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Hydrocarbon Prospectivity of Indian Sedimentary Basins-A Review

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ABSTRACT

Twenty six sedimentary basins have been recognized in India with an aerial extent of about 3.14million sq. km. covering onland and offshore. These sedimentary basins have been classified earlier into four categories depending upon their degree of hydrocarbon prospectivity. About 22% of the area of the four has been commercially well explored, 66% of the area comprises of non-commercially productive zones (either poorly explored or exploration has just initiated) and the balance 12% has been totally unexplored (no data has been acquired till now). This review systematically analysed the major constraints responsible for the lack of commercial production by comparing the Indian sedimentary basins with similar analogous basins of the world.

In order to enhance the energy security of the country, frontier basins of India need to reinvigorate the exploratory effort with improved geo-scientific understanding of the basins with advanced technologies. Advanced Seismic and Enhanced Oil Recovery (EOR) techniques are being used in analogous basins that can be adopted in similar geological provinces of Indian basins to convert non-commercial basins to commercial basins. The recent advances in geo-scientific understanding of these basins, role of non-conventional petroleum systems and development of frontier technologies are going to play critical role in identifying new petroleum provinces. In national scenario, maximum thrust is placed on frontier basin exploration including deep sea acreages. The problem need to be tackled by using advanced technologies in seismic data acquisition as well as processing for thrust-fold belts. Improved methods of interpretation of geophysical data should be used. Advanced technologies should be widely used for identification of suitable source facies and area with effective source rock development.

Introduction

Significant forward steps have been taken in exploring the hydrocarbon potential of the sedimentary basins of India for last twelve years by Directorate of Gas Hydrocarbons (DGH), Government of India. Hence the unexplored area has come down to 12-15% which was 50% in 1995-96.Most of the present production comes from the young passive margin and rift type of basins (mostly Tertiary), whereas the other basins including compressional fold thrust belt and fore-deeps (Himalaya, Ganga/ Punjab) and older rift basins (Proterozoic, Gondwana) are yet to be fully explored (Jokhan Ram, 2005). Integration of new set of data coupled with regional concepts have redefined the exploration frontiers which are more complex and challenging. A revisit to the concepts of plate tectonics in conjunction with bold ideas and innovative technology clearly suggests that deep and ultra-deep-water plays are the future frontiers of Indian petroleum search (Rabi Bastia, 2010). The petroliferous basins of peninsular India, such as Cauvery, Krishna-Godavari, Mahanadi, Barmer, Cambay, off-shore regions of Bombay, Saurashtra, and Kutch are invariably having thick units of Basalt, interlayered with sediments ranging from the beginning to the end of the Cretaceous period (Misra K S and Misra A, 2013).Pericratonic rift basins and aulacogens formed in divergent set up are favourable locales for generation and accumulation of oil and gas, e.g., Niger, Gabon, Chad, Angola shelf and Syrte basin of Africa, Campos basin of Brazil, Gulf of Mexico and Atlantic Margin basins of US etc. (Biswas S K,1999).

Methodology

The pie-chart (Figure 1) depicts that only 22% of the Indian Basinal area is explored very well, whereas 44% of the total area is under initial exploration stage but still there is 34% of the total area left which is either poorly explored or totally unexplored.Depending on the degree of hydrocarbon prospectivity, twenty six sendimentary basins have been classified into four catagories (Figure 2).

Features of the Category I basins (proven commercially productivity)

Assam Basin:

Located in North-Eastern India, Eastern part of Bangladesh, and Western part of Myanmar. Sediment thickness is nearly 7000 metres. Upper Paleocene – Lower Eocene; and Barails (Oligocene) are the significant source with Type II OM in Carbonaceous Shale with thick coal seam at a depth 2400 – 3500 m. Fractured Precambrian Basement (Borhola), Paleocene & Eocene Sandstone, Oligocene – Miocene (Barail Siltstone and Tipam Siltstone) are the main pay zones. Migration is primarily up-dip, along the Northeast-trending slope of the Assam Shelf. Mostly anticlinal structures affected by ENE – WSW & NNE – SSW faults act as traps with some stratigraphic features like lenses and channel type sand bodies. Assam oils are normal gravity (range: 15-58°API, avg: 300) with significant wax content (0.11-22%, avg. 11.5%), low sulphur content and are generally moderately mature. (Pahari et.al., 2008)

