Petrophysical Features of Linch Pay from Jotana & Linch Field of Mehsana Block, North Cambay Basin

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Summary

Jotana and Linch field In Mehsana block of North Cambay Basin is known for multiple hydrocarbon bearing sand reservoir which corresponds to Mandhali Member in Kadi Formation and Linch Pay within Older Cambay Shale. Present day thrust areas for exploration in Jotana-Linch area are deeper pay sand of Mandhali and Older Cambay Shale (Linch Pay), has been covered in details by 2D and 3D survey. Geological information has set up model of deposition of both Mandhali and Linch pay sands as well entrapment of hydrocarbon. Maximizing the economic value of reservoir rests primarily upon the adequate reservoir data acquired for finer interpretation of pore structural variance / complexities to attain a reasonable prediction and to achieve an efficient exploration and optimum exploitation of the pay.

The present work on basic and special petrophysical studies on core samples of some selected key wells of Jotana and Linch field evaluate the storing & flowing characteristics as well as the capillary and resistivity responses (at 100% and partial saturation) of Linch pay. The study is of immense economic value for clear understanding and proper evaluation of pore structural variance/complexities so as to arrive at a factual evaluation of Linch pay.

Petrophysical study reflects excellent development of Linch pay layers in these wells. These macro-porous (porosity, ϕ_e >20%) and good permeable (geometric mean air permeability, Ka >135md) layers indicate maximum storing and good flowing characteristic of reservoir. Dominance of macro-pores of >10µm along with higher values for displacement (rpd), threshold (rth), port (r_{35}) radii and lower Sirw (3-31%) exhibit the existence of an effectively interconnected and well distributed porous network within these layers to initiate entrapment and accumulation of hydrocarbon up to maximum level of pore space. About 60% non-wetting-phase saturation is attained in 1.42 m thick layer of one well during drainage even at low buoyancy pressure (0.9-2.0Kg/cm2) of migrating hydrocarbon column. The computed values of Archie's constant "a", Porosity exponent, "m" and Saturation exponent "n" for well developed layers are 0.60, 2.22 & 1.88 (at 200gpl) and 0.70, 2.01 & 1.56 (at 10gpl) respectively. These data are of crucial importance to arrive at a reasonable prediction/finer interpretation of porous network and better correlation/correction of log responses / effective reservoir management.

Systematic integration of these findings with log data will provide crucial information to realize precise estimation of the potential of Linch pay for optimum exploitation

Introduction

Jotana & Linch field is located in Mehsana tectonic block which is fairly well developed producing block of North Cambay Basin. Structurally it is a north-south trending elongated anticline with faulted western margin. The field has attained special significance for its commercial Hydrocarbon accumulation in multiple clastic reservoirs in early to middle Eocene age. Present exploratory objectives are targeted for deeper sands of linch pay in older cambay shale and Mandhali member of Kadi formation. Linch pay sands are developed as lenticular sand within older cambay shale and are encountered at an average depth of 1550m. The mandhali units which are lower subsidiary sands of Kadi formation are the main hydrocarbon bearings and occur at an average depth of 1300m.

On account of rising oil prices, eluding new oil finds, poor recovery efficiency / depleting trends, there is need of having in-depth knowledge and reliable information about reservoir characteristics like storing/transmitting capacity, initial oil/water saturation and trapping mechanism that accounts for micro-and macro-displacement processes. Maximizing the economic value of reservoir rests primarily upon the adequate reservoir data acquired for finer interpretation of pore structural variance / complexities to attain a reasonable prediction and to achieve an efficient exploration and optimum exploitation of the pay.

The present work was undertaken to update geological model and analyze the hydrocarbon pool of linch pay in jotana and linch field. Convention cores of five wells from Jotana and linch field was selected for extensive petrophysical studies so as to visualize the pore structural complexities and to evaluate the resistivity responses to arrive at reasonable prediction, efficient exploration and exploitation of linch pay. Capillary pressure studies was also subjected with this perspective only to assess pore throat sorting (PTS), pore size distribution (PSD) pattern, displacement/threshold/port pressure and water saturations (Sirw).

