO-2			CRDO-4		
	Contact	Depth (MD)	Depth (TVDSS)	Contact	Depth (MD)	Depth (TVDSS)	Contact	Depth (MD)	Depth (TVDSS)
TS-6	LKO	-	-	LKO	-	-	LKO	3956.5	3852
Safrai	LKO	-	-	LKO	4010		LKO	4000	3896
BCS-Shallow	LKO	4091.6	3983	LKO	-	-	LKO	-	-
BCS-Deep	LKO	4556.6	4448	LKO	4482	4372	LKO	4478.5	4374
BMS	LKO	-	-	LKO	4576	4466	LKO	4571.5	4467

Table 4-62: PETROPHYSICAL PARAMETERS OBTAINED IN WELLS CRDO-1, CRDO-2 AND CRDO-4

CRDO-1						
Low Case - P_{90}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	272	0.0	0.0	0.0	-	-
TS-6	275	0.0	0.0	0.0	-	-
Safrai	78	0.0	0.0	0.0	-	-
BCS	550	12.6	6.9	19.4	0.160	0.351
BMS	272	0.0	0.0	0.0	-	-
TOTAL	**1447**	**12.6**	**6.9**	**19.4**	**-**	**-**
Best Case - P_{50}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	272	0.0	0.0	0.0	-	-
TS-6	275	0.0	0.0	0.0	-	-
Safrai	78	0.0	0.1	0.1	0.190	0.569
BCS	550	18.5	17.2	35.8	0.147	0.419
BMS	272	0.0	0.0	0.0	-	-
TOTAL	**1447**	**18.5**	**17.4**	**35.9**	**-**	**-**
High Case - P_{10}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	272	0.0	0.0	0.0	-	-
TS-6	275	0.0	0.0	0.0	-	-
Safrai	78	0.0	0.1	0.1	0.190	0.569
BCS	550	20.4	27.8	48.1	0.139	0.465
BMS	272	0.0	0.2	0.2	0.116	0.699
TOTAL	**1447**	**20.4**	**28.0**	**48.4**	**-**	**-**

CRDO-2						
Low Case - P_{90}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	309	0.0	0.0	0.0	-	-
TS-6	243	0.0	0.0	0.0	-	-
Safrai	74	0.5	0.0	0.5	0.264	0.446
BCS	467	3.2	0.0	3.2	0.171	0.377
BMS	208	2.3	0.0	2.3	0.172	0.375
TOTAL	**1301**	**6.0**	**0.0**	**6.0**	**-**	**-**
Best Case - P_{50}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	309	0.0	0.0	0.0	-	-
TS-6	243	0.0	0.0	0.0	-	-
Safrai	74	2.0	0.0	2.0	0.214	0.515
BCS	467	5.6	2.4	8.1	0.158	0.449
BMS	208	5.0	0.0	5.0	0.165	0.472
TOTAL	**1301**	**12.7**	**2.4**	**15.1**	**-**	**-**
High Case - P_{10}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	309	0.0	0.0	0.0	-	-
TS-6	243	0.0	0.0	0.0	-	-
Safrai	74	3.2	0.6	3.8	0.203	0.581
BCS	467	7.0	4.4	11.4	0.151	0.499
BMS	208	8.1	0.0	8.1	0.167	0.539
TOTAL	**1301**	**18.3**	**5.0**	**23.3**	**-**	**-**

CRDO-4						
Low Case - P_{90}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	347	0.5	0.3	0.8	0.183	0.421
TS-6	271	0.0	1.8	1.8	0.152	0.426
Safrai	51	0.2	1.1	1.2	0.134	0.473
BCS	492	0.0	0.3	0.3	0.256	0.458
BMS	194	7.2	9.8	16.9	0.175	0.423
TOTAL	**1355**	**7.8**	**13.3**	**21.0**	**-**	**-**
Best Case - P_{50}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	347	0.9	0.8	1.7	0.183	0.496
TS-6	271	1.4	3.5	4.9	0.146	0.507
Safrai	51	1.8	1.8	3.7	0.130	0.516
BCS	492	2.3	3.1	5.3	0.179	0.547
BMS	194	8.2	12.2	20.4	0.168	0.439
TOTAL	**1355**	**14.6**	**21.3**	**36.0**	**-**	**-**
High Case - P_{10}						
Zones	Gross (m)	Clean Sand Net (m)	Silty sand Net (m)	Total (m)	Avg ϕ	Avg Sw
TS-5	347	1.4	3.5	4.9	0.170	0.604
TS-6	271	4.0	5.6	9.6	0.141	0.575
Safrai	51	4.9	2.3	7.2	0.127	0.570
BCS	492	3.7	9.8	13.4	0.172	0.602
BMS	194	9.8	14.6	24.4	0.161	0.465
TOTAL	**1355**	**23.6**	**35.8**	**59.4**	**-**	**-**

Table 4-63: PETROPHYSICAL PARAMETERS OBTAINED IN THE RESERVOIR ZONES.

Low Case - P_{90}						
Zones	Thickness Gross (m)	Sand Net (m)	Silty Sand Net (m)	Total Net (m)	Avg. Porosity	Avg. Sw
TS_5	347	0.2	0.1	0.3	0.183	0.421
T_6	271	0.0	0.6	0.6	0.152	0.426
Safrai	51	0.2	0.4	0.6	0.199	0.460
BCS	492	5.3	2.4	7.6	0.196	0.395
BMS	194	3.2	3.3	6.4	0.173	0.399

Best Case - P_{50}						
Zones	Thickness Gross (m)	Sand Net (m)	Silty Sand Net (m)	Total Net (m)	Avg. Porosity	Avg. Sw
TS_5	347	0.3	0.3	0.6	0.183	0.496
T_6	271	0.5	1.2	1.6	0.146	0.507
Safrai	51	1.3	0.7	1.9	0.178	0.533
BCS	492	8.8	7.6	16.4	0.161	0.472
BMS	194	4.4	4.1	8.5	0.167	0.456

High Case - P_{10}						
Zones	Thickness Gross (m)	Sand Net (m)	Silty Sand Net (m)	Total Net (m)	Avg. Porosity	Avg. Sw
TS_5	347	0.5	1.2	1.6	0.171	0.604
T_6	271	1.3	1.9	3.2	0.141	0.575
Safrai	51	2.7	1.0	3.7	0.173	0.573
BCS	492	10.3	14.0	24.3	0.154	0.522
BMS	194	5.9	4.9	10.9	0.148	0.568

Table 4-64: NTG Values Obtained for Calculating P50 Case Volumes

3 WELL AVERAGES - CHARAIDEO									
Zones	Thickness Gross (m)	Sand Gross (m)	Silty Sand Gross (m)	Shale Gross (m)	Sand Gross (%)	Silty Sand Gross (%)	Shale Gross (%)	NTG Sand	NTG Silty Sand
BCS_Shallow	56.00	8.69	17.83	29.48	0.00	8.08	14.80	15.5%	31.8%
BCS_Deep	30.67	10.75	0.56	16.42	2.93	4.90	2.19	35.1%	1.8%
BMS	50.00	20.37	0.84	13.79	15.01	6.63	6.10	40.7%	0.0%

Figure 4-119: P90, P50 & P10 CASE POLYGONS FOR BCS-SHALLOW

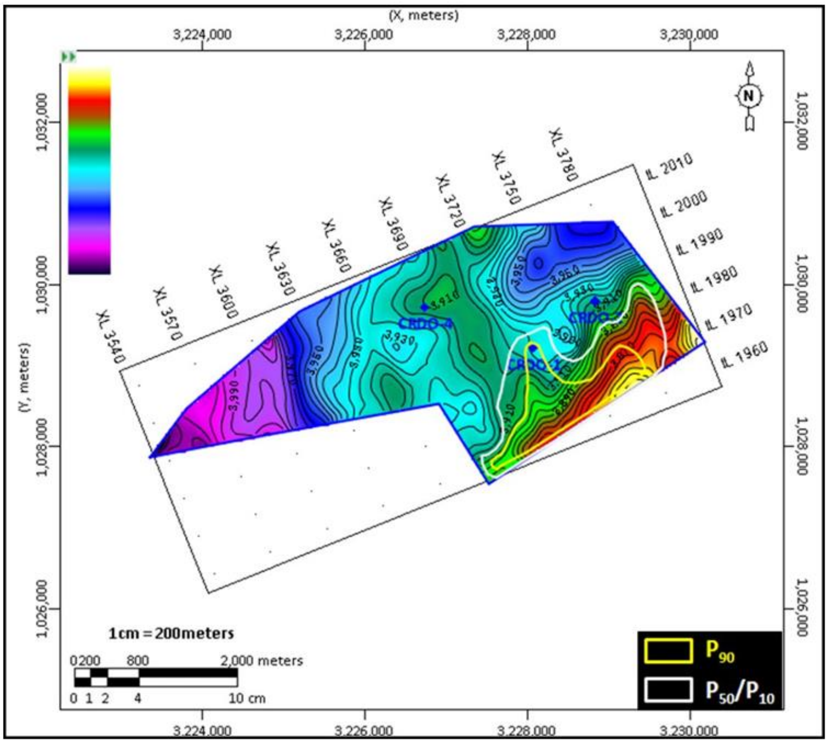


Figure 4-120: P90, P50 & P10 CASE POLYGONS FOR BCS-DEEP

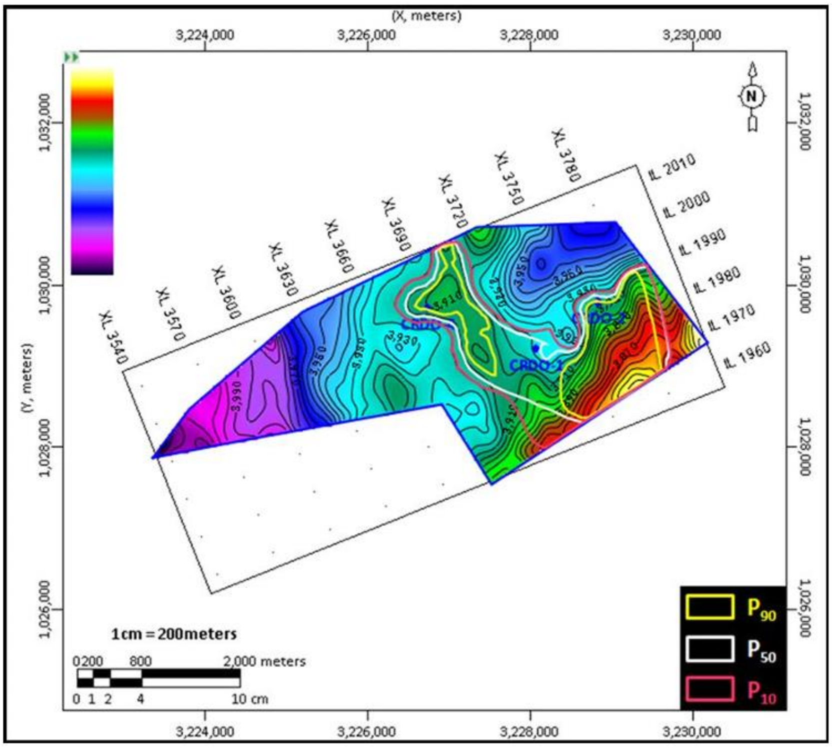


Figure 4-121: P90, P50 & P10 CASE POLYGONS FOR BMS

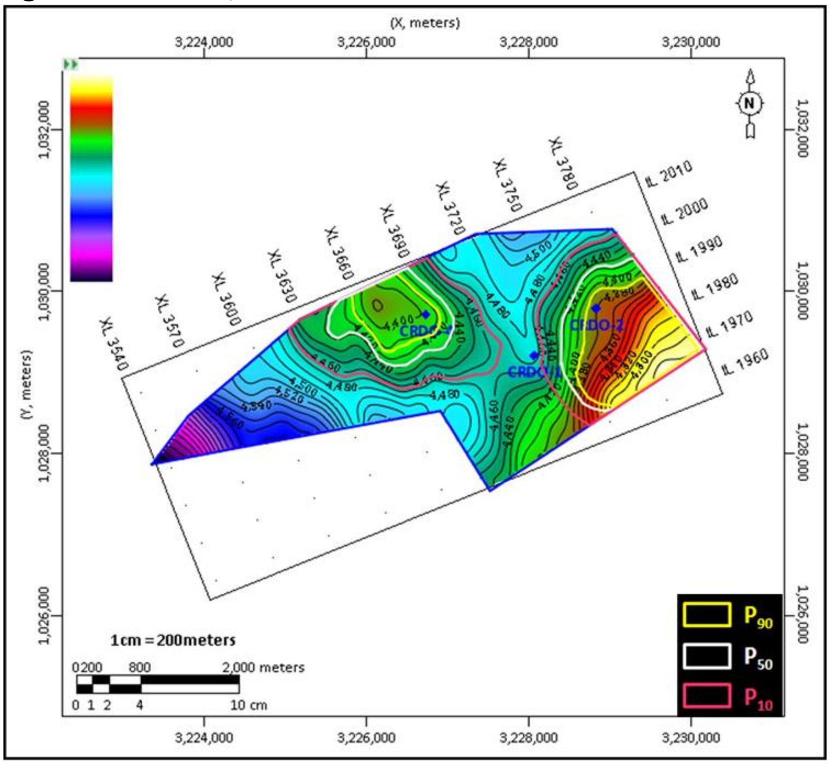


Figure 4-122: PAY THICKNESS MAP (P50 CASE) FOR BCS-SHALLOW

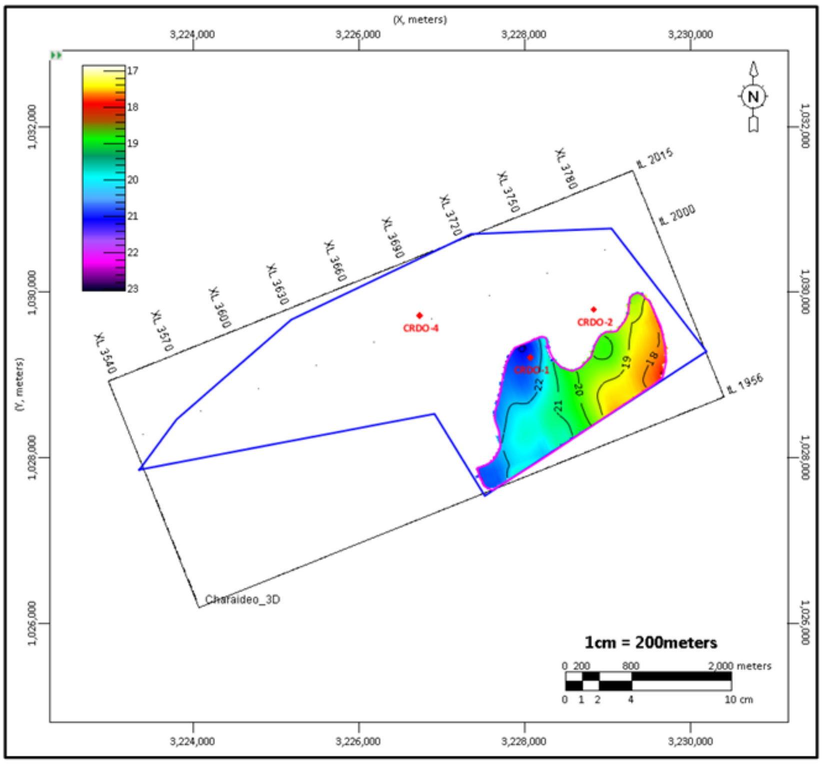


Figure-57: Pay thickness map (P_{50} case) for BCS-Shallow

Figure 4-123: PAY THICKNESS MAP (P50 CASE) FOR BCS-DEEP

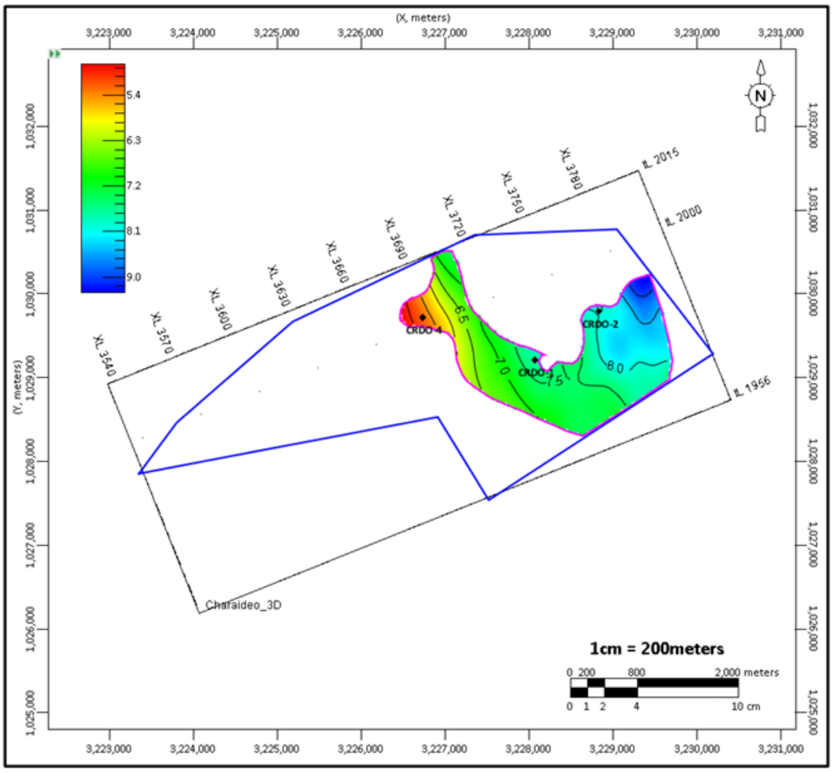


Figure 4-124: PAY THICKNESS MAP (P50 CASE) FOR BMS (WELL CRDO-2)

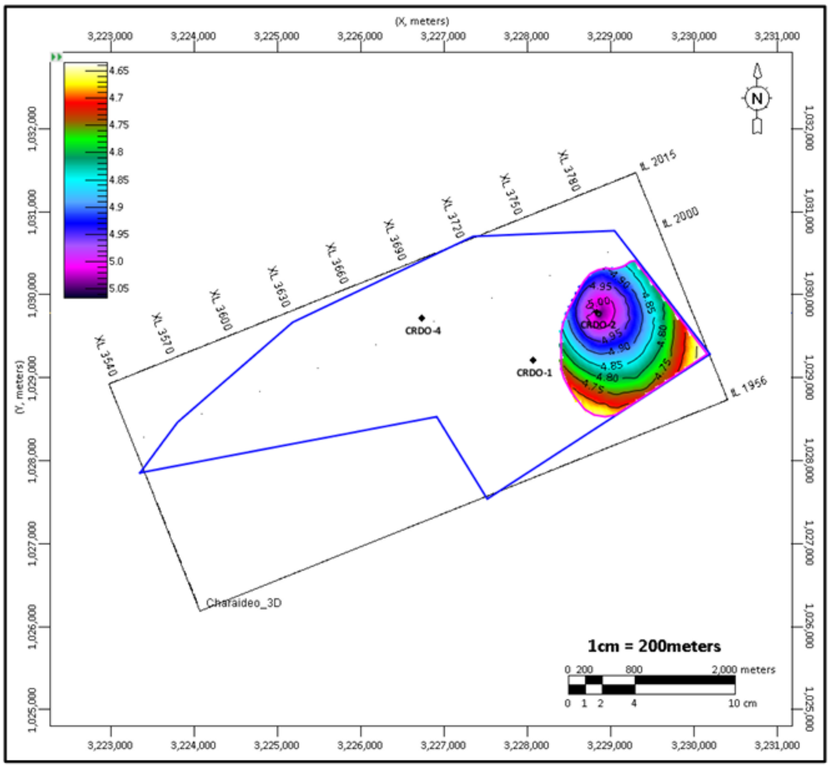
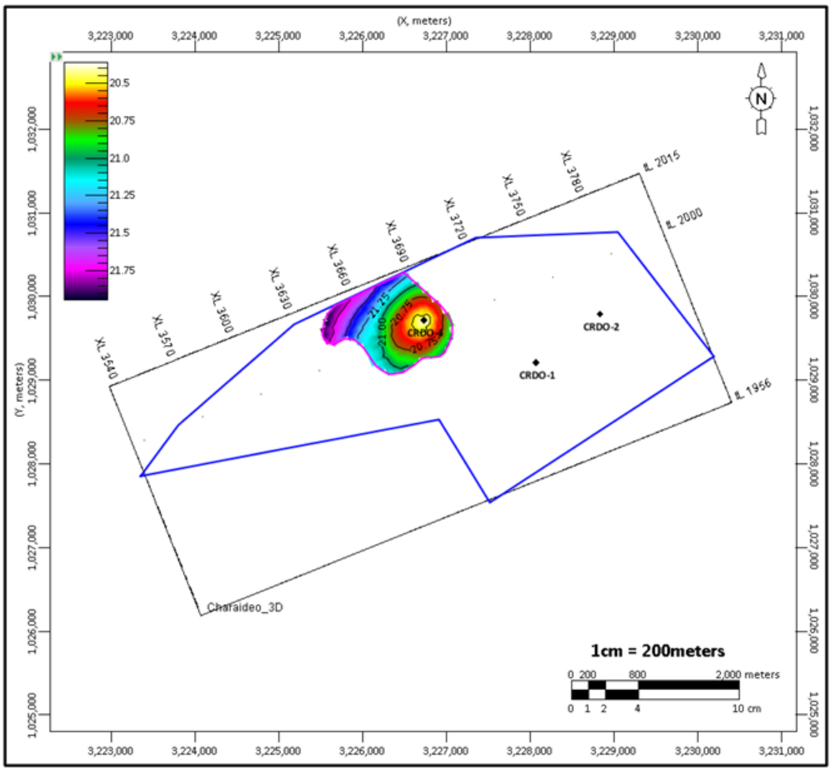


Figure 4-125: PAY THICKNESS MAP (P50 CASE) FOR BMS (WELL CRDO-4)



4.6.5.3 Estimation of In-Place Volumes and Reserves

In-place volumes and EUR have been estimated by using the polygons derived from the given maps and various petrophysical parameters for each reservoir level and the In-Place Volumes for Charaideo Field are tabulated below.

Current Oil/ Gas In-Place and Reserves estimation

The reservoir parameters and in-place are given in **Table 4-65 and Table 4-66**.

Table 4-65: RESERVOIR PARAMETERS FOR VOLUMETRIC ESTIMATION OF CHARAIDEO FIELD

Reservoir	Area	He	Phi	Hydro-carbon	FVF V/v	API	SPGR	GOR	OIIP	GIIP
Sand/ layer	SqKM	m		So	Bo			Sm3/ M3	MMstb	MMm3
BCS Shallow (CRDO-2)	2.354	15.0	0.12	0.53	1.75	31.1	0.87	210	8.1	269
BCS Deep	3.020	4.0	0.11	0.53	1.75	31.1	0.87	210	2.5	85
BMS CRDO-2	2.906	2.4	0.14	0.55	1.83	32.5	0.8628	210	1.9	62
BMS CRDO-4	2.570	10.5	0.14	0.55	1.83	32.5	0.8628	210	7.1	238
									19.6	**654**

Table 4-66: HYDROCARBON IN-PLACE(2P) CHARAIDEO FIELD

Field	O+OEG MMTOE
CHARAIDEO	**3.35**

4.6.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Charaideo field is **21 km. NE of main Geleki field and approx. 3 km. south of Lakwa field**

AA/ONDSF/ASSAM/2025 (A&AA) KHEREM FIELD

4.7 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) KHEREM FIELD

The Kherem field is located in the Ningru Extension PML in the district of Changlang in Arunachal Pradesh and is about 74 km N.E. of Duliajan in the district of Dibrugarh. The Kherem field covers an area of 14.78 Sq. Km and is bounded by the points ABCDEFG as shown in **Figure 4-126**.

The presence of a significant structure at the Pengri-Bordumsha area of the Ningru Extension PML of Arunachal Pradesh was indicated by 24-fold seismic data (21.275 LKM) acquired during 1985-87. The seismic interpretation revealed the presence of a broad asymmetrical anticline plunging towards the east at the Supra-thrust Girujan level, which appears to be the easternmost extension of the Digboi anticline. The axial plane of the anticline runs almost parallel to the Naga thrust. The northern limb of the anticline dips steeply (avg. 30-40^0) as compared to the southern limb, where dips are gentle (5-15^0).

Structurally, the area is characterized by the presence of the eastern extension of the Naga Thrust, which, however, manifests mainly in the sub-surface. The east-north-east trending thrust fault is prominent below the Dhekiajuli and divides the area into two structural blocks (segments), the southern hanging wall region and the northern foot wall blocks, which are also referred to as supra-thrust and sub-thrust, respectively. The Kherem and Kumchai fall into the supra-thrust region to the south, whereas the North Kumchai area is on the sub-thrust block to the north. Hydrocarbon has already been established in the supra-thrust block in Kumchai and Kherem areas.

Till date, three exploratory wells have been drilled in this area, viz., well Kherem-1 in 1992, well Kherem-2 in 1993 and well Kherem-3 in 1994. Drilling of well Kherem-1 started in 1992 but could not be completed due to down-hole drilling complications. The well Kherem-3 was drilled as a replacement for well Kherem-1. Neighbouring oil and gasfields to the Kherem Field can be seen in **Figure 4-128.**

A map showing the 2D-3D seismic coverage in the Kherem field is shown in **Figure 4-127**.

The Kherem-2 area is located onland within the Upper Assam Basin and has an offered area of 14.78 sq. km (**Figure 4-126**) under this DSF Bid Round IV. The area is a single area with 1 discovery/field (Kherem-2) and 2 additional wells. The coordinates of the block boundaries are given in **TABLE 4-67**.

Table 4-67: COORDINATES OF THE BLOCK BOUNDARIES: KHEREM

KHEREM Boundary Points		
Area: 14.78 sq km		
Point	**Longitude**	**Latitude**
A	95° 52′ 17.100″ E	27° 28′ 29.982″ N
B	95° 52′ 29.681″ E	27° 28′ 17.239″ N
C	95° 53′ 07.302″ E	27° 28′ 36.469″ N
D	95° 54′ 14.133″ E	27° 26′ 55.354″ N
E	95° 52′ 48.607″ E	27° 26′ 10.832″ N
F	95° 51′ 00.000″ E	27° 26′ 10.732″ N
G	95° 51′ 00.000″ E	27° 26′ 30.584″ N
A	95° 52′ 17.100″ E	27° 28′ 29.982″ N
Point G → A follows the state boundary between Assam & Arunachal Pradesh.		

Figure 4-126 : LOCATION MAP SHOWING THE KHEREM BLOCK BOUNDARY.

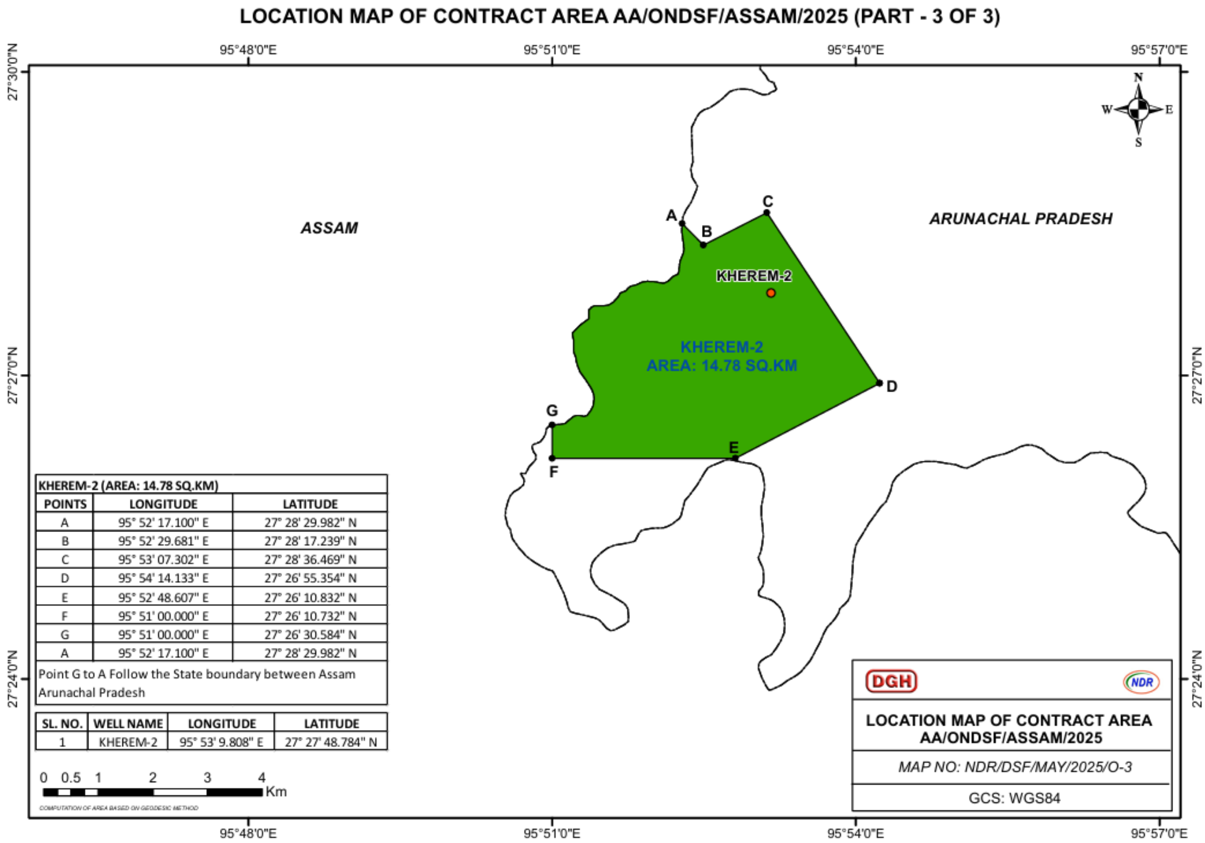


Figure 4-127 : 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: KHEREM

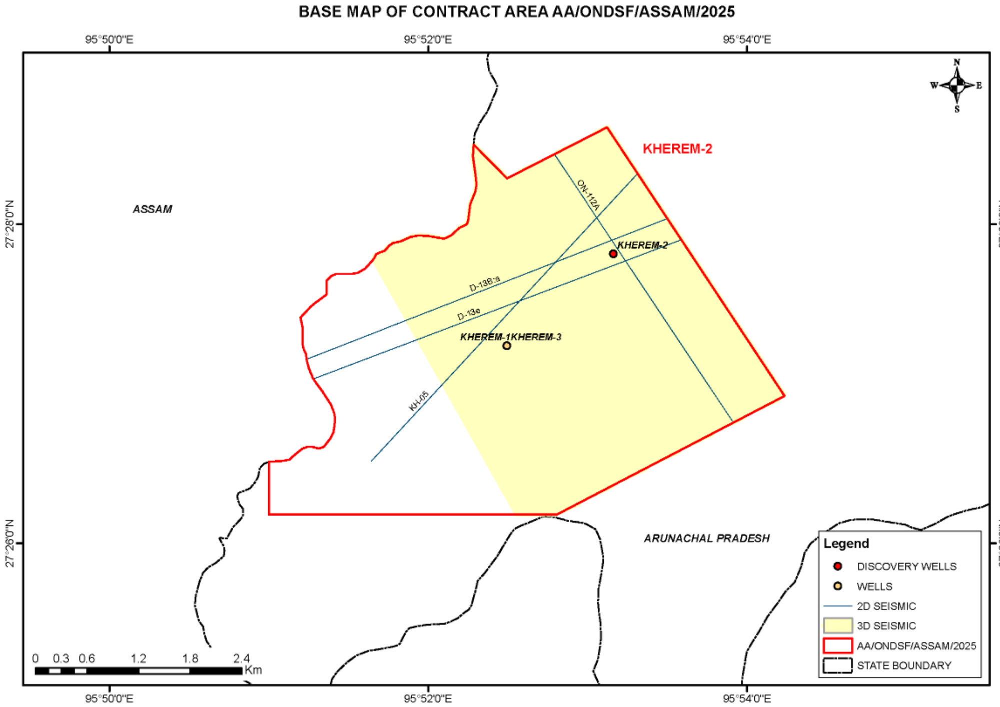
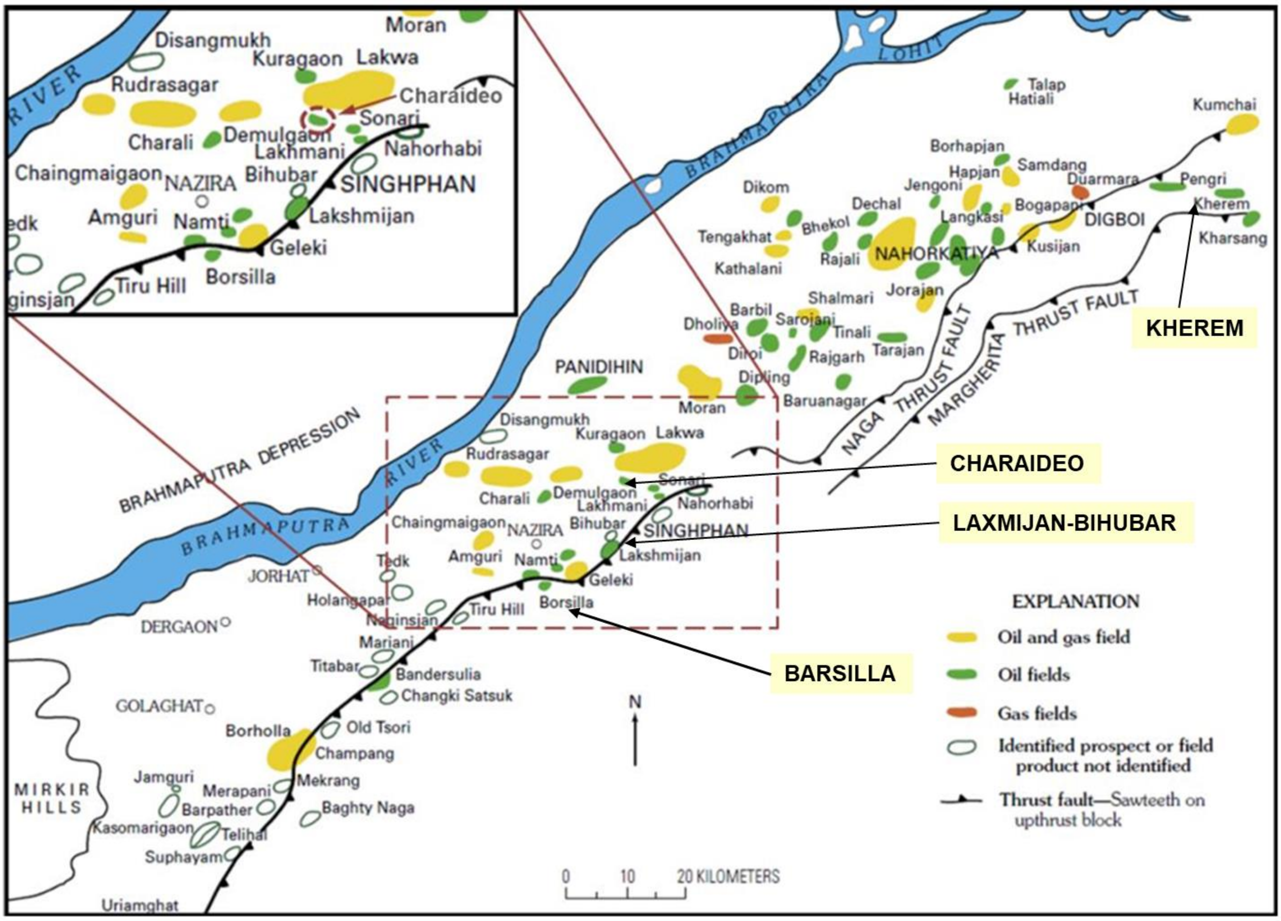


Figure 4-128 : SURROUNDING OIL AND GAS FIELDS.



4.7.1 Drilling and well completion

Key information of drilled wells have been collated and presented hereunder. The adjoining figures, wherever shown, illustrate the Well Construction Diagram for key wells. Other well statics like kelly bush reference depth, drilled and logged depth, including well coordinates are made available in Sections through various cross-references.

Till date, three exploratory wells have been drilled in this field as Kherem-1, 2, and 3. Well Kherem-1 could not be completed due to fish in hole (Bit+ drill collars and drill pipes) and a substitute well, Kherem-3, was drilled and tested. General Information about the wells, viz, Well details are given in **Table 4-68** and the Well Construction Diagram of wells Kherem-2 & 3 are given in **Figure 4-129 and Figure 4-130.**

Figure 4-129 :.WELL PROFILE OF KHEREM-2 :

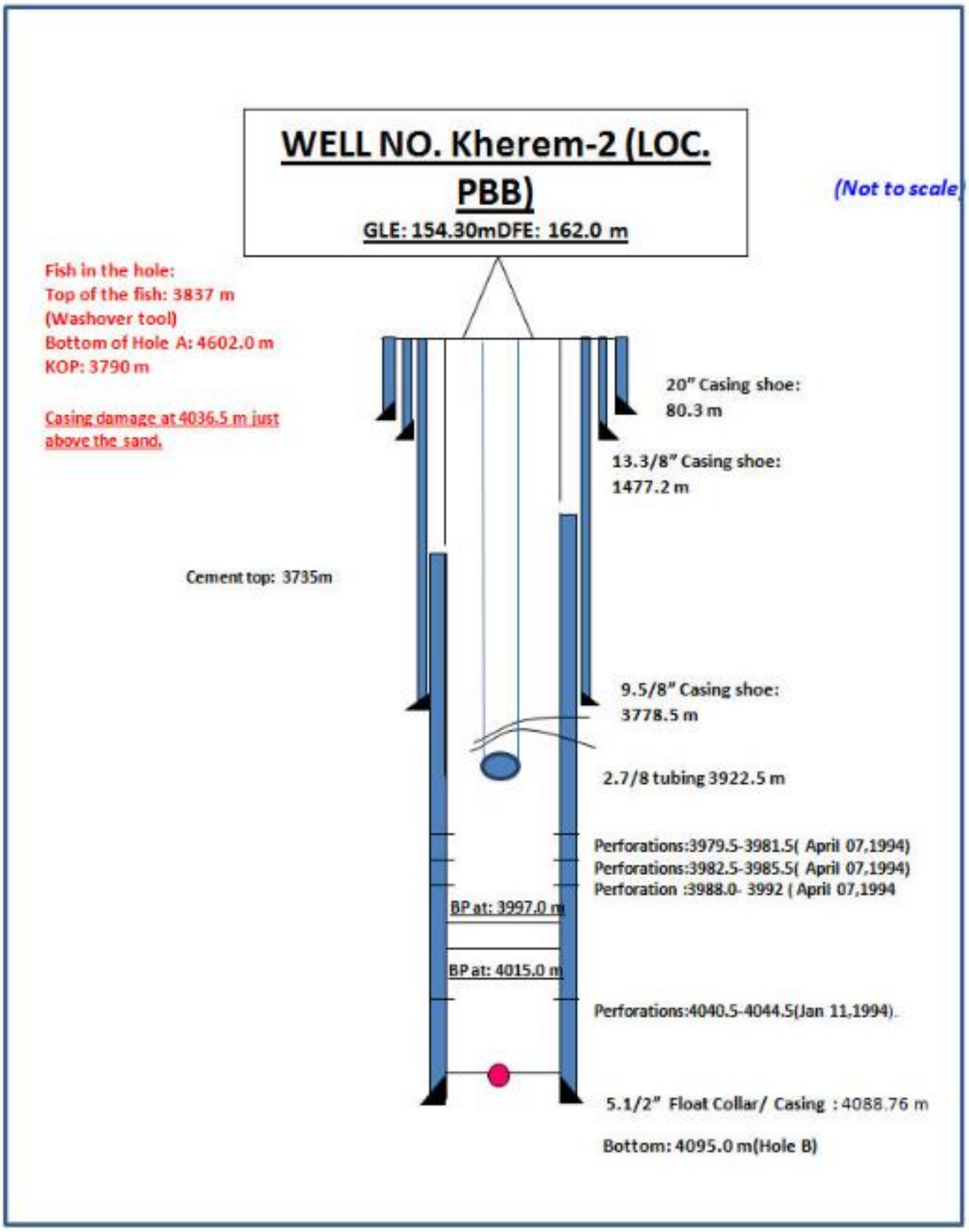


Figure 4-130 :.WELL PROFILE OF KHEREM-3 (ACTUAL)

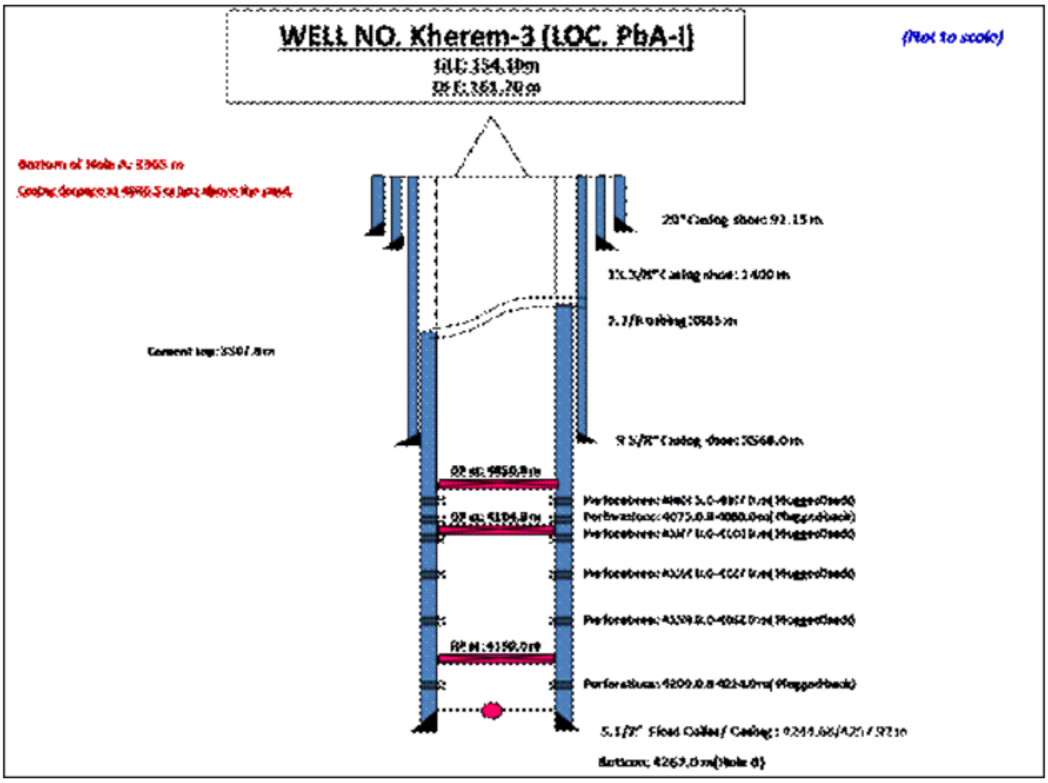


Table 4-68: GENERAL WELL WISE INFORMATION OF KHEREM FIELD:

Well Name	KHEREM-1	KHEREM-2	KHEREM-3
Category and Classification	Exploratory	Exploratory	Exploratory
Area/ Structure	Kherem	Kherem	Kherem
District & State	Lohit District, Arunachal Pradesh	Lohit District, Arunachal Pradesh	Lohit District, Arunachal Pradesh
Coordinates	Lat: 27°27'14.148" N Long: 95° 52' 29.666" E	Lat: 27° 27' 8.784" N Long: 95° 53' 9.808" E	Lat: 27° 27' 14.148" N Long: 95° 52' 29.666" E
Objective	Girujan	Girujan	Girujan
Target Depth (m)	3700	5000	4300
Drilled Depth (m)	4301	4095	4247
Logger's depth(m)	4282	4092	4262
Hydrocarbon Shows	nil	Oil	Gas
Core details	64 sidewall core samples recovered from 2109-4272m	21 sidewall core samples recovered from 3837-4061m	No sidewall cores were taken in this well
DF Elevation (m asl)	161.70	162.00	161.71
Ground level (m asl)	154.10	154.30	154.09

Well profile			
Spudded on	10.08.1991	29.01.1993	07.08.1994
Drilling completed on	04.04.1992	19.12.1993	29.05.1995
Production testing started on	22.05.1992	03.01.1994	19.06.1995
Production testing completed	04.06.1992	02.06.1994	09.09.1995
Initial Status of Well	Abandoned complicated downhole problem.	Produced @ 18 klpd clean oil (API 40°). ceased to flow due to the ingress of sand / clay / contaminated cement, owing to casing damage at 4036.5 m	The well produced intermittently condensate (API 44.8°) and a small amount of gas.
Current Status of Well	Abandoned	Shut in	Plugged back

4.7.2 Well logging and formation evaluation

The well logs of all discovery wells, along with some key wells in the Contract Area, have been reviewed. The logs recorded in various open-hole sections, along with cased-hole logs and information of conventional and other wireline formation test data, are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) has been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of the tested/ interesting zone of key wells are also appended.