Krishna Godavari Basin:

A continental passive margin pericratonic basin which came into existence following rifting along eastern continental margin of Indian Craton in early Mesozoic. Potential source rocks in this basin are Bantumilli graben – Krishna/ Golapalli formation and Gajulapadu Shale deposited in marginal marine environment. Reservoir rocks are from Permian to Pliocene age and are mainly clastic reservoirs with few local Carbonates and volcanic reservoirs. Hydrocarbons trapping regions are in Lower Gondwana which are local red clay beds and in Late Jurassic to Upper Cretaceous, Raghavpuram Shale and Basaltic trap act as hydrocarbon seals. General characteristics of crude from the Ravva field includes an avg. API of 36o, Sulphur content of 0.1%, Pour point of +30o C and distillate yield of 61%. (Mishra & Unnikrishnan, 1996)

Cauvery Basin:

Cauvery basin developed during the break-up of Gondwana land and underwent four phases of deformation in four different age first one being in Late Jurassic / Early Cretaceous where syn-rift extension took place and the second change took place in Late Cretaceous where rift / early drift stage cooling contraction happened and this contraction was followed by Late Cretaceous – Palaeogene drift stage strike slip reactivation and finally in Neogene age passive margin subsidence concluded the series of changes. These basins show alternating NE – SW trending narrow basement ridges and wide depression (troughs) and has sedimentary fill of more than 6,000 m (Permian – Recent age). Main hydrocarbon generating centres are located around Trikadiyur in Tranquebar depression, Orthanadu in Tanjore depression and Thevur in Nagapattinam depression. Oil/gas accumulations occur in fractured basement sandstones (Cretaceous to Oligocene).Main reservoirs are Sandstone deposited in Shelf environment. Each of the sub-basin has their local cap rock and this basin has both structural and combinational traps. Organic matter in the region is mainly Type III which depicts an anoxic transgressive environment. General characteristics of crude from the Narimanam field include and avg. API of 46o, Sulphur content of 0.1% and distillate yield of 80% (Mishra & Unnikrishnan, 1996).

Cambay Basin:
It is an intracratonic basin in the form of N – S (NNW – SSE) trending graben flanked in the east by Aravalli and Deccan Plateau and in the West by Saurashtra plateau which have mainly clastic sediments ranging from Eocene to recent deposits. Basin is almost covered with Sabarmati alluvium, and alluvium of Mahisagar, Dadhar, Narmada, and Tapti rivers. Shallower towards north, 8000m thick tertiary sediments overlie the Deccan Trap. It is a mature basin with multiple generative depressions and multiple source rocks at various maturity levels. As a result, different types of oil occur in different parts of the basin. It has dominant terrestrial organic matter input with Type III Kerogen in oxic environment of deposition. Major source rocks include thick Cambay Shale, Kalol Formation, top and base of Olpad Formation. Main reservoir rocks are Sandstone and Siltstones in Ankleshwar, Kalol, and Kadi Formation with a few subsidiary reservoirs in fractured Coals, Shales, & Siderite Marls. Tarapur Shales (Upper Eocene – Oligocene) in North Cambay, Telwa & Kanwa Shales (Middle Eocene – Oligocene) & the Shales intercalated with Siltstone in Dadhar Formation played the major role as cap rocks. Significant structural traps are faulted anticlinal structures, fault traps, tilted fault blocks and narrow fault controlled horst blocks. General characteristics of North Gujarat crude includes an avg. API value of 28o, Sulphur content of 0.1%, Pour point +27oC, distillate yield low 33-35% and high organic acidity (Mishra & Unnikrishnan, 1996).

