PaperID AU389

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ROLE OF MACERALS IN PETROLEUM GENERATION IN RAMNAD SUB BASIN, CAUVERY BASIN

Abstract

The primary objective of the present study is to define the type and source of organic matter by identifying the macerals and determining their composition and environment of deposition in the source rock sequences of the wells from Ramnad sub-basin, Cauvery Basin. It was also aimed to find effect of intrusive igneous bodies on macerals composition due to excessive heating (intrusive body in the studied wells at: 3763-3804m in **A**, 4524-4555m in **B** and 3532-38m & 3564-3902m in **C**). This study also exhibits the contribution from various source organofacies towards petroleum generation. Selected core/cutting samples from Andimadam section of these wells were taken up for microscopic study under incident white light and ultra-violet light, using ASTM 2011 & D2799.

Distribution pattern of the Liptinite, Vitrinite and Inertinite macerals, indicates that the organic matter is dominantly contributed from terrestrial input under anoxic environment (Type-III) . Further distribution of Liptinites also exhibits dominance of resinites and sporinites over alginites, suggesting that the organic matter has major contribution of terrestrial input (Type-III) and minor contribution from marine/lacustrine input (Type-I & II) in all the wells. This has also been validated by the Elemental analysis studies based on H/C and O/C atomic ratios.

1. Introduction:

British botanist Marie C. Stopes in 1935, proposed the term maceral to describe organic constituents present in coals as minerals (the inorganic components of rocks). The word is derived from the Latin macerare, meaning “to macerate (waste away) i.e. wastes or remains from organic matter.” Mineral names often end in “-ite.” The corresponding ending for macerals is “-inite”. In 1958 Spackman expanded the maceral concept and made it more useful for applied studies by considering macerals as “macerals are organic substance, or optically homogenous aggregates of organic substances, possessing distinctive physical and chemical properties, and occurring naturally in the sedimentary, metamorphic, and igneous materials of the earth. However, because of small size (< a hundred microns in diameter) and difficult to separate from the coal/sedimentary rock matrix, the petrographic methods, especially reflectance, fluorescence, infrared and photo acoustic microscopy have been very successful in identifying, classifying and correlating them with the behaviour of coal/sedimentary organic matter. Microscopically, macerals are individual organic constituents of Bituminous coal (fossil fuel) and can be classified into three major groups:

Vitrinite Group of Macerals (Type III Kerogen); derived from plants, exhibit moderate reflectance under white light and none or poor Fluorescence under UV light. Characterized by high oxygen to carbon ratios, and include the macerals, telinite and collinite. Most Vitrinite-rich rock tends to be prone to gas generation.

Liptinite (formerly called exinite); derived from decayed cuticles and resinous parts of plants, include sporinite, cutinite, resinite (Type II Kerogen) and green algae and blue-green algae (Type I Kerogen).Characterized by low reflectance and high hydrogen content, high hydrogen to carbon ratios, have the highest calorific values (of all coal macerals) and exhibit strong yellow or green fluorescence under UV light. Liptinites have a high oil and gas producing potential.

Inertinites (Type IV Kerogen): are formed from plant material, like roots, transformed by severe degradation during the peat stage of coalification (peats that have been oxidised early in their formation). This group consists of semifusinite, micrinite, macrinite and sclerotinite. They are rich in carbon contents and have high reflectance (brightest of all other macerals) under white light and no Fluorescence under UV light. Inertinites are not prone to oil and gas generation.

2. Objectives:

The study was aimed to:

- Identify the type, source and environment of deposition of organic matter based on macerals identification and their composition, to define the extent of contribution from various source organofacies towards petroleum generation, and
- Know the effect of excessive heating on macerals composition.

3. Geology of the Area:

The Cauvery Basin contains sedimentary rocks ranging in age from Late Jurassic to older to recent with some intervening unconformities. Occurrence of Hydrocarbons has been established in commercial quantities from Basement, syn rift, Lower and Upper Cretaceous, Palaeocene, Eocene and Oligocene reservoirs. About 33 fields have been established in onland and shallow offshore. The basin has been sub-divided into five sub-basins (Ariyalur–Pondicherry, Tranquebar, Tanjore, Nagapattinam and Ramnad sub-basin) by earlier workers summarised by Venkatrangan et al., 1993 and the stratigraphy proposed by them has been followed in the present study.

3.1. The study area: Ramnad Sub-Basin:

This southern most sub basin of Cauvery on shore has a sedimentary thickness of greater than 5km consisting of late Jurassic/Early Cretaceous to recent sediments. This sub basin is bounded by Pattukotai ridge on the West-northwest and Mandapam Drift ridge towards the South East. The exploratory success so far is restricted towards the eastern part of the sub basin.

3.2 General Source Rock Characteristics of Ramnad Sub-Basin:

The organic matter in the area is found to be dominantly type III with a proclivity to generate gas. The geothermal gradients are high (3.0°C to 3.5°C /100m) in this area compared to other sub basins and hence the deeper seated Albian/pre Albian (regional source rocks) which might have generated liquid hydrocarbons, would have cracked into condensate and lighter hydrocarbons. The analysis of oil/ condensate of this sub basin indicates that the hydrocarbons have been generated from source rocks of high maturity levels (>0.90%, VRo).

