FINAL REPORT –

Preliminary Study on Shale Gas Potentiality in Bangladesh

Prepared by

Bernd Loske & Dr. EB Teigler

DMT GmbH & Co. KG

For

Hydrocarbon Unit

Mohammed Osman Amin

Director General

BTMC Bhaban (1st Floor)

7-9 Kawran Bazar

Dhaka-1215, Bangladesh

Project Number: GB-13-042

December 2013

DMT GmbH & Co. KG

Exploration & Geosurvey
Geology & Borehole Survey

Am Technologiepark 1
45307 Essen
Germany

Phone +49 201 172-1970
Fax +49 201 172-1971
dmt@dmt.de
www.dmt.de

Managing Company:
DMT Verwaltungsgesellschaft mbH
represented by its managing directors
Heinz-Gerd Körner (CEO)
Prof. Dr. Eiko Räkers

Chairman of the Supervisory Board:
Dr. Guido Rettig

DMT GmbH & Co. KG
Registered office: Essen
Registration court: Amtsgericht
Essen, registration no. HRA 9091

DMT Verwaltungsgesellschaft mbH
Registered office: Essen
Registration court: Amtsgericht
Essen, registration no. HRB 20420

Member of TÜV NORD Group

Disclaimer

This report describing the methodology applied to appraise the potential of shale gas in Bangladesh represents DMT's assessment and opinion as of December 2013. This report has been prepared by DMT for the exclusive use of HCU and associated institutions or stakeholders on the basis of instructions, information and data supplied by HCU and other agencies. No warranty or guarantee, whether expressed or implied, is made by DMT with respect to the completeness or accuracy of any aspect of this document and no party, other than the client, is authorized to or should place any reliance whatsoever on the whole or any part or parts of the document. DMT do not undertake or accept any responsibility or liability in any way whatsoever to any person or entity in respect of the whole or any part or parts of this document, or any errors in or omissions from it, arising from negligence or any other basis in law whatsoever. Likewise DMT disclaim liability for any personal injury, property or other damage of any nature whatsoever, whether special, indirect, consequential or compensatory, directly or indirectly resulting from the publication, use or application, or reliance on this document.

This report may contain “forward looking statements” which are based on assumptions made by DMT using data supplied by HCU and other agencies/stakeholders. Assurance or warranty cannot be given, that any of the future results or achievements, expressed or implied, contained will be realized.

Summary

This preliminary study on shale gas potentiality in Bangladesh represents a desk top study based on existing data without any field and laboratory analytical work.

The assessment made for possible shale gas plays is based on compiled literature, geochemical data (total organic content and maturity) and geophysical well logs (namely the Gamma Ray).

According to the published literature the following stratigraphic units contain shale rich sequences:

- Gondwana Group (Kuchma and Paharpur Formations) – Carboniferous to Permian
- Jaintia Group (Tura Sandstone and Kopili Shale) – Paleocene to Eocene
- Barail Group (Jenum Shale) - Oligocene
- Surma Group (Bhuban and Boka Bil Formations) - Oligocene to Miocene

These units have been further screened for shale gas potential in terms of burial depth, shale thickness, total organic content, type of kerogen and maturity.

One of the most important findings of this study is that low maturity values exclude all Formations of Tertiary Age for being suitable for economic shale gas production in the Bengal Basin. They may reach favourable maturity of Ro (Vitrinite Reflection) larger than 0.8% at depths below 5000 m. In the existing wells such a suitable value has not been measured so far.

The coal bearing basins of the Gondwana Group have favourable maturity but contain only thin shale sequences. Furthermore, the total organic content is a critical factor.

It is concluded that shale gas production will not replace the foreseeable decline in conventional gas production in Bangladesh. However, very limited potential may still exist because of three reasons: (1) the data review has been restricted to historic data, (2) recent results of activities, including exploration data from international oil companies, were not available, and (3) the potential of large areas are based on interpolation between widely spaced wells and remain untested by drilling.

Despite the very limited potential for shale gas, it is recommended to focus firstly on other targets as namely Coalbed Methane (CBM) from the Gondwana Group. Its general suitability has already been demonstrated for the Jamalganj basin.

Table of Contents

List of Figures

List of Tables

1 Introduction

This section introduces the topic of the project as well as describes the general background.

The main author of this report is Bernd Loske, who is a professional economic geologist with more than 15 years experience in exploration and evaluation of sedimentary basins with hydrocarbon potential. Bernd Loske is a permanent employee of DMT since 2002. He was supported by several other specialists (e.g. geophysicist) and a local geologist A.K.M. Shahidul Hasan, providing in depth geological knowledge of Bangladesh sedimentary basins and collect data after instructions by DMT with the assistance of Junior Geologist Kamrul Hasan Bhuyian. Ernst-Bernhard Teigler, head of the Geology department of DMT, acted as Co-author. Ernst-Bernhard Teigler is with DMT since 2008. His key qualifications are generation, planning, supervision and managing of base and precious metals exploration projects from grass-roots to advanced (feasibility) stage; resource evaluation.

DMT is a German-based consulting company, which has been providing services and advice to the international mineral industry and financial institutions since 1991. DMT employs approximately 700 permanent staff, offering expertise in a wide range of resource engineering disciplines. DMT has a recognised track record in the field of independent mineral property valuations, resource and reserve estimations, project evaluations and audits, Competent Person's Reports and independent feasibility evaluations for exploration and mining companies and financial institutions worldwide.

DMT's independence is ensured by the fact that it holds no equity in any project. This permits DMT to provide its clients with conflict-free and objective recommendations on crucial judgement issues.

Bangladesh is currently producing gas from several gas fields located along its eastern border (Figure 1-1), all of which are conventional in character. The Government of Bangladesh (GoB) realizes that the supply of energy to the growing population puts more and more strain on the energy resources, especially in view of the price of natural resource commodities and its impact on domestic power generation. Hence, security of energy is very high on the agenda of the GoB. In addition, conventional energy resources are limited and depleting.

As in many countries world-wide energy demand exceeds supply putting more strain on the production of energy resources and power generation. Import of gas, coal and oil may be an alternative source of energy, but this is an expensive route requiring subsidies in order to make power affordable for the general population thus putting severe pressure on any national energy budget.

In view of the above, the GoB has considered evaluating the potential for shale gas, an unconventional source of natural gas.

