Chapter 2: Literature Review

Introduction

This chapter is written to deliberate on the information in various literatures regarding geology of shale, shale gas reservoir characters and shale gas potential in Indian basins with special reference to Raniganj Field of Damodar Basin. A voluminous study has been carried out by researchers on Gondwana sediments of Damodar Basin. Although, it is difficult to present all the earlier works, an attempt has been made to present the relevant works in this chapter.

Shale in General

The shale is the most abundant sedimentary rocks on the earth crust forming 44 to 56% of geologic column (Blatt, 1970). Potter *et al* in 1980 defined the shale rock as the fine-grained, clastic sedimentary rock composed of clay minerals (grain size less than 4µ) and tiny fragments silt-sized particles (grain size 4 to 64µ) of other minerals, principally quartz, mica, feldspar and some cases dolomite and calcite. It holds finely laminated (0.1-0.4mm thick) to fissile and blocky to massive structure. It normally contains 30-50% sand and silt, 20-40% clay or fine mica fraction, 10-15% chemical or authigenic materials like carbonates, iron oxide, sulfides, 0.5-2% organic matters and heavy minerals (Pettijohn, 1984). The bedding (slabby) and laminations (flaggy, platy, fissile, and papery) in shale are controlled by grain size, mineralogy, structure and orientation of fabric (Grim *et al*, 1951; O'Brien, 1970). The fissility increases with increasing organic matter, clay content, clay crystallinity, favored clay and mica orientation. Fast rate of sedimentation and random fabric orientation can reduce the fissility of shale (O'Brien, 1970, Spears *et al*, 1976). Hedberg (1936) stated that the pore size and porosity may be reduced under overburden pressure due to diagenetic processes like compaction, cementation, etc. The pores are predominantly micro and nanopores less than 2nm in diameter.

Clay Minerals in Shale

Clays are the major component of shale rock and studied by various researchers (O' Brien, 1970; Davies *et al*, 1991; Bowker, 2007; Bustin A. M. *et al*, 2008; Bustin R. M. *et al*, 2008; Kulia and Prasad, 2013).

Grim *et al* (1951) discussed the clay minerals or layered lattice silicates (kaolinite, montmorillonite, illite, smectite, chlorite, etc), micas etc. as the major component of shale. The type of clays present in shale is the function of provenances, palaeoclimate, lithology, palaeo tectonic environment, depositional environment and diagenetic history.

Weaver (1989) stated that smectite and kaolinite are formed by active chemical weathering environment under humid and tropical climate depending on the parent rock constituents. Montmorillonite is stable at high pH and Kaolinite is stabled at low pH, which are common in shallow depth while illite and chlorite trend to abundant with increasing depth and may be indicative of higher maturity of the sediments. Moreover, illite is the most abundant Fe- rich mineral in lacustrine environment. The authigenesis of clay minerals is due to the transformation of detrital precursor of clay minerals that have been transported into the basin and direct mineral precipitation from fluid and basin water. Each of these clays has different pore size distribution depending on the cation exchange capacity.

In the shale, the framework contains multiscale pores with complex fabric structure and orientation with ultra-low permeability.

Organic Geochemistry of Shales

Organic geochemistry of shale as source rock was studied by numerous workers since 19th Century. Hood *et al* in 1975 stated that the organic matter in shale rock can generate hydrocarbon under four successive stages i.e. (a) organic matter formation, deposition and preservation; (b) thermal degradation of organic matter during sediment burial with increasing temperature and formation of petroleum molecules, (c) expulsion of hydrocarbon from source rock to reservoir, (d) physical, chemical and biological alteration of petroleum in reservoir rock.

Tissot and Welte (1984) stated that the slow sedimentation under anoxic conditions can preserve excellent quantity of organic matter. The shale rock with 1 to 2 % TOC associated with reducing to intermediate oxidizing environment and above 2% indicate highly reducing environment with excellent potential of hydrocarbon generation.

Killops and Killops (1993) stated that adsorption of organic matter onto the surface of clays and carbonate particles is more on fine-grained sediments than coarse-grained ones and hence fine grained sediments tend to be organic-rich. Lagoons, estuaries, inland or silled seas or lakes with calm, confined and often stratified conditions provide favorable environments for organic matter to accumulate without being carried away by currents.

Hunt (1995) discussed that the presence of organic matter in shale makes them effective source rock for hydrocarbon generation and preservation based on (a) organic matter type and quantity and (b) thermal maturity The maturity of organic matter depends on geothermal gradient, burial time, depth, organic matter quality, rate of sedimentation, overburden pressure etc. The shale rock containing less than 0.5% TOC has poor hydrocarbon generation potential, 0.5 to 1% indicates marginal and more than 1% TOC often has effective source potential to generate and expel enough oil and gas.

Barker, 1974; Espitalie, 1986; Peters, 1986; Dembicki, 2009 have worked to evaluate the source potential of shale rock. However, Jarvie and Lundell, 1991, Frantz *et al*, 2005 have considered that the shale can act as both source and reservoir rock.

