DETERMINATION OF HYDROCARBON ZONE AND DEPOSITIONAL ENVIRONMENT FACIES IN TALANG AKAR FORMATION, SOUTH SUMATRABASIN AT "EPURA" FIELD

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ABSTRACT

The EPURA field is one of the oil and gas producing fields in the South Sumatra Basin, where well completion has been carried out in the Talang Akar Formation, and the production test results are interpreted to mean that in wells EP-13, EP-14, EP-15, EP-16, EP-17 and EP-23 contain several reservoir zones that have the potential to contain hydrocarbons. This research with facies interpretation analysis uses data from six wells (wireline, mudlog, RCAL and lithology data), so it is hoped that it can provide more detailed information for the development of an oil and gas field. The analysis carried out is in the form of facies analysis, depositional environment, electrofacies and facies correlation. From the research results, it was found that the Talang Akar Formation has depositional facies in the form of a fluvial, which in this study is the Lower Talang Akar Formation with depositional facies in the form of channel, Crevasse Splay, point bar and flood plain. Based on the analysis results, the Talang Akar Formation is divided into 3 reservoir zones, namely Zone EP-1, EP-2, and EP-3. After going through all stages of petrophysical analysis, it was found that zones with high hydrocarbon potential were found in wells EP-13, EP-23 and EP-16. The wells with low hydrocarbon potential are EP-14, EP-15 and EP-17 wells. The zone of highest hydrocarbon potential in prospect wells is in the EP-1 zone with a Crevasse Splay facies association and has thick sandstone lithology characteristics with medium to fine grain size.

Keywords*: EP Field, fluvial, South Sumatra, Talang Akar Formation, petrophysical analysis*

INTRODUCTION

In Indonesia, the oil and gas industryplays an important role in supporting the country's development program and it is estimated that this sector contributes 20% of the country's income. The utilization of alternative energy sources has begun to be developed but in general, the mindset of the community still considers fossil fuels as the main need. Fossil fuels such as oil and gas are not *renewable* energy, which means that one day this energy will run out if not managed properly.

The South Sumatra Basin is one of many large sedimentary basins in Indonesia that have been tested for hydrocarbon production. The South Sumatra Basin is one of the basin forms which are included in the back-arc basins in Indonesia. According to (Davis, P. R., 1984).

With that, several methods have beencarried out to maintain or increase oil andgas production rates, namely usingpetrophysical methods. This analysis aims todetermine the physical properties of rocks such as shale content, porosity, water saturation, and permeability in a formation. The petrophysical analysis will produce a description of fluid contact boundaries used to calculate hydrocarbon reserves and determine the depth of performance in the production process.

REGIONAL GEOLOGY

1. Physiography

The geology of the South Sumatra Basinis a result of tectonic activity that is closely related to the subduction of the Indi-Australian Plate, which moves north to northeast against the relatively stationary Eurasian Plate. The plate subduction zonecovers the western part of the island of South Sumatra.

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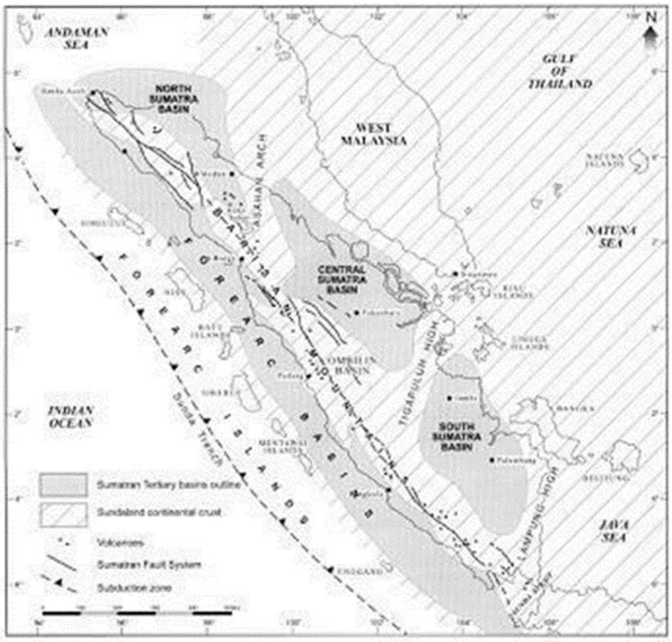