4.7.2.1 Well completion and log evaluation reports availability (KHEREM Field) :

Well	KB	Spud Date	Drilled depth	WCR Available/ Not Available	FER Available/ Not Available
Kherem-1	161.70 m	10-08-1991	4301.00 m	Available	Not Available
Kherem-2	162.00 m	29-01-1993	4095.00 m	Available	Not Available
Kherem-3	161.71 m	07-08-1994	4247.00 m	Available	Not Available

4.7.2.2 Well logs acquired (KHEREM Field) :

The list of logs acquired in Kherem wells is given in **Table 4-69.**

Table 4-69: LOG ACQUIRED IN KHEREM WELLS

Well Kherem-1	
Services	**Depth Range (m bdf)**
DIL-GR-SP	1200.0 – 3472.0
	100.0 – 4244.0
CDL-CNL-GR-CAL	100.0 – 3475.0
	3800.0 – 4224.0
DT-GR	100-1200
	2780.0 – 3474.0
	3400.0 – 4224.0

Well Kherem-2	
Services	**Depth Range (m bdf)**
DIL-GR-SP	1479.0 – 3700.5
LDL-CNL-GR-CAL	2000.0 – 3794.2
DLL-MSFL-GR-SP	3778.5 – 4255.5
DLL-GR-SPCAL	3918.0 – 4397.0
LDL-CNL-GR-CAL	3925.0 – 4254.5
LSS-GR	3918.0 – 4397.0

Well Kherem-3	
Services	**Depth Range (m bdf)**
DIL-SP=CAL	1300.0 – 3025.0
DLL-SP-GR	3575.0 – 4175.0
CDL-CNL-GR	3575.0 – 4175.0

4.7.2.3 Well log evaluation and initial test results (KHEREM Field):

Testing details of wells Kherem-1, Kherem-2 and Kherem-3 are given in **Table 4-70.** Log motifs of Kherem wells are placed at **Figure 4-131, Figure 4-132, Figure 4-133, Figure 4-134 and Figure 4-135**

Table 4-70: EVALUATION AND INITIAL TESTING DETAILS OF KHEREM WELLS

Interval (mbdf)	Formation (+ Zone, if specified)	Gross (m)	Net(m)	Phi	Sw
KHEREM-1					
2102-Bottom / 2034.73-Bottom	Girujan (2728.5-2742 mbdf)	14.5	11.0	0.27	-
	Initial testing results: Tested the 2729m Sand in the range 2730.0 -2733.0 m (within 9.5/8" casing), the well gave inflow of mainly formation water. Due to complicated downhole problems (Fish), the interesting Lower Girujan Sands encountered in the well could not be tested, and subsequently, the well was abandoned.				
KHEREM-2					
2183-Bottom / 2112.49-Bottom	Girujan (4037.5-4049.0 mbdf)	12	7	0.24	-
	Initial testing results: Tested the 4038 m sand in the interval 4040.5-4044.5m, the well produced clean oil at the rate of 18-24 klpd (API-40^0) through 7.5 mm bean at FTHP of 56-99 kg/cm^2 and then ceased to flow due to ingress of sand/clay/contaminated cement owing to casing damage at 4036.5 m just above the sand.				
	Girujan (3978.0-3994.0 mbdf)	16	11.0	0.18	-
	Initial testing results: Tested the 3978 m sand in the intervals 3979.5-3981.5m, 3982.5-3985.5m, and 3988.0-3992.0m, the well flowed at the rate of around 30 klpd with water (Oil-68%, API-39.4^0) through 3.5 mm bean with FTHP of 154.9 kg/cm^2. Due to lack of infrastructural facilities to produce on a regular basis, the well was killed with 100 lbs/cft mud on safety consideration during a W/O carried out in April' 04.				
KHEREM-3					
2103-Bottom / 2032.74-Bottom	Girujan (4206.5-4225.0 mbdf)	10	5		
	Initial testing results: Tested the 4207 m sand in the interval 4209.0-4214.0m. After prolonged testing, the well intermittently produced condensate (API-44.8^0). Plugged back to test higher up.				
	Girujan (4158.5-4162.0 mbdf)	6	3		
	Initial testing results: Tested the 4159 m sand in the interval 4159.0-4162.5m. After prolonged testing, the well displaced a little amount of gas. Hence plugged back.				
	Girujan (4123.0-4131.0 mbdf)	5	2		
	Initial testing results: Tested the 4123 m sand in the interval 4124.0-4127.5m. After prolonged testing, the well displaced little amount of condensate. Hence plugged back.				

Figure 4-131 :.WELL LOG MOTIF OF KHEREM-1 :

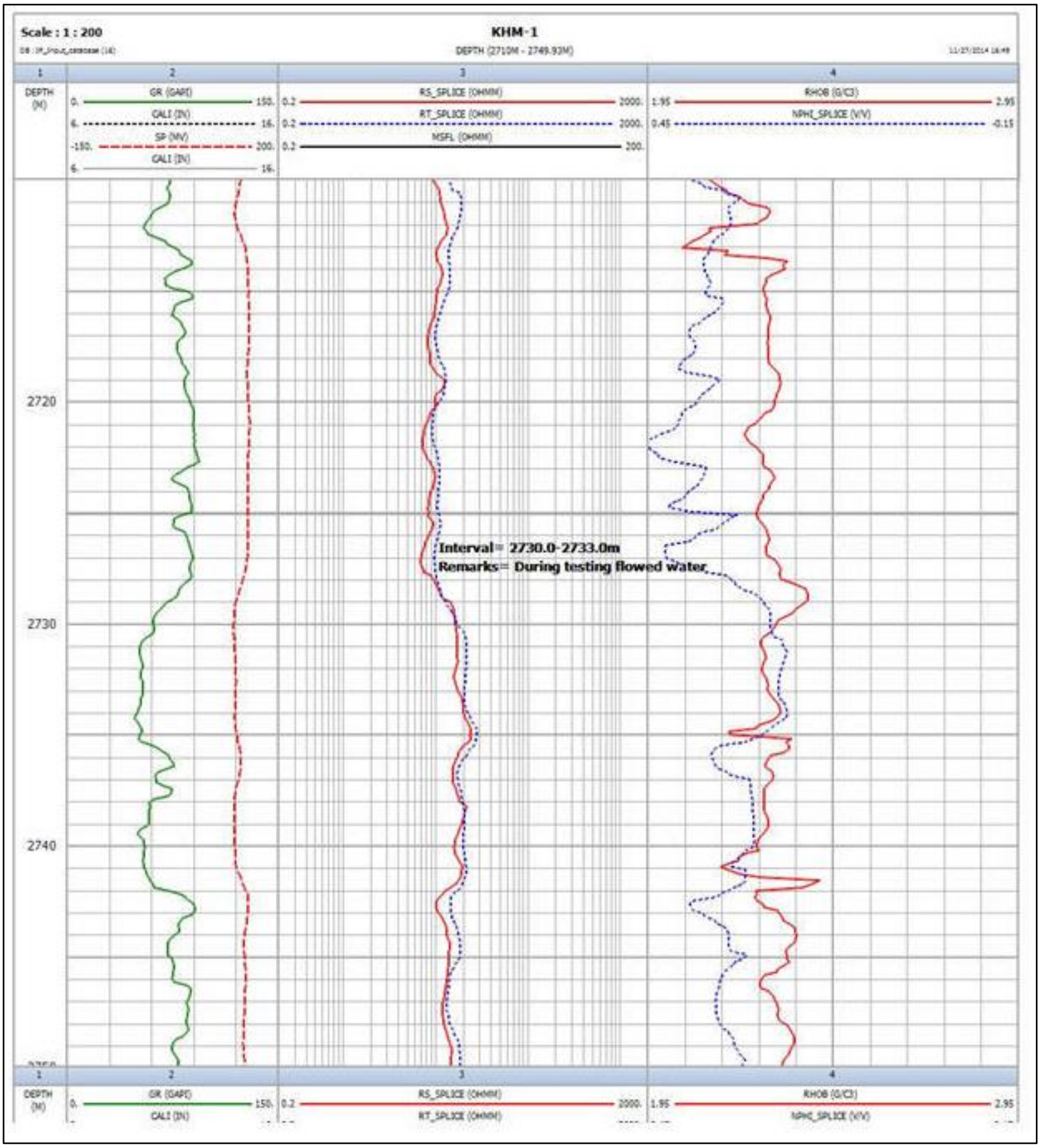


Figure 4-132 :.WELL LOG MOTIF OF KHEREM-2(3950-4018M) :

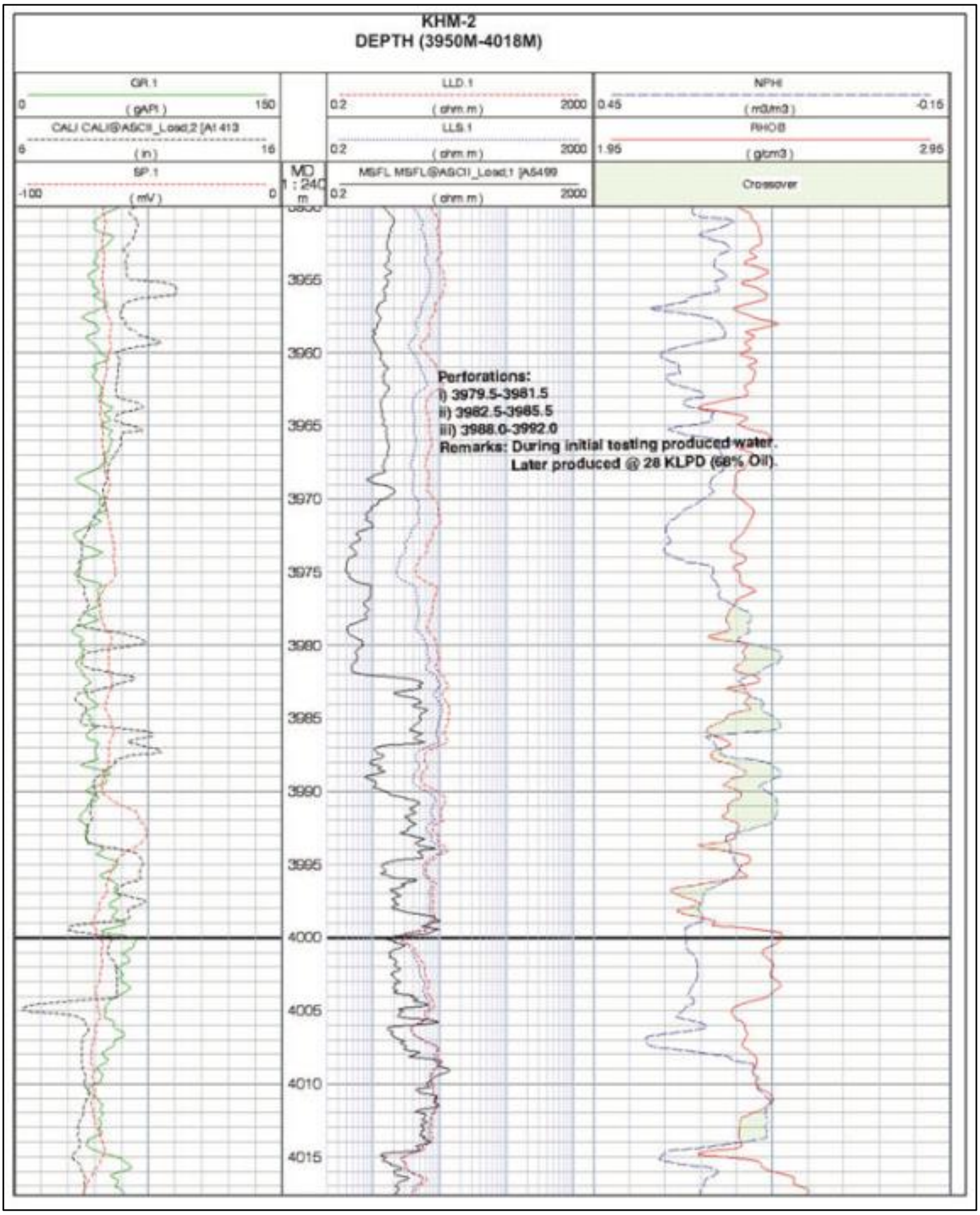


Figure 4-133 :. WELL LOG MOTIF OF KHEREM-2 (4020-4080M):

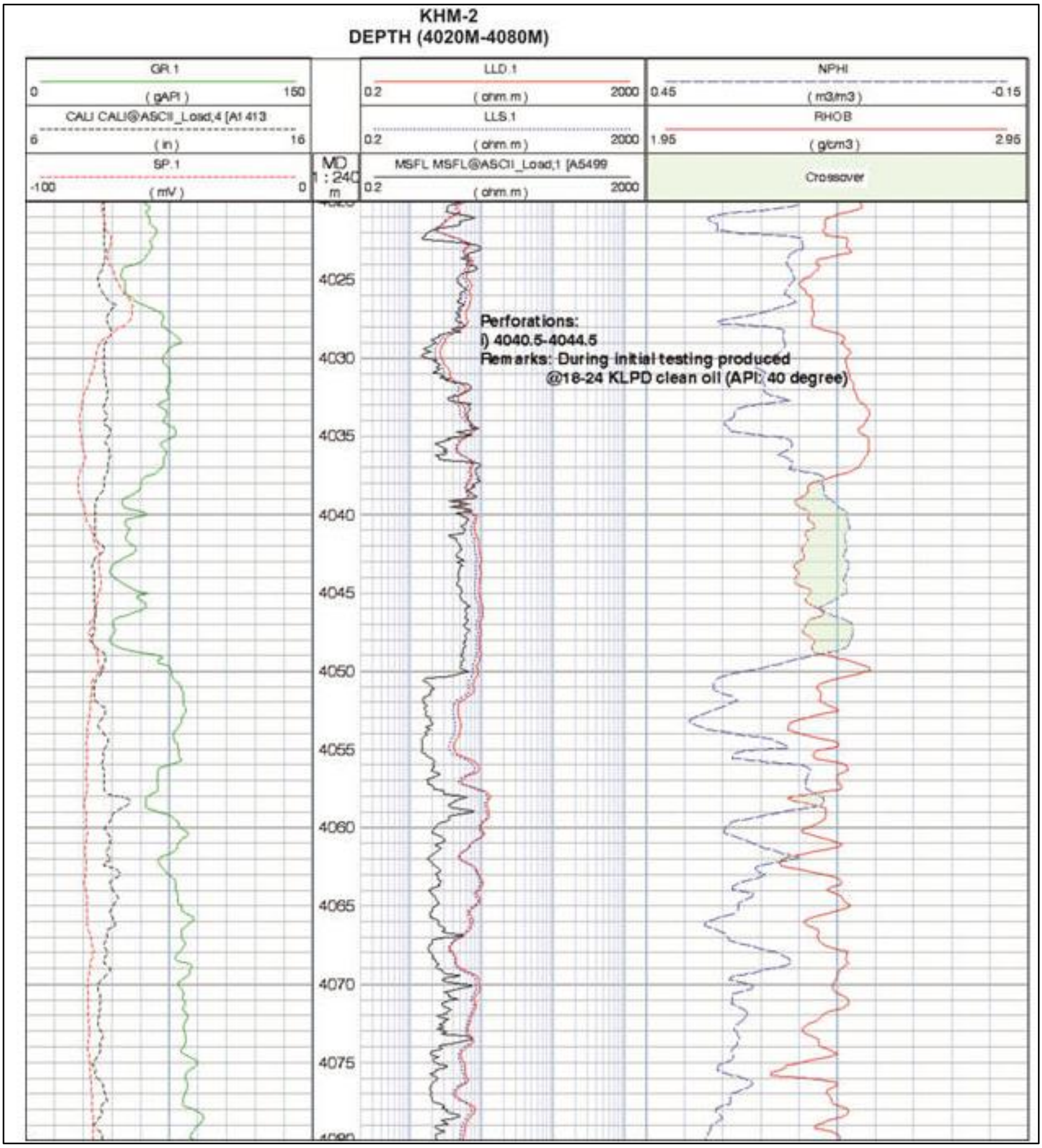


Figure 4-134 :. WELL LOG MOTIF OF KHEREM-3 (4063.5-4080M):

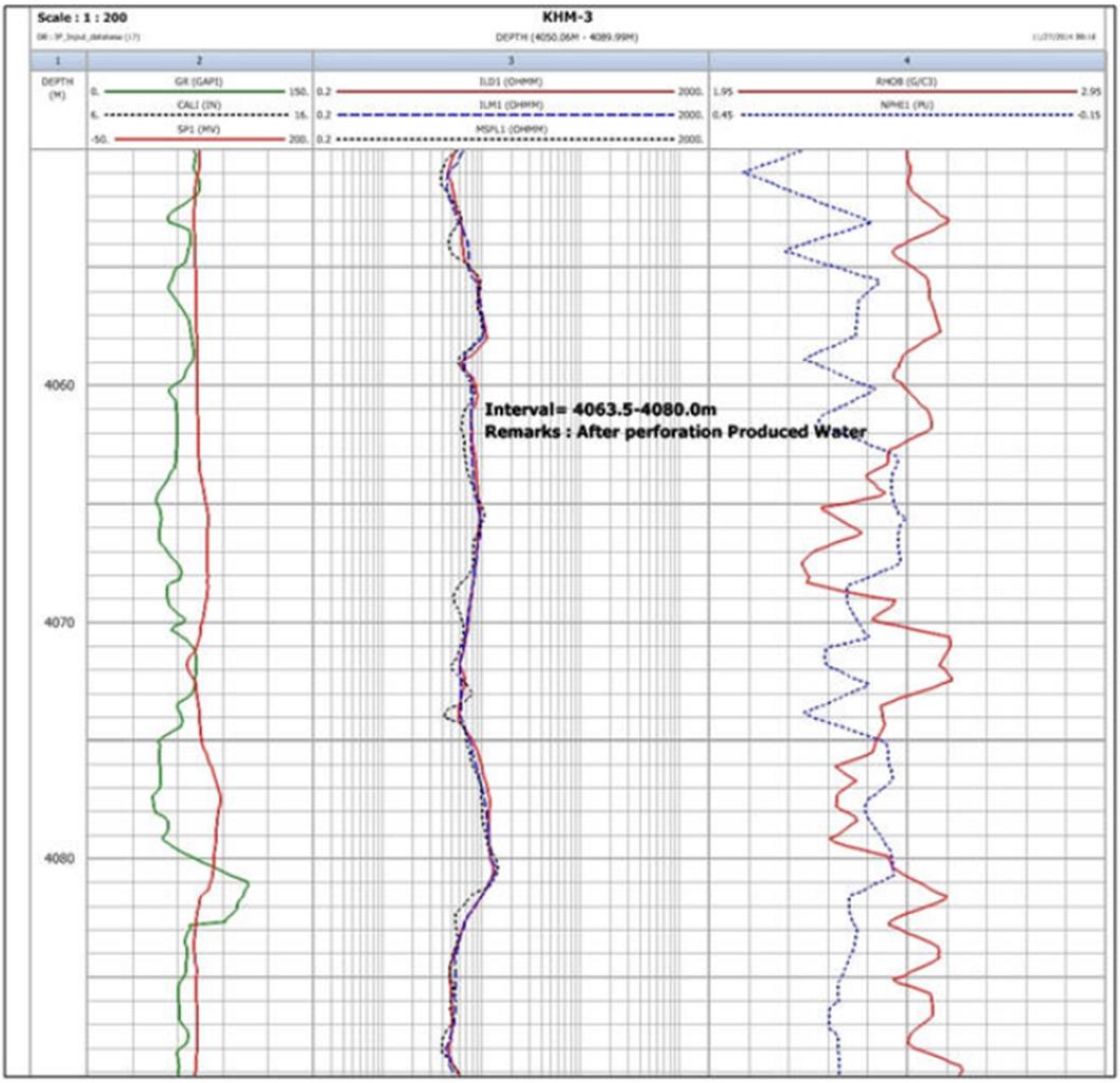
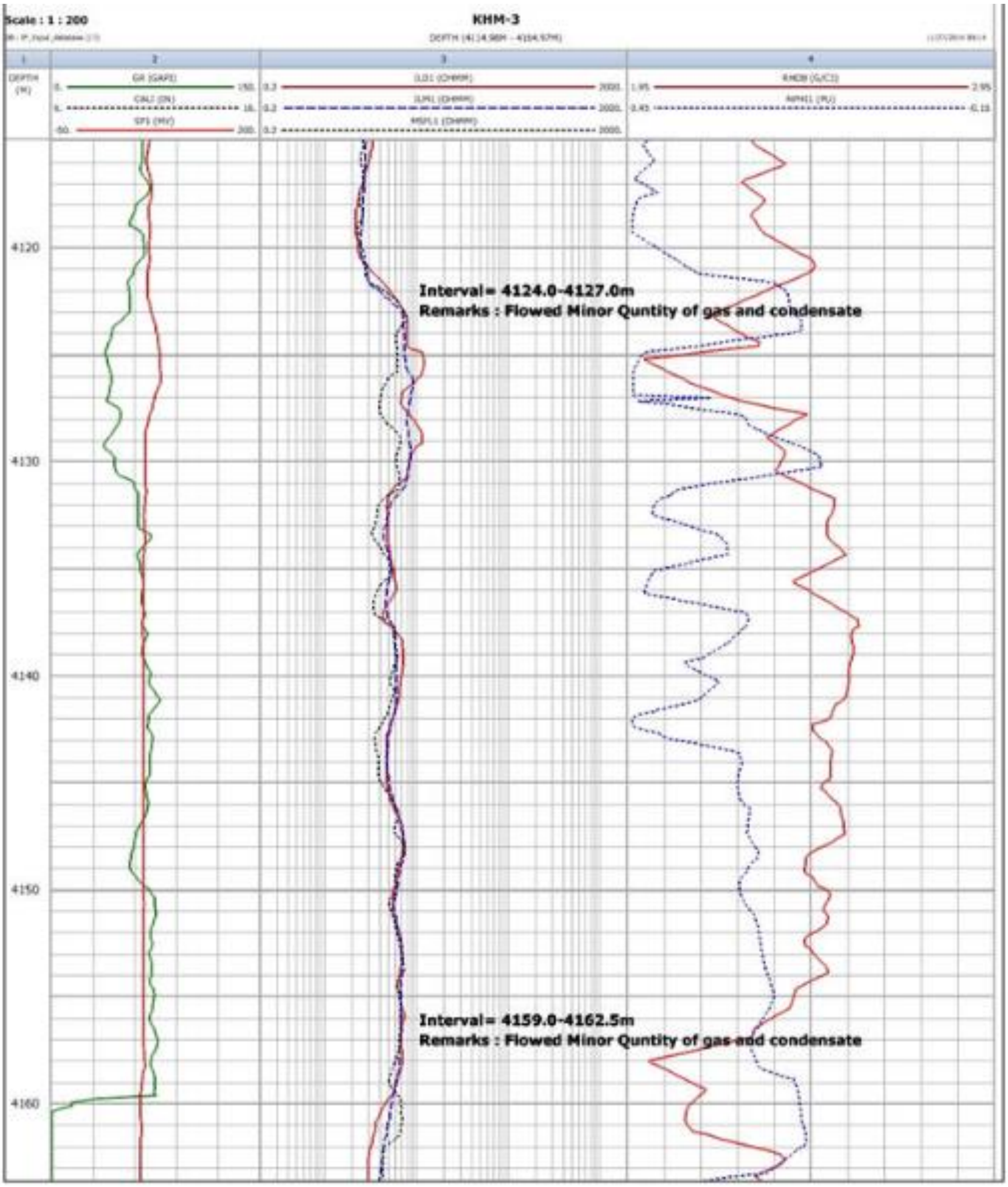


Figure 4-135 :. WELL LOG MOTIF OF KHEREM-3 (4124-4127M):



4.7.3 Well testing and workover history

Well Kherem-1:

Well Kherem-1 was drilled up to 4282m but could not be completed due to complicated downhole problems consisting of a 1303 m Fish containing BHA and drill pipe left in the hole. Prospect below 4000 m could not be tested due to a Cement plug placed above the fish top. Only one object at 2729 m Girujan Sand was tested, which gave inflow of formation water (Salinity of 300 ppm). The well was abandoned due to Fish.

Well Kherem-2:

The well was completed in 'B' hole at 4095 m with 5.1/2" oil string casing shoe at 4088.8 m after abandoning 'A' hole at 4602 due to stuck drill string. Initially, the 4037-m Girujan Sand was tested through perforations in the range 4040.5-4044.5 m in salt solution during January 1994. The well produced clean oil at the rate of **18 - 26 KLPD** (API 40°) with minor water and varying GOR of 2000 to 11000 cum/kl. The well ceased to flow on 05.03.94 due to the ingression of sand/clay/contaminated cement in the tubing. The well was then killed with 120 lbs/cft mud. CBL-VDL recorded showed casing damage at around 4036.5 m (above the sand top). A bridge plug was set at 4015 m to plug back the 4037 m Sand.

The 3978-m Girujan Sand was tested through the perforations in the ranges 3979.5-3981.5 m, 3982.5-3985.5 m, and 3988.0-3992.0 m in 90 lbs/cft mud in April '94. The sand gave inflow of mainly water, including 1 kl of floating oil (API 39.8°). Production of water from this sand was contrary to expectation and was considered to be from the Lower Sand (4007-m Sand). CBL-VDL indicates poor cement bonding with formation. Based on CBL-VDL and CCL logs, another bridge plug was set at 3997 m in order to plug back the possible casing leak.

Following setting of the plug the well produced mainly formation water with floating oil and solids during well testing from 07.05.94 - 11.05.94. Thereafter, production behavior improved and the well started producing at the average rate of 28 KLPD (oil - 68%) through 3.5 mm bean with FTHP of 155-211 kg/sq.cm and in range of **30 - 40 m3/d (Oil** 60% of 39.4° API, Water 40%) through 2.5 mm bean with FTHP of 154.9 kg/cm^2.

Due to lack of infrastructural facilities to produce on a regular basis, the well was killed with 100 lbs/cft mud for safety considerations during a workover carried out in April 2004.

Well Kherem-3:

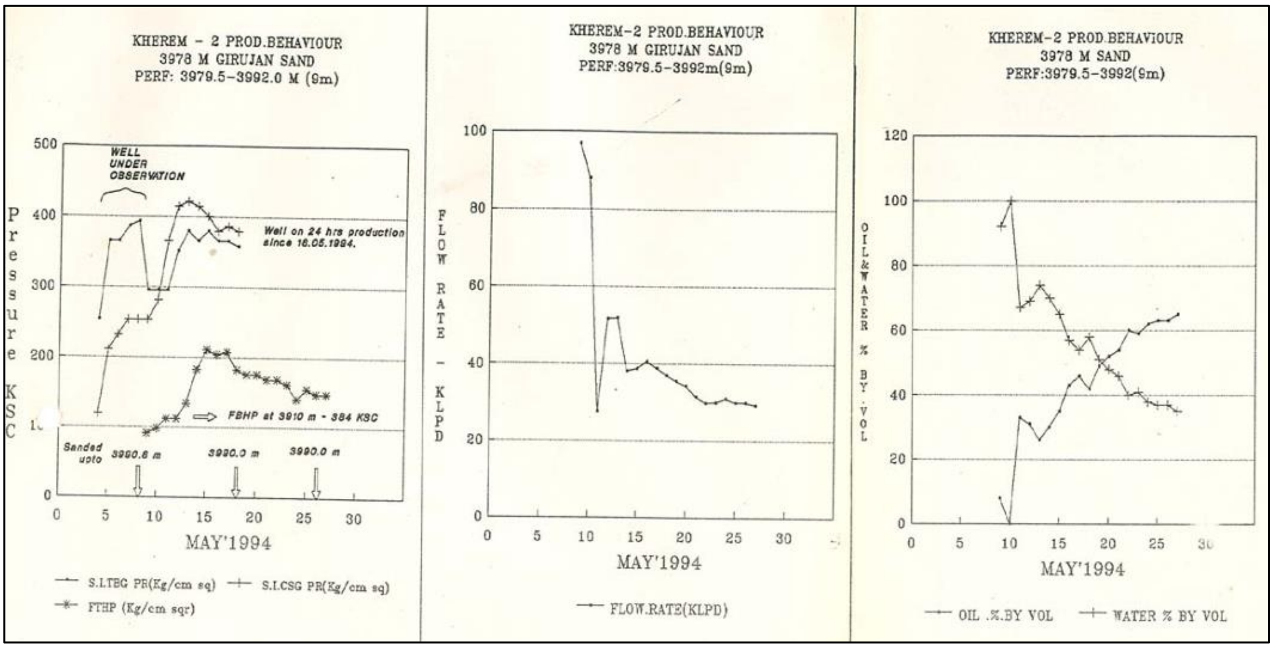
In well Kherem-3, during prolonged testing of 4207 m Girujan sand in June-July 95, the well produced intermittently condensate (44.8 Deg. API) and little amount of gas. Plugged back 4207 m Girujan sand to test higher up 4159 & 4123 m sands. During testing of 4159 & 4123 m sands, the well displaced a small amount of gas and condensate. Hence, plugged back. On testing the 4063 m sand, it produced only water. As the hole size against the higher up sand ranges is very large and the co-relatable (depth-wise) sand ranges have been tested in well Kherem-2, it was decided not to test the higher up sand ranges. Hence, the well was plugged back and kept closed.

The detailed production testing results of the wells of the Kherem block are given in the following **Table 4-71**. Production behaviour during Kherem-2 testing is shown in **Figure 4-136**.

Table 4-71: PRODUCTION TESTING DATA OF KHEREM WELLS

<table>
<tr><th>Well No.</th><th>DATE</th><th>PER.TOP</th><th>PER.BOT</th><th>REMARKS</th></tr>
<tr><td colspan="5">KHEREM-1</td></tr>
<tr><td>KHEREM-1</td><td>19-May-92</td><td>2730</td><td>2733</td><td>Abandoned well. Prospects below 4000 m could not be tested due to complicated downhole problems.</td></tr>
<tr><td colspan="5">KHEREM-2</td></tr>
<tr><td>KHEREM-2</td><td>11-Jan-94</td><td>4040.5</td><td>4044.5</td><td>Produced at the rate of 18-26 klpd clean oil (API 40 deg.) during testing and then ceased to flow due to the ingress of sands / clay / contaminated cement owing to casing damage at 4036.5 m just above the sand.</td></tr>
<tr><td>KHEREM-2</td><td>07-Apr-94</td><td>3979.5</td><td>3981.5</td><td rowspan="3">On perforating the sand produced @ 28 KLPD (68% Oil) through 3.5 mm bean with FTHP of 155-211 kg/sq.cm. Subsequently, the well was killed partially with 70lbs/cft. $CaCl_2$(to control pressure for smooth rig down operation) due to lack of infrastructural facilities to produce on regular basis.</td></tr>
<tr><td>KHEREM-2</td><td>07-Apr-94</td><td>3982.5</td><td>3985.5</td></tr>
<tr><td>KHEREM-2</td><td>07-Apr-94</td><td>3988</td><td>3992</td></tr>
<tr><td colspan="5">KHEREM-3</td></tr>
<tr><td>KHEREM-3</td><td>29-Jun-95</td><td>4209</td><td>4214</td><td>During prolonged testing in June-July;95, the well produced condensate (44.8 Deg. API) intermittently and little amount of gas.</td></tr>
<tr><td>KHEREM-3</td><td>28-Jul-95</td><td>4159</td><td>4162</td><td rowspan="9">During prolonged testing of 4159 & 4123 m sands, the well displaced little amount of gas and condensate</td></tr>
<tr><td>KHEREM-3</td><td>30-Jul-95</td><td>4159.5</td><td>4162.5</td></tr>
<tr><td>KHEREM-3</td><td>12-Aug-95</td><td>4124</td><td>4127</td></tr>
<tr><td>KHEREM-3</td><td>05-Aug-95</td><td>4159</td><td>4162</td></tr>
<tr><td>KHEREM-3</td><td>22-Aug-95</td><td>4107</td><td>4110</td></tr>
<tr><td>KHEREM-3</td><td>30-Aug-95</td><td>4075</td><td>4078</td></tr>
<tr><td>KHEREM-3</td><td>02-Sep-95</td><td>4063.5</td><td>4066.5</td></tr>
<tr><td>KHEREM-3</td><td>05-Sep-95</td><td>4077</td><td>4080</td></tr>
<tr><td>KHEREM-3</td><td>05-Sep-95</td><td>4064</td><td>4067</td></tr>
</table>

Figure 4-136 :. PRODUCTION BEHAVIOUR OF KHEREM-2 IN GIRUJAN SAND



4.7.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available, have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study, and PVT data/ results.

The shut-in bottom hole pressure data recorded in the well are given below **Table 4-72.** Oil and Gas sample analysis results are given in **Table 4-73, Table 4-74, Table 4-75 and Table 4-76**.

No PVT was carried out in Kherem-2.

No oil/gas has been produced from the field (Commercial Production has not commenced). No Workover job has been carried out in the drilled wells.

Table 4-72: SBHP DATA OF THE WELLS OF KHEREM BLOCK

Well No.	Recording Date	Measured Depth (m)	Pressure at Measured Depth (kg/cm2)
KHM-2 (4037m sand)	12-Jan-94	3881.9	656.4
KHM-2 (3977 m Sand)	31-May-94	3918.4	553.3
KHM-3	30-Jun-95	4005.9	654.6

Table 4-73: OIL ANALYSIS OF SURFACE OIL COLLECTED FROM KHEREM-2

Fluid Analysis Oil	Kherem-2
Crude Oil Date Collection	**8.4.1994**
Water (%)	**30.0**
Tests on dry sample	
Specific Gravity at 60°	0.8313
API Gravity (°)	38.7
Pour Point (°)	30.0
% Distilled under 180°C	37.0
Scotch set point of residue	45.0
Correlation Index	31.4
Characterization Factor	11.7

NOTE: Detailed study of the gas samples collected at the time of well kick at 3981 m (in A-hole) has been analysed, and the results are tabulated below

Table 4-74: GAS COMPOSITION OF TUBING HEAD SAMPLES OF KHEREM-2

Kherem-2 Gas Composition of Tubing Head Samples			
Source	**Tubing head**	**Well head**	**Tubing head**
Date	18.1.1994	18.1.1994	19.1.1994
Time	11.30 hrs.	1400 hrs.	03.18 hrs.
	% Volume		
Methane	86.634	86.844	86.586
Ethane	7.935	8.078	7.749
Propane	2.986	3.091	2.934
i-Butane	0.563	0.573	0.573
n-Butane	0.637	0.784	0.767
Pentane	0.211	0.283	0.344
Hexane	-	0.125	0.17
Nitrogen	1.034	0.127	0.869
Carbon dioxide	-	-	-
Gas gravity (Calculated)	0.649	0.654	0.655
Gas gravity (measured)	-	0.649	-
Gross Calorific value (Calculated)	10213.9	10410.9	10333.9
Net Calorific value (Calculated)	9237.5	9418.8	9348.9

Table 4-75: GAS COMPOSITION OF BOTTOMS UP SAMPLES OF KHEREM-2

Kherem-2 A-hole: Results of Gas Analysis													
Date	**Depth (m)**	**Source of collection**	**Component percentage**										**Gas Gravity (calculated)**
			N2	**C_1**	**C_2**	**C_3**	**iC_4**	**nC_4**	**iC_5**	**nC_5**	**C_{6+}**	**CO2**	**With N2**
9.6.1993	3981	Bottoms up	94.940	4.461	0.322	0.077	0.014	-	-	-	-	0.186	0.951
9.6.1993	3981	Bottoms up	95.185	3.977	0.352	0.083	0.014	-	-	-	-	0.389	0.954
9.6.1993	3982	Bottoms up	26.472	61.191	6.280	2.430	0.473	0.571	0.814	0.212	0.282	1.275	0.781
			Component percentage without N_2										
			N2	**C_1**	**C_2**	**C_3**	**iC_4**	**nC_4**	**iC_5**	**nC_5**	**C_6+**	**CO2**	**Without N2**
			-	88.160	6.360	1.520	0.277	-	-	-	-	3.683	0.641
			-	82.596	7.310	1.720	0.290	-	-	-	-	8.084	0.698
			-	83.221	8.541	3.300	0.643	0.777	1.107	0.288	0.384	1.739	0.708

Table 4-76: GAS COMPOSITION ANALYSIS OF KHEREM-3

Kherem-3 Gas Analysis	
	Mole %
Date	25.7.1995
Methane	89.69
Ethane	6.27
Propane	2.03
i-Butane	0.36
n-Butane	0.45
Pentane	0.25
Hexane	0.35
Nitrogen	0.48
Carbon dioxide	0.12
Gas gravity (Calculated)	0.34
Gas gravity (measured)	

4.7.5 Geology and Reservoir Description of KHEREM Field:

The geology of the area has been comprehensively reviewed using correlations, sections, and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude, and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.7.5.1 Geological correlations, sections, and maps (KHEREM Field):

The 2D seismic interpretation revealed the presence of a broad asymmetrical anticline plunging towards the east at the Supra-thrust Girujan level, which appears to be the easternmost extension of the Digboi anticline. The axial plane of the anticline runs almost parallel to the Naga thrust. The northern limb of the anticline dips steeply (avg. dip 30-40^0) as compared to the southern limb, where dips are gentle (5-15^0).