Rajasthan Basin:
It is pericratonic basin which forms the Eastern flank of Indus geosyncline with an average sediment approximate thickness of 5000 m. It is further categorised mainly into three sub-basins which are separated from each other by basement ridges/faults. These include Jaisalmer, Bikaner-Nagaur, and Barmer-Sanchor as sub-basins. The tectonic evolution of Rajasthan Basin took place in four distinct phases corresponding to Precambrian Triassic plate movement, breaking of Indian Plate from southern continent during Jurassic, collision of Indian Plate with the Asian Plate from Eocene onwards, Uplift of Sind-Baluchistan fold belt resulting in filling up of the Indus shelf. Major source rocks includeCambay & Tharad Shale of Barmer- Sanchor sub basin (Permian Jurassic to Cretaceous), Palaeozoic Limestone. Major pay zones are the Barmer & Tharad Siltstone, Carbonate reservoirs in Cambrian to Palaeocene sequences. Intra-formational Shale and tight Limestone are the main cap rocks with structural highs and fault closures as major structural traps. Average TOC content varied between 1-10 wt.% for different aged source rocks with Type II and III Kerogen. The oil from Mangla field is waxy crude with API value varying from 25-30o and sulphur content is less than 0.2 % (Bharani Raj and Sayantan Bhattacharya, 2012).

Reasons for lack of commercial production from some Indian Frontier Basins:

- The Upper Vindhyan (Category III) has dominantly arenaceous sequence, therefore no petroleum system is visualised in it. The main constraints observed in the basin are poor reservoir facies development. But source rocks comprising, Lower Vindhyan Shales, particularly, Hinota and Pulkova Shales with organic carbon contents of upto 3.89% and 1.86% respectively are considered to be having good potential as source rocks. From hydrocarbon point of view, Cuddapah basin (Category IV) has so far been poorly studied and understood. The Carbonaceous Shales of the Vempally Formation record a maximum of 0.24 % of TOC. The source rocks in the basin are in late catagenic or metagenic stage and thus generation of only methane gas is expected.
- In the Kaladgi Basin (Category II), the petroleum system is only envisaged in the Bagalkot group wherein Stromatolites are reported to be in abundance but no geochemical data is available for the area.
- Major constraint for hydrocarbon exploration in the Bhima and Bastar basins (Category IV) is low sedimentary thickness, although better thickness is expected in the North-Western part which is concealed under the trap.
- Development of low porosity and permeability in Gondwana reservoirs may be due to intense mechanical compaction and even formation of Sericite due to low grade metamorphism as well as cementation with mixture of Quartz overgrowth, Carbonate cements and mixed authigenic Kaolinite and Illite. .
- In Kerala-Konkan (Category III) the Tertiary and Mesozoic sediments are separated by a thick Basaltic layer. Imaging below basalts has always been a problem in oil exploration. The thick basalt is opaque and masks deeper seismic events below the basalt. Only few wells have penetrated and drilled below the basalt. Till date the petroleum system has not been established in this basin. Wells drilled in Kerala-Konkan has shown the presence of hydrocarbons while drilling but production testing results not encouraging this fact.
- North of Narmada (Category IV) lineament which is mainly a clastic basin commercial hydrocarbon accumulations are yet not proven. Because of short geology history of the basin and thinning of sediments and the complete exposure of section from basement to top Narmada basin is not considered prospective.
- In northern part of the Saurashtra basin (Category III), i.e., in Kutch good thickness of Mesozoic rocks are exposed onland and have laterally continued presence in the offshore as well. However, major part of the Saurashtra Basin (both onland & offshore) is covered by Deccan Traps which have hindered the exploration of Mesozoic hydrocarbon targets. The Tertiary sedimentary sequences consisting dominantly of Carbonates and fine grained clastics overlying the Deccan Trap Volcanics in the shelfal region have been explored for hydrocarbon prospectivity.

Some Analogies with Indian Sedimentary Basins:

- Himalayan orogeny has resulted in post deposition entrapment of hydrocarbons within the petroliferous Tarim basin of Southern China, which like the Ganga valley has Infra-Cambrian source rock for its thermogenic gas fields.
- In Bikaner-Nagaur basin, peak oil generation was estimated to be from Vendian to Cambrian times (peters et al. 1995). Analogous sequences are found to be producers in a number of petroliferous basins around the world. In the Siberian platform the main oil and gas prospects are associated with sub salt deposits of Riphean Cambrian age on the Australian platform. Hydrocarbon reserves have been established in

the lowermost Palaeozoic strata.