Sampling & experimental

About 153 samples from different wells (Table-1) were taken up for generating data on extracted core samples free of hydrocarbons / salt by using toluene and mixture of acetone / methanol respectively then dressed and dried at 60^0C for 4-6 hours for following experiments: -

- Effective Porosity (ϕ_e), Grain & Bulk Density (gm/cc) by conventional saturation method.
- Air Permeability (Ka) by Air Permeameter (Core Laboratories. Ink. USA). Ka values are corrected for klinkenberg"s slippage effect $^{\xi *}$.
- Capillary Pressure parameters by Mercury Injection Capillary Pressure Technique. Following capillary pressure related parameters are generated:-
  - Pore Size Distribution (PSD) pattern & Pore Throat Sorting (PTS)
  - Displacement (P_d), Threshold (P_{th}) & Port (Pr_{35}) Pressures.
  - Effective Pore Throat Size or Port Size (r_{35}) and Irreducible Water Saturation (Sirw).
- Electrical resistivity measurements by Resistivity Test Unit model CEF, Core laboratories USA for estimation of Formation Resistivity Factor, "F_R" and Archie's constant, "a", Cementation Factor, "m" and Saturation Exponent, " n"

Results and discussions

The porosity and permeability values of studied section of recovered core intervals of Well A, B & C and of well D & E are depicted graphically in Fig-1 & 3 respectively. The capillary pressure studies for selected samples are tabulated in Table-4. Systematic integration and interpretation of all generated data exhibits the presence of some of excellently developed linch pay in studied wells which are summarized in table no.2.

The results of excellently developed layers are discussed in details as below:

Basic & capillary pressure related parameters

Well - A

Extensive studies of 19 samples indicate the presence of 1.4m thick well developed layer in the int.1737.16–1738. In addition of high porosity and permeability data depicted in Fig 1 the higher Mean hydraulic radius ($Rmh=0.314(Ka / \phi_e)^{1/2}$) values for this layer ranges from 0.74µm - 2.51µm, with Geometric mean Rmh=1.42µm. indicate better quality reservoir formation. MICP studies, indicate effective interconnection and excellent distribution of pore throats/pore aperture radii. Displacement (P_d=0.26-0.62 Kg/cm^2) and threshold ($P_{TH=}$0.28-0.75 Kg/cm^2) pressures are low due to dominance (52-72%) of macro-pores of >10µm size. High displacement (r_{Pd}=11.85-28.27µm) & threshold (r_{th}=9.8-26.25µm) radii are responsible for smooth initiation of drainage cycle by easily forming filaments/pathways of migrating hydrocarbon to accomplish saturation up to maximum available pore space even at a lesser buoyancy pressure. About 60% non-wetting phase saturation is attained, even at lower buoyancy pressure of 0.9-2.0 Kg/cm^2, whereas to attain the same Sw %, buoyancy pressure of about 40Kg/cm^2 is required for

Table 1:

WELL No. !	CC-Int. (m), Rec.Gross Lithology	$\hat{o}$e%	Kamd	Ro / FR	RI / Sw	Capillary Press	Total
A	1737-1741, 50%Sandstone	19	19	32	28	7	105
B	1979-1984, 84%Sandstone/shale	33	27	53	24	16	153
C	1883-1888, 57%Dominantly sandstone	17	14	37	10	4	72
C	1989-1997, 100%Alt. shale/siltstone/sst	24	20	36	16	4	100
D	1752.5-1761.5, 99.5%Alt. shale/siltstone/sst	49	16	38	X	6	109
E	1741-1746.37, 81%sst/siltstone/shale	11	9	14	X	3	37
	Total	153	105	200	78	40	576

