DETERMINATION OF OPTIMUM PRODUCTION AND DEVELOPMENT STRATEGY FOR SALDA NADI GAS FIELD BY SIMULATION TECHNIQUE

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CANDIDATE'S DECLARATION

It is hereby declared that this thesis or any part of it has not been submitted elsewhere for the award of any degree or diploma.

Signature of the candidate

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ABSTRACT

Saldanadi Gas Field was discovered by BAPEX in 1996. Initially two gas sands were discovered and production was commenced with 2 wells, Saldanadi – 1 and 2. Later on 2 more were drilled. Although, the Gas initially in place (GIIP) by various estimates ranged from 300 – 328 BSCF, the total recovery from this field to date is only about 65 BSCF. This reservoir has been quite challenging from the beginning, because the wellhead pressures and production rates reduce sharply. It has been identified as a tight gas reservoir, and a sound production strategy for this field is yet to be established.

The approach taken in this work is reservoir simulation. From the available geological, geophysical and petrophysical data, a 3 dimensional reservoir model was constructed. Then by dynamic simulation the production and pressure history were matched. One a satisfactory math obtained, the model was used for prediction of future production. Five different development and production scenarios were studied. These included the existing condition as well as drilling 3 new well.

The results indicate that, with the existing system the maximum recovery from this field would be about 31.11%. However, this figure may be improved by the different strategies examined in this research. It is seen that forecast scenario 5, which considers 3 additional well and workover on the existing wells, could yield a recovery as high as 79.22%.

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NOMENCLATURE

AOFP	Absolute Open Flow Potential
BOGMC	Bangladesh Oil, Gas and Mineral Corporation (Petrobangla)
BAPEX	Bangladesh Petroleum Exploration and Production Company Limited
BHT	Bottom Hole Temperature
BSCF	Billion (10^9) Standard Cubic Feet
BUET	Bangladesh University of Engineering and Technology
DST	Drill Stem Test
SLD#1	Salda nadi First exploratory well drilled in 1996
SLD#2	Salda nadi well number 2
SLD#3	Salda nadi well number 3
SLD#4	Salda nadi well number 4
FGPR	Field Gas Production Rate
FGPT	Field Gas Production Total
GIIP	Gas Initially In Place
GasSat	Gas Saturation
GWC	Gas Water Contact
KB	Kelly Bushing
MD	Measured Depth
MMSCFD	Million (10^6) Standard Cubic Feet per Day
PMRE	Petroleum and Mineral Resources Engineering Department
Psia	Pounds per square inch absolute
P/Z	Pressure / Z factor
RPS Energy	A UK based Petroleum Consultant Company
TVD	Total Vertical Depth
TVDss	Total Vertical Depth from sub sea level
WGPR	Well Gas Production Rate
WTHP	Well Tubing Head Pressure
WWPR	Well Water Production Rate
Z	Compressibility factor

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CHAPTER I
INTRODUCTION

Three-dimensional (3D) modeling of hydrocarbon reservoirs is the vital factor that controls hydrocarbon reservoir evaluation and simulation for better exploitation and successful development. Although, 3D geological modeling can be done in oil and gas reservoirs easily using various available software, the modeling accuracy still presents a big challenge that has a great impact on the effective development of hydrocarbon reservoir (Ali, Radwan, Abd El-Gawad, & Abdel-Latief, 2022) .

The advantage of 3D modeling lies also in its capability to allow the interpreter to view and evaluate a structure, facies or petro-physical model by displaying a cross section along any line of section and through any well control. The geological capabilities found within Petrel, all seamlessly unified with the geophysical and reservoir engineering tools enable an integrated study by providing an accurate static reservoir description that evolves with the reservoir (Abdel-Fattah, Dominik, Shendi, Gadallah, & Rashed, 2010). Consequently, the development of this reservoir model is one of the key aspects of the overall reservoir management process.

Implementing integrated geological, geophysical, petro-physical, geo-statistics, and reservoir engineering approach to develop the static model of any reservoir creates a framework for a geological structure that can be used to predict the performance and production of a hydrocarbon reservoir (Rahimi, Riahi, & Evaporites, 2020). This numerical tool can solve the flow equations representative of the flow of gas and water within the reservoir. The optimization of huge investments allocated to reservoir exploitation strategies fundamentally depends on the precision of this reservoir performance production forecasts (Cunha, 2003).

The Saldanadi Gas Field is a great part of the greater Rukhia anticline of the Bengal basin and is located in Brahmanbaria. The location map of the Saldanadi Gas Field is as shown in Fig 1. This Gas Field was discovered by BAPEX in 1996 by drilling of Saldanadi well-1 and encountered two gas sands which were completed as dual producer (Petrobangla, 2004). There are four wells penetrating the Saldanadi structure which are Saldanadi well-1 (SLD#1), Saldanadi well-2 (SLD#2), Saldanadi well-3 (SLD#3) and Saldanadi well-4 (SLD#4) respectively. Subsequently, the deviated well, SLD#2, was drilled in 1999 with the objective to appraise the Saldanadi structure and encountered another layer of gas sand which was completed as a single producer.

However, SLD#1 and SLD#2 stopped production in 2012 due to excessive production of water. Only SLD# 3 and SLD# 4 are producing at low rates. There have been a number of studies on this field in the past, and the last simulation was conducted in 2009. It is therefore, necessary to re-assess the field and forecast its production by considering different production scenarios.

Figure 1: Location Map of Saldanadi Gas Field

In this study, the 3D reservoir model was constructed using Petrel™ software, Schlumberger’s reservoir modeling software. 3D Reservoir Modeling has been done by integrating interpreted seismic, wire-line logs and core data. Moreover, applied best-fit parameters in the reservoir simulation to decrease final geological model uncertainties. 3D reservoir static model is validated by production and pressure history matching with the simulated modeling (Cunha, 2003). Based on the validated 3D modeling, forecasted the performance and production of the hydrocarbon reservoir using dynamic simulation by ECLIPSE software which would aid in economic decision for further hydrocarbon exploration (Sallam, Ahmad, Nasr, Gomari, & Technology, 2015). To account for the dynamic data, an objective function quantifies the difference between observed and simulated values, which is then incorporated into the construction of the reservoir model

(Cunha, 2003; Mirzadeh et al., 2014).

The aim of this thesis is to construct a valid 3D reservoir model and simulate the reservoir performance under different production and development scenarios. It should suggest the best strategy for maximum recovery while maintaining a reasonable plateau production rate for the longest time.

1.1 Objectives

The objectives of the study are as follows:

1. To develop reservoir model and matching the production and pressure history data.
2. To find out the most suitable production and development strategy to increase production rate as well as recovery factor.

1.2 Possible Outcome

1. A more reliable reservoir model which may be used for production prediction.
2. Optimum number of wells, location of wells, and production rates to get maximum recovery from the field.

1.3 Methodology Outline

To achieve the above objectives the following methodology is adopted:

1. Collection of all relevant production and reservoir data from Petrobangla and BAPEX.
2. Construct a static model from seismic and well log interpretation.
3. Construct and run dynamic model (dynamic simulation) to evaluate the reservoir performance.
4. Use historical production and pressure data for history matching (model validation).
5. Analysis and review different approach by which recovery rate might be increased such as integration of more wells, changing production rates, and tuning wellhead pressure.

In this study, Petrel software is used to construct the reservoir model, and a 3D black oil reservoir simulator ECLIPSE is used to perform history matching and predicting production performance.

CHAPTER II

LITERATURE REVIEW

2.1 Exploration and Development History

Saldanadi is a part of greater Rukhia structure of Tripura state of India. Geological Survey of India (GSI), Burma Oil Co. (BOC) prepared photo geological map of the entire region i.e. Tripura-Chachar-Mizoram area (Petrobangla, 2004).

Oil and Gas Development Corporation (OGDC) carried out geological survey of Saldanadi area during 1964-65 field seasons. The survey confirmed the existence of a closed structure. But the prospect of hydrocarbon could not be concluded as it is a low relief anticline and large area comprising both northern and southern part of the structure is within India. Geologists of Oil and Natural Gas Corporation (ONGC) of India have been actively involved in the area since 1962 through acquiring and interpretation of geological and geophysical as well as aerial photo data. First exploratory well was drilled in Rukhia by ONGC during 1980-83. It was the deepest well in the structure and was a gas discovery. Since then ONGC continued their effort in this area and has drilled about 37 wells. However very little is known about ONGC's findings (Petrobangla, 2004).

According to the Indian geological report no fault could be observed in the geological map (Ganguly, 1983). In both geological and landsat maps oldest outcrop was mapped as Tipam Sandstone. Upper Dupi Tila was shown as the oldest exposed sequence in another map (Agarwal et.al., 1994). The hill range system constitutes a series of symmetrical anticlines and relatively broader and nearly symmetrical synclines (Zutshi 1993). The Saldanadi structure is exposed on surface and represented by series of hills and valleys. Height of the hill ranges varies between 200 and 500 m.

2.2 Drilling Activities

ONGC drilled first exploratory well in Rukhia structure at a depth of 3500 m and declared as a gas field. During the field session 1991-92, BAPEX conducted multifold seismic survey in Saldanadi area and acquired 159L km of digital seismic data with 12 fold coverage. The seismic interpretation confirmed that the existence of the faulted structure. After interpretation of seismic data, geological data, surrounding information and the presence of hydrocarbon, BAPEX drilled an exploratory well in 1996 in the territory of Bangladesh. During the field session 2010-2011, BAPEX again conducted multifold seismic survey in Saldanadi area and acquired 40L km of digital seismic data with 30-60 fold coverage.

The exploratory well SLD#1 was drilled at a depth of 2511m and discovered as a gas field. The well was completed as a duel producer. Later on deviated well SLD#2 was drilled in 1999 and completed as a single producer (Petrobangla, 2009a).

2.3 Geological Investigations

Both Gravity and Aeromagnetic survey was carried out within the study area shown in Fig 2. In relation to regional tectonic history, the Saldanadi structure has developed in the foredeep located west and south of massive orogenic uplifts. It is an anticline slightly convexly curved to the east with NNW-SSE trending axis like other structures in this Fold Belt. The Saldanadi structure is considered to be formed after the Pliocene from the seismic interpretation (Petrobangla, 2004).

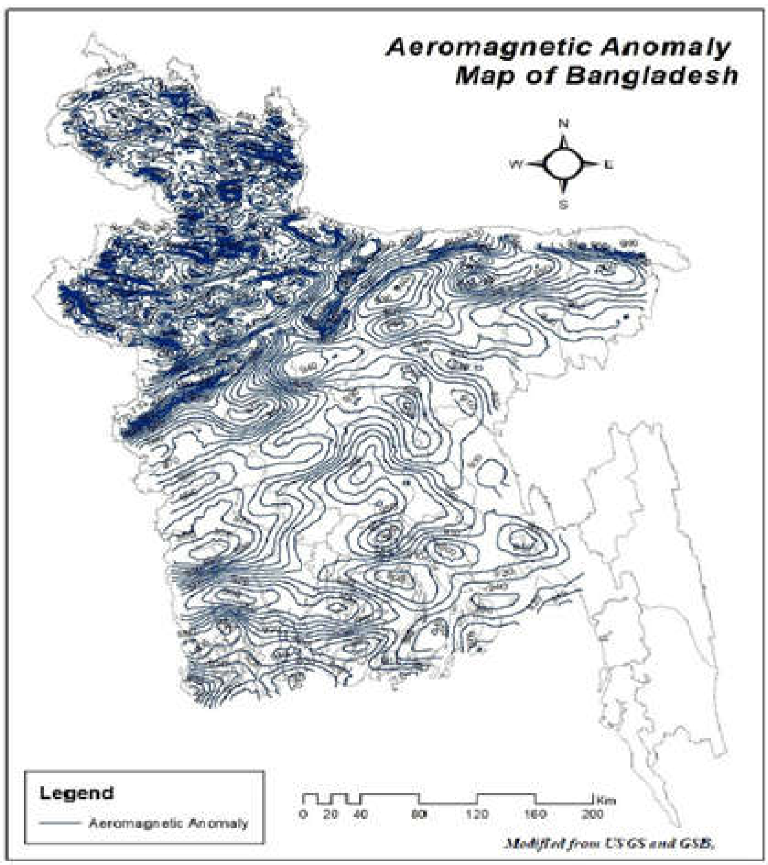

Figure 2: Aeromagnetic anomaly map of Bangladesh (Petrobangla, 2004).

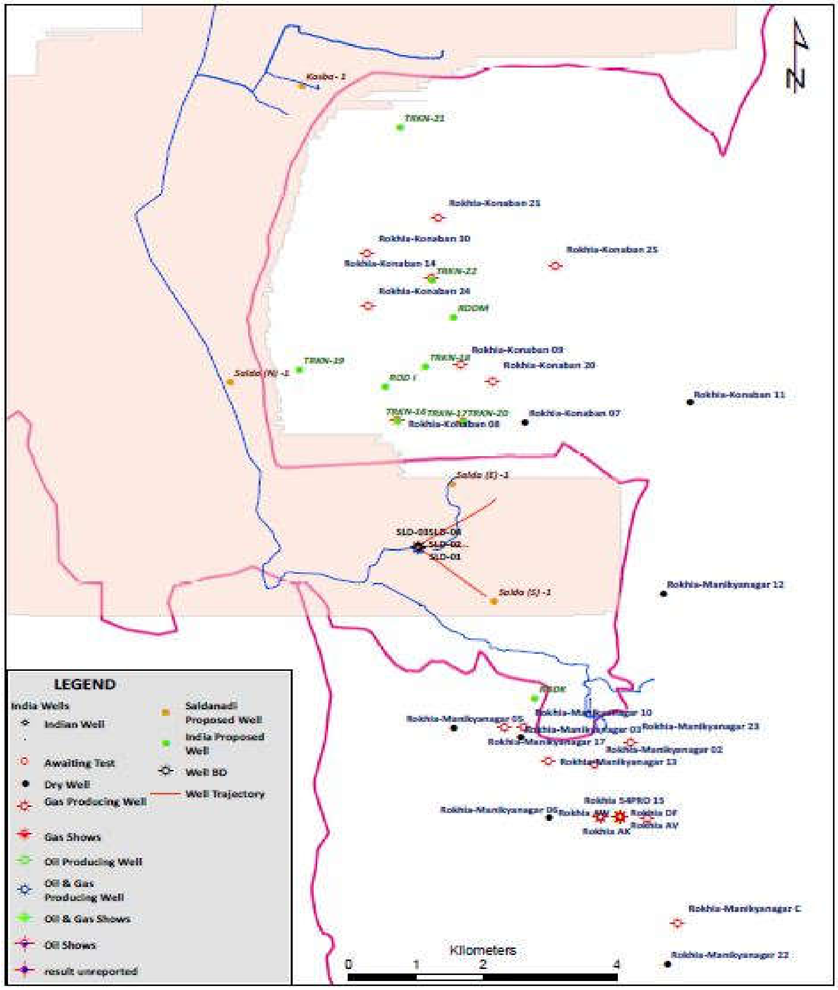

Figure 3: Well location map of Rukhia structure (Bapex)

2.4 Seismic Investigation

Seismic lines named as SD-01 to SD-09 were acquired in 1996-97 by SERCEL 368 acquisition system. Nominal fold of coverage was 30; recording time 7.0s and sampling rate 2ms (BAPEX, 2003).

All the acquired data were processed under geophysical Division of BAPEX by PROMAX 2D processing. LRU-4 seismic line was acquired in (1992) and was reprocessed along with other SD lines for interpretation (BAPEX, 2003).

2.5 Well History

2.5.1 Saldanadi well-1 (SLD#1)

This well was drilled in 1996 and it was a gas discovery. The well was completed as a dual producer and production started on 28 March, 1998. Following the discovery of hydrocarbon, 52.6 LKM 30 fold seismic data has been recorded in 1996-97.

On 3rd May 2001, when the well was shut down, cumulative production logged 14.173 Bcf gas from lower zone and 2.93 Bcf gas from the upper zone and 13,860 bbl condensates. During this period 10,480 bbl water was also produced (Petrobangla, 2004).

2.5.2 Saldanadi well-2 (SLD#2)

This directional well was drilled in 1999 with bottom-hole location about 750m east of the well no.1. In the SLD#2 well three zones were tested but only from Middle Zone gas was observed flow. The well was completed as a single producer. SLD#2 well was put into production on 3rd May 2001. Cumulative production of gas from the same well as on 30 June 2001 was 877.8131 mmscf along with 781.05 bbl condensate and 518.55 bbl water (Bapex, 2001). Well summery of SLD#1 and SLD#2 are given in Table 1 and Table 2 respectively.

Table 1: Well Summery of Saldanadi well-1 (SLD#1)

1.	Well No.	:	01	
2.	Location	:	91° 10´ 19.73″ E 23° 40´ 29.73″ N	
3.	Drilled By	:	BAPEX	
4.	Rig Used	:	IDECO H 1700	
5.	Elevation	:	KB- 28.3m AMSL ; GL- 21.94 m AMSL	
6.	Well Type	:	Exploratory (Vertical)	
7.	Total Well Depth	:	2511 m	
8.	Spud- Date	:	July 18, 1996	
9.	Date Reached @ TD	:	March 18, 1997	
10.	Work Over Date	:	Not Applicable	
11.	Casing Info		30″ 20″ 13 3⁄8″ 9 5⁄8″ 7″ Liner	0-30 m 0-250 m 0-849 m 0-1879 m 1789.74-2510 m
12.	Tubing Size	:	3 1⁄2″ VAM Tubing	
13.	Production Casing	:	7″ Liner	
14.	Sub-Surface Safety Valve	:		
15.	Perforated Interval	:	2408.5 – 2414.5 m (4 spf) 2170 – 2180 m (4 spf) 885 – 890 m (4 spf)	
16.	Production Zone	:	Upper zone (2169 – 2188 m) Lower zone (2404 – 2429 m)	
17.	Production Starting Date	:	March 28, 1998	
18.	Initial Shut-in Pressure (BH)	:	Upper zone : 3229 psi Lower zone : 3632 psi	
19.	Initial Shut-in Pressure (WH)	:	n/a	
20.	Present Shut-in Pressure (WH)	:	Upper zone :1440 psi as on 29/02/2012	
21.	Initial Flowing Pressure (BH)	:	Upper zone : 1441 psi @ 9.13 MMSCFD Lower zone : 2200 psi @ 16.27 MMSCFD	
22.	Present Flowing Tubing Head Pressure	:	Upper: 777 psi @ 0.1369 MMSCFD as on 05/12/2011 Lower: 920 psi @ 1.1689 MMSCFD as on 29/02/2012	
23.	Cumulative Production	:	Upper: 3168.9996 MMSCF as on 05/12/2011 Lower: 16577.0874 MMSCD as on 29/02/2012	
24.	Coring Interval	:		
25.	Status of Well	:	Gas Producer	

Table 2: Well summery of Saldanadi well-2 (SLD#2)

1.	Well No.	:	02	
2.	Location	:	Surface	Subsurface
			91° 10′ 19.73″ E 23° 40′ 29.70″ N	91° 10′ 35.73″ E 23° 40′ 29.70″ N
3.	Drilled By	:	BAPEX	
4.	Rig Used	:	IDECO H 1700	
5.	Elevation	:	KB- 28.3m AMSL ; GL- 21.94 m AMSL	
6.	Well Type	:	Appraisal Cum Development Directional (KOP = 373 m; HD = 740.41m E with 95°)	
7.	Total Well Depth	:	2458 m (MD), 2308.76 (TVD)	
8.	Spud- Date	:	April 11, 1999	
9.	Date Reached @ TD	:	December 16, 1999	
10.	Work Over Date	:	Not Applicable	
11.	Casing Info		30″ 20″ 13 3⁄8″ 9 5⁄8″ 7″ Liner	0-25 m 0-201.25 m 0-1177.63 m 0-2244 m 2194-2458 m
12.	Tubing Size	:	3 1⁄2″ VAM Tubing	
13.	Production Casing	:	7″ Liner	
14.	Sub-Surface Safety Valve	:		
15.	Perforated Interval	:	For Production	For DST
			2299 – 2342 m (4 spf)	2313 – 2318 m (4 spf) 2430 – 2435 m (4 spf)
16.	Production Zone	:	2300 – 2365 m (MD), 2165 m (TVD)	
17.	Production Starting Date	:	March 03, 2001	
18.	Initial Shut-in Pressure (BH)	:	3221.88 psi	
19.	Initial Shut-in Pressure (WH)	:	2787 psi	
20.	Present Shut-in Pressure (WH) as on 29/02/2012	:	1300 psi	
21.	Initial Flowing Pressure (BH)	:	2779.28 psi @ 18.66 MMSCFD	
22.	Present Flowing Tubing Head Pressure as on 23/01/2012	:	1042.00 psi @ 0.3953 MMSCFD	
23.	Cumulative Production as on 23/01/2012	:	28497.2407 MMSCF	
24.	Coring Interval	:		
25.	Status of Well	:	Gas Producer	

2.6 PVT Data

The reservoir fluid is modeled as a dry gas. Under depletion, it only exists as a single phase in the reservoir. However the condensate dropout modifies the gas density to give the desired condensate flow rate. During the DST (Drill Stem Test), four sets of gas samples were collected from each well at the surface (separator), shown in Table 3 (Petrobangla, 2009b). The PVT properties are similar for all the four gas sands that shown in Table 4 (Haq, Gomes, & Tamim, 2005). An assumed value of $C_f = 3.5E^{-06}$ psi-1 has been used for rock compressibility.

Table 3: PVT data of Saldanadi Gas Field (Petrobangla, 2009b).

Well	Samples	Sand	CH_4 (Mol %)	Specific Gravity	Reservoir Temp (°F)	B_{gi} (rb/Mscf)	Gas Gradient psi/ft^{-1})
SLD#1	1	Upper	96.3	0.57	185	0.9518	0.056
	2		95.9	0.56			
	3	Lower	96.3	0.57	194	0.8984	0.06
	4		96.2	0.57			
SLD#2	1	Middle	95.9	0.57	192.6	0.9304	0.059
	2		96.1	0.57			
	3		92.7	0.58			
	4		93.7	0.58			

Table 4: Gas composition of Saldanadi Gas Field (Haq et al., 2005)

Component	Upper	Lower	Middle
	Mol %		
Nitrogen	0.3727	0.26	0.3503
Carbon dioxide	0.613	0.71	0.5727
Methane	94.808	96.17	94.561
Ethane	2.8796	2.18	2.8314
Propen	0.8598	0.45	0.9155
Iso-Butane	0.163	0.12	0.2355
n-Butane	0.1145	0.06	0.2044
Iso-Pentane	0.0815	0.03	0.1137
n-Pentane	0.0732	0.02	0.1226
Hexane	0.0344		0.0926

2.7 Well Test Results

Well test data from the drill stem test (DST) were carried out on SLD#1 and SLD#2 which have been used to determine the initial reservoir pressure of the three gas accumulations. DST 1 in SLD#1 was carried out on 1st November 1996 in the lower sand where the interval 7805.4-7825.1 ft (TVDSS) was perforated and a gauge was set at a depth of 7705.8 ft (TVDSS). The interval produced gas at a maximum rate of 16.3 MMscf/d and the measured final build up pressure was 3,632 psia.

DST 2 in SLD#1 was performed on 7th November 1996 in the upper sand after perforating the interval 7023.1-7055.9 ft (TVDSS). The gauge depth was 6894.4 ft (TVDSS). The interval produced gas at a maximum rate of 9.1 MMscf/d and the measured final build up pressure was 3,278 psia.

DST 3 in SLD#2 was performed on 15th November 1999 in the middle sand after perforating depth interval from 7041.3-7056.8 (TVDSS). The pressure gauge is set at depth 6945.7 ft (TVDSS) The interval produced gas at a maximum rate of 26.22 MMscf/d. The measured final build up pressure was 3,420 psia.

The following table shows the brief summary of DST-1, DST-2 and DST-3 respectively.

Table 5: DST test summary of Saldanadi Gas Field (Petrobangla, 2004).

Drill Stem Test 1 (DST-1) of Saldanadi-1					
Activity	BHP (psia)	FWHP (psia)	Gas Rate (MMscf/d)	Oil Rate (stb/d	Remarks
Initial Build-up	3,641	-	-	-	Shut in downhole
Flow Test 24/64"	3,086	2545	8	-	-
Flow Test 32/64"	2,761	2160	11.3	26.8	Water 4 bbl/d
Flow Test 40/64"	2,433	1718	14.3	27.2	Water 5 bbl/d
Flow Test 48/64"	2,200	1340	16.3	27.3	Water 7 bbl/d
Final Build-up	**3,632**	-	-	-	Shut in downhole
Drill Stem Test 2 (DST-2) of Saldanadi-1					
Activity	BHP (psia)	FWHP (psia)	Gas Rate (MMscf/d)	Oil Rate (stb/d	Remarks
Initial Build-up	3,278	-	-	-	Shut in downhole
Flow Test 24/64"	2,227	1857	5.8	-	-
Flow Test 32/64"	1,822	1454	7.7	27	Water 4 bbl/d
Flow Test 40/64"	1,441	1039	9.1	28	Water 4 bbl/d
Final Build-up	3,229	-	-	-	-
Final Build-up	3,278	-	-	-	Shut in downhole
Drill Stem Test 3 (DST-3) of Saldanadi-2					
Activity	BHP (psia)	FWHP (psia)	Gas Rate (MMscf/d)	Oil Rate (stb/d	Remarks
Initial Build-up	3,252	-	-	-	-
Flow Test 16/64"	3,162	2712	5.1	-	-
Flow Test 24/64"	3,044	2562	12.3	14.6	Water 11.3 bbl/d
Flow Test 32/64"	2,872	2317	20.4	17	Water 12.3 bbl/d
Flow Test 40/64"	2,720	2041	26.2	24.4	-
Final Build-up	3,420	-	-	-	-

2.5.3 Stratigraphy

The sediments comprising the area are poorly fossiliferous to barren and consisting of alternate shales, sandstones, siltstone in varying proportion. The sedimentary strata encountered in Saldanadi Gas Field can be considered as Alluvium, Tipam Sandstone, Bokabil Formation and Bhuban Formation (Petrobangla, 2004). Figure 4 shows the regional stratigraphy and petroleum system of Bangladesh

Alluvium: This surface formation is entirely made up of loose sand.

Tipam sandstone (Mio-Pliocene): Tipam Sandstone consists mainly of a loose quartz sand, clear to white, medium to very fine grained, angular to subrounded and poorly sorted. The section is locally interbedded with silt or siltstone towards the base, the sand becomes fine to very fine grained. Tipam sandstone was deposited in a fluvial environment and is separated from the Dupitila by an unconformity. (Rahimi et al., 2020)

Bokabil Formation (Middle Miocene): This formation mainly consists of sandstones, shales and siltstones. Depositional environment is lower delta plain.

Bhuban Formation (Middle Miocene): This zone mainly consists of very fine to medium grained, well sorted, subangular to subrounded, calcareous sandstone.

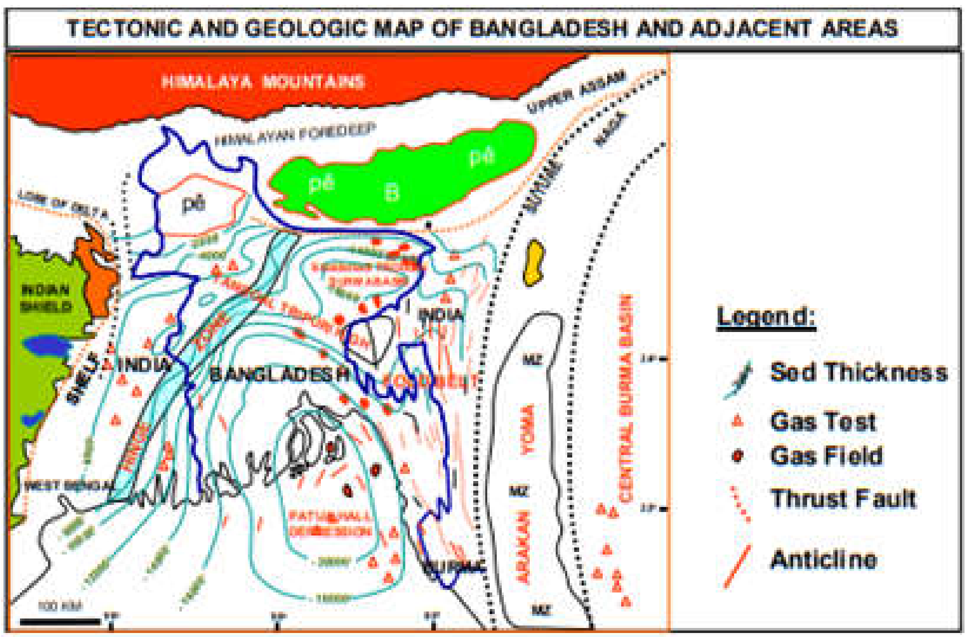

Figure 4: Regional Tectonic map of Bangladesh (Petrobangla, 2004).

Stratigraphic succession according to the well data is given in Table 7 (Bapex, 2001; Petrobangla, 2004). On the basis of geological data, seismic data and the well log data of SLD#1 and SLD#2 the following stratigraphic sequence has been outlined with response to the depth of penetration shown in Table 8 (Bapex, 2001; Petrobangla, 2004).

Table 6: Stratigraphic succession of the studied area according to well data

Age	Formation	Thickness (m)	Lithology
Sand dominant with alluvial cover			
Quarternary	Dupi Tila	0	
Pliocene	Tipam	250	Predominantly sandstone, interbedded with clay and siltstone and trace of lignite. Occasionally calcareous.
Miocene	Bokabil	1000	Upper most part of shale dominates with alteration of sandstone and siltstone
	Bhuban	1250 (base not seen)	Alteration of sandstone and shale. Predominantly sandstone white, clear and transparent. Gas saturated sand is present.

Table 7: Stratigraphic sequence of the study area with respect to depth of penetration

Depth (m)	Lithological Description
Surface-50	Sand dominant with alluvial cover.
50-530	Predominantly sandstone, interbedded with clay and siltstone and traces of lignite.
530-1140	Predominantly sandstone with alteration of shale and siltstone. Sandstone is mainly white, clear, massive, loose, occasionally consolidated, fine to medium grain, moderately sorted, dark color mineral, concentrated and occasionally calcareous.
1140-1300	Shale dominating with alteration of sandstone and siltstone. Shale is mainly light gray to dark gray, thinly laminated, hard and compact, slightly calcareous with silt partings.
1300-2070	Alteration of sandstone and shale. Predominantly sandstone white, clear, transparent. Fine to medium grain, unconsolidated, subrounded, moderately sorted, mica and dark color mineral concentrated, occasionally calcareous.
2070-2170	Predominantly shale, gray, bluish gray, thinly laminated.

2170-2215	Predominantly sandstone, light, white, coarse. This sand is gas saturated.
2215-2405	Predominantly shale, bluish gray, very thinly laminated, moderately hard and compact, silty in nature, mildly calcareous.
2405-2511	Upper part is sand dominant and this sand is gas saturated. The lower part is shaly sequence with minor sandstone.

2.6 Petroleum System

Regionally, Saldanadi area is a part of the Hatia Petroleum System that located in the south of the Tangail-Tripura High. The hydrocarbon system is characterized by Plio-Pleistocene traps in sandstone reservoirs of upper Miocene to Pliocene age. The hydrocarbon source is probably from Miocene Bhuban shale, which has generated primarily natural gas with minimal condensate (Petrobangla, 2009c).

2.6.1 Traps

Elongated anticline structure with trending almost NW-SE is the trap type for Saldanadi Gas Field. This compressional structuring took place from Miocene to Recent.

2.6.2 Source rocks

It has been mentioned above that all the Saldanadi wells penetrated the Bhuban shale. The Miocene Bhuban Shale is widely developed over the Bengal Basin. The sequence is poor to lean in terms of source rock potential, with TOC values averaging from 0.2 to 0.7 %.

2.6.3 Vertical seal

The Upper Marine Shale (late Miocene-early Pliocene) is clearly recognized from seismic and supposed to be a regional vertical seal in Saldanadi area. Intra formational seal also recognized both from well and seismic section.

2.6.4 Timing and Migration

In the Saldanadi as a part of Hatia area, the rapid sedimentation rates during the Miocene pushed the Oligocene before the formation of the structural traps in the Pliocene to Recent. The most likely gas source is in shaly sections of the middle to lower Miocene. The migration pathway is probably a combination of vertical migration from earlier Miocene through flanking faults and lateral migration form upper Miocene in basinal, "kitchen" areas.

2.6.5 Reservoirs

Proven reservoir rocks in Saldanadi areas are all sandstones of Bokabil and Upper Bhuban Formations. The reservoir sandstones are Middle to Late Miocene of age, with porosities ranging from 15 to 21 % and with permeability in the order of between 116 to 193 md.

2.7 Previous Studies

A number of studies were carried out on Saldanadi Gas Field since its discovery. Petrobangla, Hydrocarbon Unit Bangladesh (HCU) / Norwegian Petroleum Directorate (NPD) and National Committee for Gas Demand and Reserve (NCGDR) made an estimation in three consecutive year and found the result, which has been shown in Table-8 and Table-9 (Dey, Deb, Akhter, Dey, & Studies, 2016).

Table 8: Comparison of different gas reserve (Proved + Probable) estimation.

Saldanadi Gas Field	Proved + Probable (Bcf)	Recovery Rate (%)	Total Recoverable Reserve (Bcf)
Petrobangla (2000)	200	70	140
HCU/NPD (2001)	200	70	140
NCGDR (2002)	380	65	247

In another BAPEX report (2001), Estimation of the total gas initially in place (GIIP) of Saldanadi Gas Field was 165.80 BCF, out of which recoverable gas was 116.03 BSCF. In addition, the overall gas in place recovery of the field is 70%. After that in 2008 Khalid and Kazi re-estimate the gas reserve of Saldanadi Gas Field for both zone which are demonstrated in Table-11. In addition, GIIP was calculated 442.56 Bcf in that field 442.56 Bcf in 2008.

Table 9: Reserve estimation made by Khalid & Kazi.

Saldanadi Gas Field	Proved P1 (Bcf)	Proved P2 (Bcf)	Recovery Rate (%)	Recoverable Reserve (P1 + P2) (Bcf)
Upper Zone	48.00	284.40	70	232.68
Lower Zone	14.72	95.44	70	77.11

According to RPS Energy report in 2009, The volume of gas initially-in-place (GIIP) estimated from the simulation model (ECLIPSE™) is in line with values from the volumetric calculations, done in Petrel™ and REP™ (Table 10). There are no measured static BHP data from the field but there are measured THP and a few shut-in periods in the well SLD#1 in both upper and lower sand. A few static BHP data have been estimated from measured THP at the end of each shut-in period. The match is acceptable to the early data points (Petrobangla, 2009c). These estimated static BHP data are not totally reliable; downhole measured data is of course the most reliable. They did not match any historical production data with their developed geological model.

Table 10: GIIP calculation of Saldanadi Gas Field (Petrobangla, 2009c).

Pool	Volumetric Calculation (Bcf)		Simulation Model (Bcf)		Estimated Connected Volume (Bcf)	
	Petrel™	REP™ (P50)	Before History Match	After History Match	Production Analysis	Material Balance
Upper Sand	274.5	-	273.2	273.2	12	6-16
Middle Sand	49.6	-	47.2	47.2	53	-
Lower Sand	59.6	-	59.6	59.6	60	40-60
Total	383.7	-	379.9	379.9	125	-

According to M. Sc. Thesis (BUET) in 2011, MBAL software calculation is used to estimate the total gas in place (GIIP) of Saldanadi Gas Field which is 114.96 BCF. In addition, the overall gas in place recovery of the field is 54%. PROSPER software is used to predict tubing and pipeline hydraulics and temperatures with accuracy. In this case, when production tubing inner tubing inner diameter decreases then the gas flow rate also decreases but flow period of gas production increases i.e. recovery of gas increases (Paul, 2003).

Prokash in 2016 estimated the reserve of this field by using trapezoidal rule and area using planimeter, isopach maps. This study highlighted the reserve estimation and remaining reserve calculation of Saldanadi Gas Field one of the prominent and vital gas field for geological situation as the underground reservoir rock is shared by both Bangladesh and India. The total GIIP (2P) from both upper and lower gas sand was 501.186 Bcf among which 350.83 Bcf is recoverable with 70% recovery rate. In addition total remaining reserve is 282.95 Bcf (Dey et al., 2016).

CHAPTER III

DATA ACQUISITION AND DATA INTERPRETATION METHODOLOGY

3.1 Database Formation

The data required for the geological study in the Saldanadi area were delivered by Petrobangla and BAPEX. The quality of data is variable from medium to good. 2D seismic data and well log data are used for this thesis work. Seismic data were in SEG-Y format and log data were in LAS format. All other data types such as well head data, Gas-water contact data, velocity data etc. are given in ASCII format. To initiate the project, a database file was created and initialized. All of the well log data was loaded in Petrel™ on text and LAS format. The log curves contained in the database were checked against the original logs to ensure that the data were correct. The missing log curves have been digitized from hard copy since the digitizing tool become available. Six conventional cores were cut both in shale and sandstone of SLD#1 well to study the physical properties of the rock such as porosity, permeability, reservoir parameters, age and depositional environment. No core was taken from SLD#2 well. The list of the Saldanadi wells that are available and used for this project is shown in Table 11.