Shale as reservoir, its insitu gas generation and accumulation potential, etc. are presented in the proceeding paragraphs.

Shale Gas Resources

Thomas, 1951; Hunter *et al,* 1953; Curtis, 2002; Montgomery *et al,* 2005 have defined that the shale gas is biogenic, thermogenic or/and combination of both. Gas accumulation characterized by wide spread gas saturation, subtle trapping mechanism, relatively short hydrocarbon migration distance where gas accumulated in three forms: (a) adsorbed gas on the matrix, (b) free gas within the primary and secondary pores, (c) free gas in micro fractures. The shale gas reservoirs usually contains 3-10% TOC, thermally matures gas (up to 2.0% Ro).Claypool (1998) separated shale gas systems by gas type: Biogenic Gas, Thermogenic Gas, and Mixed Gas.

Boyers *et al* (2006) had discussed the development of fracture in shale under external forces. Fractures provide hydrocarbon migration conduits and accumulation spaces for formation fluids. The wider fracture in shale may cause fluid loss. However, sometimes due to lack of micro fracture, hydrocarbon cannot expel from source rock to reservoir and remain inside the source rock and based on the type of organic matter and maturity, the source rock became reservoir for oil or gas. Thus, a shale play can be shale oil or shale gas reservoir based on its geological, geochemical and petrophysical properties. The insitu hydrocarbon gas within shale rock in the form of free gas or absorbed gas or both is known as shale gas. Unlike the conventional petroleum system, shale gas can be accumulated throughout the shale formation and shale source itself acts as reservoir and seal.

Jarvie *et al* (2007) had opined that when organic matter gets converted into hydrocarbon, its volume increases and exert pressure on the surface of the source rock which creates micro-factures or pathways for oil or gas expulsion from source rock to reservoir. Due to lack of micro fractures, hydrocarbon accumulates in the source rock itself and hence the source rock acts as reservoir rock. Jarvie (op. cited) had classified the shale gas systems into several types: High-thermal maturity shales (e.g. Barnett Shale); Low-thermal maturity shales (e.g. New Albany Shale); Mixed lithology intra formational systems (e.g. Bossier Shale of East Texas); Combination plays that have both conventional and unconventional gas production (e.g. in Woodford shale gas and conventional gas accumulation in Anadarko Basin).

Bustin *A. M. et al* (2008) has stated that the shale gas resources are unconventional hydrocarbon system characterized by complex properties with great heterogeneities at all scales. The relative abundance of adsorbed versus free gas are controlled by the amount of organic matter, pore size distribution, mineralogy, diagenesis, rock texture, reservoir pressure and temperature. The sorbed gas capacity of shale also depends on surface area, pressure, and temperature and sorption affinity.

Rickman *et al* (2008) has described that the shale with high quartz, feldspar and carbonate have low Poisson's ration and high Young's modulus which causes high brittleness. From the proportion of quartz, clay and carbonates the brittleness index is defined as: Brittleness Index (%) = Quartz/ (Quartz+ Carbonates+ Clays). Shale with Poisson's ration < 0.25 and Young's modulus < 34.5 MPa are considered as brittle.

The fluid flow in shale includes free gas flow, desorption, diffusion and imbibition suction. Wang *et al*, 2009 viewed that the flow is non-Darcy type in both organic matter and matrix as a result of slippage effect whereas it is Darcy type in both natural and hydraulic fracture. According to Kellerman *et al*, 2015, perseverance of dissolved organic matter in lakes related to its molecular characteristics. Inherent molecular properties are a significant controller of organic matter reactivity.

Shale Gas Worldwide

The first commercial shale gas production (in 1821) was started from organic rich Devonian shale of Appalachian Basin in United States of America. After the great economic success of the Barnett Shale play in Texas (Montgomery *et al*, 2005; Bowker, 2007; Hickey and Henk, 2007; Martineau, 2007; Slatt & O'Brien, 2011; Sondergeld and Rai, 2011) the interest had spread in search for of shale gas resources across the United States, Canada, Europe, Asia and Australia. Rogner (1996) had estimated world gas shale resources approximately 16110 Tcf and 40% of those resources are recoverable (World Energy Outlook, 2009). The shale gas production in US is expected to be increase up to 4.2 Tcf by 2030 which will be 18% of total US natural gas production.

The classical examples of some world shale gas systems are described in the following paragraphs to understand their potential and characteristics.