Figure 1. Formation of the Back Arc Basin on the Island of Sumatra

Basin is a northwest-southeast trending Tertiary basin, which is bounded by the Semangko Fault and Bukit Barisan to the southwest, the Sunda Shelf to the northeast, the Lampung Plateau to the southeast which separates the basin from the Sunda Basin, and the Twelve Mountains and Thirty Mountains to the northwest which separate the South Sumatra Basin from the Central Sumatra Basin.The position of the South Sumatra Basin as a back-arc basin (Blake, 1989).

2. Regional Tectonics

Broadly speaking, the formation of theSouth Sumatra Basin order is divided into three phases based on **Figure 2.**

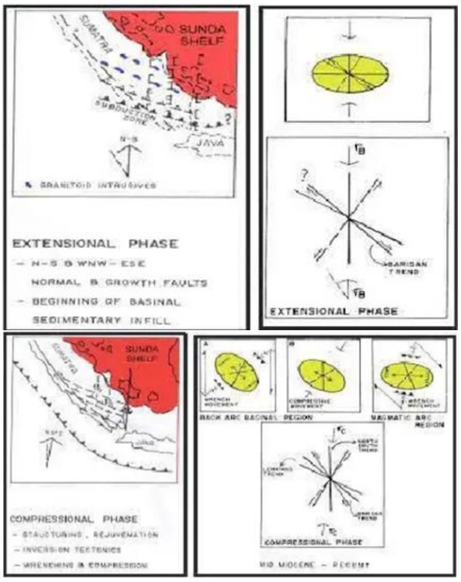

Figure 2. Tectonic Phase

Among others:

1) Compression Phase

   This phase lasted from the early Jurassic to the Cretaceous. In this phase, the *basement was* formed which became the beginning of the formation of the basin.

2) Extensional Phase

   This phase took place in the late Cretaceous- early Tertiary. Basin-filling sedimentation occurred on top of bedrock along with volcanism. This phase also produced the Lahat/Lemat Formation. Tectonic activity inthe Miocene produced the Talang Akar Formation, Baturaja Formation, GumaiFormation, Air Benakat Formation, andMuara Enim Formation.

3) Compressional Motion

   This phase occurred in the Plio-Plistocene which at the end of this phase also depositedthe Kasai Formation.

3. Regional Stratigraphy

The stratigraphy of the South Sumatra Basin consists of Tertiary sedimentary rocks deposited unconformably on top of basement rocks. Where the rocks The basement of the basin consists of metamorphic and igneous rocks of pre-tertiary age.

The South Sumatra Basin undergoes a sedimentation cycle that begins with the transgression phase and ends with the regression phase. The transgression phase began when the Lahat Formation was deposited in the Early Oligocene, which then

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continued with the Talang Akar Formation being depositedon top of it in a misaligned manner. Afterthe Talang Akar Formation, the Batu RajaFormation developed and the maximumtransgression phase was marked by the deposition of the lower Gumai Formation in line with the Batu Raja Formation. Thenafter the transgression phase was completed,it was followed by a regression phasecharacterized by the deposition of the upperGumai Formation, then continued with thedeposition of the Air Benakat Formation inharmony. In the Late Miocene, there wasthe deposition of the Muara Enim Formationwhich lasted until the Pliocene, and also theKasai Formation which lasted from thePliocene to the Pleistocene.

4. Petroleum System South Sumatra Basin

The South Sumatra Basin is a basin thathas the potential to become a productive oil and gas-producing field. The South Sumatra Basin can fulfill the five requirements of the petroleum system where the formations in it have formations that can act as good parent rocks, adequate reservoir rocks and the presence of overlying cover rocks. The following is a further explanation of the petroleum system in the South Sumatra Basin (**Figure 3**).