Table-2 Petro-physical Features Of Well Developed Linch Pay

well	Flow Unit	ϕ_e, %	Ka (md)
A	1737.16-1738.58m,1.4m(top)	22.18-25.44% Geom. Meanϕ_e=23.91%	129.4-1550.5md Geometric Mean Ka=490.26md
B	1979.23-1979.95m0.7m	20.2-29.73% GeometricMean=25.83%	40-682mdGeo.Mean Ka=136.94md
B	1981.36-1981.99m0.6m	25.92-29.58%GeometricMean=27.08%	170-369mdGeometricMean=264.15md
C	1883.18-1883.68m0.5m at top	23.34-26.66% GeometricMean=24.8%	69.1-319.3md GeometricMean=213.69md
C	1885.26-1885.43m,0.17m	21.41-22%	319.21-398.93md
C	T-3 to T-22*(Box No.-1/9 to middle of Box No.-5/9)	9.33-26.56% GeometricMean=21.66%	33.57-1735.16md GeometricMean =659.17md

well	Sirw, %	PSD Pattern	Fr (Fa & Fl)	Category
A	5.5-11%	52-72% pore of >10µm.	6.77-12.486.22-16.67	Excellent reservoir
B	3-30%	6.5-84.5% pores of >10µm size.	8.37-15.198.67-18.11	Well developed layer
B	3.5-16.5%	21-68% pores of >10µm,15-56% pores of 10-1µm	8.66-12.059.7-12.74	Well developed layer
C	11%	49% pores of >10µm size.	5.2-12.319.08-11.46	Excellent reservoir
C	15%	45% pores of >10µm size	10.86-11.3210.38-10.99	Excellent
C	5-31%	11-82% pores of >10µm.	6.6-31.69.17-40.07	Excellently developed layer.

Remarks: * Plug position could not be worked out as some pieces were missing in the boxes due to sample taken for studies earlier. Grain density varies from 2.54 to 2.88 gm/cc with maximum frequency between 2.61 to 2.74 gm/cc.

Table- 3 Petro-physical Features Of Poor Reservoir In Linch Pay

well	Flow Unit	ϕ_e, %	Ka (md)
well	Flow Unit	ϕ_e, %	Ka (md)
D	1752.76-1758.95m6.19m (top)	6.58-21.89% Geo-Mean=15.67%	Immeasurably Low – 0.59md
D	1759.01-1761.18m2.17m	11.08-27.39%Geo-Mean=18.9%	0.08–51.58md, GeoMean=4.1md
E	1741.2-743.14m1.9m	16.43-23.98%	Imm.low-0.44md

well	Sirw, %	PSD Pattern	Fr (Fa & Fl)	Category
D	44-86	70-97% pores of < 1µm size.	15.97-89.0525.28-118.95	Poor reservoir .
D	27-68	3-11% pores of >10µm, 17-49% pores (10-1µm)	7.89-41.0211.03-65.92	Poor to fair layer
E	31-59	66-98% micro-pores of <1µm size.	14.77-19.6726.1-31.63	Poor reservoir

the sample at position 1738.7m with ϕ_e=18.07% & Ka=5.6md. Higher effective pore throat size (r_{35}=6.68-13.13µm) and Sirw (5.5-11%) are also indicative of an easier drainage cycle for entrapment & accumulation of hydrocarbons. Pore throat sorting, PTS for developed layer, ranges from 1.61-2.37 indicates better sorting of pore throats in the scale of 1(perfect sorting) to 8 (essentially no sorting) (FIG-1 & Table-4).

Well - B

Studies indicate the presence of two well developed layers within studied int. 1979.23-1982.49m. The upper layer of 0.7m thickness developed in the int. 1979.23-1979.95m (ϕ_e=20.2-29.73% & Ka=40-682md, Geometric mean ϕ_e=25.83% and Ka=136.94md) and the middle layer of about 0.6m thickness developed in the int. 1981.36-1981.99m (ϕ_e=25.92-29.58% & Ka=170-369md, Geometric mean ϕ_e=27.08% & Ka=264.15md) are excellently developed with higher values for Rmh (0.36-1.62µm), reflecting the existence of a highly favorable pore network that have a decisive control on drainage/imbibition cycles during migration/accumulation of hydrocarbon. MICP studies from these layers indicate effective interconnection and excellent distribution of the pore throats/pore aperture radii. Displacement (P_d=0.24-1.15 Kg/cm^2) and threshold (P_{th} =0.32-1.2Kg/cm^2) pressures are appreciably low due to the dominance of a larger fraction (6.5-84.5%) of macro-pores of >10µm. Higher effective pore throat (r_{35} =2.3-15.31µm) and low Sirw (3-30%) are