Structurally, the area is characterized by the presence of the eastern extension of the Naga Thrust, which, however, manifests mainly in the sub-surface. The east-north-east trending thrust fault is prominent below the Dhekiajuli and divides the area into two structural blocks (segments), the southern hanging wall region and the northern foot wall blocks, which are also referred to as supra-thrust and sub-thrust, respectively. The Kherem and Kumchai fall in the supra-thrust region to the south, whereas the North Kumchai area is on the sub-thrust block to the north. Hydrocarbon has already been established in the supra-thrust block in Kumchai and Kherem areas.

The first well in the structure, i.e., Kherem well no. 1 was drilled in 1992 to the depth of 4301m in "A' hole (4146 m in “B” ho!e) had encountered a number of promising Girujan sands, especially, below 3900m that showed positive indication of the presence of hydrocarbon as per the gas reading, drill cutting/side wall core fluorescence, and wire line log evidences. Owing to fish in the hole, none of the prospective Girujan sands could be tested in the well.

The presence of producible oil in Girujans in Kharsang and Kumchai areas and indications of the presence of hydrocarbons in the well Kherem-1 have encouraged drilling of well Kherem-2, which encountered a number of prospective sand ranges within the Girujans. The Well Kherem-2 encountered around 18m of net pay, which tested oil.

The following figures illustrate the structure, distribution, and seismic character in and around the Kherem discovery:

A) Time/Depth structure maps close to the top of Tipam and Girujans, **at Figure 4-137, Figure 4-138, Figure 4-139 and Figure 4-140**

B) Isopach maps of Base Dhekiajuli to close to Tipam Top and Base Dhekiajuli to close to Girujan Top **Figure 4-141 and Figure 4-142**

C) Integrated seismic amplitude map close to Tipam top, superimposed on depth contour map of reflector close to Tipam top, and Integrated seismic amplitude map close to Girujan top, superimposed on depth contour map of reflector close to Girujan top are placed at **Figure 4-143 and Figure 4-144**

D) Synthetic seismogram of well Kherem-2 (using VSP data of Kherem-2), **Figure 4-145**

E) Seismic sections in Kherem-1 & 2 at **Figure 4-146**

Figure 4-137 :. TWT CONTOUR MAP CLOSE TO TIPAM TOP

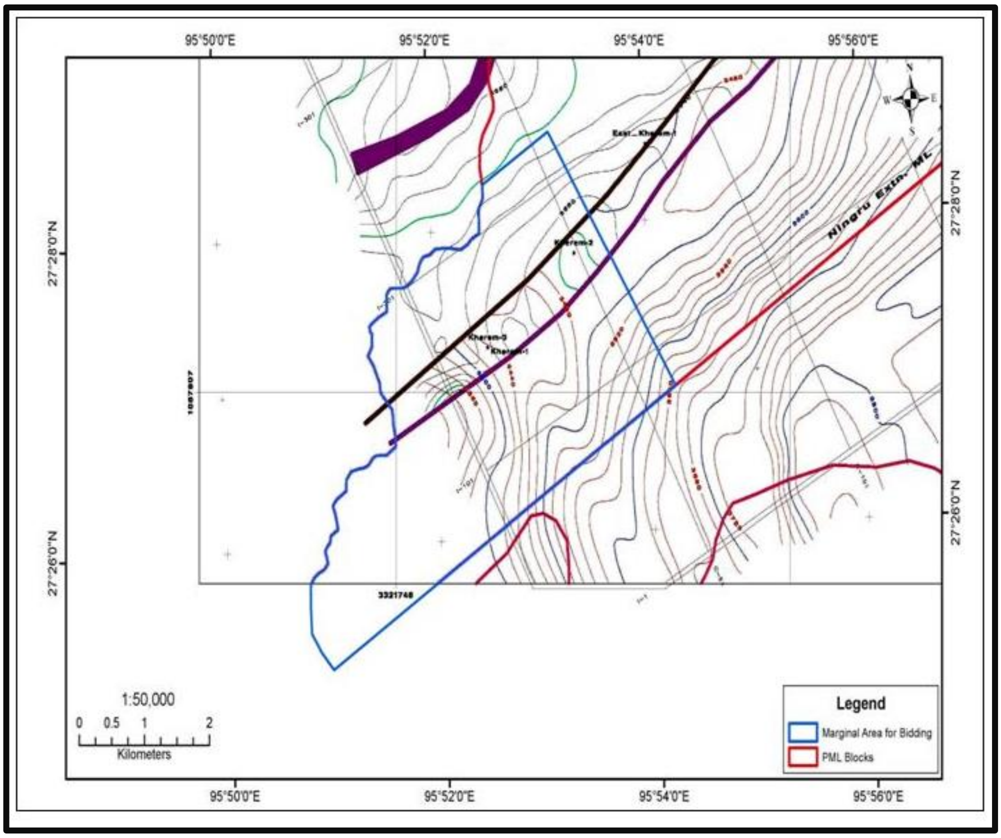


Figure 4-138 :. TWT CONTOUR MAP CLOSE TO GIRUJAN TOP

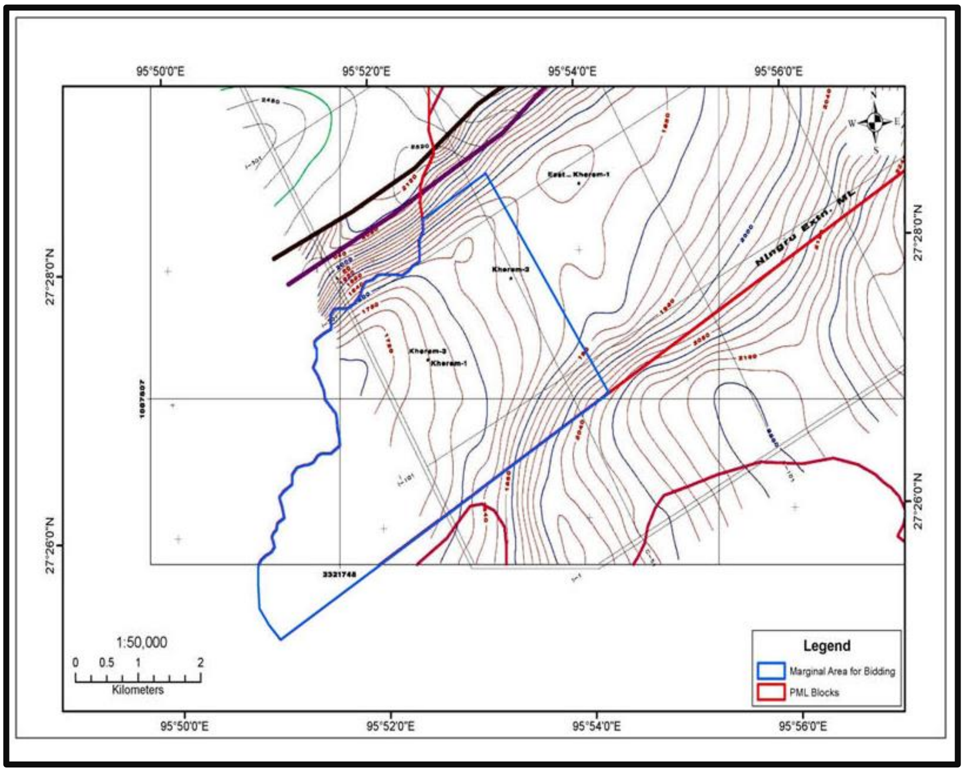


Figure 4-139 :. DEPTH CONTOUR MAP CLOSE TO TIPAM TOP

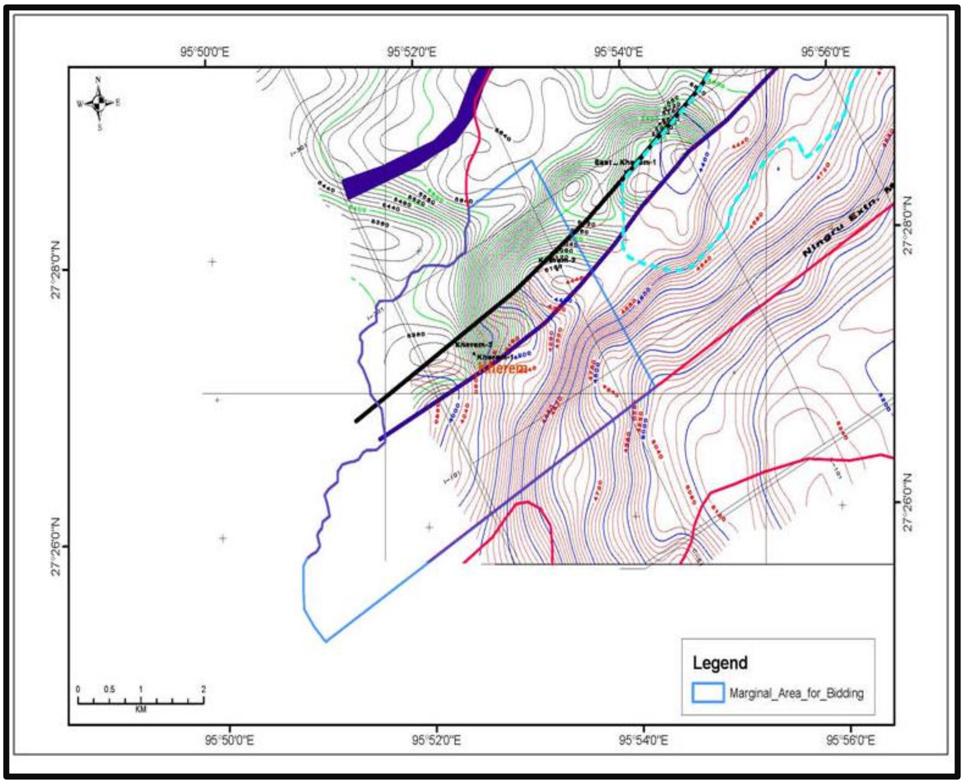


Figure 4-140 :.DEPTH CONTOUR MAP CLOSE TO GIRUJAN TOP

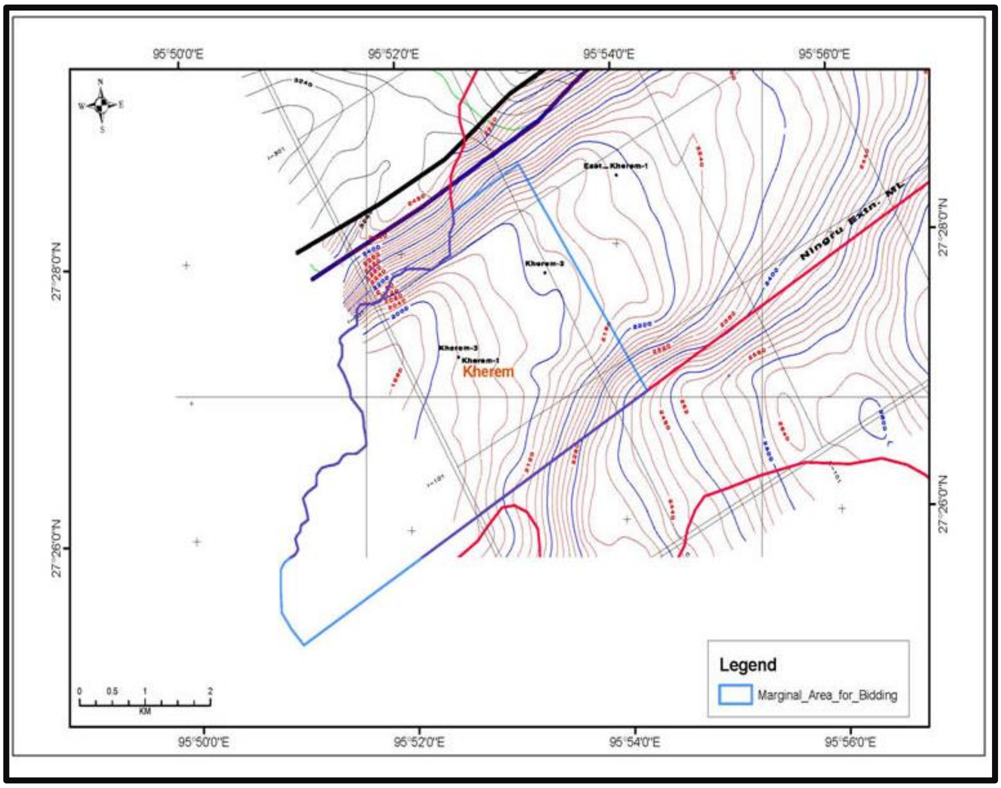


Figure 4-141 :.ISOPACH MAP OF BASE DHEKIAJULI TO CLOSE TO TIPAM TOP

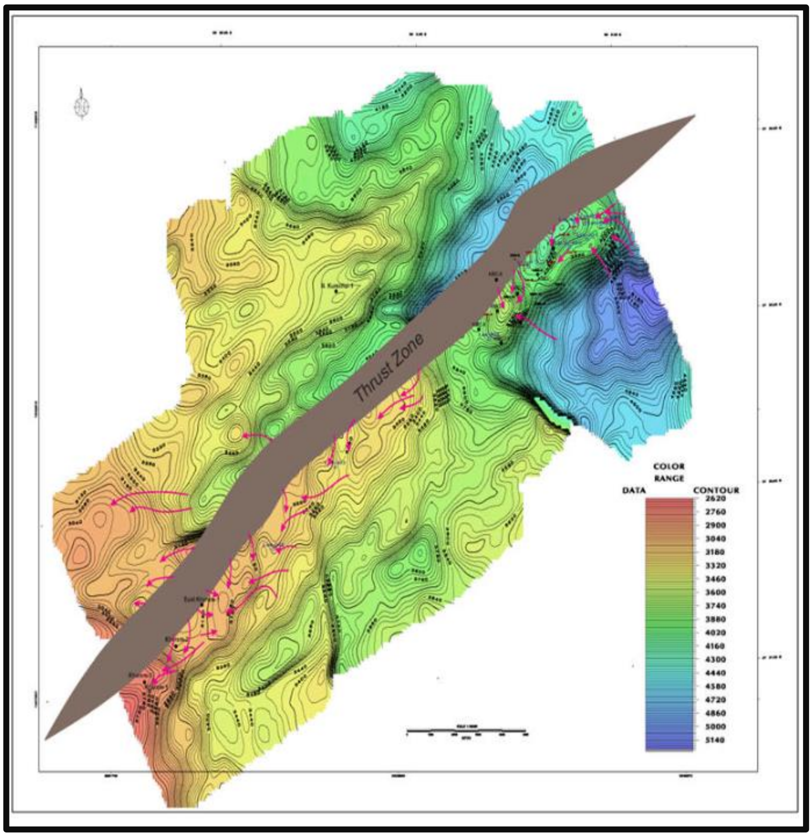


Figure 4-142 :.ISOPACH MAP OF BASE DHEKIAJULI TO CLOSE TO GIRUJAN TOP

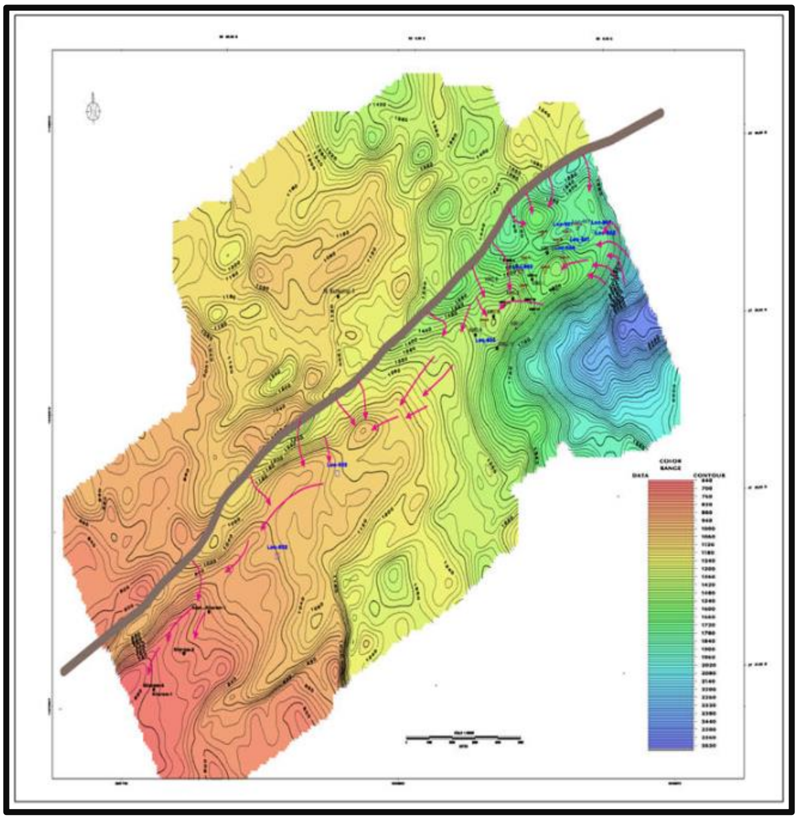


Figure 4-143 :.SEISMIC AMPLITUDE MAP CLOSE TO TIPAM TOP:

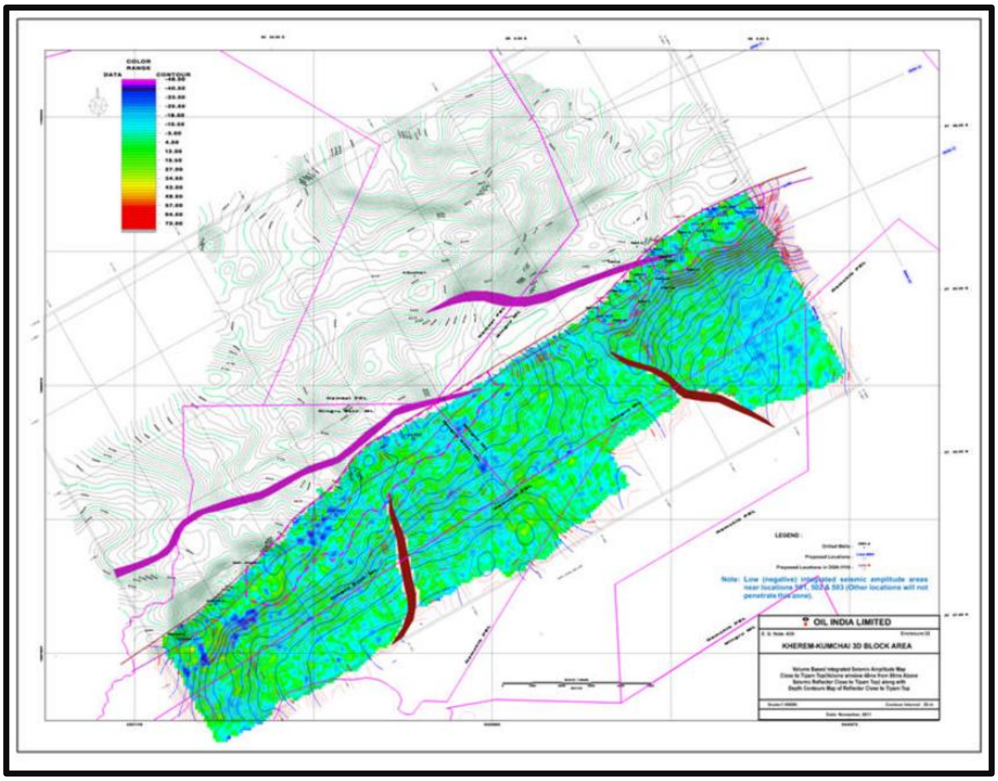


Figure 4-144 :.SEISMIC AMPLITUDE MAP CLOSE TO GIRUJAN TOP

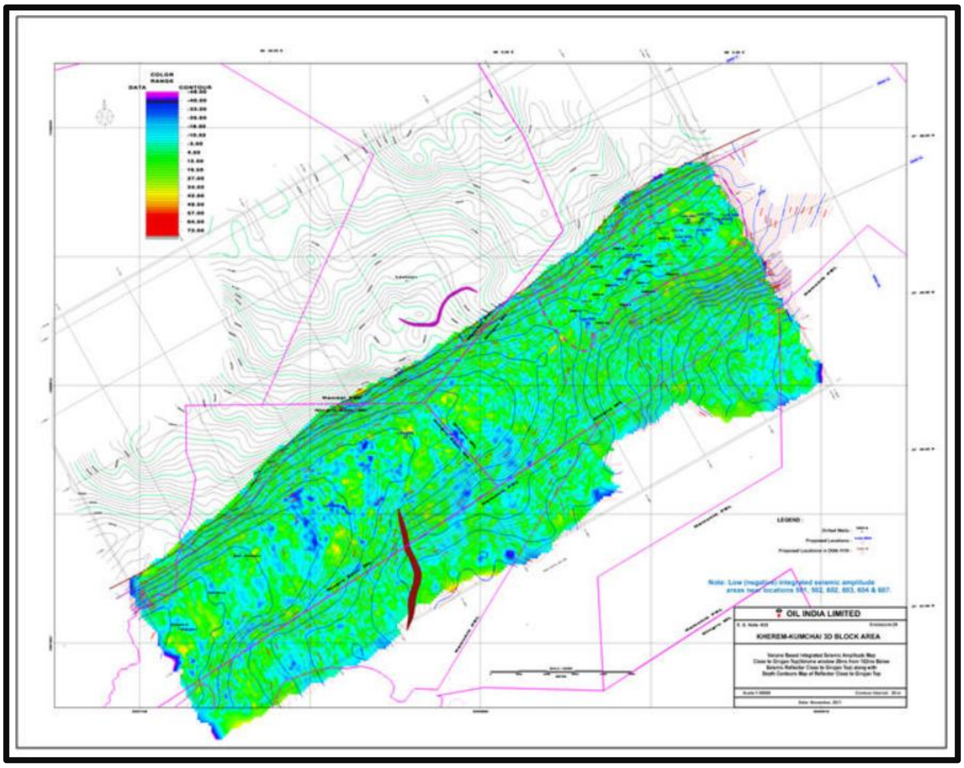


Figure 4-145 :. SYNTHETIC SEISMOGRAM OF WELL KHEREM-2

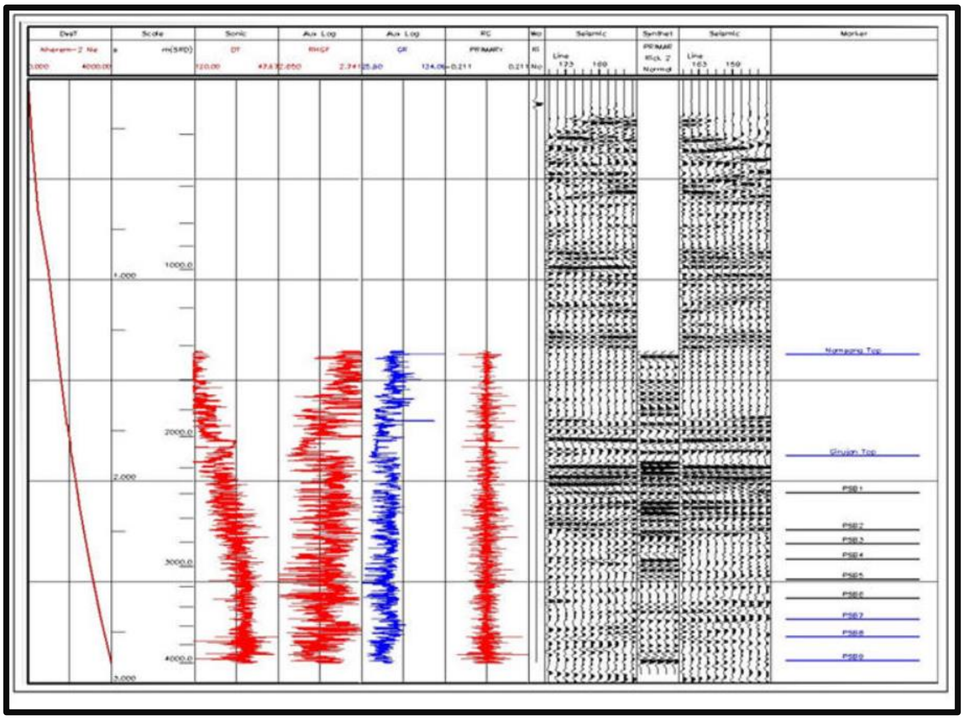
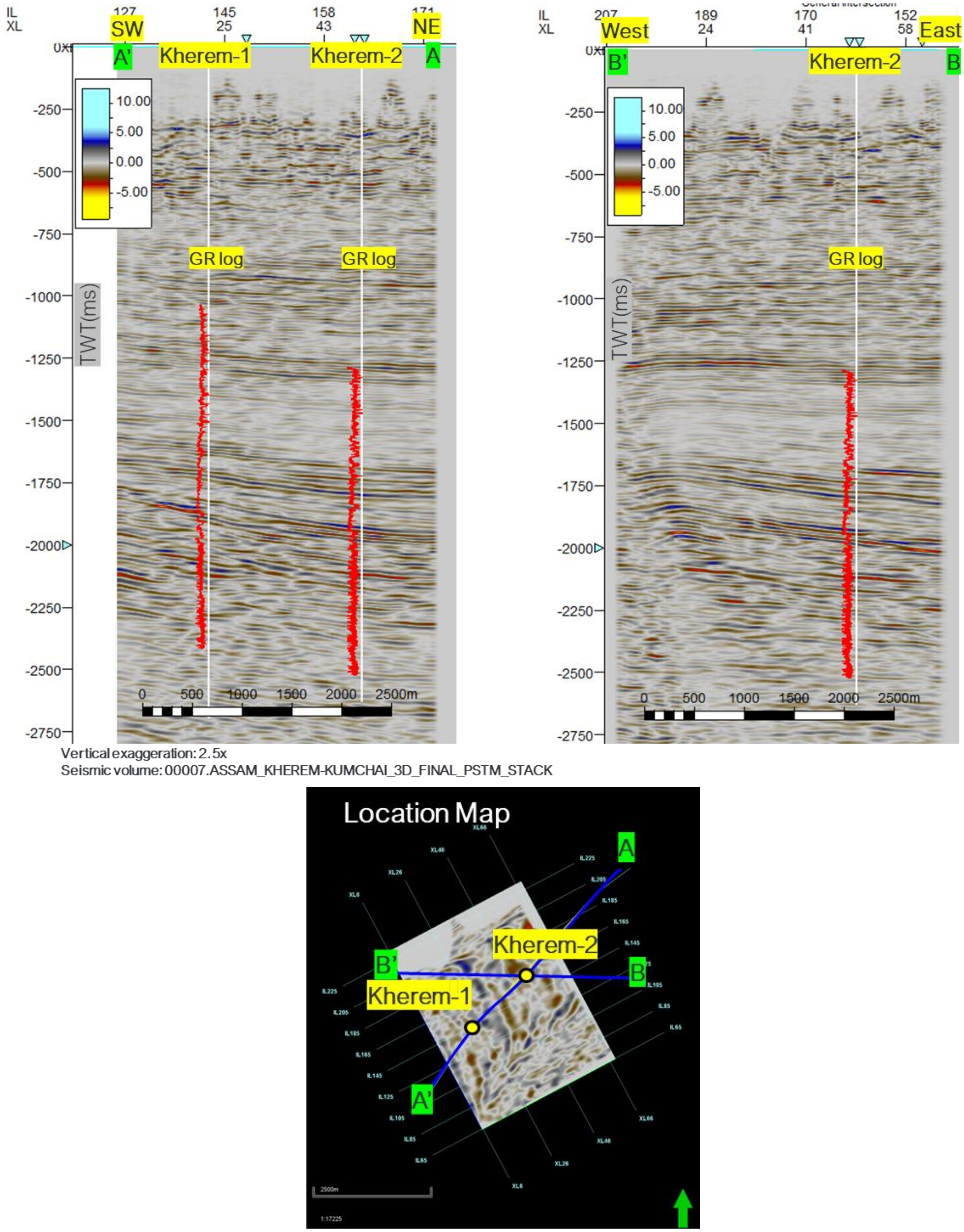


Figure 4-146 :.SEISMIC SECTIONS IN KHEREM-1 &KHEREM 2



Stratigraphic sequence encountered in Kherem wells is given in **Table 4-77**

Table 4-77: WELL WISE STRATIGRAPHY; KHEREM-1 (FORMATION TOPS ARE PROVIDED BASED ON DRILL-CUTTINGS AND CORRELATION FROM WELL KUMCHAI-1)

Formation	Top (m KB) MWD	Thickness (m)
Well Kherem-1		
Alluvium/Dhekiajuli	Surface	937.4
Namsang	945	1157
Girujan	2102	2199+
Well Kherem-2		
Alluvium/Dhekiajuli	Surface	977.38
Namsang	985	1197
Girujan	2183	2419+
Well Kherem-3:		
Alluvium/Dhekiajuli	Surface	937.4
Namsang	945	1158
Girujan	2103	2159+

4.7.5.2 Reservoir parameters and hydrocarbon estimates (KHEREM) Field:

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

The reservoirs of the Kherem field comprise of sandstone with shale intercalations. Porosity development is good (average 14%). Oil-Water Contact not encountered. The Girujan sands have a gross pay thickness of 27m and net pay thickness of 18m. Oil reserves for Kherem-2 and Gas Volume for Kherem-3 are being estimated by fixed acreage method, hence, no isopay map has been prepared. Reservoir parameters for estimating in-place oil & gas reserves are given in **Table 4-78** and **Table 4-79** below.

Table 4-78: RESERVOIR PARAMETERS OF KHEREM FIELD

Parameters	Oil (Girujan Kherem-2)	Gas (Girujan Kherem-3)
Area, SqKm	**0.385**	**1.3279**
Thickness, m	18	10
Porosity	0.20	0.18
Shc	0.65	0.65
FVF, rm3/sm3	1.18	0.003
GOR, m3/m3	245	
Oil API, sp gr	38.7 /0.8313	
OOIP, MMstb	4.8	
GIIP, MMm3	187	518

Table 4-79: 2P HYDROCARBON IN-PLACE KHEREM FIELD

Field	O+OEG MMTOE
KHEREM	**1.34**

Erstwhile Operator-reported estimates on record:

The field, Kherem has a reported oil and gas estimate of **0.89 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the currently reported estimates.

4.7.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Kherem field is **Bordumsa Terminal, ~ 18 Km**

The wells Kherem- 2 and 3 are fitted with well head spool. No other production facilities are available in this area. The nearest production facility available is at Bordumsa Terminal, which is 18 km from Kherem field.

AA/ONDSF/ASSAM/2025 (A&AA) TUKBAI-2 FIELD

4.8 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) TUKBAI-2 FIELD

The location TUKB -3A (side-track) in Tukbai structure, falling in Sector V-C PEL block, is located at a distance of 400m towards 342^0 from well TUKB-2. Before drilling this location, the well TUKB-3 (TKAC) was drilled to explore equivalent gas sand encountered in the Upper Bhuban Formation in well TUKB-2, but it was found that this gas sand had completely wedged out. Zero Offset and Offset VSP were recorded and evaluated to chase the extension of the equivalent gas sand of TUKB-2. Based on the results, the location TUKB-3(Sidetrack) was released to explore the equivalent gas sand encountered in Upper Bhuban Formation in TUKB-2 with a target depth of 900m (TVD) and planned to be side-tracked from TUKB-3 with a horizontal drift of 380m in 218^0 at 811 m TVD MSL (top of gas sand). Based on the Production Testing and Reservoir study results, TUKB- 3A was declared as a gas well with a maximum flow of 12900m3/day through 6.0 mm bean.

The Tukbai anticline is located in the Sector VC-PEL Block of the Cachar Fold Belt Area. The structure is situated in the north-eastern part of Cachar. It trends in NNE-SSW direction and extends into the North Cachar hills. This anticline is flanked by the Labak syncline in the west and a narrow Diksha syncline in the east. The axes of both the synclines have been faulted. The Tukbai anticline is dissected by a number of NE-SW trending cross faults. The structure is a broad SSW plunging anticline with gentle dips at the plunge part and steep dips at the core of the anticline.

Disang shale is exposed at the core of the anticline. The structure was mapped in detail with the seismic survey. Interpretation of 3D and 2D seismic data in and around the Tukbai area reveals that the structural style is largely controlled by the NNW-SSE trending reverse faults on the west and NNE-SSW trending reverse/normal faults on the east. All the faults mapped in the sub-surface can elegantly be correlated to the surface faults. A number of second-generation SW-NE trending cross faults have also been identified on different time slices.

Cachar area is part of the frontal thrust and fold belt of the Assam-Arakan geosyncline. The basin is influenced by three tectonic movements in E-W, NE-SW, and N-S directions and is represented by trends of the Dauki fault, Naga thrust belt, and Arakan fold belt. The area has a huge sedimentary cover of approximately 10-11 km. This consists of alternating sandstone, siltstone, shale, and claystone beds ranging in age from Eocene to Recent, belonging to the Disang, Barail, Surma, Tipam, and Dupitila groups. These were deposited in this sub-basin under varying environmental conditions, from marine to marginal marine to fluvial.

So far, four wells, TUKB-1/1A, 2, 3/3A & 4 were drilled on this structure.

The well **TUKB-1** was drilled in 2003 to a depth of 3701m (3711m loggers' depth) to probe the hydrocarbon potential of Bhuban, Renji, and partly Jenam Formation. Based on analysis of well data, including electro logs, lab data, etc., a thrust was envisaged in the Renji Formation at 3185m. In the up-thrust section, the well has penetrated 452 m of Bokabil, 803 m of Upper Bhuban, 1105m of Middle Bhuban, 706 m of Lower Bhuban, and 119m of Renji Formation. In the sub thrust section, 465m thickness of Lower Bhuban and 61m thickness of Renji have been encountered. The Jenam Formation is not encountered up to 3700m in this well. A number of sand bodies have developed in this well, and six objects have been identified for testing. Barring objects IV, V, and VI, which could not be tested due to complications leading to well abandonment, three objects were tested. Object: I (3587-3582 m) In Sub thrust Lower Bhuban, Object II (3175-3173 m) In Lower part of Renji Formation, Object III (3104-3100m,3095-3093m) both Up thrusts. However, all these objects were proved to be water bearing with no hydrocarbon show. Due to inordinate delay and complications in fishing of 2 7/8" tubing which fell inside the well leading to abandonment of the well TUKB-1 without testing of Object-IV (3065-3052m), Object-V (2843-2833m, 2830-2828m and 2825-2823m) and Object-VI (2413-2402m), a side-tracked well (TUKB-1A) was drilled through this well and remaining equivalent objects were tested later. As the three objects tested, viz. I, II, and III were proved to be dry, this well was declared as dry and abandoned.

The **TUKB-2** well in the Tukbai structure was drilled with an objective to explore hydrocarbon leads obtained in well TUKB-1 in Up-thrust Middle, Lower Bhuban, and Renji formations. The well was spudded on 29.03.2010 and drilled up to 2387m on 04.07.2010 against the target Depth of 3500m. It penetrated through the Bokabil formation (310m) and has penetrated Upper Bhuban (700m), Middle Bhuban (1140m), and Lower Bhuban (237m+). Target depth could not be achieved due to complications at shallow depth, followed by toppling of the rig, and further drilling of the well has been terminated. So, the hydrocarbon potential of the well could not be ascertained at the expected zones underneath. Considering the above, the well was declared abandoned with the status "Abandoned due to Complication". .

The well **TUKB-3 (TKAC)** is located at a distance of 400m towards 342^0 from well TUKB-2 and was drilled to explore equivalent gas sand encountered in the Upper Bhuban Formation in well TUKB-2, but it was found that this gas sand had completely wedged out. Zero Offset and Offset VSP were recorded and evaluated to chase the extension of the equivalent gas sand of TUKB-2. Therefore, it was sidetracked to TUKB-3A.

The well TUKB-3A was released as an exploratory “B” category location with an objective to explore the equivalent gas sand encountered in Upper Bhuban Formation in TUKB-2 well (at the depth of 854.5 m - 868 m). It was planned to be side-tracked from TUKB-3 with a horizontal drift of 380m in 218^0 at 811 m TVD MSL (top of gas sand). Based on the Production Testing and Reservoir study results, TUKB- 3A was declared as a gas well with a maximum flow of 12900m3/day through 6.0 mm bean.

The well **TUKB-4 (TKAD)** was drilled with an objective to explore the hydrocarbon potential of the Upper Bhuban formation. It was spudded on 26.04.2016 and drilled as a vertical well with a target depth of 1200m. As no zone of interest was found, the target depth was revised to 1755m to encounter sands in the Middle Bhuban Formation. During drilling, the well penetrated through Bokabil and Upper Bhuban and was terminated within the Middle Bhuban formation. Based on the log evaluation of the present well, all the sand layers developed in Bokabil, Upper Bhuban, and Middle Bhuban Formations are interpreted as water bearing. As no prospective zone could be identified from hydrocarbon point of view in all Formations, the well was abandoned without lowering the production casing.

The discovery area, Tukbai-2, is located onland within the Assam-Arakan Fold Belt (AAFB) Basin and has an offered area of 494.31 sq. km. under this DSF Bid Round IV. The area is a single area (**Figure 4-147**) with 1 discovery/field (TUKB-2), and 5 additional wells (+2 S/T). Surrounding wells of TUKB-2 are shown **Figure 4-149**

2D-3D surveyed area in Tukbai block is shown in **Figure 4-148**

The coordinates of the block boundaries are given in **Table 4-80**.

Table 4-80: COORDINATES OF THE BLOCK BOUNDARIES: TUKBAI

	Tukbai Boundary Points		
	Area: 494.31 sq km		
	Point	**Longitude**	**Latitude**
	A	92° 56′ 00.000″ E	24° 59′ 00.000″ N
	B	92° 56′ 00.000″ E	24° 58′ 00.000″ N
	C	93° 02′ 00.000″ E	24° 58′ 00.000″ N
	D	93° 02′ 00.000″ E	24° 57′ 00.000″ N
	E	93° 08′ 00.000″ E	24° 57′ 00.000″ N
	F	93° 08′ 00.000″ E	24° 50′ 00.000″ N
	G	92° 46′ 00.000″ E	24° 50′ 00.000″ N
	H	92° 46′ 00.000″ E	24° 56′ 00.000″ N
	I	92° 53′ 00.000″ E	24° 56′ 00.000″ N
	J	92° 53′ 00.000″ E	24° 59′ 00.000″ N
	A	92° 56′ 00.000″ E	24° 59′ 00.000″ N
SL No.	**Well Name**	**Longitude**	**Latitude**
1	TUKB-2	93° 04′ 57.360″ E	24° 54′ 13.695″ N

Figure 4-147 :.LOCATION MAP SHOWING THE TUKBAI BLOCK BOUNDARY.