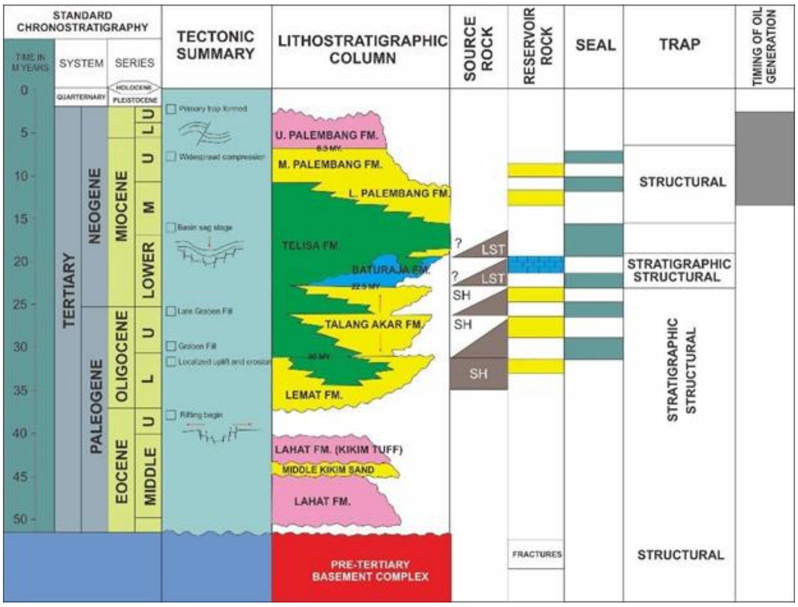

Figure 3. Stratigraphy and petroleum system of the South Sumatra Basin.

RESEARCH METHODS

This research went through several stages in the identification process as well as interpretation to determine the evaluation of the formation of the research area using well-log data and petrophysical analysis and some other supporting data. There are two stages of analysis: qualitative and quantitative.

Qualitative analysis was conducted tointerpret the lithology and as an initial interpretation to determine the top andbottom markers of the reservoir zone layeras a prospect for work. The logs used in this qualitative analysis are gamma ray log, resistivity log (ILD), and combined neutron-density log.

Quantitative analysis was carried out by calculating petrophysical parameters of*shale volume* (Vsh), porosity (ϕ), and water saturation (Sw) with methods appropriate to field conditions. Followed by Lumping to determine *net pay*.

RESULTS AND DISCUSSION

1. Lithofacies

In this study, a lithological description was also carried out from the secondary dataof the PT. PURISKA company with lab results in the form of color, texture, sedimentary structure to the shape of rock grains contained in the wells in this field. Since all wells do not have core rocks, lithology description and lithofacies determination are only done with mudlog interpretation available in the EP field well data. The following table shows the results of the Lithofacies analysis using mudlogs in well BN_13 (**Figure 4**).

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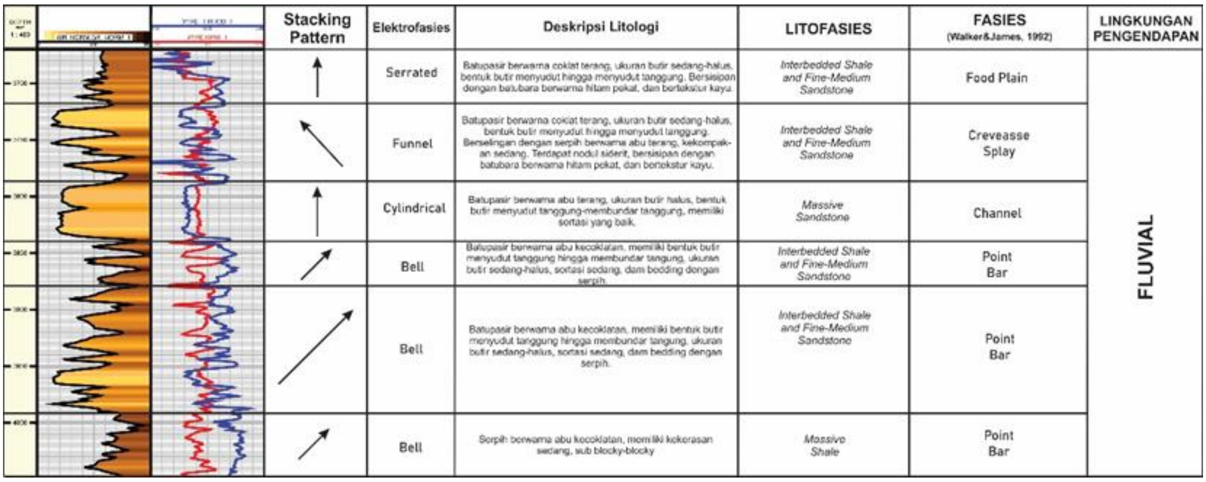