Table 11: List of wells used for Saldanadi Project (BAPEX)

Well Name	Vertical / Deviated	Company	Northing (m)	Easting (m)	KB	TD	Completed
SLD#1	Vertical	BAPEX	2618568.36	619661.8	17.639	2839	19.10.1996
SLD#2	Deviated	BAPEX	2618549.18	619659.94	17.528	2458	25.11.1999
SLD#3	Deviated	BAPEX	2618560.48	619660.73	20.452	2860	01.12.2011
SLD#4	Deviated	BAPEX	2618560.48	619660.73	20.452	2860	10.02.2016

3.2 Data Type

3.2.1 Seismic data

Seismic interpretation of Saldanadi structure has been performed by Petrel software. Seismic data format was in SEG-Y format. All seismic interpretation and structure map including time and depth map are created with this SEG-Y data format of seismic interpretation.

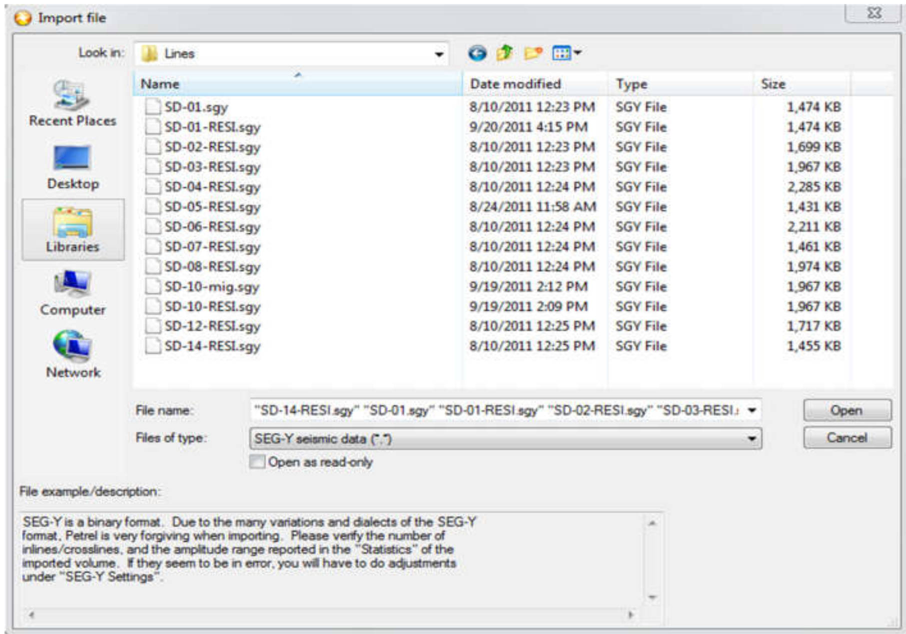

Figure 5: Seismic data importation in SEG-Y format.

3.2.2 Well head data

Well head data has been prepared according to the format by including Name, Y (northing), X (easting), Kelley Bushing (KB) and TD in Measured Depth (MD) of the wells. Well head data are created in excel sheet or notepad or WordPad and is imported as well head format.

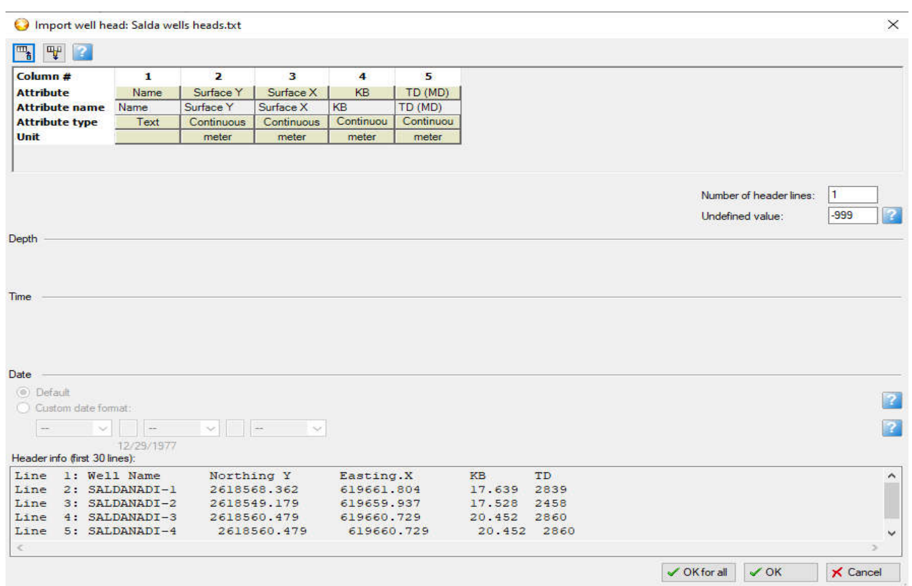

Figure 6: Importation of well head data.

3.2.3 Deviation data

SLD#1 is a vertical well. This is why no deviation well data is required for this well. On the other hand all the four wells (SLD#1, SLD#2, SLD#3 and SLD#4) are drilled at same location but SLD#2, SLD#3 and SLD#4) are deviated well. That is why to locate these wells accurately in map deviated well data is required. The deviation well data include Measured Depth (MD), Inclination and Azimuth etc. These data have been prepared in excel sheet and then saved in notepad/WordPad in text format. Deviation data have been arranged according to the required format for Petrel software and imported into the model in order to make the well deviated as Well path/deviation (ASCII) format.

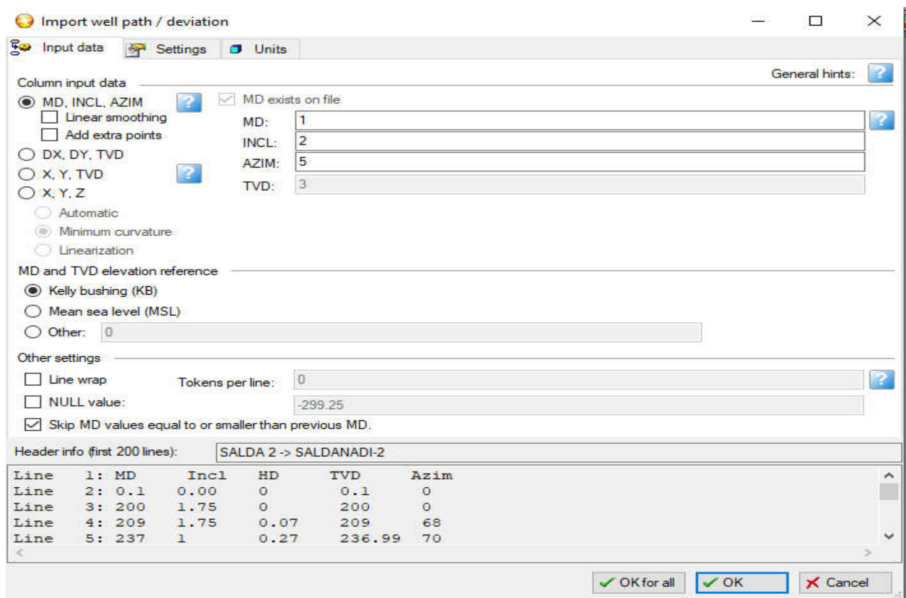

Figure 7: Deviation well data import for SLD#2 well.

3.2.4 Wire line Log data

Conventional wire line log data which are available for the study includes Caliper, Gamma Ray, Resistivity (Deep, Medium and Shallow), Micro Resistivity, Sonic log, Neutron log, Density log, Facies log, Self-Potential (SP) log etc shown in Fig 8. Data have been provided by Geological Division of BAPEX. All these data are created in notepad or excel sheet and in Petrel software. These log data are imported as LAS format. These data are used for correlation between well to well and other purpose also.

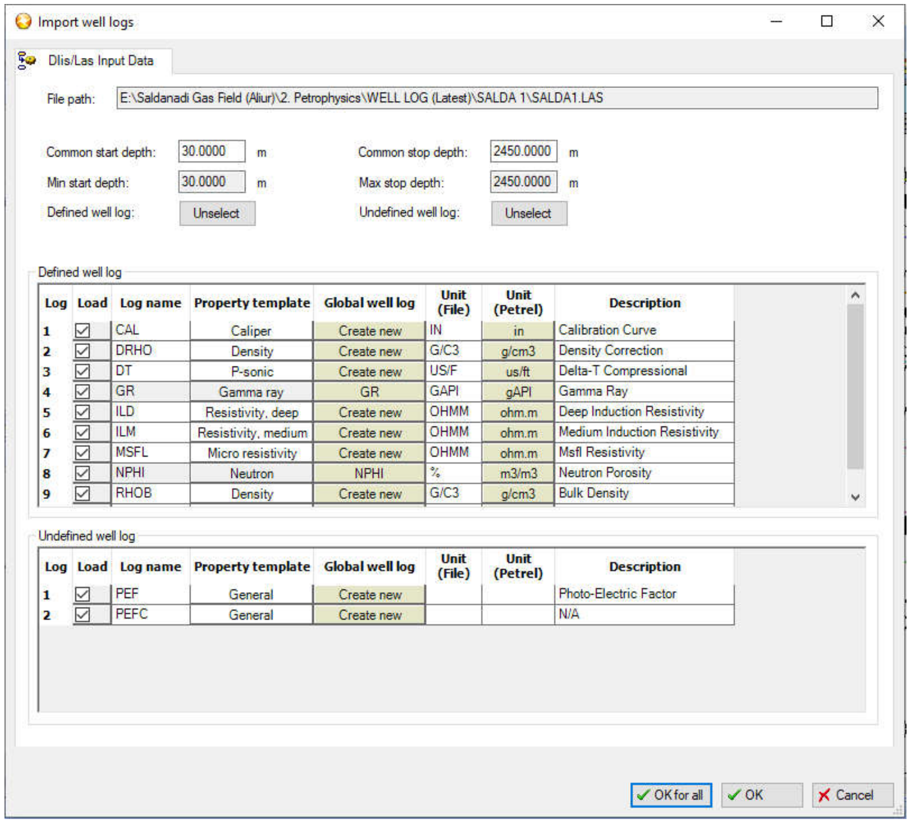

Figure 8: Importation of different logs data from SLD#1 well Log.

3.2.5 Petro-physical Data

The available conventional logs stated earlier have been interpreted in Petrel software and clay content, porosity, permeability, water saturation have been calculated. These properties together with the conventional logs have been imported into Petrel as "well log ASCII" format.

3.3 Seismic Interpretation

The interpretation of seismic data is an integral part of the hydrocarbon development strategy of the Gas Field. It performs a variety of tasks in 3D seismic interpretation, such as analyzing the parameters that govern reservoir architecture (Adeoti, Onyekachi, Olatinsu, Fatoba, & Bello, 2014).

Two types of interpretation process used in this research work are following:

1. Time to depth conversion using T-Z curve.
2. Interpretation of seismic lines.

3.3.1 Time to depth conversion using T-Z curve

Velocity data of SLD#1 well was created for this thesis work. Average velocity of the well was used to convert the two way travel time (TWT) into the depth using the following equation:

$$\mathbf{Z}_i = \mathbf{Z}_{i-1} + \mathbf{V}^*(\mathbf{t}_i\text{-}\mathbf{t}_{i-1})/2 \text{ .... } (3.1)$$

With all these data a time distance (T-Z) curve was made which is useful for seismic line interpretation. The corrected VSP of Saldanadi-1 is shown in figure-9.

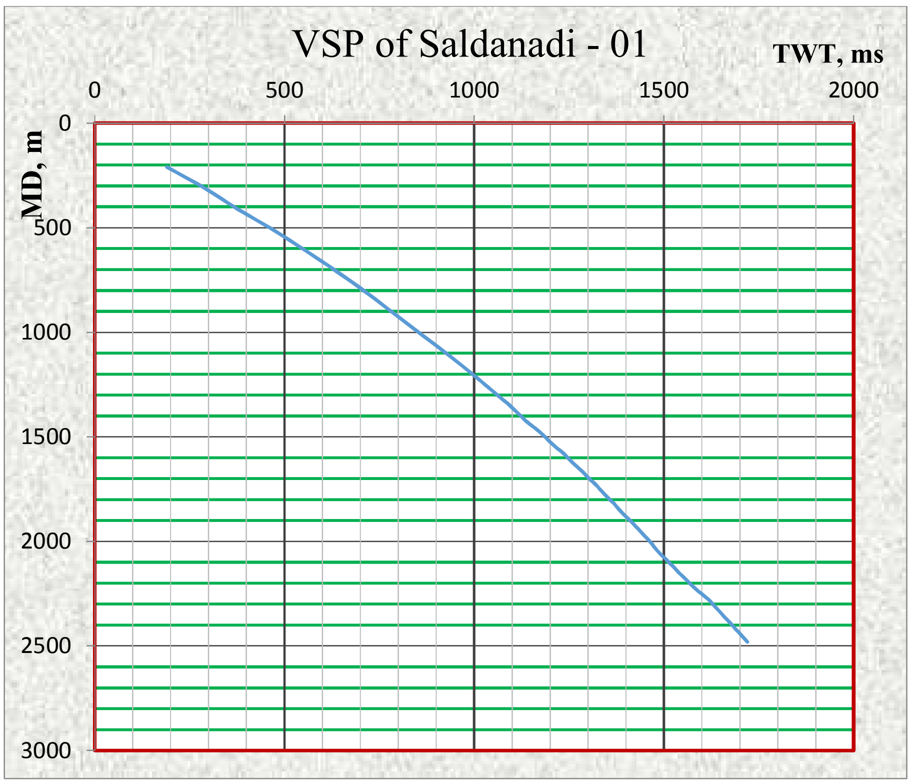

Figure 9: Time Depth (T-Z) curve of SLD#1 well.

3.3.2 Interpretation of Seismic lines

Twelve seismic lines have been interpreted using Petrel interpretation software. Seismic lines are SD-01-RESI, SD-02-RESI, SD-03-RESI, SD-04-RESI, SD-05-RESI, SD-06-RESI, SD-07-RESI, SD-08-RESI, SD-10-RESI, SD-12-RESI, SD-14-RESI (Fig 10). A project was created to interpret these seismic lines and to prepare the time contour map and depth contour map of the Saldanadi Gas Field in Petrel Software.

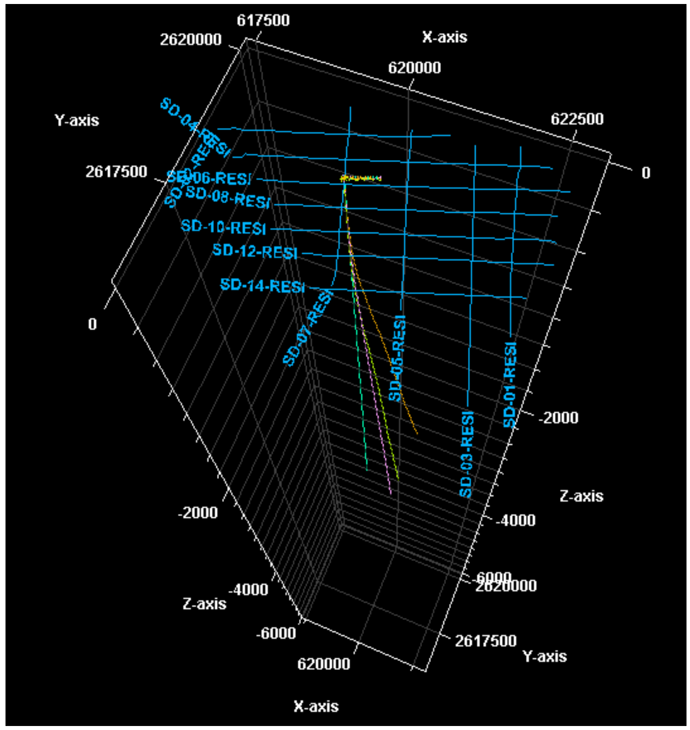

Figure 10: 3D Seismic lines showing the studied 11 Seismic lines with 4 wells.

3.3.3 Importing Seismic trace in SEG-Y format:

- Import SEG-Y files into single seismic survey.
- Co-ordinates and shot point scaling action.
- Selecting seismic data volume name.
- Defining trace number for seismic 2D import.
- Setting time data bound.
- Assigning 2D shot point to traces.
- Bulk importing 2D SEG-Y traces.
- Assigning traces to shot points.

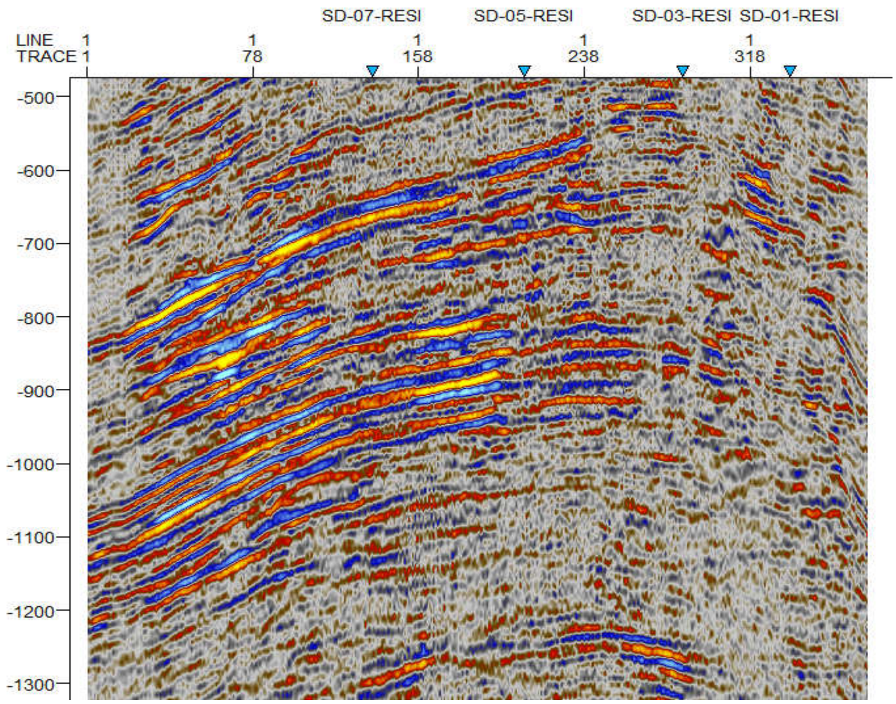

Figure 11: Loaded Seismic section

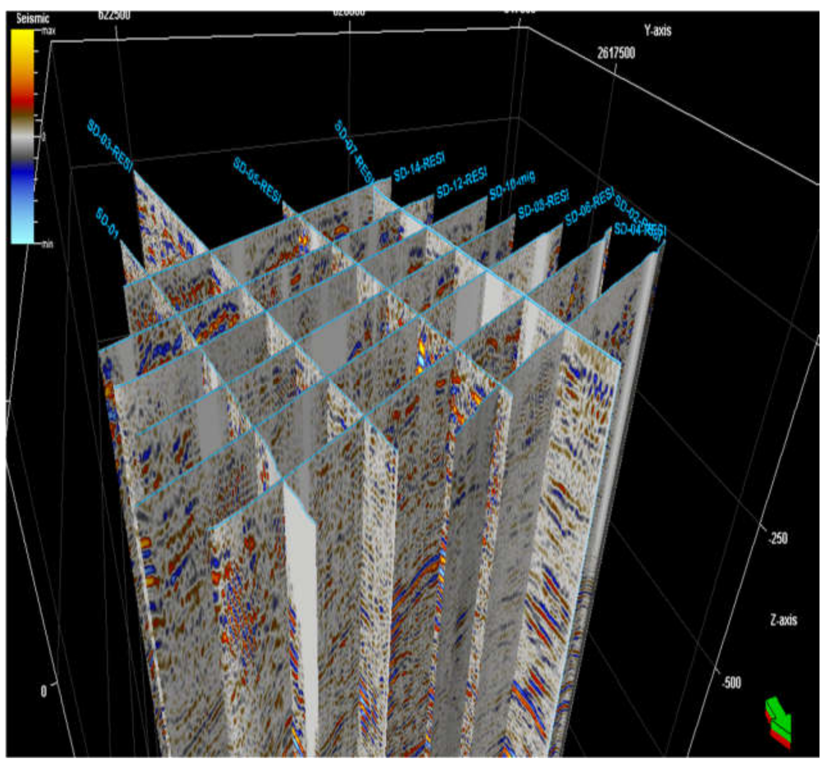

Figure 12 : Seismic lines with seismic section in 3D view

Importing well data:

- Inserting new wells.
- Importing ASCII format of wire line log in each wells.
- Importing well Tops.
- Well tie up with seismic sections.
- Inserting deviation data for well SLD#2, SLD#3 and SLD#4

3.4 Relative Permeability

There are no special core analysis (SCAL) data for the Saldanadi Gas Field. Therefore, Brooks-Corey correlation for two-phase flow is used to generate relative permeability curves for the simulation (Fig. 13). It is assumed that capillary pressure to water is the average values of the available capillary pressure, P_c data from other fields of Surma basin. The initial water distribution was used to scale the water-oil capillary pressure curves such that this water distribution is honored in the initial equilibration.

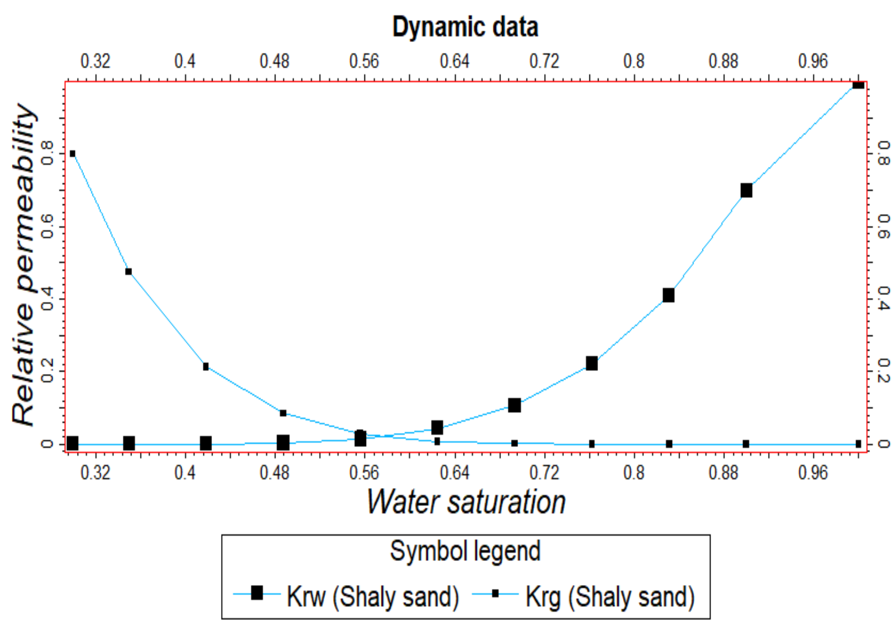

Figure 13: Gas Water Relative Permeability

3.5 Capillary Pressure

The initial water saturation data logged in wells SLD#1, SLD#2, SLD#3 and SLD#4 show no clear evidence of a transition zone. This does not necessarily imply that the wells will not experience any capillary effects during production. The completion in the upper sand is more than 100 ft above the gas-water contact encountered in the sand. The water production history of the wells also suggests that no aquifer water has been produced so there is either no transition zone or if there is, the impact is insignificant. Gas viscosity and pressure relationship is given in the following figure 14.

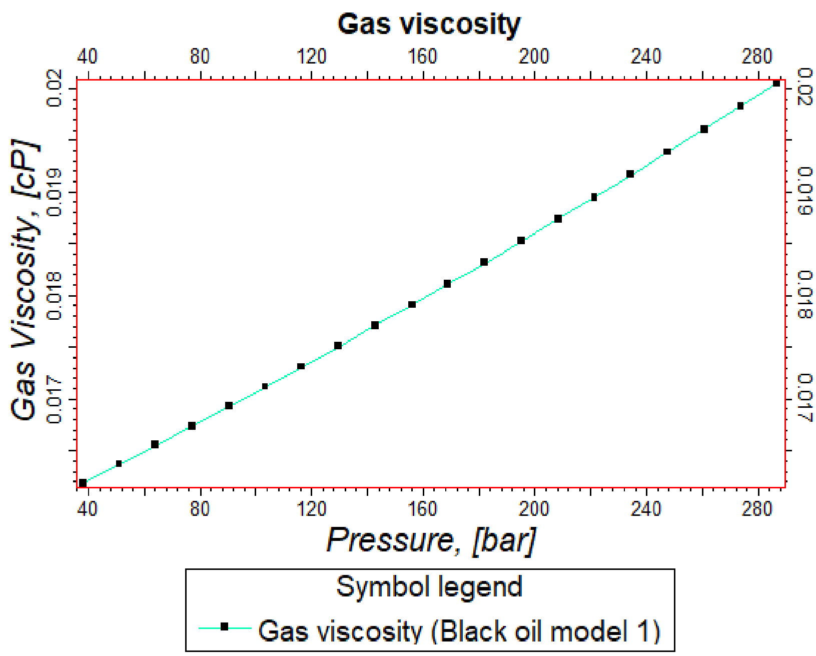

Figure 14: Gas viscosity with respect to pressure

3.6 Flowchart of the steps followed in this research work.

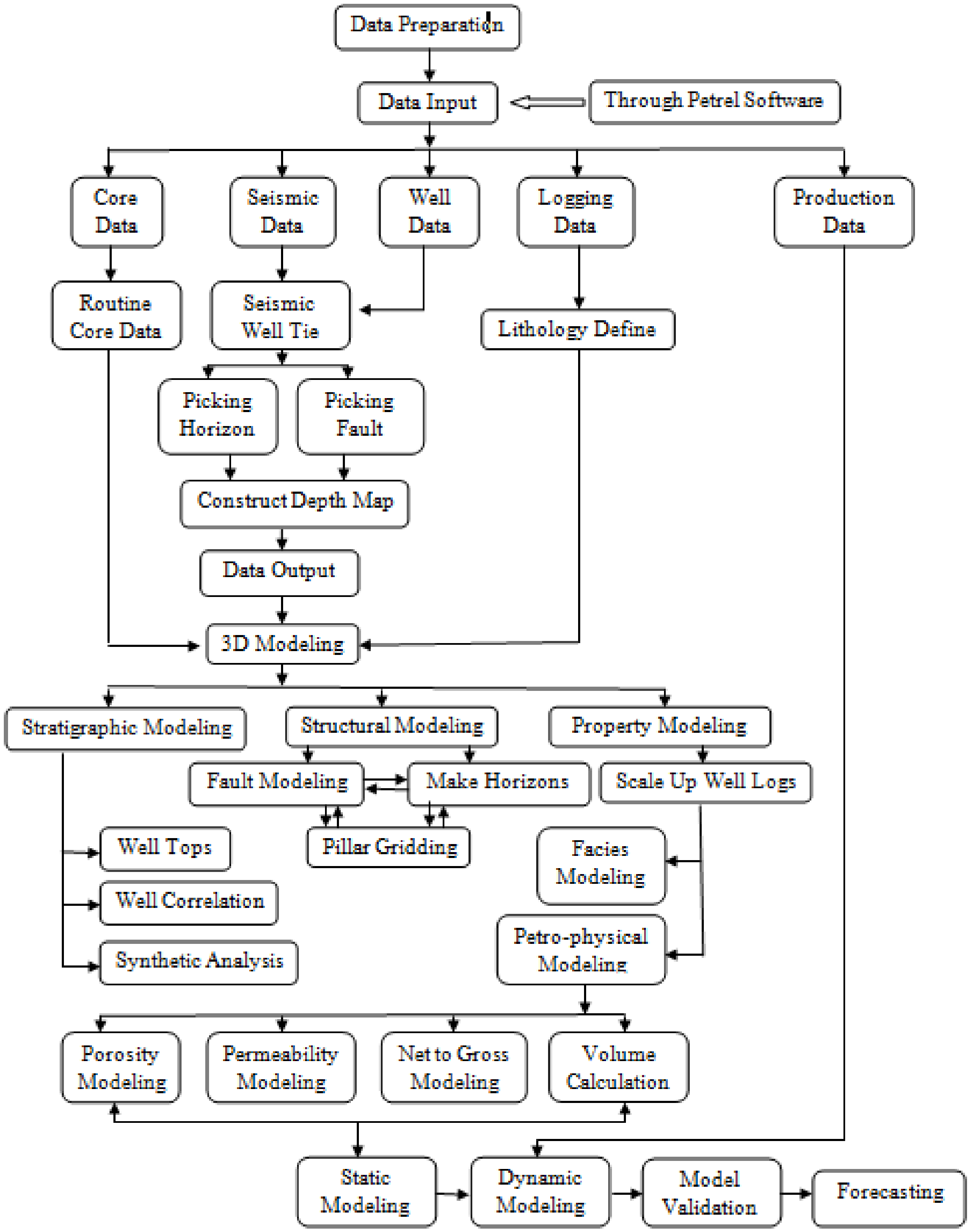

Figure 15: Flowchart of the steps followed in this research work.

CHAPTER IV

RESERVOIR SIMULATION MODEL DEVELOPMENT

The purpose of simulation is to estimate the field performance under one or more operating conditions. Practically a field can operate only once, at considerable expense. On the other hand, a model virtually can be operated or run many times at low expense over a short period of time. Observation of model performance under different operating conditions helps to select an optimal set of conditions for the reservoir (Paul, 2003).

In this chapter, the detailed procedure of simulation model construction of the field is being discussed. This section addresses the following issues: selection of the number of space/grid dimensions, representation of the reservoir rock and fluid properties, and coupling of the wells and the reservoir.

The first step is to create a geological model of the reservoir. It is also called a **static model**, since it represents the reservoir fluids in static condition. Flow through the reservoir and production/injection of fluids through the wells are not considered at this stage. The second step is to import the static model and apply fluid flow phenomenon to it. On order to do this, the static model is modified and more data such as fluid properties, injection and production rates etc. are incorporated. Then it is called a **dynamic model**.

Simulation of petroleum reservoir performance refers to the construction and operation of a model whose behavior assumes the appearance of actual reservoir behavior. The model can be either physical or mathematical. A mathematical model is simply a set of equations that subject to certain assumptions, describes the physical processes active in the reservoir. Although the model itself obviously lacks the reality of the oil or gas field, the behavior of a valid model simulates that of the field. Basic equation of reservoir simulation with governing condition and theory are available in literature [Ref max]. A computer program which solves these numerical equations is called reservoir simulator.

4.1 Performing Seismic to Well Tie

The seismic data are estimated in time domain, and are compared with the well data, which are measured in depth. In this regard, the primary goal of well-to-seismic ties is the correlation of horizon tops that are found in a well with specific seismic reflections. In this study, the data were used to tie well data to seismic are simple because the seismic in depth domain facilitated the connection between wells and seismic lines (Rahimi et al., 2020). Synthetic seismogram analysis has been conducted between SLD#1 with Gamma Ray log and survey line of SD 07 of seismic section. Here, gas bearing sandstone zones has been identified by matching Gamma Ray log response and seismic reflection peak which is shown in the following Fig 16.

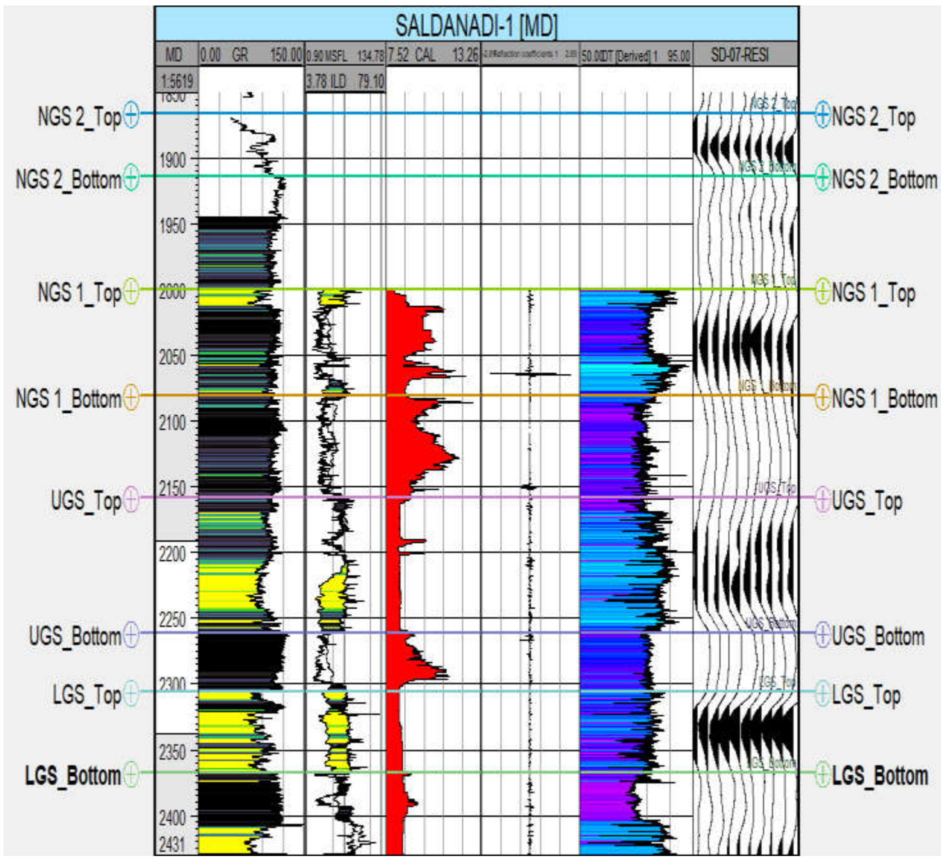

Figure 16: Synthetic Seismogram of SLD#1 with Seismic SD#07.

Seismic reflection data from every in-line and cross line were interpreted to overcome the data quality issue and retain the precision of horizon and fault interpretation. The interpreted seismic section in different directions is passed near to all wells. All lines intersect in the seismic grid (Rahimi et al., 2020).

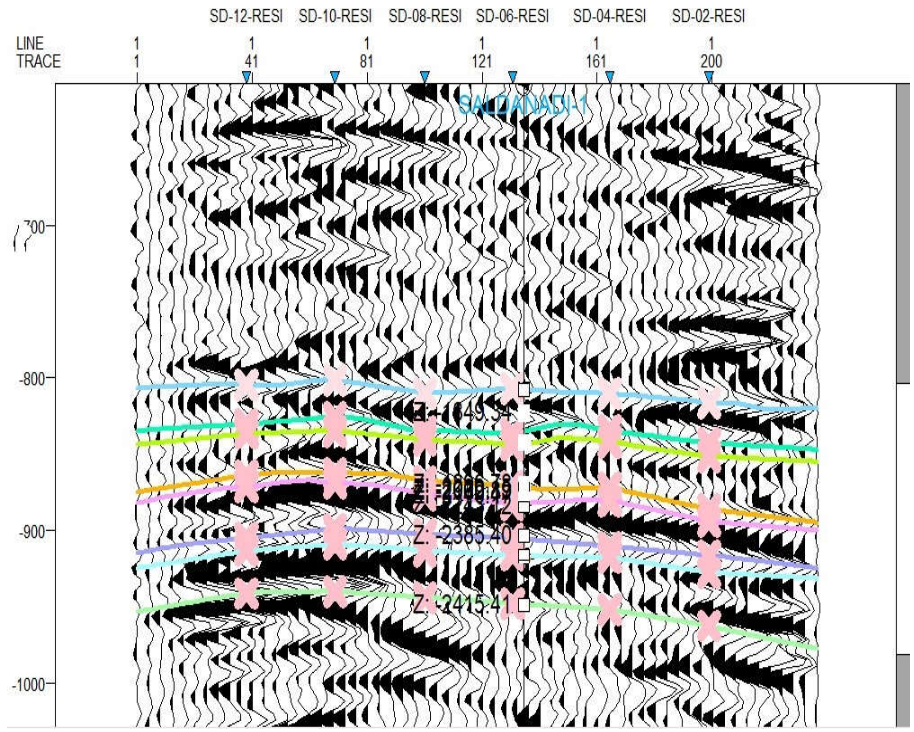

Figure 17: Determination of well tops by correlation of well logs

Well head has been inputted as ASCII format to correlate seismic reflection. Continuity of seismic reflection was also considered. Top NGS 2, Base NGS 2, Top NGS 1, Base NGS 1, Top UGS, Base UGS, Top LGS and Base LGS horizons are picked by manual interpretation of seismic horizon of different seismic sections which are shown in Fig 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27 and 28).