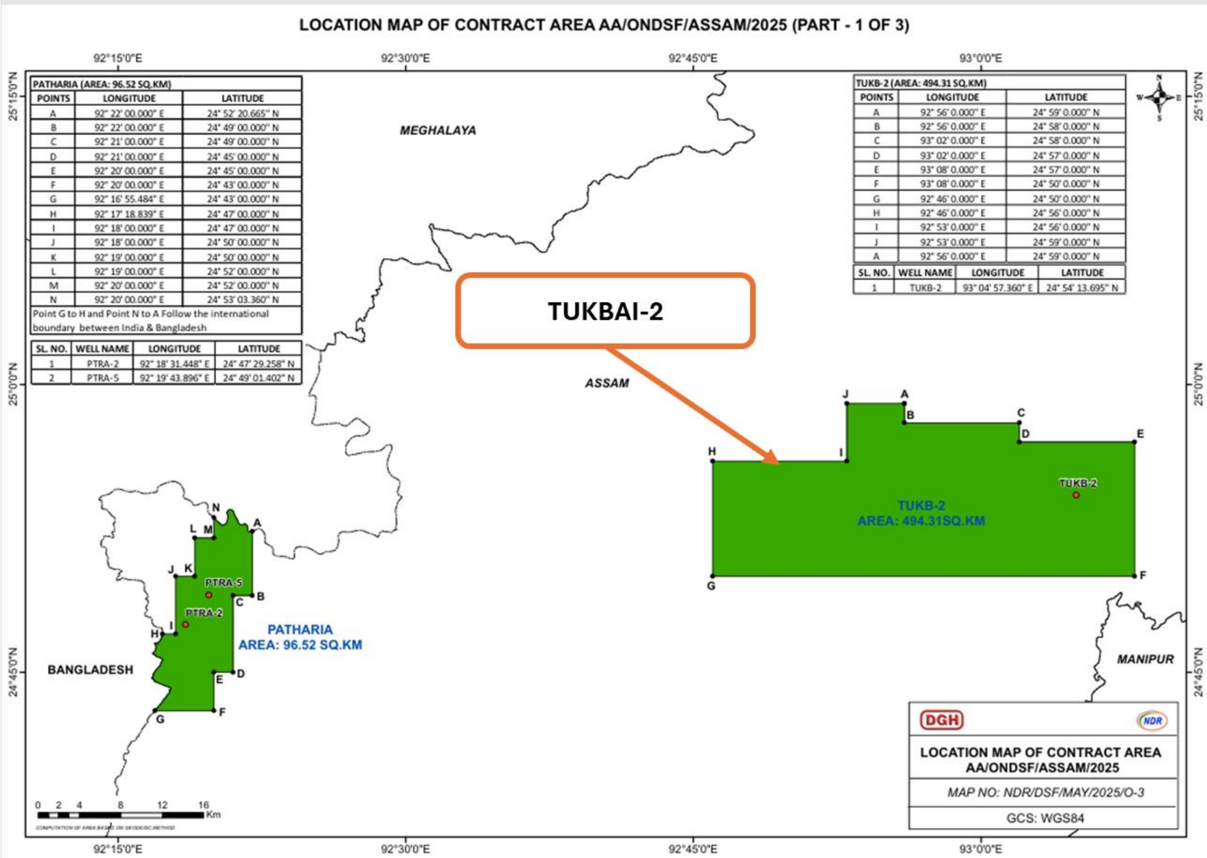


Figure 4-148 : 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: TUKBAI-2-

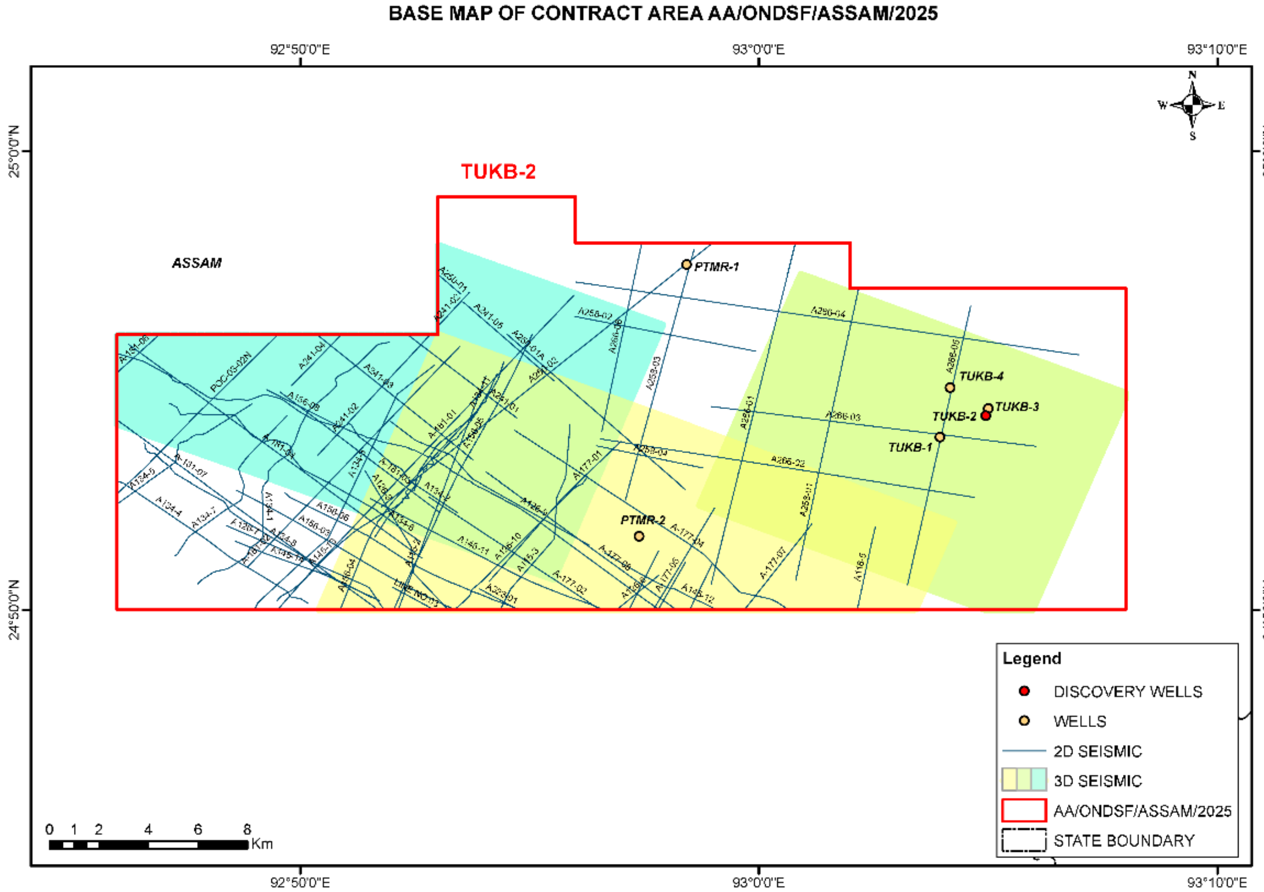
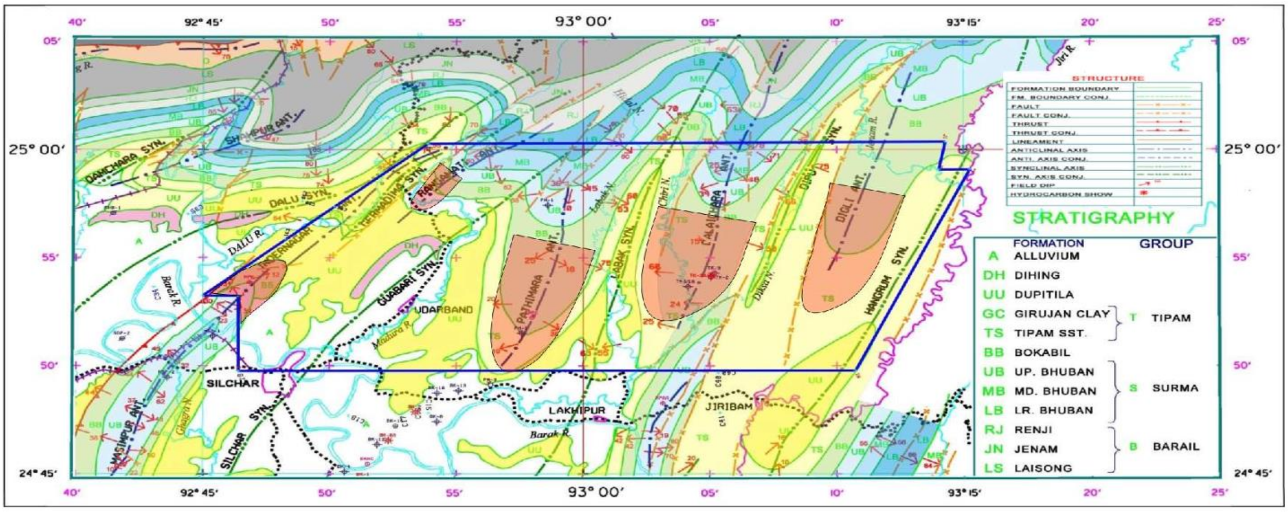


Figure 4-149 :.SURROUNDING OIL AND GAS FIELDS :



4.8.1 Drilling and well completion

Key information of drilled wells have been collated and presented hereunder. The adjoining figures, wherever shown, illustrate the Well Construction Diagram and the Litho-column Information for key wells. Other well statics like kelly bush reference depth, water depth, drilled and logged depth, including well coordinates, are made available in Sections through various cross-references.

Figure 4-150 shows the well construction diagrams of TUKB-2 and TUKB-3A.

Figure 4-151 shows the litho section of TUKB-2

Figure 4-150 :.WELL PROFILE OF TUKB-2 (WITH LITHOLOGY) & TUKB-3A:

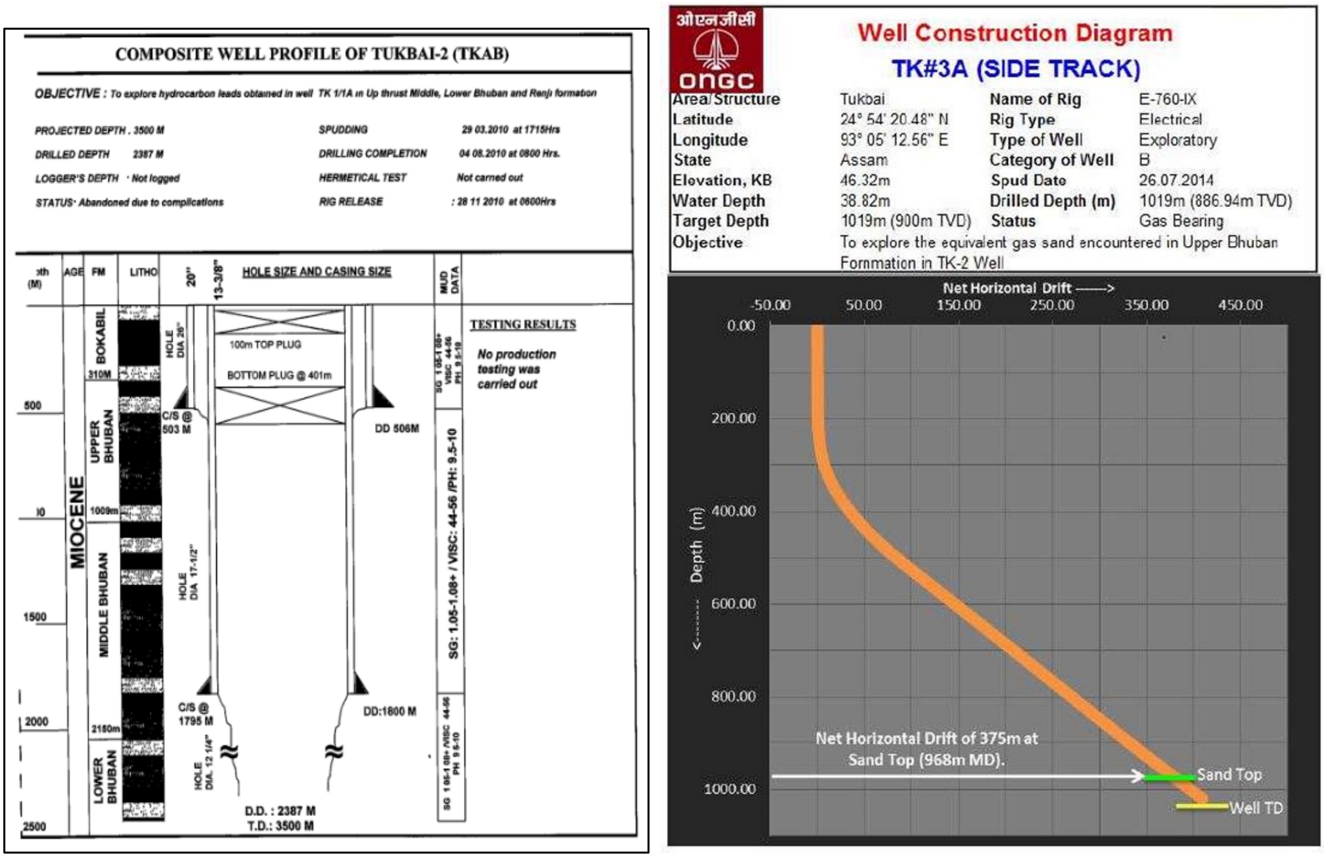
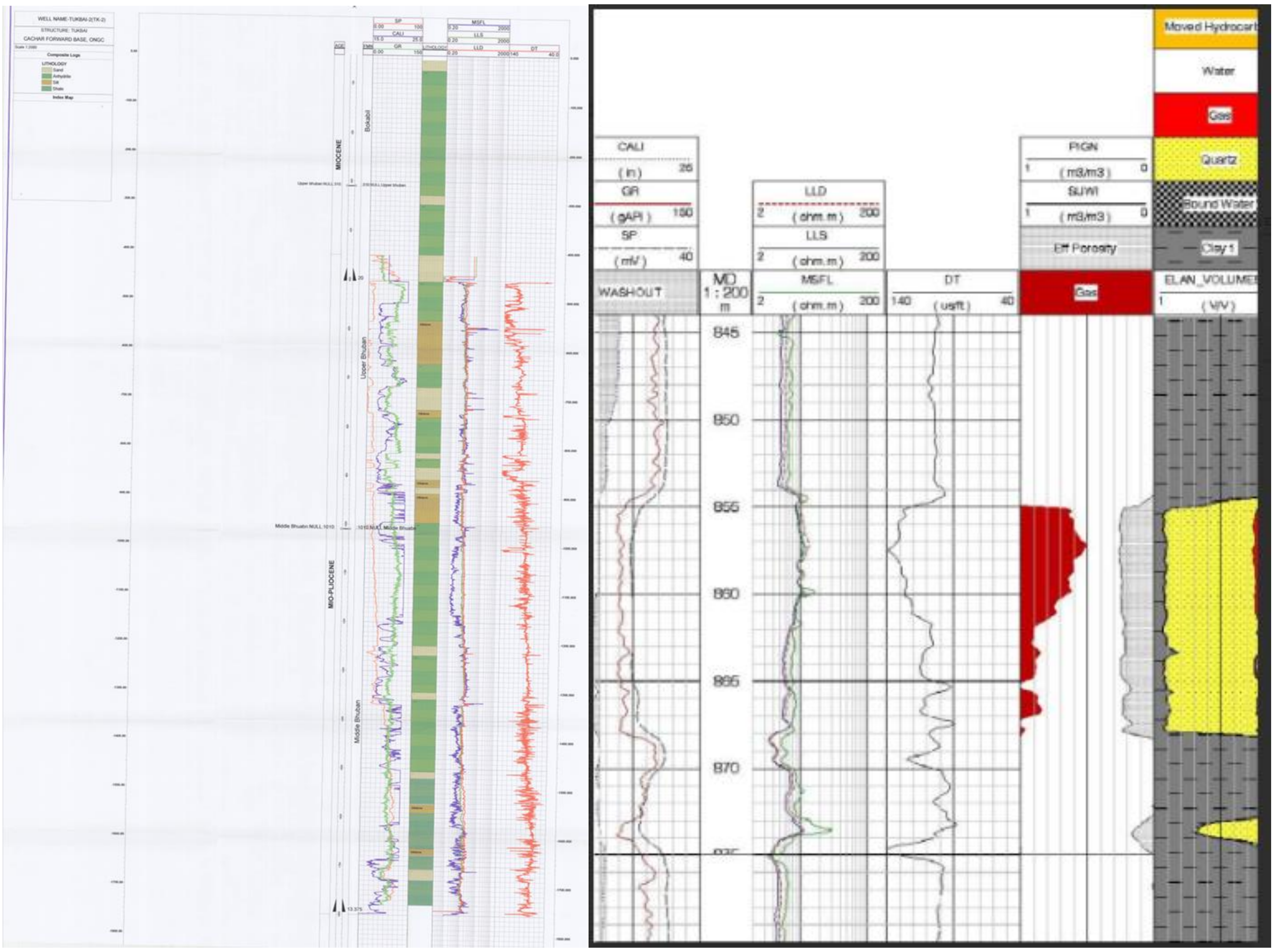


Figure 4-151 :.LITHO-SECTION INFORMATION OF TUKB-2:



4.8.2 Well logging and formation evaluation

The well logs of all discovery wells, along with some key wells in the Contract Area, have been reviewed. The logs recorded in various open-hole sections, along with cased-hole logs and information of conventional and other wireline formation test data, are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) has been checked, and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.8.2.1 Well completion and log evaluation reports availability :

Well	WCR/ FER availability	Spud date	KB	Drilled depth
TUKB-2	Both available	29.03.2010	43.15m	2387 m
TUKB-3A	Both available	26.07.2014	46.32 m	1019 m

4.8.2.2 Well logs acquired (TUKB-2, 3 & 3A) :

Well logs acquired in Tukbai field are listed in **Table 4-81.**
Conventional core details, MDT pressure tests, and samples taken during MDT are given in **Table 4-82, Table 4-83 and Table 4-84.**

Table 4-81: WELL LOGS ACQUIRED IN TUKBAI WELLS

Sl No.	Hole Size	Date of Recording	Logs Recorded	Interval (m)	Remarks
TUKB-2					
	17 ½”	07.07.2010	SP-GR-DLL-MSFL-CAL	1797.5-502.2	**HLS**
			SONIC-GR	1797.5-502.2	
TUKB-3					
	12 ¼”	24.04.2014	DLL-MSFL-GR-SP-CAL, LDL-CNL-GR, BHC-IDT-GR	150-499	
	8 ½”	13.05.2014	PEX-HRLS, DSI, FMI	498-998 494-1006 498.5-1005	
	8 ½”	14.05.2014	MDT	19 pretests, 6 samples	
TUKB-3A					
1			Perforation @ 4 SPF		For cement squeeze job
2	8 ½”	08.08.2014 to 14.08.2014	**LWD logs** GR-CALL-RESISTIVITY-DENSITY-NEUTRON	218-1005	Sidetrack from 223.5m.
3	5 ½"casing	21-Aug-2014	CBL-VDL-CCL-GR @0 PSI.	990-700	
4		21-Aug-2014	CBL-VDL-CCL-GR @700 PSI.	990-800	
5			Perforation @6 SPF		Object-1

Conventional Cores:

No Conventional cores were taken in wells TUKB-2 & 3A . Details of conventional cores taken in TUKB-3 are given below (Table **4-82**):

Table 4-82: CONVENTIONAL CORES IN TUKB-3

Well: Tukbai-3 (TKAC)					
Conventional Cores					
Sl No	**Core No**	**Interval**	**Recovery**	**Gross Lithology**	**Hydrocarbon Shows**
1	CC1	814–820 m	379 cm (63.17%)	Claystone with interbedded Sandstone and minor Coal	NF/NC
2	CC2	843–850.6 m	591.1 cm (77.78%)	Claystone with Sandstone intercalations	NF/NC

Sidewall Cores:

No SWC attempted in TUKB-2, 3 & 3A.

SFT/MDT

MDT was not carried out in TUKB-2 & 3A. Details of MDT recorded in TUKB-3 are as given below (**Table 4-83 and Table 4-84**).

Table 4-83: MDT IN TUKB-3

Pretest / Sample Inspection Sheet TABLE-IV

Field	Tukbai	Tukbai	**Date(s) of Logging**	14-May-14
Well	TKAC		**Logging Interval**	
Toolstring	LEH-EDTC-EDTA-PC-MS_1-SC_2-SC_1-LFA-PO-PS_1-HY_1--BN		**Run**	MDT-LFA-GR
Engineer	Shubhang/Phani		**Witness**	MR Vijay Singh
Mud	KCL PHPA POLYOL		**Client**	ONGC
Rig	E-760-IX		**Files forwarded to Resv Engg.**	Ankit Agarwal

Remarks	CQG used for all pressure measurements							Pretest Codes:				
	Total:	19	G=Good	15		D=Dry	1	L=Lost Seal	3	S=Super-charged	0	Not Attempted

Pretest	File	MD (m)	TVD (m)	Res. Cell Temp (DegF)	Mud Pressure (psi) Before	Mud Pressure (psi) After	Equivalent MP in ppg	Last BUP (psia)	Formation Pressure (psia)	Equivalent FP in ppg	Mob.	Pretest Type	Pretest Rate (cc/min)	Pretest Volume (cc)	Pretest Code	Remarks (Please mention all the details including anomolous events)
Main Pretests																
1	3	648.50	648.50	108.1	1039.0	1039.4	9.4	938.8	938.8	8.5	109.1	Volumetric Drawdown	60,60,60	5,5,5	G	
2	4	650.50	650.50	108.2	1042.6	1042.5	9.4	942.2	942.2	8.5	96.9	Volumetric Drawdown	60,60	10,5	G	
3	5	671.70	671.70	108.3	1076.4	1076.4	9.4	971.7	971.7	8.5	43.0	Volumetric Drawdown	60,60	10,5	G	
4	6	673.70	673.70	108.3	1079.3	1079.3	9.4	974.5	974.5	8.5	133.4	Volumetric Drawdown	60,60,60	10,5,5	G	
5	8	663.00	663.00	109.0	1060.2	1061.5	9.4	959.3	959.3	8.5	64.8	Volumetric Drawdown	60,30,30	10,5,5	G	
6	9	661.80	661.80	109.3	1058.3	1058.4	9.4	1057.8	-	-	-	Volumetric Drawdown	30,60	5,5	L	
7	10	664.00	664.00	109.3	1061.7	1061.7	9.4	1061.6	-	-	-	Volumetric Drawdown	60,30	10,5	L	
8	12	661.60	661.60	108.3	1056.1	1056.0	9.4	1055.8	-	-	-	Volumetric Drawdown	60,30	10,5	L	
9	13	666.50	666.50	108.7	1063.8	1063.6	9.4	964.5	964.5	8.5	47.8	Volumetric Drawdown	60,30	10,5	G	
10	14	898.00	898.00	109.6	1435.2	1435.3	9.4	1305.6	1305.6	8.5	10.7	Volumetric Drawdown	60,30	10,5	G	
11	15	902.00	902.00	116.4	1438.9	1438.7	9.4	1310.9	1310.9	8.5	7.5	Volumetric Drawdown	60,30	10,5	G	
12	16	903.50	903.50	116.0	1440.8	1439.8	9.4	1404.7	-	-	4.9	Volumetric Drawdown	60,30	10,5	D	
13	17	899.20	899.20	116.2	1432.2	1432.4	9.3	1308.1	1308.1	8.5	5.8	Volumetric Drawdown	30,30	5,5	G	
14	19	700.20	700.20	109.4	1108.1	1108.0	9.3	1012.0	1012.0	8.5	88.6	Volumetric Drawdown	60,60	10,5	G	
15	20	694.50	694.50	110.0	1098.3	1098.4	9.3	1004.0	1004.0	8.5	40.2	Volumetric Drawdown	60,60	10,5	G	
16	21	610.50	610.50	110.3	961.2	961.3	9.2	885.1	885.1	8.5	91.7	Volumetric Drawdown	60,60	10,10	G	
17	22	607.50	607.50	108.8	955.9	955.9	9.2	880.8	880.8	8.5	27.7	Volumetric Drawdown	60,60	10,10	G	
18	25	544.70	544.70	104.8	849.6	849.4	9.1	786.5	786.5	8.5	156.5	Volumetric Drawdown	60,60	10,10	G	
19	26	535.50	535.50	105.4	834.3	834.7	9.1	773.4	773.4	8.5	75.4	Volumetric Drawdown	60,60	10,5	G	

Table 4-84: MDT SAMPLES IN TUKB-3

Well: Tukbai-3 (TKAC) MDT Sample Data						
Sl. No.	**Depth (m)**	**Resistivity**	**Temp**	**Sal**	**pH**	**Volume Collected (ml)**
1	698.5	0.444 Ωm	77.5°F	12288	9	450
2	672.5	0.832 Ωm	77.5°F	7605	9	450
3	664	0.414 Ωm	77.5°F	14625	9	450
4	646.5	0.485 Ωm	77.8°F	12870	9	450
5	606.5	0.425 Ωm	78.5°F	13455	9	450
6	548.5	0.500 Ωm	77.8°F	12820	9	450

VSP

VSP was carried out in TUKB-3 only.

4.8.2.3 Well log evaluation and initial test results:

Results of formation evaluation and Initial testing details of zones are given in the table below (**Table 4-85**).

Table 4-85: FORMATION EVALUATION AND INITIAL TESTING DETAILS (TUKB-3A)

Tukbai Formation Evaluation						
Interval (mMDRT/mTVDSS)	**Formation (+ Zone, if specified)**	**Gross(m)**	**Net(m)**	**Phi**	**Sw**	
391-1005 / 341-830, (976-980 mMDRT)	Upper Bhuban	4.0	3.6	0.23	0.81	
	Initial testing results: Not tested. Remarks: Water Bearing					
(972.4-976 mMDRT)	Upper Bhuban	3.6	3.6	0.20	0.59	
(969.8-972 mMDRT)	Upper Bhuban	2.2	2.2	0.21	0.47	
(968-969.2 mMDRT)	Upper Bhuban	1.2	1.2	0.15	0.73	
	Initial testing results: On initial testing, the interval **968-972m** has produced gas at the rate of 9700 m3 /day through 5mm bean (FTHP 57.26 ksc) and 13000 m3 /day through 6mm bean (FTHP52.27 ksc).					

Log motifs of TUKB-2 and TUKB-3A are placed at **Figure 4-152 and Figure 4-153** respectively.

Figure 4-152 :.WELL LOG MOTIF OF TUKB-2 :

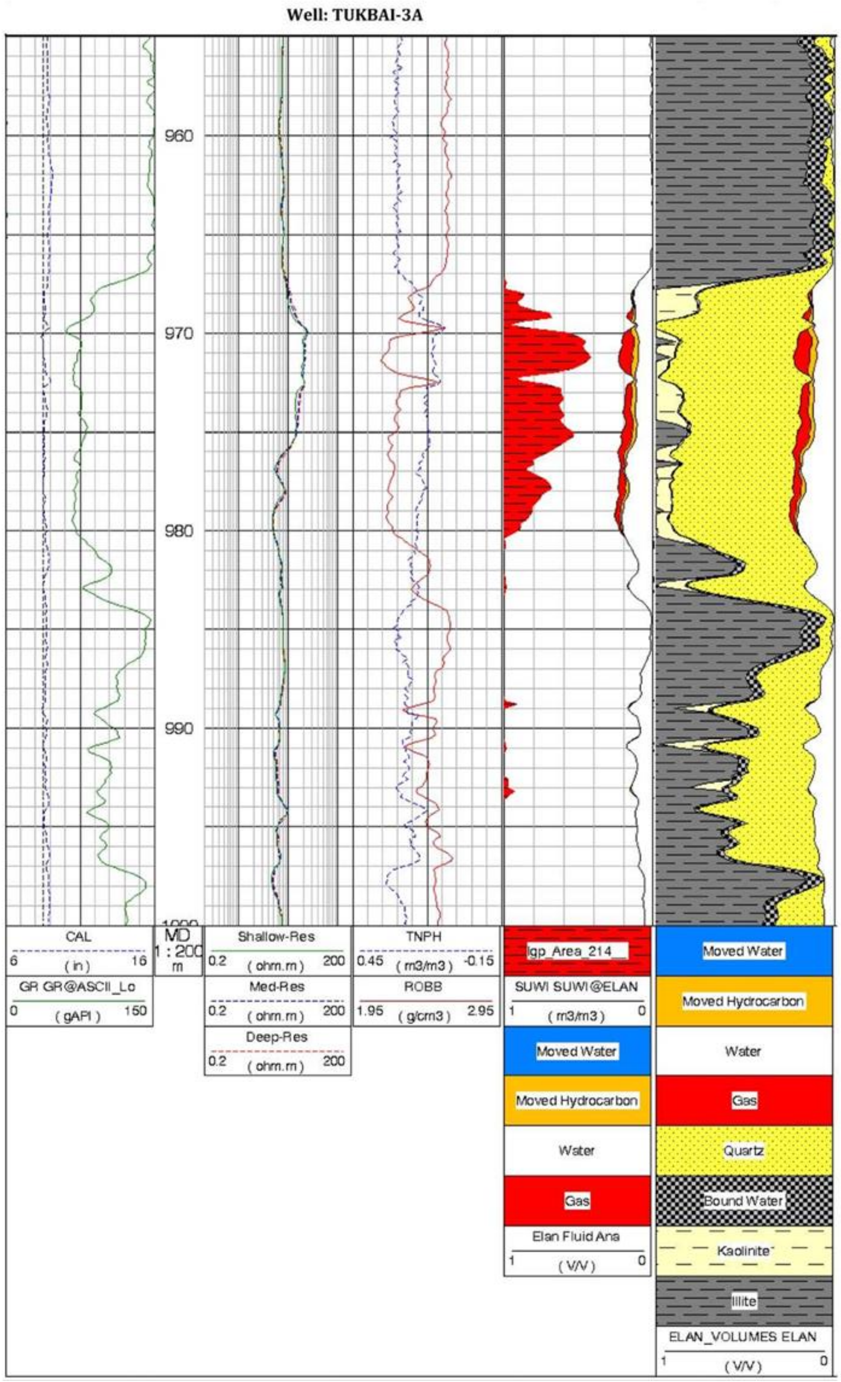
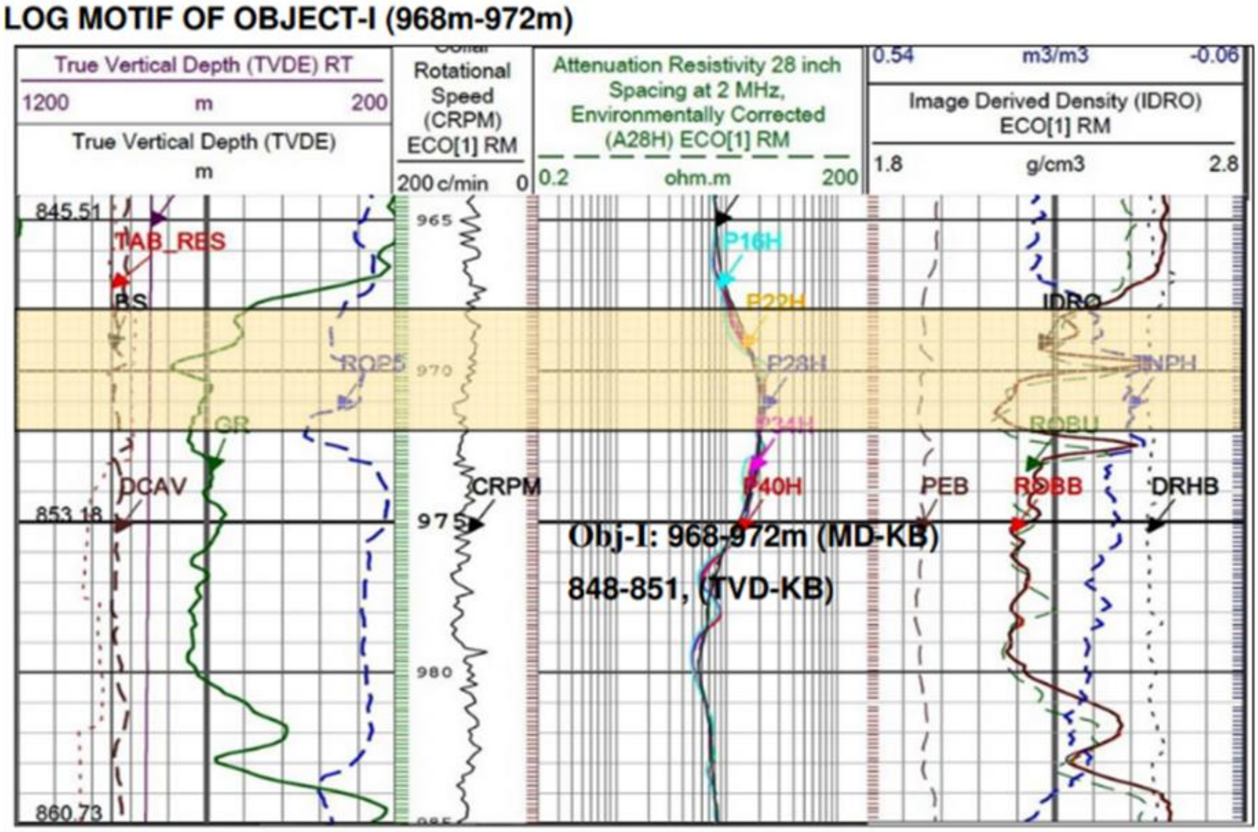


Figure 4-153 :.WELL LOG MOTIF OF TUKB-3A :



4.8.3 Well testing and workover history

The objective sand was encountered at 968m- 982m (847.5 m- 860m TVD) in Upper Bhuban. Object-I in the interval 968 m-972m MD (848 m- 851m TVD) was perforated @ 6spf, and on production testing , the object has produced gas with a flow rate of 12,900scmd through 6mm bean (FTHP/CHP: 64/60Ksc). The well is temporarily abandoned with a provision for re-entry. Testing Details are given below in **Table 4-86.**

Table 4-86: WELL TESTING RESULTS OF TUKB-3A

Well Testing Results of TUKB-3A				
Object	**OBJ - I**			
Interval (m)	**968-972m, Upper Bhuban**			
Perforation type		Conventional, 6spf		
Activation Type		On activation by applying compressor up to 50 ksc, well became active and flowed gas		
Bean (mm)	3mm	4mm	5mm	6mm
Flow Rate- Gas M3/d	4000	6200	9700	13000
Flow rate-water	---	---	---	---
GOR	--	--	--	--
FTHP (KSC)	61.77	67	57.26	52.27
Salinity (gpl)	---		---	---
Density	---		---	---
Status	**FBHP: 63.38 kg/cm2 (6mm bean) at 850m** **SBHP: 68.08 kg/cm2** **Gas Well, temporarily abandoned with provision for Re-entry**			

4.8.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available, are collated and presented under various data genres. However, in the present context, there is no such analysis/study available/accessible at the time of writing this report, except for bottom hole pressure measurements. The bottom hole pressures recorded in the well are as given below in **Table 4-87**.

Table 4-87: STATIC AND FLOWING BOTTOMHOLE PRESSURE IN TUKB-3A

BHS in TUKB-3A						
Date	**Type of Study**	**Bean Size (mm)**	**Qg (m3 /d)**	**THP (Kg/Cm2)**	**BHP at Datum (850m) (Kg/Cm2)**	**BH Grad. (Kg/Cm2 / 10m)**
05-Sep-14	FBHP	6	12,900	52.27	63.38	0.22
06-Sep-14	FBHP	3	4,000	61.77	66.10	0.12
07-Sep-14	SBHP	-	-	64.20	68.08	0.05
08-Sep-14	FBHP	4	6,200	-	65.72	-
09-Sep-14	SBHP	-	-	-	68.08	-
09-Sep-14	FBHP	5	9,700	57.26	63.92	0.11

4.8.5 Geology and Reservoir Description of TUKB-2 Field:

The geology of the area has been comprehensively reviewed using correlations, sections, and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude, and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.8.5.1 Geological correlations, sections, and maps (TUKB-2 Field):

This structure was mapped in detail with the help of both 2D and 3D seismic data. Interpretation of seismic data reveals that the structural style is largely controlled by the NNW-SSE trending reverse faults on the west and NNE-SSW trending reverse/normal faults on the east. All the faults mapped in the sub-surface can elegantly be correlated to the surface faults. A number of second-generation SW-NE trending cross faults have also been identified on different time slices.

Tukbai anticline is a part of the frontal fold belt of the Tripura-Cachar-Chittagong fold system. The structure is situated in the north-eastern part of Cachar. It trends in NNE-SSW direction and extends into the North Cachar hills. This anticline is flanked by the Labak syncline in the west and a narrow Diksha syncline in the east. The axes of both the synclines have been faulted. The Tukbai anticline is dissected by a number of NE-SW trending cross faults. This structure is a broad SSW plunging anticline with gentle dips at the plunge part and steep dips at the core of the anticline.

5.3 m of gas pay has been encountered at the well location at a depth of 801 m.

Based on the analysis of drill cutting samples and characters of electro logs recorded in the wells TUKB-2 and TUKB-3/3A, the following stratigraphic boundaries were envisaged (**Table 4-88**).

Table 4-88: STRATIGRAPHIC SEQUENCES IN TUKB-2 AND TUKB-3A

Formation	Age	Interval (m)	Thickness (m)	Lithology
TUKB-2				
Bokabil	Mio-Pliocene	0- 310	310	Mainly clay/claystone with sandstone alterations
Upper Bhuban	Miocene	310 - 1010	700	Mainly sandstone with clay/claystone alterations .
Middle Bhuban		1010 - 2150	1140	Shale interbedded with thin sandstone .
Lower Bhuban		2150 – 2387 +	237 +	Mainly sandstone with shale alterations
TUKB-3				
Bokabil		0 - 385		Mainly Clay/Claystone and shale layers with intercalations of sand
Upper Bhuban		385 - 896		Thick sandstone separated by thin shale layers
Middle Bhuban		896 - 998+		Mainly Clay/Claystone intercalated with thin shaly sand layers

TUKB-3A				
Bokabil	Mio-Pliocene	Surface - 245	245	Mainly claystone with minor sandstone alternations.
Upper Bhuban	Miocene	245 – 1019	642	Mainly sandstone with a few claystone alternations

The well has been correlated with its nearby wells Tukbai-2 and Tukbai-3. The correlations at various stratigraphic and pay levels are given below (**Table 4-89**):

Table 4-89: STRATIGRAPHIC AND PAY LEVEL CORRELATION OF TUKBAI WELLS

FORMATION	CORRELATION LEVEL	Tukbai-2	Tukbai-3	Tukbai-3A
		KB: 43.15 Vertical MD(MSL)	**KB: 46.32 Vertical MD(MSL)**	**KB: 46.32 Inclined Well MD(MSL)**
Bokabil	Formation Top	Logs not recorded	0 (0)	0 TVD: 0 (0)
	Formation Bottom		385 (339)	387 TVD: 387 (341)
Upper Bhuban	Formation Top	< 503 Logs recorded upto 503m only	385 (339)	391 TVD: 387 (341)
	Objective Sand Top	855 (812)	NOT DEVELOPED	968 TVD: 848 (802)
	Objective Sand Bottom	868 (825)		980 TVD: 857 (811)
	Formation Bottom	1002 (959)	896 (850)	1000+ TVD: 876+ (830+)
Middle Bhuban	Formation Top	1002 (959)	896 (850)	NOT DRILLED
	Formation Bottom	1380+ (1337+)	998+ (951+)	

Note: The depths given in parentheses are TVD-MSL depths.

A) In Tukbai-2, no logs were recorded in Bokabil, and the well was terminated within the upper Bhuban formation; hence, correlation could be carried out at the Upper Bhuban level.

B) In Tukbai-3A, drilling was terminated within the Upper Bhuban formation; hence, the top of Middle Bhuban (Bottom of Upper Bhuban) could not be correlated.

Based on the Log analysis and geological data, the following conclusions were drawn (TUKB-3A):

- Top of the Upper Bhuban is encountered at 391m (341 MSL).
- Porous sand developed within the Upper Bhuban formation in the interval 968-984m and is interpreted as gas bearing with an estimated gas-water contact at 976m.
- All other sands developed in the Upper Bhuban formation are interpreted as water bearing.

Upper Bhuban Formation Interval: 968-972m was identified for testing.