The voluminous previous literatures (Jarvie and Lundell, 1991; Jarvie *et al*, 2001; Frantz *et al*, 2005; Pollastro, 2007; James *et al*, 2007; Bowker, 2007) illustrate that the Barnett shale was deposited in marine to near shore environment under anoxic, strong upwelling and normal salinity conditions. It is 100 to 1000 ft (30.48 to 304.8m) thick, black, siliceous rock with 2-8% TOC, 45% quartz, 20-40% illite, 8% calcite and dolomite, 7% feldspar, 5% pyrite, 3% siderite, 0.6-1.6% Vro with 1 to 6% matrix porosity. Most of the pores are micro to nano pores and associated with organic matter or pyrite. The pores with a size range of 5 to 1000nm can be formed in organic matter during oil or gas generation. The OM fragments can act as porous medium in shale. These pore spaces can adsorb methane (molecular size of 0.38nm) and store free methane at the same time. The gas content ranges from 100 to 200 bcf at pressure gradient 0.45- 0.52 psi/ ft.

The Antrim shale plays in Michigan Basin of Late Devonian age is producing 25-190 thousand cubic feet gas per day. The shale is up to 800m thick, with TOC 1-25 wt% hydrogen rich and oil prone. The gas is mainly biogenic in origin and VRo 0.4-0.6% and thermally matured at the deeper part of the basin. The gas is accumulated in fractures of the shale, in adsorbed state, in matrix porosity, dissolved in the bitumen (Manger *et al*, 1991). The gas production is from 350-600m; however depth is 790m in Cowferd country and 1000m in Mesaukee country (Zuber and Voneiff, 1994, Zuber *et al*, 1994).

The Ohio shale of Devonian age in Appalachian Basin is producing from 152 m thick black shale facies since 1820. It is kerogen type II, Vro 1-1.3% thermally matured gas. The gas is stored as adsorbed gas onto the clay and kerogen with permeability 10^{-9} to 10^{-7} md (Thompson *et al*, 1984; McLaughlin *et al*, 1987).

The New Albany shale in Southern Indiana and Illinois and in Northern Kentucky is almost 30-50m thick and is being produced from 160-600m depth. The shale is of both thermogenic and biogenic origin with 0.4-0.6% VRo (Chou and Dickerson, 1985; Ulrike *et al*, 2005; Mastalerz *et al*, 2013).

The Marcellus shale of Appalachian Basin was deposited in Middle Devonian age under deep sea environment. The shale is 50-300m thick and mainly comprised of limestone beds, iron pyrites, siderite etc (Wang and Carr, 2013; Qingmin, 2015).

Shale Gas Prospect in India

To understand better on shale gas prospects in India, available literature have been referred and classical works on various Indian basins are described in the proceeding paragraphs.

Earlier researchers (Mohan, 1995; Mishra, 2009; ONGC, 2010; Sharma and Kulkarni, 2010; Boruah, 2014; Boruah and Ganapathi, 2015) have proposed that Damodar Valley Gondwana basins, Cambay basin, Assam-Arakan basin, Krishna Godavari basin, Cauvery basin, Vindhyan basin etc are the shale gas prospective sedimentary basins in India.

Mondal and Roychoudhury (2010) have stated that Raniganj, South Karanpura, North Karanpura etc are promising shale gas fields in Damodar Valley Basin. The Barren Measures shale of Permian age is predicted as the shale gas prospective horizon based on thickness (upto 1000m), higher content of organic matter (4-25%) and higher degree of thermal maturity (>1%).

Banerjee *et al* (2002) demarcated the Cambay shale in Cambay Basin as organically rich with average 700m thickness, kerogen type is both type II and III (oil and gas prone). Geological studies of Biswas (1999) and Choudhary (2004) have revealed that the maturity level of Cambay shale is higher (>0.7%) at the Tankari lows, depressions of Jambusar- Broach and Ahmedabad- Mehsana blocks. In the northern part of the basin, most of the places Olpad formation is within gas window with marginal source rock potential.

Banerjee *et al* (2006) had studied the black shale units belonging to the Semri Group in Vindhyan Basin where total organic carbon content of many of the shales > 1%. The mean Tmax for the black shales translate to a vitrinite reflectance range of 2.05–2.40%.

Padhy *et al* (2012) have opined that Kommugudem shale Formation of (up to 900m thickness) Permian age is shale gas prospect in Krishna Godavari basin. The shale is dark grey to black hard compact, silty and occasionally carbonaceous. The inter-bedded sandstones in coal-shale are dirty white, medium to coarse grained, feldspathic. Glauconite and pyrites are often found. The shale is having more than 2% TOC and kerogen type II & III.

Padhy (2013) considered the Cretaceous-Cenozoic Cauvery basin in south eastern India is another basin with prospective shales. The formations of interest are the early Cretaceous Andimadam Formation and the Sattapadi shale its stratigraphic equivalent deposited in marine environments. The Sattapadi shale contains 2 to 2.5 weight percent TOC and is thermally mature for hydrocarbon generation in deeper parts of the basin. Ro values vary from approximately 1.0 percent to as much as approximately 1.5 percent. Kerogen types are predominantly type III with minor amounts of type II.

Several papers in support of gas generation potential of Indian shales have given the impression since the last 10 years to find out sweet spot for its exploration and to develop technologies for it. Therefore, the technologies for shale gas exploration and development are elaborated in next paragraphs in support of previous works of different scholars.