- Recent drilling within the Ganga valley has suggested the possibility of an Ordovician Silurian petroleum system. Such a system has already established commercial production in the nearby analogous basins in Oman and China and in Australia. The similar age of this petroleum system within the Ganga valley suggest a possible similarity in terms of stratigraphy, sedimentology, structural styles and reservoir qualities with these analogous basins.
- Non-commercial hydrocarbon accumulations discoveries have been made in India from Neoproterozoic and Paleozoic basin and one discovery has recently been made in Bikaner-Nagaur basin in Western Rajasthan. Commercial production and accumulations are known in analogous basins in Pakistan, Oman and Northern Australia.
- Jammu foothills were in geological and depositional continuity with the salt range- Potwar depression (Pakistan). The most famous gas show is of the Jwalamukhi temple area which mostly consists of methane (87%) with small amounts of CO_2, N2 and O2 (Mudiar and Shukla, 1991). Thermal Gradient of Punjab plain nearly 2 degree Celsius/ 100 m similar to that of Potwar region (Pakistan).
- The recent exploratory drilling has opened a new realm in order to look for the possibilities of an Ordovician Silurian petroleum system within the Ganga valley which has already been established for the analogous petroliferous Chinese basins of Sichuan and Tarim. The elements of such a petroleum system together with the related super sequences of the Chinese basins are correlatable within Indian corridors.
- Based on the correlation of Indian Proterozoic super basin with their analogous Chinese and Australian basins, it appears that elements of similar petroleum system exist between these basins together with the possibility of an active Ordovician Silurian petroleum system with the Northern most Ganga valley Vindhyans, where sedimentation continued upto the Lower Devonian.
- The Indian Mesoproterozoic (1600-1900Ma) and Neoproterozoic (900-570 Ma) sedimentary super basins share similar tectonic settings and depositional environments as analogous areas in other parts of the world. The restricted marine Evaporite deposits in NW India, Pakistan and Southern Oman formed in rift grabens that were close proximity to one another on a Broad Carbonate Shelf (BCS) along the northern margin of Gondwana land during the Infra-Cambrian.
- Using databases of analogues, particularly similarities in the age of rift formations, environment of deposition, source and seal, reservoir and trapping mechanism. East African Rift System (EARS) has been compared mostly with the Yishu graben of China, the central Sumatra basin of Indonesia, and to a smaller extent to Cambay basin of India and the Phetchabun basin of Northern Thailand.
- The carbon isotopic pattern observed in Birmania succession appears to be similar to that observed in the well-established Precambrian-Cambrian boundary sections of the world (Kaufman and Knoll, 1995; Aharon and Liew, 1992; Friedman and Chakraborty, 1997). The Birmania succession is sadly unfossiliferous, resembling the Precambrian-Cambrian boundary succession in Oman, where the strata lack Cambrian body fossils (Burns and Matter, 1993).

Conclusion

Basins categorised under Category II and III comes under poorly explored areas, therefore technological advancement in seismic methods may provide a better view for future petroleum prospects in these basins. Today, almost around two-third of the total available basinal area is unexplored or poorly explored which can be further boosted by the technological advancements in the petroleum industry with enhanced working equipment and skilled professionals. Reasons for lack of commercial production from some frontier basins have also been pointed out which further helps in maximizing production through mitigation of existing problems. The analogies of Indian basins made with the other basins of the world in terms of similar tectonic activities, geothermal gradient and sedimentary layers helps in providing future petroleum prospects in Category IV Indian basins if the interested regions are technologically studied and explored.

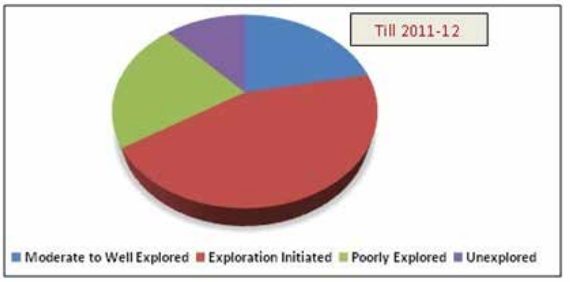

Fig.1 Pie chart indicating the percentage of exploration in Indian Sedimentary basins (2011-2012)

(SOURCE: DGH)