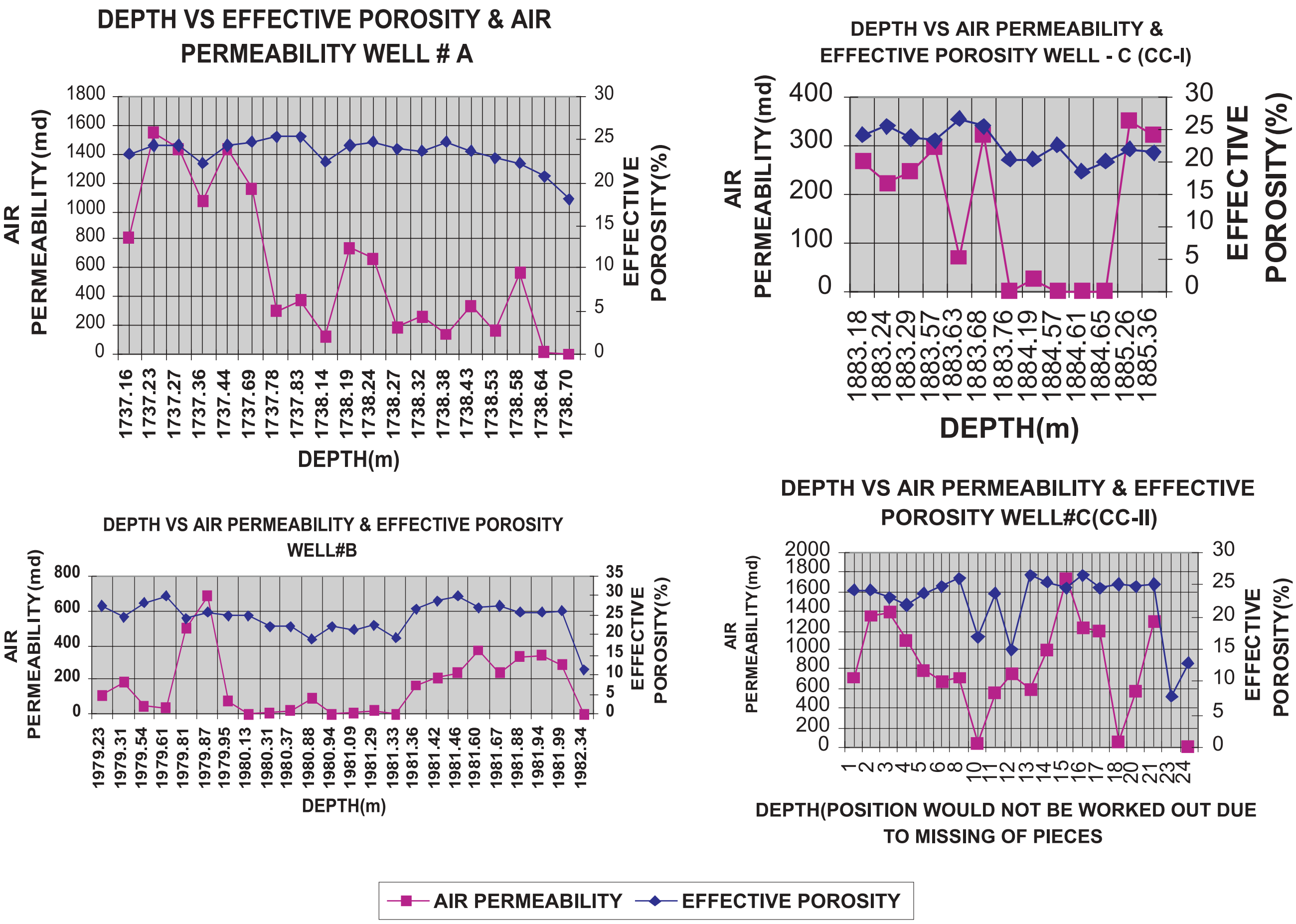


Fig. 1

also indicative of the presence of an excellent reservoir formation. (FIG-1 & Table-4).