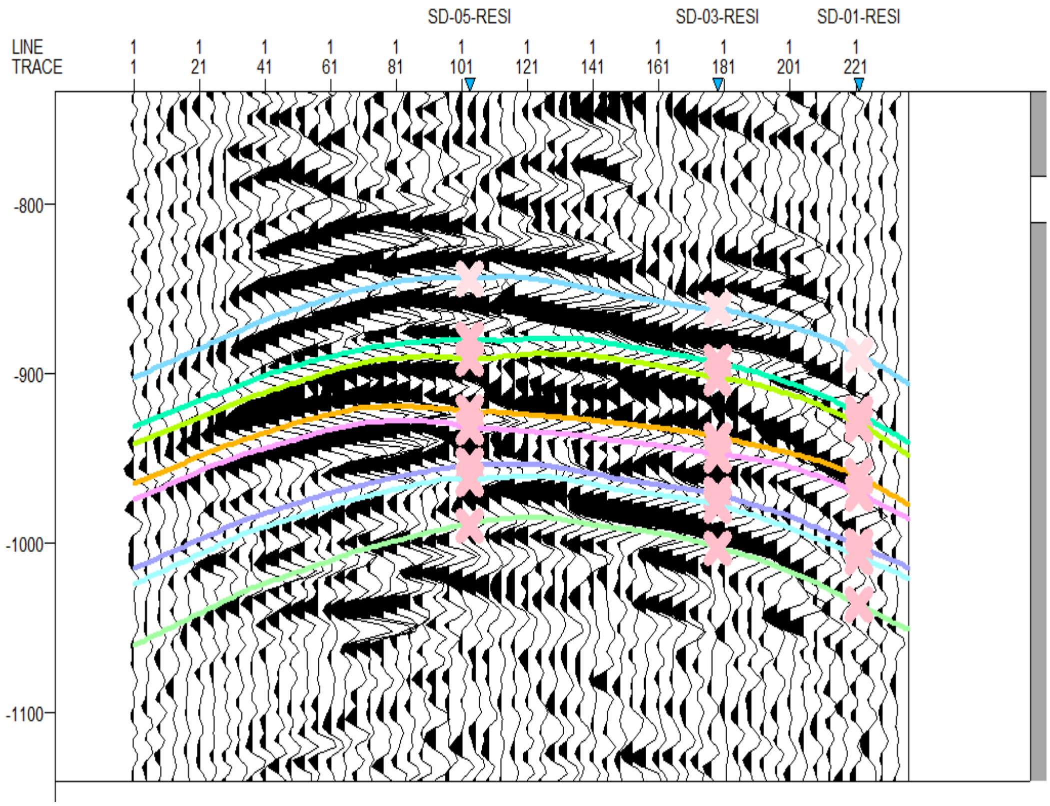

Figure 18: Horizon picking of SD#14

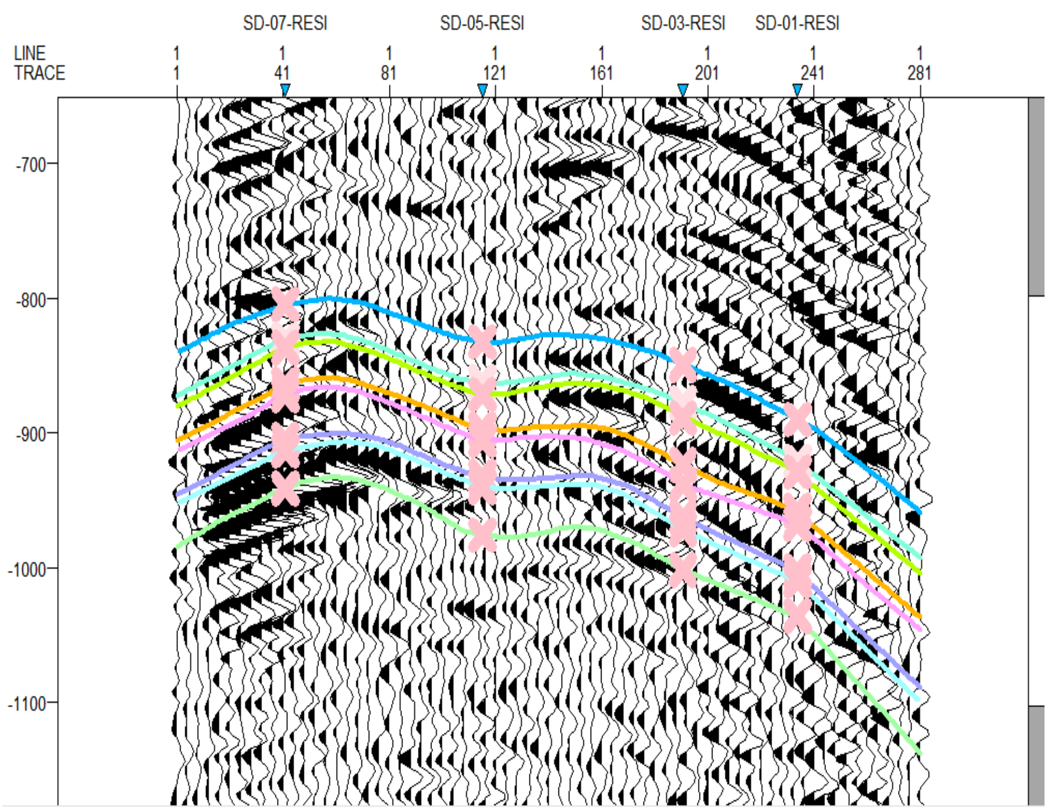

Figure 19: Horizon picking of SD#12

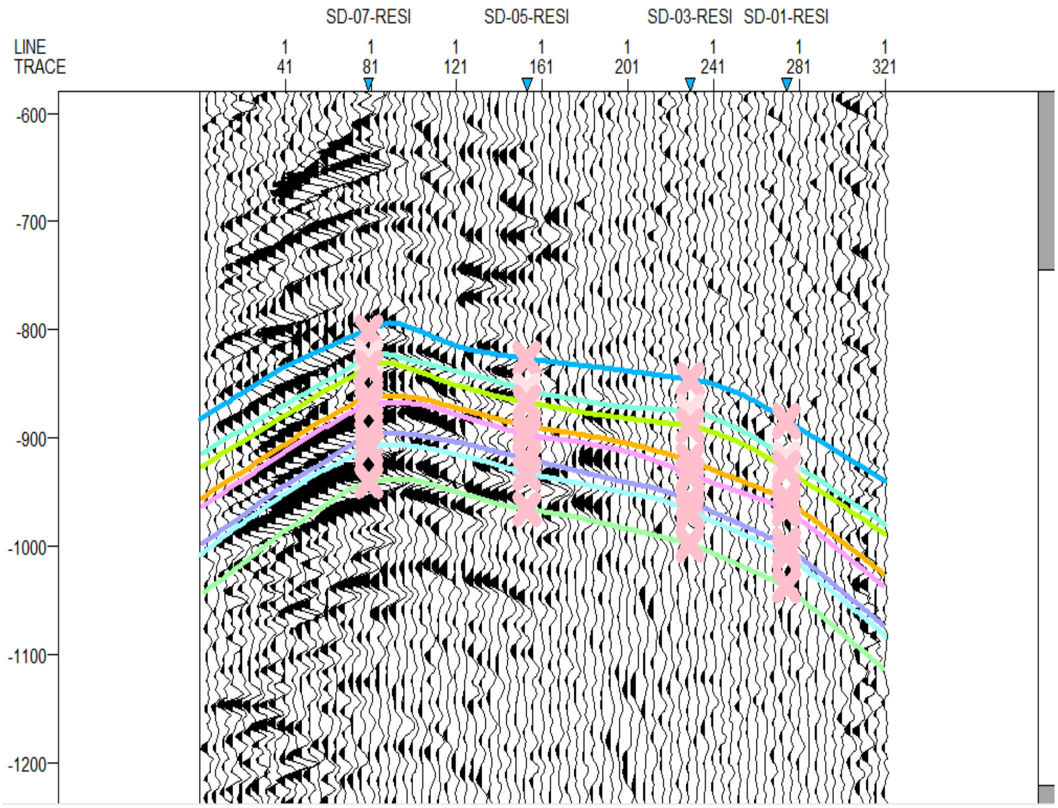

Figure 20: Horizon picking of SD#10

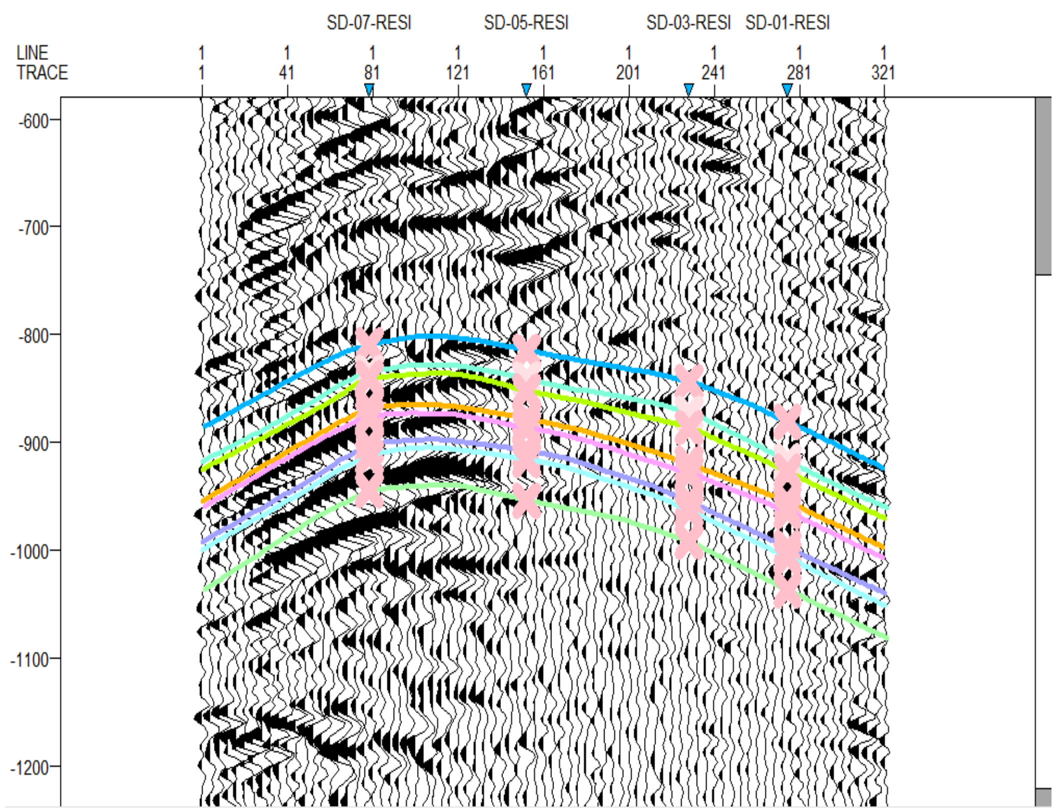

Figure 21: Horizon picking of SD#08

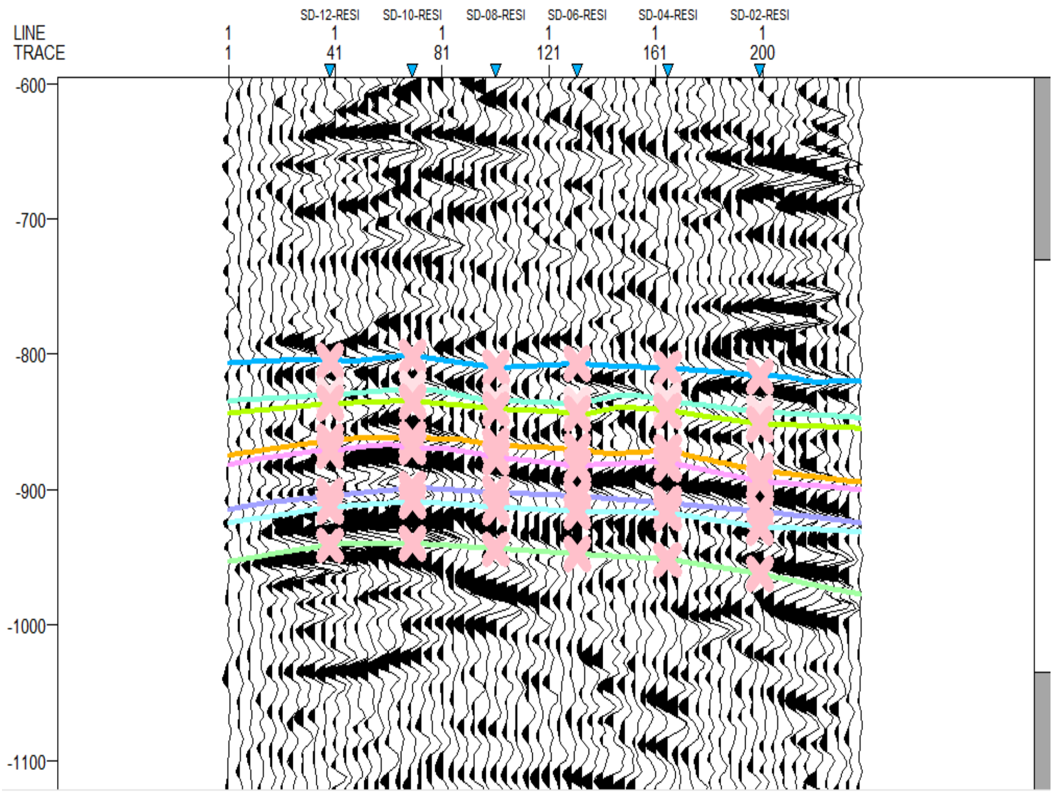

Figure 22: Horizon picking of SD#07

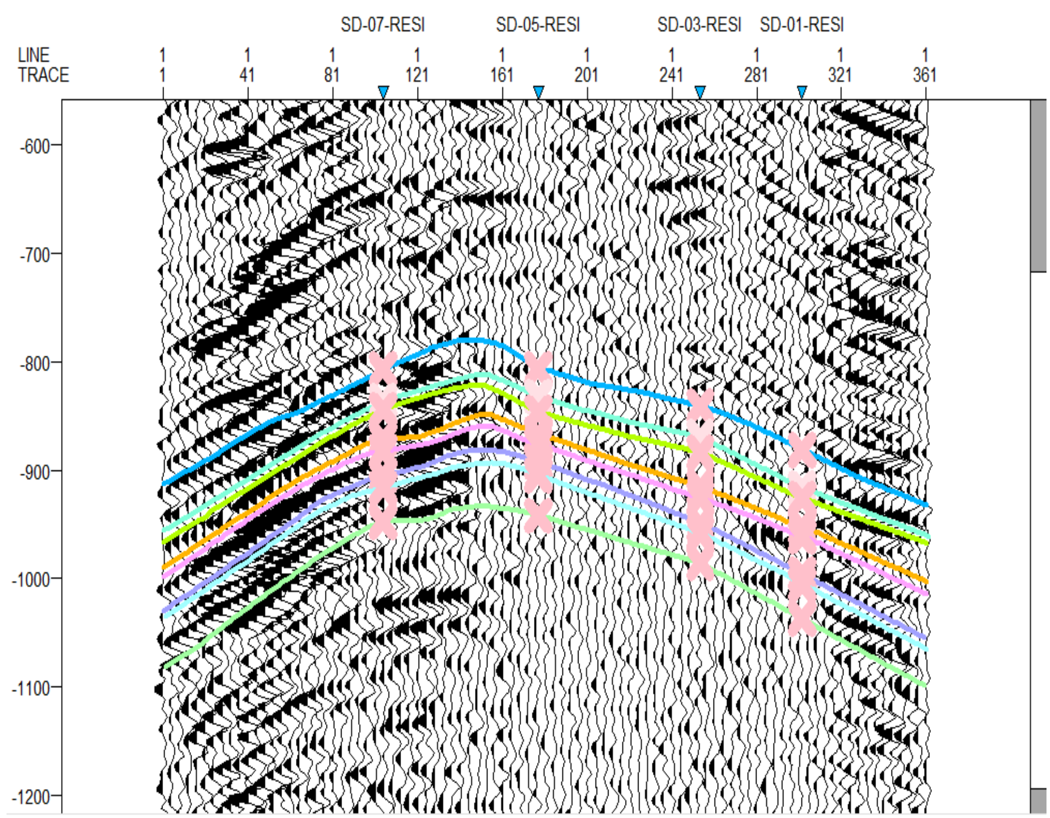

Figure 23: Horizon picking of SD#06

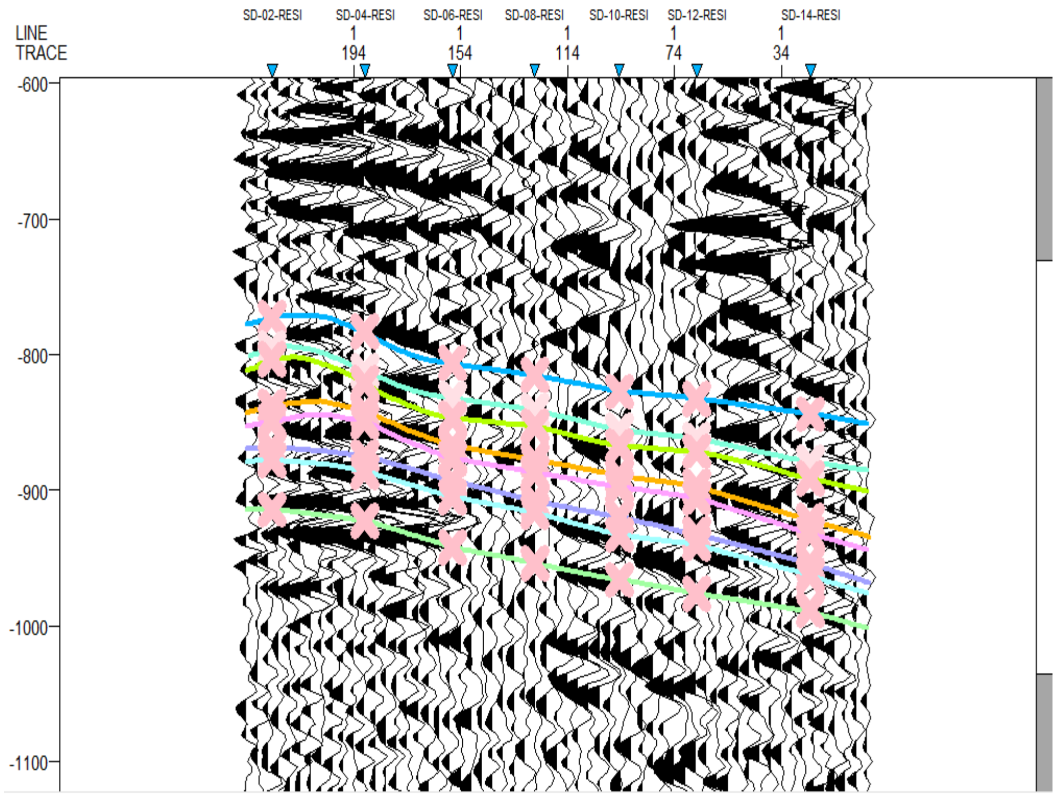

Figure 24: Horizon picking of SD#05

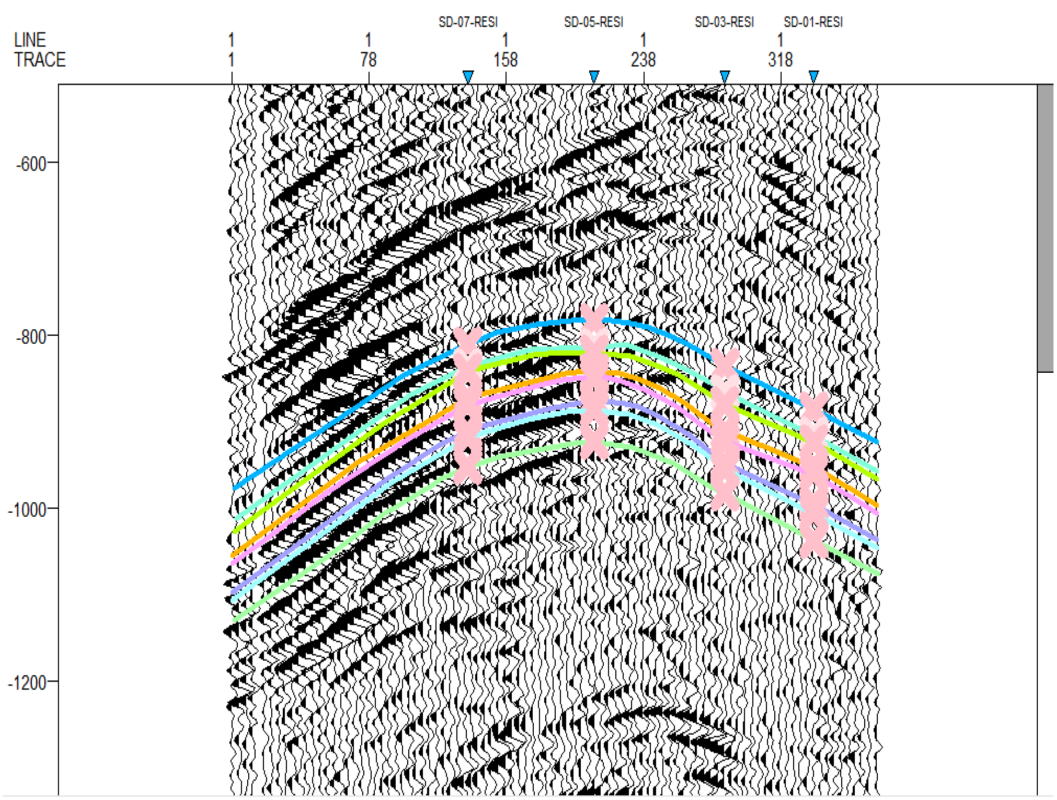

Figure 25: Horizon picking of SD#04

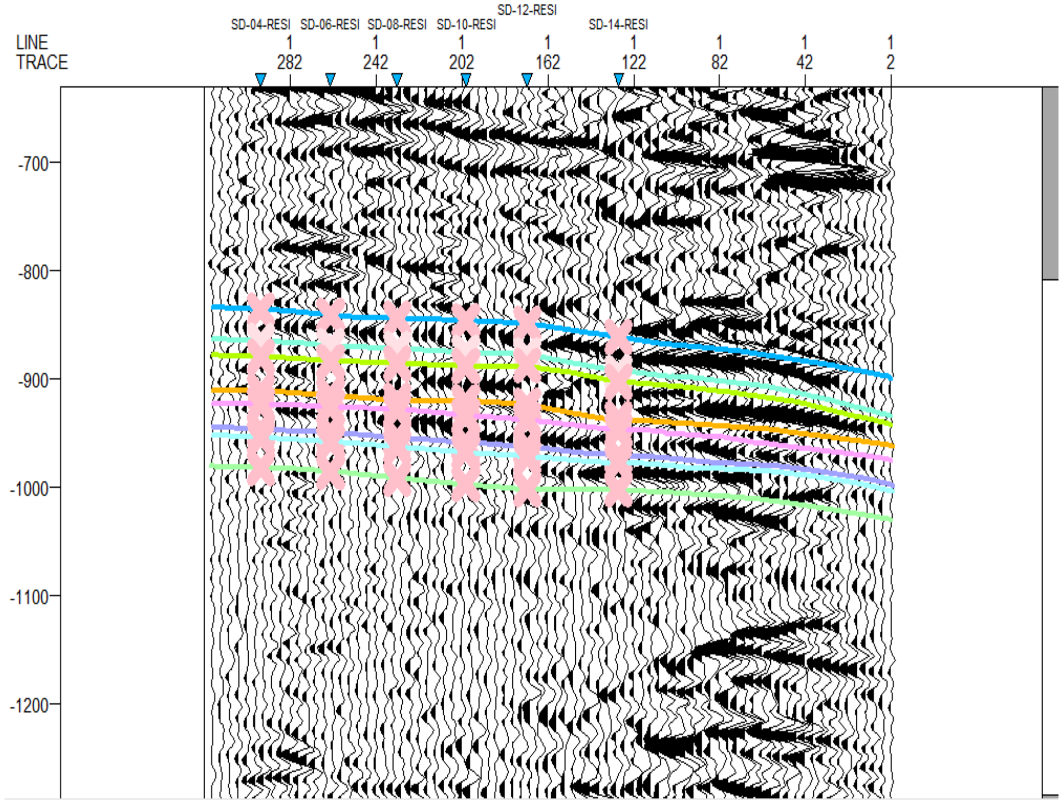

Figure 26: Horizon picking of SD#03

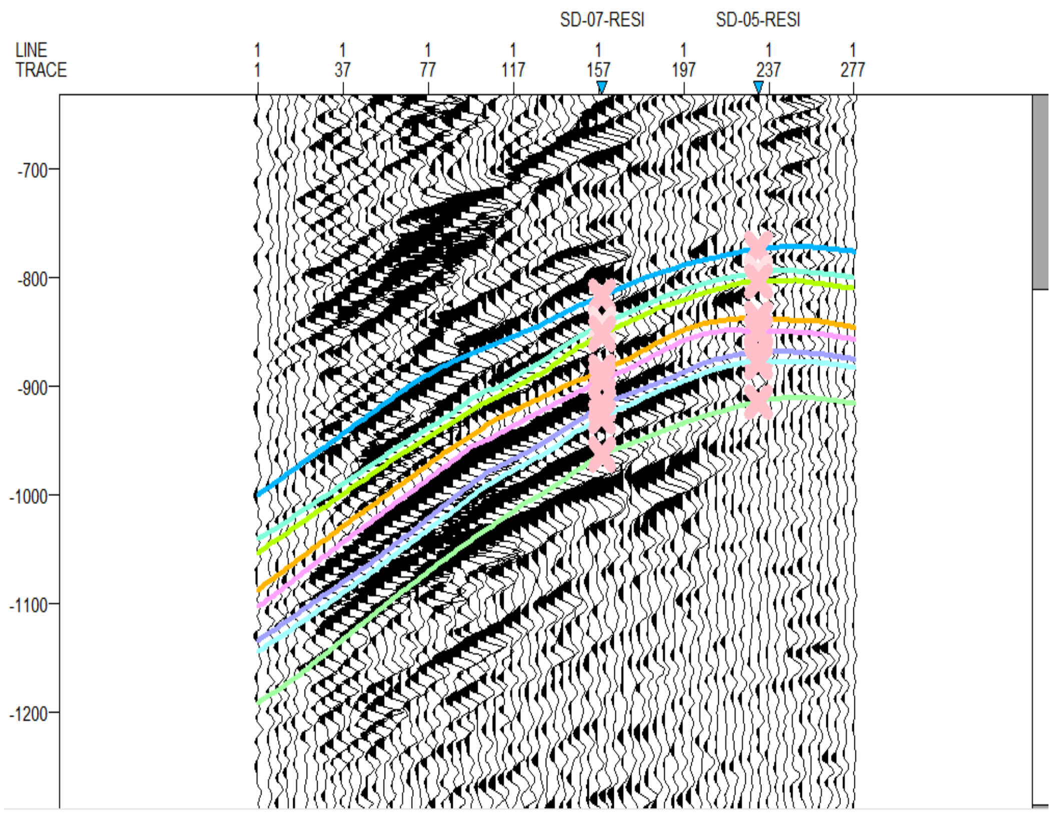

Figure 27: Horizon picking of SD#02

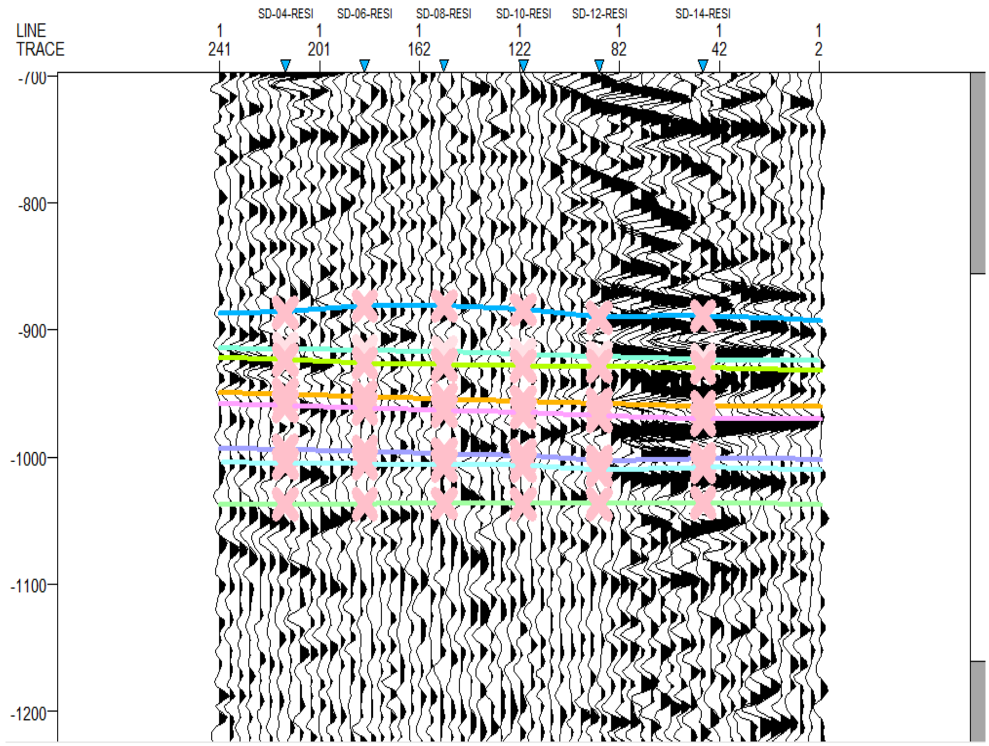

Figure 28: Horizon picking of SD#01

4.2 Structural Modeling

Structural modeling is the main step in geological modeling. It includes:

- Fault Modeling
- 3D grid modeling
- Making horizon
- Make zones
- Make layering

4.2.1 Fault modeling

From the available seismic data no major or large scale fault could be interpreted in the Saldanadi structure. This is why no fault line picking, fault modeling, and pillar modeling could be performed.

4.2.2 3D grid modeling

As fault is absent in this structure, “Make Simple Grid” in the Utility process has been used for gridding. It produces three skeleton of the structure named: Top, Middle and Base. This gridding represents the skeleton of the model as shown in the Fig 29.

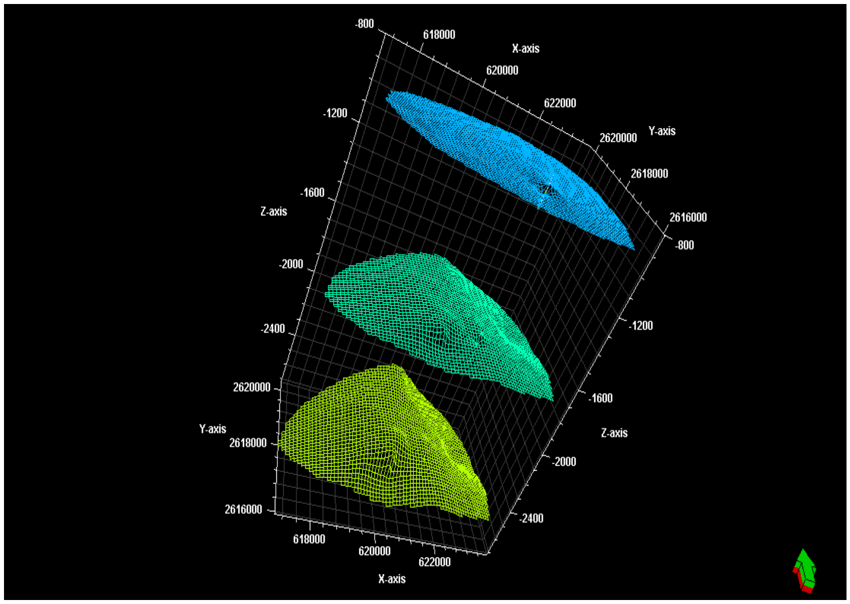

Figure 29: 3D Model Grid Skeleton of Saldanadi Gas Field.

4.2.3 Making Horizon

The Seismic grid/depth maps imported in Petrel have been converted into surfaces using make/edit surface option in the “Make Horizon Process”. Created horizons are Top and Base of UGS and LGS. Top and base horizons have been created by taking the tops and bases respectively of the respective gas sands from the wells (figure-30).

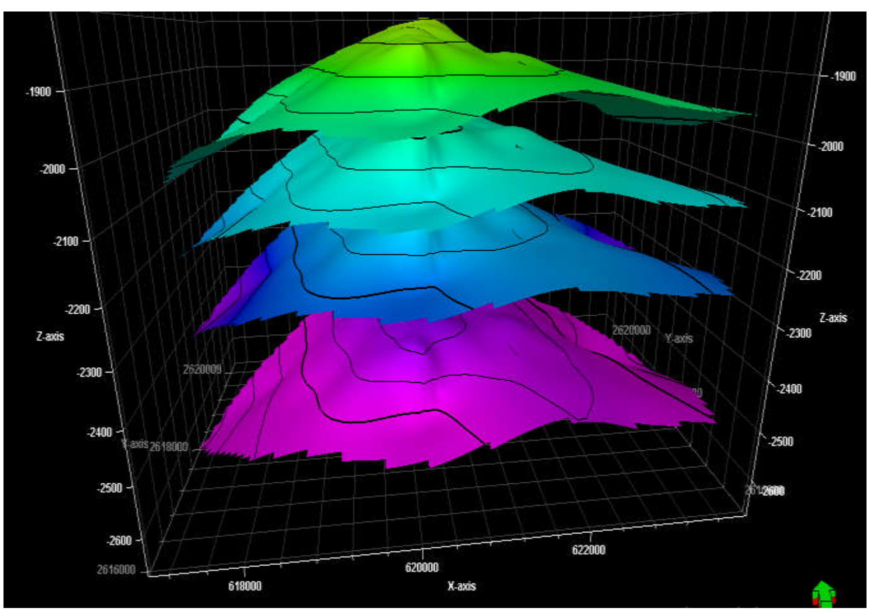

Figure 30: Seismic horizons (four) used for modeling.

4.2.4 Make Zones

Make zone process has been used for zone making. Depth maps along the tops and bases are converted into surfaces and have been used as input for zone making. The zones have been built from Top Horizon along stratigraphic thickness where tops and bases lie as conformable in the model.

4.2.5 Make Layering

Artificial layer have been created using proportional thickness for NGS 2, NGS 1, UGS and LGS that have been corrected later according to the vertical range of the facies (Figure 31).

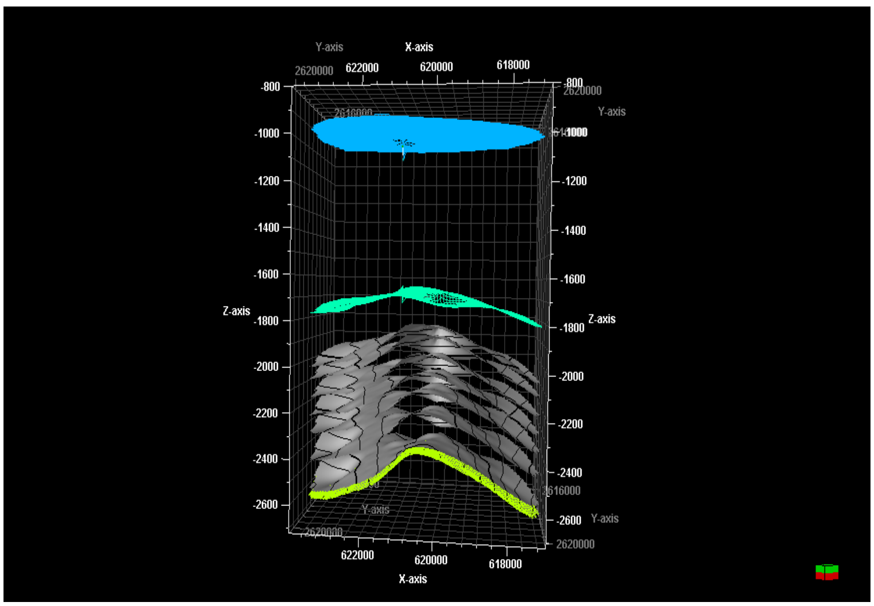

Figure 31: 3D cellular grid showing artificial layer.

The NGS 2 and NGS 1 have been subdivided into 5 to 11 artificial layers with average thickness of 10.2 m. The UGS and LGS on the other hand have been subdivided into 12 to 24 layers with average thickness of 9.5 m. This layering results the grid block dimension into (70 × 44 × 23) cells and total number of 2D nodes is 2475.

4.3 Correlation

The reservoir succession is divided into four main zones: New Gas Sand 2 (NGS 2), New Gas Sand 1 (NGS 1), Upper Gas Sand (UGS) and Lower Gas Sand (LGS), each separated by a well-developed shale section that can be correlated across the field (Figure 32). Zone UGS is the thicker of the four and provides the most laterally extensive and productive reservoirs in the field. Four gas bearing horizons were encountered in all the wells accordingly. The reservoir tops of NGS 2, NGS 1, Upper and Lower Gas Sands were correlated using well logs and the depth interval is shown in Table 7.