Figure 4. EP 13 Well Facies and Depositional Environment

Also described eachinterval as follows.

a) Interval 3690-3720 *ft*

This interval has a *shally* lithology that has afine- very fine grain size, has a GR value of 70-130 GAPI. The lithofacies name of this interval is *Interbedded Shale and FineSandstone.*

b) Interval 3720-3780 *ft*

This interval has a *shall* lithology that has afine-very fine grain size, has a GR value of 31-155.

GAPI. The lithofacies name of this interval is *Interbedded Shale and Fine-Medium Sandstone.*

c) Interval 3780-3840 *ft*

This interval has a *blocky sand* lithology thathas a medium-fine grain size, has a GR value of 35-76 GAPI. The lithofacies name of this interval is *Massive Sandstone.*

d) Interval 3840-4040 *ft*

This interval has a *silly* and slightly clayey lithology that has a very fine grain size, having a GR value of 88-159 GAPI. The lithofacies named of this interval are *Interbedded Shale and Fine-Very Fine Sandstone*.

2. Facies Correlation

Of the two trajectories determined based on the base map (**Figure 5**), the Northwest-Northeast trending facies correlation (pink trajectory) has similar characteristics to the Northwest-Southeast trending facies. The gamma-ray logs tend to have a fairly uniform sand-shaly lithology between wells.

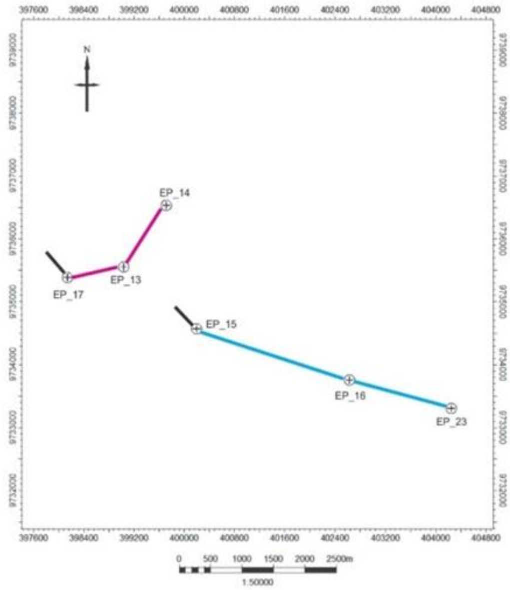

Figure 5. Map of well trajectories in the EP Field

The division of the cross-well direction is determined from the shape of the wellpattern to the uniformity of the sediment thickening pattern between wells so that 2 wells correlate according to this sediment thickening.

Facies deposition consists of several constituent depositional facies. Facies deposition can be The depositional facies can be determined by looking at the association or distribution offacies shapes. Determination of the depositional facies can first be seenfrom the electrofacies pattern. Electrofacies obtained from theinterpretation ofmud logs in the area The research area consists of 4forms, namely Flood Plain, Crevasse Splay, Channel and Point Bar based on Walker and James (1992).