Well – C (CC-1)

A layer of 0.5 m thickness developed **i**n the int. 1883.18-1883.68m (ϕ_e=23.34-26.66% & Ka=69.1-319.3md, Geo.mean ϕ_e=24.8% & Ka=213.69md). Similar characteristics were observed for thin layers developed in the int. 1885.26-1885.43m. Higher Rmh values of 1.04 & 1.25 indicate better quality reservoir formation. MICP studies of two samples from these layers indicate the presence of 45-49% macro-pores of >10micron size. Sirw is around 11-15%. (FIG-1 & Table-4)

Well - C (CC-2)

Some of core pieces were missing in the boxes due to samples taken for studied earlier the Plug position could not be worked out. Petrophysical evaluation on samples from T-3 to T22 exhibit excellent reservoir characteristics with ϕ_e=9.33-26.56% (maximum frequency in between 21-25%, Geo.mean ϕ_e=21.66%) and Ka=33.57-1735.16md, Geo.mean Ka=659.17md. Higher values for mean hydraulic radii (Rmh=0.44 -2.33µm exhibit the presence of highly favorable pore geometry for smooth displacement and accumulation of migrating non-wetting phase up to maximum available pore space. MICP studies on four samples from this section exhibit the presence of much larger displacement (r_{Pd}=21-44.55µm), threshold (r_{th}=15.64-40.83µm) & port (r_{35}=0.7-22.27µm) radii for initiating and accomplishing excellent storing and fluid distribution characteristics. Mega-pores of >25µm have contributed 4-70% in the pore network and Sirw is 5-31%. (FIG-1 & Table-4).

Resistivity studies (FR, RI vs Sw, & n)

True resistivity "Rt" of a reservoir rock is a function of formation water resistivity (Rw), rock structure

Table 4 : Capillary Pressure Related Parameters Linch Pay- Linch & Jotana Field (Developed Reservoir)

Sl. No	DEPTH (m)	Ka (md)	Φe (%)	Rmh micron	Sirw (%)
	WELL - A , CC-1, Int. 1737-1741m, Rec.-50%				
1	1737.27	1440	24.42	2.41	5.5
2	1737.69	1156.7	24.78	2.15	8
3	1738.14	129.41	22.54	0.75	11
4	1738.27	193.39	23.82	0.89	6
5	1738.43	346.1	23.64	2.69	10
6	1738.58	569.16	22.18	2.77	10
7	1738.7	5.6	18.07	0.18	25.5
	WELL - B, CC-1, Int. 1979-1984m, Rec.-84%				
1	1979.31	180	24.4	0.85	30
2	1979.81	495	24.02	1.43	20
3	1979.87	682	25.77	1.62	3
4	1980.37	14.9	22.06	0.26	57.5
5	1981.29	20.22	22.33	0.3	42
6	1981.36	170	26.43	0.8	10.5
7	1981.46	235	29.58	0.89	16.5
8	1981.60	369	26.85	1.16	3.5
9	1981.88	331	25.93	1.12	7.5
10	1984.94	340	25.92	1.14	11.5
11	1981.99	285	26.2	1.03	11
12	1982.34	3.84	11.26	0.18	41.5
	WELL - C, CC-1, Int. 1883-1888m, Rec.-57%				
1	1883.18	265.8	23.97	1.04	11
2	1884.61	0.92	18.54	0.07	38
3	1885.36	319.21	21.41	1.2	15
	WELL - C, CC-2, Int. 1989-19971m, Rec.-100%				
1	T-3B, 3cm Top	716.53	24.27	1.69	12
2	T-3B, 7cm Top	1346.91	24.15	2.33	5
3	T-13, 5cm Top	33.57	17.03	0.44	31
4	T-16, 2cm Top	1230.4	26.49	2.13	6