Technology

The porous and permeable space within the shale is not sufficient for even tiny methane molecules to flow through easily. Thus, gas production in commercial quantities requires fractures to provide flow media. This leads to the development of the use of techniques that create artificial fractures around well bores i.e. hydraulic fracturing. Horizontal wells are being used in several gas shale formations. This is because natural fractures (also known as "joints") in some shale, like the Marcellus, are vertical. When vertical wells are drilled, the borehole does not intersect many vertical fractures. Horizontal wells are drilled through the shale formation itself. Thus, the wellbore in the shale is perpendicular to the most common fracture orientation, which allows it to intersect a much greater number of fractures (Gale *et al*, 2007).

Jaeger *et al (2009)* have studied the mechanical properties of shale i.e. brittleness and ductility using seismic data. Seismic properties of kerogen shows very low density (~1.3g/cc) and Very low velocity. It may cause high amplitude and low impedance reflections like coal in favorable conditions.

Schmoker, 1979 and Passey *et al*, 1990 used Wireline log techniques, using mainly gamma, resistivity, density and sonic logs have been using to determine the organic matter richness of shale. The common equations were $Øo= (\rho\beta-\rho)/1.378$ and $Øo=(\gamma\beta-\gamma)/1.378$. Where Øo= organic matter, ρ=formation density (g/cm3), ρβ=formation density of organic matter; γ= gamma; γβ=gamma of no organic matter. The higher value of gamma ray indicates the higher TOC content due to presence of radioactive uranium in sea shale. As the plankton in the sea water absorb uranium ions from seawater which increase the concentration of uranium. But non marine or lacustrine shale may do not show gamma ray anomaly due to low concentration of uranium (Meyer and Nederlof, 1984).

X-ray computed tomography technique was used to study microstructures of shales including bedding, fractures, pore system, fluid flow media, etc. by Guoping and Elizabeth (2010), bedding plane orientation (Audibert & Bieber, 1994). The gas storage and transport in shales were studied by Wang *et al* (1984); Lu *et al* (1992); Paul (1996); Guoping and Elizabeth (op. cit.); Josh *et al* (2012).

SEM and FIB/SEM provide micro to nano scale information based on internal images of shale cores and cuttings (Huggett & Shaw, 1997; Slatt and O'Brien, 2011). Atomic force microscopy (AFM) and Transmission electron microscopy (TEM) are used to visualize the pore system which is too fine to observe by other microscopes (Chalmers and Bustin, 2008; Chalmer *et al*, 2012; Loucks *et al*, 2009 & 2012).

Kulia *et al* (2012); Kulia and Prasad (2013) estimated the adsorbed gas in shale with the help of Brunauer-Emmett-Teller (BET) analysis.

Szabo *et al* (2014) proposed that gas from the shale reservoir can be produced at economic flow rates using hydraulic fracture treatment, horizontal well bore, or by using multilateral well bores covering more area of the reservoir to the well bore.

Successful shale gas production in U.S. shales and wide investigations of gas shale reservoirs by peer geoscientists has exhausted the interest toward understanding of shale horizons in Indian sedimentary basin. As the earlier literatures tell that the Raniganj Field of Damodar Basin is one of the most promising shale gas prospects in India, the author has considered the Raniganj Field for comprehensive investigation.

Raniganj Field

The current boom in the exploration and development of shale reservoirs has emphasized the need for extensive investigation of the study area for shale gas prospect identification. Various aspects of the Raniganj Field of Damodar Valley Gondwana Basin have been discussed by earlier workers (Sastry, 1977; Dutta, 2002) and in Geological Survey of India published reports. The next paragraphs are highlighting the important works on geological setting, stratigraphy, tectonic evaluation, and sedimentation and petroleum geology of the Basin.

The Damodar Basin of India is a part of the Gondwana Super Continent which comprises India, Madagascar, West Australia, North Australia, East Antarctica and Sri Lanka. India got separated from the supercontinent during Early Cretaceous Period. The Gondwana sediments in India were deposited within a time span of about 200 million years. The term 'Gondwana sediments' was originally used to a sequence of principally non-marine sedimentary rocks exposed in a series of small, graben-type basins of Peninsula India in published work by Lele (1964) and Maheshwari (1991). The earliest studies done by Cotter (1917); Fox (1931) defined a two-fold subdivision of the Gondwanan strata: the 'Lower' and 'Upper' Gondwana for Permian (Glossopteris-bearing) and Mesozoic (Ptilophyllum bearing) sediments, respectively. Later, Feistmantel (1882); Lele (1964) adopted a threefold subdivision of the Gondwana sequence based Triassic, Dicroidium dominated, fossil floras in sediments present between those bearing Glossopteris and Ptilophyllum.