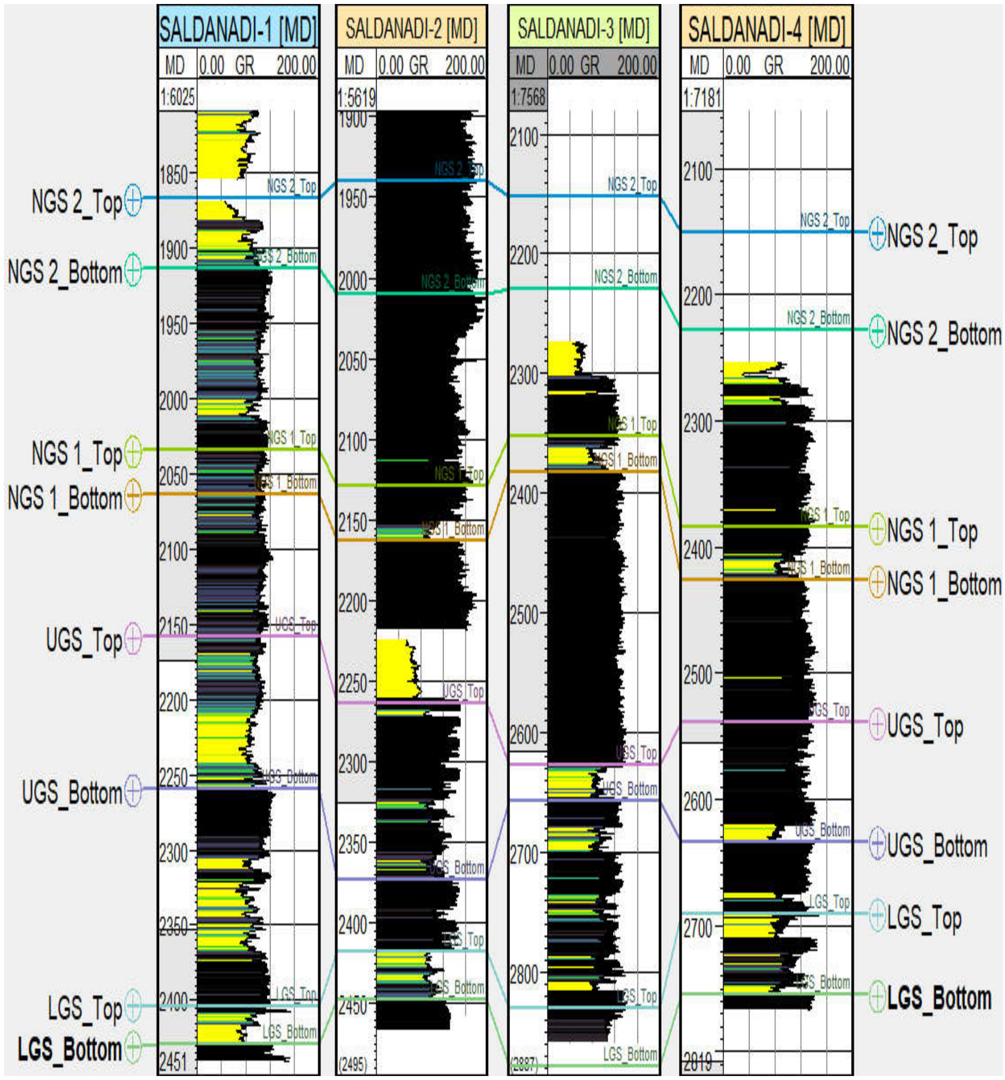

Figure 32: Well correlation among Saldanadi well no 1, 2, 3 and 4

4.4 Well Completion design

Well completion is a series of steps depending upon the completion method performed after the drilling and casing phase, that enable well to produces hydrocarbons. The primary goals are to stimulate the well to maximize production and running tubing to enhance the well's lifespan**.** The parameters (Casing details, Perforation interval and Completion date) of well completion design are shown in Table 12.

Table 12: Well Completion design parameters (BAPEX)

Ser No	Well Name	Casing Details	Date of Completion	Perforation Interval (MD)
1	**Saldanadi-1**	30"- (0-30) m 20"- (0-250) m 13 3/8"- (0-849) m 9 5/8"- (0-1879) m 7" Liner - (2510) m	Start: 28 Mar 1998 End: 05 Dec 2011	DST-1: 2408.5-2414.5 DST-2: 2170-2173 2176-2180
2	**Saldanadi-2**	30"- (0-25) m 20"- (0-201.25) m 13 3/8"- (0-1177.63) m 9 5/8"- (0-2244) m 7" Liner-(2194-2458)m	Start: 03 May 2001 End: 23 Jan 2012	Production: 2299-2342 DST-2 : 2313-2318 (7 Nov 1999) 2430-2435 (26 Oct 1999)
3	**Saldanadi-3**	30"- (0-25) m 20"- (0-120) m 13 3/8"- (0-911) m 9 5/8"- (0-2303) m 7" Liner-(2268-2888) m	NGS 1: 10 Dec 2011 NGS 2: 31 Jan 2012	DST: 2189.5-2195.5 (NGS-2) 2361.55-2368 (NGS-1) 2368.55-2375 (NGS-1)
4	**Saldanadi-4**	30"- (0-33) m 20"- (0-116) m 13 3/8"- (0-916) m 9 5/8"- (0-2254) m 7" Liner - (2775) m	Start Production: 19 Feb 2016 End:	DST-1: 2570.5-2582.5 DST-2: 2403.5-2414.5

Well completion design of Saldanadi well 1 and well 2 is given in the following figure 33. Among all 4 gas sand unit, Upper gas sand is the thickest gas sand. Perforation had been conducted in UGS and LGS in SLD#1 and in UGS in SLD#2.

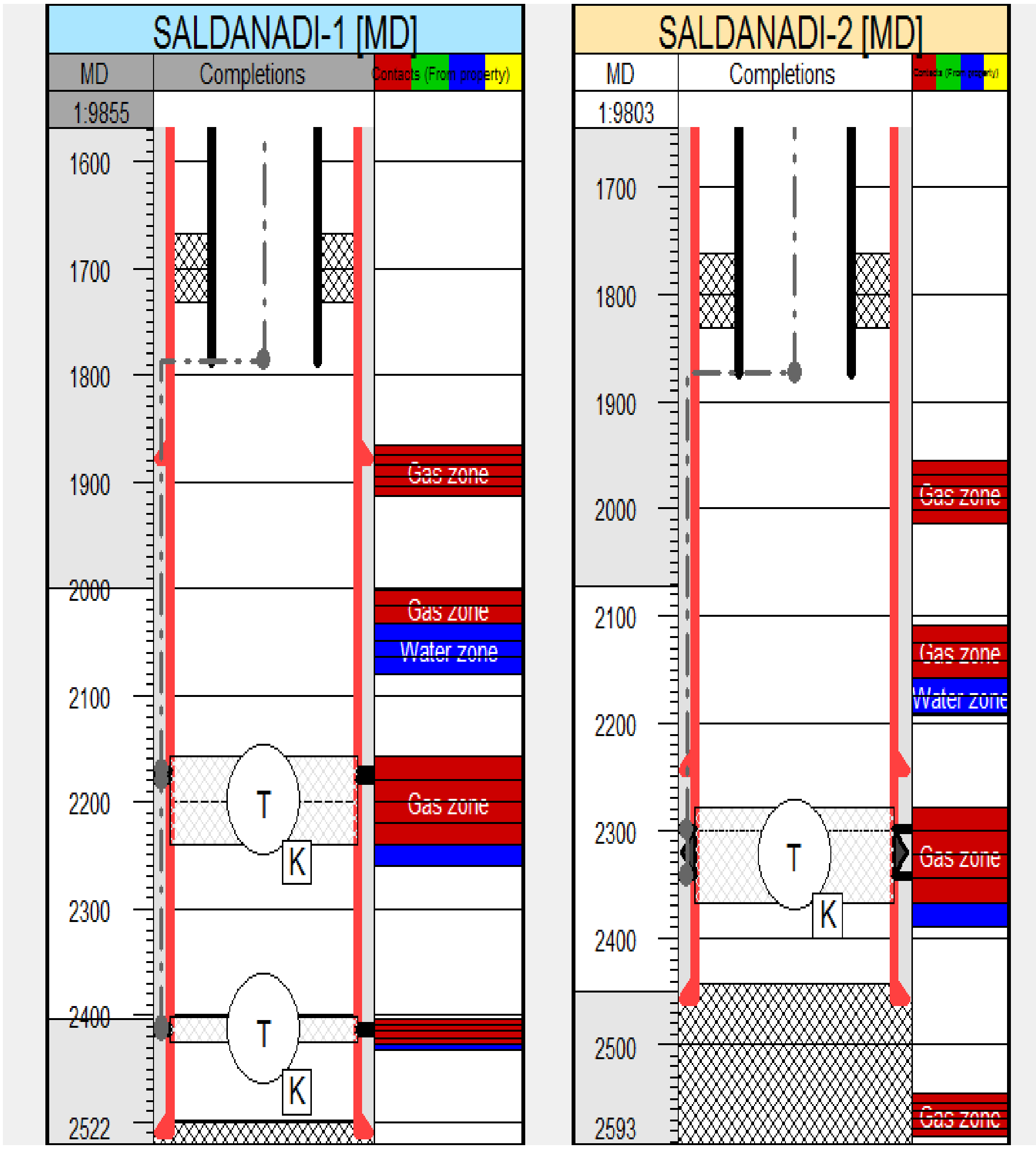

Figure 33: Well Completion design of Saldanadi Well No 1 and Well No 2.

Well completion design of Saldanadi well 3 and well 4 is given in the following figure 34. Among all 4 gas sand unit, Upper gas sand is the thickest gas sand. Perforation had been conducted in NGS 1 and NGS 2 in SLD#3 and in UGS in SLD#4.

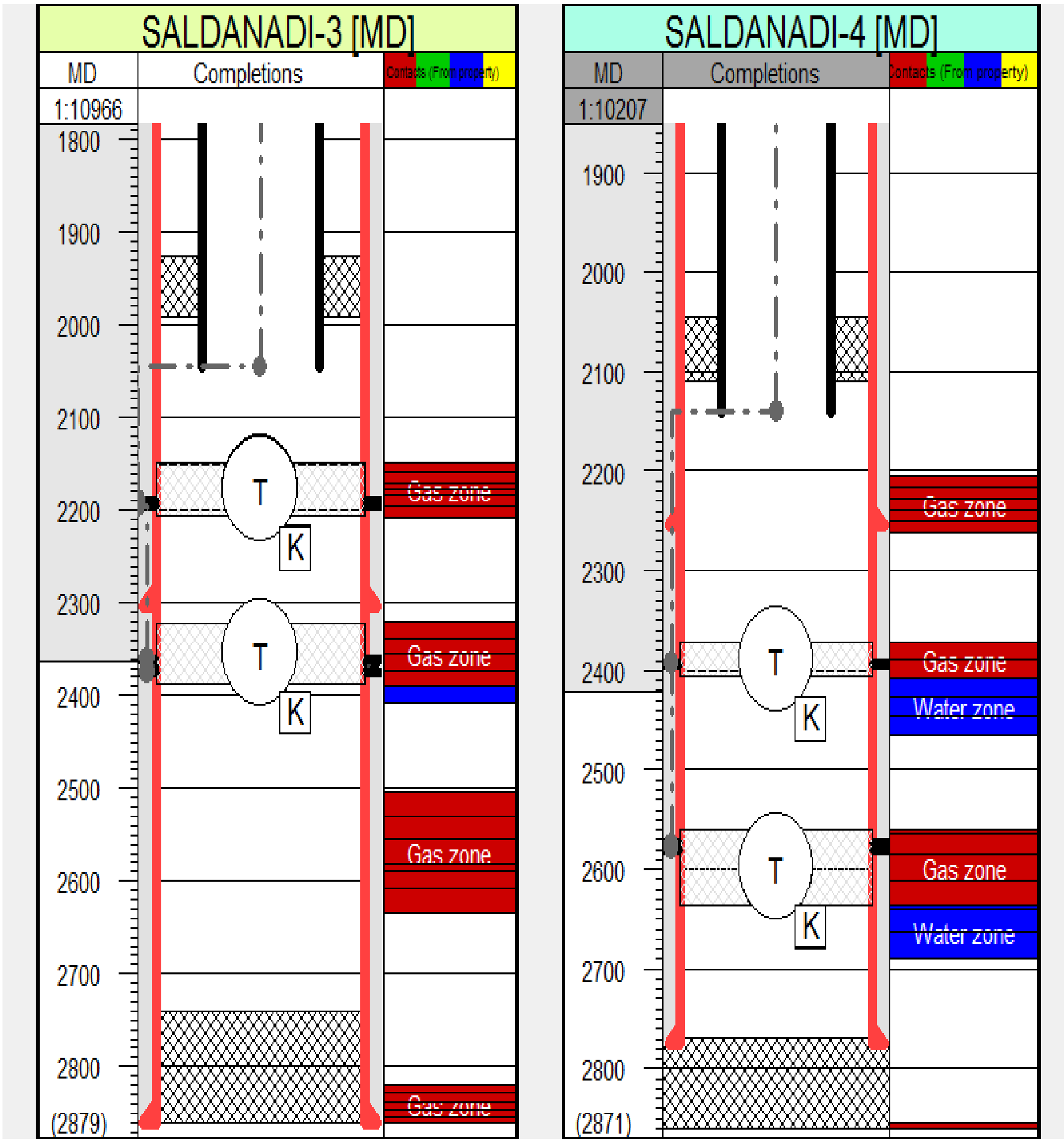

Figure 34: Well Completion design of Saldanadi Well No 3 and Well No 4.

4.5 Structure

The basic advantage of a 3D model is that it allows the analyst to observe and evaluate structural data by showcasing a cross section across the model in multi-direction. The construction of a structural model gives us visualization for new well trajectories and also allows us to test the model through structural sections, volumetric calculations, and reservoir simulation grids. Three major processes were required to complete the structural modeling (i.e., fault modeling, pillar gridding, and horizon generation) (Abdelmaksoud et al., 2019; Radwan, 2022) (Rahimi et al., 2020).

A few minor faults were observed from the 2D seismic data at the Saldanadi structure and vicinity. This is probably due to the low resolution of the variable quality 2D seismic data and probably more faults can be expected to be seen in a higher resolution 3D seismic dataset.

In the present study, depth structure contour maps were constructed for the Saldanadi gas field by using Petrel software to illustrate the subsurface structural configuration of the investigated area. The interpreted seismic data were the main container for the 3D geologic modeling (facies and their petrophysical characteristics). During the 3D structural modeling, the seismic interpretations were the main input data (Rahimi et al., 2020).

The depth structure map of NGS 2, NGS 1, UGS and LGS are shown in Figure 35, 36, 37 and 38 respectively. Figure 39 demonstrate about the depth map of all gas sands including four studied wells. Structural correlation though saldanadi anticline is shown in Fig-40.

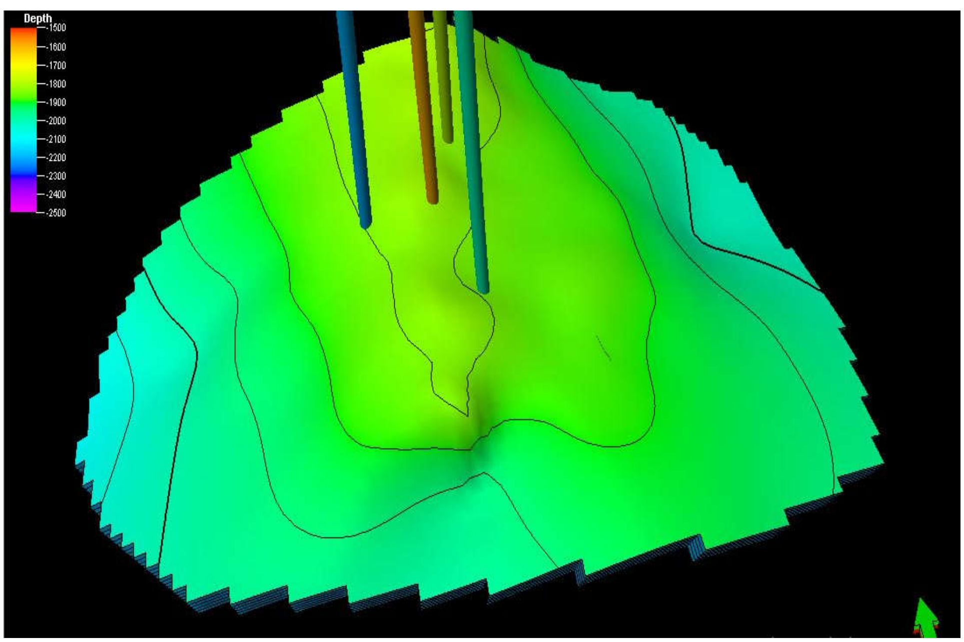

Figure 35: Depth Structure Map of NGS 2 with all wells of Saldanadi Gas Field

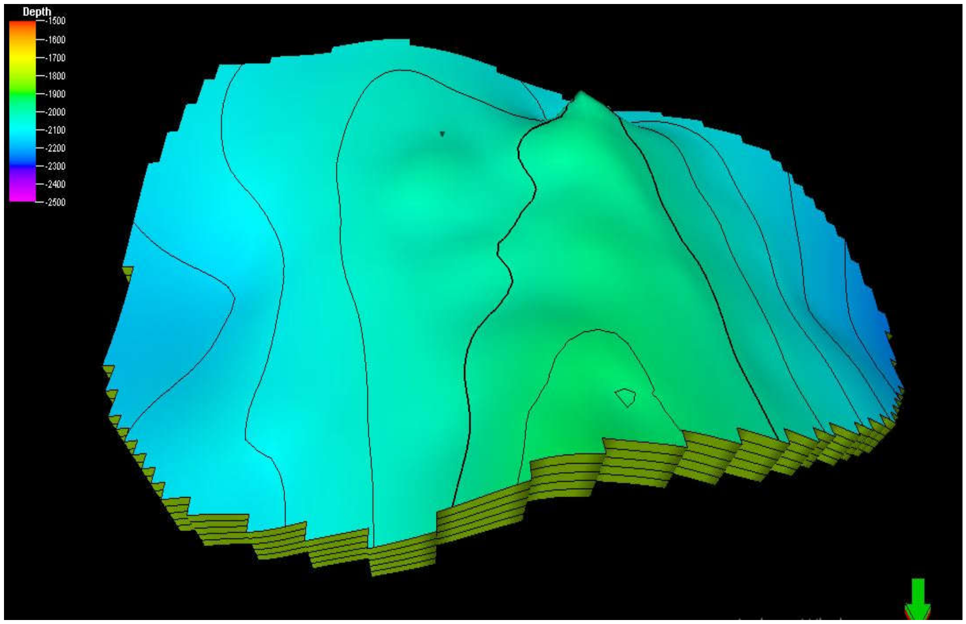

Figure 36: Depth Structure Map of NGS 1 of Saldanadi Gas Field.

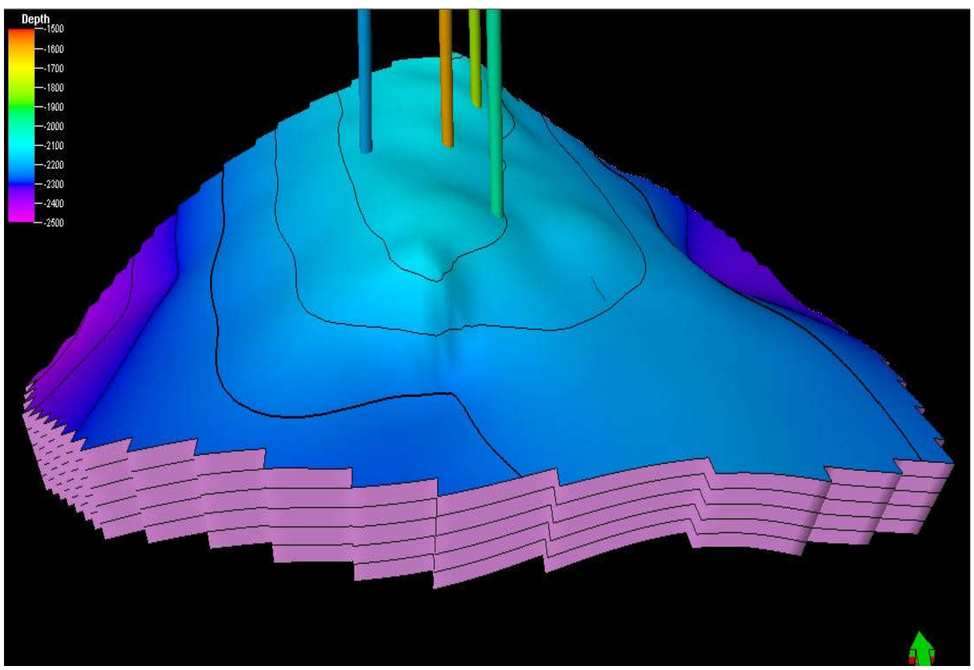

Figure 37: Depth structure map of UGS with four wells.

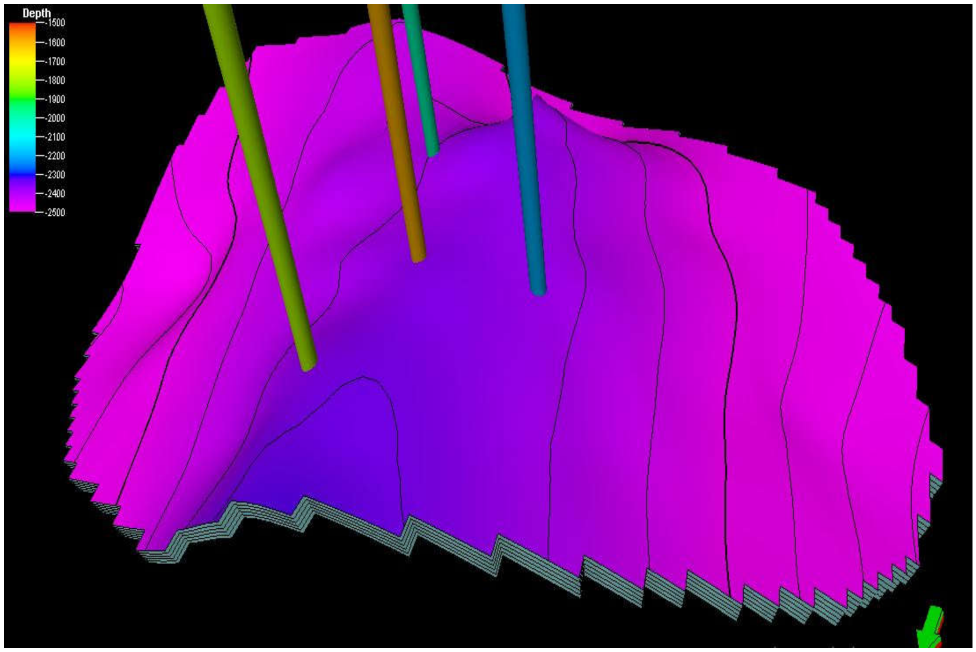

Figure 38: Depth Structure Map of LGS with all four wells.

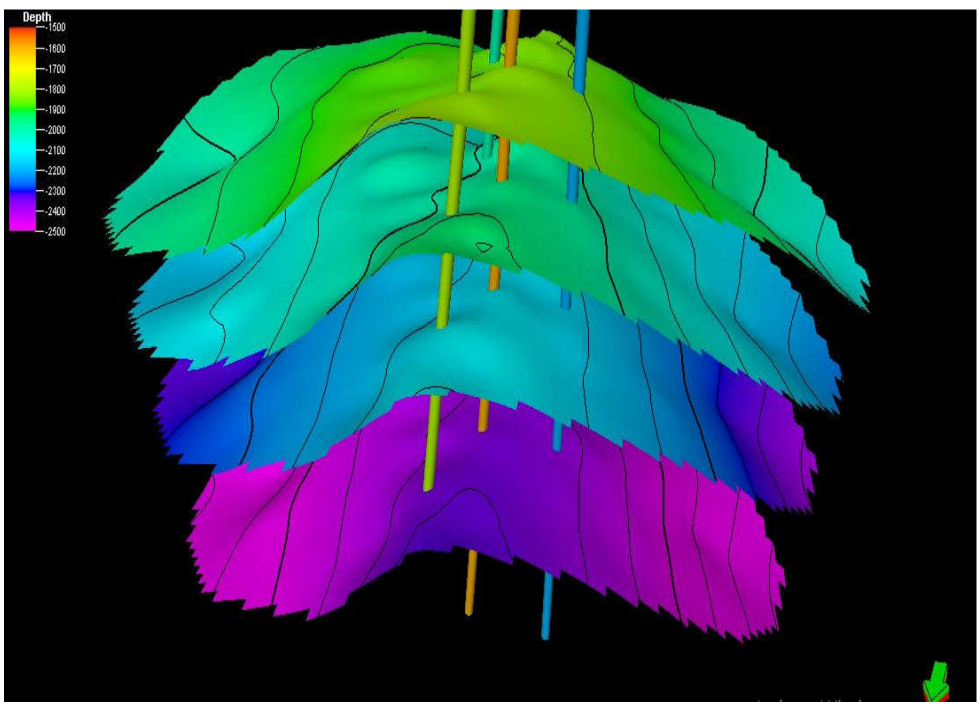

Figure 39: Depth Map of all Gas Sands tops including all wells.

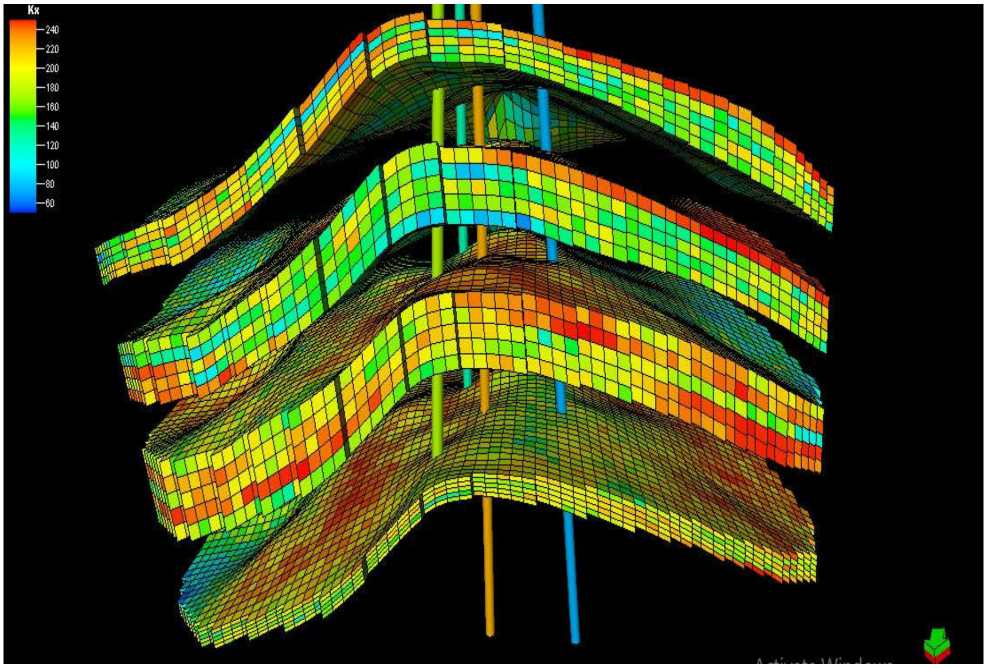

Figure 40: Structural Cross-Section through Saldanadi anticline.

4.6 Properties Modeling

Properties modeling are the main step of distributing porosity, permeability and facies modeling between the wells and the model. It includes geometrical modeling, scale up well logs, facies modeling and petro-physical modeling. These steps are followed during modeling process and described below successively.

4.6.1 Geometrical Modeling

Geometrical properties such as cell height, bulk volume, zones (hierarchy) etc have been modeled in this process according to required method. The main purpose of geometrical modeling is to calculate bulk volume, pore volume etc.

4.6.2 Scale up Well Logs

Scale up means averaging log values in a cell. Log value is distributed by considering cell value through the model. In this step both discrete (facies) and continuous properties (porosity, permeability etc.) are averaged in each grid cell along the well path. For each grid cell, all log values that fall within the cell are averaged according to the selected algorithm to produce one log value for that cell (Fig-41).

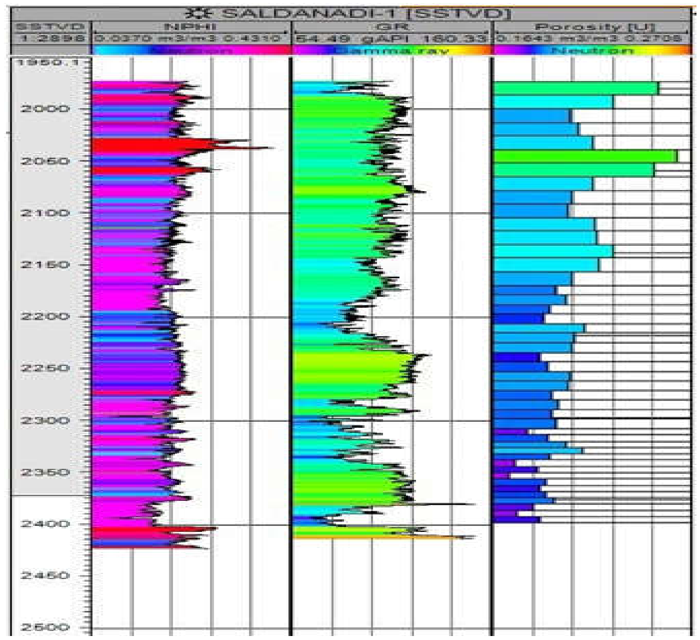

Figure 41: Scale up well log showing upscale porosity log of SLD#1 wells.

4.6.3 Data Analysis

Data analysis is an important step for facies and petrophysical modeling. Depending on whether a property is discrete (e.g. facies) or continuous (e.g. porosity) different tools and methods are available within the data analysis process window. Before facies modeling and petro-physical modeling data analysis has to be performed. In Saldanadi Model, both discrete and continuous data analysis have been performed based on available log data from two wells which are stated in facies and petro-physical modeling.

4.7 Geological Model Construction

The geological model was constructed based on structural map, well log data and core analysis data. After making required modifications, the dynamic model was obtained.Then simulation was run to obtain history matching and forecasting.

A most likely model was built for the Saldanadi Field to estimate the Gas Initially In place (GIIP) and to generate input for the reservoir simulation model that will be used to formulate the depletion strategy and reservoir management plan for the field. The model integrated the seismic interpretation, petrophysical data and well data.

The structural and stratigraphic modeling of the reservoirs has been made with the seismic depth grids of the top of main four reservoir sand units: NGS 2, NGS 1, UGS and LGS. The grid was built using a 100 x 100 m grid spacing which resulted in grid dimensions of 70 x 44 x 23 (x, y, z) to represent the four distinct gas sands encountered in the field, with a total of 70840 cells. A thick continuous shale interlayer separates the four gas sands from each other resulting in no vertical communication between the zones. The model grid layering is presented in Table 13.

Table 13: Layering of grid model of the reservoir

SL.	Horizon		Simulation Layer	Status
1	New Gas Sand 2	NGS 2	1-5	Active
	Inter Layer	-	6	Inactive
2	New Gas Sand 1	NGS 1	7-11	Active
	Inter Layer	-	12	Inactive
3	Upper Gas Sand	UGS	13-17	Active
	Inter Layer	-	18	Inactive
4	Lower Gas Sand	LGS	19-23	Active

In the Saldanadi Field the facies models for the reservoir sand were made from porosity logs. The structural correlation of Saldanadi-1 for the field is presented in Figure 42.

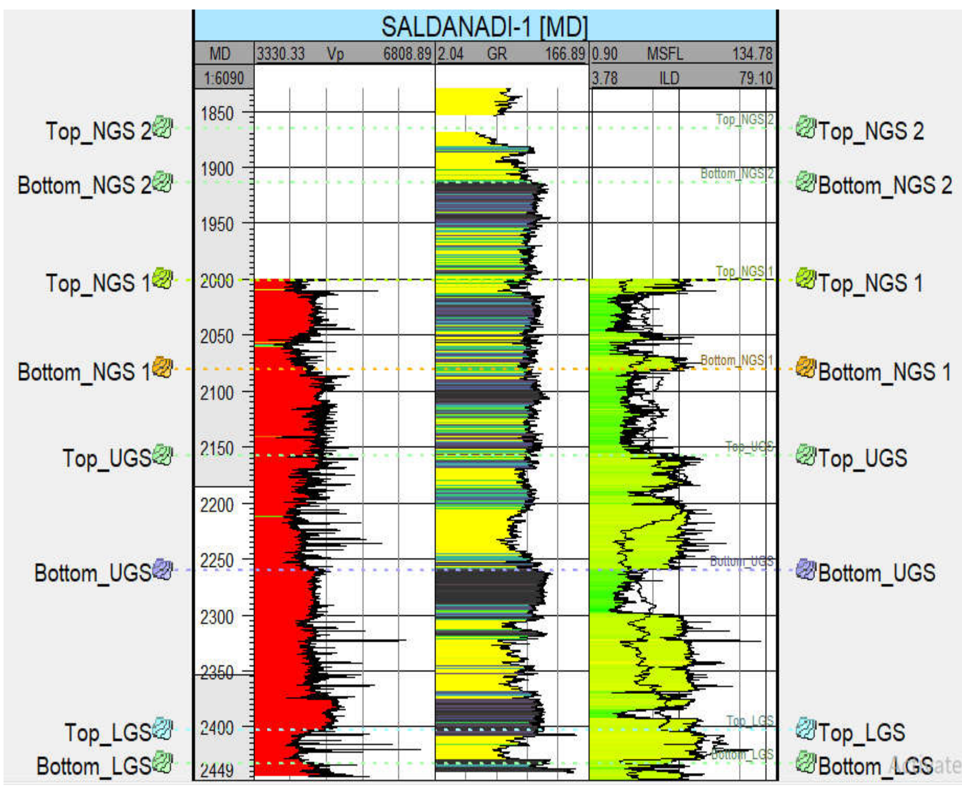

Figure 42: Structural Correlation of SD-1

4.8 Petro-physical Modeling

The major inputs for the petrophysical modeling included upscaling of well logs, input distribution, and variogram construction. The vertical range was set to twice the zone's thickness. To ensure that the transformation applied to the data was reasonable (valid), a statistical quality check was done between both of the upscaled and modeled petrophysical attributes to ensure that the upscaled and modeled petrophysical characteristics' standard deviations and variances were nearly identical (Abdelmaksoud et al., 2019a; Radwan, 2022), (Rahimi et al., 2020). Petrophysical modeling consists of Facies, Porosity, Permeability and Net to gross modeling and is described as following:

4.8.1 Porosity Modeling

Porosity of geological model was kept same in simulation model. Porosity distribution of NGS 2, NGS 1, UGS and LGS of Saldanadi is shown in Figure 43, 44, 45 and 46 which shows how the porosity distribution varies aerially. Figure 47 shows all gas sands of Saldanadi and Figure 48 represents the porosity distribution from Neutron Log. Porosity from analyzed sandstone ranges from 13.72 to 28.85. It is seen that most of the cells contain around 16.61% average porosity

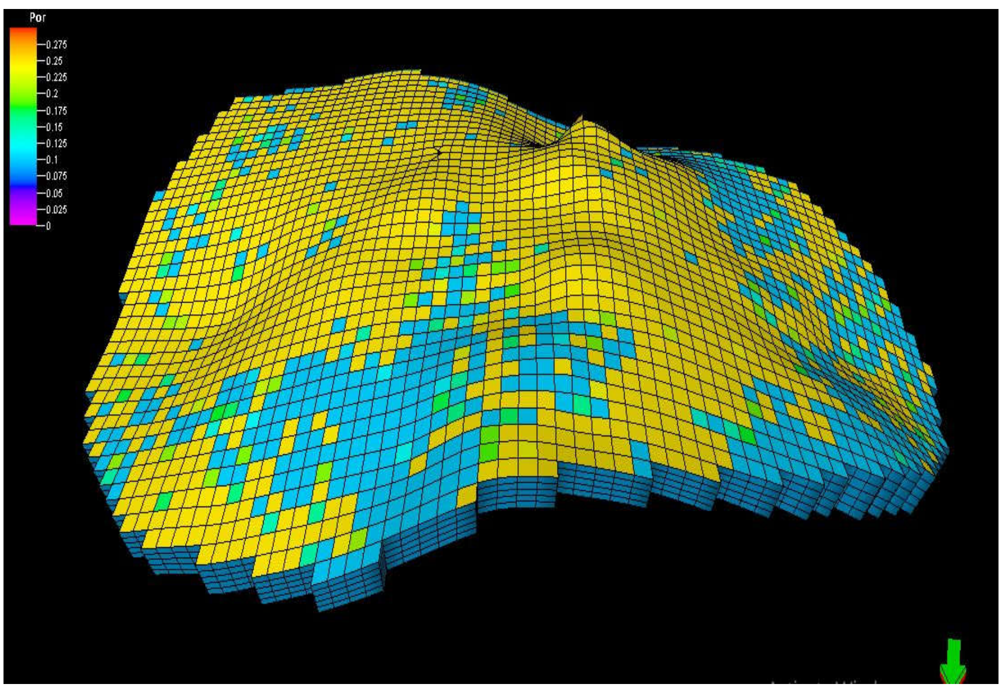

Figure 43: Porosity Model of NGS 2.