Sl No	P_d < Kg/cm^2 >	P_{th}	Pr_{35}	r_{pd} < µm >	r_{th}	r_{35}
	WELL - A , CC-1, Int. 1737-1741m, Rec.-50%					
1	0.26	0.28	0.72	28.27	26.25	10.21
2	0.31	0.33	0.56	23.71	22.27	13.13
3	0.62	0.74	1.1	11.85	9.93	6.68
4	0.61	0.75	0.86	12.05	9.8	8.55
5	0.35	0.51	0.76	21	14.41	9.67
6	0.44	0.55	0.83	16.7	13.36	8.85
7	1.8	2.0	8.4	4.08	3.67	0.87
	WELL - B, CC-1, Int. 1979-1984m, Rec.-84%					
1	0.56	0.58	1.29	13.13	12.67	5.7
2	0.49	0.52	0.92	15	14.13	7.99
3	0.24	0.32	0.43	30.62	22.97	15.31
4	0.55	0.6	46	13.36	12.25	0.016
5	0.98	1.3	17	7.5	5.65	0.043
6	0.48	0.5	1.6	15.31	14.7	4.6
7	0.72	0.74	1	10.5	9.93	7.35
8	0.44	0.46	0.9	16.7	15.98	8.16
9	0.69	0.72	0.94	10.65	10.21	7.82
10	0.52	0.54	0.98	14.13	13.61	7.5
11	0.5	0.54	1.05	14.7	13.61	7
12	3.5	4.4	19.5	2.1	1.67	0.038
	WELL - C, CC-1, Int. 1883-1888m, Rec.-57%					
1	0.48	0.51	0.83	15.3	14.4	8.9
2	3.1	3.9	22	2.4	1.9	0.3
3	0.39	0.42	0.76	18.8	17.5	9.7
	WELL - C, CC-2, Int. 1989-19971m, Rec.-100%					
1	0.16	0.18	0.39	44.55	40.83	18.85
2	0.18	0.19	0.33	41.29	38.68	22.27
3	0.35	0.47	10.5	21	15.64	0.7
4	0.33	0.35	0.54	22.27	21.00	13.61

Sl. No	PTS	PSD PATTERN, µm >25µm	25-10µm	10-1µm	<1µm
	WELL - A , CC-1, Int. 1737-1741m, Rec.-50%				
1	2.03	31	27	33	9
2	1.61	42	30	13	15
3	2.21	7	45	24	24
4	1.68	7	52	28	12
5	1.75	22	38	26	14
6	2.37	20	33	55	22
7	2.91	-	-	44	56
	WELL - B, CC-1, Int. 1979-1984m, Rec.-84%				
1	2.05	3	33.5	25.5	38
2	1.5	7	50	17	26
3	1.33	62	22.5	9	6.5
4	3.9	1.5	5.5	15.5	77.5
5	36.84	nil	7	26	67
6	1.75	5.5	20.5	50.5	23.5
7	1.39	0.5	59.5	17	23
8	1.32	11	64	15	10
9	1.32	3	53.5	19.5	14
10	1.26	2	66	16	16
11	1.42	4	55	23	18
12		nil	1	27	72
	WELL - C, CC-1, Int. 1883-1888m, Rec.-57%				
1	3.85	8	41	21	30
2	2.22	-	-	23	77
3	3.02	21	24	20	25
	WELL - C, CC-2, Int. 1989-19971m, Rec.-100%				
1	1.77	50	23	10	17
2	1.54	70	12	8	10
3	3.11	4.0	7.0	30	59
4	1.70	43	28	15	14

($FR = a\,\phi_e^{-m}$) and hydrocarbon influence ($RI = Rt/Ro = Sw^{-n}$). In order to negate/essentially nullify the influence of electrical constriction factor and to reflect true tortuosity, resistivity studies were carried out at 200gpl (limiting salinity) & 10gpl (formation salinity). For the computation of "a*/a" and "m*/m", resistivity studies at 100% saturation were conducted on samples from well developed layer. "FR" (Fa & Fl) values are comparatively in low range as shown in Table-2 for the well developed layers due to well-distributed / effectively inter-connected pore geometry/ lesser tortuosity, thus resulting in lesser resistance to electrical flow as compared to tight layers. Graphical presentation of Formation factor "FR" (Fa & Fl) vs depth for studied section is depicted in Fig-2.