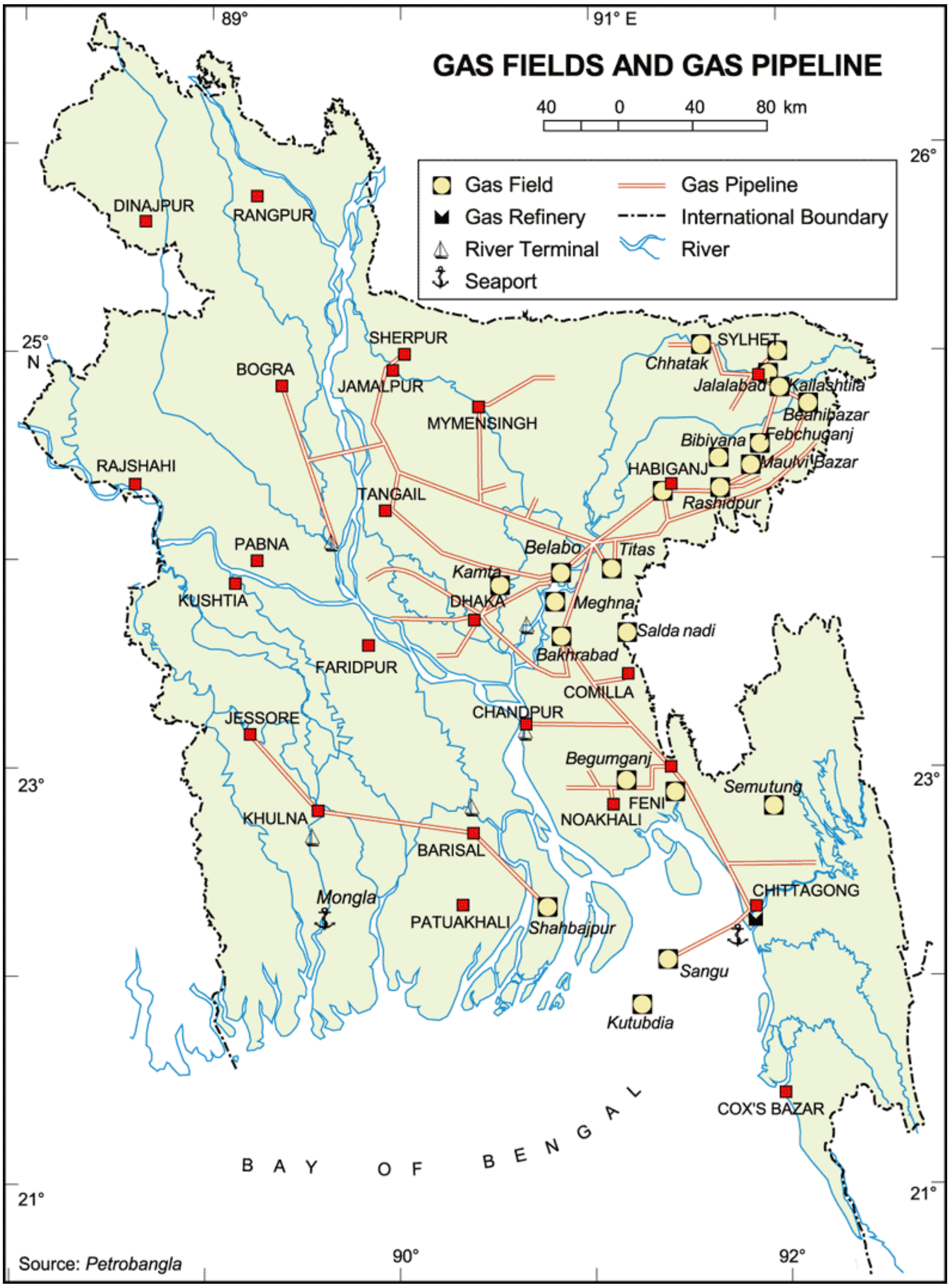

Figure 1-1 Map of Bangladesh showing the current conventional gas fields and pipelines

(Source: PetroBangla web site)

1.1 List of Abbreviations

In the report the following abbreviations are used:

BAPEX	Bangladesh Petroleum Exploration & Production Company Limited
DMT	DMT GmbH & Co. KG (the consultant)
e.g.	for example
etc.	and so on
GIIP	Gas initially in place
GoB	Government of the People's Republic of Bangladesh
HCU	Hydrocarbon Unit (the client), Energy & Mineral Resources Division, Government of the People's Republic of Bangladesh
i.e.	that is
TOR	Terms of Reference
TOC	Total organic content
OM	Organic matter
R_0	Vitrinite reflectance
USGS	United States Geological Survey
km	kilometre (1000 m)
m	metre
wt. %	weight per cent
viz.	namely
PetroBangla	Bangladesh Oil, Gas & Mineral Corporation (BOGMC)
2D/3D survey	seismic data acquired in groups of 2D or multiple closely spaced lines (3D).

2 Background and Context

Shale gas is natural gas that is found trapped within shale formations, which act both as reservoir and cap.

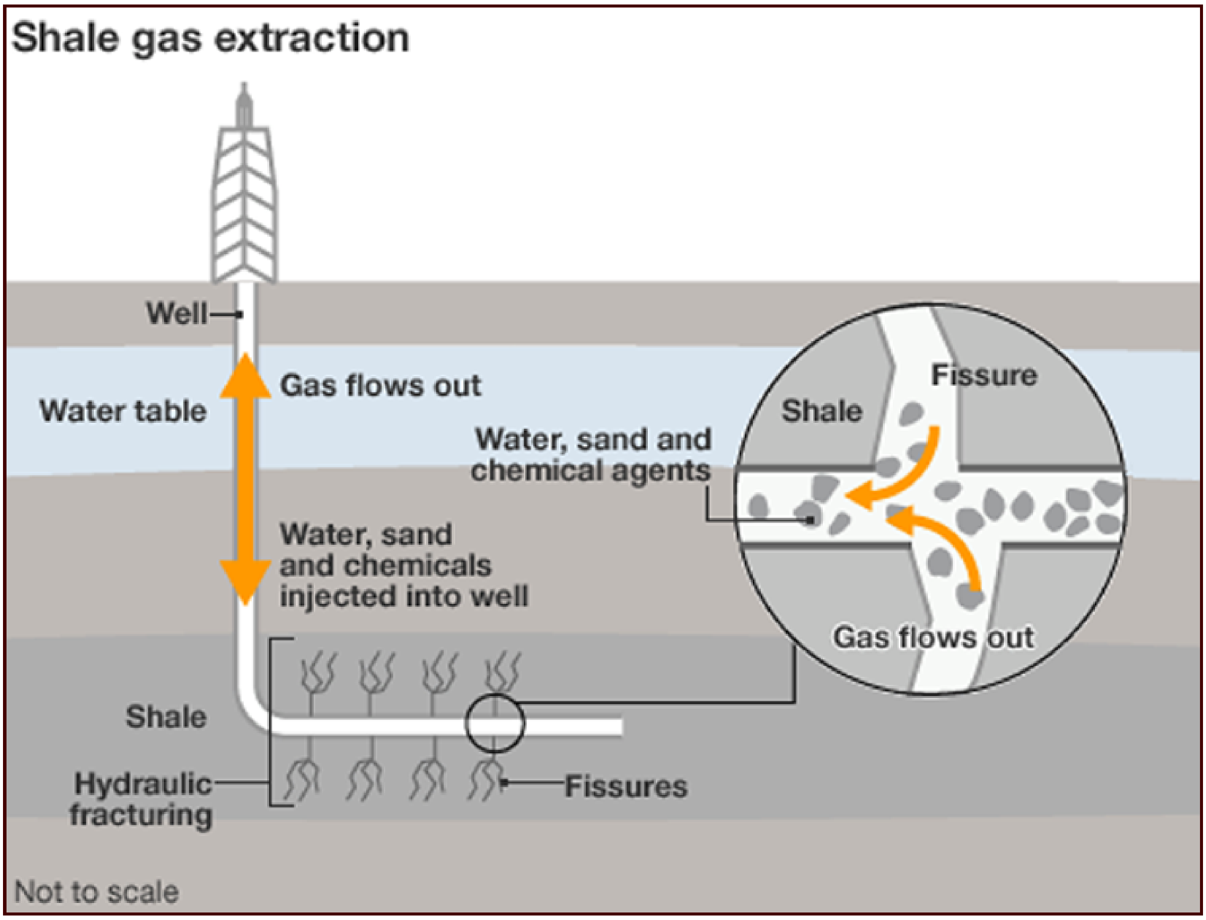

Figure 2-1 Principles of shale gas extraction

(Source: http://thewatchers.adorraeli.com/2012/04/18/uk-will-allow-shale-gas-fracking-despite-earthquake-connections/ visited on June, 26th, 2013).

However, permeability of shales is very low and exploitation is, therefore, only possible by reservoir stimulation, i.e. fracturing (Figure 2-1). Three essential factors have influenced the development of shale gas:

- advances in horizontal drilling, which is a requirement for successful stimulation
- hydraulic fracturing

- higher natural gas prices in the past several years.

Shale gas and shale gas plays have gained predominance, particularly, in North America. In the USA, shale gas is one of the most rapidly expanding parts of onshore domestic oil and gas exploration and production. Currently, it contributes more than 15% of total gas production in the USA. Several countries in Europe and Asia are assessing the potential of shale gas in their respective domestic hydrocarbon production. In addition, shale gas plays are getting more widespread, very often driven by successful Northern American shale gas producers.

3 Scope of Work

In this section the methodology will be described to achieve the objectives of the project, which can be summarized as follows:

- Taking stock of information available description of shale plays
- Review of existing wells logs of selected area
- Establishing Shale plays and their lateral extents
- Establishing thickness and depth of the shale plays
- Review existing geochemical data of the shale formations (as available)
- Identify areas where further investigation is necessary
- TOR for future phases of work, on the basis of Preliminary Study

3.1 Methodology

The project's TOR stipulates that the work will be a desk top study based on existing data without any field and laboratory analytical work.

3.2 Methods of Data Collection and Analysis

Data have been collected with support of and/or have been made available by the Geological Survey, BAPEX, Petrobangla and HCU. Data quality has not been verified in detail. However, for the purpose of this regional study the quality of the data is considered as appropriate.

From the data collected relevant information data is listed in the Appendices or on the Data CD and catalogued in order to set up an inventory for later use. This will be, especially, important for well data and geophysical data and less critical for general information. For the inventory Microsoft's Office Excel was utilized. The inventory comprises several worksheets:

- general information and reports
- maps

- drill hole data
- geophysical data

Each worksheet lists important information as columns.