3.3 The Studied wells:

The location of the studied wells has been shown in Fig.-1 and Age boundaries of studied wells have been given in Table-1.

3.3.1. Well No A:

The location was drilled to explore the hydrocarbon potential within lower part of Andimadam formation, in Ramnad sub-basin of Cauvery Basin. Based on the geological data and electro log evaluation, three well was declared dry and mild gas influx in Object –I was observed.

Andimadam (3379-4225m) consists of thick sandstone with intercalations of shales. In this section, Organic matter richness is found to be poor to very good (0.22-3.29%) with good average organic matter richness (Avg. TOC 1.32%). Poor to fair hydrocarbon generation potential (S2 values 0.03-2.41 mg HC/g rock) and poor average hydrocarbon generation potential value 1.21 mg HC/g rock are observed. HI values in the range 14-250 mg HC/g of TOC, with average HI value of 98 mg HC/ g of TOC are observed (FAR Report, 2009**;** well no. A, RGL, Chennai).

3.3.2. Well No B:

Well was drilled down to 3902m to explore the lower part of Andimadam formation and terminated as dolerite was encountered between 3561-3902+m. Andimadam formation (2752-3561m) consists of alternations of sandstone with thin laminae of shale. Organic matter richness (TOC 0.23-2.87%, Avg. TOC 1.63%) is found to vary from poor to good. Hydrocarbon generation potential (S_2 0.11-4.82 mg HC/ g of rock, Avg. S_2 1.49 mg HC/ g of rock) is found to be poor to fair in the studied samples (FAR Report, 2011**;** well no. B, RGL, Chennai).

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3.3.3. Well No C:

The location was drilled to 4611m to explore the hydrocarbon potential of Andimadam formation and Pre-Rift sediments in Perungulam area of Ramnad sub basin. Andimadam formation

(3301-4616+m) consists of alternations of calcareous sandstone and carbonaceous shale with dolerite intrusion. Organic matter richness is found to vary from poor to excellent (TOC 0.02 – 8.87% Avg. TOC 1.77%), with poor to fair residual hydrocarbon generation potential (S_2 values 0.01-4.19mg HC/g rock, Avg. S_2 1.05 mg HC/g rock) (FAR Report, 2010**;** well no. C, RGL, Chennai).

4. Methods and Materials:

ASTM Standard D2798-99 & D2799-99 (Test Method for Microscopical Determination of the Maceral Composition of Coal) was adopted using. Fluorescence Microscopic system-Leica DM 6000M with photomultiplier combination.The reflectance measurements are made by, illuminating a polished surface of a section of sample under incident white light using an immersion oil with a refractive index of 1.518, at a wavelength of 546 nm. The samples are also examined in ultra-violet light in order to determine the composition and colour of the fluorescent material present in them. For maturation studies, the reflectance of the vitrinite particle of an optical glass standard with known reflectance (0.58, 1.3 & 3.1 Refractive Index) of a similar order to that of the sample were used. The colour of certain liptinite macerals in ultra-violet light can be related to the thermal maturity of the sample (Jagdish Pandey et al., 1991**:** Standard laboratory Techniques and procedures in Geology).

5. Results & Discussion:

Hydrocarbons begin to be generated above the temperature threshold of 60°C. This process, where peats and lignites become dehydrated and lose other volatiles and kerogen splits into its four distinctive types is known as the 'carbonization jump'. The 'oil window' lies between temperatures of ~ 60-120°C; the gas window between ~ 120-150°C. At temperatures greater than 150°C, the organic matter is said to be post mature and is no longer reactive to the development of hydrocarbons. At temperatures of 200°C, organic compounds are reduced to graphite and methane. In general, there is an empirical relationship between vitrinite reflectance and hydrocarbon generation (Tissot et.al., 1985) Ro% of 0.5 to 1.5 is oil generation, Ro% of 1.5 to 3 is gas generation, and over Ro% 3.0 is all graphite (an end product of organic matter which no longer can generate hydrocarbons).

Organic matter is generally needs to be stored, in the sediment under anoxic conditions, in the form of peat, coal, organic shales and dispersed organic matter (DOM). Maceral, a basic OM particle in source rock is chemically heterogeneous and changes colour from green to yellow to orange to red to dark brown to black with increasing temperature. The differences in maceral composition will inevitably lead to different types of organic matter. Kerogen is complex agglomerate of macerals, which can be petrographically characterized in a way similar to the classification of coals. This leads to the concept of classifying kerogen as types from I to IV (Tissot-Welte) based on the presence of macerals.

5.1. Present study

The compositional data of various macerals, from selected depth intervals in the wells A, B & C are shown in Table 2 & 3 and plotted in the Ternary diagram (Fig. 5 & Fig. 6).