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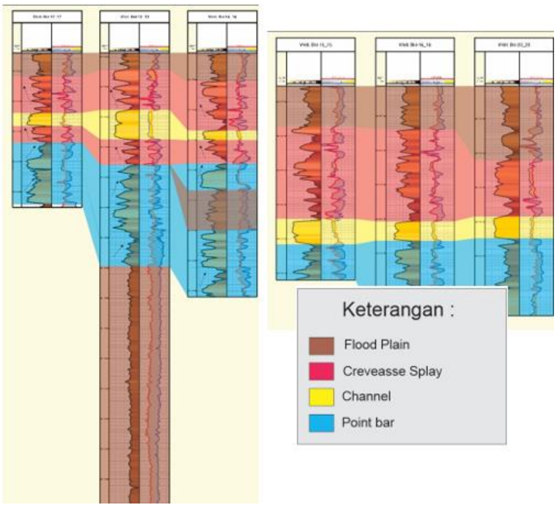


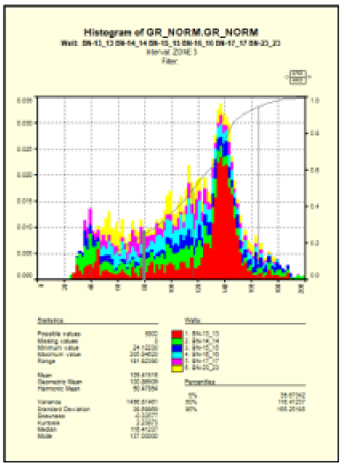
Figure 6. Determination of Facies in the EP Field

3. Petrophysical Parameters

a. Shale Content (vsh)

The shale content calculation stage iscarried out using the Linear Method because this method takes into account the lithology of shale and sand content in the Talang Akar Formation in the "EP" Field. This is becausethe Linear Method is a method that has the same calculation as the gamma-ray index(IGR) and is the most pessimistic calculation method where the shale content value tends to be greater than the Clavier, Steiber, and Larionov Methods (Asquith and Krygowski,2002).

In the calculation of shale content usingthe Linear Method, calculations were carriedout by entering the Gamma-ray Shale (GR Max) and Gamma-ray Matrix (GR Min) values from the research interval into the calculation parameters with the help of petrophysical modeling software. (**Figure 7**).



Grsand	23
Grshale	195

Figure 7. Histogram Nilai Sand dan Shale di Lapangan EP

The average value of vshale from all wells in Table 1

SUMUR	Nilai Rata-rata Vshale (%)
EP_17	12
EP_13	18
EP_14	18
EP_15	17
EP_16	28
EP_23	24

b. Porosity

Porosity is a measure of the space between materials and is the fraction of the volume of space to the total volume. This porosity calculation uses the Density-Neutron equation from BatemanKonen. After that, the values of Fluid (F), DSH, Shale (SH), and matrix (MA) are required using the ternary diagram as a calculation tool as shown in **Figure 8** toobtain the values of Shale Neutron Porosityand Shale Density.

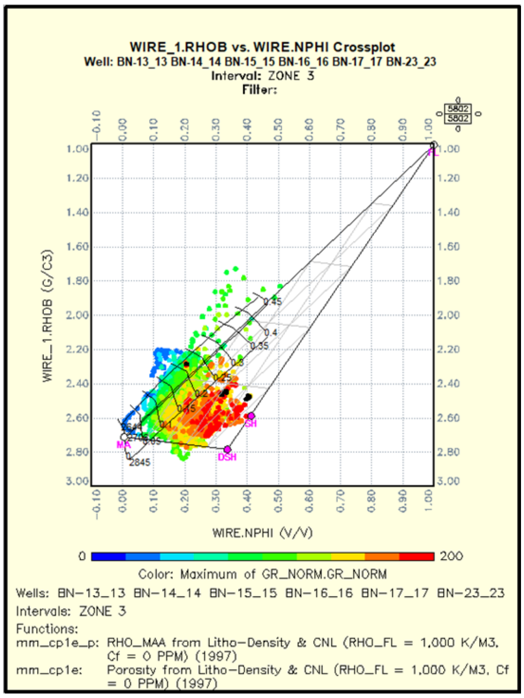


Figure 8. Diagram Ternary

Table 2. Matrix RHOB and fluid RHOB parameters (Scjon, J., 2015)

Point	RHOB	NPHI
FL	1	1
MA	2.65	0
DSH	2.71	0.34
SH	2.52	0.420967

The results of this porosity calculation need to be validated using SCAL data from core data obtained by entering points intothe porosity log. Here is the validation which looks quite accurate and matches withPHIT. (**Figure 9**).