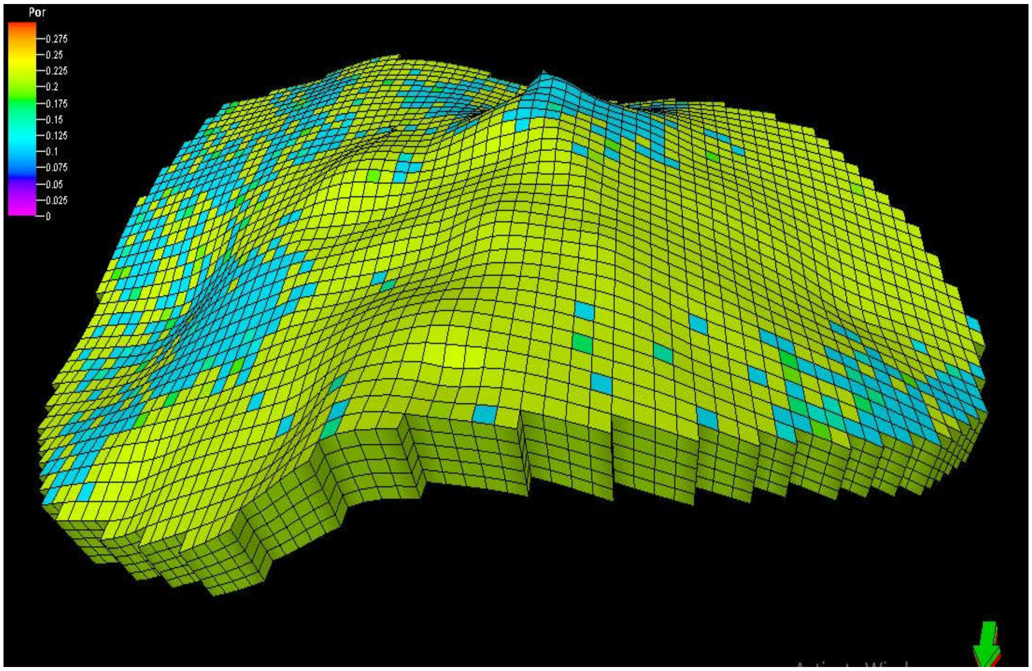

Figure 44: Porosity Model of NGS 1.

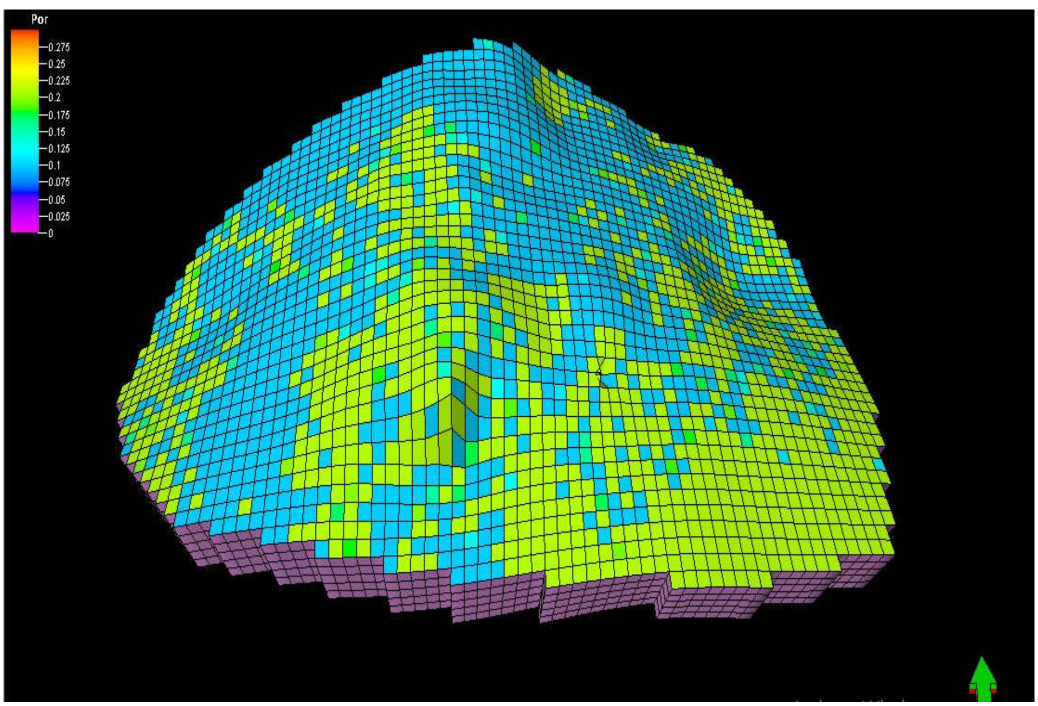

Figure 45: Porosity Model of UGS.

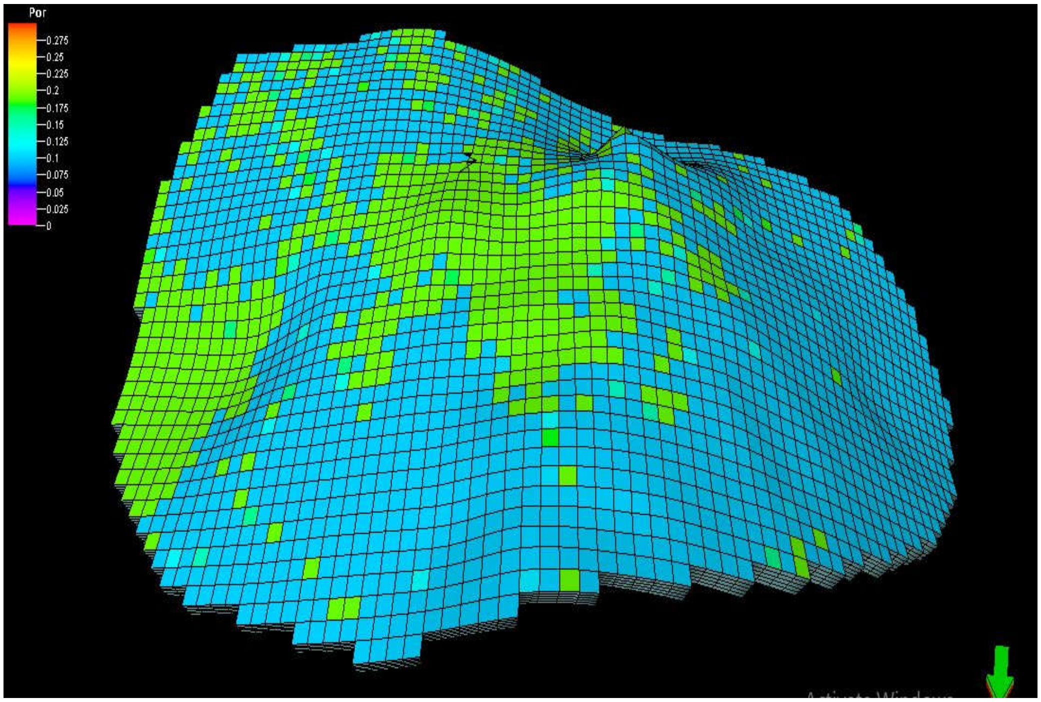

Figure 46: Porosity Model of LGS.

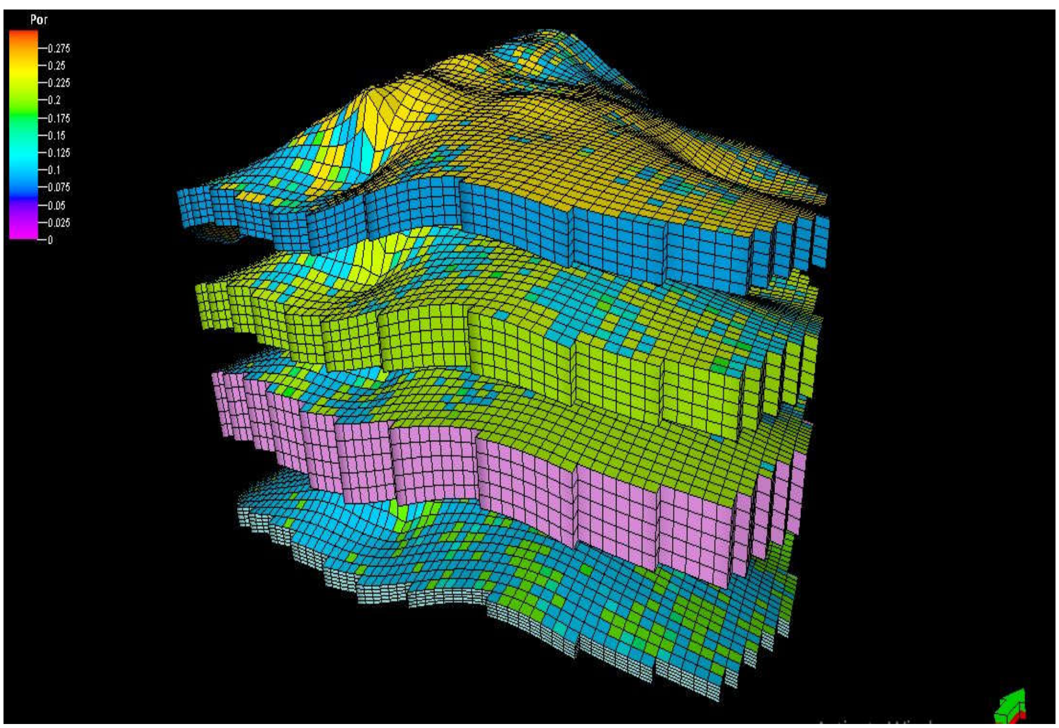

Figure 47: Porosity Model of All Gas Sand.

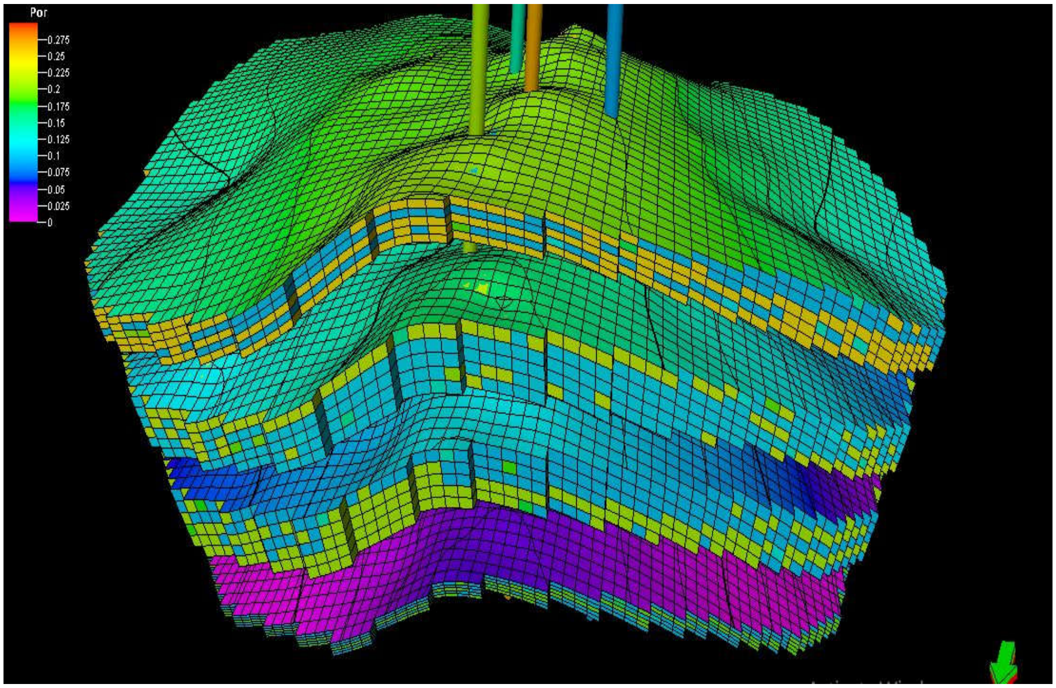

Figure 48: Porosity Model of All Gas Sand with all wells (From Neutron Log).

4.8.2 Permeability Modeling

Based on log data, horizontal permeability was distributed in the geological model. This data was imported in Eclipse and maximum value of permeability was found almost 592 mD. Permeability from analyzed sandstone ranges from 60 mD to 240 mD. Average permeability of 192.40 mD is used for these four sands with respect to core analysis data. The obtained data can be rated as, porosity and it's permeability in moderate to fair range.

Figure 49-60 shows the permeability distribution of NGS 2, NGS 1, UGS and LGS for X-direction, Y-direction and Z-direction. Figure 61 demonstrates the permeability distribution of all gas sand unit including studied four wells.

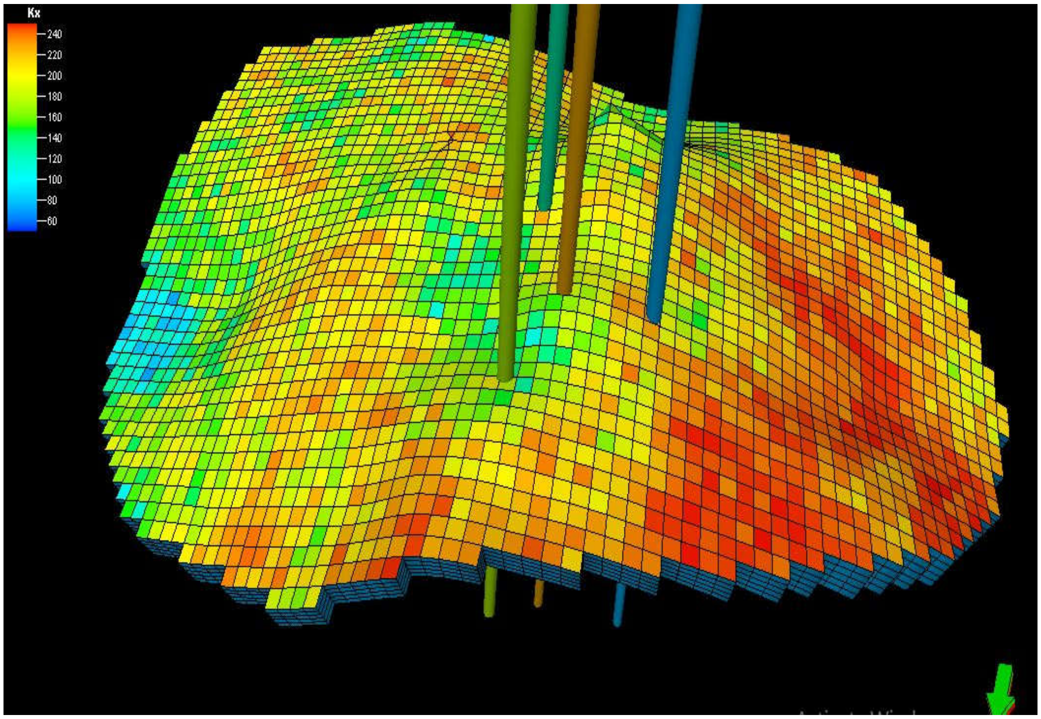

Figure 49: Permeability distribution of NGS 2 (X-direction)

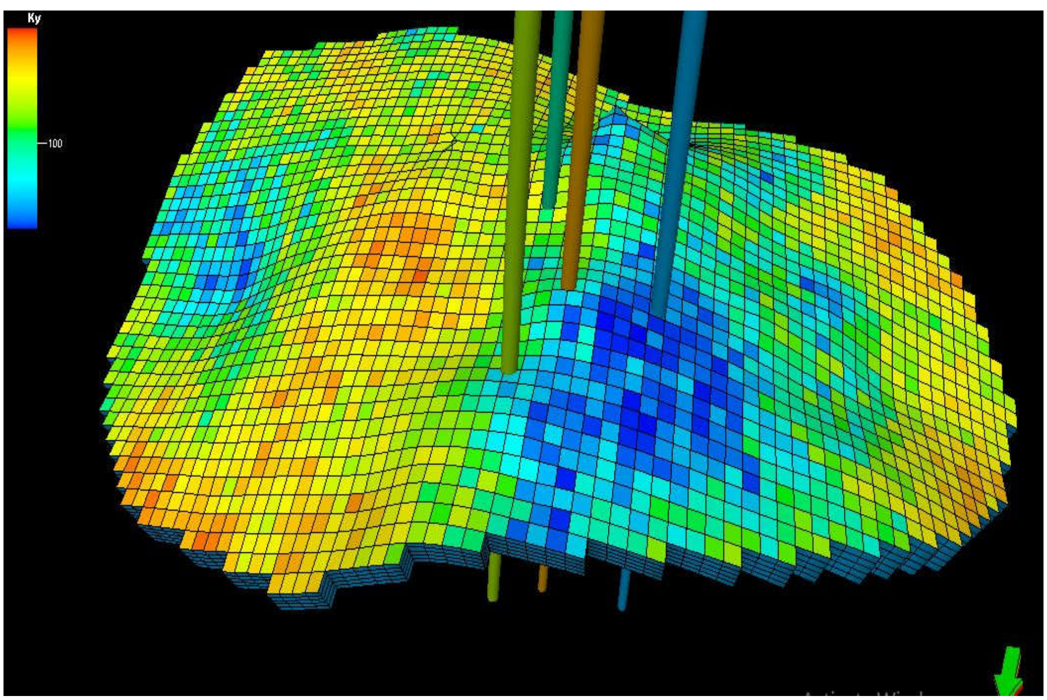

Figure 50: Permeability distribution of NGS 2 (Y-direction).

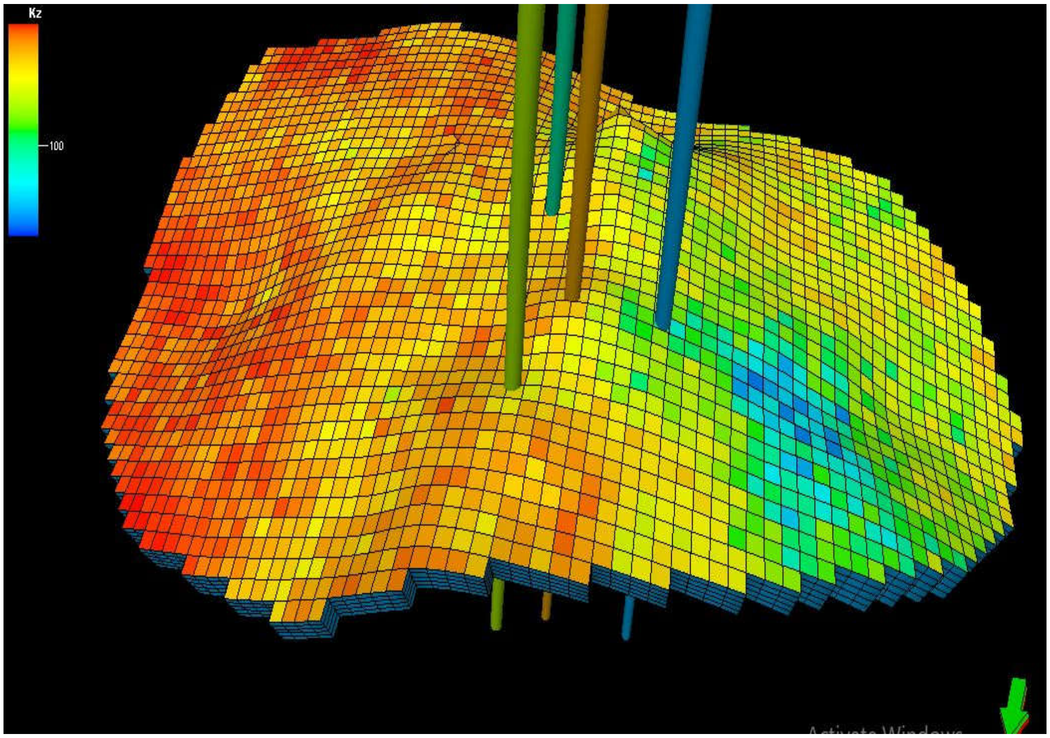

Figure 51: Permeability distribution of NGS 2 (Z-direction)

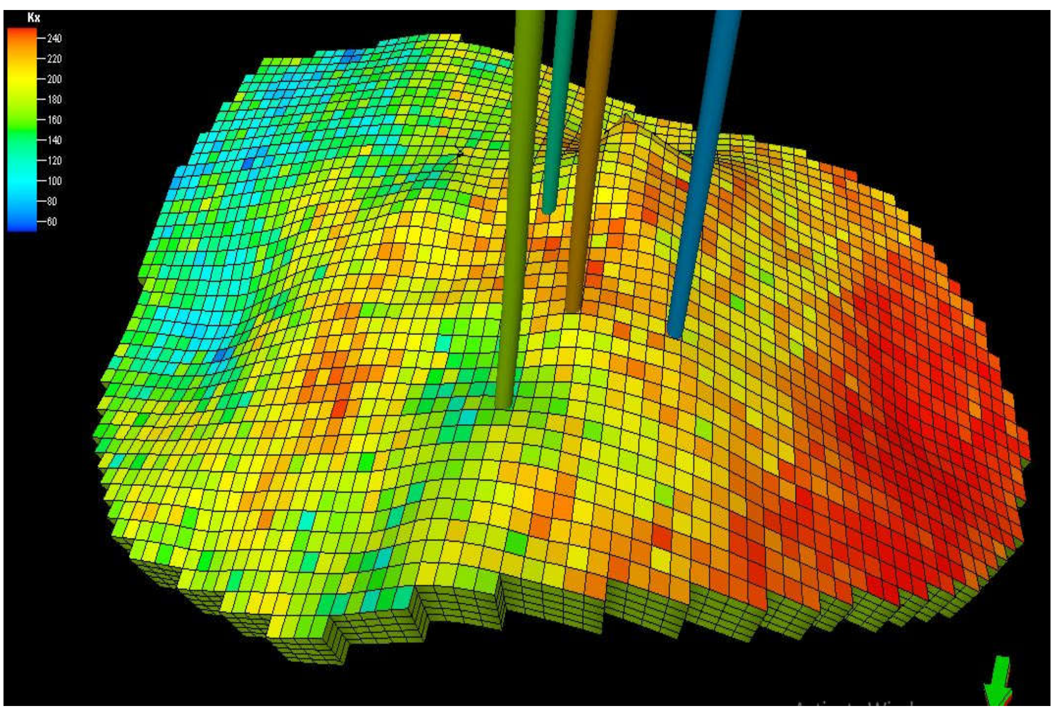

Figure 52: Permeability distribution of NGS 1 (X-direction)

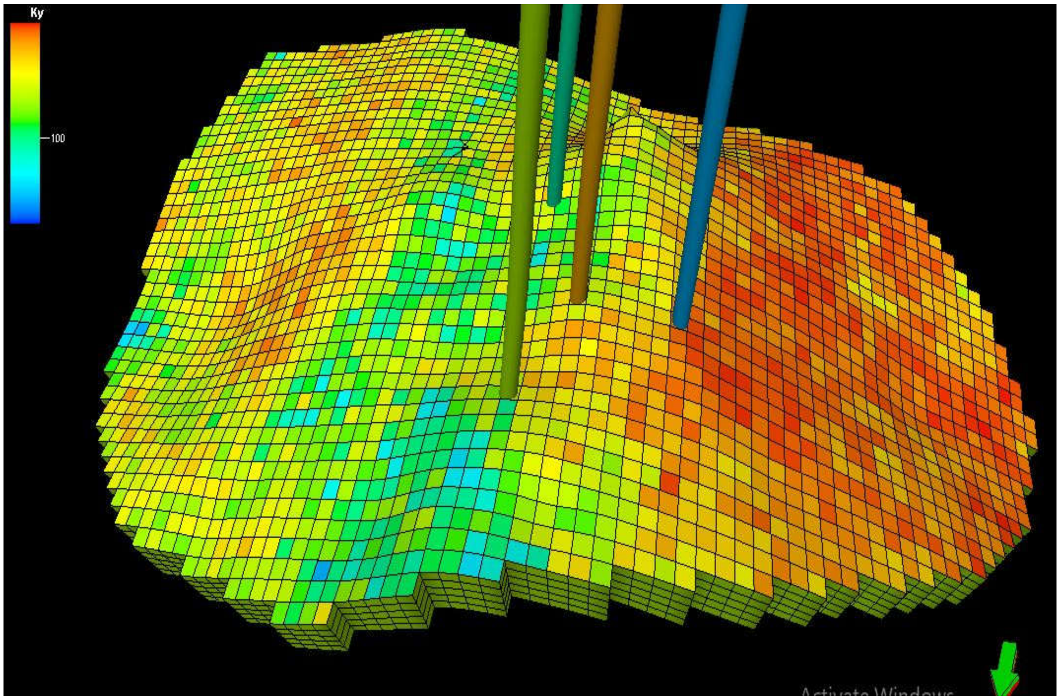

Figure 53: Permeability distribution of NGS 1 (Y-direction)

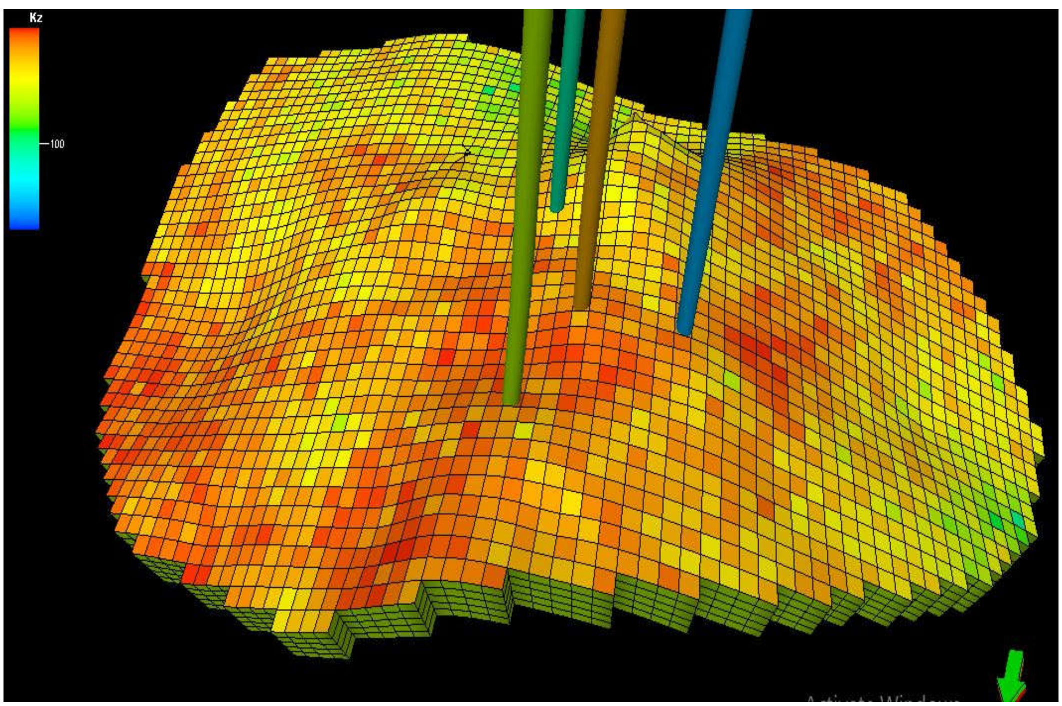

Figure 54: Permeability distribution of NGS 1 (Z-direction)

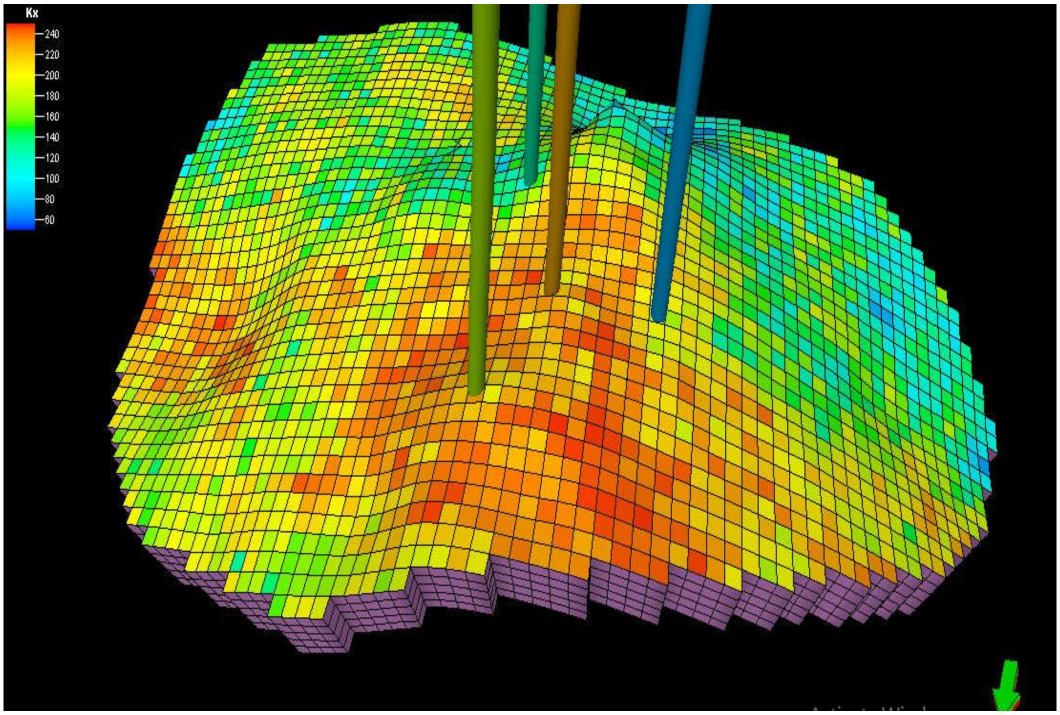

Figure 55: Permeability distribution of UGS (X-direction)

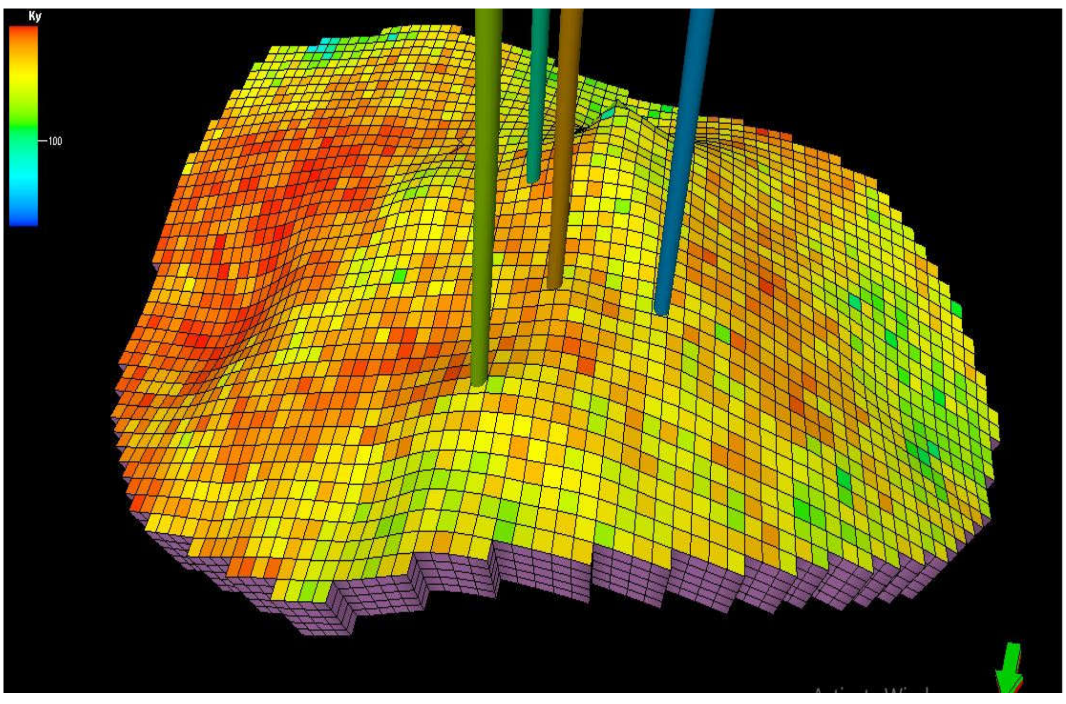

Figure 56: Permeability distribution of UGS (Y-direction)

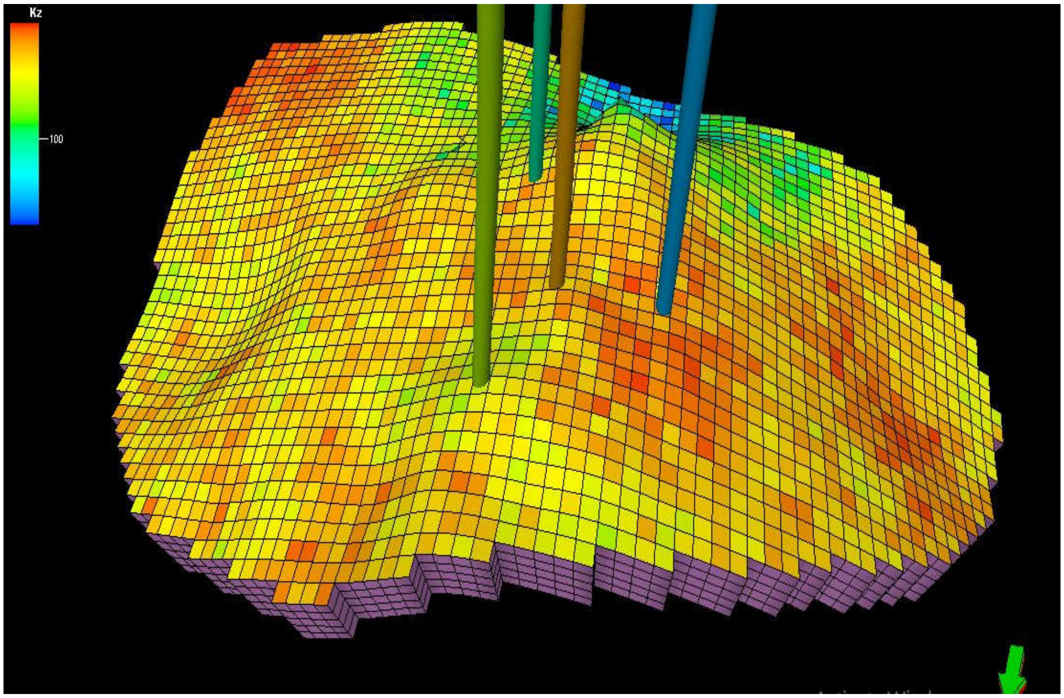

Figure 57: Permeability distribution of UGS (Z-direction)

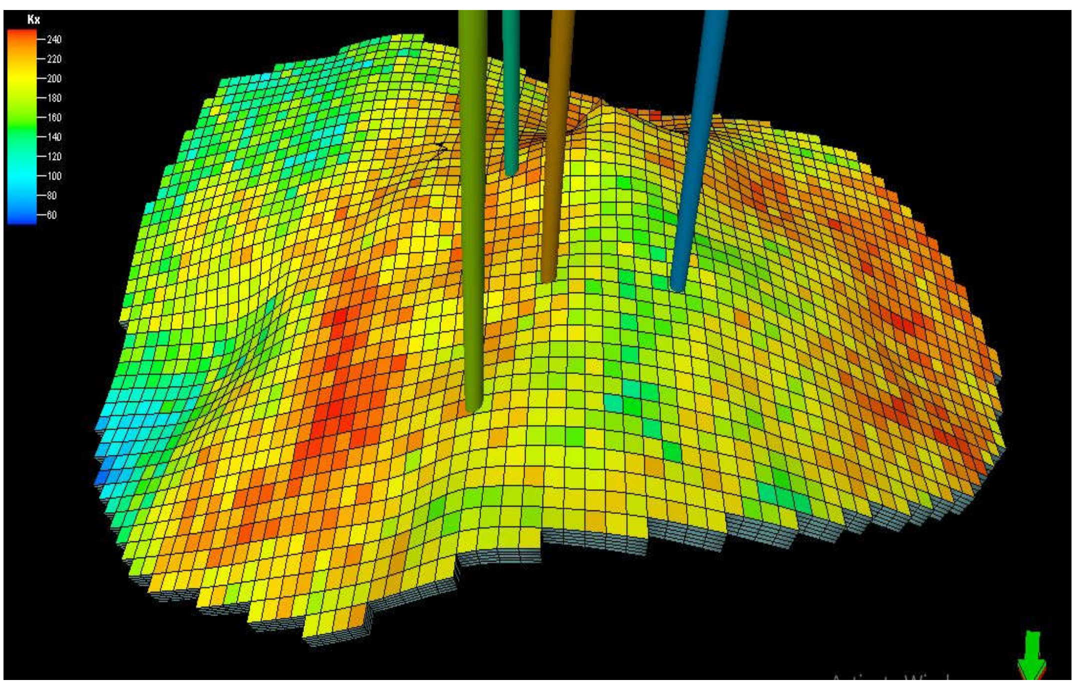

Figure 58: Permeability distribution of LGS (X-direction)