De-saturation studies at partial saturation were conducted on samples from well developed layers for the generation of data on resistivity index (RI) versus water saturation (Sw% Pore Space) to compute "n*/n". Attained <20% water saturation during such studies for most of the samples at slow de-saturation process to cover wide range of RI vs Sw spectra and during this process from >100 to >50 RI vs Sw data points were acquired for these samples at formation salinity (10gpl, brine) as well as at limiting salinity of 200gpl, brine to generate quality data on "n*/n" with high correlation coefficient. After clubbing all data on RI vs Sw for these samples, the computed values for "n*/n" for well developed layers of studied wells are tabulated as below:

"n* / n" For Well Developed Linch Pay

WELL	At 200gpl, brine n*	At 10gpl, brine n
WELL - A	1.81	1.57
WELL - B	2.0	1.49
WELL - C (CC-1)	1.88	1.79
WELL - C (CC-2)	1.77	1.60

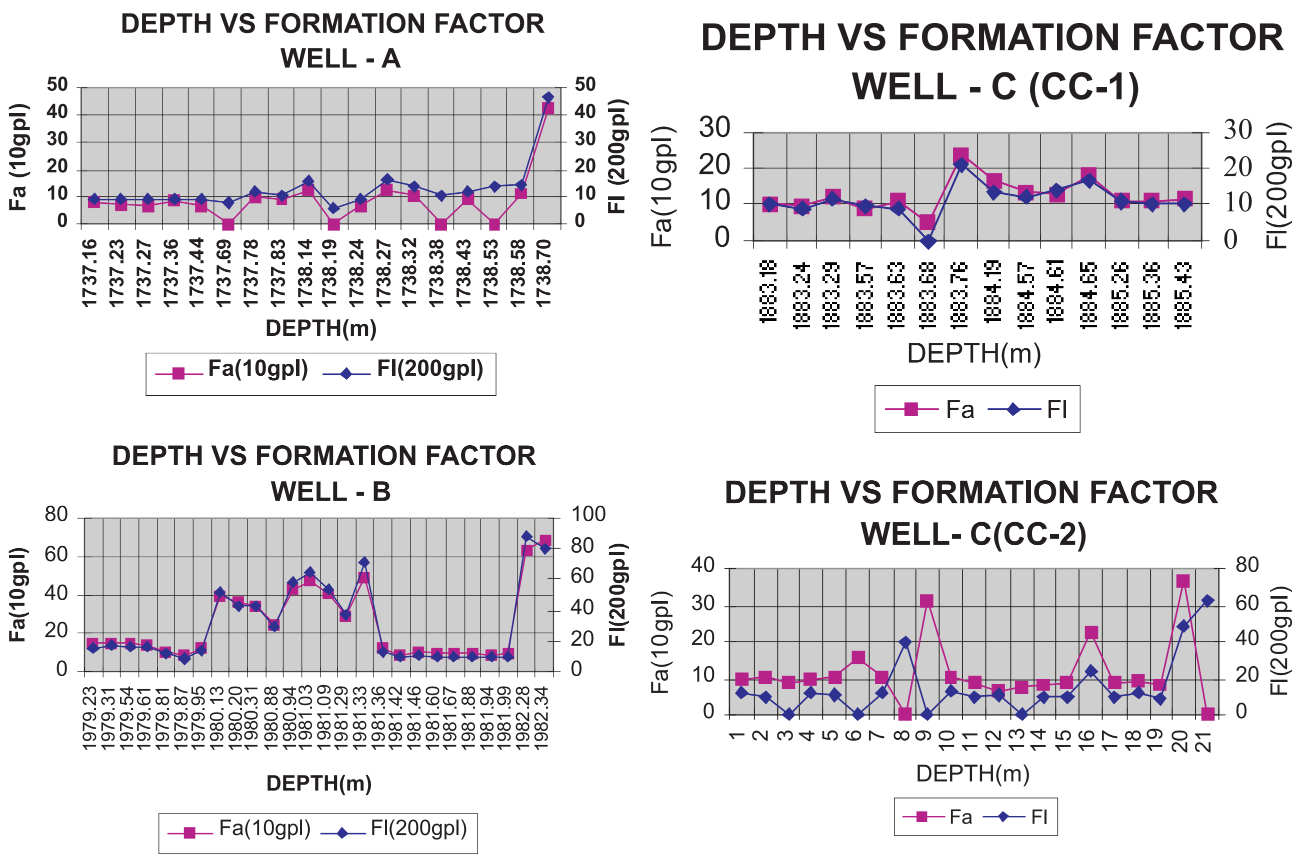


Fig. 2

The "a" & "m" values, through the log-log cross plot of F_R vs ϕ_e for 79 samples studied for linch pay for well developed layers from the above wells are 0.60 & 2.22 (at 200gpl) and 0.70 & 2.01 (at 10gpl) respectively. De-saturation studies at partial saturation for computation of "n*/n" were conducted on 45 samples from above wells. After clubbing >210 RI vs Sw data points for these samples, the computed values for "n*" & "n" for Linch Pay are 1.88 and 1.56 respectively.(Figure - 6 & 7). The values are summarized as below:

"a" , "m" & "n" For Linch Pay From Jatana Field

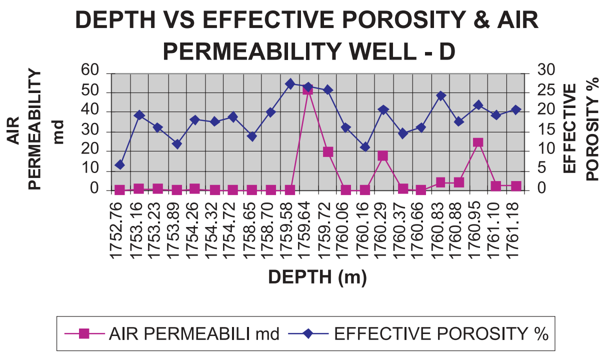
WELLS	At 200gpl, brine			At 10gpl, brine		
	a*	m*	n*	a	m	n