In the well **A**, seven cutting samples in the interval 3200-3900m and three samples from core (CC-1) in the interval 2907-2913.59m were studied. In the well **B**, seven cutting samples in the interval 2750-3540m were studied. Additional two cutting samples (3550-3750 & 3750-3900m) were also taken up to know the dolerite intrusion effect on the macerals. Core sample in this well could not be taken up due to dolerite content in the core. In the well **C**, thirteen cutting samples in the interval 3300-4500m and three core samples from CC-1 in the interval 4370-4375.49m were studied.

The maceral distribution (Table 2 & Table-3) in the studied wells was found as; the liptinites (2.02-54.75%, 07.00-39.43% & 7.98- 59.48%), vitrinites (38.55-86.79%, 15.57-89.54% & 17.18-73.14%) and inertinites (06.04-27.70%, 3.44-70.05% & 3.28-66.96%). Further the breakup of liptinite maceral composition shows the dominance of resinite (13.73 – 97.17%, 48.50-87.79% & 35.78 - 97.39%) and sporinite bodies (2.83 – 81.41%, 12.21-51.50% & 2.61-62.32%) besides presence of alginite in few samples (5.71-13.66%, 1.06- 6.58% & 0.33-24.81%).

Composite macerals distribution pattern in Ternary plot (Fig. 5) shows dominance of vitrinite over other two macerals (liptinite and inertinite) indicating main contribution of the terrestrial organic matter (type III) in all three wells. This suggests that the sediments in all these wells have proclivity to generate gaseous hydrocarbons and very low liquid hydrocarbons. Further, the distribution of Liptinite macerals pattern (Fig. 6) indicates that the contribution from resinite and sporinite is dominating in all the three wells. This suggest that organic matter input has major contribution of terrestrial organic matter (Type-III) and minor contribution of marine/lacustrine (Type-II, I) organic matter input in all the three wells.

Van Krevelen diagram (Fig. 8), based on the elemental analysis (Table-3), exhibits that the organic matter in the studied wells fall along the type III kerogen pathway suggesting its origin from land plants. The cross plot of H/C vs. depth & O/C vs. depth (Fig. 9.1 & 9.2) exhibits the depletion of hydrogen & oxygen content and increase in carbon content with the increase in depth due to thermal maturation effect. This suggests that the studied sediments of the wells A,B & C have low oil and gas generative potential.

In order to define various macerals findings (Fig. 2,3 & 4) for better understanding the well wise observations are discussed in detail below:

5.2. Well wise distribution of macerals:

5.2.1. Well No A:

Albian (2875-3200m):

Based on the macerals compositional data on available core (CC-1; 2907-2913.59m), in this age, oil prone organic matter (type II) from liptinites was found to be 42.74%. Whereas the dominant gas prone organic matter from vitrinites (type-III) 49.75% & organic matter (type-IV) which does not generate hydrocarbons (inertinites) were found to be 7.51%. This suggests that Albian sequence in Well No A has type-II & III organic matter. Out of 42.74% oil and gas prone organic matter, contribution from type II has been observed as 40.79% (24.88% from resinite and 15.91% from sporinite bodies). The low contribution of 1.95% from alginitic bodies (marine/lacustrine source) indicates that terrestrial input has mainly contributed in this sequence.

(0.72 to 0.73; Avg - 0.72) indicates that the organic matter in this sequence has entered into peak oil generation stage. The onset of gas window (gas generation from gas prone organic matter) is beyond Ro% 1.3 value. Hence about 49.75% of gas prone organic matter (type III from vitrinites) has not yet generated hydrocarbons.

Kimmeridgian & Tithonian of Late Jurassic (3200-4225m)

In this studied sequence (3200-3890m) of Well No A, dominant gas prone organic matter from vitrinites (type III) is 72.62%, whereas oil and gas prone organic matter (type-II from liptinites) was found to be 9.64% and inertinites (type-IV) was found to be 17.74%. This suggests that Kimmeridgian & Tithonian sequence in Well No A has dominantly type-III organic matter contribution with minor inclusion of marine or lacustrine (type II) input. Out of 9.64% oil prone organic matter liptinites, contribution from terrestrial input has been observed as 9.56% (6.24% from resinite and 3.32% from sporinite bodies). Beside this the very low contribution of 0.08% from alginitic bodies has been observed which may have originated from marine or lacustrine source.

The VRo % (0.78 to 1.01; Avg. - 0.87) indicates that the sediments in this sequence are mature and have attained peak oil generation stage. The marine/lacustrine (type-II) organic matter, i.e. about 0.08% alginites have generated oil and gas up to its fullest extent and little remaining generation potential is left over in this source. The sudden increase in reflectivity value (Ro %) from 0.86 to 0.98 between 3600m to 3800m (Fig. 7) shows the thermal intrusion effect on the sediments. In the intrusive section of KJ-8, liptinites percentage is found to be lowest as compared to vitrinites and inertinites.

5.2.2 Well No B:

Turonian and Older Age of Cretaceous (2385-3561m):

In Turonian and Older sequence (2385-3561m) of Cretaceous age in well no B, the cutting samples from interval (2750-3540m) oil prone (type II) organic matter from liptinites was found to be 24.59% only, whereas gas prone organic matter (type-III) from vitrinites is 53.46%. Inertinites (type-IV) were found to be 21.95%. This indicates organic matter in this well dominantly contributed by type III organic matter.