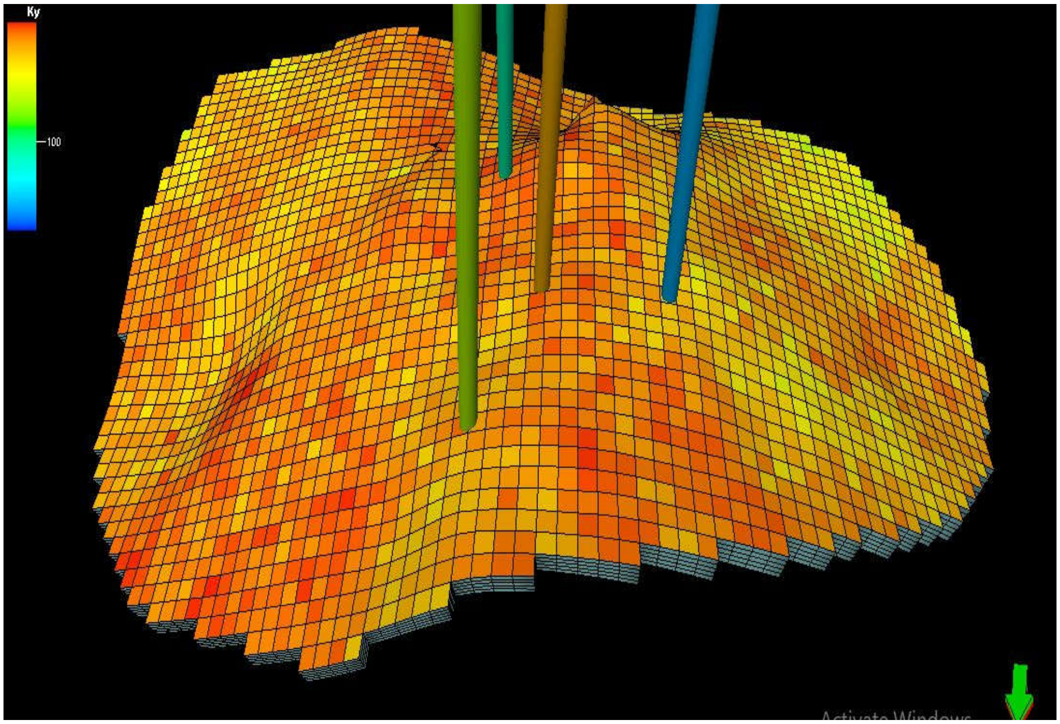

Figure 59: Permeability distribution of LGS (Y-direction)

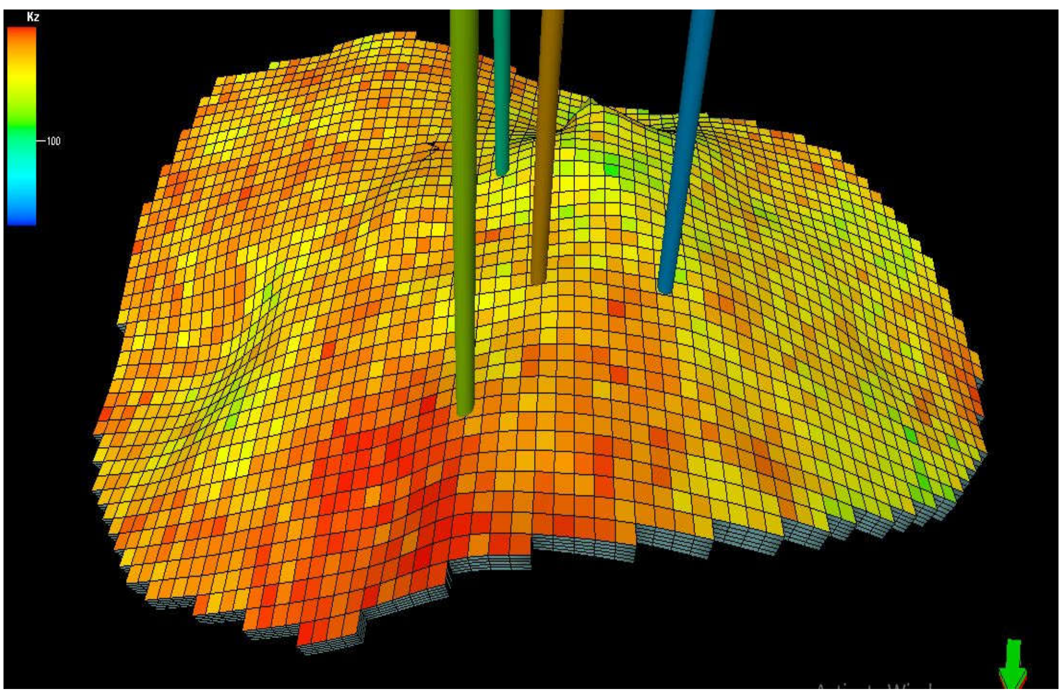

Figure 60: Permeability distribution of LGS (Z-direction)

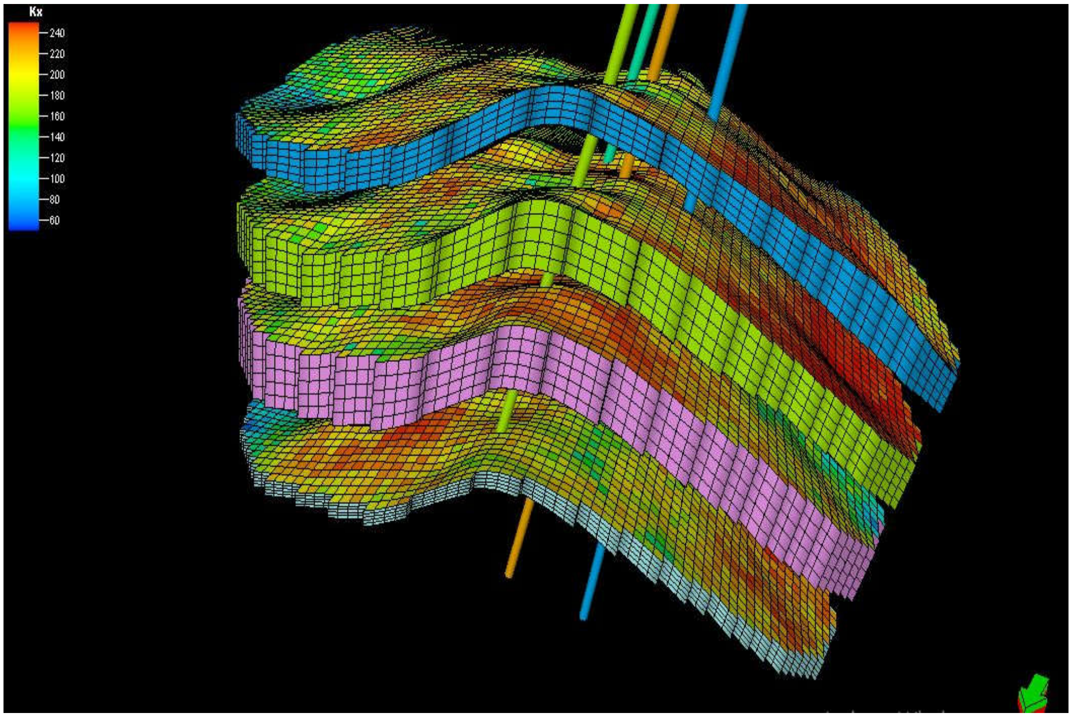

Figure 61: Permeability distribution of all gas sands (X-direction)

4.8.3 Facies Modeling

To build the 3D facies model, the allocated values were loaded in a distinct code for the lithology distribution, and then dispersed in two directions (vertically and horizontally) across the grid cells to fill the full 3D grid between the wells (Abdel-Fattah et al., 2018; God)

In addition, the 3D facies model was applied using the stochastic sequential indicator simulation (SIS) method (Deutsch & Journel, 1998; Journel, 1982; Radwan, 2022; Remy et al., 2009). This algorithm is the most widely used for discrete or categorical variable data such as facies, whereby upscaled facies values and allocated variograms are the most important factors (Deutsch & Journel, 1998; Radwan, 2022),(Rahimi et al., 2020).

The log has been upscaled later in “Scale up well log” process. Sequential Indicator Simulation (SIS) algorithm has been used for facies modeling. Variogram have been used as input for facies modeling and making anisotropy of facies distribution. The major and minor ranges of variogram have been set as 5000 and 3000 respectively with azimuth -45 as there are two wells penetrating the structure. The resulting facies model for all gas sand units shown in figure 63.

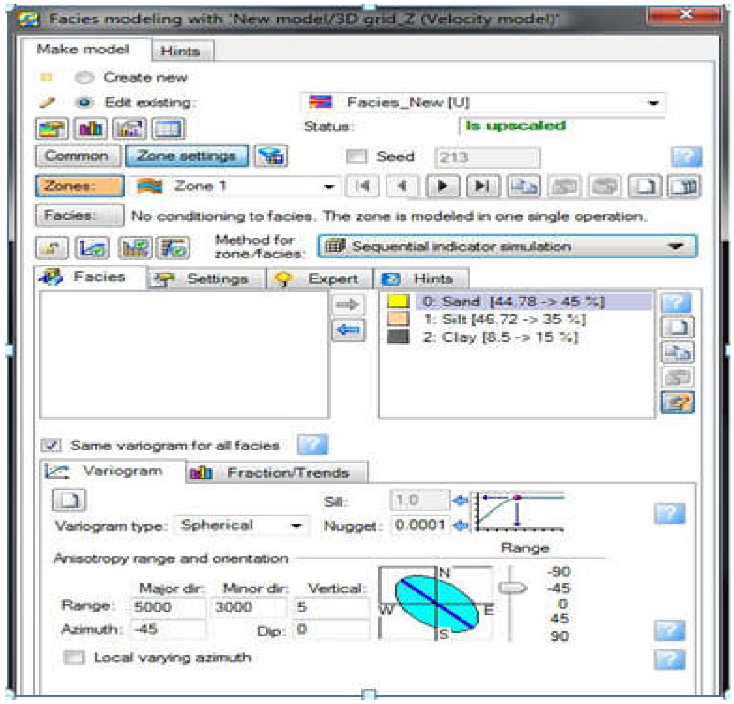

Figure 62: Facies modeling showing Sequence Indicator Simulation method.

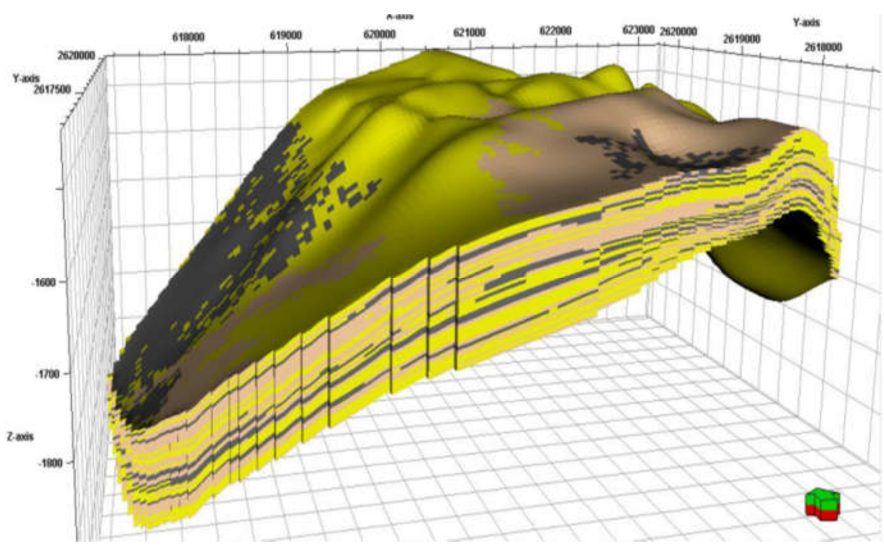

Figure 63: Facies distribution Model of all four zones of Saldanadi Gas Field

4.8.4 Net to Gross Ratio

The net to gross ratio is the total amount of pay footage divided by the total thickness of the reservoir interval. To define productive zones in the reservoir for hydrocarbon exploitation, the significance of Net to Gross (NTG) is well acquainted. Figure 64-67 shows the net to gross ratio model of NGS 2, NGS 1, UGS and LGS respectively.

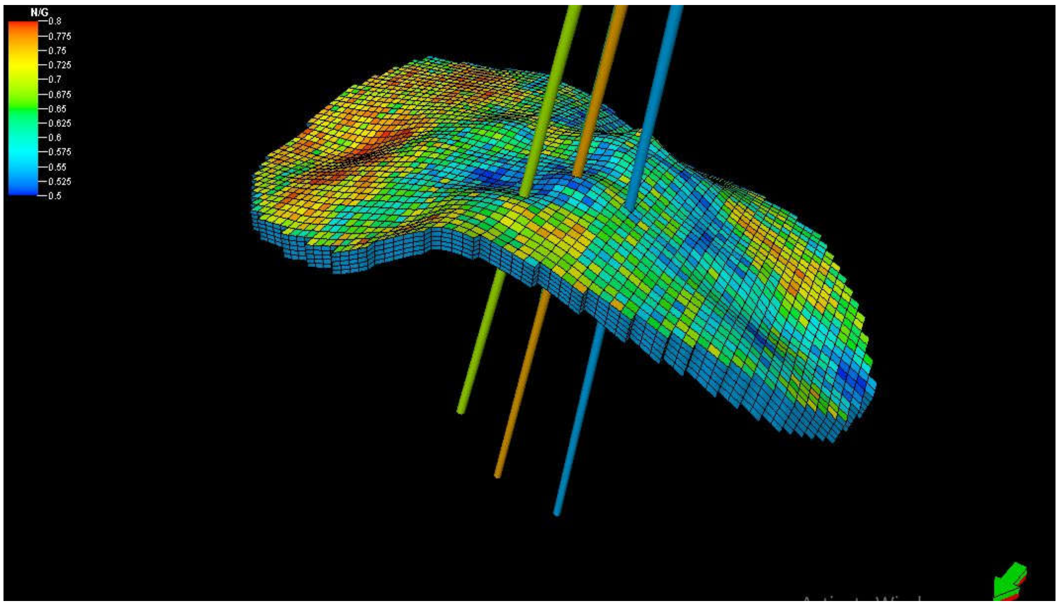

Figure 64: Net to Gross Ratio of NGS 2

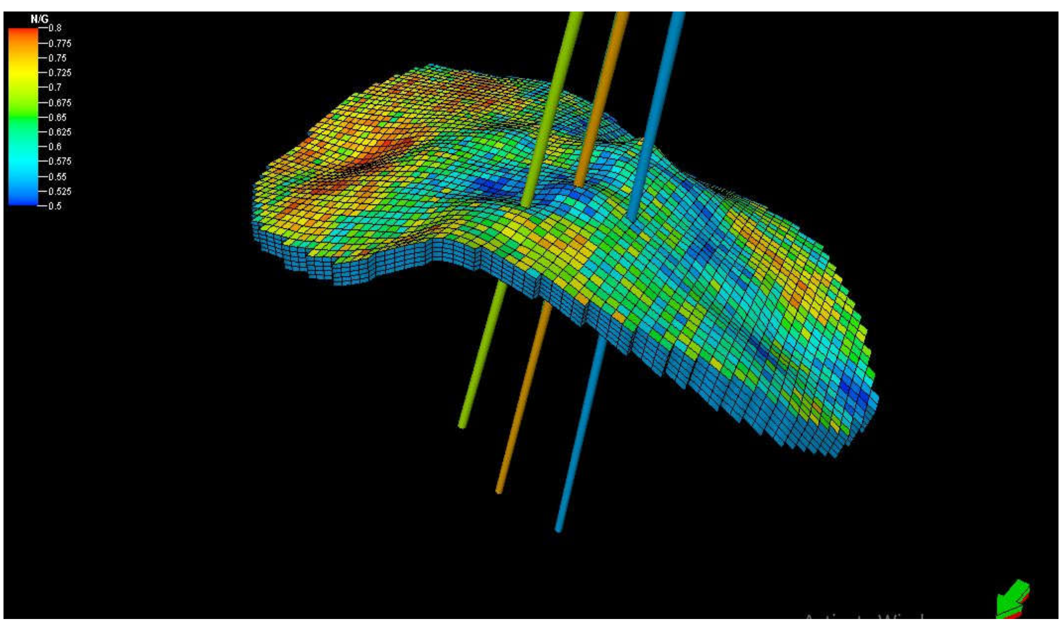

Figure 65: Net to Gross Ratio of NGS 1

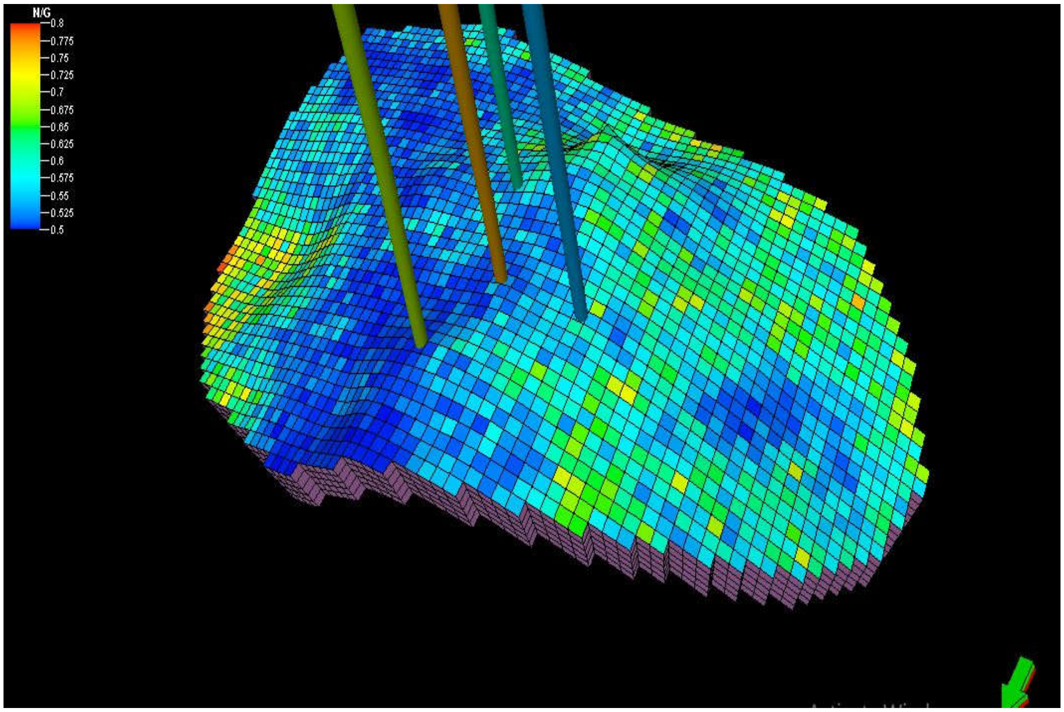

Figure 66: Net to Gross Ratio of UGS

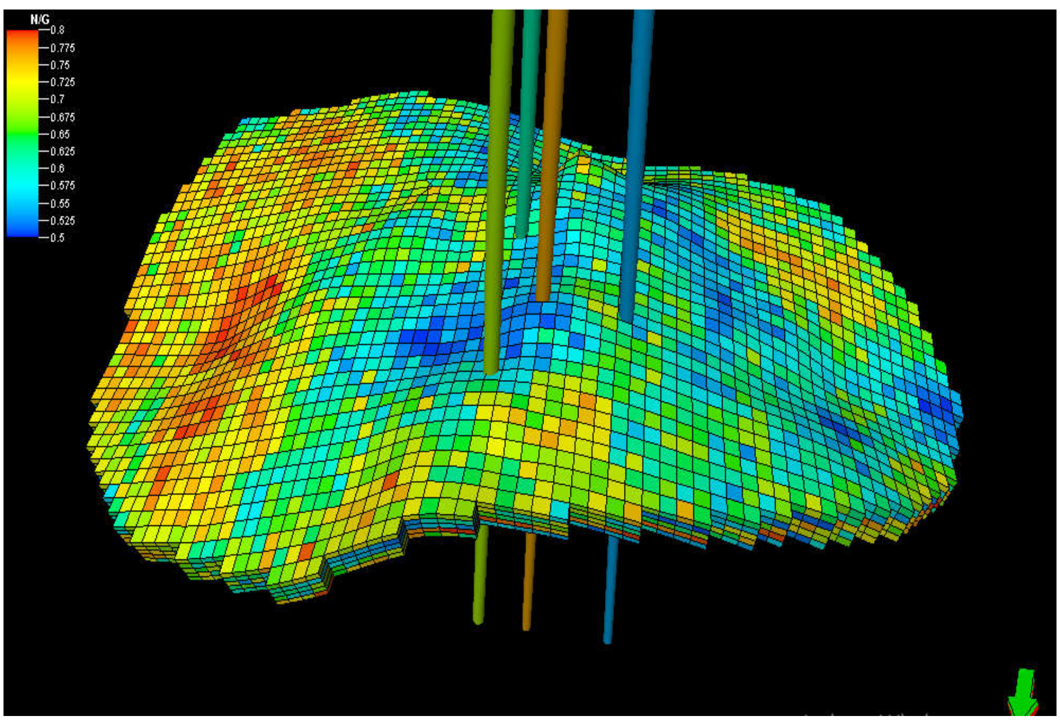

Figure 67: Net to Gross Ratio of LGS

4.8.5 Fluid Distribution

The quantity of fluid contained in the pores, expressed as a percentage of Vp is known as fluid saturation. Figure 68-71 shows the permeability distribution model of NGS 2, NGS 1, UGS and LGS of saldanadi gas field where the red portion indicates the gas saturation and blue colour indicates the water zone. Figure 72 demonstrates the fluid distribution model of all four gas sands correlating with porosity model.

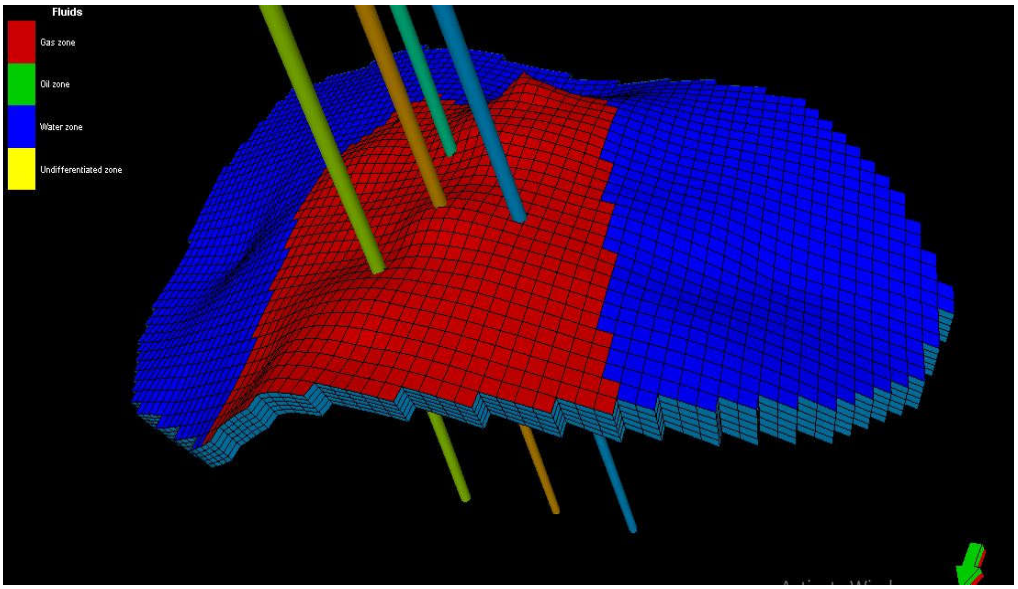

Figure 68: Fluid Contacts of NGS 2

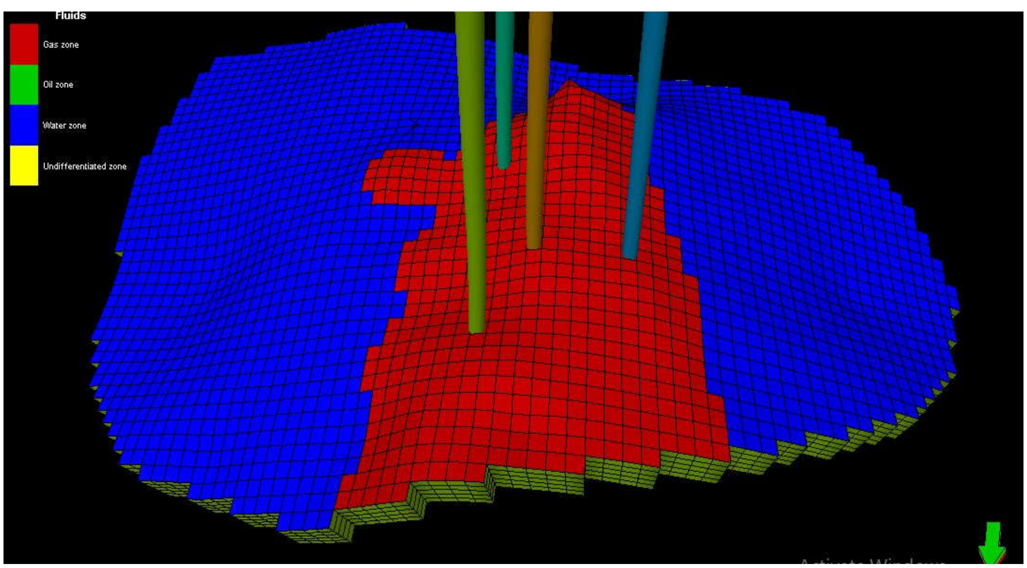

Figure 69: Fluid Contacts of NGS 1

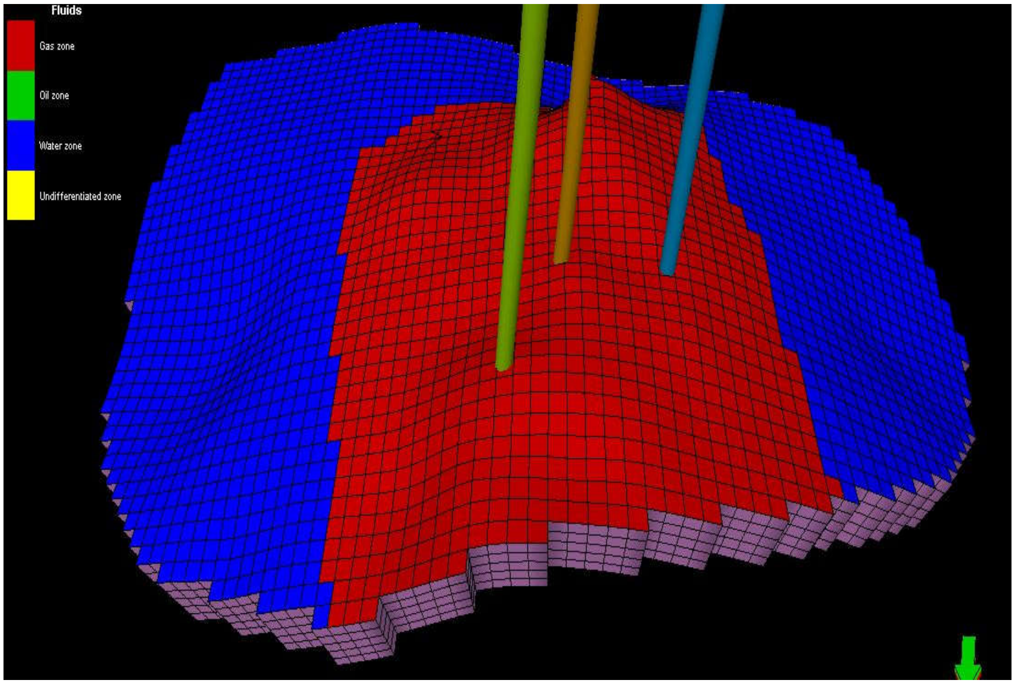

Figure 70: Fluid Contacts of UGS

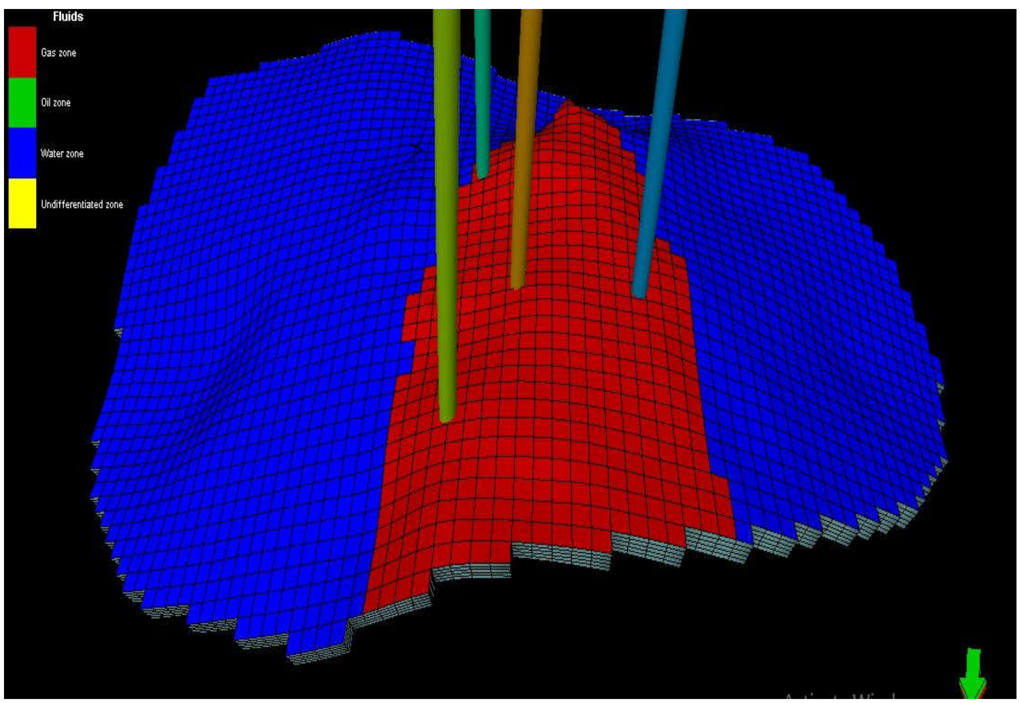

Figure 71: Fluid Contacts of LGS

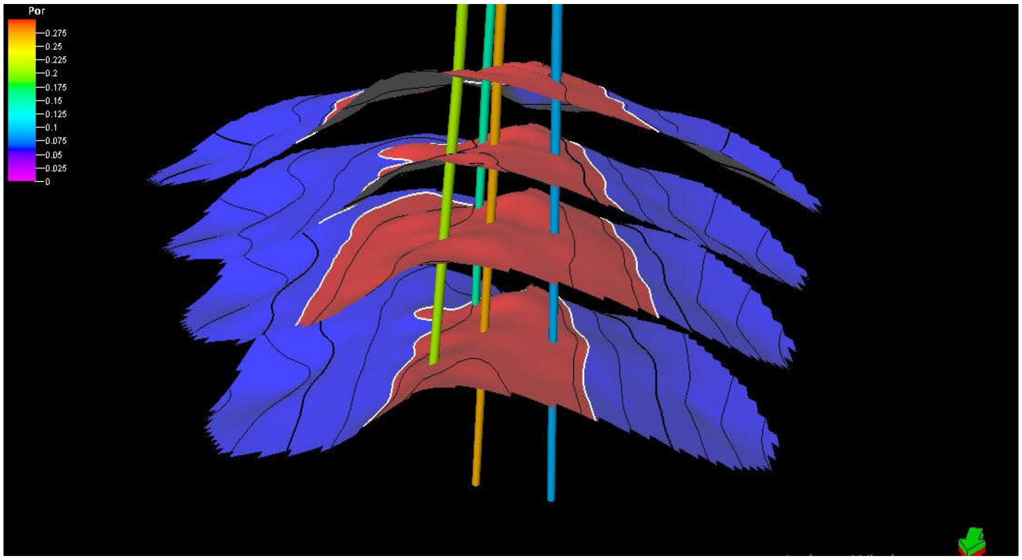

Figure 72: Gas Saturation distribution in all gas sands top with porosity model.

4.8.6 Gas Water Contact

The identification of fluid contacts ((gas-water contact – GWC, oil-water contact – OWC and gas-oil contact – GOC) is essential for field reserve estimates and field development and also for detailed formation evaluation. The methods used for determining the fluid contacts include fluid sampling, water and hydrocarbons saturation estimation from geophysical well logs, analysis of conventional cores, and measurements of formation pressure. (Niculescu & Ciupercă, 2019). Figure 73-75 reveals the gas water contact model for all four gas sands of saldanadi gas field.

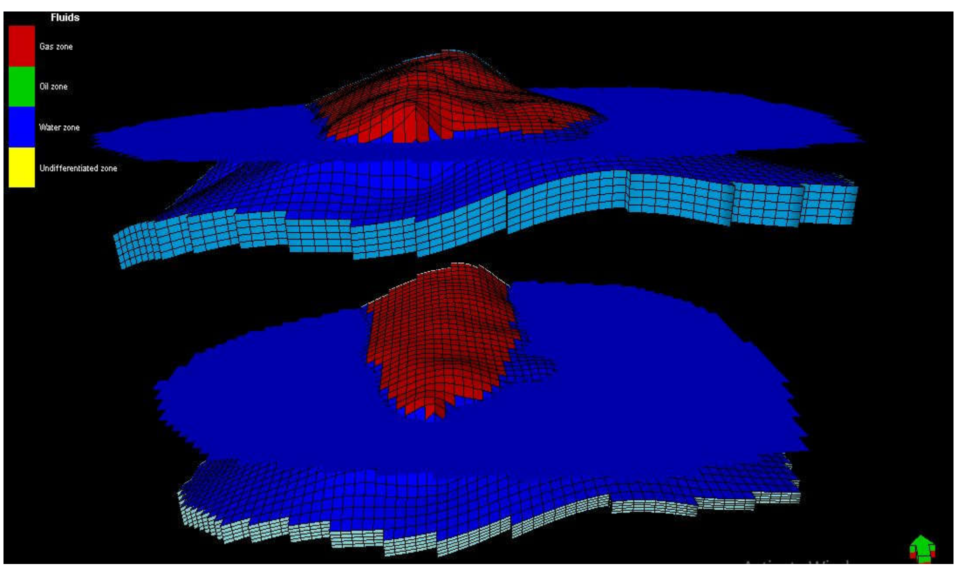

Figure 73: Gas Water Contacts of NGS 2 and LGS

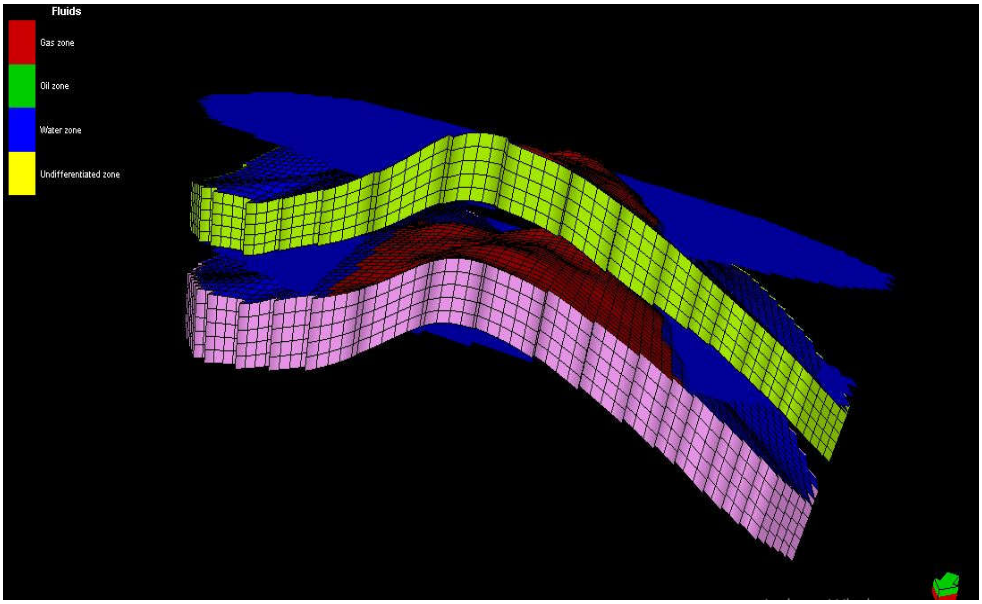

Figure 74: Gas Water Contacts of NGS 1 and UGS

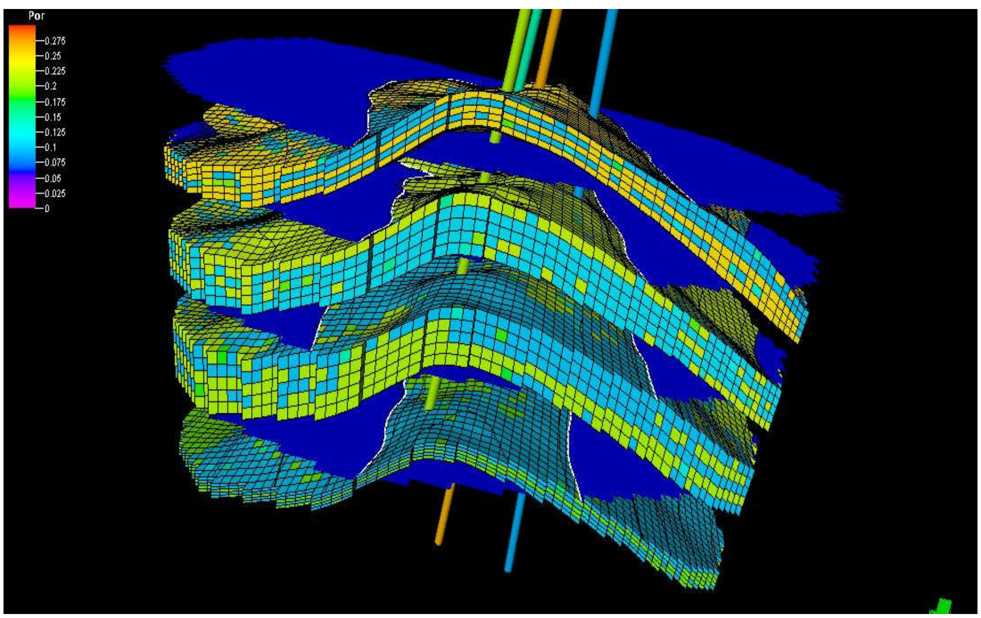

Figure 75: Fluid Contacts of all gas sands with GWC with Porosity Model.