- general information and reports: author, date, title, editor, publisher
- maps: author, date, scale, topic, area
- drill hole data: name, location (coordinates), elevation, total depth, target layers, formation at total depth, gas field, area, intersected shales, down hole geophysical survey data

Bulk rock volumes will be calculated using mapped areal extents and cumulative vertical thickness of the respective shale unit. The resulting volumes will be multiplied by a mean shale density of 2.65 t/m³ yielding respective bulk shale tonnages. Ranges for GIIP will be calculated by multiplying the bulk rock volume and the gas content. Sensibilities will be considered by running probabilistic Monte Carlo simulations.

3.3 Sampling

This project is a desk top study without any field or laboratory work. Field and/or analytical work may be recommended as part of the findings of this review study.

3.4 Limitations to Evaluation

The desk top study is strongly depending on the salient data existing in the data of various parties (HCU, Petrobangla, BAPEX, GSB etc.). Despite the prolific exploitation of natural gas, all of which are in conventional setting, in Bangladesh and hence associated exploration work, salient data for source and seal lithologies are limited. During exploration for conventional HC deposits detailed studies of source rocks are often not done because sandstone, as a reservoir, was the target.

In the discussions during the initial meetings in Dhaka, reservations have been expressed that the known source rocks are either too deep or too shallow (i.e. immature), and the shales in the seal packages do not contain high concentrations of TOC. However, formations described as seal rocks form packages several hundred metres thick, which may contain thin units with appropriate contents of TOC. In addition, due to the structural framework, parts of the packages hosting the source rocks may be at the suitable burial depths and within the required maturity range.

4 Geological Setting

The Bengal Basin in the northeastern part of Indian subcontinent, between the Indian Shield and Indo-Burman Ranges, can be subdivided into three geo-tectonic provinces (Figure 4-1 to Figure 4-3): (1) The Stable Shelf; (2) The Central Deep Basin (extending from the Sylhet Trough in the northeast towards the Hatia Trough in the south); and (3) The Chittagong–Tripura Fold Belt. Due to location of the basin at the juncture of three interacting plates, the Indian, Burma and Tibetan (Eurasian) Plates, the basin-fill history of these geotectonic provinces varied considerably.

Sedimentation within the Bengal Basin is thought to have taken place in five distinct phases: (I) Permo-Carboniferous to early Cretaceous; (II) Cretaceous–Mid-Eocene; (III) Mid-Eocene–Early Miocene; (IV) Early Miocene–Mid-Pliocene; and (V) Mid-Pliocene–Quaternary. Each of these sedimentation phases has been controlled by the tectonic cycles, which involved the interaction and collision pattern of the major plates. In terms of the tectonic evolution of the basin, these phases could be called: (I) Syn-rift stage; (II) Drifting stage; (III) Early collision stage; and (IV) and (V) Late collision stage (Figure 4-5, Curiale et al. 2002, Alam et al. 2003).

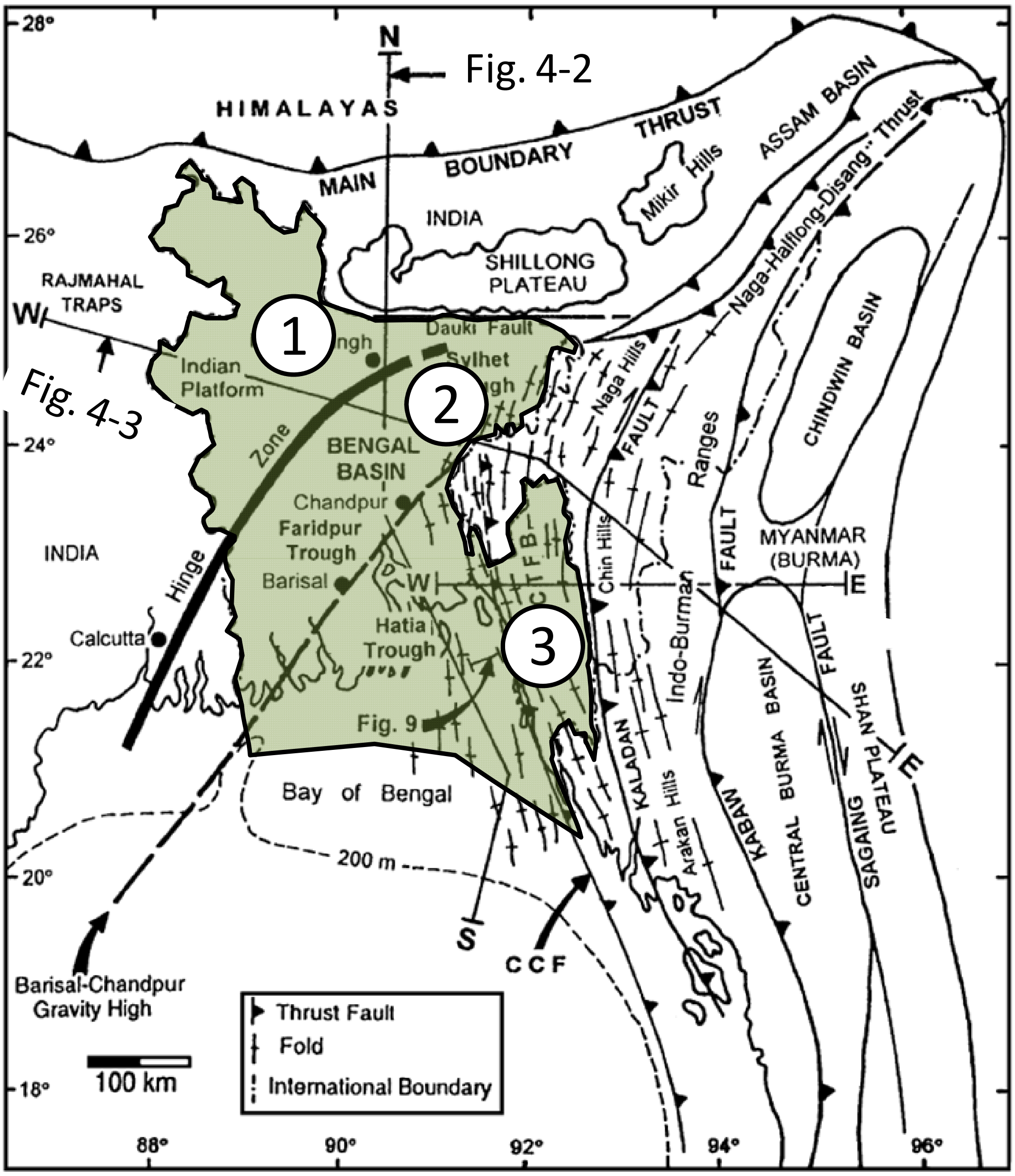

Figure 4-1 **Tectonic Framework of the Bengal Basin and Surrounding Areas**

(After Alam et al. 2003)
1=Stable Shelf, 2=Central Deep Basin (Sylhet Trough and Hatia Trough),
3= Chittagong-Tripura Fold Belt, CTFB=Chittagong-Tripura Fold Belt,
CCF=Chittagong-Cox's Bazar Fault

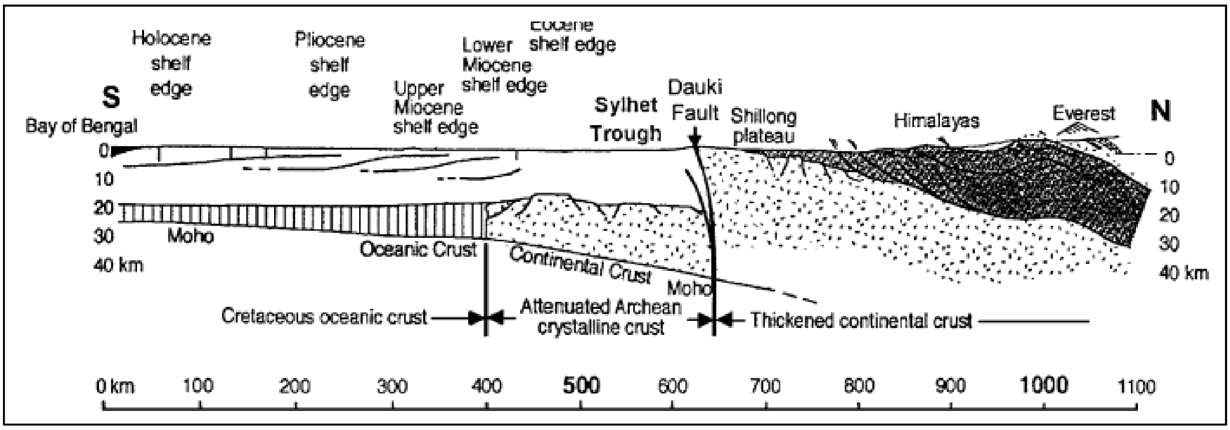

Figure 4-2 North-South Cross-Section through the Bengal Basin

(Source: BOGMC, 1986)