Tectonic Settings

Casshyap and Tiwari (1987) have discussed that the Gondwana basins of India together cover an area of about 48,000 sq. km; excluding the areas beneath the Bengal Basin in Eastern India and the Deccan traps in Central India. The basins are intracratonic in nature and occur along four major linear belts i.e. 1) Trans Indian basin belt, 2) Wardha-Pranhita-Godavari Valley basins, 3) Mahanadi Valley basins and 4) Rajmahal-Galsi basins (Figure 2.1). The Trans Indian belt includes the Satpura basin, Son Valley basin and Damodar-Koel valley basins along with subsidiary basins from west to east. All the Gondwana Basins of India are bearing graben or half-graben geometry and restricted within the mobile belts in between the cratonic blocks. The sediment deposition in these basins occurred during latest Carboniferous, Permian, Triassic, and Early Jurassic times on the basement of Archean and Proterozoic rocks between the Tethyan margin and interior of the Gondwanaland province of Pangea. The deposition was continuing till the breakup of India from the rest of Gondwanaland in the Late Jurassic and Early Cretaceous. Casshyap and Tiwari (op. cited) studied the Gondwana basins of India, based on lithofacies association and sedimentary characters along with the tectonism and climatic control on basin evaluation and configuration.

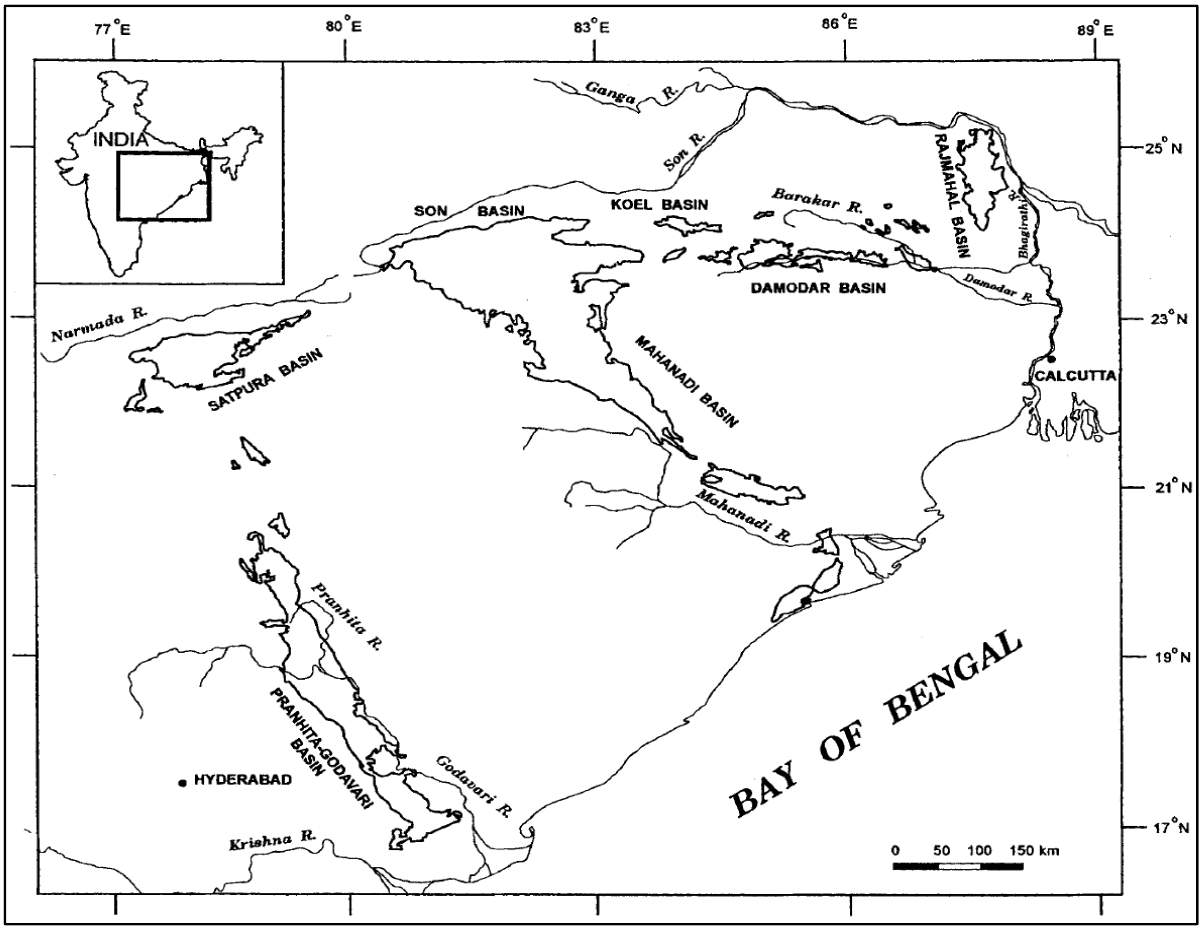

***Figure 2.1** Map showing the distribution of Gondwana basins in Peninsular India (after Dutta, 2002)*

Their study suggested that the Barren Measures and Raniganj Formations were deposited by meandering streams flowing on gentle palaeoslope towards North West and West with a possibility of slow to rapid deposition and rapid subsidence of Upper Permian sediments.