Geological cross-section of Tukbai area and the structural correlation of Tukbai wells are shown in **Figure 4-154 and Figure 4-155.**

Figure 4-154 :.GEOLOGICAL CROSS-SECTION OF THE TUKBAI AREA:

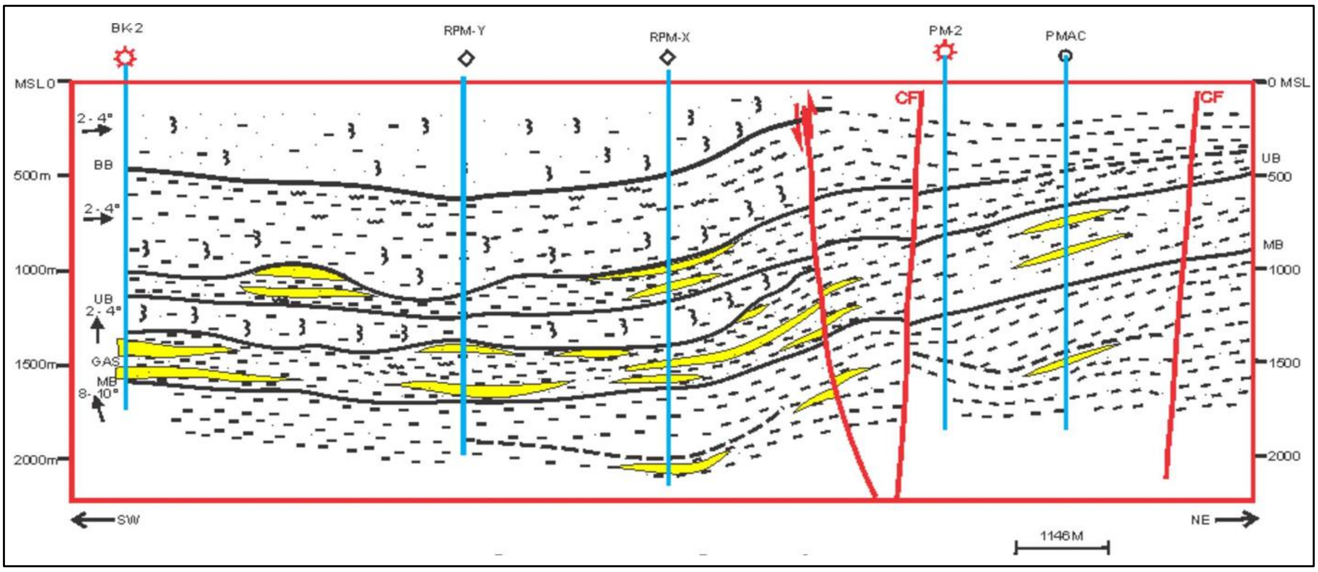
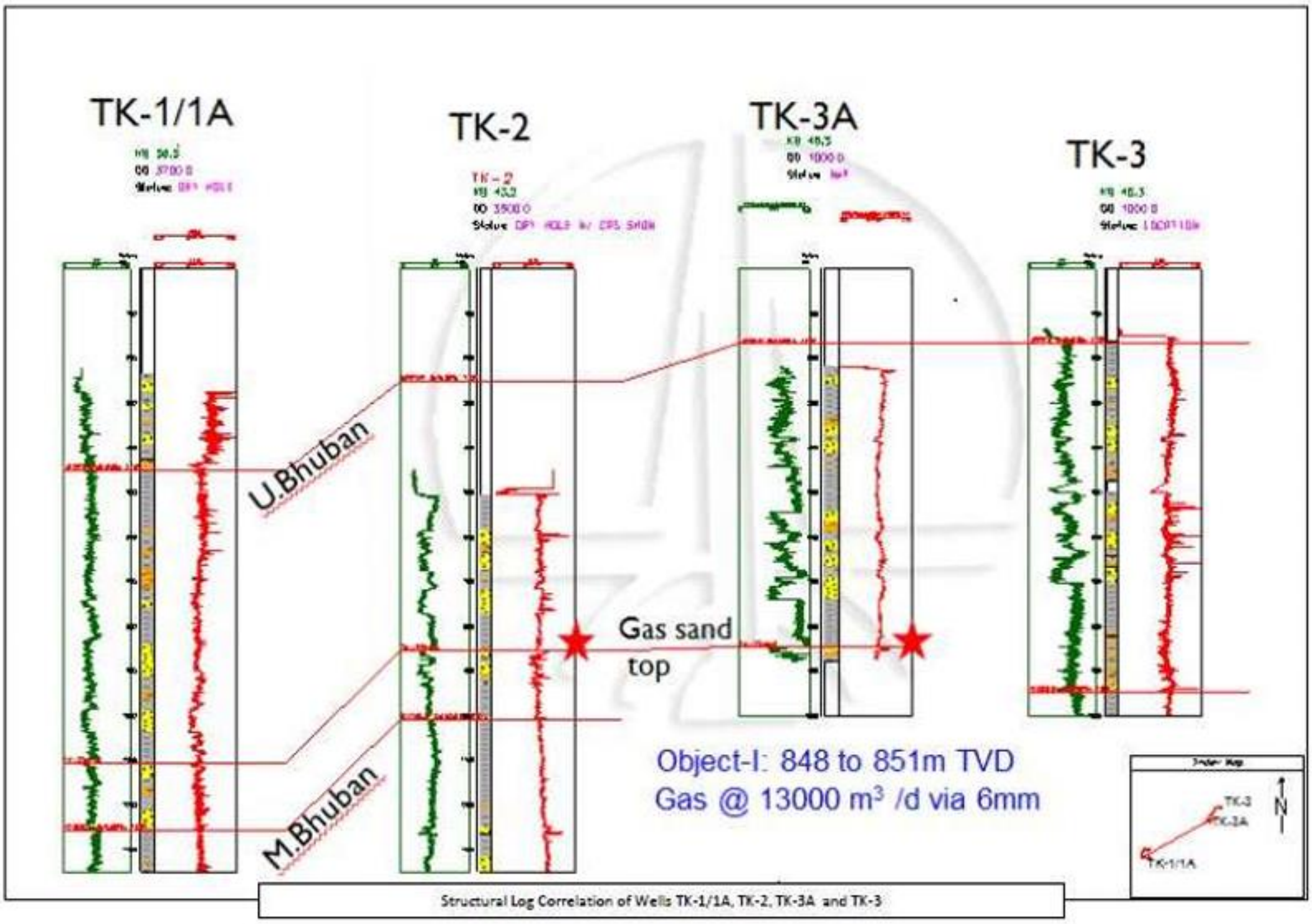


Figure 4-155 :.STRUCTURAL CORRELATION OF TUKBAI WELLS :



Sesmic crossections of Tukbai wells are shown in

Figure 4-156 **and Figure 4-157**. Time structure and Net sand/Pay maps of Tukbai field are shown in **Figure 4-158 and Figure 4-159.**

Figure 4-156 :.SEISMIC SECTIONS ALONG THE TUKBAI WELLS:

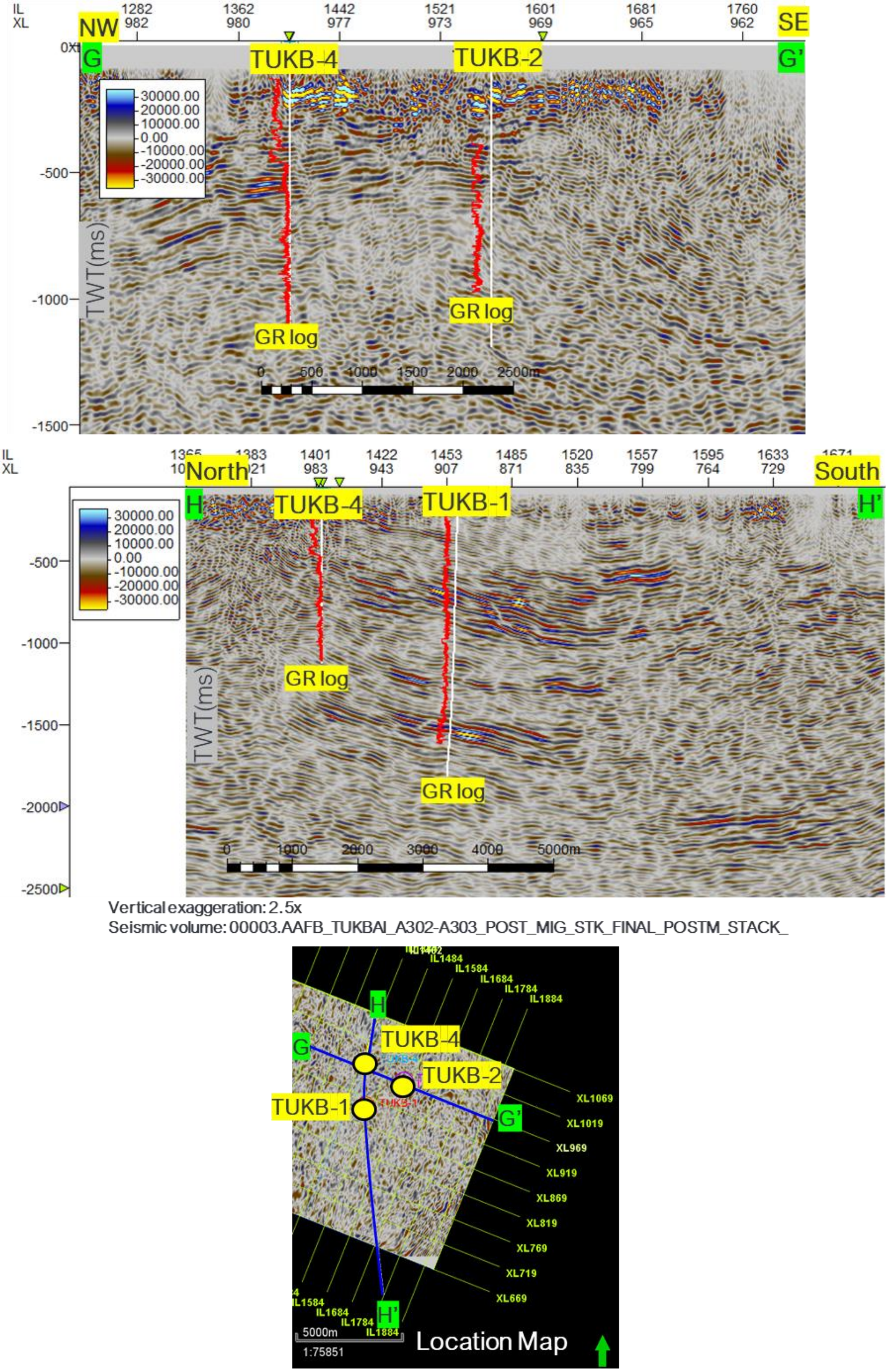
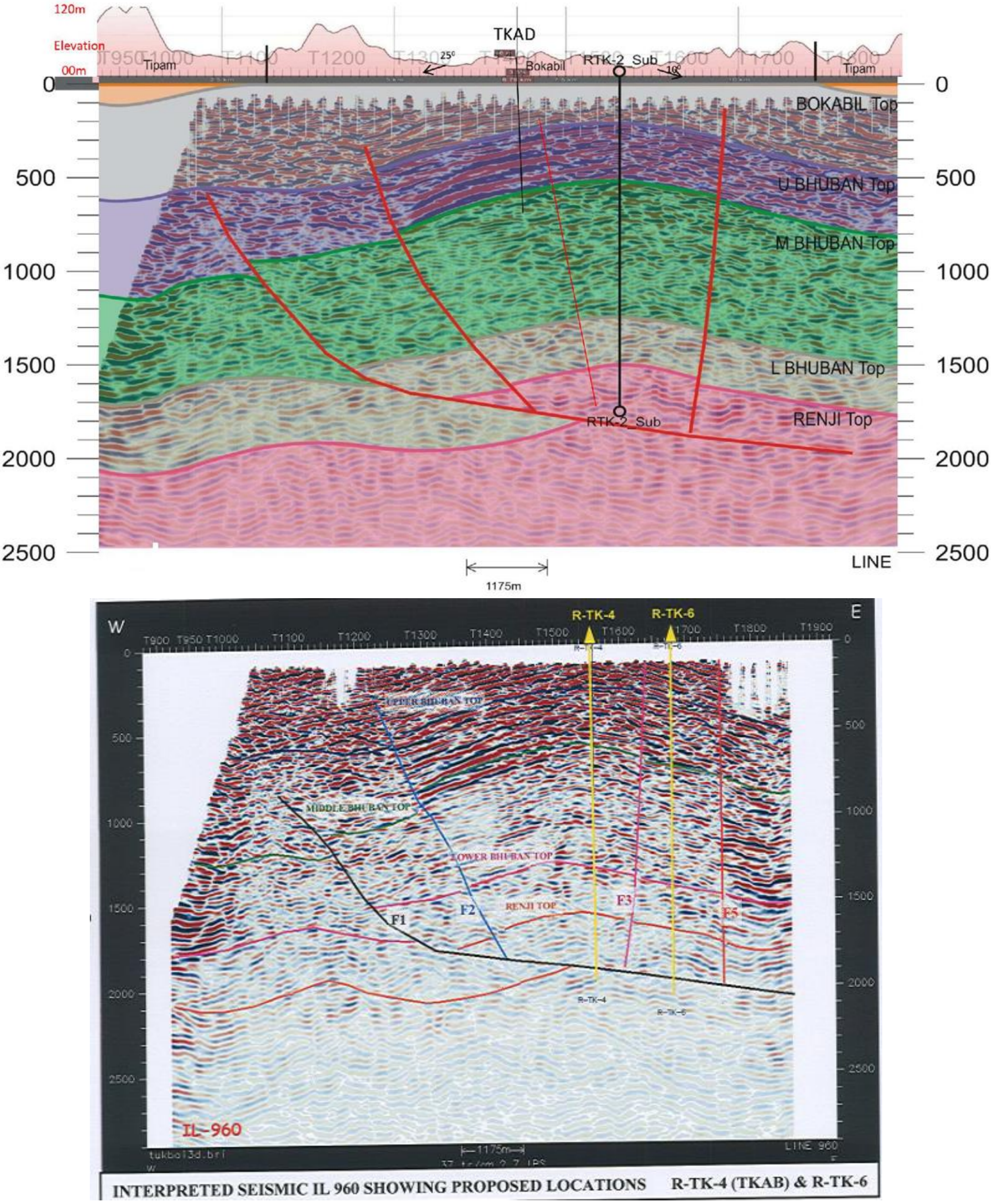


Figure 4-157 :. SEISMIC SECTIONS ALONG THE TUKBAI WELLS:



3D seismic data of series A302 and A303, acquired in 2007-08, were interpreted thoroughly to map the Tukbai Structure. Lithostratigraphic correlation between TUKB-2 and TUKB-3 primarily indicated that the gas sand in Upper Bhuban Formation in the interval 854.5-868m in well TUKB-2 has been shaled out in well TUKB-3. To target the above gas sand, well TUKB-3 was planned to deviate along 218 deg. with a net drift of 409.10m at target depth of 1019m. Two gas sands were expected at TVD 630m and 868m from the electro log correlation.

Figure 4-158 :.TIME STRUCTURE MAP OF UPPER BHUBAN IN TUKBAI AREA:

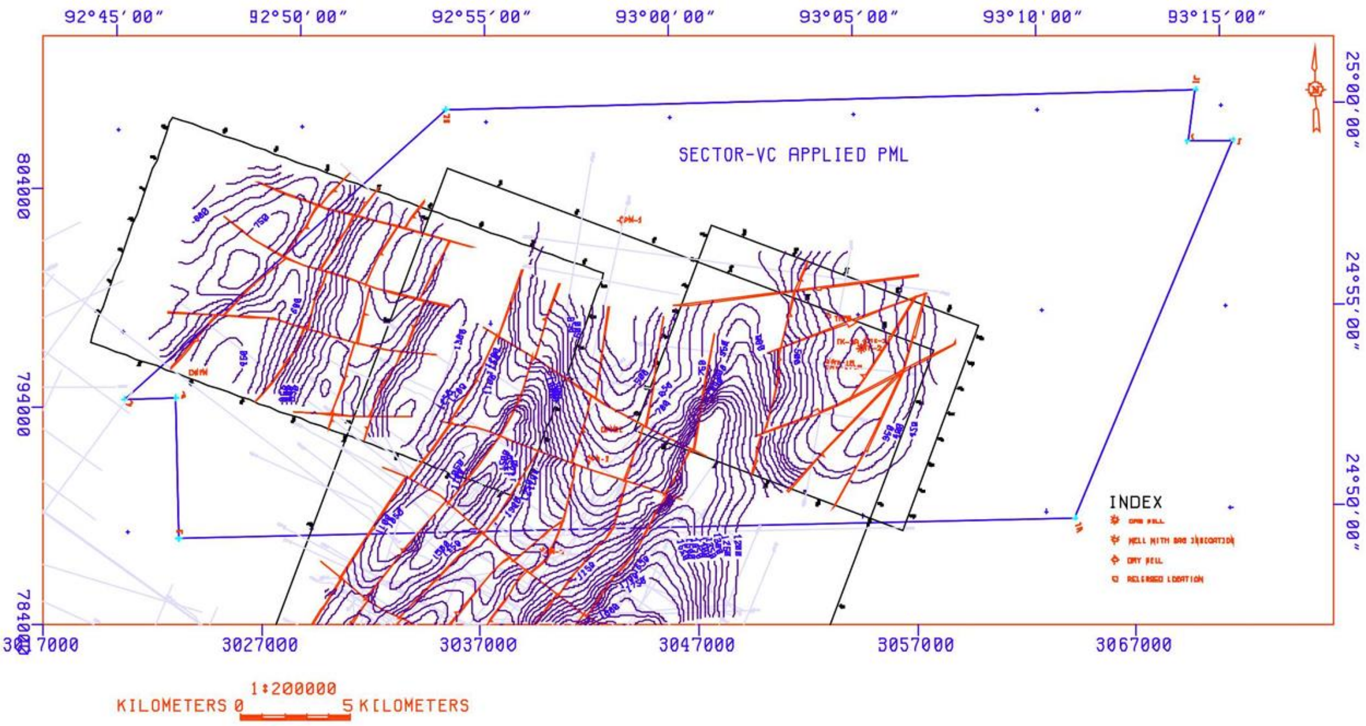
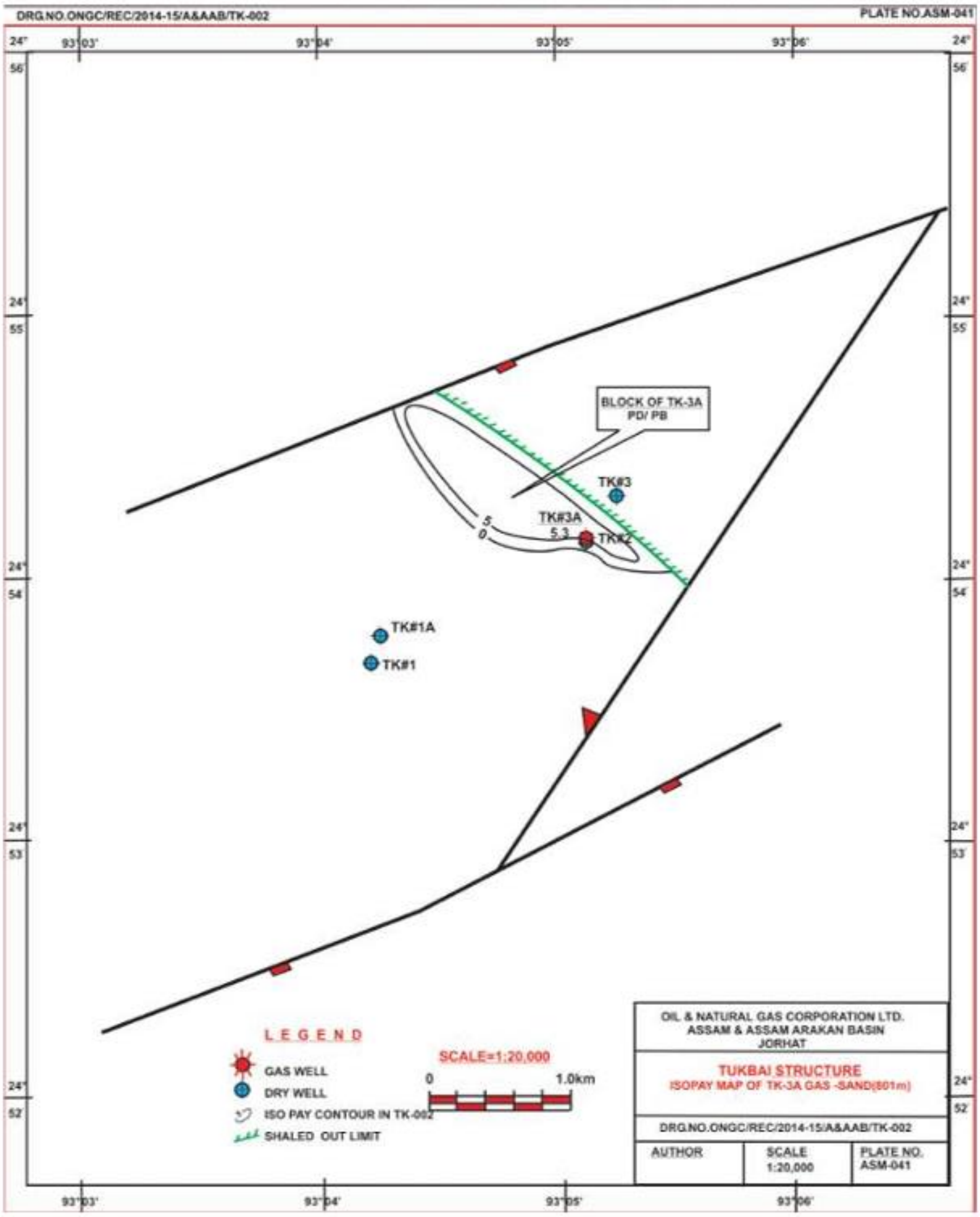


Figure 4-159 :.NET SAND/ PAY MAP OF UPPER BHUBAN IN TUKBAI AREA:



4.8.5.2 Reservoir parameters and hydrocarbon estimates TUKBAI Field:

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

Average reservoir properties and petrophysical parameters and in-place for Tukbai are given in **Table 4-90, Table 4-91 and Table 4-92.**

Table 4-90: AVERAGE RESERVOIR PARAMETERS WITH GLOBAL CUT-OFF: PHIMIN >=3%, SWMAX<=90%

Formation: Bhuban											
			Net Reservoir Parameters				Net Pay Parameters				
Top MD (m)	Bottom MD (m)	Gross Thick ness (m)	Thick ness (m)	Poro sity (m3/ m3)	Clay Vol Fraction (m3/m3)	Wtr Satn	Thick ness (m)	Poro sity (m3/ m3)	Clay Vol Fraction (m3/m3)	Wtr Satn	Remarks
968.00	**969.20**	1.20	1.20	0.15	0.26	0.73	1.20	0.15	0.26	0.73	Shaly H/C
969.80	**972.00**	2.20	2.20	0.21	0.09	0.47	2.20	0.21	0.09	0.47	H/C
972.40	**976.00**	3.60	3.60	0.20	0.14	0.59	3.60	0.20	0.14	0.59	H/C
976.00	**980.00**	4.00	4.0	0.23	0.09	0.81	3.60	0.23	0.09	0.81	Water

Table 4-91: PETROPHYSICAL PARAMETERS TUKBAI FIELD:

Reservoir	**Upper Bhuban**	**Upper Bhuban**	**Upper Bhuban**	**Upper Bhuban**
Interval, m	**(976-980)**	**(972-976)**	**(970-972)**	**(968-969)**
Area: sq.km	0.7854	2.35	2.35	2.35
Thickness, m	3.6	3.6	2.2	1.2
Porosity:	0.23	0.20	0.21	0.15
Hydrocarbon saturation:	0.19	0.41	0.53	0.27
Formation volume factor:	0.004	0.004	0.004	0.004
Gas In Place, MMm3		173	144	29
Remarks:	Water Bearing	H/c	H/c flowed gas	

Table 4-92: HYDROCARBON IN-PLACE (2P) TUKBAI FIELD

Field	O+OEG MMTOE
TUKBAI	**0.17**

Erstwhile Operator-reported estimates on record:

The Tukbai Field has a reported gas estimate of **0.03 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the currently reported estimates.

4.8.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to the Tukbai field is **Banaskandi GCS (28 km)**

AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA-2 BLOCK

4.9 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA BLOCK

The Patharia structure geographically falls in both Indian and Bangladesh territories. It is the westernmost structure developed in the Karimganj district of Assam on the Indian side, and bounded in the west and southwest by the Indo-Bangladesh border. Geologically, the structure forms a part of the frontal folded part of the Assam Arakan belt. It is bounded in the west by the Juri syncline of Bangladesh and in the east by the Nilambazar syncline. The Patharia structure is a tightly folded, doubly plunging, asymmetrical anticline trending NNE-SSW from Karimganj in the north to Dashgram in the south. The structure runs with a sinuous axial trend over a length of 50 km with an average outcrop width of 9 km through Cachar, Tripura, and Bangladesh. Only the northern plunge area, a part of the eastern limb, and the southern plunge area fall in the Indian territory. The rest of the structure is in Bangladesh. Major thrust faults are recognized in the western limb and close to the central part. A prominent fault with downthrow towards the east is seen in the eastern flank.

The Patharia area is located onland within the Assam-Arakan Fold Belt (AAFB) Basin and covers an area of 96.52 Sq. Km under this DSF Bid Round IV. The area is a single area with 2 discoveries/fields (PTRA-2 & PTRA-5) and 2 additional wells. The coordinates of the block boundaries are given in **Table 4-93**. Location and Seismic coverage in this block is shown in (**Figure 4-160**) and **Figure 4-161.**

Table 4-93: COORDINATES OF THE BLOCK BOUNDARIES: PATHARIA

	Patharia Boundary Points		
	Area: 96.52 sq km		
	Point	**Longitude**	**Latitude**
	A	92° 22′ 00.000″ E	24° 52′ 20.665″ N
	B	92° 22′ 00.000″ E	24° 49′ 00.000″ N
	C	92° 21′ 00.000″ E	24° 49′ 00.000″ N
	D	92° 21′ 00.000″ E	24° 45′ 00.000″ N
	E	92° 20′ 00.000″ E	24° 45′ 00.000″ N
	F	92° 20′ 00.000″ E	24° 43′ 00.000″ N
	G	92° 16′ 55.484″ E	24° 43′ 00.000″ N
	H	92° 17′ 18.839″ E	24° 47′ 00.000″ N
	I	92° 18′ 00.000″ E	24° 47′ 00.000″ N
	J	92° 18′ 00.000″ E	24° 50′ 00.000″ N
	K	92° 19′ 00.000″ E	24° 50′ 00.000″ N
	L	92° 19′ 00.000″ E	24° 52′ 00.000″ N
	M	92° 20′ 00.000″ E	24° 52′ 00.000″ N
	N	92° 20′ 00.000″ E	24° 53′ 03.360″ N
Note: The segments G→H and N→A follow the international boundary between India & Bangladesh.			
SL. No.	**Well Name**	**Longitude**	**Latitude**
1	PTRA-2	92° 18′ 31.448″ E	24° 47′ 29.258″ N
2	PTRA-5	92° 19′ 43.896″ E	24° 49′ 01.402″ N

Figure 4-160 :.LOCATION MAP SHOWING THE PATHARIA BLOCK BOUNDARY.

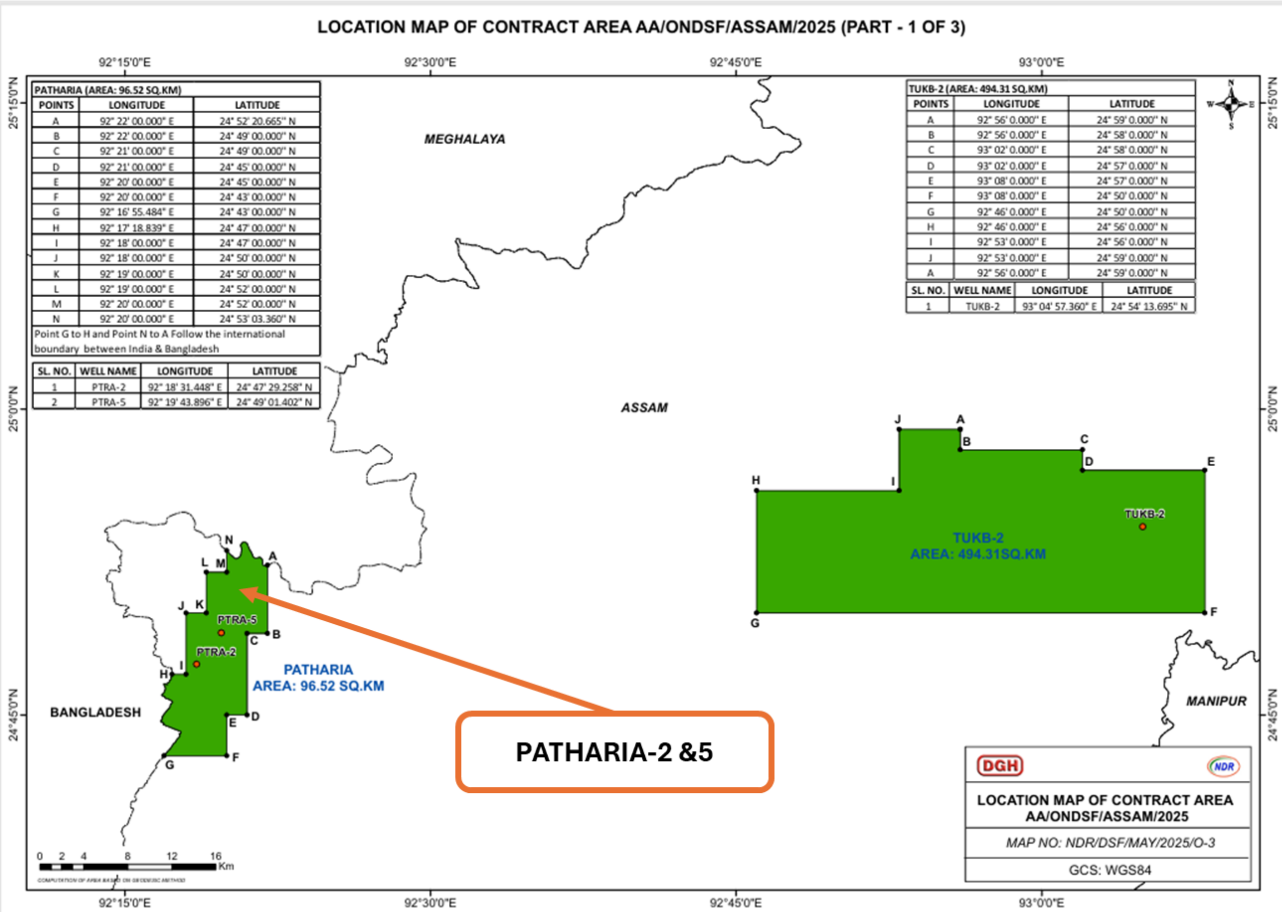
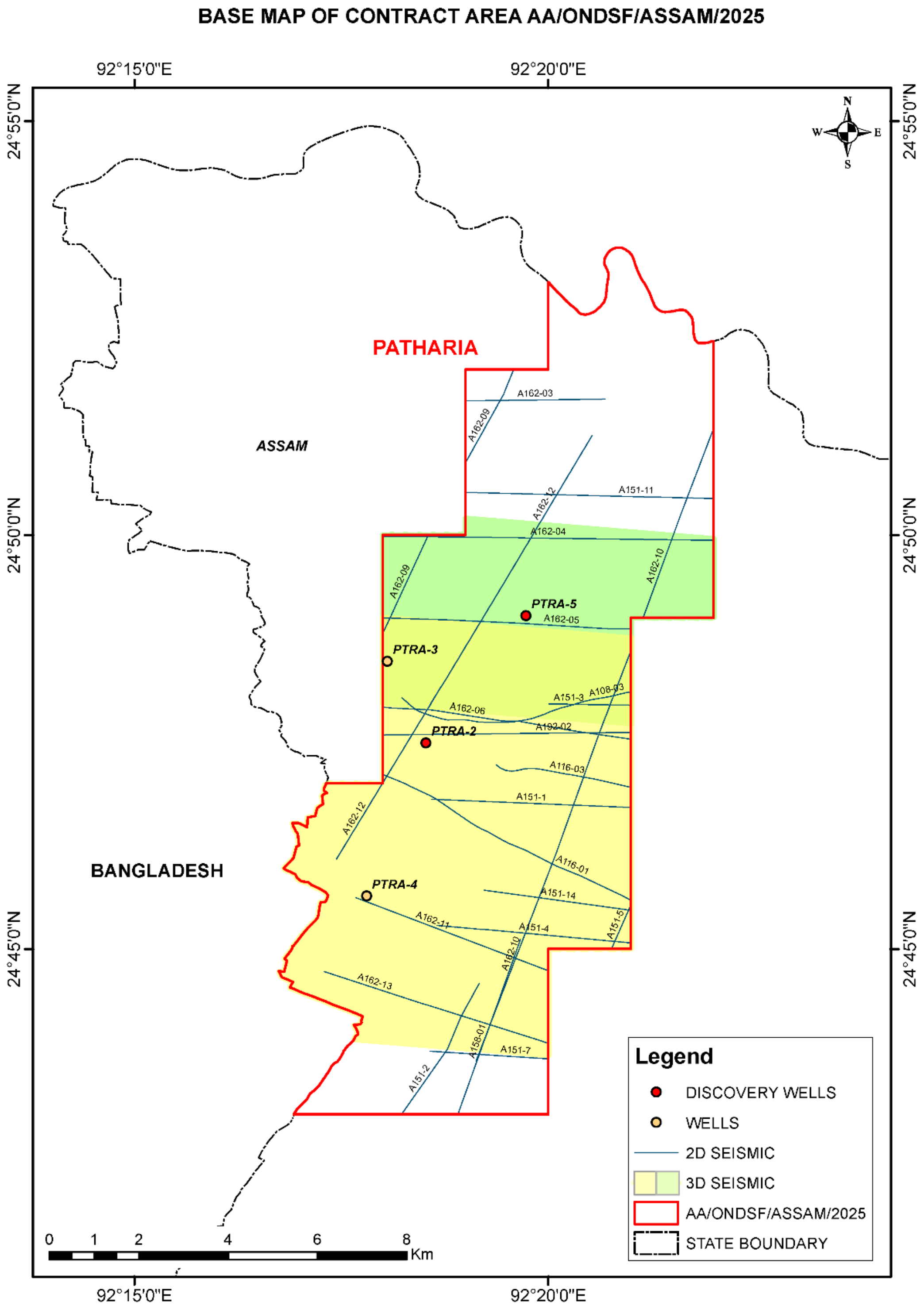


Figure 4-161 : 2D-3D SEISMIC DATA COVERAGE MAP OF AA/ONDSF/ASSAM/2025 CONTRACT AREA: PATHARIA-



AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA-2 FIELD

4.10 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA-2 FIELD

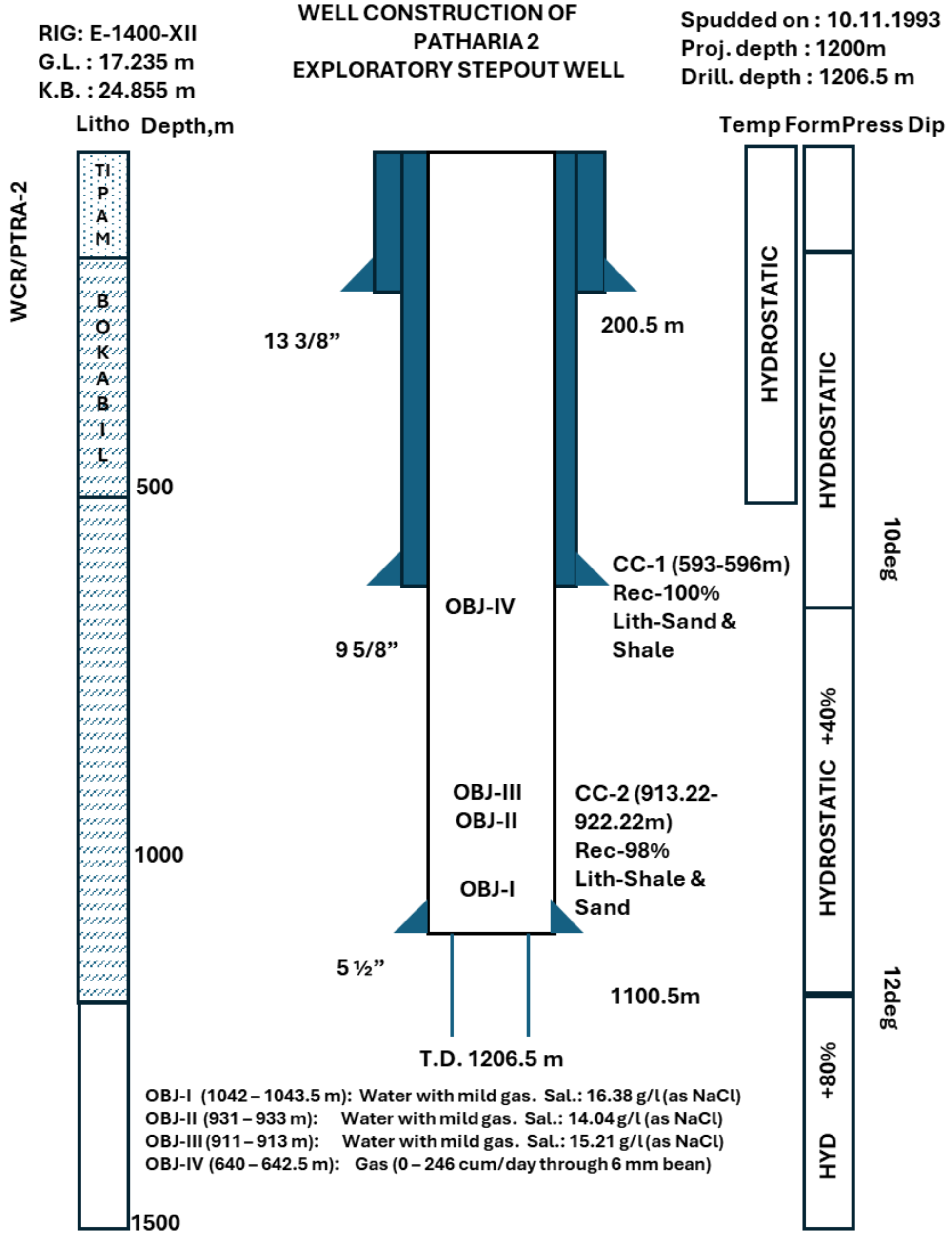
The well Patharia-2 was drilled in 1993-1994 with an objective to test the Bokabil sands. It is located on the eastern flank of the northern plunge of the Patharia anticline, just 5 metres NNE of Patharia well-1. During the drilling of Patharia-1, the presence of gaseous hydrocarbons was noticed in the drilled interval of 590-1149m. The interesting zone could not be tested since these are behind two casings. Hence Patharia-2 was proposed to test the Bokabil sands.

4.10.1 Drilling and well completion

Key information of drilled wells have been collated and presented hereunder. The adjoining figures wherever shown illustrate the Well Construction Diagram and the Litho-column Information for key wells. Other well statics like kelly bush reference depth, water depth, drilled and logged depth, including well coordinates are made available in Sections through various cross-references.

Well diagram for PTRA-2 is shown in **Figure 4-162.**

Figure 4-162 :.WELL PROFILE OF PTRA-2:

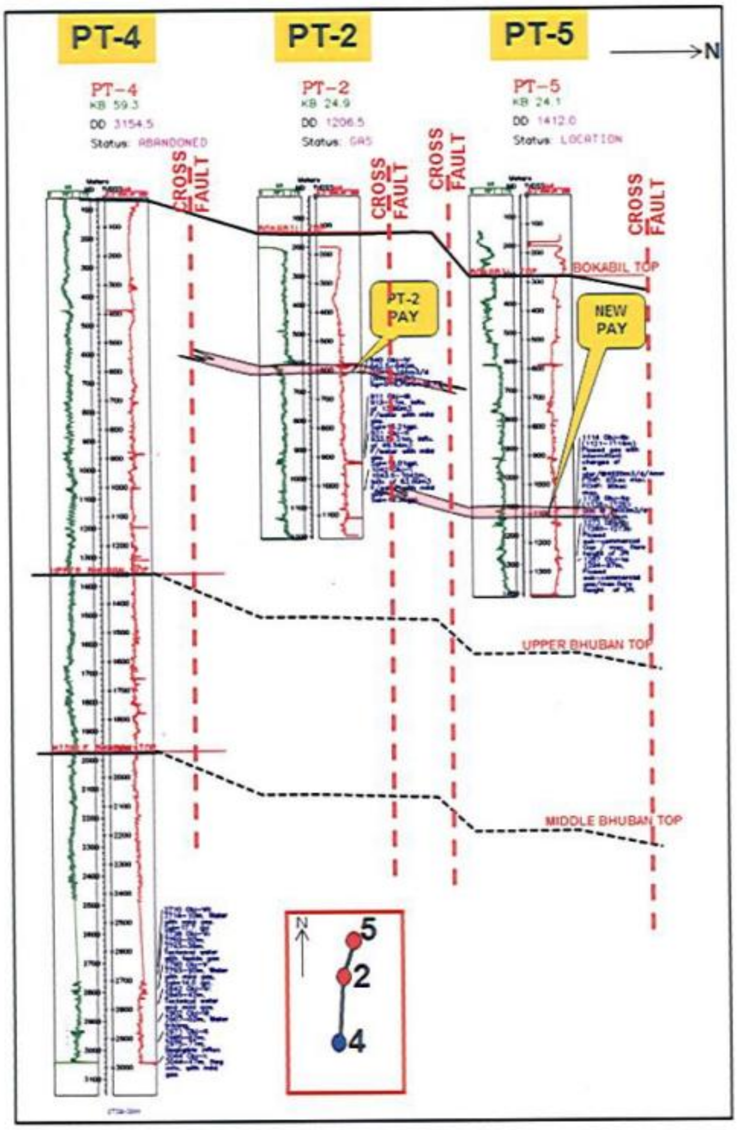


LITHO-SECTION INFORMATION OF PTRA-2 :

The following stratigraphic boundaries are envisaged, based on the lithological character of cutting/core samples and interpretation of wireline logs recorded in well PTRA-2. Electro Log Correlation of Well Patharia-4, Patharia-2, and Patharia-5 is given in **Figure 4-163.**

Group	Formation	Age	Interval (m)	Thickness (m)	Lithology
Tipam	Tipam Sandstone	Mio-Pliocene	Surface - 948	948	Dominantly sandstone with subordinate clay and claystone
Surma	Bokabil	Miocene	948 - 2173,5+	1225.5+	Mainly claystone and shale with thin interbedded siltstone and sandstone

Figure 4-163 :.ELECTRO LOG CORRELATION OF WELL PATHARIA-4, PATHARIA-2, AND PATHARIA-5:



4.10.2 Well logging and formation evaluation

The well logs of all discovery wells along with some key wells in the Contract Area have been reviewed. The logs recorded in various open-hole sections, along with cased-hole logs and information of conventional and other wireline formation test data are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Reports (FER) have been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.10.2.1 Well completion and log evaluation reports availability (Patharia-2) :

WCR/ FER availability	Spud date	KB	Drilled depth
Both available	10.11.1993	24.9 m	1206.5 m

4.10.2.2 Well logs acquired (PTRA-2) :

Log suites recorded in Patharia-2 are listed in **Table 4-94.**

Table 4-94: LOGS AQUIRED IN PATHARIA-2

DATE	Drill hole size(inch)	LOGS RECORDED	INT. LOGGED		DRILLED DEPTH	LOGGER DEPTH	Temp DegC
			From	To			
28.12.93	12 ¼	RUN-1					
		1.DLL-MSFL-SP-GR	611.9	200	612M.	612.7M.	44.4
		2.LDL-CNL-GR	612.0	200			
		3.BHC-SONIC	610.5	200			
27.1.94	8 ½	RUN-2					
		1.DLL-MSFL-SP-GR	1197.0	600	1200M.	1206.5 M.	61.3
		2.LDL-CNL-GR	1205.0	600			
		3.BHC-SONIC	1204.0	600			
28.01.94		CST RUN-1 (Attempted 21, Recovered 18					

4.10.2.3 Well log evaluation and initial test results (PTRA-2):

Petrophysical properties and Initial testing of Patharia-2 are given in **Table 4-95**. Details of the core data acquired in this well is given in the following paragraph below, and a log motif of PTRA-2 is shown in **Figure 4-164.**

Table 4-95: PETROPHYSICAL PROPERTIES AND INITIAL TESTING OF PATHARIA-2

Interval (mMDRT/mTVDSS)	Formation (+ Zone, if specified)	Gross(m)	Net(m)	Phi	Sw
480-1200 / 455.15-1175.15	Bokabil_Miocene(640-642.5 mMDRT)	5.0	3.5	0.19	0.49
Initial testing results: Tested interval 640-642.5m flowed gas @ 10,246m3/d gas through 3mm bean. FTHP: 10-12KSC					

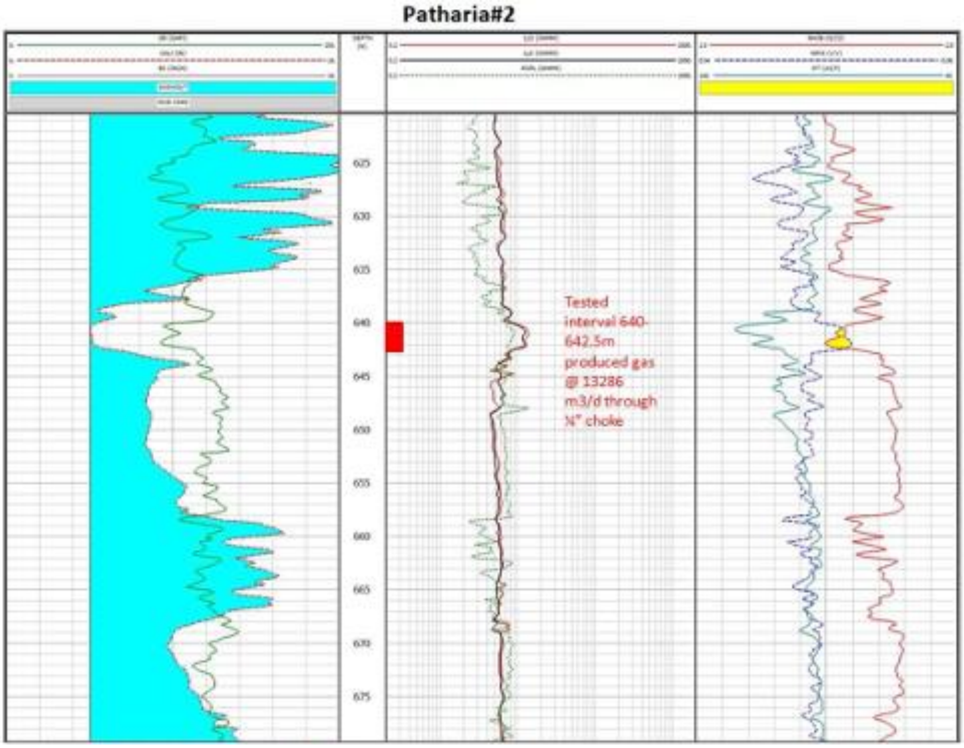
Core Data:

Two conventional cores were cut in intervals 590.0-596.00 (Rec 100%) and 913.22-922.22 (Rec 98%). A total of 21 side wall cores were shot and recovered in the interval of 614-1141m.