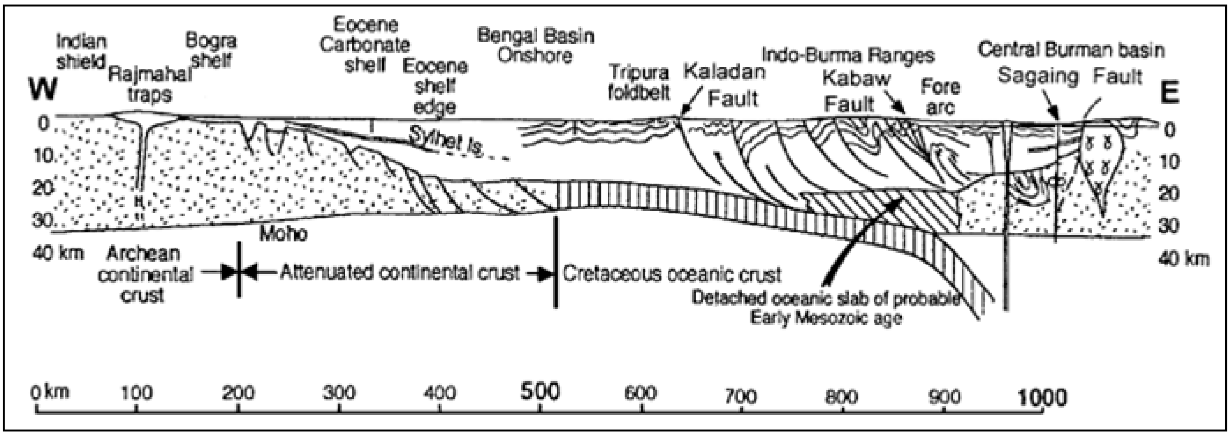

Figure 4-3 West-East Cross-Section through the Bengal Basin

(Source: Alam et al. 2003, p. 183)

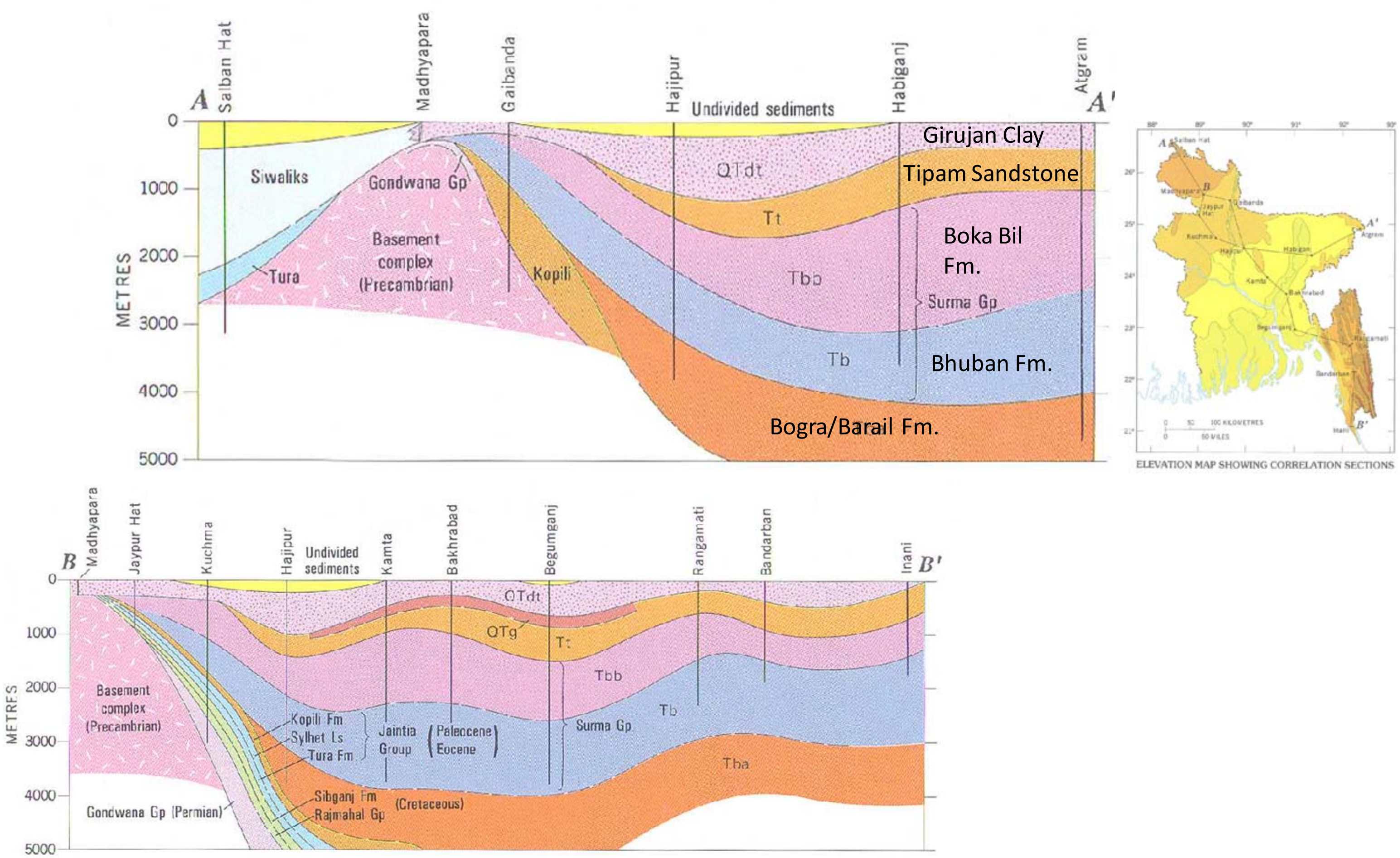

Figure 4-4 Structural cross-sections across the Bengal Basin showing the sedimentary cover

(Source: Alam et al. 1990)