4.9 Uncertainty Analysis

A variety of uncertainty that has been handled here is includes:

- The imported seismic surfaces were not matching perfectly with the well tops which are probably because of seismic velocity variation. These surfaces have been tied with well tops before horizon and zone making.

- The seismic data are variable in quality which deteriorates with depth and is relatively poor at the zone of interest. The shallower horizons are picked with confidence and provide clear structural definition, but the deeper horizons are difficult to interpret. This may probably due to the low acoustic contrast and the discontinuity nature of the deeper horizons.
- Depth conversion is main realms of uncertainties in this interpretation. However the depth conversion should be reasonably good at the crestal part of the structure where the two wells are located but depth conversion is a major uncertainty on the flank of the structure.
- Reservoir area is extended from Bangladesh to India. Only four wells are present in the structure. There is no well control over the entire reservoir structure because of Indian boundary of the structure making uncertainties for structural modeling and properties distribution. Number of wells are present in indian part beside the boundary so it is very complex to investigate or dynamic characterization of the salda nadi reservoir.

Some of the uncertainties have been minimized using Workflows in the Petrel Software. This is also a mini Petrel built within the software. New well data, seismic depth maps and relevant information can be updated without making new models.

Limitations

- Since the data are of various vintages, variable qualities, low frequency and thus low resolution, it is not able to resolve and imaging the reservoir properly.
- Different logs are discontinuous especially at reservoir zone.
- VSP data is not sufficient.
- Some log value shows enormous variation.
- Amplitude extraction of the individual reservoir is difficult sometimes that are probably associated with noise.
- There is no major fault identified in the study area by 2D seismic survey but still there are possibilities of minor faults in the area which may be obtained from 3D seismic survey.

CHAPTER V

RESULT ANALYSIS AND HISTORY MATCHING

5.1 Petrophysical Properties

Petrophysical investigation identified four principal reservoir intervals; these are NGS 2, NGS 1, UGS and LGS from shallow to deep. Both the well logs and seismic horizon mapping indicated that these reservoirs are laterally extensive throughout the modeled area and affected by the interpreted normal faults. Reservoir interval distributions in the studied wells are documented in Table 15.

Table 14: Depth Interval of Reservoir NGS 2, NGS 1, UGS and LGS of Saldanadi Gas Field.

Well Name	Depth Interval (MD)			
	New Gas Sand 2 (NGS 2)	**New Gas Sand 1 (NGS 1)**	**Upper Gas Sand (UGS)**	**Lower Gas Sand (LGS)**
SLD#1	1866-1913	2034-2063	2158-2260	2404-2429
SLD#2	1940-2010	2129-2163	2263-2373	2417-2447
SLD#3	2152-2228	2353-2384	2628-2657	2830-2880
SLD#4	2150-2227	2384-2426	2539-2633	2690-2755

Average porosity and permeability in these reservoirs vary in the range of 13–28.5% and 60 – 240 mD. The average mean porosity and mean permeability are 16.61% and 192.02 mD respectively. Reservoir net-to-gross (NTG) varies in the range of 0.6 to 1. Water saturation varies from 36.3 to 74%, while hydrocarbon saturation values vary in the range from 26 to 63.7%.

5.2 Gas Water Contact

The Gas Water Contact (GWC) for the New Gas Sand 2, New Gas Sand 1 and Lower Gas Sand has been interpreted from the logs. Figure 76 demonstrates the Gas Water Contact (GWC) of NGS 2, NGS 1, UGS and LGS of Saldanadi Gas Field.

Gas water contact (GWC) was found at 1897 meter TVDSS in NGS 2, at 2021 meter TVDSS in NGS 1, at 22145 meter TVDSS in UGS and the GWC in the LGS is detected at 2411 meter TVDSS.

Table 15: Identification of Gas sands contact points of Saldanadi Gas Field

Ser No	Zone	Top (Measured Depth)	Bottom Measured Depth	Contact GWC/GDT (m tvdss)
1	NGS 2	1866	1913	GWC-1897 m
2	NGS 1	2001	2078	GWC-2021 m
3	UGS	2157	2260	GWC-2215 m
4	LGS	2404	2433	GWC-2411 m

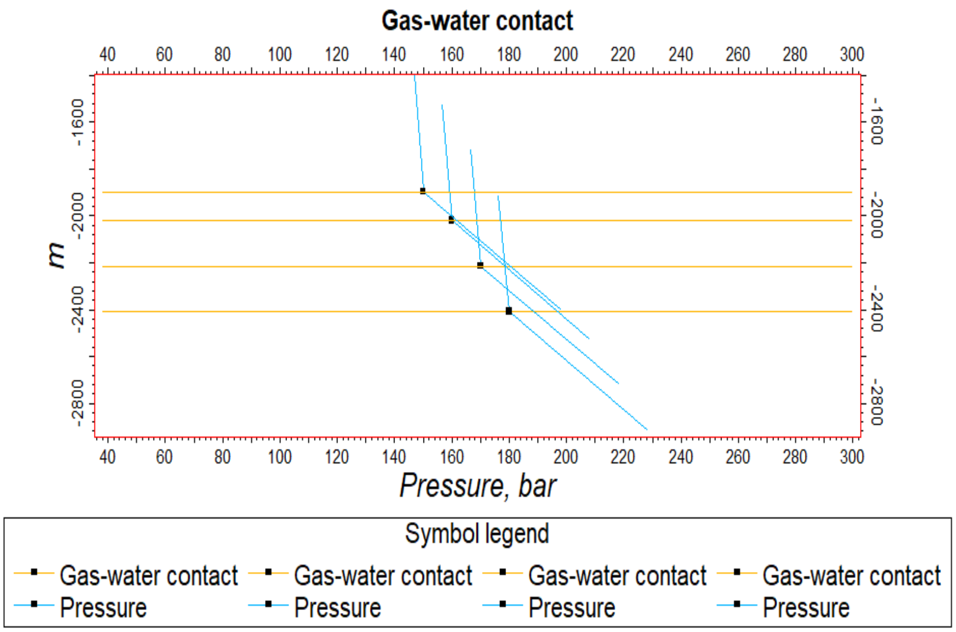

Figure 76: Gas Water Contact of NGS 2, NGS 1, UGS and LGS

5.3 Reservoir Volumetric Analysis

Table 17 reveals volumetric after modeling. Reservoir volumetric is the mechanism by which the hydrocarbon concentration in a reservoir is determined (Ali et al. 2020; Egbe et al. 2019). After a static field model was created, the structural model and the constructed petro-physical model were used to measure the reserves in terms of gas initially in place (GIIP) of the reservoir.

After completing the coding of all input data into the model and checking thereliability of volumetric calculation, a restart file is generated for history matching of the production and pressure profile of the field with respect to simulated model. It is discussed inthe next chapter.

Volumetric GIIP is found to be 14.96×10^9 Sm^3 and the remaining reserve in the field is 92.87×10^8 Sm^3 which is shown in Table 18. This is the updated GIIP for Saldanadi Gas Field. All provided seismic, well log and core data were in metric unit that is why volumetric calculation is done following that SI unit. And also, production data (pressure and rate) has been provided in SI unit so GIIP measurement and production profile are conducted following in the SI unit through Eclipse software.

Table 16: Volumetric Calculation of Saldanadi Gas Field

Gas sand Unit	Bulk Volume (10^6 sm^3)	Net Volume (10^6 sm^3)	Pore volume (10^6 sm^3)	HCPV gas (10^6 sm^3)	GIIP (10^6 sm^3)
NGS 2	258	171	32	25	4,275
NGS 1	207	127	21	17	2,835
UGS	518	326	48	38	6,456
LGS	121	80	10	8	1,397

Table 17: Model estimated GIIP of Saldanadi Gas Field

Ser No.	Reservoir	Gas Initially in Place GIIP (Sm^3)	Cumulative Production (Sm^3)	Remaining Reserve (Sm^3)
1	NGS 2	4275×10^6	**18.40×10^8**	**92.87×10^8**
2	NGS 1	2835×10^6		
3	UGS	6456×10^6		
4	LGS	1397×10^6		
Total		**14.96×10^9**		

The available data and development of the simulation model have been reported in the previous section. The reservoir fluid is modeled as a dry gas reservoir but a constant CGR has been used to account for condensate dropout. The history matching of the model to match the observed production and pressure data and to confirm the GIIP is reported in this section.

5.4 Gas Rate Match

Figure 77 to Figure 80 show the match to gas rate in each of SLD#1, SLD#2, SLD#3 and SLD#4, respectively. And also the cumulative production of individual well are shown in the graph. Excellent match is achieved for each, which implies that the wells are controlled on the gas rate in the simulator.

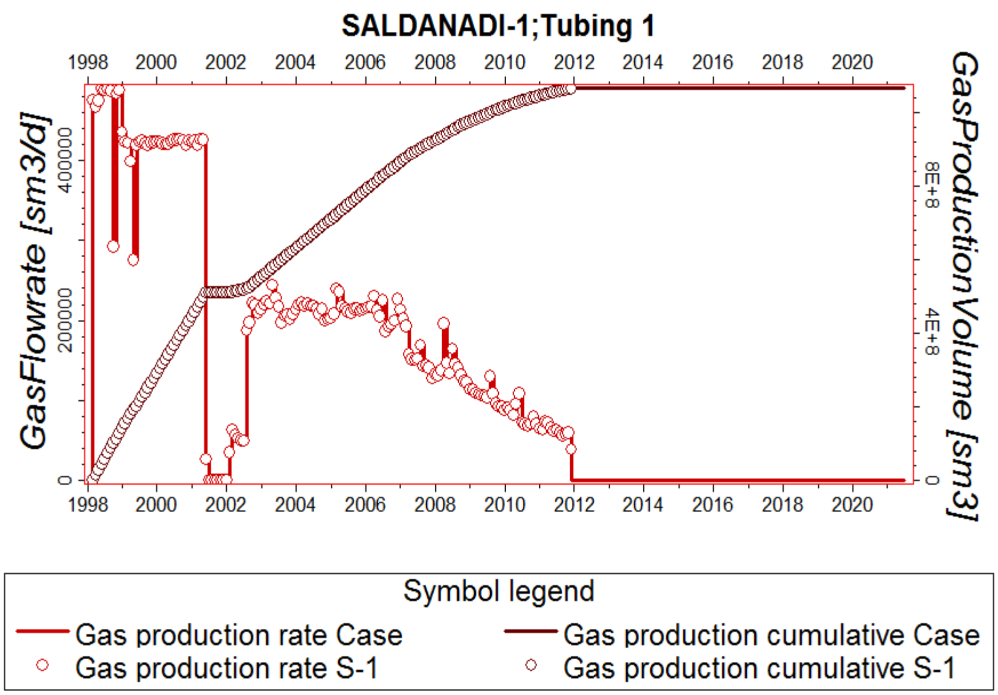

Figure 77: Saldanadi-1 Gas Rate History Match

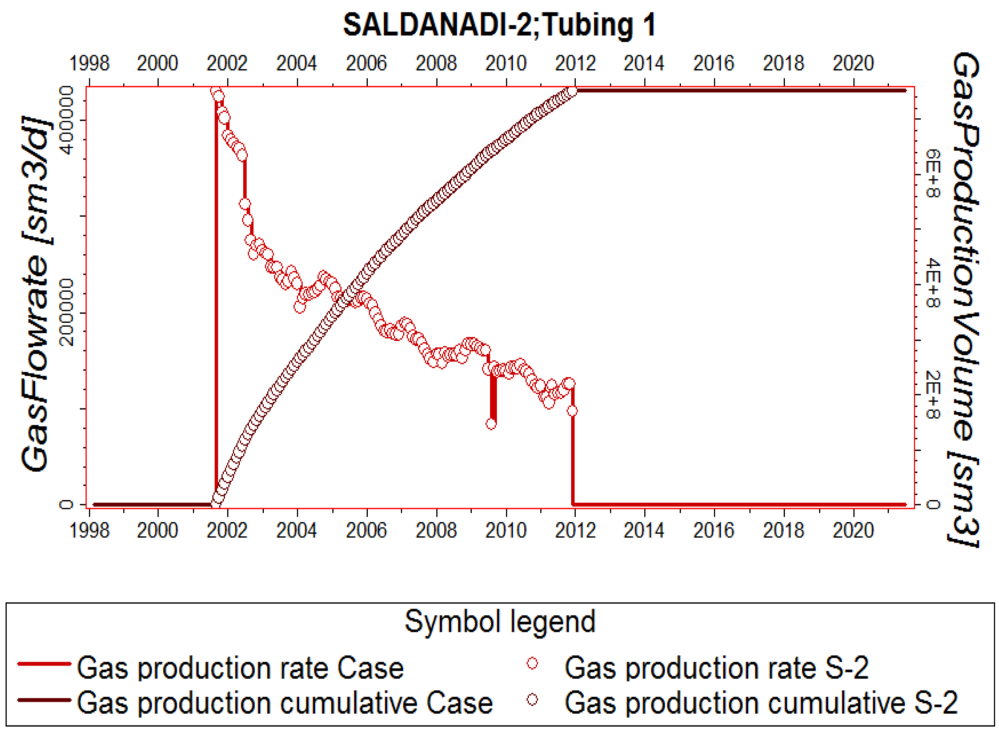

Figure 78: Saldanadi-2 Gas Rate History Match

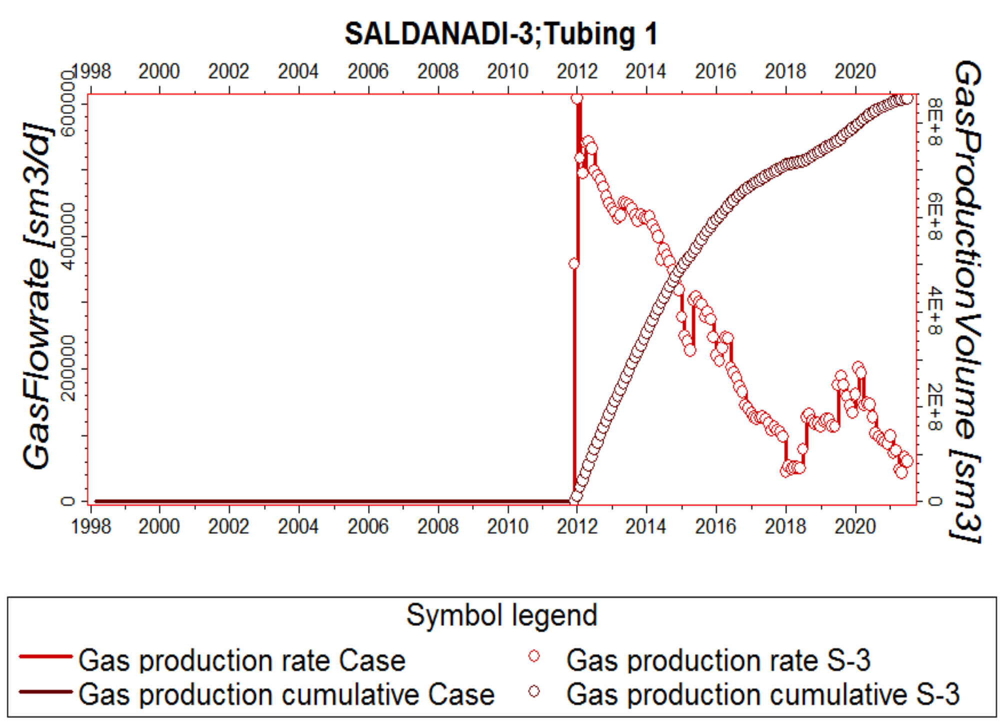

Figure 79: Saldanadi-3 Gas Rate History Match

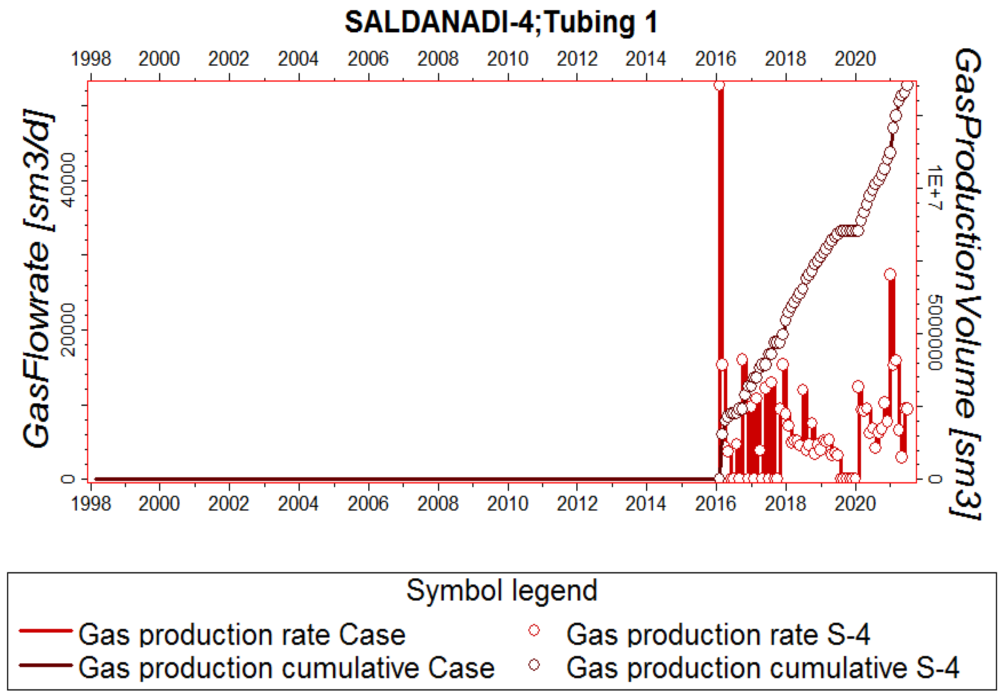

Figure 80: Saldanadi-4 Gas Rate History Match

From the above figures, indicate gas flow rate versus time which represent the previous gas flow rate history of SLD#1, SLD#2, SLD#3 and SLD#4 well. For all cases, it is indicated that gas production rate profile declined continuously. In SLD#1, workover was conducted in 2002 and after 2002, production rate of SLD#1 increased rapidly because of the completion of workover operation. The quality of history matching for all wells are excellent.

5.5 Pressure History Matching

Regional pressures and pressure gradients are matched during the first stage of history match. To match pressure and pressure gradients, the matching parameters most commonly used are aquifer connectivity, reservoir permeability depth product (kh), transmissibility across faults, and regional pore volume. Changing aquifer connectivity and regional pore volume may affect the match to average reservoir pressures and the match to average reservoir pressure may need to be revised. Excessive water production has found all the wells may be due to inadequate standard practice of drilling and completion design. This water may come beside the casing area from upper dupitila formation through leaching way.

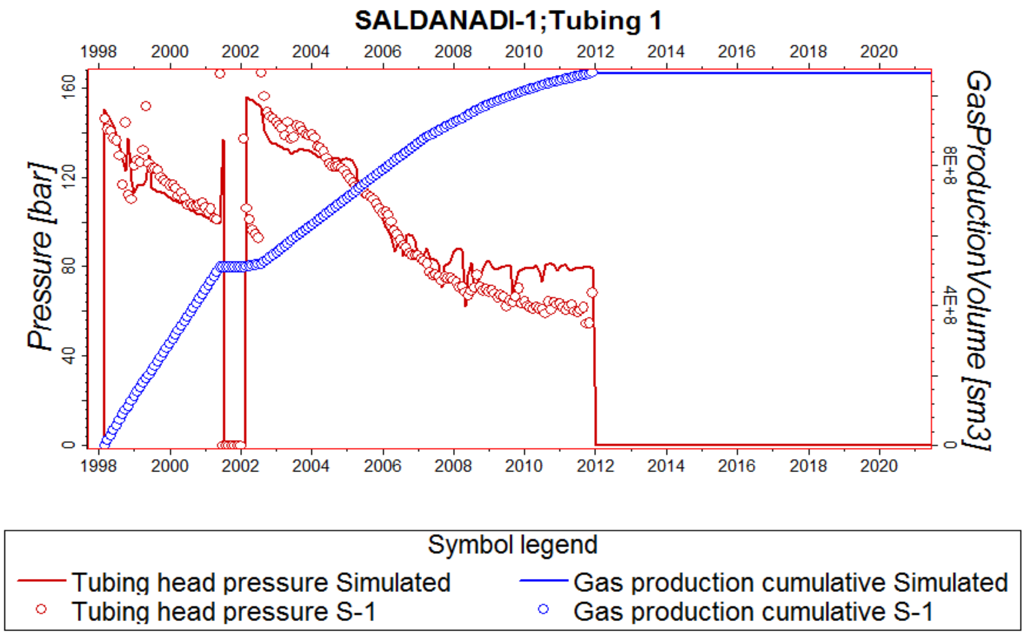

Figure 81: Well Head Pressure History Match of SLD#1

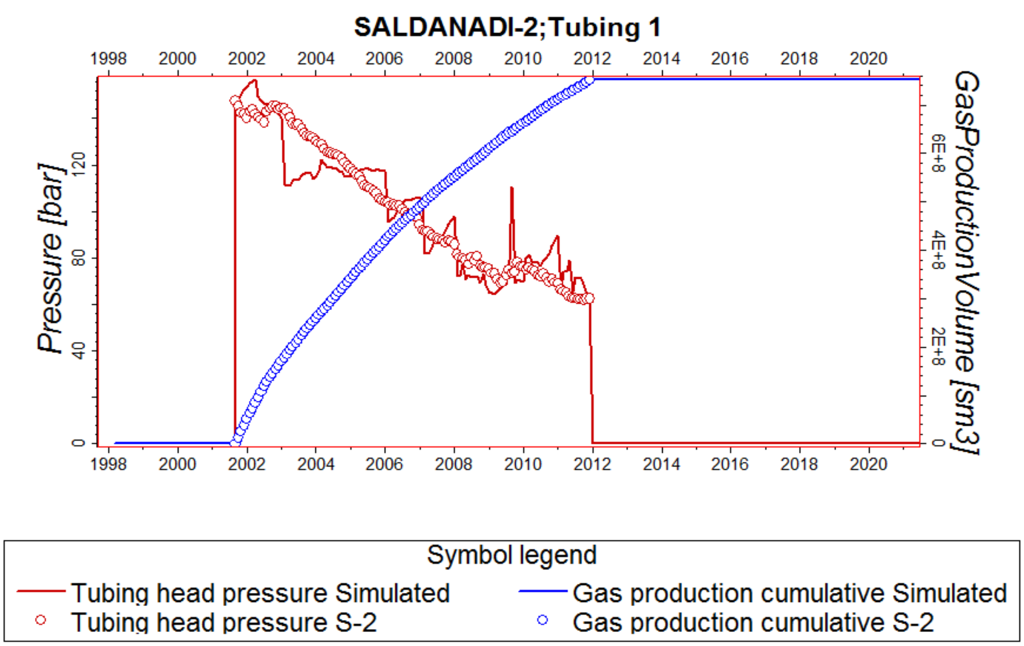

Figure 82: Well Head Pressure History Match of SLD#2

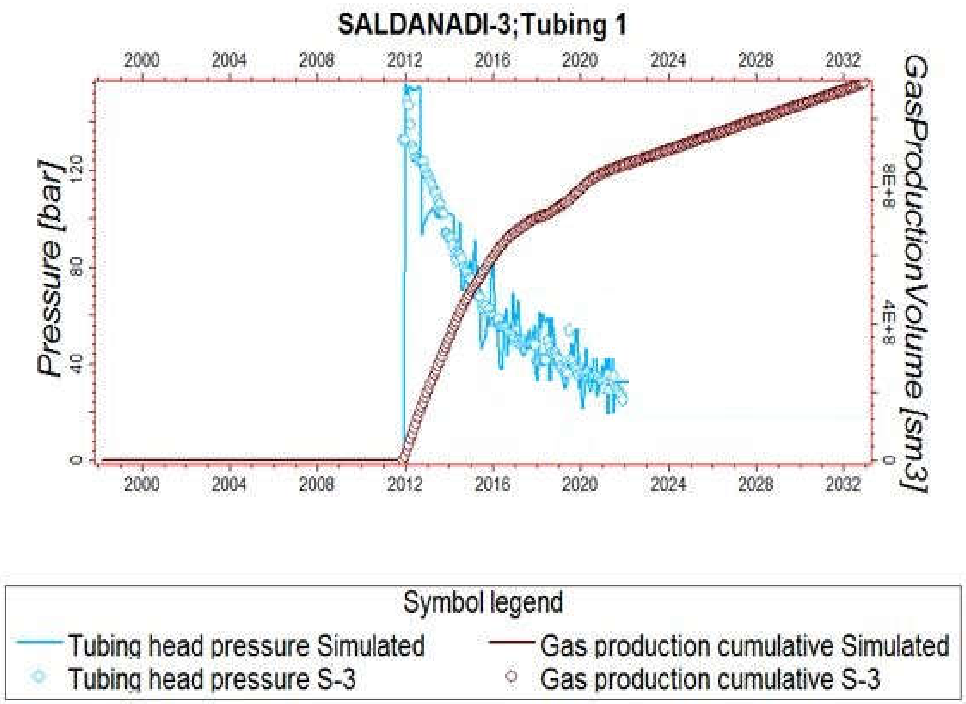

Figure 83: Well Head Pressure History Match of SLD#3

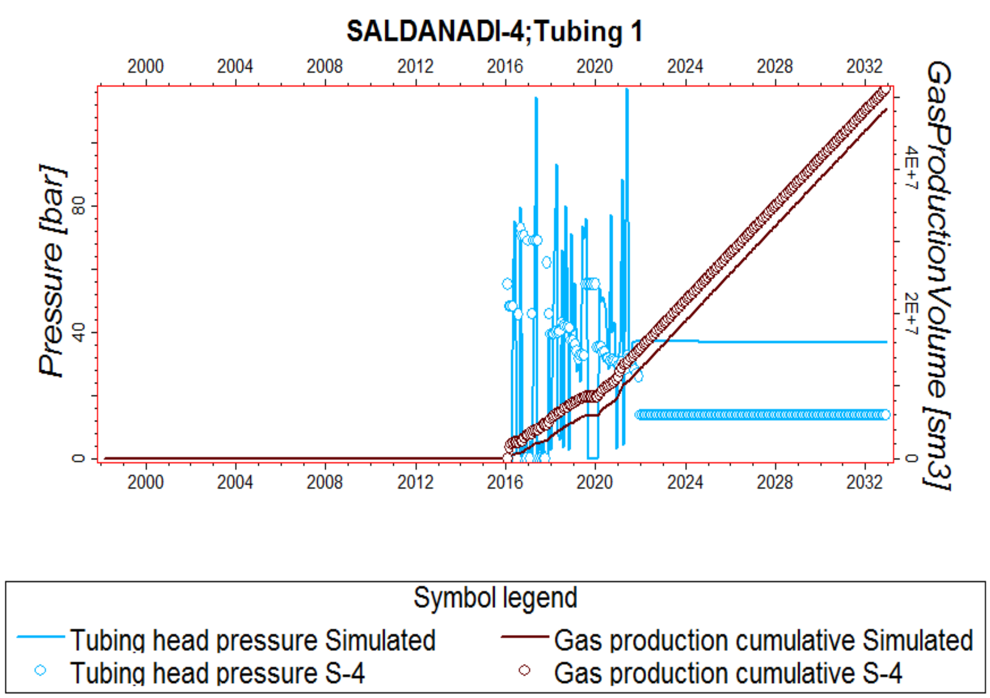

Figure 84: Well Head Pressure History Match of SLD#4

Figure 81 to 84 demonstrate pressure distribution of observe data with simulated pressure profile. Pressure profile of all four wells reveal perfect matching at the initial stage but later on it is slightly deviated because of scaling formation within the tubing and formation damage. In SLD#1, pressure profile match initially and in 2002 work over was conducted and pressure profile match again as there is no wax formation or no tortuosity within the tubing. The tubing head pressure profile versus time indicate that tubing head pressure declined sharply and also maintain ups and down trend. It is therefore concluded that it is the characteristics of a tight gas reservoir. The quality of pressure history matching for all wells are good to excellent.

CHAPTER VI
FORECASTING FIELD PERFORMANCE

The history matching part of this simulation work is presented in the previous chapter. It is shown that the historical pressure and rates matched reasonably well. Thus it can be assumed that the reservoir was modeled correctly. Based on that model, the future performance of the field is evaluated. Different development scenarios are considered.

Forecast Assumptions and Cases

Before embarking on forecasts, a number of following forecasting assumptions and cases require further explanation.

Duration: Simulation started from May 1998 to December 2021 (for history matching).

Then forecasts are generated for the next 20 years up to June 2041.

Economic Gas Rate: A minimum gas rate of 28316 Sm^3 per well is applied.

Flowing Wellhead Pressure (FWHP): Wellhead pressure is set to 68 bar for all cases. A minimum value of 34 bar was also used to compare the impact whether it would increase the life of the producing wells, or increase ultimate recovery.

Well type: Additional three (3) vertical well (infill development well) were considered with dual completion producing from separate layers.

Existing wells: All the existing wells were re-used in the predictive scenarios.

Predictive Cases

Predictive cases were run up to 2041, with five different scenarios including a "Do Nothing" Case. From the available production data, it was observed that water production increases rapidly to a restrictive level after a certain period of time. However, sand of the field is tight formation type. For all cases abandonment pressure is set to 68 bar.

The following prediction cases were investigated.

- Forecast Case 1: Do nothing, i.e., to continue gas production with the existing wells without any investigation to improve well or reservoir performance.
- Forecast Case 4: Workover operation of all four wells has been conducted at different scenarios.
- Forecast Case 5: Three additional wells (DW-1 and DW-2) has vertically drilled which connect all gas sand such as NGS 2, NGS 1, UGS and LGS.

Results of Predictive Cases

Forecast Case 1:

Do nothing case; i.e., continue gas production with the existing two wells (SLD#3 and SLD#4) without improving well or reservoir performance in anyway. The production profile of the field for the ―Do Nothing‖ case is presented in Figure 85 & 86. Here SLD#3 is shown in production from UGS and LGS respectively. First peak production of about 42.47 × 10^4 Sm^3 was sustained for two years. Then the production rate decline continuously up to July 2021. Then forecasting starts from August 2021 to 2030 with declining production of 6.79 × 10^4 Sm^3. Simulation indicates that the production of this well will be stopped at the end of 2024 keeping shutting pressure at 2.07 bar. However, total gas production will be 19.82 × 10^8 Sm^3 with recovery factor of 25.81%.

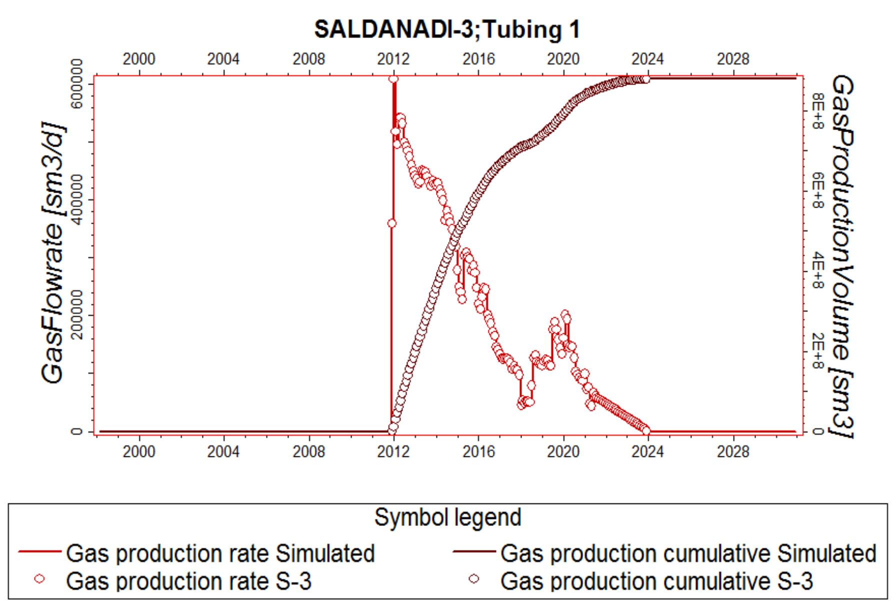

Figure 85: Field Production profile of forecast case 1 (SLD#3)

Here SLD#4 is shown in production from UGS. First peak production of about 50.96 × 10^4 Sm^3 was sustained for two years. Then the production rate shown up and down trend continuously up to July 2021. Then forecasting starts from August 2021 to 2030 with declining production of 3.96 × 10^4 Sm^3 Simulation indicates that the production of this well will be stopped on august 2024 maintaining shutting pressure at 2.07 bar. However, total gas production will be 84.94 × 10^4 Sm^3 with recovery factor of 15.78%.

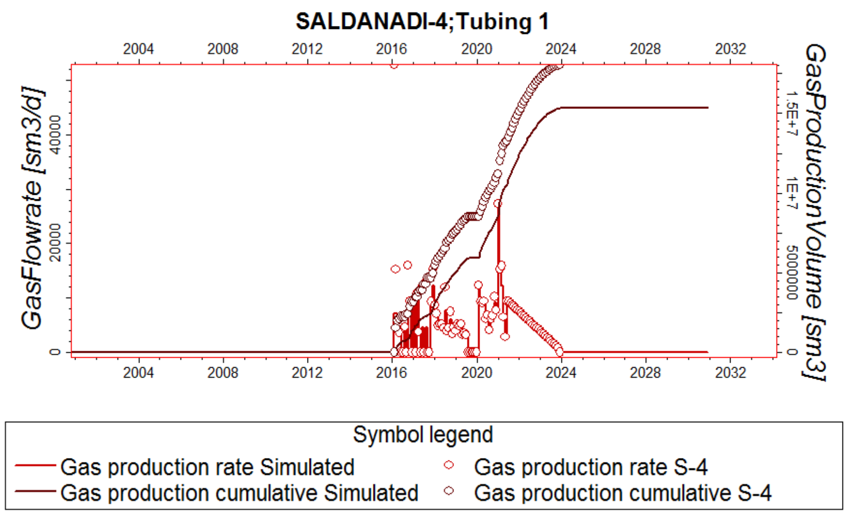

Figure 86: Field Production profile of forecast case 1 (SLD#4)

Individual Well performance with other considerations

Forecast case 5 was found to be most beneficial. Therefore, it is discussed in more detailed by mentioning the individual well performance separately in the following sections. Also well location, water movement, saturation change, impact of abandonment pressure on recovery, etc., are discussed in later sections.

Individual well performance

Saldanadi well-1 is completed through perforation in NGS 2 and NGS 1 which started production from March 1998. After water production by SLD#1, Upper gas sand (UGS) and Lower gas sand (LGS) perforation was plugged off to continue production. Now, it is proposed to do workover where perforation will be conducted in NGS 2 (1878-1900 m) and NGS 1 (2005-2025m). The proposed well completion design for SLD#1 and SLD#2 is shown in figure 87.

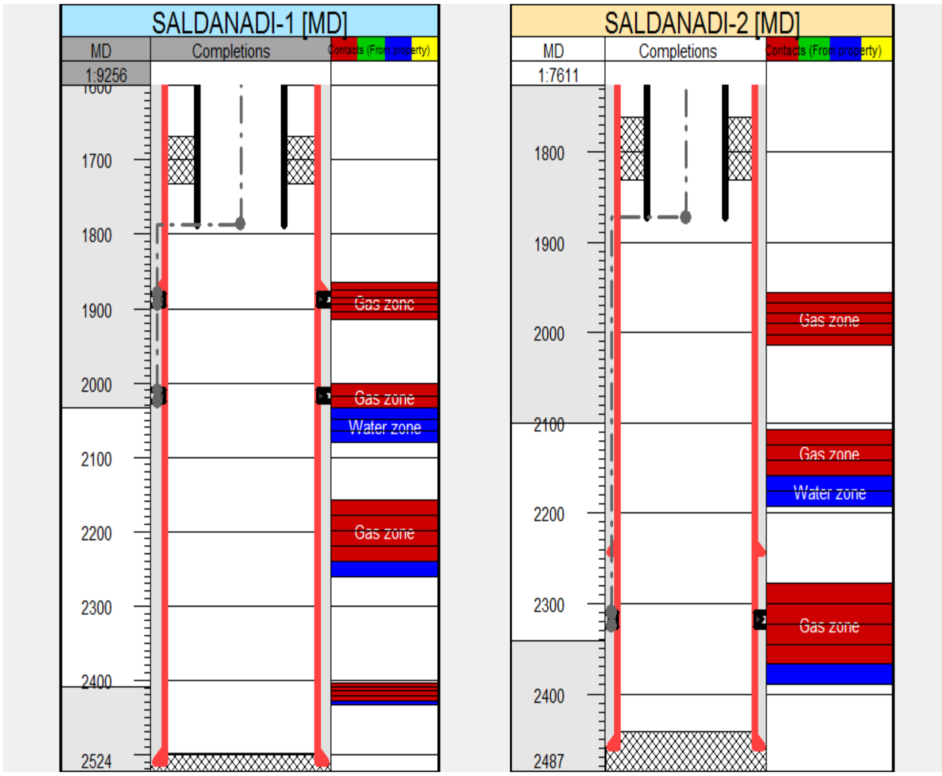

Figure 87: Well completion design of Saldanadi well - 1 & 2 (Workover-Proposed)

It is found that SLD#1 will produce 12.17×10^5 Sm^3 more gas through workover operation. Figure 90 shows pressure and production profile after the workover. Finally, SLD#1 will be shut off in July 2027 due to water and gas production constrain though tubing head pressure will be still higher than 82.50 bar.