Veevers and Tewari (1995) considered that the Gondwana successions of Damodar Valley in Peninsular India accumulated in a number of discrete basins during the Permo-Triassic period. The main Damodar valley basins are Hutar, Auranga, Karanpura, Bokaro, Jharia and Raniganj basins/ Fields and the Raniganj is the easternmost depository within the Damodar Valley Gondwana Basins. The Damodar Valley lies within the Chotanagpur Granite Gneiss belt and these basins have faunal and floral characteristics similar to the equivalent strata of

South America, South Africa, Australia and Antarctica the other constituents of the southern hemispheric part (Gondwanaland) of the Paleozoic supercontinent, Pangea.

According to Biswas (1999), intra-continental extensional tectonics was active during Permo-Triassic and this was responsible for the formation of the sag basins of the Gondwana period; most of the continental Gondwana sediments in India including Raniganj Basin were deposited during this extensional regime.

McLoughlin (2001) had stated that the origin of basins within Gondwanaland is due to mainly three geotectonic mechanisms followed by the Late Carboniferous thermal uplift i.e. 1) heat withdrawal from beneath the Pangea leading to the development of "sag-type" basins; 2) compressional tectonics leading to the development of "foreland and transpressional" type basins; and 3) extensional tectonics leading to the development of "rift" type basins. The earliest rifting within the supercontinent was initiated in the west (between South America and Africa) and it propagated eastward with major phases of continental fragmentation in the Early Cretaceous and Late Cretaceous to Paleogene.

Ghosh (2002) had divided the fault systems in Raniganj Basin into three major groups: (i) boundary fault zones, (ii) faults at the basin margin and (iii) intrabasinal faults. The southern boundary of the Raniganj Basin is defined by an E–W striking fault zone, extending laterally for about 50 km, from Panchet hill in the west to Andal in the east. The throw across this southern boundary fault zone has been estimated to be more than 1000–1500 m. Slickensides observed in the borehole cores, close to the southern boundary fault zone show down-dip linear features; indicate that the movement on the faults has taken place dominantly with dip-slip components. These geometrical and kinematic signatures imply that the southern boundary fault zone represents normal faults, which is a typical feature of extensional (rift) tectonics. The southern boundary faults appear to have led to the development of a half graben type of basin, giving rise to increasing thickness of the sediments towards the south.

The eastern margin of the Raniganj Basin is bounded by a zone of NNW–SSE trending normal faults. This marks the contact of the Pre-Cambrian basement with the overlying Gondwana sediments. The contact of the sediment cover with the underlying Pre-Cambrian basement has been affected by several transverse (at an angle to the Raniganj Basin axis) normal faults. At the southern margin of the basin, the major boundary faults are disrupted by these transverse faults. It indicates that the transverse faults had developed after the main boundary faults and affected all Gondwana formations. In places, the faults penetrate down to the basement. Overall, the intrabasinal faults occur in conjugate sets, dipping towards the NE and NW. However, there is a discernible lateral variation in the fault strike. The general strikes of these faults are NNE and NNW in the western part of the basin whereas those in the eastern part of the basin tend to be ENE and WNW. These faults are recognized as normal faults with a predominant dip-slip component, as revealed from down-dip slickenside lineation in close proximity to the faults. The throw on intrabasinal faults varies from 50 m to 250 m. Other sets of faults occur sparsely all over the basin, which are parallel to the strike of the basin. They are generally less than 3 km in length and have been considered as a variety of synthetic faults. Thickening of strata, appearance of coarser clastic sediments in the down-thrown block, as well as splitting and coalescence of coal beds across the faults indicate that these intrabasinal faults are probably growth faults formed during the process of sedimentation.

Chakraborty *et al* (2003) have discussed that all the Gondwana basins developed under a single tectonic system characterized by a roughly E–W motion. The motion caused strike-slip displacement on an E–W oriented fault lineament and orthogonal extension across two preexisting fault zones disposed at high angle to the direction of bulk E–W motion. This caused preferential subsidence in locales of preexisting discontinuities in the Pre-Cambrian basement and led to development of Raniganj basin. The Raniganj is a rhombic basin and prominent fault zone trending WNW–ESE marks its northern boundary. The southern boundary also shows several faults along its trend. The western margin of the basin is demarcated by two major faults trending NW–SE and NNE–SSW. The sediments are dipping southerly. There are two sets of intrabasinal, normal faults trending NNW–SSE and NNE–SSW. The basin profile indicates fault-controlled subsidence formed along an E–W trending lineament. The basin appears to be a strike-slip basin, which is compatible with the regional E–W bulk motion inferred here, and is also reflected in the presence of cross faults. There are also intrabasinal faults parallel to the basin-bounding strike-slip faults, which indicate that the basin might have experienced trans tensional movement.