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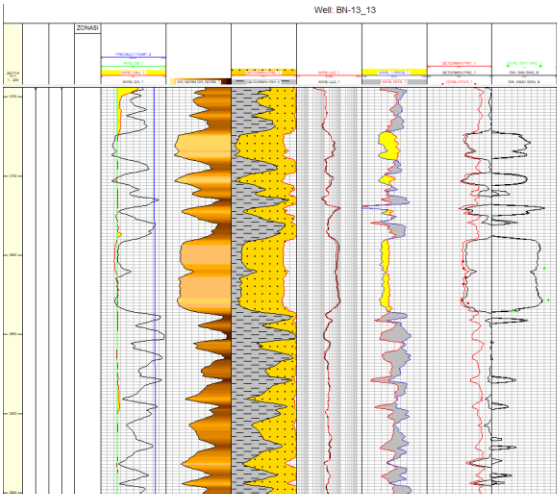


Figure 9. EP-13 Porosity Log Results (match with core data)

Also validated with the results of the average porosity value in all wells has good to very good quality based on the classification of porosity quality according to Kosoemadinata (1978).

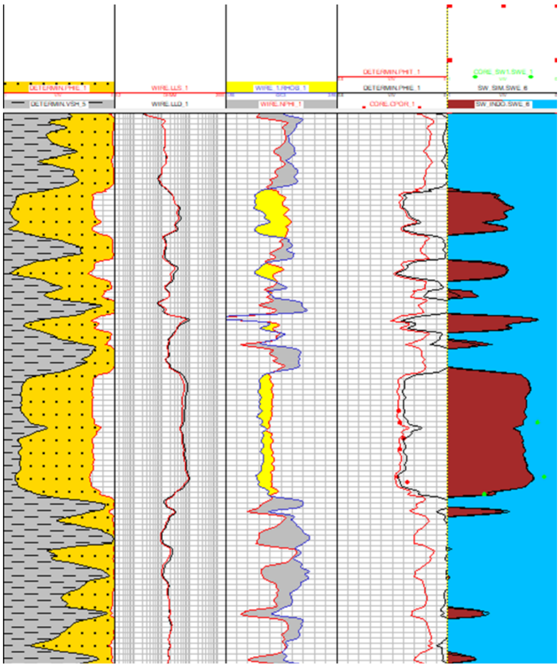
Table 3. Average porosity values and Kosoemadinata Classification (1978)

SUMUR	PHIE (%)	Klasifikasi Porositas Kosoemadinata (1978)
EP_17	22	Sangat Baik
EP_13	28	Sangat Baik
EP_14	22	Sangat Baik
EP_15	22	Sangat Baik
EP_16	19	Baik
EP_23	18	Baik

c. Water Saturation (SW)

Water saturation is the level of water saturation contained in the rock pore. In this study, the Simandoux Method was used, this method was chosen by the reservoir lithology of the research areabecause the EPURA Field is shaly-sand.

After obtaining the results of the water saturation calculation, validation is carried out with the watersaturation contained in the SCAL data.Based on the results of data validationcarried out on the EP-13 well, there are also anomalies and misalignments between coredata and log results. This may be due tomeasurement results that are not maximizeddue to scale limitations or loss and displacement of fluid saturation in the core rock during sampling at the well. (**Figure 10**).



Gambar 10 Log results of water saturation calculations in the EP-13 well

From the entire calculation, the following is the average value of all wells using the Simandoux Method:

Table 4 Average Value of Water Saturation

SUMUR	Nilai Rata-rata Saturasi Air (%)
EP_17	54
EP_13	18
EP_14	61
EP_15	60
EP_16	41
EP_23	32

d. Permeability

Permeability is the ability of a layer to passa fluid. In this study, I used the Coates Free Fluid Index method because this method uses porosity data that has been validated using core data. The following is the averagevalue of permeability in the "EP" field. The overall results of the wells have very good toexcellent permeability values based on the Kosoemadinata Classification, 1978.