Further breakup of oil prone liptinite macerals (24.59%) shows that resinites 15.68% and sporinites 8.64%, indicating the dominance of terrestrial organic matter over marine/lacustrine organic matter, which is only 0.27% (alginites) in liptinites. However, presence of exsudatinite in few samples only indicates that the sediments have very low potential to expel hydrocarbons (remaining hydrocarbons generation potential) as compared to wells A and C. The sediments in this well have entered into oil window but have not yet attained maturity level as indicated by the VRo% range (0.55-0.68%, Avg- 0.60%).The sudden increase in reflectivity value (Ro %) from 0.68 to 0.81

between 3540m to 3750m (Fig.-7) shows the thermal intrusion effect on the sediments. In the intrusive section of well no B liptinites are found to be absent.

5.2.3. Well No. C:

Albian (3175-3325m):

In this sequence of well no C dominant oil and minor gas prone (type-II) organic matter from liptinites was found to be 54.88% whereas gas prone organic matter (type-III) from vitrinites was found to be 41.84% and organic matter which does not generate hydrocarbons (type-IV from inertinites) was 3.28%. This suggests Albian (3175-3325m) sequence in well no C has mixed organic matter (type-II & III).Out of 54.88% oil and gas prone (type II) organic matter, terrestrial contribution has been observed as 41.27% (30.82% from resinite and 10.45% from sporinite bodies). The significant contribution of 13.62% from alginitic bodies may be originated from marine or lacustrine source. In this sequence, among Liptinites macerals (type-II), terrestrial organic matter (resinites & sporinites) is dominating over marine/lacustrine organic matter. Maturity data (Avg Ro% 0.62) indicates that the sediments in this sequence have entered into oil window but not yet attained the peak oil generation stage.

Tithonian (3325-4075m):

Based on the macerals composition (Fig.3 &Table 2-3) of the Tithonian sediments, dominant gas prone (type III) organic matter from vitrinites was found to be 54.95% whereas oil and gas prone organic matter from liptinites (type-II) was found to be 37.37% and organic matter (type-IV) which does not generate hydrocarbons (inertinites) was found to be 7.68%. Out of 37.37% type-II organic matter from liptinites, contribution from terrestrial organic matter has been observed as 36.81% (29.04% from resinite and 7.77% from sporinite bodies). The very small contribution of 0.56% from alginitic bodies may be originated from marine or lacustrine source. This suggests that Tithonian sequence in this well has dominance of terrestrial organic matter (type-III) over marine/lacustrine organic matter in this sequence.

Maturity range from 0.64 to 0.75 Ro% (Avg. Ro% - 0.70) indicates that the sediments in this sequence of well no C have just attained peak oil generation stage at 3700m for marine/lacustrine organic matter, i.e. for about 0.56% (alginites) and prior to that the sediments are in the early stage of oil generation for terrestrial organic matter, which is about 36.81% % (resinites & sporinites). Further, it is evident from Ro% values that vitrinite macerals (type-III) has not yet attained the onset of oil generation.

Kimmeridgian (4075-4610m)

In this sequence of well no C, dominant gas prone (type-III) organic matter from vitrinites was found to be 50.28% whereas oil and minor gas prone organic matter from liptinites (type-II) was found to be 29.19% and type-IV organic matter (inertinites) was found to be 20.53%. Out of 29.19% oil and gas prone organic matter terrestrial input contribution has been observed as 28.15% (14.20% from resinite and 13.95% from sporinite bodies). As compared to resinitic and sporinitic bodies, alginites of marine or lacustrine origin are considerably low (1.05%). This indicates the dominance of terrestrial organic matter (type-III).

Maturity range from 0.81-0.99 Ro% (Avg. Ro% - 0.87) indicates that the sediments in this sequence are mature and have attained the peak oil generation stage. The sudden increase in reflectivity value (Ro %) from 0.91 to 0.99 between 4490m to 4590m (Fig. 7) shows the thermal intrusion effect on the sediments. Presence of fair amount of exsudatinite with fluorescence was also observed which is yet to expel hydrocarbons (remaining hydrocarbons generation potential). All the core samples also exhibits dominance of terrestrial organic matter (type III) which has attained the peak oil generation stage (Avg. Ro% - 0.86) in this interval. Absence of alginites in these sediments indicates least possibility of marine or lacustrine input inclusion.

5.3. Elemental Analysis Studies:

Based on the elemental Analysis, atomic ratios H/C and O/C versus depth were plotted on the Van Krevelen diagram (Fig. 8).