Conventional Core Data:

Core	Interval (m)	Recovery (%)	Formation	Lithology	Dip (^{0})
CC-1	590 – 596	100	Bokabil	Interbedded Sandstone and shale	5 - 12
CC-2	913.22 – 922.22	98	Bokabil	Shale with minor Sandstone	10 - 12

Figure 4-164 :.WELL LOG MOTIF OF PTRA-2 :



4.10.3 Well testing and workover history

The following four objects were tested in Patharia-2.
Object I (1042-1043.5m),
Object II (931-933.5m) and
Object-III (911.0-913.0m) produced water with feeble flow of gas.
Object IV (640-642.5m) flowed gas @ 10,246m3/d gas through 6 mm bean. FTHP: 10- 12 KSC (142.23psi).

The details of the well testing of all the Patharia wells are given in **Table 4-96.**

Table 4-96: DETAILS OF WELL PRODUCTION TESTING IN PATHARIA WELLS

Well	Obj. No.	Interval (m)	Formation	Testing Results
	In Bokabil Formation, a few gas bearing sands in the interval 479-481m, 483-486m, 613-620 m, 639-642m, 913-919m, 1071-1075 m, and 1138-1142m were identified, but could not be tested. 3 Objects in Upper Bhuban were tested by CHDST in 9⅝" casing. 5½" casing was not lowered due to lack of interesting zone below 9⅝" casing shoe at(2487.25m).			
PTRA-1	I	2035-2032	U. Bhuban	Influx of 5.7 m3 of mud/ filtrate. Maximum sal -3.46 gpl as NaCl. Reservoir pressure 345 Kg/Cm2
	II	1995-1989	U. Bhuban	Surface flow of gas with influx of 2.4 m3 of formation water. Maximum sal 8.19 gpl. Reservoir pressure 326 Kg/Cm2
	III	1940-1936	U. Bhuban	Influx of 5 m3 of formation water. Maximum sal. 14.63 gpl. Reservoir pressure 309 Kg/Cm2
PTRA-2	I	1042.0-1043.5	Bokabil	Yielded 63.60 m3 of water with mild gas. Salinity : 16.38 gpl (as NaCl). STHP : 55 Kg/ cm2, SCHP : 65 Kg/ cm2
	II	931.0-933.5	Bokabil	Yielded 49.54 m3 of water with mild gas. Salinity : 14.04 gpl (as NaCl). FTHP : 10 Kg/ cm2, SCHP : 40 Kg/ cm2
	III	911.0-913.0	Bokabil	Yielded 13.90 m3 of water with mild gas. Salinity : 15.21 gpl (as Nacl). STHP : 55 Kg/ cm2, SCHP : 62 Kg/ cm2
	IV	640.0-642.0	Bokabil	Produced **11761 m3/ day** of gas through 20/64" bean, FTHP: 56.892 psi. wtr traces Produced **10246 m3/ day** of gas through 16/64" bean, FTHP: 142.23 psi. wtr traces Produced **9804 m3/ day** of gas through 12/64" bean, FTHP: 156.453 psi. wtr traces Produced **8531 m3/ day** of gas through 10/64" bean, wtr traces. FTHP: 227.568 psi.
PTRA-3	Abandoned due to drilling complications			
PTRA-4	I	3047-3044	L. Bhuban	No/ Negligible influx with mild gas. Salinity of bottom sample is 572 ppm.
	II	2985-2982 2975-2971	L. Bhuban	No/ Negligible influx. Salinity of bottom sample is 580 ppm.
	III	2907-2902	L. Bhuban	Water trickling
	IV	2845-2842	M. Bhuban	No influx. Only technical water with mild gas on activation.
	V	2793-2790	M. Bhuban	Water with mild gas. Max influx 1.46m3 of water. Max sal of bottom sample is 14000ppm. Object concluded as having poor permeability.

	VI	2759-2750 2743-2738	M. Bhuban	Technical water with feeble flow of gas Object concluded as having No/ Negligible influx.
	VII	2714-2710	M. Bhuban	Water with mild gas on activation. Max Sal at 110 Kg/cm2 & 17740ppm. Object concluded due to poor permeability and negligible influx.
PTRA-5	Ia	1294-1287	Bokabil	Flowed sub-commercial Gas (max. 3ft flare height)
	Ib	1280-1273	Bokabil	Flowed sub-Commercial Gas (max. 3ft flare height)
	IIa	1136-1128	Bokabil	Flowed Gas @ 9400m3/d/3mm/ with little water in surges. FTHP: 44KSC at the time of flow measurements. After 30Hrs Shut-In STHP:109KSC / SCHP: 90KSC.Flowed Gas for 10days continuously, pressure not stabilized. Salinity: 21,000ppm as NaCl
	IIb	1121-1114	Bokabil	Flowed Gas @ 3160m3/d/3mm/ and 4820m3/d/4mm with little water in surges. FTHP: 67/65KSC at the time of flow measurements. After 49 Hrs. Shut In STHP: 114KSC/ SCHP: 98KSC. Flowed Gas for 21days continuously pressure not stabilized. Salinity: 24570ppm as NaCl.

4.10.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available, have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study, and PVT data/ results.

Gas composition analysis (PTRA-2)

Gas composition analyses of Patharia-2 gas samples are given in **Table 4-97**

Table 4-97: GAS COMPOSITION ANALYSIS (PTRA-2)

1.	LAB SL. NO.	**G 48/94**	**S 69/94**
2.	WELL NO.	PTRA-2	PTRA-2
3.	OBJECT	IV	IV
4.	DEPTH (m)	612.5 - 640	612.5 - 640
5.	SAMPLING POINT	CHK. MANIF.	SEPARATOR
6.	FMP (Kg/Cm^2)	29.0	16.0
7.	CHP (Kg/Cm^2)	33.0	20.0
8.	DATE OF COLLECTION	17-04-94	08-05-94
S.NO.	**COMPONENTS**	**VOLUME %**	**VOLUME %**
1.	METHANE	96.15	93.10
2.	ETHANE	1.73	0.39
3.	PROPANE	0.37	0.07
4.	i-BUTANE	0.08	0.00
5.	n-BUTANE	0.00	0.00
6.	i-PENTANE	0.00	0.00
7.	n-PENTANE	0.00	0.00
8.	HEXANE PLUS	0.00	0.00
9.	CARBON DIOXIDE	0.05	1.65
10.	N_2 & O_2	1.62	4.79
	CALORIC VALUE (NET) K Cal/m^3	8150.00	7829.00

	SPECIFIC GRAVITY (AIR = 1)	0.5743	0.5823

Pressure build-up study (PTRA-2)

No transient/pressure build-up studies were carried out.

4.10.5 Geology and Reservoir Description of PTRA-2 Field:

The geology of the area has been comprehensively reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.10.5.1 Geological correlations, sections and maps (PTRA-2 Field):

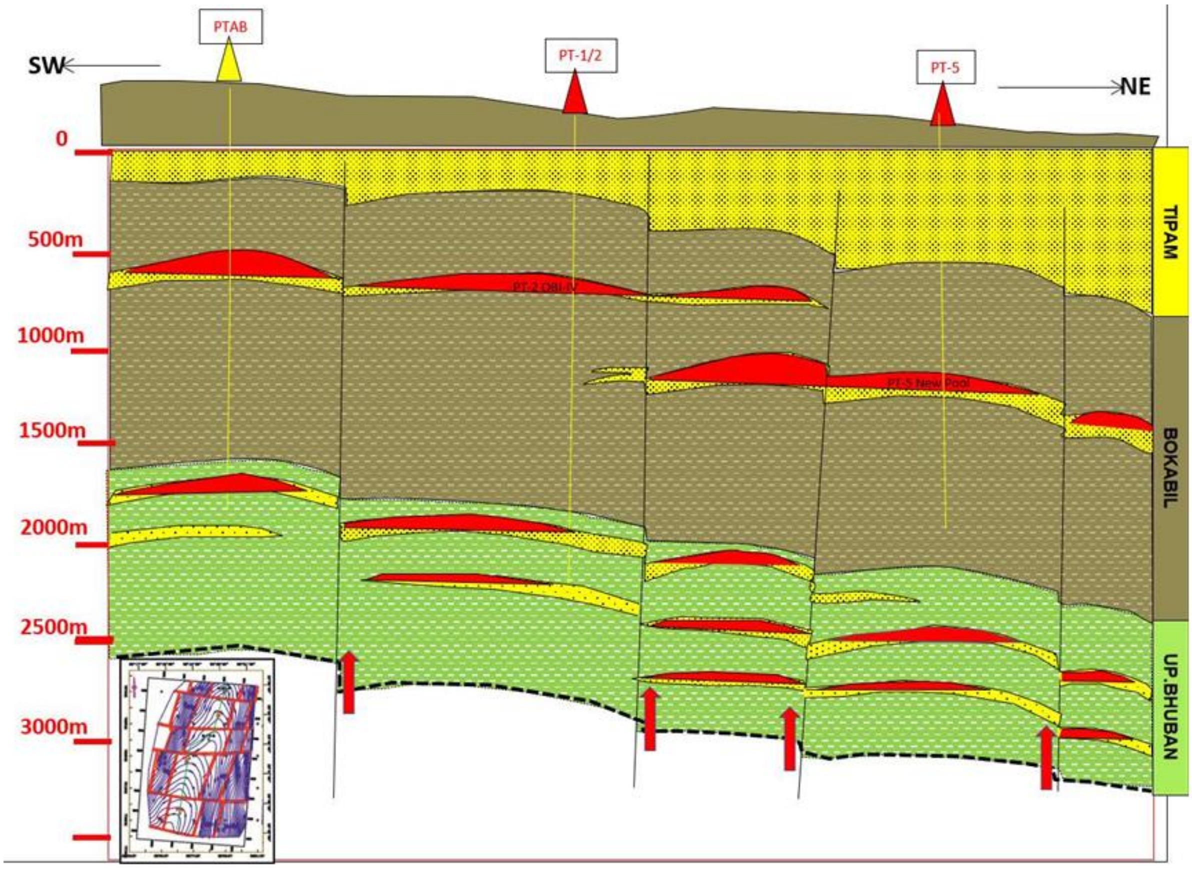
The Patharia Structure falls in the Cachar Fold Belt. Patharia Anticline is the westernmost structure in the Cachar Fold Belt. It is bounded by the Indo-Bangladesh border in the west and south-west, Nilambazar Syncline in the east, and Adamtila Gas field in the south-east. It is a tightly folded, doubly plunging, NNE-SSW trending, from Karimganj in the north to Dashgram in the south. The central crest part of the structure lies in Bangladesh, and only the northern and southern plunging parts of the anticline are present in India.

In the northern plunge, the eastern limb is steeper than the western one, whereas the reverse is the case to the south. Major thrust faults are recognized in the western limb and close to the central part. A prominent fault downthrown towards the east is seen in the eastern flank. Patharia is the structurally highest uplifted structure in the Surma Trough. A thick sequence of Neogene section is exposed in the Patharia structure. These formations are, from top to bottom - Dupitlla, Girujan Clay, Tlpam, Bokabil, and Bhuban. Tipam and Bokabil Formations are exposed in the Cachar part, whereas Middle Bhuban is exposed in the core of the doubly plunging anticline in the Bangladesh part. The northern plunge of the Patharia anticline exhibits prograding updip sand bodies from NE-SW, which form favourable locales for trapping hydrocarbons.

The seismic Inline 650 and 590 show an anticlinal structure bounded by faults. Seismic maps have brought out longitudinal and transverse faults, which have created compartments in the plunging part. These compartments are proven gas-bearing blocks.

Around 2.5 m of gas pay has been encountered at the well location within Bokabil.

Figure 4-165 :.GEOLOGICAL CROSS-SECTION OF THE AREA:



Following is the stratigraphic succession penetrated in the well (**Table 4-98**). Geological cross-section in Patharia area is shown in **Figure 4-165.** Seismic section, depth structure map, and net sand/Pay map are shown **in Figure 4-166, Figure 4-167 and Figure 4-168.**

Table 4-98: STRATIGRAPHIC SUCCESSION PENETRATED IN THE WELL PTRA-2

AGE	FORMATION	INTERVAL (m.)	DRILLED THICKNESS	TRUE THICKNESS
Mio Pliocene	Tipam Sst.	0 - 158	158 m	147 m
Miocene	Bokabil	158 - 1205.5(+)	1056.5(+)	1033(+)

Figure 4-166 :.SEISMIC SECTION ALONG THE WELLS :

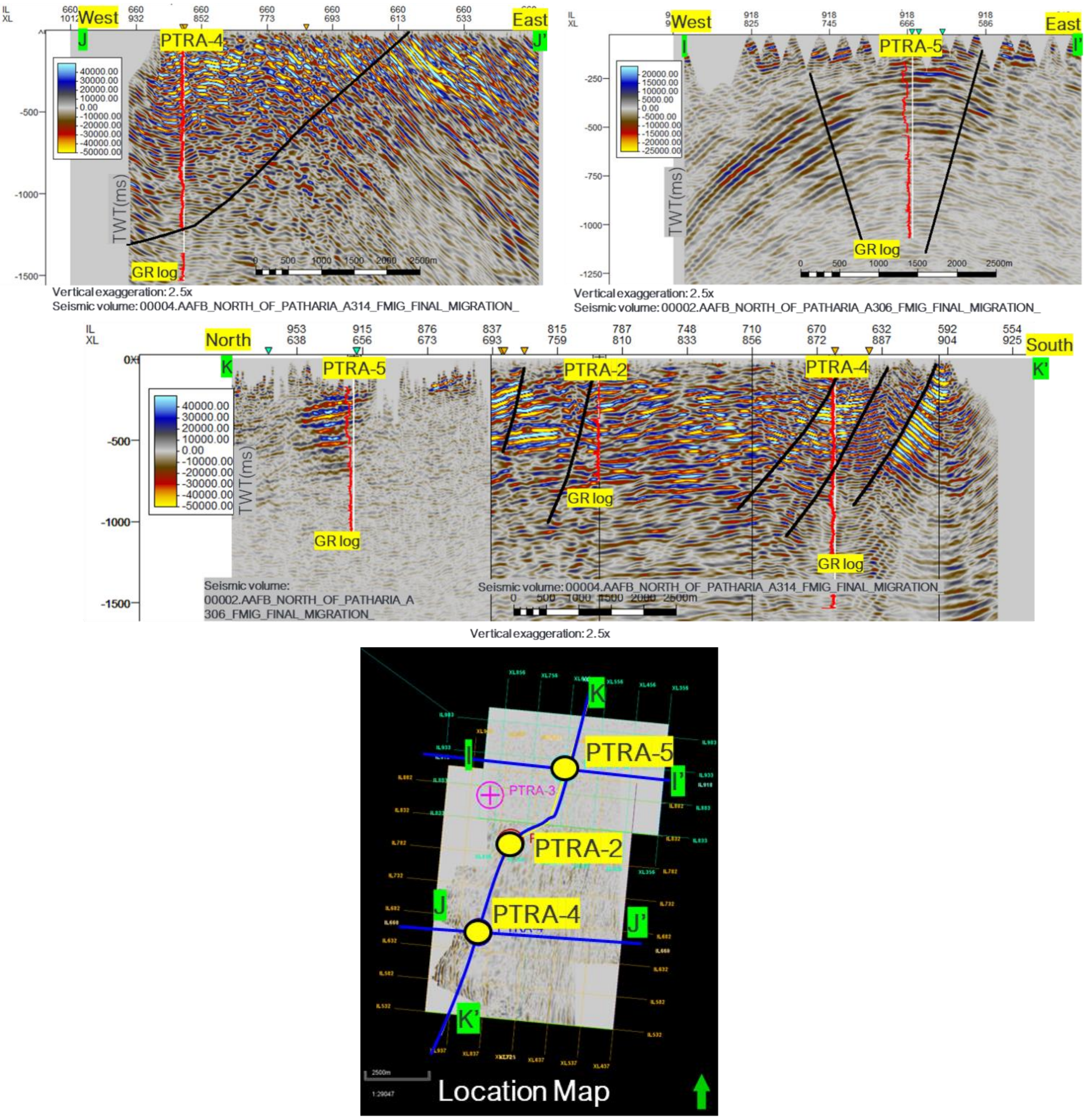


Figure 4-167 :.DEPTH STRUCTURE MAP OF BOKABIL :

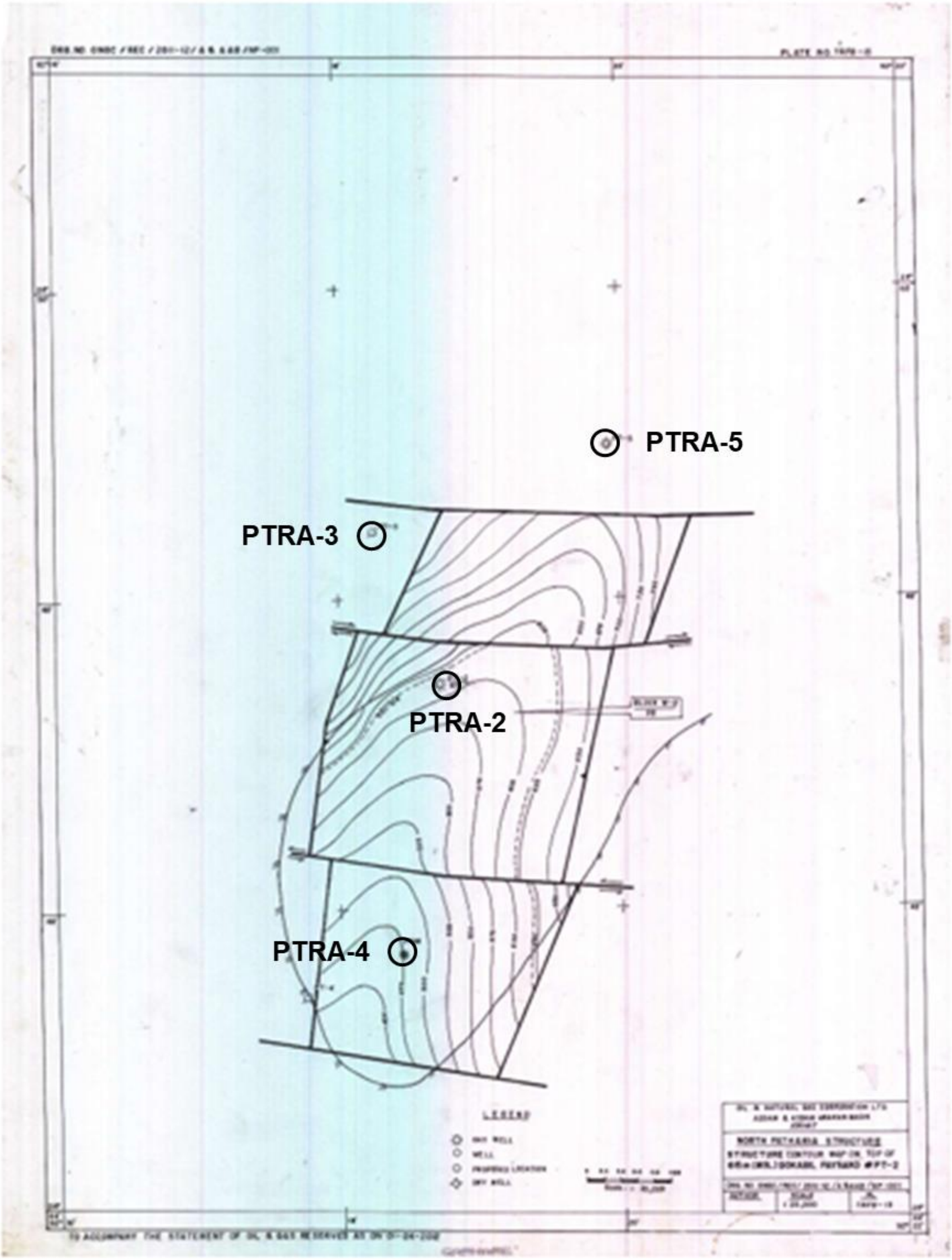
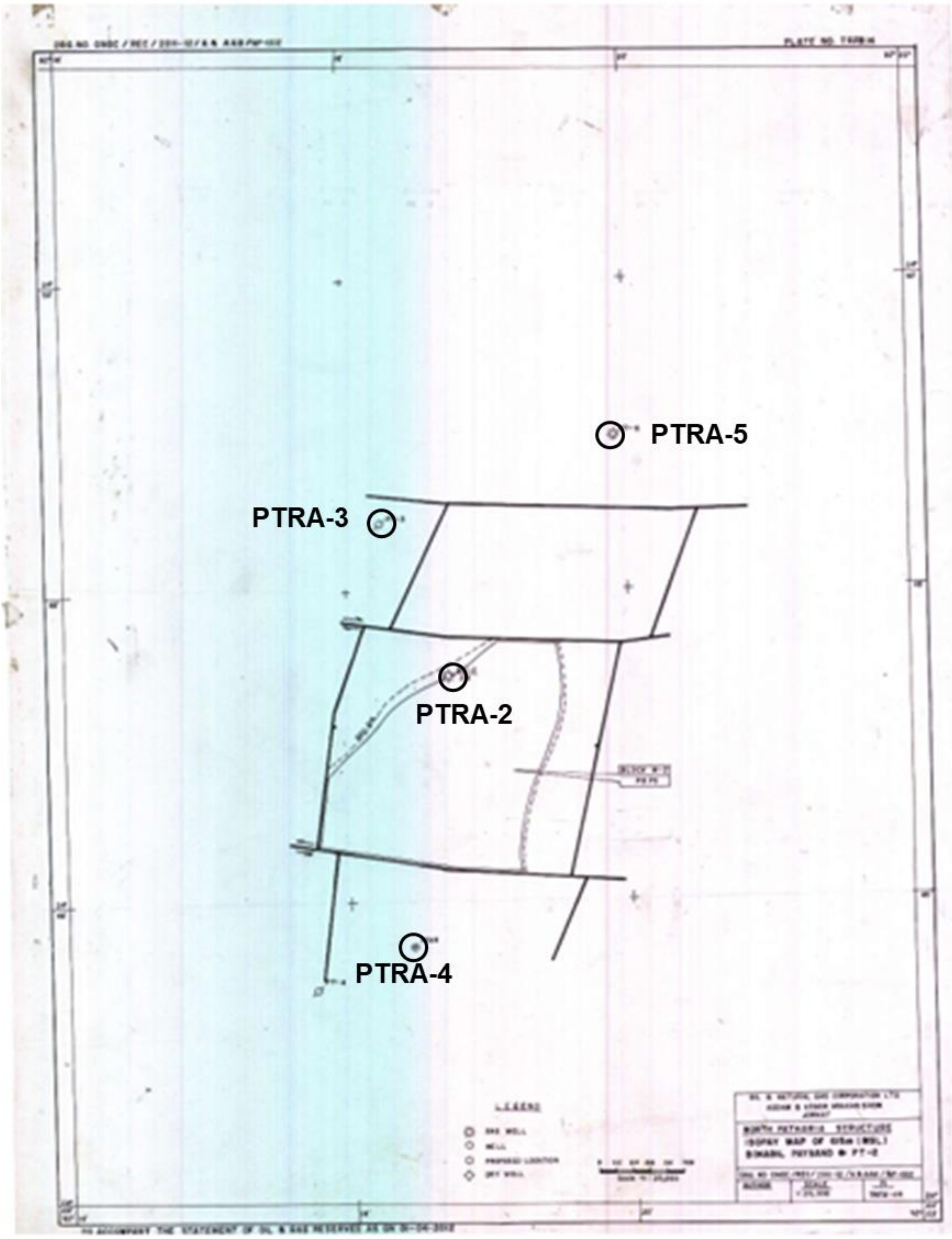


Figure 4-168 :. NET SAND/ PAY MAP OF BOKABIL :



4.10.5.2 Reservoir parameters and hydrocarbon estimates (PTRA-2) Field:

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

Petrophysical parameters and hydrocarbon estimates:

The petrophysical properties of the sands in Patharia-2 field and in-place are given in **Table 4-99 and Table 4-100.**

Table 4-99: PETROPHYSICAL PARAMETERS PATHARIA-2 FIELD

Petrophysical parameters and hydrocarbon estimates Patharia-2 Field	
Reservoir: Bokabil_Miocene (640 – 643 m)	
Area:	**5.0 sq.km (map based)**
Thickness:	**3.5 m**
Porosity:	**0.19**
Hydrocarbon saturation:	**0.51**
Formation volume factor:	**0.00742**

Table 4-100: HYDROCARBON IN-PLACE (2P) PATHARIA-2 FIELD

Field	**Initial In-place**
	O+OEG **MMTOE**
PATHARIA-2	**0.23**

Erstwhile Operator-reported estimates on record:

The field, Patharia-2, has reported gas estimate of **0.18 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant a possible revision of the currently reported estimates.

4.10.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Patharia field is **Banaskandi GCS (88KM)**

AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA-5 FIELD

4.11 DESCRIPTION OF AA/ONDSF/ASSAM/2025 (A&AA) PATHARIA-5 FIELD

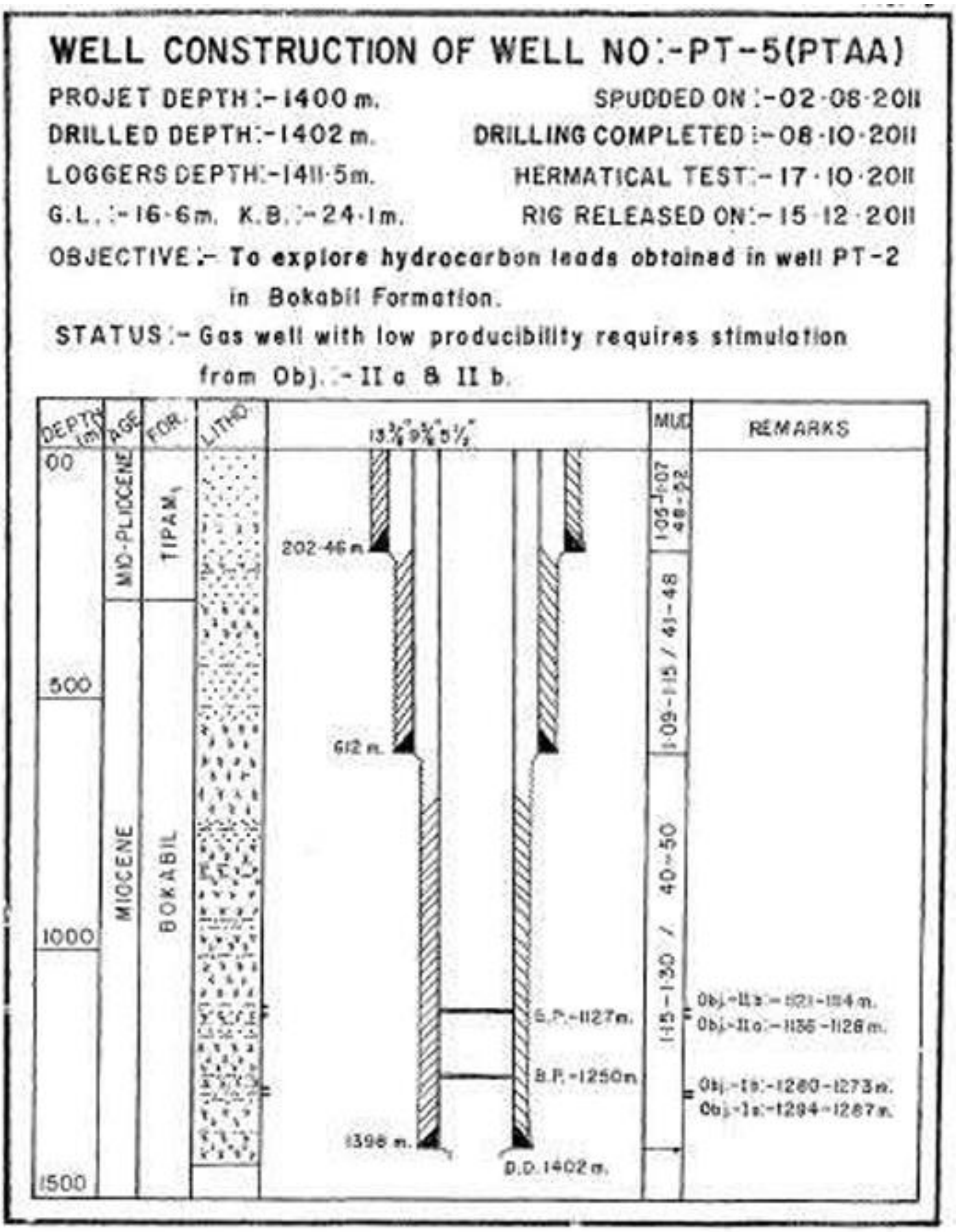
The exploratory location PTAA (Patharia-5) was proposed in 2010 to explore the hydrocarbon leads obtained in well PTRA-2 in the Bokabil Formation. The well is located in the northern plunge of the Patharia anticline, which is flanked by the Juri Syncline of Bangladesh to the west, Nilambazar Syncline to the east, and Adamtila Structure to the southeast. The central crest of the structure lies in Bangladesh, and only the northern and southern plunges are present in India.

4.11.1 Drilling and well completion

Key information of drilled wells have been collated and presented hereunder. The adjoining figures, wherever shown, illustrate the Well Construction Diagram and the Litho-column Information for key wells. Other well statics like kelly bush reference depth, water depth, drilled and logged depth, including well coordinates, are made available in Sections through various cross-references.

Well diagram of Patharia-5 is given below in **Figure 4-169**,

Figure 4-169 :.WELL PROFILE OF PATHARIA-5 :



4.11.2 Well logging and formation evaluation

The well logs of all discovery wells, along with some key wells in the Contract Area, have been reviewed. The logs recorded in various open-hole sections, along with cased-hole logs and information of conventional and other wireline formation test data, are presented in this docket. The availability of key input reports like Well Completion Reports (WCR) and Formation Evaluation Report (FER) has been checked and information given. Reservoir parameters of interesting zones and results of the tested zone(s) have been included in this report. Log motifs of tested/ interesting zone of key wells are also appended.

4.11.2.1 Well completion and log evaluation reports availability (PTRA-5) :

WCR/ FER availability	Spud date	KB	Drilled depth
Both available	02.08.2011	24.1 m	1402 m

4.11.2.2 Well logs acquired (PTRA-5) :

Details of Electrologs recorded in Well PTRA-5 are tabulated below in **Table 4-101.**

Table 4-101: LOGS RECORDED IN PTRA-5

Section	Run-	Date of Recording	Logs Recorded	Interval (m)
12¼"	1	18-Sep-2011	DLL-MSFL-INCL-GR-SP-CAL	605-201.65
	2	19-Sep-2011	SDL-DSNL-CAL CSNGR	612.38-201.65 601.74-201.65
	3	19-Sep-2011	WSTT-GR	608.1-201.65
	4	19-Sep-2011	XRMI-GR	611-201.65
8½"	1	7-Oct-2011	DLL-MSFL-INCL-GR-SP-CAL	1282.3-612.9
	1	11-Oct-2011	DLL-MSFL-INCL-GR-SP-CAL	1409.9-1150
	2	11-Oct-2011	SDL-DSNL-CAL CSNGR	1410.4-612.9 1401.2-612.9
	3	11-Oct-2011	WSTT-GR	1407.73-612.9
	4	11-Oct-2011	XRMI-GR-CAL	1411.5-612.9
9⅝" casing	5	12-Oct-2011	CBL-VDL-CCL-GR	612.2-300

Section	Run-	Date of Recording	Logs Recorded	Interval (m)
5½" casing	1	24-Oct-2011	CBL-VDL-CCL-GR (0 psi) CBL-VDL-CCL-GR (700 psi)	1373-580 1330-1080

Conventional Cores:
No conventional core collected.

Side Wall Cores:
24 side wall cores collected in the 12 ¼” section on 21sep2011. No SWC was attempted in the 8 ½” section due to poor hole condition.

Zero-offset VSP
Zero-offset VSP was recorded from 1356m to 376m @ 20m intervals on 21-Oct-2011. SSW-offset VSP was recorded from 1360m to 660m @ 20m intervals on 22-Oct-2011. ESE-offset VSP could not be recorded due to malfunctioning of the Geotelemetry unit of the VSP tool. (**Table 4-102**)

Table 4-102: VSP RECORDED IN PTRA-5

MD (m)	TVD (m)	X Offset (m)	Y Offset (m)	Two Way Time (ms)	Subsea TVD
376	376	0	0	368	-351.9
396	396	0	0	386	-371.9
416	416	0	0	402	-391.9

4.11.2.3 Well log evaluation and initial test results (PTRA-5):

Petrophysical properties and Initial testing of Patharia-5 are given in **Table 4-103** . Log motifs of PTRA-5 are shown in **Figure 4-170, Figure 4-171, Figure 4-172, Figure 4-173 and Figure 4-174.**

Table 4-103: PETROPHYSICAL PROPERTIES AND INITIAL TESTING RESULTS OF PATHARIA-5

Interval (mMDRT/mTVDSS)	Formation (+ Zone, if specified)	Gross(m)	Net(m)	Phi	Sw
300-1411.5 / 275.9-1387.4	Bokabil_Miocene(1287-1294 mMDRT)	7	-	-	-
	Initial testing results: Interval 1287.0 - 1294.0 m was tested as Object-Ia. During activation with compressor, well flowed mild gas (flame height 1-2 ft) with water of salinity 18720 ppm				
	Bokabil_Miocene(1273-1280 mMDRT)	7	-	-	-
	Initial testing results: Interval 1273.0 -1280.0 m as Object-Ib was tested. On activation with compressor, well flowed mild gas (flame height 1.5 ft) with water of salinity 18135 ppm				
	Bokabil_Miocene(1128-1136 mMDRT)	8	4.0	0.12	0.65
	Initial testing results: Object-IIa in the interval 1128.0 -1136.0 m was tested. During activation with compressor, well flowed mild gas (flame height 4 – 12 ft) intermittently with water of salinity varying from 16401- 17572 ppm and Qg @ 2500 scmd.				
	Bokabil_Miocene(1114-1121 mMDRT)	7	3.5	0.14	0.64
	Initial testing results: The sand interval 1114.0 - 1121.0 m was tested as Object-IIb. During activation with the compressor, well flowed mild gas (flame height 3-4 ft) intermittently with water of salinity 18135- 19305 ppm.				