WELL - A	0.60	2.22	1.88	0.70	2.01	1.56
WELL - B						
WELL – C-1						
WELL - C-2						

Petro-physical features of Poor Reservoir for Well D & E

Petrophysical features studies on 49 samples of Well D and 11 samples of Well E indicate poor development of Linch pay in these two wells (Fig-3 and Table-3). Measo porous, poorly permeable and presence of micro-pore throats reflects non-existence of interconnected macro porosity, partial cementation/plugging of pore throats by authigenic clay, grain coats/pore bridging to destroy permeability extensively. Due to dominance of micro-pores/increase in tortuosity, micro-porous, poor-permeable samples have shown higher values for Fa & Fl due to increase in pore constriction factor/electrical constriction factor (Table-3). As most of samples are tight in nature, de-saturation studies at partial saturation were not conducted.

Conclusions

The petrophysical studies describe excellent development of reservoir rock characteristics of Linch Pay in studied wells. However poor to fair developed layers in Linch Pay is observed in petrophysical studies of some wells. As Jotana field is divided into several pools by number of longitudinal faults so Petrophysical studies for more exploratory wells is recommended for precise evaluation of linch and mandhali reservoir. The data generated at micro level are recommended to be used for improved wire line log evaluation.



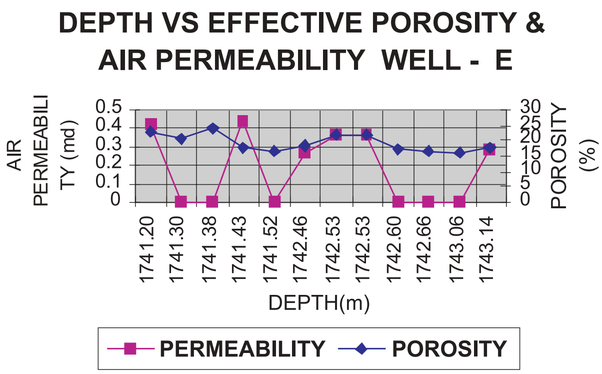


Fig. 3

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Views expressed in this paper are those of the authors only and may not necessarily be of ONGC.

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