Atomic ratios H/C and O/C:

The major contribution is from gas-prone Type-III kerogen as indicated by H/C ratio ranges from 0.54-0.84 (avg-0.71) in well A, 0.56-0.86 (avg-0.74) in well no B and 0.53-0.78 (avg-0.65) well no C (Table 4). The maturity indicators shows that majority of the samples of all three wells are falling towards left side on the Van Krevelen diagram (Fig. 8) and have attained the peak maturation stage. The presence of low quantity of sulphur in all the studied samples (0.21-0.76 in well **A** & 0.51-0.72 in well B and 0.51-1.08 in well C by wt %) indicates the oxidising environment of deposition of the sediments with inclusion from terrestrial organic matter. The low quantity of alginites (mainly *Botryococcus*) in all three wells A, **B** & C also indicates towards contribution of lacustrine input (type-III) over lacustrine /marine input (type I/ II).

Since in our studies the cross plot of H/C vs. depth & O/C vs. depth (Fig. 9.1 & 9.2) exhibits the depletion of hydrogen & oxygen content and increase in carbon content with the increase in depth due to thermal maturation effect. This suggests that the studied sediments of the wells wells A, **B** & C are more gas prone have low oil and gas generative potential (Van Krevelen, 1961; Stach et. al. 1982; Tissot et al. 1974; Jones and Edison 1978).

6. Conclusions:

Based on the macerals identification and compositional data of Well No A,B & C following conclusions were made:

- Distribution of macerals exhibits dominance of vitrinites over liptinites and inertinites indicating dominance of terrestrial organic matter (Type-III) in all three wells A,B and C.
- Distribution of liptinites macerals also exhibits dominance of resinites and sporinites over alginites. This indicates that the organic matter has been contributed mainly by terrestrial input (Type-III) in all the studied wells.
- The VRo profile of all the studied wells clearly exhibits the increase in VRo% value and inertinite percentage in the interval of dolerite intrusion (intrusion:3763-3804m in A, 3443-3445, 3532-38m and 3564-3902m in B and 4524-4555m in C).
- Elemental analysis studies based on H/C and O/C ratio indicates and further validates that the organic matter in all the three wells have been contributed mainly by terrestrial input (Type-III). The increase of H/C and O/C with depth and increase of VRo with depth also corroborates each other.
- The presence of small amount of alginites (Type-I and II) indicates low contribution from marine/lacustrine organic matter input in these wells.
- Low-Fair amount of exsudatinite (pre-cursor of oil) has been observed in the studied sequences of all the wells, which indicates significant quantity of the yet to expel hydrocarbons (remaining hydrocarbons generation potential).

Acknowledgements:

We thank Mr. R.K. Khanna, ED-Basin Manager-Cauvery Basin for his patronage and full support. We acknowledge the guidance and keen interest rendered by Dr. B.G. Goswami, GM-Head-RGL. We thank the Group in-charges Geology Dr. B.C. Jaiprakash, GM (Geol.) and Chemistry Subramanyam Bhatt, GM (Chem) for their help provided during the completion of project. We thank Mr. P. K. Nag, DGM (Chemistry) and Mr HS Aswal, DGM (Geology) for their valuable suggestions during the study. Authors are thankful to Mrs. P. Neeraja, GM (Chemistry)-Head Geochemistry, KDMIPE, Dehradun, and her team for providing elemental analysis data required for supporting the study. Special thanks to Mr. P. Kalaiarasu, JTA (Chem) for providing analytical support during the course of study.

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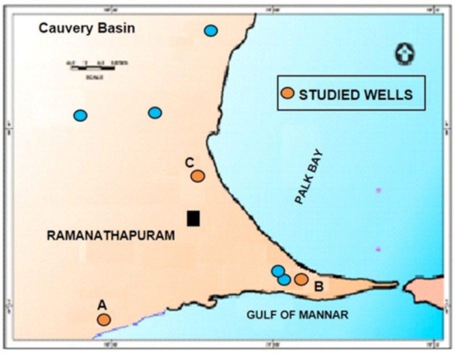