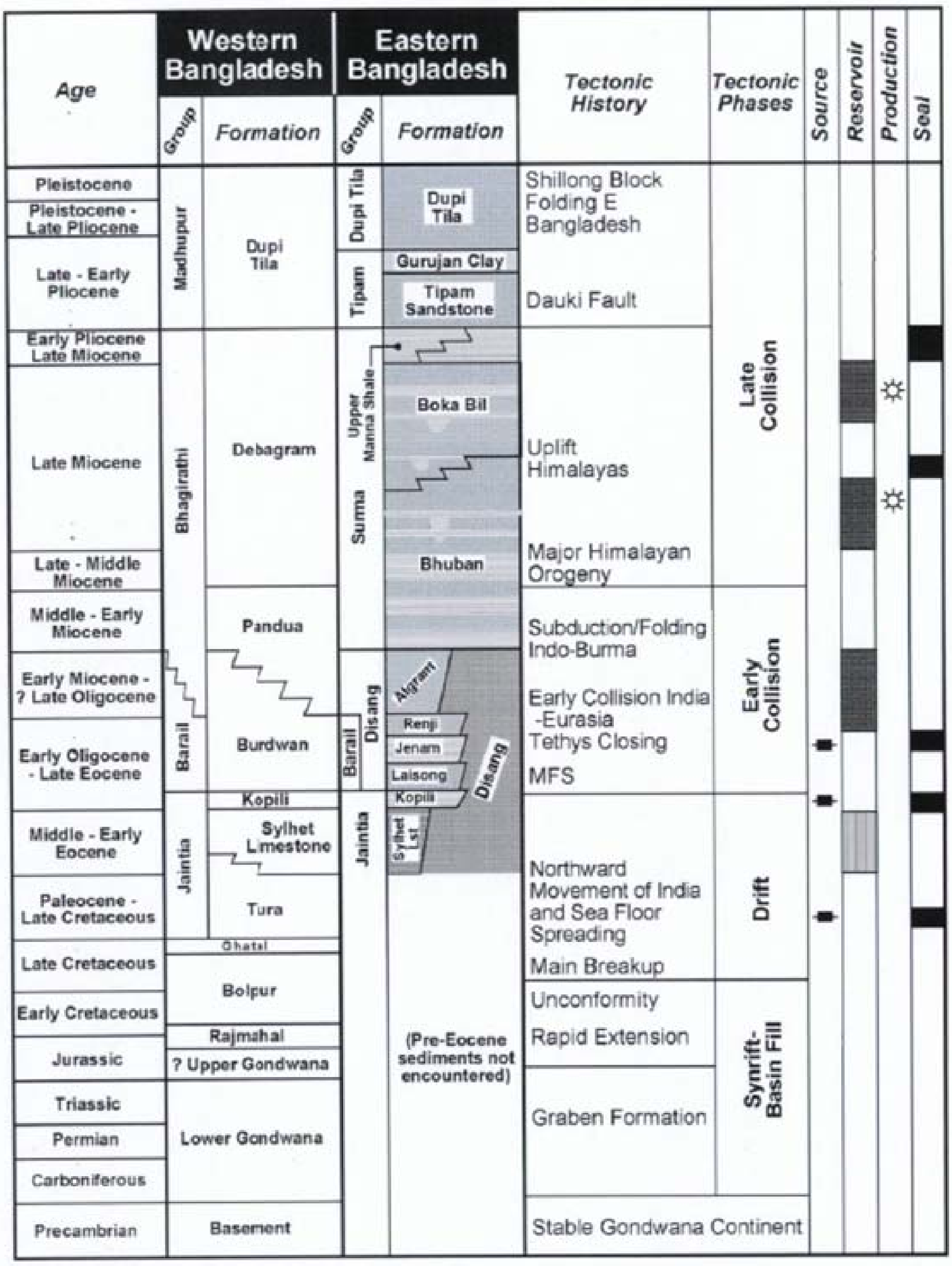

Figure 4-5 **Stratigraphic Sections for Eastern and Western Bangladesh, showing tectonic history, phases and megasequences, and petroleum system elements**

(Curiale et al. 2002, p. 630)

4.1 Precambrian, Paleozoic and Mesozoic

Only on the stable shelf (Province 1) Precambrian metasediments and Permian–Carboniferous rocks have been encountered only in drill holes. The Precambrian Basement consists of gneiss, schist, diorite, granodiorite and granite.

The first phase of sedimentation in the Bengal Basin on top of the Precambrian rocks started during the Permian–Carboniferous with the deposition of the Gondwana Group. Deposition took place in intracratonic basins. The sediments are preserved in many isolated and sometimes very large deposits. The Gondwana sediments are interpreted to have been deposited in low-sinuosity braided fluvial systems flanked by vegetated overbank and swampy floodplain areas (Alam et al. 2003). The coal bearing series within this sequence are considered to represent gas source rocks (Curiale et al. 2002, Islam & Eickhoff 2001). TOC up to 60% is reported (Curiale et al. 2002).

The Gondwana Group can be subdivided into two Formations: the Kuchma and the Paharpur Formation (Table 4-1). Alternations of fine to medium grained, whitish feldspathic sandstone and carbonaceous shale compose the most dominant rock types of the Kuchma Formation. In borehole Kuchma-XI (Figure 4-6) a 494 m thick interval has been drilled between 2363 and 2857 m, consisting of 307 m Sandstone with shale and coal intercalations, 135 m of dark grey to black carbonaceous shale and 52 m coal (Khan 2000). However, our quick-look evaluation of the GR log shows just 58 m of shale with higher GR readings (Appendix 0).

The Late Permian Paharpur Formation resembles the Kuchma Formation. Medium, coarse to very coarse, whitish to light grey feldspathic sandstones constitute the most dominant lithology. Abundant are carbonaceous shales with streaks, pockets, lenses, bands of coal and carbonaceous materials (Khan 2000). A representative succession has been encountered in borehole EDH-10 with 322 m sandstone, 95 m shale and 68 m coal (Figure 4-7). The volatile matter on a dry basis is between 30 and 40%, corresponding to high volatile bituminous coal.

The Rajmahal Group (Jurassic to Late Cretaceous) unconformably overlies the Gondwana Group and the Precambrian rocks; and comprises two formations: the Rajmahal Traps and the Sibganj Trapwash (Table 4-1). The Rajmahal Traps are about 610 m thick and consists of hornblende basalt, olivine basalt and andesite with minor agglomerate, tuff and ash beds. The Sibganj Trapwash unconformably overlies the volcanic rocks of the Rajmahal Traps; and consists of poorly sorted coarse sandstones (trapwash), shale/claystone with locally kaolinitic sandstone. The rocks of the formation are thought to have been deposited in fluvial and coastal settings, particularly tidal flats, deltaic and lagoonal environments. No lithologies favourable for shale gas generation are contained in the Rajmahal Group.

Table 4-1 Stratigraphic Succession of the Stable Shelf Province

Series	Group	Formation	Lithology	Depositional environment
Holocene		Alluvium	Silt, clay, sand and gravel	Fluvial-alluvial and rapidly prograding delta
Pleistocene - Late Pliocene	Barind (200 m)	Barind Clay (50 m)	Yellowish brown to reddish brown clay, silty-clay and silty-sand with minor sand	
		Dihing (150 m)	Oxidized sand with clay and silicified wood fragments	
Early Pliocene - Late Miocene	Dupi Tila (280 m)	Dupi Tila (280 m) *(Debagram and Ranaghat)**	Claystone, siltstone, sandstone and gravel	Fluvial and prograding delta-shelf
Early to Middle Miocene	Jamalganj (415 m)	Jamalganj (415 m) *(Pandua)**	Alternating sandstone, siltstone and shale	Delta front to shelf and slope
Oligocene	Bogra (165 m)	Bogra (165 m) *(Memari and Burdwan)**	Siltstone, carbonaceous shale and fine-grained sandstone	Increasing sedimentation rates
Late Eocene	Jaintia (735 m)	Kopili Shale (240 m)	Sandstone, locally glauconitic and highly fossiliferous; shale with thin calcareous bands	Deltaic to slope
Middle Eocene		Sylhet Limestone (250 m)	Nummulitic limestone with sandstone interbeds	Carbonate platform
Early Eocene		Tura sandstone (245 m) *(Jalangi)**	Sandstone, coal and shale	Deltaic to outer shelf
Paleocene				
Middle to Late Cretaceous	Rajmahal (840 m)	Sibganj Trapwash (230 m) *(Ghatal and Bolpur)**	Coarse yellowish brown sandstone; volcanic materials with clay	In western Bangladesh only: Coastal to fluvial-alluvial
Early Cretaceous - Jurassic		Rajmahal Traps (610 m)	Amygdaloidal basalt, andesite, serpentinized shale and agglomerate	Subaerial lava flows Fluvio-deltaic to shallow marine
Late Permian	Gondwana (955 m)	Paharpur (465 m)	Feldspathic sandstone with thick coal seams	Fluvial to delta plain, coal swamps
Permian - Carboniferous		Kuchma (490 m)	Coarse-grained sandstone and conglomerate with thick/thin coal seams	
Precambrian		Basement complex		Stable Gondwana Co

(After Alam et al. 2003, p. 192) Green boxes indicate shale prone intervals. * Denote equivalent formation of West Bengal, India