Figure 4-170 :.WELL LOG MOTIF OF PATHARIA-5 BOKABIL :

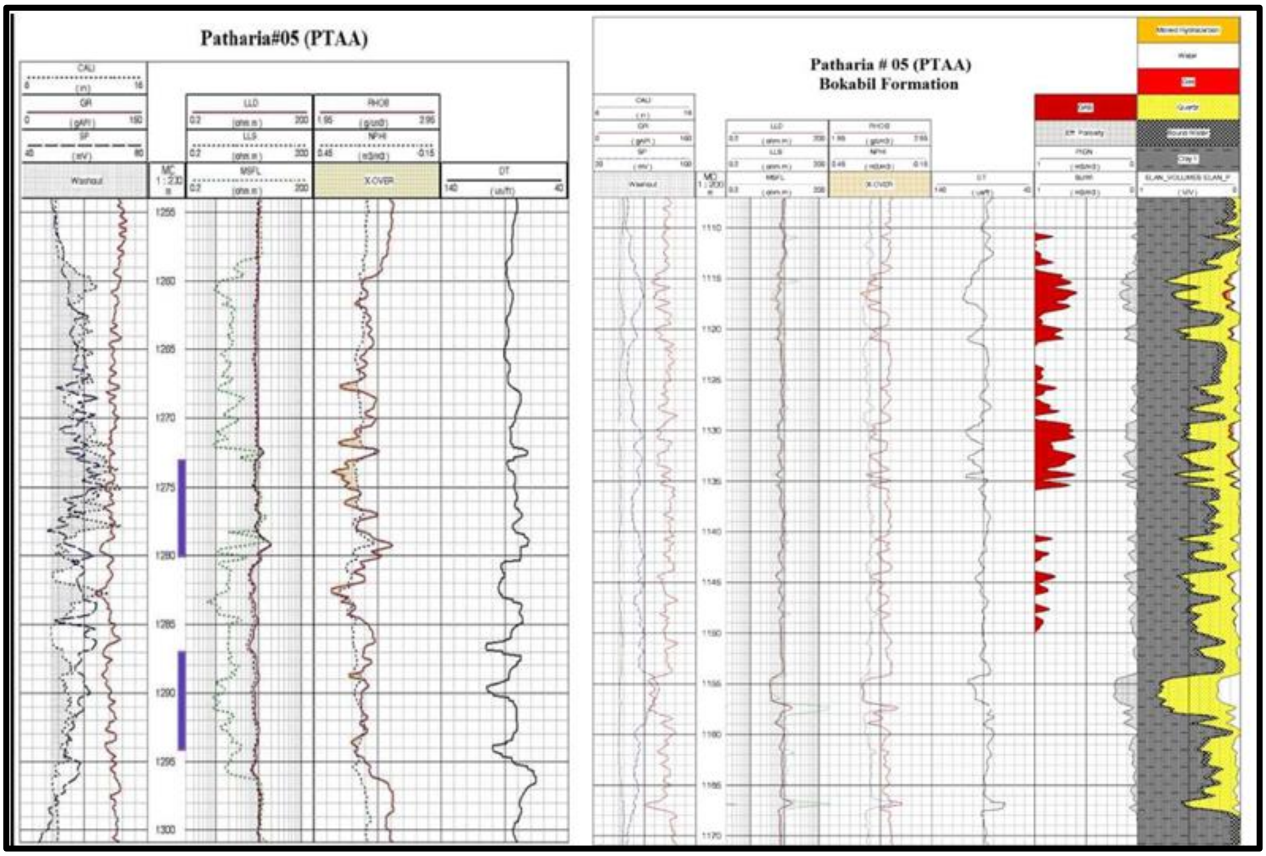
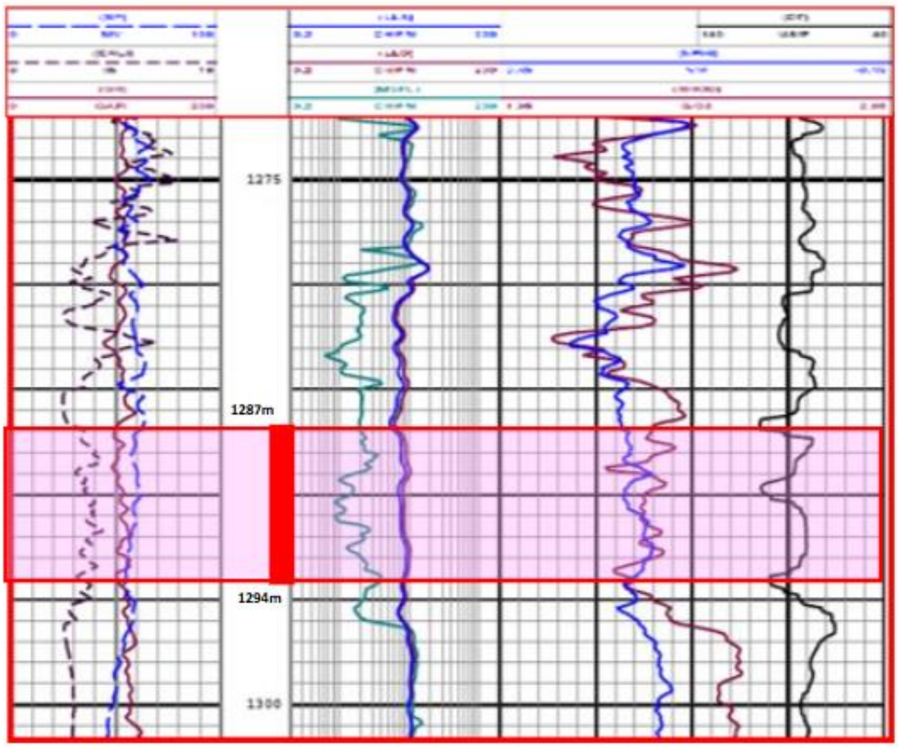


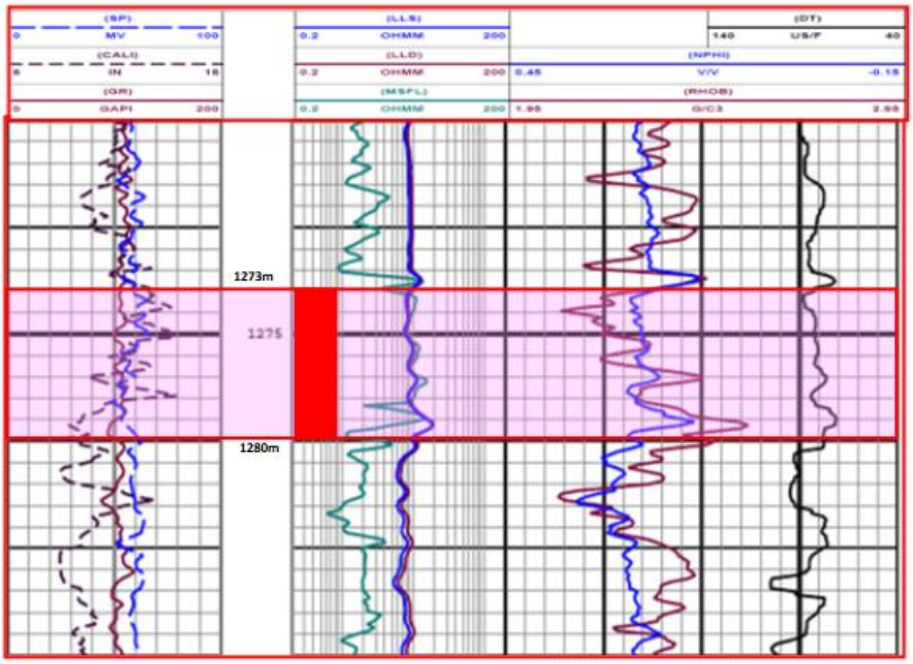
Figure 4-171 :. WELL LOG MOTIF OF PATHARIA-5 OBJECT-IA



RESULT:

OBJECT – Ia
Interval:
1294m- 1287m,
Flowed sub-commercial Gas (max. 3ft flare height)

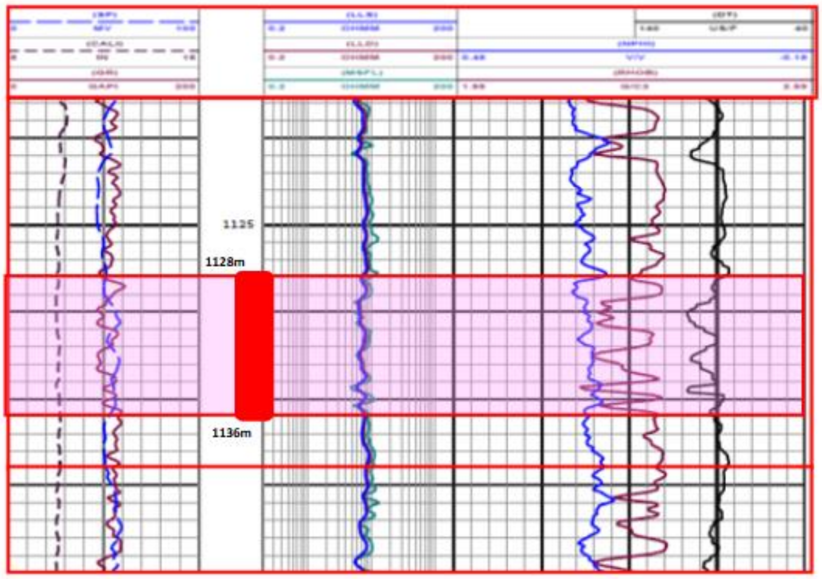
Figure 4-172 :. WELL LOG MOTIF OF PATHARIA-5 OBJECT-IB



RESULT:

Object-Ib
Interval:
1280m -1273m,
Flowed sub-Commercial Gas (max. 3ft flare height)

Figure 4-173 :. WELL LOG MOTIF OF PATHARIA-5 OBJECT-IIA

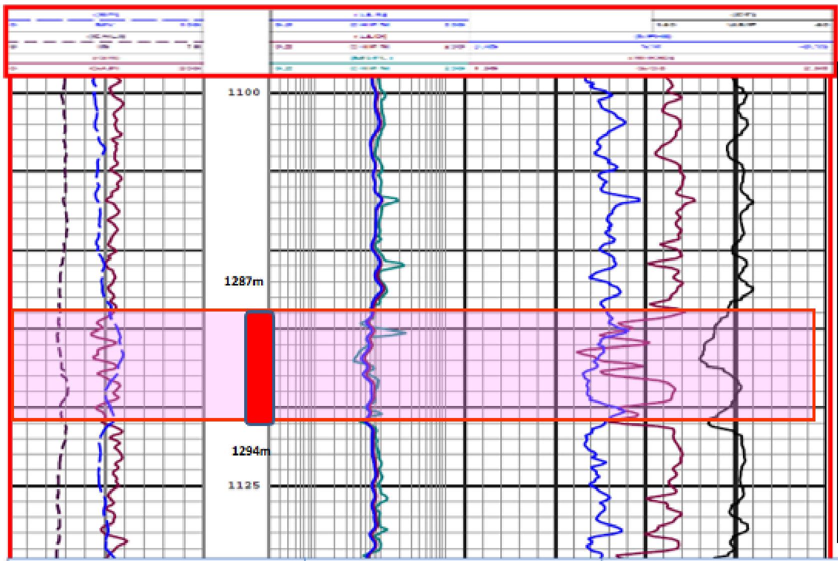


RESULT:

OBJ: IIa
INT:1136m-1128m,
FLOWED GAS WITH LITTLE WATER IN SURGES/ 3mm BEAN/ @9,400m3/d, MAX FTHP:44KSC.
After 30Hrs shut in STHP:109KSC/ SCHP: 90KSC.
Flowed gas for 10days continuously, pressure not stabilized.

Bean Size	FTHP (KSC)	Qg (m3/d)	Qw (m3/d)
3mm	44 (Max.)	9,400	Little water in surges
Note: Pressure not stabilized. Flow measurements were carried out after 49hrs shut-in.			

Figure 4-174 :. WELL LOG MOTIF OF PATHARIA-5 OBJECT-IIB



RESULT:

OBJECT:IIb
Interval: 1121-1114m
FLOWED GAS WITH Little water in surges/4 & 3mm/ 4820 & 3160m3/d;
FTHP:67/65KSC max/ 4/3mm.
After 49hrs Shut In: STHP:114 KSC/ SCHP 98 KSC.
Flowed gas for 21days continuously, pressure not stabilized.

Bean Size	FTHP (KSC)	Qg (m3/d)	Qw (m3/d)
3mm	67 (Max.)	3,160	Little water in surges
4mm	65 (Max.)	4,820	
Note: Pressure not stabilized. Flow measurements were carried out after 49hrs shut-in.			

4.11.3 Well testing and workover history

The sand layer interval 1287-1294 m was tested as Object-Ia. During activation with compressor, well flowed mild gas (Flame height 1-2 ft) with water of salinity 18720 ppm.

The interval 1273-1280 m was tested as Object Ib. On activation with compressor, well flowed mild gas (flame height 1.5 ft) with salinity 18135 m.

Object-IIa (1128-1136m), on activation with compressor, flowed mild gas (Flame height 4-12 ft) with water of salinity varying from 16401-17572 ppm and Qg @ 2500 scmd.

The sand interval 1114.0-1121m was tested as Object-IIb. During activation with compressor, well flowed mild gas (Flame height 3-4ft) intermittently with water of salinity 18135-19305 ppm.

Well was declared as low producible gas well, requiring stimulation.

Testing details in wells PTRA-1, PTRA-2, PTRA-3, PTRA-4 and PTRA-5 in **Table 4-104.**

Table 4-104: TESTING DETAILS IN WELLS PTRA-1, PTRA-2, PTRA-3, PTRA-4 AND PTRA-5

Well	Obj. No.	Interval (m)	Formation	Testing Results
	In Bokabil Formation, a few gas bearing sands in the interval 479-481m, 483-486m, 613-620 m, 639-642m, 913-919m, 1071-1075 m, and 1138-1142m were identified, but could not be tested. Three Objects in U.Bhuban were tested by CHDST in 9⅝" casing. 5½" casing was not lowered due to lack of interesting zone below 9⅝" casing shoe at (2487.25m).			
PTRA-1	I	2035-2032	U. Bhuban	Influx of 5.7 m3 of mud/ filtrate. Maximum sal -3.46 gpl as NaCl. Reservoir pressure 345 Kg/Cm2
	II	1995-1989	U. Bhuban	Surface flow of gas with influx of 2.4 m3 of formation water. Maximum sal 8.19 gpl. Reservoir pressure 326 Kg/Cm2
	III	1940-1936	U. Bhuban	Influx of 5 m3 of formation water. Maximum sal. 14.63 gpl. Reservoir pressure 309 Kg/Cm2
PTRA-2	I	1042.0-1043.5	Bokabil	Yielded 63.60 m3 of water with mild gas. Salinity : 16.38 gpl (as NaCl). STHP : 55 Kg/ cm2, SCHP : 65 Kg/ cm2
	II	931.0-933.5	Bokabil	Yielded 49.54 m3 of water with mild gas. Salinity : 14.04 gpl (as NaCl). FTHP : 10 Kg/ cm2, SCHP : 40 Kg/ cm2
	III	911.0-913.0	Bokabil	Yielded 13.90 m3 of water with mild gas. Salinity : 15.21 gpl (as Nacl). STHP : 55 Kg/ cm2, SCHP : 62 Kg/ cm2
	IV	640.0-642.0	Bokabil	Produced 11761 m3/ day of gas through 20/64” bean, FTHP: 56.892 psi. wtr traces Produced 10246 m3/ day of gas through 16/64” bean, FTHP: 142.23 psi. wtr traces Produced 9804 m3/ day of gas through 12/64” bean, FTHP: 156.453 psi. wtr traces Produced 8531 m3/ day of gas through 10/64” bean, wtr traces. FTHP: 227.568 psi.
PTRA-3	Abandoned due to drilling complications			

PTRA-4	I	3047-3044	L. Bhuban	No/ Negligible influx with mild gas. Sal of bottom sample is 572 ppm.
	II	2985-2982 2975-2971	L. Bhuban	No/ Negligible influx. Sal of bottom sample is 580 ppm.
	III	2907-2902	L. Bhuban	Water trickling
	IV	2845-2842	M. Bhuban	No influx. Only technical water with mild gas on activation.
	V	2793-2790	M. Bhuban	Water with mild gas. Max influx 1.46m3 of water. Max sal of bottom sample is 14000ppm. Object concluded as having poor permeability.
	VI	2759-2750 2743-2738	M. Bhuban	Technical water with feeble flow of gas Object concluded as having No/ Negligible influx.
	VII	2714-2710	M. Bhuban	Water with mild gas on activation. Max Sal at 110 Kg/cm2 & 17740ppm. Object concluded due to poor permeability and negligible influx.
PTRA-5	Ia	1294-1287	Bokabil	Flowed sub-commercial Gas (max. 3ft flare height) with water. Self flow of technical water @150 lt/hr
	Ib	1280-1273	Bokabil	Flowed sub-Commercial Gas (flare height of 1 foot and reached upto 3 feet.) with water. Self flow of technical water followed by gas with a flame height
	IIa	1136-1128	Bokabil	Flowed Gas @ **9400m3/d**/3mm/ with little water in surges. FTHP: 44KSC at the time of flow measurements. After 30Hrs Shut-In STHP:109KSC / SCHP: 90KSC.Flowed Gas for 10days continuously, pressure not stabilized. Salinity: 21,000ppm as NaCl
	IIb	1121-1114	Bokabil	Flowed Gas @ **3160m3/d**/3mm/ and **4820m3/d**/4mm with little water in surges. FTHP: 67/65KSC at the time of flow measurements. After 49 Hrs. Shut In STHP: 114KSC/ SCHP: 98KSC. Flowed Gas for 21days continuously pressure not stabilized. Salinity: 24570ppm as NaCl.

4.11.4 Reservoir engineering studies and analysis

Key reservoir engineering datasets, wherever available, have been collated and presented under various data genres. In a comprehensive data presentation, the results are included from well tests, formation dynamics tests, reservoir pressure build-up study, and PVT data/ results.

Formation dynamics tests (PTRA-5)

16 pressure tests were attempted in the 12 ¼” section from 19-21 Sep 2011. No RDT pressure tests were attempted in the lower 8 ½” section due to gas bubbling and intense well activity, (**Table 4-105**)

Eight RDT samples were attempted and collected in the 12 ¼" section from 19-Sep-2011 to 21-Sep-2011. No RDT sampling was attempted in the lower 8 ½" section due to gas bubbling and intense well activity. (**Table 4-106**)

Table 4-105: RDT PRESSURE TESTS IN PTRA-5

Sr. No.	Depth (m)	Temp (°C)	Hydrostatic Pressure (psi) Before	Hydrostatic Pressure (psi) After	Pore Press. (psi)	Statistical Validity (%)	Exceeding Stability
1	209.97	100.6	347.18	347.44	306.41	45.2	Excellent Stability
2	243	102.1	400.26	400.6	353.13	54.3	Excellent Stability
3	247.99	101.6	415.55	415.07	359.85	11.3	Excellent Stability
4	254.98	101.3	425.65	425.34	366.82	17.9	Excellent Stability
5	289	104.3	491.83	491.57	417.61	37.9	Excellent Stability
6	381.98	101.2	629.74	629.43	549.01	79.2	Excellent Stability
7	386.99	101.6	635.88	635.9	556.04	70.1	Excellent Stability
8	392.99	101	649.87	649.24	565.64	24.5	Excellent Stability
9	399.01	101.6	656.4	656.17	572.91	11.4	Excellent Stability
10	415.02	101.7	681.44	681.71	595.64	62.4	Excellent Stability
11	419.79	104.4	712.22	712.04	601.4	39.9	Excellent Stability
12	461.02	105	782.23	780.83	660.17	12.7	Excellent Stability
13	470.01	101.7	773.11	773.17	673.56	95.1	Excellent Stability
14	496.04	104.8	839.41	839.37	709.82	45.5	Excellent Stability
15	525.19	104.4	891.85	891.18	751.56	61.6	Excellent Stability
16	531.04	101.3	876.68	876.53	759.78	129	Excellent Stability

Table 4-106: DETAILS OF RDT SAMPLES OF PTRA-5

Stn	Depth (m)	Pressure (psia)	Temp. (°F)	Spherical Mobility (md/cp)	Water Analysis Salinity (ppm as NaCl)	Water Analysis pH	Gas Analysis (% mole) CH_4	Gas Analysis (% mole) CO_2	Gas Analysis (% mole) N_2
1	243*	352.66	101.3	644.93	351	9.0	-	0.413	99.587
2	289	417.61	104.3	373	585		-		100
3	382*	548.09	101.6	73.06	819	8.5		0.898	99.102
4	393*	564.25	100.9	6977.33	819	9.0	4.496	0.691	94.814
5	419.5	601.4	104.4	399	761	10.0	6.651	0.436	92.913
6	461	660.12	105	127	878	9.0	-	0.207	99.793
7	496	709.82	104.8	45.5	1404	9.0	5.287	0.311	94.402
8	525.5	751.56	104.4	61.6	819		2616	1046	96.338

Side wall cores:

24 SWCs were recovered, which show gross lithology as sandstone with NF/NC. Tipam formation is of no interest from hydrocarbon point of view. On the basis of log evaluation and gas indications during drilling, four intervals in the Bokabil formation were identified for production testing.

The following objects were tested in well PTRA-5 (**Table 4-107**): -

Table 4-107: IDENTIFIED ZONES FOR PRODUCTION TESTING IN PTRA-5

Object	Interval (m)	Formation	R (Ωm)	N (%)	S (%)	Perforation Density (SPM)
I A	1295*-1287	Bokabil	6-8	19-22	60	18
I B	1280-1273	Bokabil	7-8	18-21	63	18
II A	1136-1128	Bokabil	8-10	19	68	18
II B	1121-1114	Bokabil	8-9	19	72	18

*In order to avoid casing collar, the interval of Object-IA was modified to 1294-1287m.

4.11.5 Geology and Reservoir Description of PTRA-5 Field:

The geology of the area has been comprehensively reviewed using correlations, sections and maps. The well correlation, seismic sections, top structure, seismic attribute/amplitude and net sand/pay maps have been used to illustrate the magnitude and distribution of key reservoir properties in and around the discovered oil/gas pools (accumulations). The local tectonic setting and geological section of the area, wherever available, are also given. These maps/sections are sequentially shown field-wise and reservoir unit-wise through figures, appropriately titled and illustrated in the following section.

4.11.5.1 Geological correlations, sections and maps (PTRA-5 Field):

The Patharia Structure falls in the Cachar Fold Belt. Patharia Anticline is the westernmost structure in the Cachar Fold Belt. It is bounded by the Indo-Bangladesh border in the west and south-west, Nilambazar Syncline in the east, and Adamtila Gas field in the south-east. It is a tightly folded, doubly plunging, NNE-SSW trending, from Karimganj in the north to Dashgram in the south. The central crest part of the structure lies in Bangladesh, and only the northern and southern plunging parts of the anticline are present in India. In the northern plunge, the eastern limb is steeper than the western one, whereas the reverse is the case to the south. Major thrust faults are recognized in the western limb and close to the central part. A prominent fault downthrown towards the east is seen in the eastern flank. Patharia is the structurally highest uplifted structure in the Surma Trough. A thick sequence of Neogene section is exposed in the Patharia structure. These formations are, from top to bottom - Dupitlla, Girujan Clay, Tlpam, Bokabil, and Bhuban. Tipam and Bokabil Formations are exposed in the Cachar part, whereas Middle Bhuban is exposed in the core of the doubly plunging anticline in the Bangladesh part. The northern plunge of the Patharia anticline exhibits prograding updip sand bodies from NE-SW, which form favourable locales for trapping hydrocarbons.

The seismic Inline 650 and 590 show an anticlinal structure bounded by faults. Seismic maps have brought out longitudinal and transverse faults, which have created compartments in the plunging part. These compartments are proven gas-bearing blocks.

Around 6.5 m of gas pay has been encountered at the well location in two sand ranges within Bokabil.

Seismic sections along the wells, Geological cross-section of the area, Time structure map of BOKABIL and BHUBAN, Depth structure and net sand maps of BOKABIL, and Bokabil thickness map of Patharia field are given in **Figure 4-175, Figure 4-176, Figure 4-177, Figure 4-178 and Figure 4-179.**

Figure 4-175 :SEISMIC SECTIONS ALONG THE WELLS

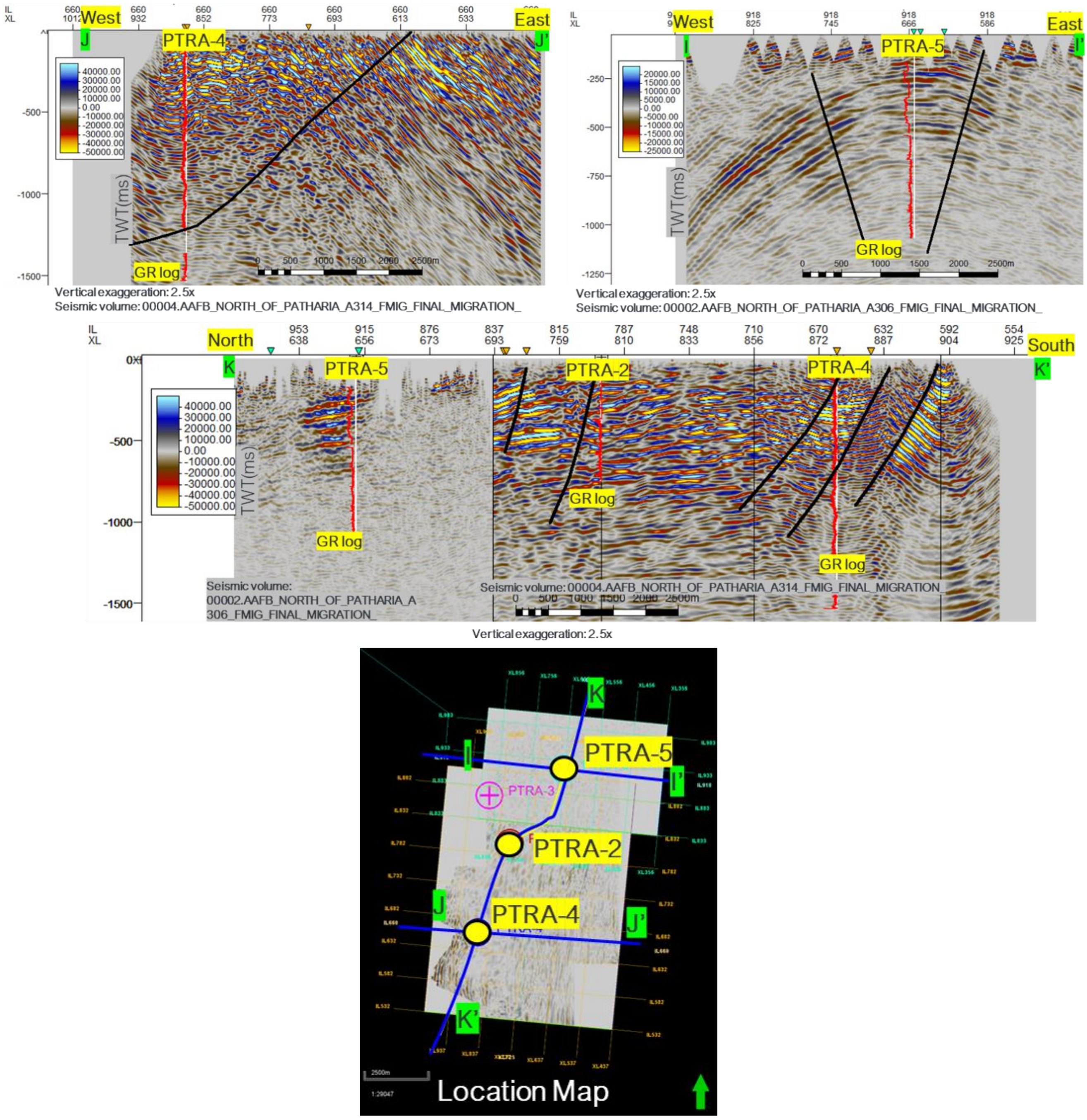


Figure 4-176 : GEOLOGICAL CROSS-SECTION OF THE AREA:

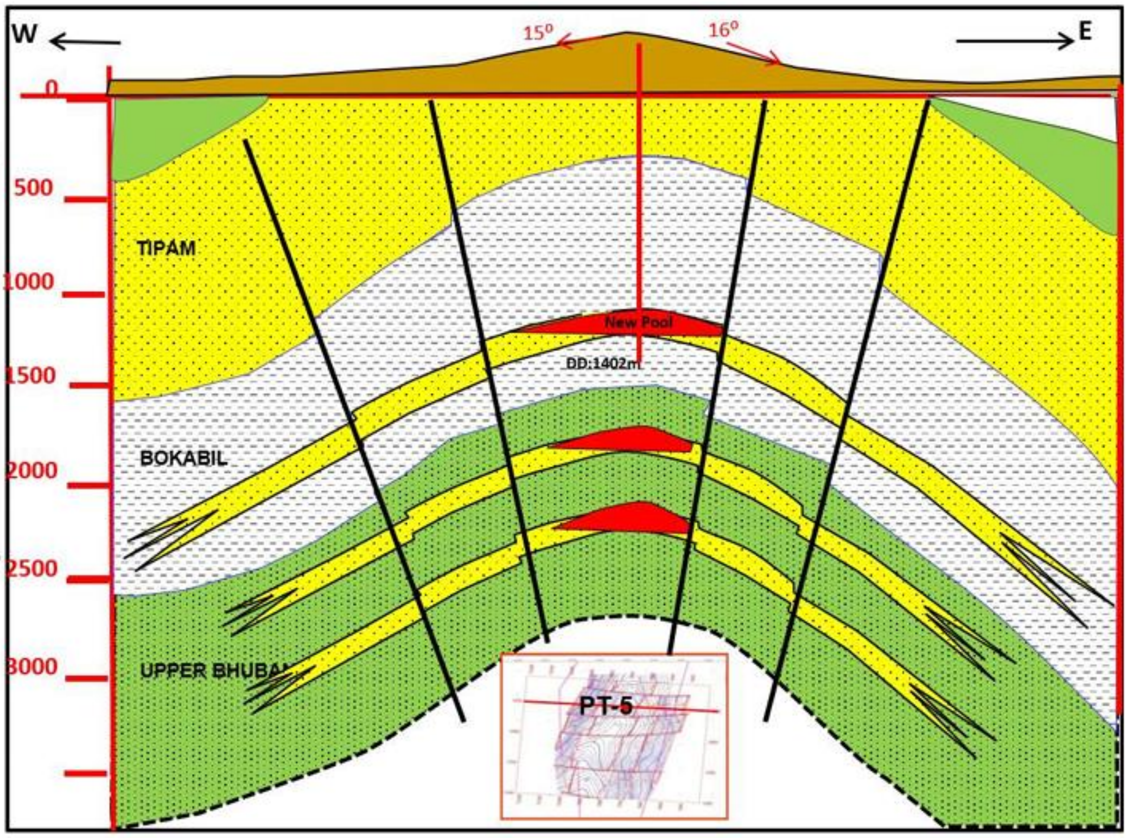
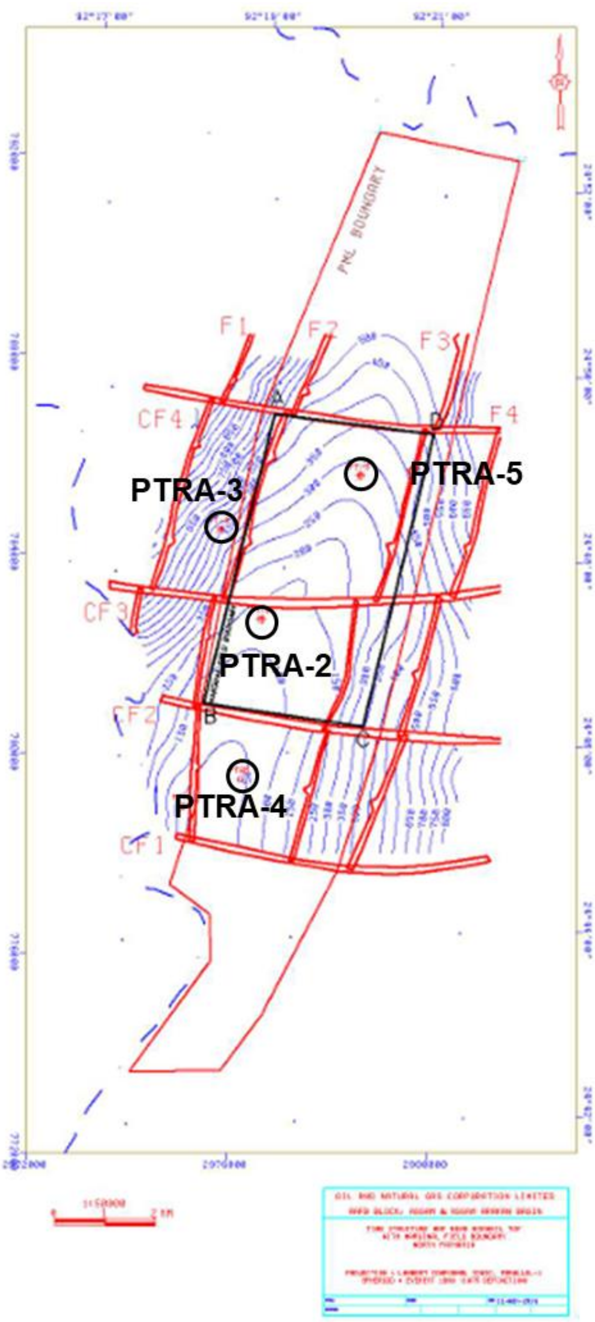


Figure 4-177 :TIME STRUCTURE MAP OF BOKABIL AND BHUBAN



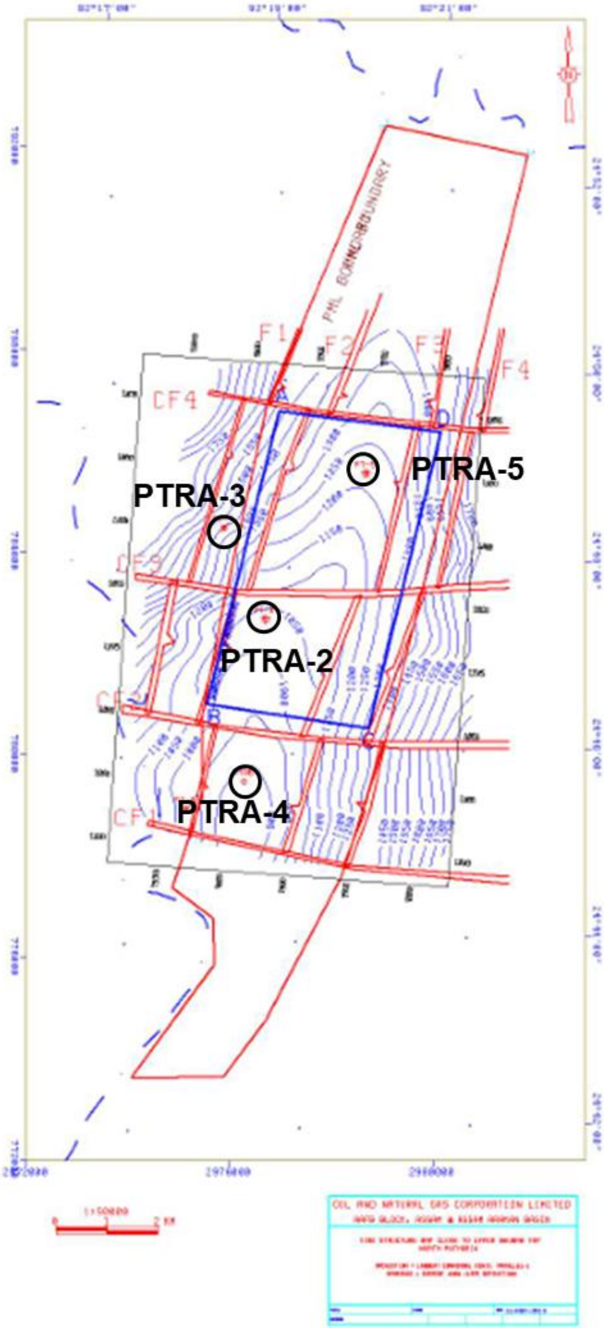


Figure 4-178 :DEPTH STRUCTURE MAP OF BOKABIL

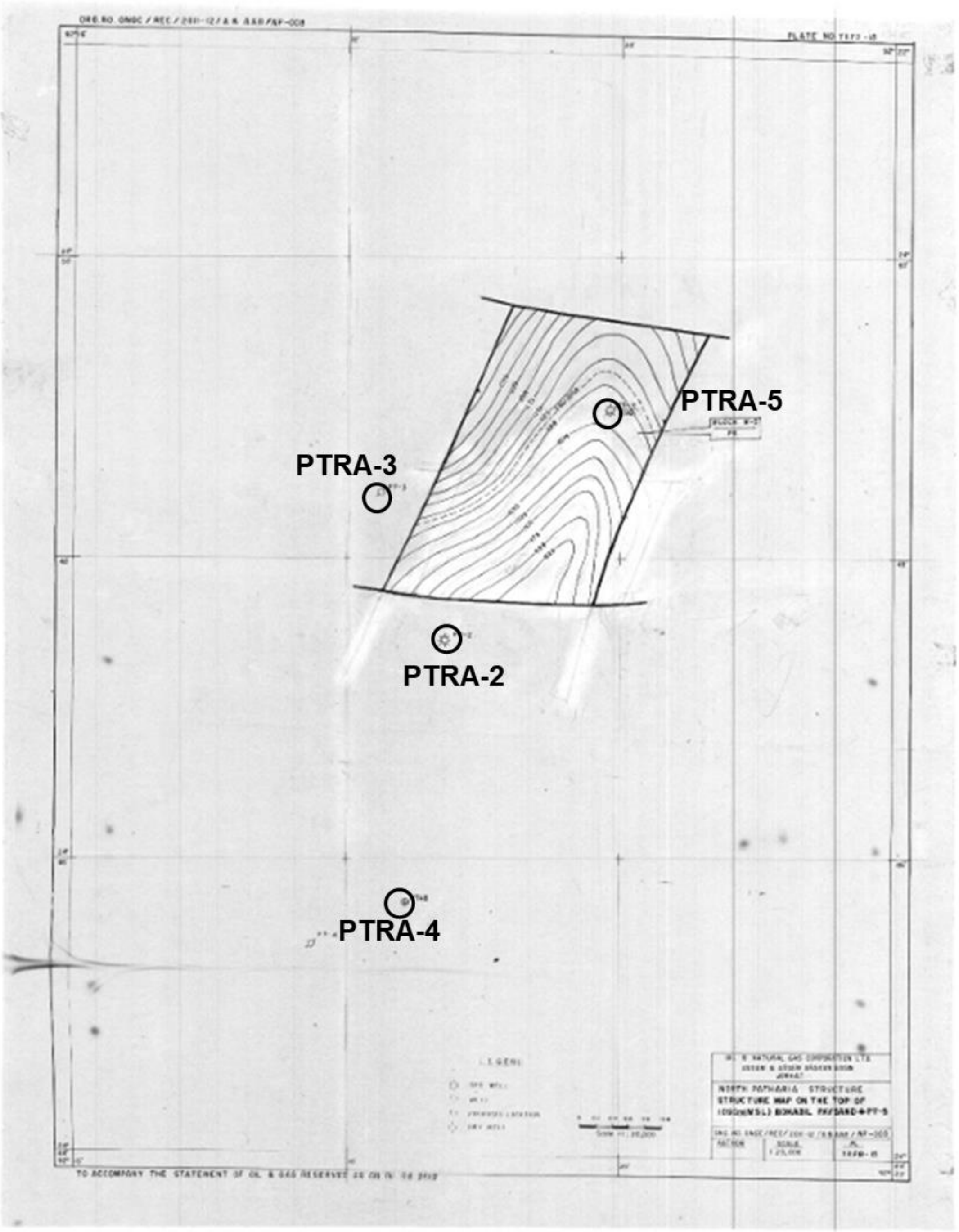
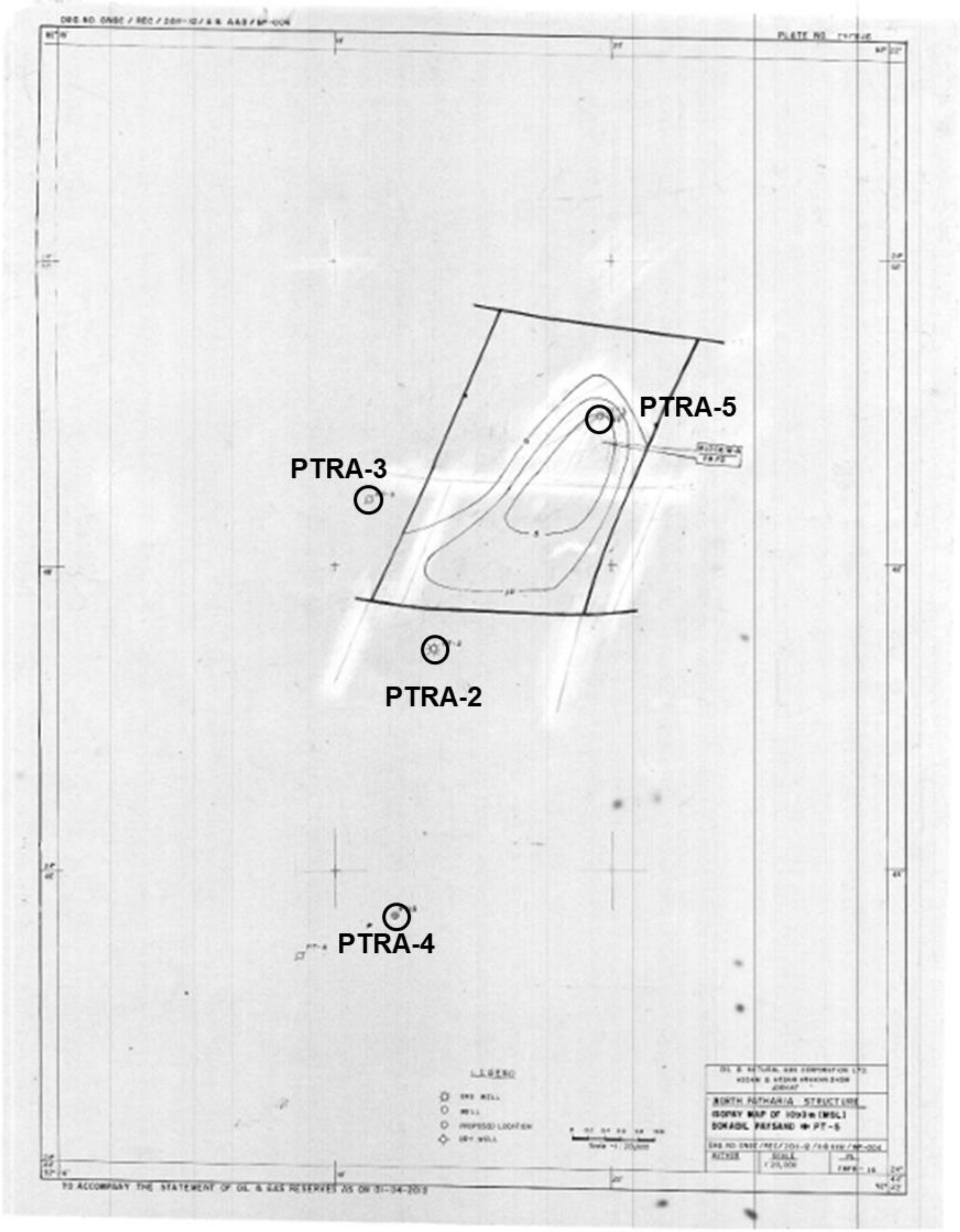


Figure 4-179 :NET SAND/ PAY MAP OF BOKABIL



STRATIGRAPHY (PATHARIA-5) field:

Based on the cutting sample analysis of the master log and the characters of electro log recorded, the following stratigraphic boundaries are envisaged in this well. The well PTRA-5 was drilled down to 1411.5m (logger's depth), and electro log was recorded from 1411.5m.