Fig.-1:Location Map of Svtudied Wells

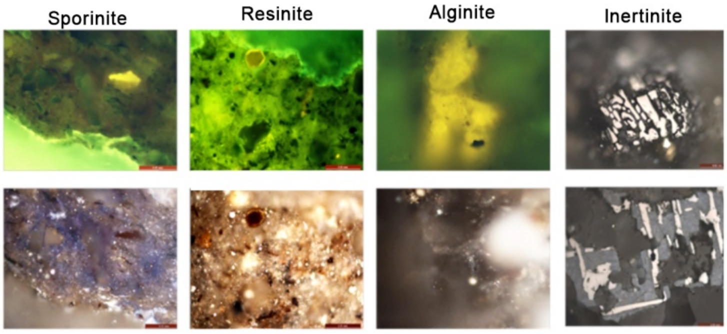

Fig.-2:Macerals observed in Well No. A,CC-1 2907-2913.09m

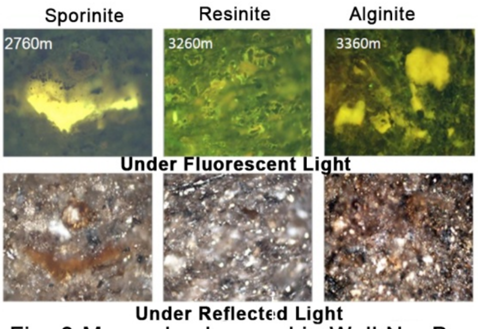

Fig.-3:Macerals observed in Well No. B

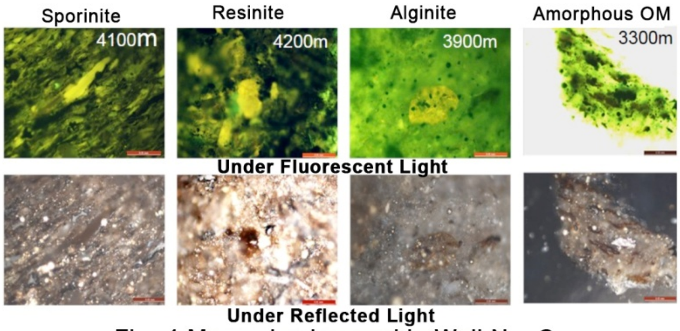

Fig.-4:Macerals observed in Well No. C

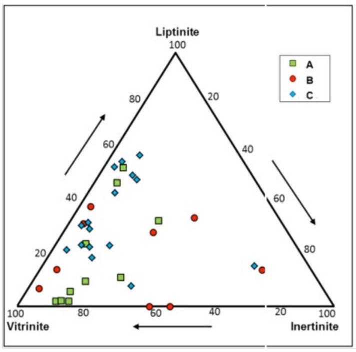

Fig.-5:Ternary Diagram of All Macerals Distribution in Well No. A,B & C

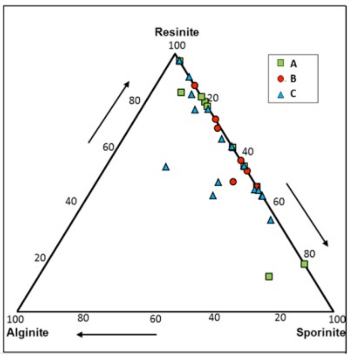

Fig.-6:Ternary Diagram of Liptinite Macerals Distribution in Well No.A,B & C

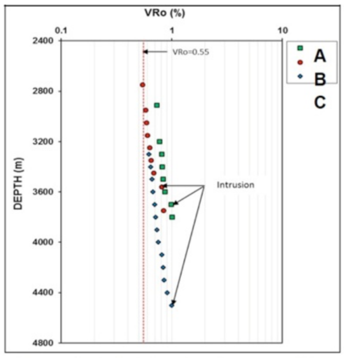

Fig.-7:VRo Profile of Well No.A,B & C

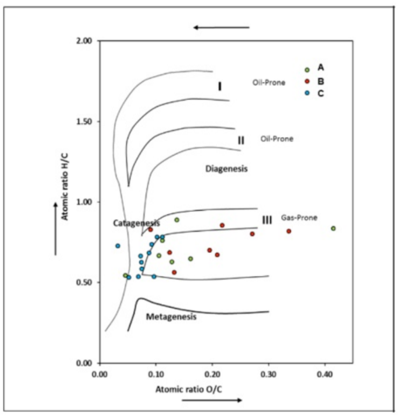

Fig.-8:Van Krevelen diagram showing maturation path of OM in Well No. A,B & C

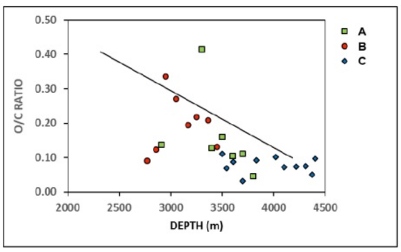

Fig.-9.1:Cross Plot of Depth vs O/C ratio of Well No. A,B & C

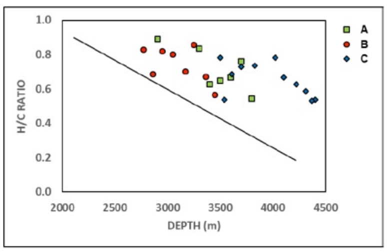

Fig.-9.2:Cross Plot of Depth vs H/C ratio of Well No. A,B & C

A			B			C		
Depth		Age	Depth		Age	Depth		Age
GL-320		Post Middle Miocene				GL-270		Post Middle Miocene
320-415		Early-Middle Miocene	200-390		Post early-Middle Miocene	270-450		Early-Middle Miocene
415-535		No fauna Oligocene-Late Eocene	390-610		Early-Middle Miocene	450-600		Middle Eocene
535-860		Middle Eocene	610-640		No fauna (Middle Eocene-Oligocene?)	600-1050		No fauna
860-1445		Early Eocene	640-1100		Middle Eocene	1050-1300		Early Eocene
1445-1705		Early-Late Paleocene	1100-1365		Middle Eocene	1300-1544		Late Paleocene
1705-1775		Maastrichtian	1365-1870		Early Eocene	1544-1575		Early Paleocene
1775-1940		Campanian	1870-2000		Paleocene	1575-1740		Maastrichtian (Late-Middle)
1940-2225		Coniacian-Santonian	2000-2045	Cretaceous	Early Mastrichtian	1740-1880		Campanian-Early Maastrichtian
2225-2675		E-Mid Turonian	2045-2200		Campanian	1880-2700		Santonian
2675-2875		Cenomanian	2200-2300		Santonian	2700-3050		Turonian
2907-2913		CC-1 No fauna	2300-2385		Cenomanian-Turonian	3050-3175		Cenomanian
2875-3200		Albian	2385-2500		Agglutinated forms	3175-3325		Albian
3200-4225	Late Jurassic	Tithonian+ Kimmridgian	2500-3561		No index fauna	3325-4075	Late Jurassic	Tithonian
			3561-3902		Dolerite	4075-4610		Kimmridgian