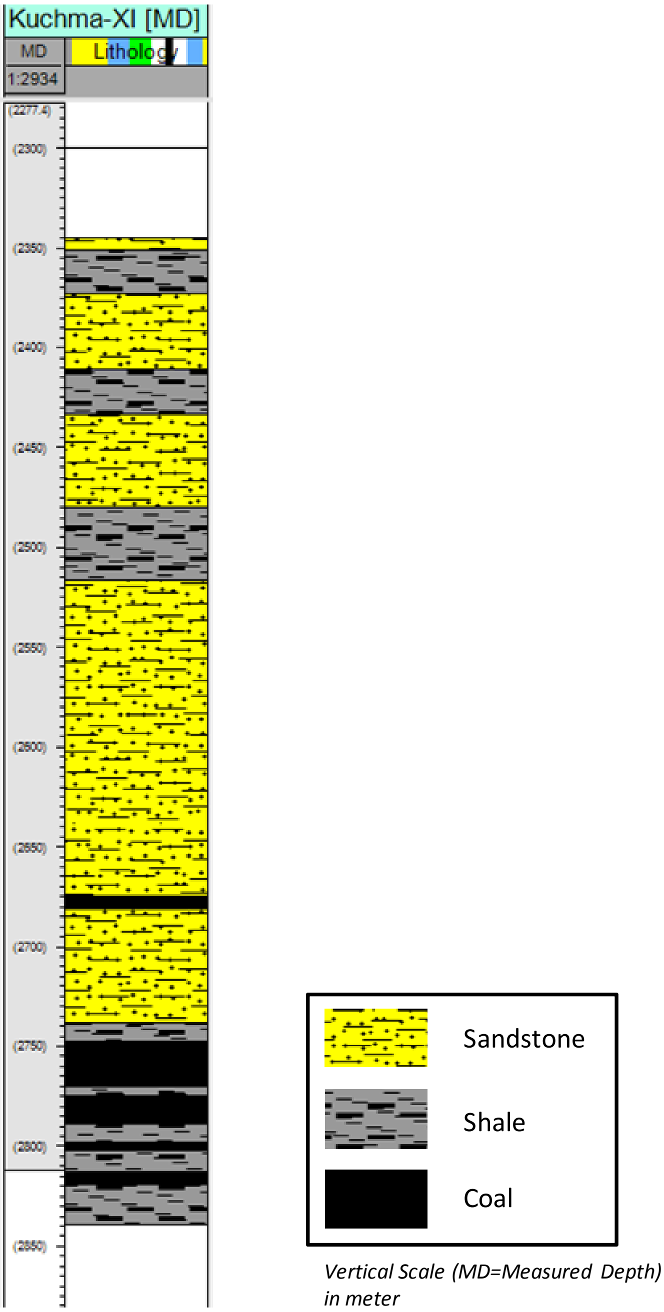

Figure 4-6 Simplified Lithology of the Kuchma Formation in borehole Kuchma-IX

(Source: Compilation for this report), lithology after Khan 2000)

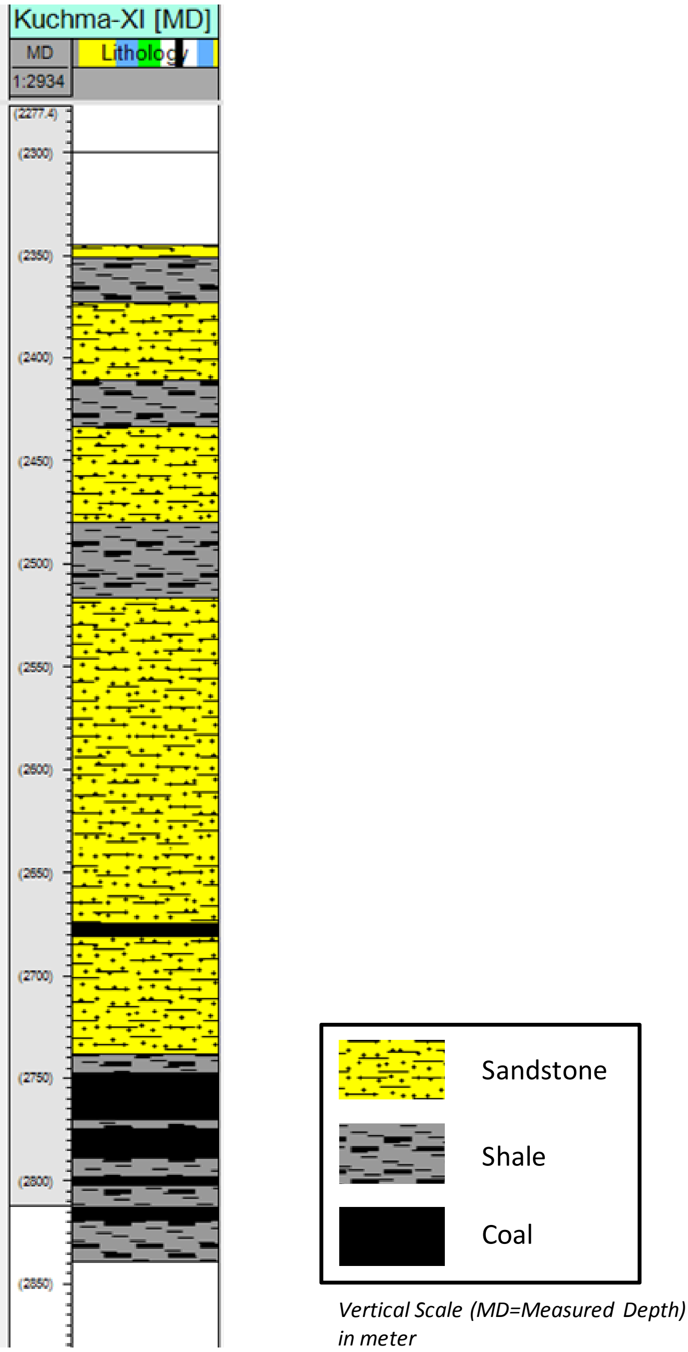

Figure 4-7 Simplified lithology of the Paharpur Formation in borehole EDH-10

(Source: compilation for this report, lithology Khan et al. 2000)

4.2 Paleocene to Eocene

The Cretaeceous is unconformably overlain by the Jaintia Group, which consists of the Tura Sandstone, Sylhet Limestone and Kopili Shale Formations (Table 4-1).

The Tura Sandstone is about 245 m thick and consists of sandstones, siltstone, carbonaceous mudstone and thin coal seams. In the representative section in well Lalghat V the unit is subdivided into four parts:

- Some 70 m predominantly sandstone, shale and coal seams; the shale is generally carbonaceous and contains plant fossils; Grey, arenaceous shale is also common; Pyrite and other ferruginous nodules and calcareous concretions have developed in some beds;
- Some 35 m limestone with beds of shale and sandstone; shale generally carbonaceous and non calcareous; additionally non calcareous grey shale; coal at top
- Some 15 m sandstone and two coal seams;
- 20 m limestone (partly drilled, base not reached at well´s total depth) with interbeds of shale and sandstone; shale dark grey, carbonaceous, soft, with mica; additionally calcareous shale without mica.

In well Bogra X-1 the Tura Sandstone was encountered between 1973 m down to the total depth at 2100 m. The shale is described as being dark to dark brown, compact, flaky, and carbonaceous.

Thicknesses and depth settings for the Tura Sandstone are shown in Figure 4-9.

The Sylhet Limestone is massive and compact containing abundant foraminifera with minor algal debris. Sylhet Limestone forms a broad time-transgressive facies extending from the shelf edge to the upper shelf area. Thickness of the formation decreases from over 800 m on the shelf edge in the southeast to about 250 m in wells located in the northwestern part of Province 1 (the stable shelf).

The Kopili Shale Formation (Late Eocene) conformably overlies the Sylhet Limestone and comprises thin-bedded sandstone and shale in varying proportions, and occasional fossiliferous limestone. These rocks are interpreted as deposits of distal deltaic to shelf and/or slope environments. Maximum thickness of the formation is 240 m in Bangladesh. Due to the unconformal contact with the overlying sequences the penetrated borehole thickness varies much. In the Singra-1X well it is 30 m thick. In Bogra X-1 (Figure 4-8) it is 173 m thick and according to our quick-look interpretation of the GR (Appendix 11.3), it consists of 79 m sandstone and of 94 m shale. In outcrop section of the Kopili Hill (Assam, India) the formation is about 500 m thick, while in West Bengal (India) it is much thinner, probably about 30 m. Outcrop samples from the Assam area indicate TOC up to 16%. No TOC measurements and pyrolysis analyses (type of kerogen) have been made in the wells (Reimann 1993). The completion report of the Bogra-I well indicates good source rock rating. Kerogen includes algal, amorphous and herbaceous categories.

The following descriptions for the Kopili Formation from various areas are provided in Khan 2000:

- Bagali Bazar: grey, dark grey to black mostly calcareous and grey to bluish grey sparsely fossiliferous shale, light grey to grey, fine to medium grained sandstone, medium hard, subordinated grey fossiliferous limestone;
- Lamakata-Charagaon-Lalghat-Takerghat-Bhangerghat area: mostly grey, strinking uniform in composition with several interbeds of sandstone and limestone; non calcareous shale common in the upper part;
- Kuchma and Bogra: Alternating very coarse sandstone and shale, lower part contains fine to very fine glauconitic sandstone and grey, silty carbonaceous and pyritic shale.

Figure 4-10 shows thicknesses and depth settings for the Kopili Shale Formation.

CORE NO. 1

TYPICAL FEATURE OF KOPILI SHALES REPRESENTED BY DARK COLOUR AND WELL DEVELOPED LAMINATION & PARTINGS.