Table 5 Average permeability valueof EPURA field

SUMUR	Permeability
EP_13	1013
EP_23	1287
EP_16	984
EP_14	872
EP_15	1030
EP_17	1112

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e. Lumping

The lumping stage is obtained from the cut-off values of all calculated petrophysical parameters. Based on the calculation of the lumping zone that passes the determination, all wells have cut-off values for several zones. Then each good zone that passes will be regrouped in Table X

Table 6. Recapitulation of EP field totalpay zone value

SUMUR	Interval	Top	Bottom	Pay				NetPay	Total NetPay
				VSH	PHIE	SW	Perm		
EP-13	EP-A	3721	3787	0.16	0.2	0.49	53.02	25.84	72.18
	EP-B	3787	3878	0.2	0.21	0.32	64.92	46.34	
	EP-C	3878	4047	0	0	0	0	0	
EP-14	EP-A	4402	4548	0.18	0.25	0.61	36.82	13.12	13.12
	EP-B	4548	4580	-	-	-	0	0	
	EP-C	4580	4759	-	-	-	0	0	
EP-15	EP-A	3935	4072	0.17	0.25	0.58	32.45	5.74	7.38
	EP-B	4072	4107	-	-	-	0	0	
	EP-C	4107	4159	0.18	0.23	0.65	23	1.64	
EP-16	EP-A	3818	3953	0.25	0.23	0.41	62.81	30.76	34.45
	EP-B	3953	3980	-	-	-	0	0	
	EP-C	3980	4096	0.5	0.22	0.59	0	3.69	
EP-17	EP-A	3757	3875	0.12	0.23	0.54	55.21	6.97	6.97
	EP-B	3875	3930	-	-	-	0	0	
EP-23	EP-A	3909	3991	0.23	0.21	0.32	65.41	44.29	44.29
	EP-B	3991	4042	-	-	-	0	0	
	EP-C	4042	4136	-	-	-	0	0	

4. Relationship between Petrophysics and DepositionalFacies

In this subchapter it can be concluded that the most developed facies is Crevasse Splay, this also underlies that the potential hydrocarbon zone in the EPURA field is int h i s facies. Not only that, It is also evident from the largest netpaywhich is divided into zone A, zone B, andzone C for the hydrocarbon zone. The following is a recapitulation table for the relationship between petrophysical values and depositional facies in the EPURA Field. The conclusion that Crevasse Splay and Channel have larger hydrocarbon potential zones while the point bar facies have the smallest net pay results and only exist in the EP_16 well while Crevasse Splay is passed by all wells in this study.

Table 7. Relationship between Petrophysics and Depositional Facies

SUMUR	INTERVAL	TOP	BOTTOM	Net Pay	Fasies
EP 13	A	3721	3787	25.84	Creveasse Splay
	B	3787	3878	46.34	Channel
	C	3878	4047	0	Point Bar
EP 14	A	4402	4548	13.12	Creveasse Splay
	B	4548	4580	0	Channel
	C	4580	4759	0	Point Bar
EP 15	A	3935	4072	5.74	Creveasse Splay
	B	4072	4107	0	Channel
	C	4107	4159	1.64	Point Bar
EP 16	A	3818	3953	30.76	Creveasse Splay
	B	3953	3980	0	Channel
	C	3980	4096	3.69	Point Bar
EP 17	A	3757	3875	6.97	Creveasse Splay
	B	3875	3930	0	Channel
EP 23	A	3990	3991	44.29	Creveasse Splay
	B	3991	4042	0	Channel
	C	4042	4136	0	Point Bar

CONCLUSIONS

1. The study area consists of 4 faciessuch as channel, Crevasse Splay, point bar and flood plain. And has a fluvial depositional environment.
2. The study area has lithofacies of massive shale, massive sand,interbedded shale and fine-medium sandstone.
3. 4Electrophasies that develop in the study area are serrated, funnel, bell, and cylindrical.
4. Based on the petrophysicalparameters in all wells, the intervalhas values ranging from 18-35% for shale volume, 18-28% for effective porosity, and 18-61% for water saturation.
5. The hydrocarbon potential zones with the largest net pay in the EP Field are mostly found in the EP-A zone,

The facies that develop in this zone are crevasse splay with funnel-shaped electrifies and characterized by thick sandstone lithology with medium-fine grain size.

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