Table-1: Age boundaries of studied wells
(Source: FAR Report,RGL Chennai)

Sl. No.	Depth (m)	Age	Formation	Macerals Composition			VRo Profile		
				Liptinite (%)	Vitrinite (%)	Inertinite (%)	Min (%)	Max (%)	Avg. (%)
KJ-8									
1.	CC-1,2907-	Upper Cretaceous	Sattapadi	48.73	44.09	7.18	0.56	0.85	0.72
2.	CC-1, 2907-			24.73	65.94	9.32	0.58	0.88	0.73
3.	CC-2, 2907-			54.75	39.21	6.04	0.58	0.88	0.73
4.	3200-3300			33.75	38.55	27.70	0.65	0.94	0.78
5.	3300-3400		Satpadi/Ad	2.02	86.79	11.19	0.73	0.96	0.81
6.	3400-3500	Lower Cretaceous	Andimad am	2.26	85.04	12.70	0.73	1.00	0.82
7.	3500-3600			5.94	80.25	13.81	0.73	0.98	0.83
8.	3600-3700			9.95	73.47	16.58	0.71	1.01	0.86
9.	3700-3800			11.52	61.58	26.90	0.79	1.27	0.98
10.	3800-3900			2.06	82.65	15.29	0.85	1.33	1.01
AG-1									
11.	2750-2840	Cretaceous	Satpadi/Ad	14.58	80.20	5.22	0.45	0.67	0.55
12.	2950-3040			7.00	89.54	3.46	0.48	0.71	0.58
13.	3050-3140			39.43	57.13	3.44	0.49	0.71	0.59
14.	3150-3240			32.72	62.65	4.62	0.50	0.72	0.60
15.	3250-3340			34.87	26.67	38.46	0.50	0.74	0.63
16.	3350-3440			29.14	42.48	28.38	0.51	0.76	0.65
17.	3450-3540			14.37	15.57	70.05	0.54	0.83	0.68
18.	3550-3750			0.00	51.79	48.21	0.62	1.13	0.81
19	3750-3900			0.00	58.22	41.78	0.64	1.31	0.84
PE-8									
20.	3300-90	Lower Cretaceous	Andimadam	54.88	41.84	3.28	0.48	0.79	0.62
21.	3400-90			56.96	38.30	4.74	0.50	0.83	0.64
22.	3500-90			23.39	65.46	11.14	0.51	0.89	0.66
23.	3600-90			24.26	67.52	8.22	0.52	0.88	0.68
24.	3700-90			59.48	31.60	8.92	0.53	0.89	0.70
25.	3800-90			30.48	61.86	7.66	0.54	0.93	0.71
26.	3900-90			22.34	73.14	4.52	0.54	0.94	0.73
27.	4000-90			44.64	46.79	8.57	0.55	0.98	0.75
28.	4100-90			33.04	61.05	5.91	0.62	0.97	0.81
29.	4200-90			49.89	37.25	12.86	0.64	1.01	0.83
30.	4300-90			23.94	58.78	17.28	0.66	1.14	0.85
31.	CC-1, 4370-75.02			19.28	66.65	14.06	0.66	1.11	0.86
32.	CC-1, 4370-			7.98	59.97	32.04	0.69	1.16	0.86
33.	CC-1, 4370-			31.82	63.70	4.48	0.70	1.13	0.86
34.	4400-90			51.72	37.66	10.62	0.69	1.16	0.91
35.	4500-90			15.85	17.18	66.96	0.72	1.17	0.99