Stratigraphic sequence encountered in PTRA-5 and its correlation with nearby wells on the basis of cutting samples and electrolog data are given below in **Table 4-108, Table 4-109** and **Figure 4-180.**

Table 4-108: STRATIGRAPHIC SEQUENCE IN PTRA-5

Group	Formation	Age	Interval (m)	Thickness (m)
Tipam	Tipam	Mio-Pliocene	0-300	300
Surma	Bokabil	Miocene	300-1411.5+	1111.5+

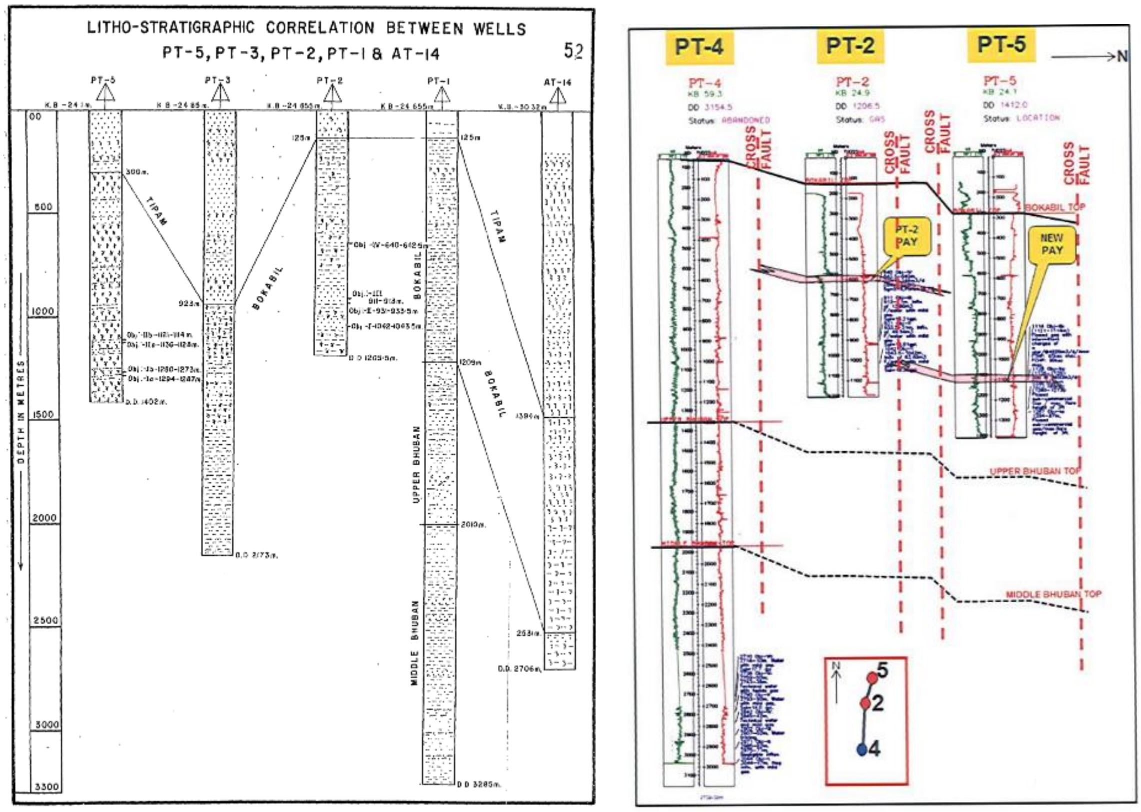
STRATIGRAPHIC Correlation in Patharia field (PTRA-1, PTRA-2, PTRA-3, PTRA-4 and PTRA-5):

Table 4-109: STRATIGRAPHIC CORRELATION IN PATHARIA FIELD

Formation/ Well	PTRA-5	PTRA-2	PTRA-1	PTRA-3	AT-14
Tipam	Surface-300m	Surface - 150m	Surface - 150m	Surface - 948m	Surface - 1394m
Bokabil	300m-1411.5+m	150m-1206.5+m	150m-1234m	948m-2173.5+m	1394m-2531m

Logs show that the development of sandy facies is better in the well PTRA-5 in the Bokabil Formation compared to PTRA-2.

Figure 4-180 :. STRATIGRAPHIC CORRELATION IN PATHARIA FIELD



4.11.5.2 Reservoir parameters and hydrocarbon estimates (PTRA-5) Field

The estimates of hydrocarbon in-place have been worked out under various field assumptions and all inputs, working, and results, as available and sourced, are presented in the following section.

Petrophysical parameters and hydrocarbon estimates:

The petrophysical properties of the sands in Patharia-5 field and in-place are given in **Table 4-110 and Table 4-111**.

Table 4-110: PETROPHYSICAL PARAMETERS AND VOLUMETRIC ESTIMATES

Formation	Reservoir	Object	Interval (m)	Map Area SqKM	Thick ness m	Porosity %	Shc	FVF rm3/scm3	GIIP MMm3
Miocene	**Bokabil**	**IIa**	1136-1128	**4.1**	4.0	0.12	0.35	0.00742	92.8
Miocene	**Bokabil**	**IIb**	1121-1114	**4.1**	3.5	0.14	0.36	0.00742	97.5
									190.3

Table 4-111: HYDROCARBON IN-PLACE (2P) PATHARIA-5 FIELD

Field	O+OEG MMTOE
PATHARIA-5	**0.19**

Erstwhile Operator-reported estimates on record:

The field, Patharia-5, has reported a gas estimate of **0.14 MMTOE**.

All these hydrocarbon estimates are subject to future assessments based on Operator's own technical insights and additional information/data, which may warrant possible revision of the current reported estimates

4.11.6 Production Facility for Oil and Gas Evacuation:

The nearest surface facility to Patharia field is **Banaskandi GCS (88KM)**

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4.12 STATUS OF ADDITIONAL WELLS IN AA/ONDSF/ASSAM/2025 CONTRACT AREA

The Contract Area is a single area with 8 discoveries/fields (LXMJ-1A, BHBR-1, NAHB-1, CRDO-1, KHEREM-2, PTRA-2, PTRA-5 and TUKB-2) and 20 additional wells. The status of the additional well(s) has been described field-wise in the following section. Where reports/information were not available/accessible at the time of writing this report, the same may be enquired with NDR later.

LAXMIJAN field:	
LXMJ-2	The well LAXMIJAN-2 (LJE) is an exploratory test well on Laxmijan Structure. The well has been drilled upto a depth of 4760 m with an objective to explore Barail formation. Well was spudded on 22.03.97 and was drilled vertically upto the depth of 4142 M. Drilling was suspended on 06.09.97 as the rig was deputed for Bangladesh operation. Again, the drilling was resumed after finishing the Bangladesh operation on 10.02.2000. The well was drilled vertically upto the target depth i.e. 4757 m and rig was released on 25.12.2000.Open hole log data was acquired in five stages covering the stratigraphic units Girujan Clay Section, Tipam, Surma, Barail and other sequences. No conventional core was cut in this well. On the basis of available geological informations and by correlation with Laxmijan-1A, only one object was identified for production testing in TS-5A. On testing Object-1 in the interval 3393-3399 m flowed water.
BIHUBAR field:	
Bihubar 2	Bihubar 2 is the second exploration well drilled South East of Bihubar-1 on Bihubar structure to know the hydrocarbon prospects of Tipams and Barails. The Bihubar structure is located close to Naga thrust Northeast of Geleki field. The target depth (extended) for this well was 4600 m depth; but the well had to be terminated at the depth of 4485 m (driller's depth) due to some technical problem. This well has crossed two thrusts viz., Cholsima and Naga thrusts at depths of around 750 and 1950 m respectively as per geological information. The earlier well Bihubar-1 was drilled down to Barails, but this well also had to be abandoned at the depth of 4020 m due to technical complications and no zone could be tested either in Tipams or in Barails. However, Tipam Sands were interpreted as water bearing and a few layers in Barails were interpreted as hydrocarbon bearing on the basis of well logs.
Bilhubar-3 (BMA)	Bilhubar-3 (BMA) is an exploratory step out well for the sand body within the Girujan Clay which could not be tested in Bilhubar-2 as it was behind double casing. It has been drilled upto a depth of 2067 M with a vertical shortening 55.83 M at 1792.0 M. The well has deviated from 756.0 M. The interval 623.0-640.0 M (Log Depth) in Barail Main Sand appeared hydrocarbon bearing. Conventional core in the interval 616.0-641.0 M shows bright GYF and +ve cut. Electrolog correlation with Bihubar-2 shows that the sands in the interval 1740.0-TD of Bihubar-3 is equivalent of 1854-1950 M in Bihubar-2, characterised by GYF in SWC, but structurally lower by 30 M at 1940.0 M. These sands appear to be within Girujan Clay Section. Thrusts viz Cholingen and Naga are crossing at depths 755.0 M and 1705.0 M respectively. In Girujan Clay sands the intervals 1959-1954 M, 1947-1943 M showing comparatively lower water saturations than the underlying intervals, needed testing. The interval 1902-1905 M in Girujan Clay appears hydro-carbon bearing (Sw - 50%). Two objects were tested conventionally (1960–1951m. & 1947m.–1942m.) **Obj-I: 1959.0-1954.0 M**, produced **water** (salinity = 0.1053–0.2924 gm/lit.) with traces of oil—the oil probably be dead oil, coming from invaded zone, which was spotted while the drill string got stuck at the final depth. **Obj-II: 1947.0-1943.0 M**, testing could not be completed due to complications (tubing got choked and later on stuck due to heavy sand cut) arose during testing. **Obj-III**: 1905.0-1902.0 M, Not tested **Obj-IV: 640.0-623.0 M**. Not tested It was decided to drill a vertical well (Bihubar-3A) from the same location as BMA.

Bihubar-3A	Bihubar-3A is an exploratory step out well for Tipam Sand 1 and was drilled upto 1986 M (log depth). Correlation with Bihubar-2 indicates that the sand for which the well was drilled, may be a part of Girujan Clay and may not belong to Tipam Sand 1. Although the uncertainties in the estimation of Sw makes the interpretation of fluid nature difficult, a few zones were recommended for testing on the basis of GIF in the present as well as in Bihubar-2 and Bihubar-3 and comparison of apparent formation water resistivity. These zones were tested; namely, (i) 1879-1888 & 1850-1864 (ii) 725-745 M and (iii) 620-641 M and all the three-zone yielded water.
Bihubar-4	The well Bihubar-4 was spudded on 7-7 1996 and drilled down to 3374m Drilled down to 3910m. Three objects were released and tested in Barails and Tipams as follows: Object I: 1879-1900 m in Barails was found to be water bearing. Object II: 1395-1420m in pre-Barails water with traces of oil and Object III: 1240-1300 & 1210-1215 m in Tipam was water bearing. The well is abandoned as dry.
NAHOHABI field:	
Nahorhabi-2	The well Nahorhabi-2 was drilled upto 4451m to explore hydrocarbon potential of Tipam and Barails. Seven objects were identfied for testing. Object-I(4406-4408m) of BMS flowed water with little oil even with additional perforation of 4408-4411m . Object-II(4363-4365m) of BCS gave influx 2m3 of Oil and 6 m3 of formation water (Salinity 4.45 gpl). Onject-II 4300-4305m, 4320-4321.5m) yielded water salinity of 3.2 gpl with oil and gas. Object-IV (3924-3929m) gave water of salinity 2.56 gpl. Object-V(3892-3897m), Safrai formation gave water of salinity 2.9 gpl with traces of oil. Object-VI(3853-3854, 3873-3877m) of Safrai formtion flowed water of salinity 2.85 gpl with tracesof oil. Object-VII (3616-3619m) of Geleki formation yielded water of salinity 4.69 gpl. Testing results indicated presence of Hydrocarbons at BMS, BCS and Safrai levels. The well was abandoned.
Nahorhabi-3	The location NHAA (NAHB-3) was released as a ‘B’ category exploratory step out location in Naharhabi structure to explore the hydrocarbon prospects of Barails and Safrai. The structure is located in the south of producing Lakwa field and in S-W direction of Sonari field. The well was drilled down to 4705m. Seven objects were identified for testing. First two Objects (Object-I & II) in Kopili sand showed no encouraging result . The third Object 4582-4577m showed no influx on activation .The fourth object 4397.5-4395m in BMS attained self flow of oil, gas with high water cut(85%).
CHARAIDEO field:	
CRDO-4	The well CRDO-4 was spudded on 24.06.2009 and was drilled down to 4708m (TD) against the targeted depth of 4700m. The well was terminated within the BMS Formation and was sidetracked three times due to drilling complications. During the course of drilling, hydrocarbon shows were observed in sands of Tipam Formation (TS-6), Rudrasagar Formation and Demulgaon Formation. The well CRDO-4 is correlatable with nearby wells CRDO#2 & CRDO-3 of Charaideo structure and NH#02 & NH#03 of Nahorkatia structure. At the top of LBS-II, well CRDO-4 is structurally down by 133m and 176m respectively from wells NH-02 and NH-03. At the top of BMS, well CD-04 is structurally up by 45m wrt CRDO-1. In the neighboring wells, object testing remained somewhat inconclusive (BCS & BMS respectively) due to technical reasons. Oil and gas indications were observed in BCS (Obj-VI) sand of CRDO-1 and BMS (Obj-I) sand of CRDO-2. The third well of Charaideo i.e. CRDO-3 (CDAA_Z) has flowed oil (intermittently) from Safrai Formation. All the sand layers developed within Girujan clay as well as all the Tipam layers (TS-2, TS-3, TS-4, TS-5 and TS-6; TS-1 not developed in this area) are interpreted water bearing. BCS Formation encountered in CRDO-4 well is mainly shale/coal alternations with highly washed out/bad-hole sections. The sand units LBS-II and LBS-I are interpreted either silty/poor reservoir facies or water bearing. The BMS sand encountered at 4558m (-4453.5m) is

	interpreted hydrocarbon bearing with OWC at 4571m (-4466.5m). GYF/+ve cut was observed in the interval 4570-4605m in the cutting samples during drilling. Conventional core recovered in the interval 4501-4508m shows GYF/+ve Cut. **On testing CRDO-4, Object-I (4566-58m/BMS) gave poor influx of oil. During activation observed 300LT of oil while subduing the well.** **Object II (4506-02m/ BCS) tested dry with no fluid influx.** Based on results of Obj-II, Object III (3932-28.5m/Safrai, lying behind double casing) was cancelled. **Due to poor influx it was recommended to retest the Object-I and improve the influx after Hydro-fracturing.**
KHEREM field:	
KHEREM-1	The well was drilled to explore the HC in Mio-Pliocene turbidite fans and the underlying Paleogene banded events. The well was drilled down to 3150 m against the target of 3800 m. **No hydrocarbons were encountered.** **Abandoned.**
KHEREM-3	Replacement well drilled at the plinth of Kharem 1.The well was drilled down to 2550 m against the target depth of 4000 m to explore turbidite fan prospects of Mio-Oligocene & Eocene sediments. During prolonged testing 4207 m sand in June-July 95 the well produced intermittently condensate (44.8 Deg. API) and little amount of gas. During prolonged testing of 4159 & 4123 m sand, the ell displaced little amounof gas and condensate. On testing 4063 m sand, it produced only water. As the hole size against the higher up sand ranges are very large and the correlatable (depth-wise) sand ranges of interest have been tested in KHM 2, it was decided not to test the higher up sand ranges. Hence it was not appraised and plugged back.
TUKBAI field:	
TUKB-1 & 1A	The well Tukbai-1 was drilled in 2003 to a depth of 3701m (3711m loggers' depth) to probe the hydrocarbon potential of Bhuban, Renji, and partly Jenam Formation. On the basis of analysis of well data, including electro logs, lab data etc, a thrust has been envisaged in the Renji Formation at 3185m. In the up-thrust section, the well has penetrated 452 m of Bokabil, 803 m of Upper Bhuban, 1105m of Middle Bhuban, 706 m of Lower Bhuban, and 119m of Renji Formation. In the sub thrust section, 465m thickness of Lower Bhuban and 61m thickness of Renji have been encountered. The Jenam Formation is not encountered up to 3700m in this well. A number of sand bodies have developed in this well, and six objects have been identified for testing. Barring the objects IV, V and VI which could not be tested due to complications leading to well abandonment, three objects were tested. **Object: I** (3587-3582 m) In Sub thrust Lower Bhuban, **Object II** (3175-3173 m) In Lower part of Renji Formation, **Object III** (3104-3100m,3095-3093m) Both Up thrusts. However, **all these objects were proved to be water bearing with no hydrocarbon show** Maximum water salinities obtained from objects I, II and III were 210.8 ppm, 263 ppm and 234.87 ppm as NaCl. Due to inordinate delay and complications in fishing of 2 7/8" tubing which fell inside the well leading to abandonment of the well TUKB-1 without testing of Object-IV (3065-3052m), ObjectV (2843-2833m,2830-2828m and 2825-2823m) and Object-VI (2413-2402m), a side-tracked well (TUKB-1A) was drilled through this well and remaining equivalent objects were tested later. As the three objects tested viz: I, II and III were proved to be dry, this well was declared as dry and abandoned.
TUKB-2	The well TUKB-2 in the Tukbai structure of Sector VC-PEL was drilled with an objective to explore hydrocarbon leads obtained in well TUKB-1/ 1A in Up- thrust Middle, Lower Bhuban and Renji formationThe well was spudded on 29.03.2010 and drilled up to 2387m on 04.07 2010 against the target Depth of 3500m. It penetrated through Bokabil formation (310m) and has penetrated Upper Bhuban (700m), Middle Bhuban (1140m) and Lower Bhuban (237m+). Target depth could not be achieved due to complication at shallow depth followed

	by **toppling of rig and further drilling of the well has been terminated. So, hydrocarbon potential of the well could not be ascertained at the expected zones underneath.** Considering the above, the well has been declared abandoned with the status "Abandoned due to Complication".
TUKB-3 & 3A	The location TUKB -3A (side-track) in Tukbai structure, falling in Sector V-C PEL block, is located at a distance of 400m towards 3420 from well TUKB-2. Before drilling this location, the well TUKB-3 (TKAC) was drilled to explore equivalent gas sand encountered in the Upper Bhuban Formation in well TUKB-2, but it was found that this gas sand had completely wedged out. Zero Offset and Offset VSP were recorded and evaluated to chase the extension of the equivalent gas sand of TUKB-2. Based on the results, the location TUKB-3(Sidetrack) was released to explore the equivalent gas sand encountered in Upper Bhuban Formation in TUKB-2 with a target depth of 900m (TVD) and planned to be side-tracked from TUKB-3 with a horizontal drift of 380m in 218 degree at 811 m TVD MSL (top of gas sand). **Based on the Production Testing and Reservoir study results, TUKB- 3A was declared as a gas well with a maximum flow of 12900m3/day through 6.0 mm bean.**
TUKB-4	The well Tukbai-4 (TKAD) was drilled with an objective to explore hydrocarbon potential of Upper Bhuban formation. It was spudded on 26.04.2016 and drilled as a vertical well with a target depth of 1200m. As no zone of interest was found, target depth was revised to 1755m, to encounter sands in Middle Bhuban Formation. During drilling the well penetrated through Bokabil and Upper Bhuban and was terminated within Middle Bhuban formation. Based on the log evaluation of the well, all the sand layers developed in Bokabil, Upper Bhuban and Middle Bhuban Formation are interpreted as water bearing. MDT was attempted in 8.5" section and carried out 17 pre-tests. Out of which13 pertest reported as tight. Only one water sample could be collected at 1217m with salinity 24.8 gpl and formation pressure 125. 30ksc. As no prospective zone could be identified from hydrocarbon point of view in all the Formations, the well was **abandoned without lowering production casing.**
PATHIMARA-1 (PTMR-1)	The well Pathimara-1 (PTMR-1) drilled down to the depth 3000m against the target depth of 3000m and bottomed in Jenam Formation. Maximum total gas content of 1.09% was recorded in MLU at depth 2158m. Maximum total gas 1.15% was recorded at 1190m in MLU during drilling. milky fluorescence and mild +ve cut were observed in SWC. On the basis of log evaluation, **four objects** in lower bhuban formation were tested conventionally and all are proved to be **water bearing**. In view of testing results, the well has been declared as "dry and abandoned".
PATHIMARA-2 (PTMR-2)	The well pathimara-2 (PTMR-2) was drilled as an exploratory "B" category well with a target depth of 2750m to explore clastic reservoir within upper and middle Bhuban formations. The well was drilled down to the depth of 2955m against extended target depth of 2950m and terminated in lower bhuban formation. No HC shows were observed during drilling. However, based on log evaluation two objects were tested in lower bhuban formation. Only feeble gas was observed in object-I (2848-2850m, 2851-2854m). Object-I was reperforated but **no indication of gas or any influx** observed. Based on testing results well has been declared as "Abandoned with gas indication".
PATHARIA field:	
PATHARIA-3 (PTRA-3)	The well Patharia-3 was planned at a target depth of 3750m but had to be prematurely abandoned at a drilled depth of 2173.5m due to drilling complications. The objective was to explore the hydrocarbon potential of the Surma Group. The well was spudded in Tipam Formation and encountered the Bokabil formation from 948m onwards. **Indication of gas were noticed at 2173.5m in Bokabil formation** however complications in the well started thereafter and well was Abandoned.
PATHARIA-4 (PTRA-4)	The well Patharia-4 is located on the western flank of patharia anticline, and drilled upto a depth of 3154.5m against the target depth of 3500m with an objective to explore the hydrocarbon prospectivity of the Surma group. After 3154.5 m due to drilling complications,

	the well was side-tracked upto 3065m (side-tracked). The well was spudded in Tipam sandstone formation and ended in lower Bhuban formation. The well encountered stratigraphic thickness of 125m of Tipam, 1142m of Bokabil, 639m of Upper Bhuban, 996m of Middle Bhuban, and 252.5m of Lower Bhuban formations. A Total of **7 objects; 3 in Lower Bhuban and 4 in Middle Bhuban formations were tested**, **none of which yielded hydrocarbons due to poor permeability and absence of good quality reservoir facies. The well was declared dry and Abandoned..**

5. DATA PACKAGE INFORMATION

This information docket for the Contract Area, titled, AA/ONDSF/ASSAM/2025 is available with Data Package, which includes seismic data, well data and well completion and other reports. Apart from seismic and well data, the Contract Area has **58** reports. Given below is the detail of datasets that are available in the Data Package.

5.1 Well, Seismic Data and Reports Availability

5.1.1 Well Data:

SL. No.	Well Name	Longitude	Latitude	CRS
1	LXMJ-1A	94° 47' 09.201" E	26° 47' 53.894" N	WGS84 UTM 46N
2	BHBR-1	94° 46' 20.495" E	26° 49' 22.705" N	WGS84 UTM 46N
3	NAHB-1	94° 52’ 28.070” E	26° 58’ 35.319” N	WGS84 UTM 46N
4	CRDO-1	94° 53’ 25.000” E	26° 57’ 20.000” N	WGS84 UTM 46N
5	KHEREM-2	95° 53’ 09.808” E	27° 27’ 48.784” N	WGS84 UTM 46N
6	TUKB-2	93° 04’ 57.360” E	24° 54’ 13.695” N	WGS84 UTM 46N
7	PTRA-2	92° 18’ 31.448” E	24° 47’ 29.258” N	WGS84 UTM 46N
8	PTRA-5	92° 19’ 43.896” E	24° 49’ 01.402” N	WGS84 UTM 46N

5.1.2 Seismic 2D data:

Contract Area: AA/ONDSF/ASSAM/2025

DSF-IV CONTRACT AREA	Line segment name	Processing type	FSP/CDP	LSP/CDP	Length (Km)	CRS
AA-ONDSF-ASSAM-2025	D-13e	FINAL_MIGRATION	2	2074	4.1346	WGS84 UTM 46N
	ON-112A	FINAL_MIGRATION	1	451	3.6209	WGS84 UTM 46N
	D-13B:a	FINAL_PSTM_STACK	1	2015	4.0714	WGS84 UTM 46N
	KH-05	MIGRATION_STACK	1	373	4.3242	WGS84 UTM 46N
	131-04	FINAL_STACK	1	536	5.6102	WGS84 UTM 46N
	131-07	FINAL_STACK	1	296	3.5296	WGS84 UTM 46N
	202-01	FINAL_MIGRATION	1	657	7.4218	WGS84 UTM 46N
	202-03	FINAL_MIGRATION	1	818	1.9569	WGS84 UTM 46N
	202-05	FINAL_MIGRATION	825	1930	9.0733	WGS84 UTM 46N
	202-07	FINAL_MIGRATION	60	724	0.7445	WGS84 UTM 46N
	202-07	FINAL_MIGRATION	60	724	3.8334	WGS84 UTM 46N
	202-08	FINAL_MIGRATION	42	644	4.8492	WGS84 UTM 46N
	202-13	FINAL_MIGRATION	1	734	6.4615	WGS84 UTM 46N
	120-1	FINAL_MIGRATION	11	279	2.794	WGS84 UTM 46N
	120-10	FINAL_MIGRATION	63	402	5.7337	WGS84 UTM 46N
	120-11	FINAL_MIGRATION	64	405	5.4091	WGS84 UTM 46N
	120-12	FINAL_MIGRATION	64	581	9.4591	WGS84 UTM 46N
	120-2	FINAL_MIGRATION	57	630	7.639	WGS84 UTM 46N
	120-4	FINAL_MIGRATION	62	688	6.6823	WGS84 UTM 46N
	120-6	FINAL_MIGRATION	62	505	9.5689	WGS84 UTM 46N
	120-7	FINAL_MIGRATION	62	315	3.5693	WGS84 UTM 46N
	120-8	FINAL_MIGRATION	62	685	3.6087	WGS84 UTM 46N
	A202-06	FINAL_MIGRATION	1	1236	8.5289	WGS84 UTM 46N
	A202-09	FINAL_MIGRATION	1	1052	6.3632	WGS84 UTM 46N
	A202-10	FINAL_MIGRATION	1	1020	5.2789	WGS84 UTM 46N
	A202-12	FINAL_MIGRATION	1	1122	7.633	WGS84 UTM 46N
	A119-05	REPROCESSED_FINAL_PSTM_STACK	1	483	3.1361	WGS84 UTM 46N
	A119-04	REPROCESSED_FINAL_PSTM_STACK	1	483	3.1361	WGS84 UTM 46N
	A119-03	REPROCESSED_FINAL_PSTM_STACK	1	653	4.757	WGS84 UTM 46N
	A119-01	REPROCESSED_FINAL_PSTM_STACK	2	694	7.142	WGS84 UTM 46N
	A119-10	FINAL_MIGRATION	68	436	3.7476	WGS84 UTM 46N
	A119-02	FINAL_MIGRATION	56	391	1.9688	WGS84 UTM 46N
	A119-09	FINAL_MIGRATION	68	620	3.9614	WGS84 UTM 46N
	A119-07	FINAL_MIGRATION	68	642	4.3479	WGS84 UTM 46N
	A119-06	FINAL_MIGRATION	63	455	1.0971	WGS84 UTM 46N
	A59-03	FINAL STACK	44	225	4.3533	WGS84 UTM 46N
	A192-02	FINAL_STACK	1	2985	5.0545	WGS84 UTM 46N
	A162-13	FINAL_STACK	8	791	4.8396	WGS84 UTM 46N
	A162-12	FINAL_STACK	2	883	1.9339	WGS84 UTM 46N
	A162-12	FINAL_STACK	2	883	8.8383	WGS84 UTM 46N
	A162-11	FINAL_STACK	10	807	4.2484	WGS84 UTM 46N
	A162-10	FINAL_STACK	8	1235	9.6828	WGS84 UTM 46N
	A162-10	FINAL_STACK	8	1235	4.47	WGS84 UTM 46N
	A162-09	FINAL_STACK	2	865	2.381	WGS84 UTM 46N
	A162-09	FINAL_STACK	2	865	2.2969	WGS84 UTM 46N
	A162-06	FINAL_STACK	11	957	5.1123	WGS84 UTM 46N
	A162-05	FINAL_STACK	11	805	5.0601	WGS84 UTM 46N
	A162-04	FINAL_STACK	114	985	6.7373	WGS84 UTM 46N
	A162-03	FINAL_STACK	2	867	2.8425	WGS84 UTM 46N
	A158-01	FINAL_MIGRATION	58	2239	4.1106	WGS84 UTM 46N
	A151-7	FINAL_STACK	6	612	2.4167	WGS84 UTM 46N
	A151-5	FINAL_STACK	1	2254	1.0672	WGS84 UTM 46N
	A151-4	FINAL_STACK	55	860	3.9763	WGS84 UTM 46N
	A151-3	FINAL_STACK	58	968	1.6736	WGS84 UTM 46N
	A151-2	FINAL_STACK	1	1085	3.3453	WGS84 UTM 46N
	A151-14	FINAL_STACK	58	478	3.0232	WGS84 UTM 46N
	A151-11	FINAL_STACK	1	1786	5.0541	WGS84 UTM 46N
	A151-1	FINAL_STACK	94	1023	4.0685	WGS84 UTM 46N
	A116-03	REPROCESSED_FINAL_POSTM_STACK	1	1049	2.8399	WGS84 UTM 46N
	A116-01	REPROCESSED_FINAL_POSTM_STACK	1	1273	5.8	WGS84 UTM 46N
	A108-03	REPROCESSED_FINAL_POSTM_STACK	24	1405	4.9083	WGS84 UTM 46N
	A126-9	FINAL_STACK	104	817	8.9356	WGS84 UTM 46N

DSF-IV CONTRACT AREA	Line segment name	Processing type	FSP/CDP	LSP/CDP	Length (Km)	CRS
AA-ONDSF-ASSAM-2025	A126-8	FINAL_STACK	104	1154	6.5118	WGS84 UTM 46N
	A126-7	FINAL_STACK	106	1154	6.8437	WGS84 UTM 46N
	A126-6	FINAL_STACK	97	971	2.0842	WGS84 UTM 46N
	A126-10	FINAL_STACK	182	1176	7.2994	WGS84 UTM 46N
	POC-03-02N	RAW_MIGRATION_STACK	1119	2679	8.707	WGS84 UTM 46N
	LINE NO:04	FINAL_PSTM_STACK	1451	6066	2.0234	WGS84 UTM 46N
	LINE NO:03	FINAL_PSTM_STACK	1494	4919	1.7841	WGS84 UTM 46N
	LINE NO:02	FINAL_PSTM_STACK	1497	6109	2.6183	WGS84 UTM 46N
	A116-5	FINAL_STACK	151	985	3.4367	WGS84 UTM 46N
	A134-11	FINAL_STACK	167	754	8.0684	WGS84 UTM 46N
	A134-8	FINAL_STACK	100	975	10.921	WGS84 UTM 46N
	A134-7	FINAL_STACK	52	527	7.4577	WGS84 UTM 46N
	A134-6	FINAL_STACK	104	995	11.555	WGS84 UTM 46N
	A134-5	FINAL_STACK	293	921	6.649	WGS84 UTM 46N
	A134-4	FINAL_STACK	414	1462	8.6335	WGS84 UTM 46N
	A134-3	FINAL_STACK	232	1188	12.027	WGS84 UTM 46N
	A134-2	FINAL_STACK	54	1531	14.884	WGS84 UTM 46N
	A134-1	FINAL_STACK	149	1155	13.039	WGS84 UTM 46N
	A323-04	PSDM_SCALED_TO_TIME	1451	6066	2.0234	WGS84 UTM 46N
	A323-01	PSDM_SCALED_TO_TIME	1509	4348	1.6531	WGS84 UTM 46N
	A258-04	FINAL_STACK	5	330	4.0233	WGS84 UTM 46N
	A258-03	FINAL_STACK	1	780	10.384	WGS84 UTM 46N
	A258-02	FINAL_STACK	5	552	6.8179	WGS84 UTM 46N
	A-177-08	FINAL_STACK	1	1224	8.9008	WGS84 UTM 46N
	A-177-07	FINAL_STACK	1	687	4.2931	WGS84 UTM 46N
	A-177-05A	FINAL_STACK	1	323	1.5471	WGS84 UTM 46N
	A-177-05	FINAL_STACK	1	591	4.6881	WGS84 UTM 46N
	A-177-04	FINAL_STACK	1	1102	12.577	WGS84 UTM 46N
	A-177-02	FINAL_STACK	1	1137	7.7765	WGS84 UTM 46N
	A-177-01	FINAL_STACK	1	603	7.4313	WGS84 UTM 46N
	A258-01	FINAL_MIGRATION	1	1084	12.012	WGS84 UTM 46N
	A266-06	FINAL_STACK	1	764	7.747	WGS84 UTM 46N
	A266-05	FINAL_STACK	2	916	11.502	WGS84 UTM 46N
	A266-04	FINAL_STACK	168	1666	18.791	WGS84 UTM 46N
	A266-03	FINAL_STACK	41	1014	12.094	WGS84 UTM 46N
	A266-02	FINAL_STACK	1	1123	13.983	WGS84 UTM 46N
	A266-01	FINAL_STACK	1	1176	14.09	WGS84 UTM 46N
	A145-14	FINAL_STACK	100	540	5.5053	WGS84 UTM 46N
	A145-13	FINAL_STACK	100	987	11.905	WGS84 UTM 46N
	A145-12	FINAL_STACK	106	982	4.7582	WGS84 UTM 46N
	A145-11	FINAL_STACK	100	1659	9.6604	WGS84 UTM 46N
	A156-08	FINAL_STACK	100	2012	17.082	WGS84 UTM 46N
	A156-06	FINAL_STACK	100	1806	9.9341	WGS84 UTM 46N
	A156-05	FINAL_STACK	109	1916	12.196	WGS84 UTM 46N
	A156-04	FINAL_STACK	1	1909	11.826	WGS84 UTM 46N
	A156-03	FINAL_STACK	121	2008	9.3613	WGS84 UTM 46N
	A156-01	FINAL_STACK	100	1168	2.1692	WGS84 UTM 46N
	A250-02	FINAL_MIGRATION	1	1364	16.17	WGS84 UTM 46N
	A250-01A	FINAL_MIGRATION	1	710	9.0704	WGS84 UTM 46N
	A250-01	FINAL_MIGRATION	1	474	1.1408	WGS84 UTM 46N
	A241-05	FINAL_MIGRATION	1	362	4.608	WGS84 UTM 46N
	A241-04	FINAL_MIGRATION	1	566	2.751	WGS84 UTM 46N
	A241-03	FINAL_MIGRATION	1	687	7.6721	WGS84 UTM 46N
	A241-02	FINAL_MIGRATION	1	689	6.3742	WGS84 UTM 46N
	A241-02	FINAL_MIGRATION	1	689	1.7964	WGS84 UTM 46N
	A241-01	FINAL_MIGRATION	1	1194	5.2261	WGS84 UTM 46N
	A-181-07	FINAL_MIGRATION	1	1587	12.262	WGS84 UTM 46N
	A-181-06	FINAL_MIGRATION	1	1270	2.1897	WGS84 UTM 46N
	A-181-04	FINAL_MIGRATION	1	1111	13.782	WGS84 UTM 46N
	A-181-03	FINAL_MIGRATION	1	614	7.613	WGS84 UTM 46N
	A-181-02	FINAL_MIGRATION	1	948	11.83	WGS84 UTM 46N
	A-181-01	FINAL_MIGRATION	1	1402	16.697	WGS84 UTM 46N
	A115-3	FINAL_MIGRATION	4	2129	7.985	WGS84 UTM 46N
	A115-3	FINAL_MIGRATION	104	2231	8.166	WGS84 UTM 46N
	A115-2	FINAL_MIGRATION	105	2133	9.9338	WGS84 UTM 46N

5.1.3 Seismic 3D Data:

AA/ONDSF/ASSAM/2025 Contract Area:

00001.GLKI_LAX_BIH_SAN_FMIG_FINAL_MIGRATION_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00001.GLKI_LAX_BIH_SAN_FMIG_FINAL_MIGRATION_.sgy INTERVAL:

Point	Inline	Crossline	Easting	Northing
1	215	1179	678839.88	2975644.00
2	375	1179	675999.38	2983132.75
3	375	1760	689595.12	2988291.25
4	215	1760	692435.88	2980802.00

00002.GLKI_LAX_BIH_SAN_FMIG_FINAL_MIGRATION_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00002.GLKI_LAX_BIH_SAN_FMIG_FINAL_MIGRATION_.sgy

Point	Inline	Crossline	Easting	Northing
1	23	767	672607.12	2963002.00
2	119	767	670902.88	2967495.50
3	119	1139	679607.88	2970796.50
4	23	1139	681311.75	2966303.25

00002.AAFB_NORTH_OF_PATHARIA_A306_FMIG_FINAL_MIGRATION_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00002.AAFB_NORTH_OF_PATHARIA_A306_FMIG_FINAL_MIGRATION_.sgy

Point	Inline	Crossline	Easting	Northing
1	833	356	435754.00	2742326.00
2	1002	356	436155.44	2746534.75
3	1002	905	429318.69	2747186.75
4	833	905	428918.22	2742978.00

00004.AAFB_NORTH_OF_PATHARIA_A314_FMIG_FINAL_MIGRATION_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00004.AAFB_NORTH_OF_PATHARIA_A314_FMIG_FINAL_MIGRATION_.sgy

Point	Inline	Crossline	Easting	Northing
1	532	437	434030.81	2734926.25
2	908	437	434924.12	2744289.75
3	908	1012	427763.81	2744972.50
4	532	1012	426871.34	2735608.25

00003.AAFB_TUKBAI_A302-A303_POST_MIG_STK_FINAL_POSTM_STACK_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00003.AAFB_TUKBAI_A302-A303_POST_MIG_STK_FINAL_POSTM_STACK_.sgy

Point	Inline	Crossline	Easting	Northing
1	669	884	497793.00	2750702.00
2	1070	884	501523.00	2760014.00
3	1070	1920	513552.28	2755194.50
4	669	1920	509822.47	2745883.50

00006.AAFB_TUKBAI-PATHMARA_A312-313_PSDM_SCALE_PSDM_SCALED_TO_TIME_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00006.AAFB_TUKBAI-PATHMARA_A312-313_PSDM_SCALE_PSDM_SCALED_TO_TIME_.sgy

Point	Inline	Crossline	Easting	Northing
1	406	171	483818.00	2746507.00
2	883	171	488254.00	2757585.00
3	883	1800	507169.00	2750008.00
4	406	1800	502732.38	2738931.75

00005.AAFB_INDRANAGARRANGAMATI_A309_PSTM_FINAL_PSTM_STACK_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00005.AAFB_INDRANAGARRANGAMATI_A309_PSTM_FINAL_PSTM_STACK_.sgy

Point	Inline	Crossline	Easting	Northing
1	1	100	475216.06	2754444.75
2	221	100	479215.75	2764699.50
3	221	841	496486.00	2757962.00
4	1	841	492485.00	2747708.00

00007.ASSAM_KHEREM-KUMCHAI_3D_FINAL_PSTM_STACK_.sgy
3D bin centre corner points - all traces

3D bin centre corner points - all traces : 00007.ASSAM_KHEREM-KUMCHAI_3D_FINAL_PSTM_STACK_.sgy

Point	Inline	Crossline	Easting	Northing
1	65	3322095	782720.56	3038007.00
2	215	3322095	782798.69	3042007.00
3	215	3326395	787075.62	3043163.25
4	74	3326399	787016.00	3039560.00

5.2 Data Package Cost

The Data Package contains seismic (2D and/or 3D) and well data along with reports. The cost of the Data Package of this Information Docket (AA/ONDSF/ASSAM/2025 Contract Area) comes to be **USD 10,320**. This cost is as per the current data policy of NDR at the time of writing this report and subject to changes if data rates or policy framework are revised.

S.No.	Contract Area on offer	AREA (SQ KM)	NIO Map reference no.	Total Wells	2D Seismic (LKM)	3D Seismic (SKM)	No. of Reports	FINAL COST in USD ($)
1	AA/ONDSF/ASSAM/2025	709.85	O-3	32	830.81	532.64	58	10,320

6. CONTRACT AREA SUMMARY

Contract Area name: **AA/ONDSF/ASSAM/2025**

NIO map reference no.: **O-3**

Geographical area: **ASSAM Onshore**

Number of field(s)/discoveries: **8**

Number of well(s): **32**

Total area: **709.85 Sq. Km**.

Seismic 2D data: **830.81 Line Km**.

Seismic 3D data: **532.64 Sq. Km**.

Report(s) available: **58**

Hydrocarbon In-Place (2P) O+OEG: **8.77 MMTOE**

Data package cost: **USD 10,320**

7. CONCLUSIONS

The information docket has been prepared from the geoscientific and engineering data sets, made available by NOCs. The work has been primarily accomplished with all requisite data/information pre-processed using various in-house interpretation software. Desktop publishing applications of documents, spreadsheets and images including Google maps have also been extensively used.

The 8 discoveries, which are lying unpursued and holding contingent resources/ reserves are potential to be further developed/commercially produced. This booklet will be a useful supplement to the Data Package of the corresponding Contract Area. Such data represent 2D/3D seismic, well logs and reports on key information from various field operations pertaining to drilling, logging, testing and production. The total data package on offer under this bid round includes **830.81 LKM 2D** seismic, **532.64 SKM 3D** seismic, and **32** well data. The Data Package will be hosted in Data rooms for viewing and for sale from National Data Repository (NDR) to the interested investors/ bidders.

Though, the docket mentions estimated hydrocarbon, it indicates extent and order of hydrocarbon pool size. DGH strongly recommends that bidders must have their own understanding and independent assessment of resource base to support any forward bidding decision.

पेट्रोलियम एवं
प्राकृतिक गैस मंत्रालय
MINISTRY OF
PETROLEUM AND NATURAL GAS

सत्यमेव जयते

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