Figure 4-8 Core within the Kopili Shale (Bogra X-1)

(BAPEX Geological Report, Bogra x-1)

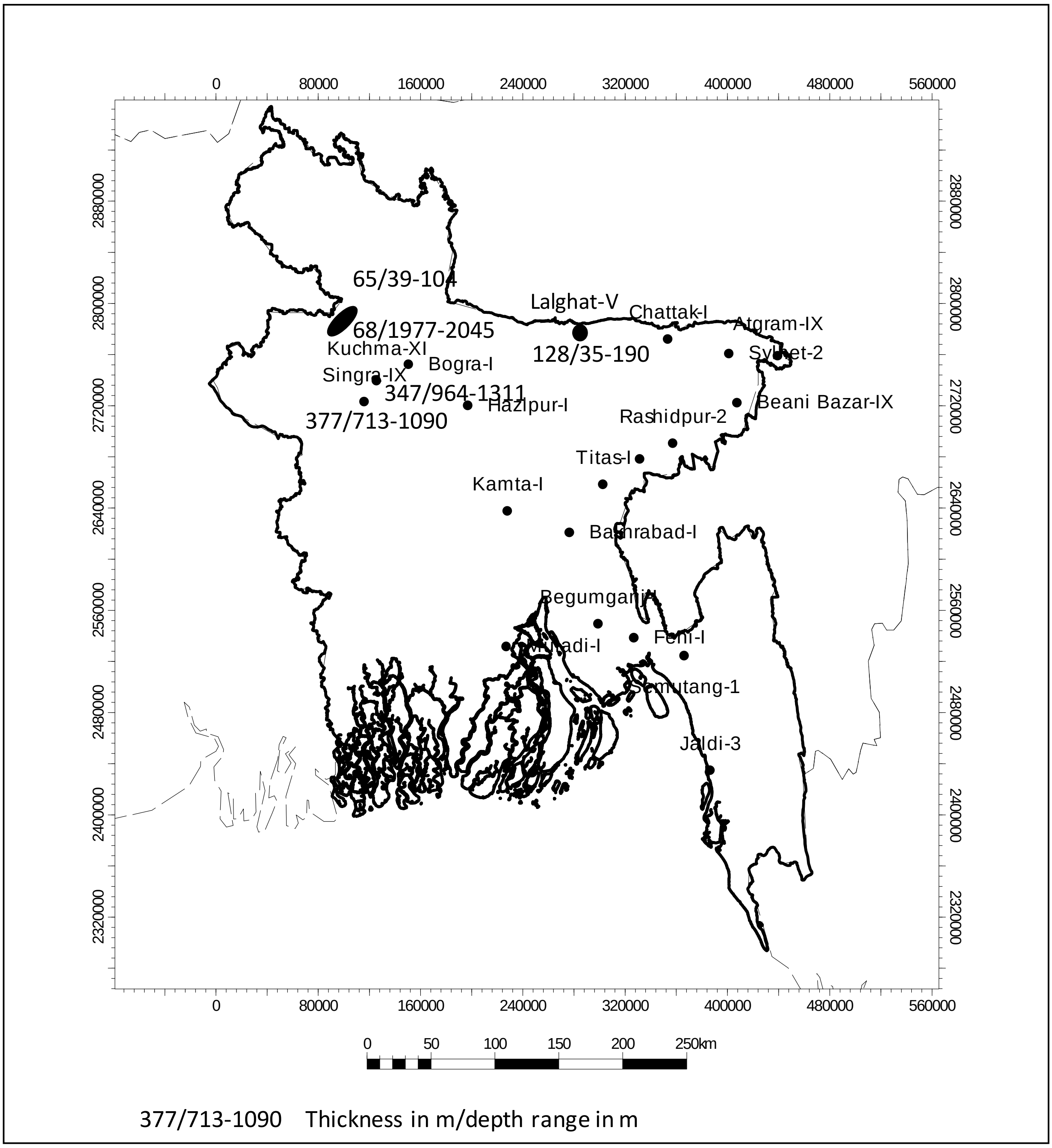

Figure 4-9 Thickness and depth ranges of the Tura Sandstone

Map projection: UTM 46N

(Source: Compilation for this report)

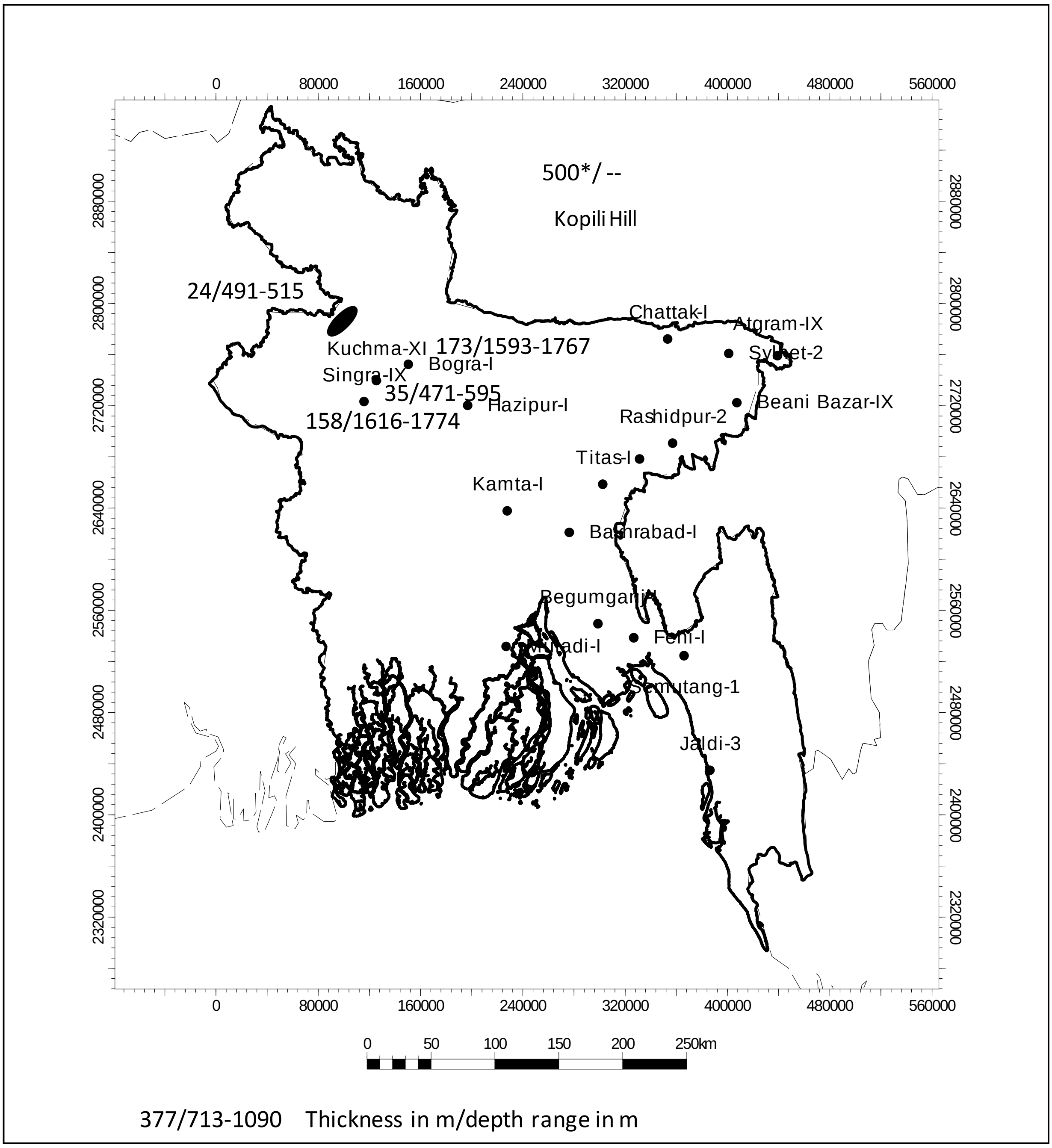

Figure 4-10 Thickness and depth ranges of the Kopili Shale Formation

* thickness according to Khan, F.H. (2000) / no depth range stated

Map projection: UTM 46N

(Source: Compilation for this report)

4.3 Oligocene

On the stable shelf the Oligocene is built up by the Bogra Formation. In the Sylhet Trough and in the Chittagong-Tripura Fold Belt it is equivalent with the Barail Group.

The Bogra Formation on the stable shelf is ca. 165 m thick and consists of sandstone and mudstone with a high sand/mud ratio. It was deposited in deltaic to marine shelf environments. It was encountered in the Bogra, Kuchma and Singra wells.