Table-2: All Maceral composition of sediments from Studied wells

Sl. No.	Depth (m)	Age	Formation	Macerals Composition			VRo Profile		
				Liptinites					
				Resinite (%)	Sporinite (%)	Alginite (%)	Min (%)	Max (%)	Avg. (%)
KJ-8									
1.	CC-1,2907-	Upper Cretaceous	Sattapadi	13.73	72.61	13.66	0.56	0.85	0.72
2.	CC-1,2907-			63.75	36.25	0.00	0.58	0.88	0.73
3.	CC-1,290713.592			97.17	2.83	0.00	0.58	0.88	0.73
4.	3200-3300			81.35	18.65	0.00	0.65	0.94	0.78
5.	3300-3400		Sattpadi/Adm	18.59	81.41	0.00	0.73	0.96	0.81
6.	3400-3500	Lower Cretaceous	Andimada m	79.76	20.24	0.00	0.73	1.00	0.82
7.	3500-3600			56.39	43.61	0.00	0.73	0.98	0.83
8.	3600-3700			83.33	16.67	0.00	0.71	1.01	0.86
9.	3700-3800			85.03	9.26	5.71	0.79	1.27	0.98
10	3800-3900			48.65	51.35	0.00	0.85	1.33	1.01
AG-1									
11	2750-2840	Cretaceous	Sattpadi/Adm	50.55	42.88	6.58	0.45	0.67	0.55
12	2950-3040		Andimadam	58.71	41.29	0.00	0.48	0.71	0.58
13	3050-3140			71.27	27.67	1.06	0.49	0.71	0.59
14	3150-3240			48.50	51.50	0.00	0.50	0.72	0.60
15.	3250-3340			74.66	25.34	0.00	0.50	0.74	0.63
16	3350-3440			54.78	45.22	0.00	0.51	0.76	0.65
17	3450-3540			87.79	12.21	0.00	0.54	0.83	0.68
18	3550-3750			0.00	0.00	0.00	0.62	1.13	0.81
19	3750-3900			0.00	0.00	0.00	0.64	1.31	0.84
PE-8									
20	3300-90	Lower Cretaceous	Andimadam	56.16	19.03	24.81	0.48	0.79	0.62
21	3400-90			47.48	51.43	1.09	0.50	0.83	0.64
22	3500-90			67.00	31.18	1.81	0.51	0.89	0.66
23	3600-90			78.38	17.12	4.49	0.52	0.88	0.68
24	3700-90			78.46	21.21	0.33	0.53	0.89	0.70
25	3800-90			97.39	2.61	0.00	0.54	0.93	0.71
26	3900-90			84.20	13.13	2.67	0.54	0.94	0.73
27	4000-90			91.07	8.93	0.00	0.55	0.98	0.75
28	4100-90			45.14	54.86	0.00	0.62	0.97	0.81
29	4200-90			50.30	38.47	11.23	0.64	1.01	0.83
30	4300-90			35.78	62.32	1.90	0.66	1.14	0.85
31	CC-1, 4370-75.02			64.15	35.85	0.00	0.66	1.11	0.86
32	CC-1, 4370-			56.58	43.42	0.00	0.69	1.16	0.86
33	CC-1, 4370-			44.87	55.13	0.00	0.70	1.13	0.86
34	4400-90			45.02	39.39	15.59	0.69	1.16	0.91
35	4500-90			47.23	52.77	0.00	0.72	1.17	0.99

Table-3: Liptinite composition of sediments from Studied wells

Sl. No.	Depth (m)	Elemental composition % (wt)					Atomic ratio	
		N	C	H	O	Total S (org+ Inorg)	O/C	H/C
KJ-8								
1.	CC-1, 2907T1	1.01	29.61	2.21	5.41	1.21	0.14	0.89
2.	CC-1, 2907T3	0.33	6.54	0.55	3.08	0.09	0.35	1.00
3.	3300	0.50	12.26	0.87	6.53	0.21	0.40	0.84
4.	3400	1.12	46.86	2.48	7.98	0.70	0.13	0.63
5.	3500	1.85	48.31	2.64	10.37	0.49	0.16	0.65
6.	3600	0.76	32.38	1.82	4.53	0.76	0.11	0.67
7.	3700	1.29	47.26	3.03	7.02	0.67	0.11	0.76
8.	3800	0.35	12.26	0.57	0.74	0.28	0.05	0.55
AG-1								
9.	2770	1.05	39.55	2.75	4.77	0.55	0.09	0.83
10.	2860	0.99	41.78	2.41	6.89	0.68	0.12	0.69
11.	2950	1.00	39.66	2.73	17.77	0.55	0.34	0.82
12.	3050	0.96	34.47	2.32	12.45	0.72	0.27	0.80
13.	3170	1.08	43.68	2.57	11.37	0.68	0.20	0.70
14.	3250	0.99	36.78	2.64	10.66	0.72	0.22	0.86
15.	3365	0.86	32.57	1.84	9.04	0.57	0.21	0.67
116.	3450	1.04	50.93	2.41	8.96	0.51	0.13	0.56
PE-8								
17.	3500	1.19	37.96	2.50	5.63	0.63	0.11	0.78
18.	3540	0.74	25.07	1.13	2.29	1.08	0.07	0.54
19.	3610	1.20	37.34	2.15	4.36	0.63	0.09	0.69
20.	3700	0.92	29.02	1.78	1.22	0.56	0.03	0.73
21.	3830	0.85	25.46	1.58	3.12	0.53	0.09	0.74
22.	4020	1.49	47.88	3.14	6.49	0.64	0.10	0.78
23.	4100	1.34	49.72	2.78	4.79	0.75	0.07	0.67
24.	4220	1.43	51.85	2.73	5.09	0.68	0.07	0.63
25.	4310	1.60	52.78	2.59	5.27	0.63	0.07	0.59
26.	4400	1.49	51.76	2.34	6.65	0.62	0.10	0.54
27.	4370	1.38	57.55	2.57	3.94	0.51	0.05	0.53

Table-4: Elemental Analysis data of sediments from Studied wells