Cross section along UGS and LGS in SLD#1 with perforation intervals (i-direction) is shown in figure 88. In figure 89, cross section along NGS-2 and NGS-1 in SLD#2 with perforation intervals (i-direction) is shown. It reveals that perforation placement is appropriate in gas sands with the reservoir model.

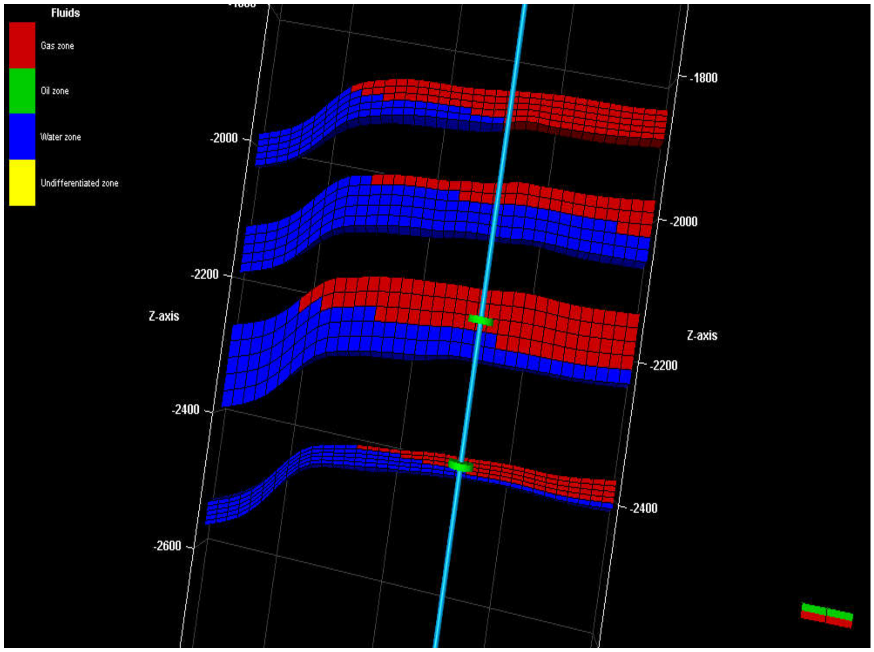

Figure 88: Cross Section along UGS and LGS in SLD#1 (i-direction)

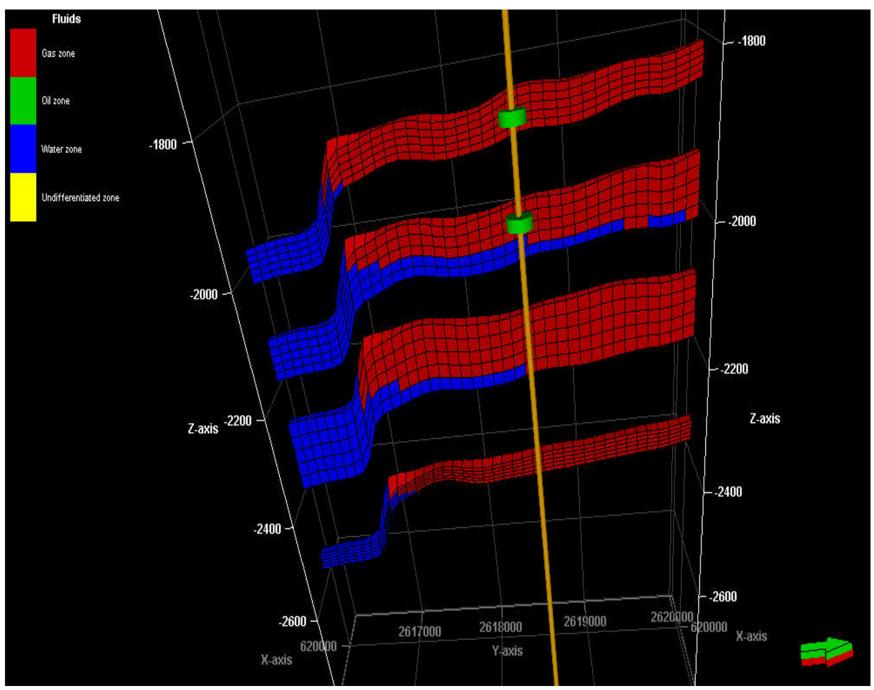

Figure 89: Cross Section along NGS-2 and NGS-1 in SLD#2 (i-direction)

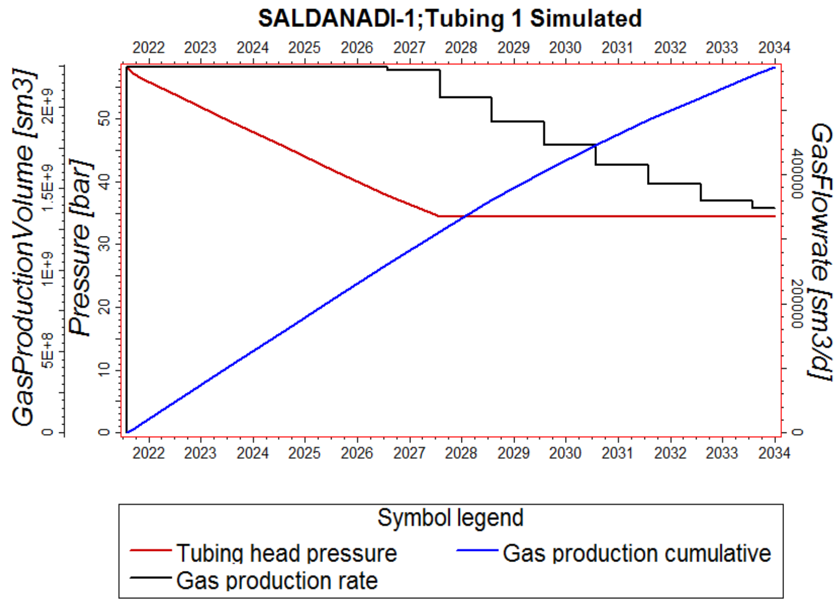

Figure 90: Pressure and Production profile for SLD#1 (forecast)

Saldanadi well-2 is completed through perforation in Upper gas sand (UGS) which started production from March 1998. After water production by SLD#2, Upper gas sand (UGS) perforation was plugged off to continue production. Now, workover operation will be done and reperforation will be conducted in UGS (2307-2329m) and NGS 1 (2005-2025m).

It is observe that SLD#2 will produce 79.28×10^4 Sm^3 more gas through workover. Figure 91 shows pressure and production profile after the workover. Finally, SLD#2 will be shut off in August 2025 due to water and gas production constrain though tubing head pressure will be still higher than 82.50 bar.

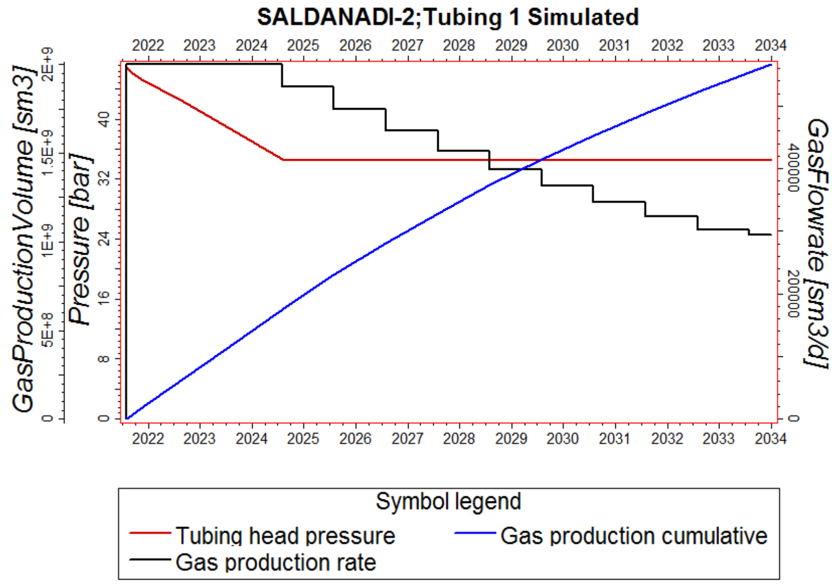

Figure 91: Pressure and Production profile for SLD#2 (forecast)

Saldanadi well-3 is completed through perforation in New gas sand 2 (NGS 2) and New gas sand 1 (NGS 1) which started production from February 2012. Perforation in NGS 2 and NGS 1 is plugged off to continue production. Now, workover opration will be done and reperforation will be conducted in same gas sand NGS 2 (2177-2195 m) and NGS 1 (2355-2381 m).

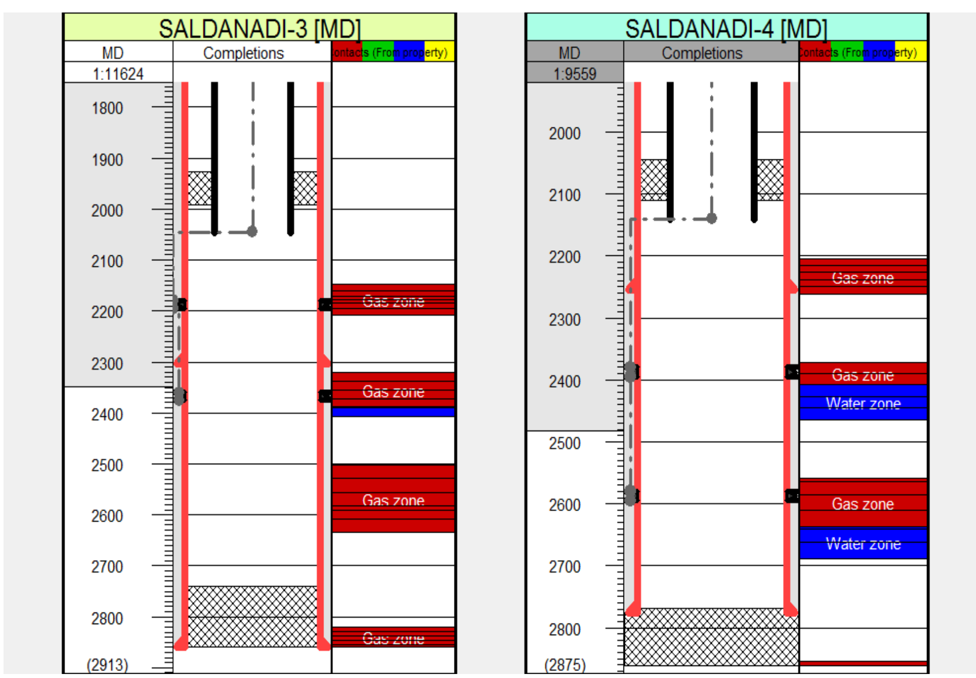

Figure 92: Well completion design of Saldanadi well - 3 & 4 (Proposed)

It is reveal that SLD#3 will produce 82.11 × 10^4 Sm^3 more gas through workover. Figure 93 shows pressure and production profile after the workover. Finally, SLD#3 will be shut off in August 2025 due to water and gas production constrain though tubing head pressure will be still higher than 82.50 bar.

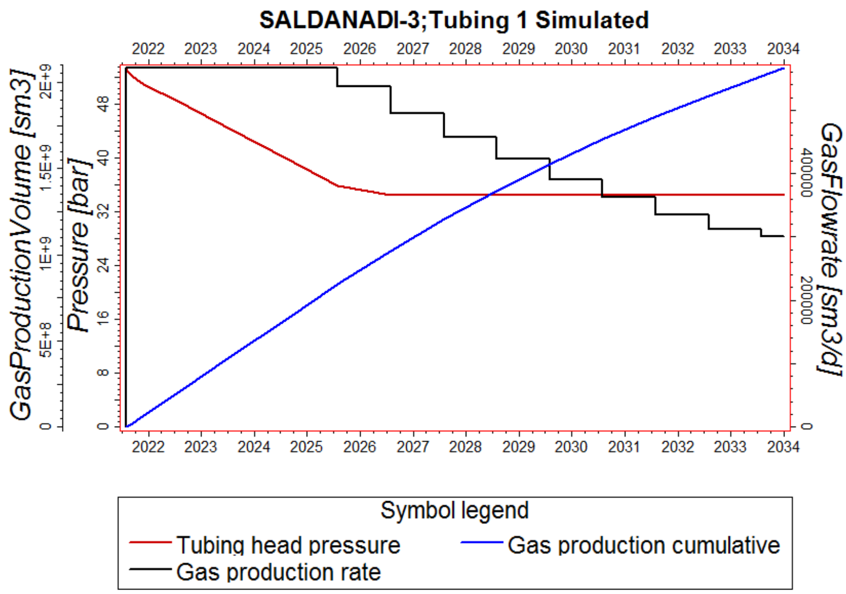

Figure 93: Pressure and Production profile for SLD#3 (forecast)

Saldanadi well-4 is completed through perforation in New gas sand 1 (NGS 1) and Upper gas sand (UGS) which started production from February 2012. Perforation in NGS 1 and UGS is plugged off to continue production. Now, workover operation will be done and reperforation will be conducted in same gas sand NGS 1 (2375-2397 m) and UGS (2580-2596 m).

It is observe that SLD#4 will produce 13.59 × 10^5 Sm^3 more gas through workover. Figure 94 shows pressure and production profile after the workover. Finally, SLD#3 will be shut off in August 2027 due to water and gas production constrain though tubing head pressure will be still higher than 82.50 bar.

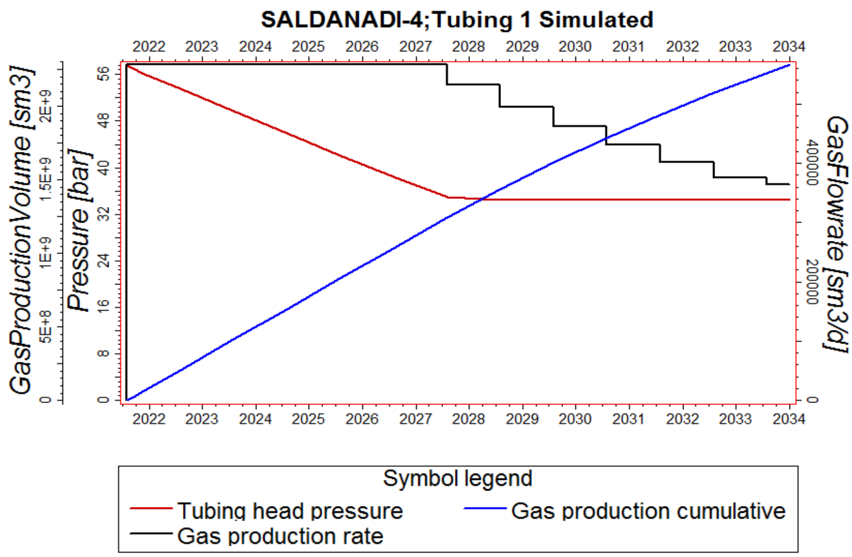

Figure 94: Pressure and Production profile for SLD#4 (forecast)

The new development well is place at the suitable place in the reservoir where the maximum bottom hole pressure exist, highest pay thickness of gas sands. Perforation will be conducted through all 4 gas sands in development well 1, 2 and 3 which are shown in figure 95 and 96.

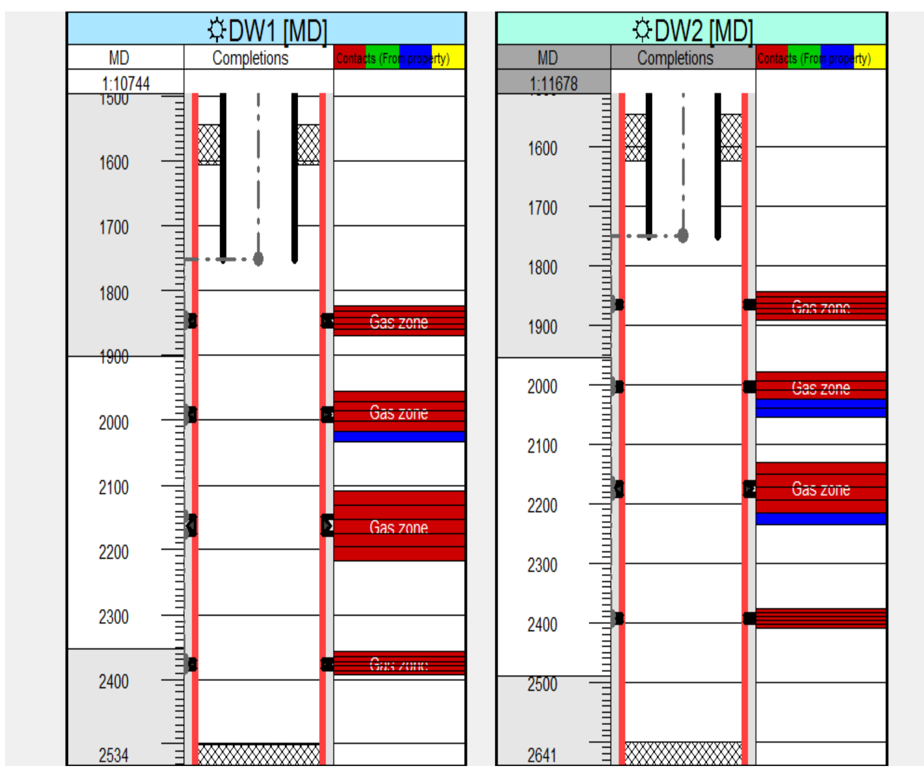

Figure 95: Well completion design of proposed development well 1 and 2

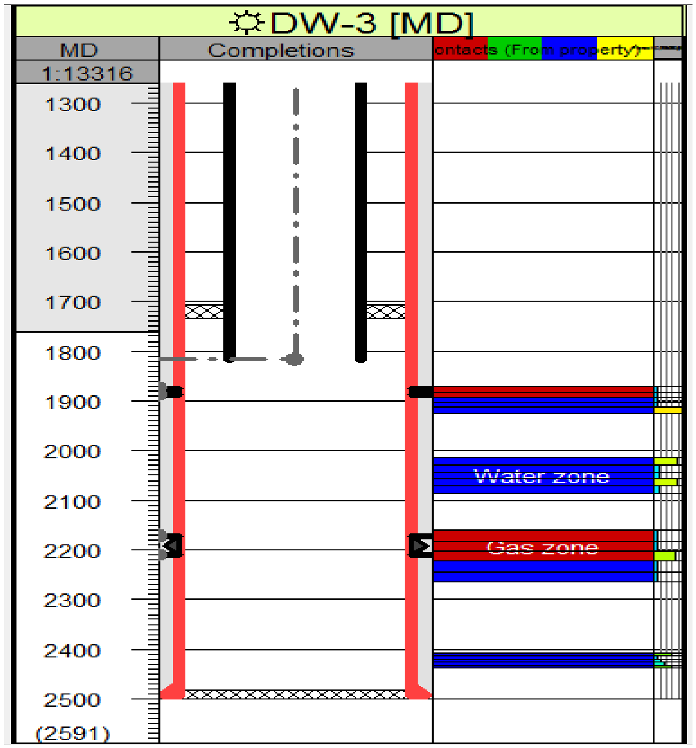

Figure 96: Well completion design of new development well 3 of Saldanadi Gas Field

Cross section along all gas sands for the proposed development well-1 with perforation intervals (align along i-direction) is shown in figure 97. It reveals that perforation placement is perfect in gas sands with the reservoir model.

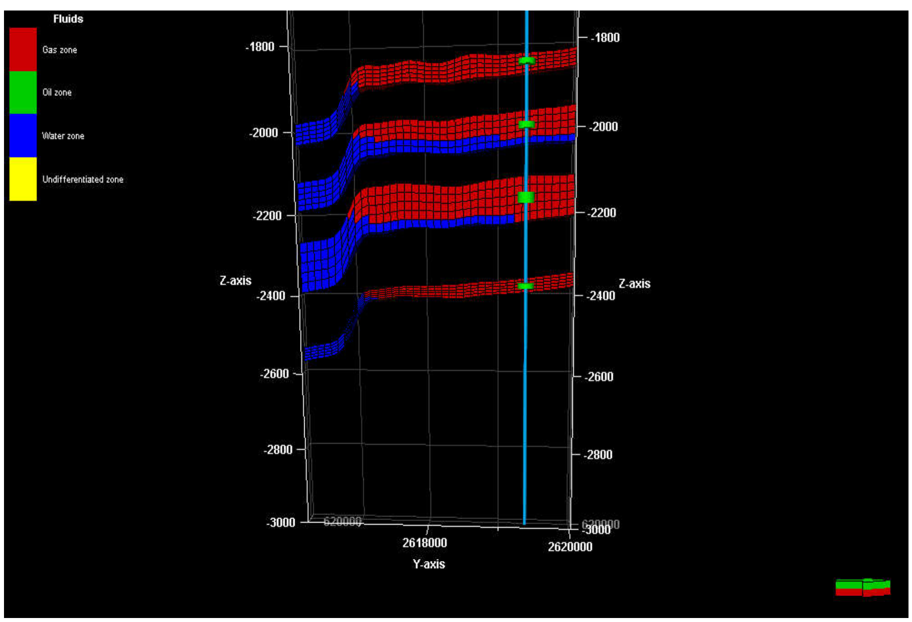

Figure 97: Cross Section of DW-1 connecting all gas sands (align along I-direction)

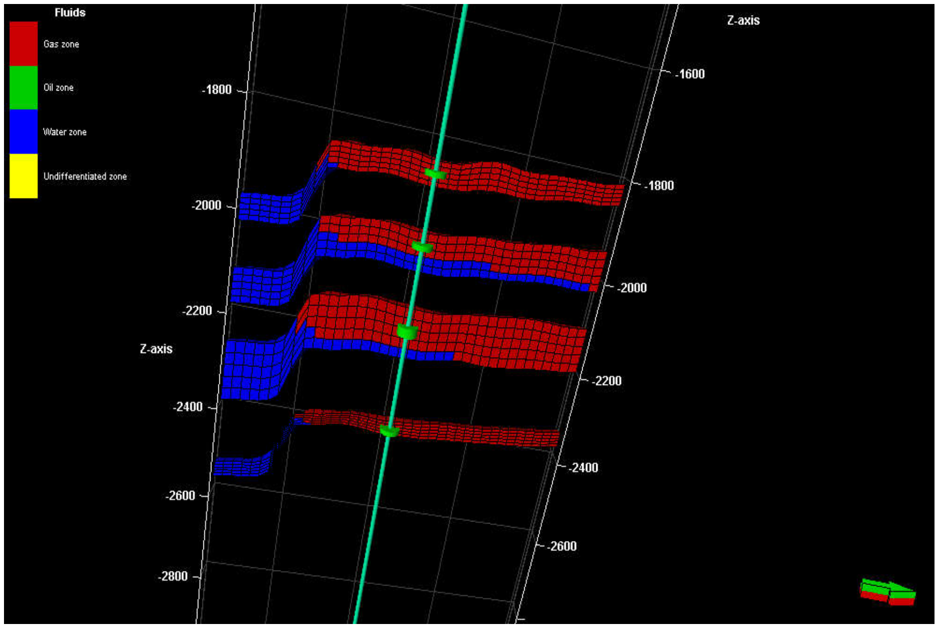

Figure 98: Cross Section of DW-2 connecting all gas sands (align along I-direction)

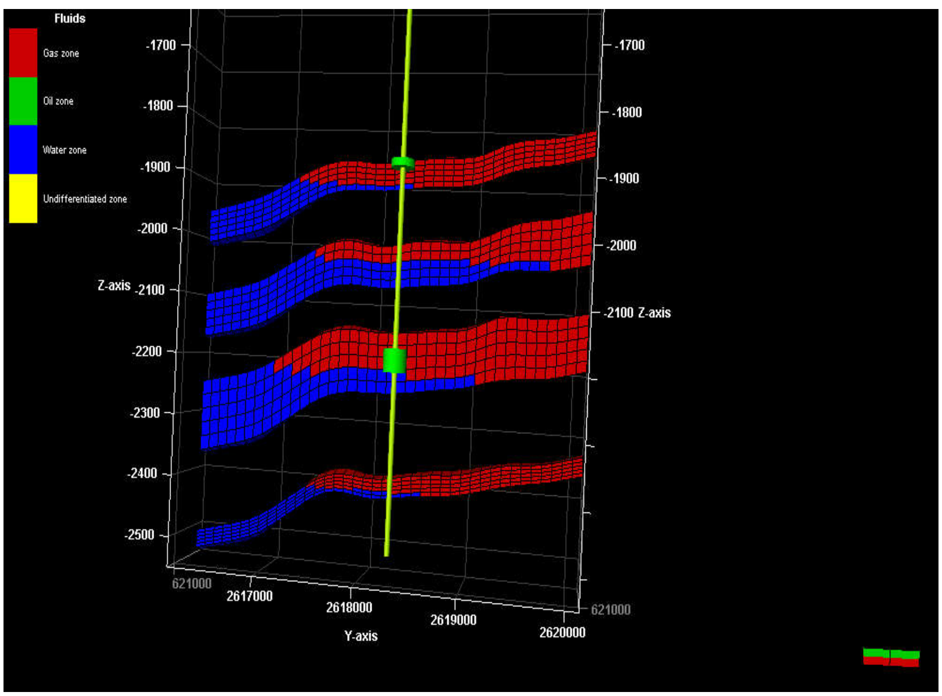

Figure 99: Cross Section of NGS-2 and UGS of development well 3 (align along I-direction)

Figure 100, 101 and 102 are showing the forecast profile of development well 1, 2 and 3 respectively. It will start from 48.13 × 10^4 Sm^3 gas from January 2022 and will continue up to February 2034. Abandonment pressure of the well will be 6.89 bar during 2034. On the other hand, DW-2 will start from 48.13 × 10^4 Sm^3 gas from January 2022 and will continue up to March 2039. Tubing head pressure profile during shut off will be still high about 68.96 bar during 2039.

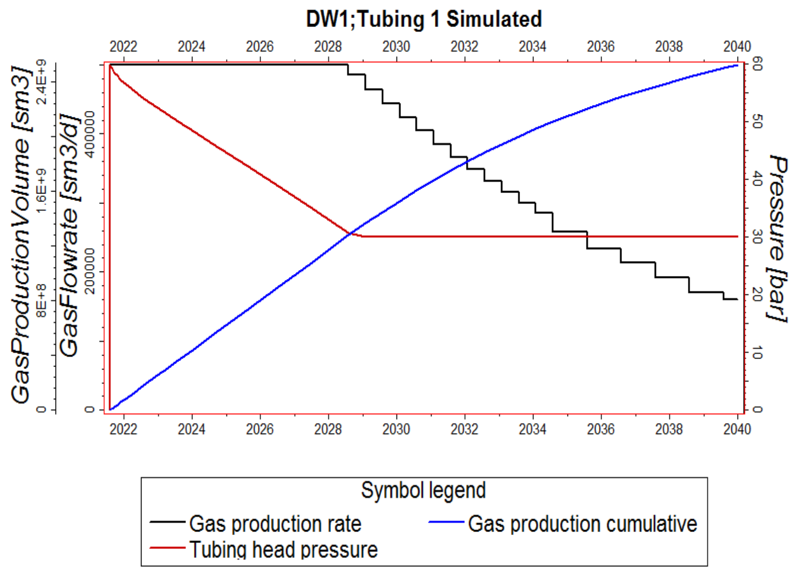

Figure 100: Pressure and Production profile for development well - 1 (forecast case 5)

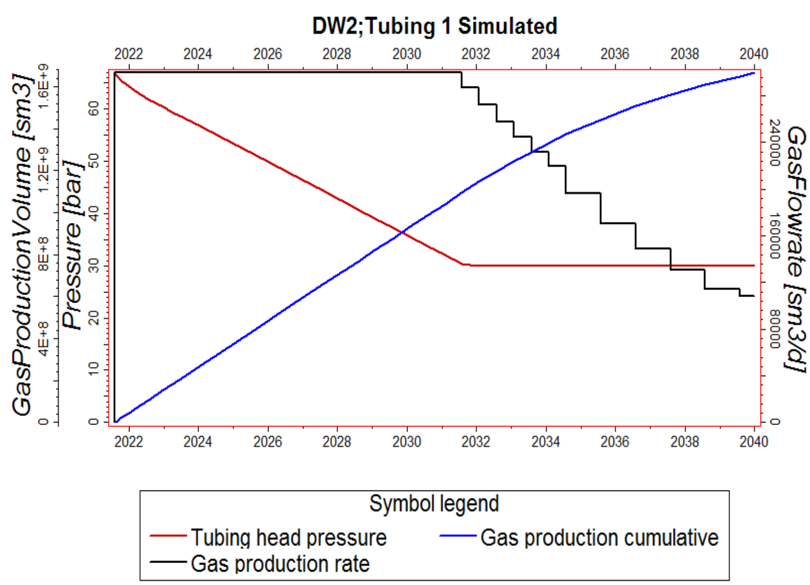

Figure 101: Pressure and Production profile for development well - 2 (forecast case 5)

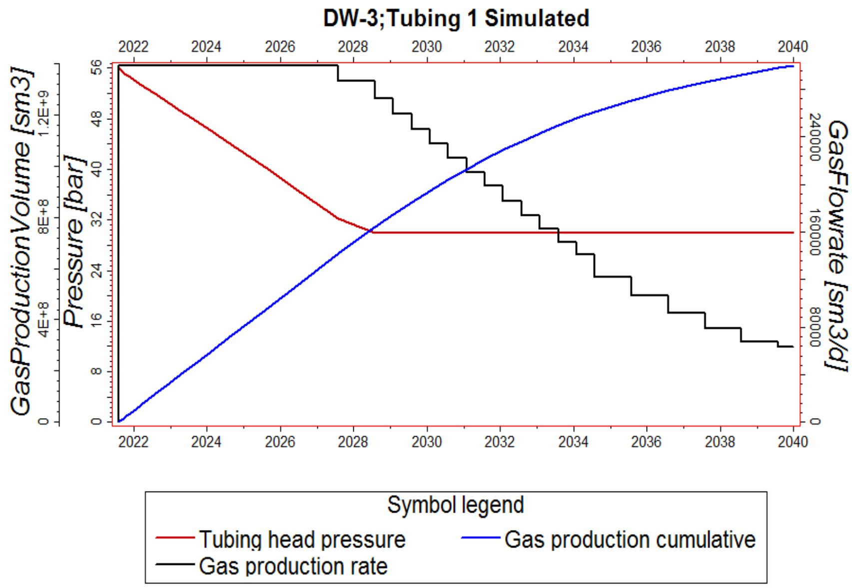

Figure 102: Pressure and Production profile for development well - 3 (forecast case 5)

The result from the five forecast cases are tabulated in Table 18. Forecast 4 and 5 give the indication that numbers of wells have significant impact on ultimate recovery.

Table 18: Summery of all Forecast cases Run of Saldanadi Gas Field

Forecast Case 1: Do Nothing Case (THP 15 bar)				
Well	**Well Lifetime**	**Cumulative production, Sm^3**	**GIIP, Sm^3**	**Ultimate RF**
SLD#1		1064433536	14.96×10^9	**31.11%**
SLD#2		751542144		
SLD#3	July'2021-Dec'2024	2570984192		
SLD#4	July'2021-Nov'2024	268608064		
Forecast Case 2: Do Nothing Case (THP 30 bar)				
Well	**Well Lifetime**	**Cumulative production, Sm^3**	**GIIP, Sm^3**	**Ultimate RF**
SLD#1		1064433536	14.96×10^9	**28.91%**
SLD#2		751542144		
SLD#3	July'2021-Sep'2024	2260974282		
SLD#4	July'2021-Aug'2024	248608064		
Forecast Case 3: After Workover operation (SLD#1 & SLD#2)				
Well	**Well Lifetime**	**Cumulative production, Sm^3**	**GIIP, Sm^3**	**Ultimate RF**
SLD#1	July'2021-Mar'2034	1850894447	14.96×10^9	**42.36%**
SLD#2	July'2021-Apr'2034	1977709233		
SLD#3	July'2021-Sep'2024	2260974282		
SLD#4	July'2021-Aug'2024	248608064		
Forecast Case 4: After Workover operation (all 4 wells)				
Well	**Well Lifetime**	**Cumulative production, Sm^3**	**GIIP, Sm^3**	**Ultimate RF**
SLD#1	July'2021-Feb'2034	1750984448	14.96×10^9	**49.99%**
SLD#2	July'2021-Jan'2034	1928809344		
SLD#3	July'2021-Mar'2034	1886246656		
SLD#4	July'2021-May'2034	1914567680		
Forecast Case 5: Workover of existing 4 wells and adding 3 development infill wells				
Well	**Well Lifetime**	**Cumulative production, Sm^3**	**GIIP, Sm^3**	**Ultimate RF**
SLD#1	July'2021-Dec'2033	1640974437	14.96×10^9	**79.22%**
SLD#2	July'2021-Nov'2033	1628809345		
SLD#3	July'2021-Jan'2034	1686246656		
SLD#4	July'2021-Oct'2033	1614567680		
DW-1	July'2021-Jan'2041	2424706048		
DW-2	July'2021-Mar'2041	1567063808		
DW-3	July'2021-Dec'2040	1291138176		

CHAPTER VII
CONCLUSIONS AND RECOMMENDATIONS

The present work deals with the interpretation of geological and geophysical data to evaluate the reservoir characterization, visualization, potential zone detection, reservoir parameters analysis and dynamic behavior of the reservoir through simulation investigation. After validation of static model we implement forecasting in the studied gas field to find out the best recovery factor conducted through various development plans. In this study, we used integrated datasets to assess the distribution and quality of the reservoir, as well as to reduce uncertainty during gas field development design.

In absence of special core analysis data, Corey's correlation was used to generate the relative permeability curves for this study. There was no bottomhole pressure data. Wellhead pressure data of the wells together with the wellbore diagrams were used to tune the multiphase flow correlation to obtain bottomhole pressures. Then, various wellhead pressures as well as possible production rates were used to generate the vertical flowing performance curves.

In this study, 3D geological model was updated and validated by the historical production and pressure data. Seismic and log data with reservoir performance were correlated to revise the geological model. Later, this updated geological model was imported in Eclipse to generate the simulation model. Updated model estimated GIIP was found to be 14.96×10^9 Sm^3 considering the four sands tested (NGS 2, NGS 1, UGS and LGS), which is about to be 56.63×10^5 Sm^3 higher than the previously estimated GIIP. A better history matching was achieved using the updated information. The revised model adopted in this study yields more reliable prediction.

Based on the current model, a recovery factor of 31.11% (forecast-1) is achievable using the existing wells. Recovery factor could be increased to 79.22% (forecast-5: with recoverable gas of 11.95×10^9 Sm^3 BSCF out of GIIP to be 14.963×10^9 Sm^3) by drilling additional three new development infill wells and performing workover to the existing wells.

Conclusions

The following conclusions can be made from the study.

1. Four gas sand unit is identified and revised 3D reservoir model yields better match with actual production history. Therefore, forecasts based on the updated model give more confidence. Revised 3 D model estimated GIIP is 528.429 BSCF, which is about to be 200 BSCF higher than the previous estimation. Because a new gas sand has been detected in this investigation.
2. Water breakthrough of SLD#1 occurred near 2011 if SLD#3 is put under production from UGS as shown in forecast 5 from 2012. Moreover, for SLD#3 and SLD#4, water breakthrough will occur after 2025.
3. Different production development strategies has been tested with validated 3D static model which indicates rapid increases of recovery factor.
4. Based on the current model, a recovery factor of 31.11% (forecast 1) is achievable using the existing wells. However, we analyzed and reviewed different approach by which recovery rate might be increased such as workover of existing wells, integration of more infill wells, changing production rates, and tuning wellhead pressure. Additional infill wells have significant impact on recovery. It is therefore conclude that recovery factor could be increased to 79.22% (forecast 5) by drilling additional three new infill development wells and performing work over to the existing wells.

Recommendation

1. Saturation log should be run to determine GWC movement and to identify water breakthrough. There should be an integrated program for proper testing and bottom hole pressure surveys on a periodic manner. That will help to characterize the reservoir, model it accurately for updating reserves and diagnose any problem easily.
2. To carry out 3D seismic survey in this field not only in these existing wells but also behind the fault to confirm the extent of reservoir continuity. It will also delineate the reservoir margin and give an updated reservoir characterization.
3. From the simulation study, it is observed that workover operation and additional

development infill wells have significant amount of recovery factor. So, it is suggested that workover of existing wells and new infill wells strategy should be taken immediately.

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