The seismogenesis in Parts of Bankura-Burdwan area of Raniganj basin was studied by Das and Kumar (2012) to detect faulting and regional tectonic of the area. The tectonic framework reveals several lineaments trending NE-SW/NE-SE and underlying basement fault trending Koel Damodar Graben fault.

Stratigraphy

Detailed geological studies and mapping in Raniganj field was carried out during the year 1925-28 by a team of the Geological Survey of India comprising Massers E.R. Gee, Rao Bahadur Sethu Rama Rao, A.K. Banerjee and J.B. Auden. The geology and coal resource potentialities were further studied by Sen and Dutta (1980), Datta, Sen and Choudhuri (1985) and Datta and Sen (1986) studied the geology and coal seams of some blocks in Raniganj field like Chanch-Begunia, Begunia-Kulti-Chalbalpur and Ramnagar Colliery sector.

Kutty *et al* (1987), Casshyap and Tiwari (1987) and Kundu *et al* (1993) studied the Gondwana stratigraphy of the Basin based on paleontological evidence while Dutta (2002) reconstructed the stratigraphy based on order of superposition. The Gondwana sequences differ from basin to basin and a stratigraphic correlation of Gondwana basins of India are presented in the Table 2.1.

Table 2.1 *Stratigraphy of Gondwana sediment in India. Compiled after Kutty et al (1987), Tiwari and Casshyap (1996), Kundu et al (1993), GSI, 2003.*

		Damodar-Koel valley	Rajmahal	Mahanadi	Son	Satpura	Godavari	
Cretaceous	Lower				Bansa bed	Jabalpur	Chikiala/ Gangapur	
Jurassic	Upper		Dubrajpur					
Jurassic	Middle		Dubrajpur			*Bagra*		
Jurassic	Lower		Dubrajpur		Bandhavgarh		Kota	
Triassic	Upper	SupraPanchet	Dubrajpur		*Parsora* *Tiki*		Dharmaram Maleri	Maleri Group
Triassic	Middle			Kamthi		Denwa	Bhimaram Yerrapalli	Maleri Group
Triassic	Lower	Panchet		Kamthi	Pali	Panchmarhi	*Upper Kamthi* Middle Kamthi	Kamthi Group
Permian	Upper	Raniganj		Raniganj (Kamthi)	Raniganj	Bijuri	Lower Kamthi	Kamthi Group
Permian	Upper	Barren Measures		Barren Measures (Kamthi)	Barren Measures	Motur	Barren Measures ? ?	Barakar
Permian	Lower	Barakar	Barakar	Barakar	Barakar	Barakar	Barakar	Barakar
Late Carboniferous		Talchir	Talchir	Talchir	Talchir	Talchir	Talchir	

The glacial sediments were including tillite, conglomerate, sandstone and shale of Early Permian age known as Talchir Formation. During age of Early Sakmarian (around 290 + 4 Ma) the sea level was increased due to deglaciation and it resulted in marine transgression from the West and North West. The Karharbari and Lower part of Barakar Formation were deposited in India during this period (Chakraborty *et al*, 2003). Barakar Formation is overlying the Karharbari Formation and it is the major coal bearing formation among all the basins has more than 90% of total coal resource of the country. The Raniganj Formation of Upper Permian age is also having thick coal measures. These two coal bearing formations are separated by Barren Measures or Ironstone Formation of a thick fluvio-lacustrine deposit which is devoid of coal. The Barren Measures (Damodar Valley, Mahanadi Valley, Godavari) and Motur Formation (Satpura, Wardha and northern part of Godavari Valley) were deposited in peripheral part of the basins which comprises mainly carbonaceous shale, iron bands, siltstones and sandstone, red clay respectively. On the other hand, the interior part of the basins received sand dominated fluvial sediments during that period. The Barren Measures (Ironstone shale) and Motur Formations were deposited during the early part followed by Raniganj, Bijori, and Lower Kamthi Formations. Panchet Formation in Damodar Valley Basins, Pali-Tiki Formation in Son Valley Basins, Lower Panchmarhi-Denwa in Satpura Basin, Lower Kamthi in Mahanadi Valley, Middle Kamthi and Yerapalli-Bhimaram-Maleri members of Maleri Formation in Godavari Valley Basin were deposited during the period of Ladinian (233 Ma) to Early Norian. Suprapanchet in Damodar Valley, Dubrajpur in Rajmahal, Upper part of Kamthi in Mahanadi Valley, Mahadeva, Parsora, Bandhavgarh in Son Valley, Upper part of Panchmarhi and Upper part of Bagra in Satpura, Upper Kamthi and Kota in Godavari Valley were likely to be deposited during Pliensbachian (Lower Jurassic) to Oxfordian (Upper Jurassic) (~185-160 Ma).

Banerjee (1966) identified an occurrence of non-flysch turbidites from ancient glacial-lake sediments belonging to the Talchir formation (Upper Carboniferous) of the Raniganj coalfield. Based on petrographic study, the turbidites sequence was found to be comprised of very fine-grained, moderately to poorly sorted arkosic wackes with unimodal, nearly lognormal grain-size.