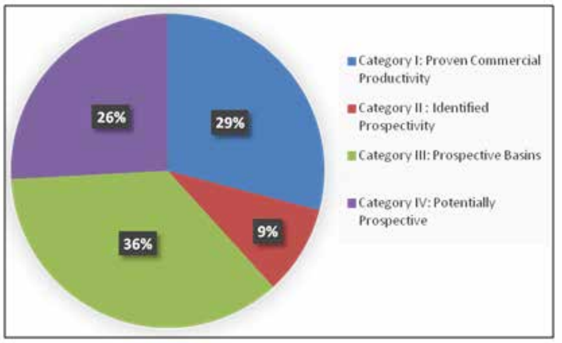

Fig. 2 Pie chart indicating the percentage of Category I, II, III & IV

(SOURCE: DGH)

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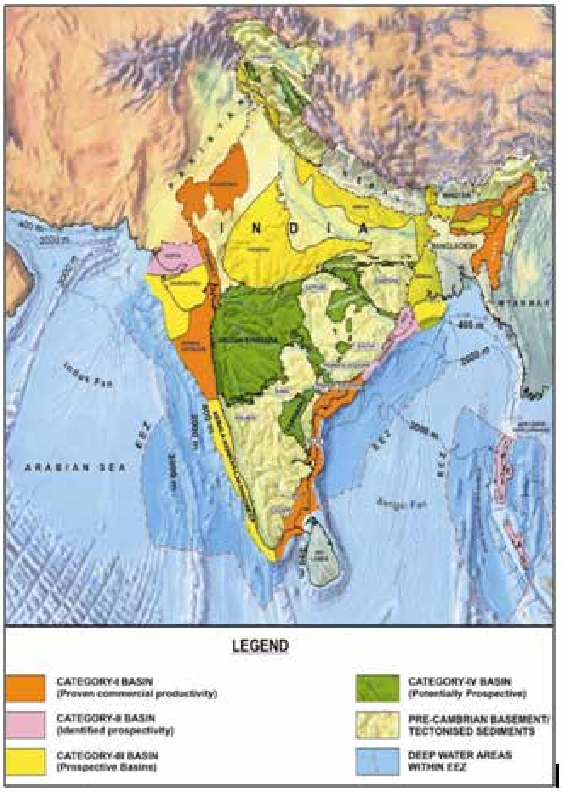

Comparative study for Category I Basins				
Basin Name	Source Rock	Reservoir Rock	Cap Rock	Sediment Thickness
Assam-Arakan	Upper Paleocene – Lower Eocene; and Barails (Oligocene) Cabonaceous Shale	Oligocene- Miocene (Barail Silt stone) and Miocene (Tipam Silt stone)	Argillaceous Kopili Formation (upper Eocene), Barail Coal Shale unit (Mio-Pliocene)	7000m from tertiary period
Mumbai Offshore	Panna Formations (Paleocene to early Eocene)	Bassein Lst. (Mid Eocene to Oligocene)	Post – Middle Miocene Shales	1100-5000m (Late Cretaceous to Holocene)
Cambay	Kalol & Anklesvar Formations. (Oligocene) Cambay shale (Palaeocene to early Eocene)	Silt stone in Ankalesvar, Kalol Formation (Middle Eocene), Siltstone in Olpad Formation (Paleocene)	Tarapur Shales (Upper Eocene – Oligocene), Telwa & Kanwa Shales (Middle Eocene Oligocene)	8000m thick Tertiary sediments

Cauvery	Sattapadi Shale within Cretaceous, Kudavasal Shale of Kamalapuram Formation. (Paleocene)	Precambrian Basement to Oligocene multi-stacked Siltstone	Sattapadi Shale within Cretaceous post-unconformity Shales like Kudavasal, Kamlapuram	> 6,000m (Permian to Recent)
Krishna-Godavari	Krishna / Golapalli Formation and Gajulapadu Shales (Permo – Triassic to Pliocene)	Permain to Pliocene Clastic reservoirs with few local Carbonates and volcanic reservoir	Red clay beds (lower Gondwana), Raghavpuram Shale and Basaltic trap (late Jurassic to Upper Cretaceous)	Max. thickness upto 5000m (Late Carboniferous to Pleistocene)
Rajasthan	Cambay & Tharad Shale of Barmer-Sanchor sub basin (Permian Jurassic to Cretaceous), Palaeozoic)	Barmer & Tharad Siltstone, Carbonate reservoirs in Cambrian to Palaeocene sequences	Intra-formational Shale and tight Lime stones	Average thickness is approximately 5000m

Table 1 Comparative study of Category-I basins.

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