Chandra (1966) had recovered different species of spores on maceration from Ironstone or Barren Measures Formation which include Striatites, Striatopodacarpites, Lahirites, Sulcatisporites, Faunipollenites, Densipollenites, Barakarites, Lophotriletes, Punctatisporites and Leiotriletes etc.

Ghosh and Singh (1977); Casshyap and Tewari (1987) have described that the Barren Measure sediment are deposited gradationally over the Barakar Formation and comprises dark grey to black shale with ironstone bands/nodules, the monotonous grey to black micaceous, carbonaceous shale with very thin sand/silt/shale intercalation. The rock splits into thin slices along fissile planes. Angular to sub angular quartz grains are often seen sparsely distributed within this unit at irregular intervals. Concretion of grains often found as bands increases towards bottom particularly near Barren Measure/ Barakar contact. Thickness of Barren Measures is ranging from 200-800m and it is average 1000m in the Suraj Nagar area in the Raniganj Field.

Dutta (2002) classified the Gondwana sequence into four sedimentary facies; a glaciogenic facies, a coal-bearing facies, red shales and a hill-forming coarse sandstone-conglomeratic facies. The sediments were derived from the adjacent upland of mostly granitic rocks with moderate to low relief. Except for the ice contact deposits at the base, the sediments were laid down within a fluvial regime and environment of deposition changed between braided streams and meandering river systems. He has emphasized the climate as the most decisive factor in controlling the nature of the lithic fill that helped to define lithostratigraphic units. During Gondwana sedimentation the climate changed from glacial Icehouse Stage to warm-humid Greenhouse stage. A rapid climatic change took place and the cold glacial climate ushered in a temperate humid condition. Consequently, a dramatic change was observed in depositional setting. The periglacial outwash plain of braided rivers and glacial lakes gave rise to a meandering fluvial system with well-defined channels and broad floodplains. Coal, carbonaceous shale, gray shale, and siltstone were deposited within the vast floodplain with its extensive coal swamps while the sands were deposited within the meandering channels.

Coarser, pebbly lenses occurred mostly as channel lag deposits. After this initial phase of extensive coal deposition in Lower Permian time, the coal-forming environment dwindled, possibly as a response to a relatively less humid condition. During this period, relatively few thin coal seams and/or thin coal stringers developed in some basins. The coal-forming environment returned in the late Permian though it was less extensive than the preceding Lower Permian interval. The meandering river system continued uninterrupted into the Triassic

Mukhapadhyay *et al* (2010) have addressed the problems of Indian Gondwana stratigraphy and used marine flooding surfaces, large scale tectonic events or major change in depositional environment as the tools for temporal correlation within the Gondwana basins of India. A detailed study of the Indian basins reveals that the sedimentation in Gondwana basins of India evolved through a complex interplay of faulting, changes in sea level and climate.

Petroleum Geology

Numerous studies have been done on coal geology (coal and coal bed methane, coal mine methane resources) even though very few literatures are available on the oil and gas prospects of the Raniganj field.

Sharma *et al* (1987) studied the source rock potential of carbonaceous shales of Damuda Group in Damodar Valley basins and found that the total organic carbon content (TOC) up to 25 wt%, hydrogen indices ranges from 15 to 325 mg HC/gm rock, the maturity range was within gas window and having predominantly type III gas prone kerogen. This study had emphasized that the basin can be taken for hydrocarbon exploration target in the future.

Mondal and Roychoudhury (2010) have studied the shale gas prospect within Gondwana sediments in India and identified Barren Measures Formation as the shale gas prospective horizon. Moreover, based on thickness (600m), higher content of organic matter and higher degree of thermal maturity, they identified the southwestern part of the Raniganj coalfield is the most promising area for exploration as well as exploitation of shale gas. At the end of the deposition of Barakar sediments, marine transgression took place and this is the cause of deposition of thick (300- 600m) clay dominated Barren Measures sequence in the basins of Damodar Koel Valley extending up to Ramkola- Tatapani in Son Valley. The Barren Measures sediments are characterized by dark grey to black shale with ironstone bands/ nodules. Presence of Bryozoan in Raniganj Basin indicates the marine influence. The shale of Barren Measures Formation in this zone is mainly silty in nature and this silty nature may favor the permeability for shale gas exploration.

Varma *et al* (2015) has carried out geochemical investigation for the shale gas exploration in Raniganj field of Damodar valley basin. The borehole samples of shale and siltstone were studied from Permian shales of Raniganj Basin. The results suggested that the shale samples have good organic richness (5.45 to 28.86 wt %) and appear to have well to very good hydrocarbon generation potential.

Very few workers have defined the geochemical properties of Barren Measures, but its reservoir quality assessment has not been reported yet. That is why the author has perceived the present research and investigated the Barren Measures shale to holistic approach to depict the geology, organic geochemistry and reservoir properties in succeeding chapters based on adequate laboratory investigations.

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