The time equivalents (Barail Group) in the Sylhet Trough and Chittagong-Tripura Fold Belt are up to 7200 m thick and represent deposition in deltaic, shelf, nearshore and tidal facies. TOC from outcrops near the border to India show 1.4 to 2.7% (Curiale et al. 2002). Reimann 1993 describes the Jenum Fm. in well Atgram-1X consisting of 261 m strongly compacted, dark siltstone and shales with interbedded quartzitic sand layers; at top conglomerates; thin conglomeratic intercalations. The TOC is between 0.75-3.74% and the shales are gasprone. Maximum R_o in Atgram-1X is 0.7%. In Hazipur X-1 a sand/shale ratio of 1:1 is reported.

Table 4-2 Stratigraphic Succession of the Sylhet and Hatia Trough

Age (approx.)	Group	Formation	Seismic marker	Thickness (max.) (m)
Holocene		Alluvium		
Pleistocene	Dihing	Dihing Upper Dupi Tila		3350
Late Pliocene	Dupi Tila	Lower Dupi Tila	→ Yellow	
Mid-Pliocene	Tipam	Girujan Clay Tipam Sandstone		3500
Early Pliocene Miocene	Surma	Upper Marine Shale Upper Lower	→ Brown → Red	3900
Oligocene	Barail	Undifferentiated Jenum Fm.	→ Violet	7200
Paleocene-Eocene	Jaintia	Kopili Shale Sylhet Limestone Tura Sandstone	→ Blue	
Pre-Paleocene	Undifferentiated sedimentary rocks (with some volcanics ?) on the continental basement complex			

(After Alam et al. 2003, p. 196) Green boxes indicate shale prone intervals.

Table 4-3 Stratigraphic Succession of the Chittagong-Tripura Fold Belt

Age (approx.)			Traditional nomenclature*		Proposed nomenclature	Thickness (m)	Brief description
Quaternary	Recent		Alluvium		Alluvium		
Quaternary / Neogene	Plio-Pleistocene		Dupitila Fm.		Kaptai Group (A)	1100 to 1600	Large-scale, low-sinuosity braided river deposits grading upward into high-sinuosity meandering river deposits. Very high sand-shale ratio. Characteristically yellowish-brown very coarse to fine sand.
			Tipam Group	Girujan Clay Fm.			
			Tipam Group	Tipam Sst. Fm.			
Neogene	Miocene	Late	Surma Group	Boka Bil Fm.	Mirinja Group (B)	1200 to 1600	Alternating nearshore sand and shelfal mud with regional erosion surfaces related to relative sea level cycles. High sand-shale ratio. Predominance of tidal structures is obvious.
Neogene	Miocene	Middle	Surma Group	Bhuban Fm.	Sitapahar Group (C)	1000 to 1500	Slope mud predominant; sandy deposits ranging from base-of-slope turbidites to nearshore tidal sands. No major erosion surfaces.
Paleogene	Oligocene	Early	Surma Group	Bhuban Fm.	boundary not established Chittagong Group (mostly in subsurface)	2000 +	Speculated submarine fan complex in trench setting; mud dominated.
Paleogene	Oligocene		base not exposed Barail Group (in subsurface)				

(After Alam et al. 2003, p. 201) Green boxes indicate shale prone intervals.

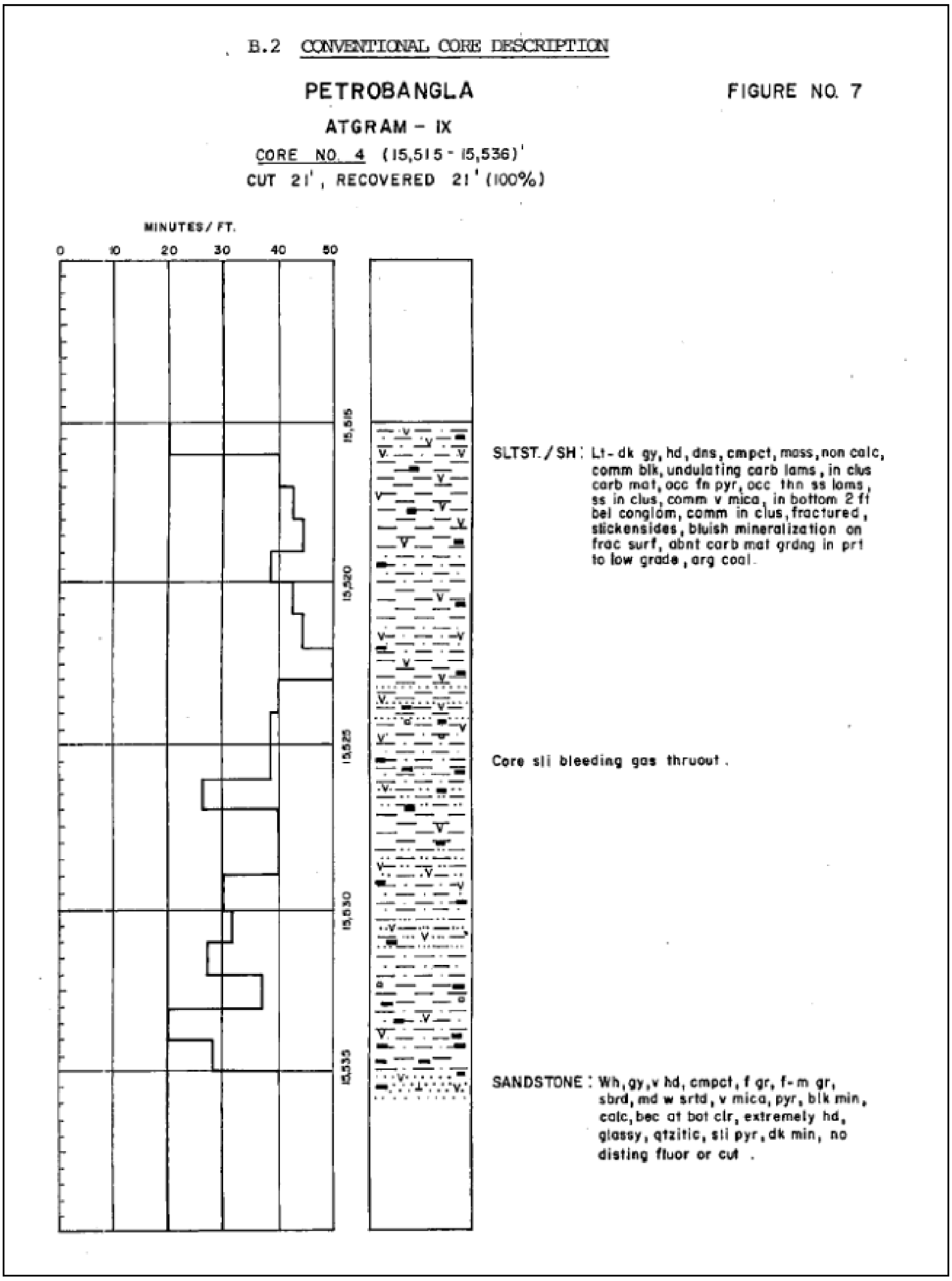

Figure 4-11 Jenum Shale, cored interval in Atgram-1X

(Source: Atgram-1X, Well Completion Report, July 1982)

4.4 Miocene

The Oligocene section on the stable shelf is unconformably overlain by the Early to Middle Miocene Jamalganj Formation. In the other provinces it is represented by the time equivalents of the Surma Group. The Jamalganj Formation comprises alternating sandstone, siltstone and shale of deltaic origin. It is about 415 m thick. The thickness of the Surma Group varies between 2700 (Atgram-IX well) to over 3900 m (Fenchuganj-II). It is subdivided into the underlying Bhuban Formation and the overlying Boka Bil Formation. The Bhuban Formation is interpreted as prodelta to delta front deposits. The Boka Bil Formation constitutes sediments of subaerial to brakish environments with shallow marine incursions. In the Chittagong-Tripura Fold Belt Alam et al. 2003 introduce the Sitapahar Group as an equivalent to the Middle Surma Group, ranging in thickness between 1000 to 1500 m and representing a progressive basin filling from deep marine slope apron to shallow marine nearshore deposits. Here the Mirinja Group (equivalent to the Upper Surma Group) is 1200 to 1600 m thick and shows a shelfal to coastal succession.

In outcrops along the river Hari the shales within the Middle and Upper Bhuban are characterized as well laminated, bluish to grayish in colour and weathering to yellowish grey. Calcareous matrix imparts moderate hardness to the shale. The silty shale within the Boka Bil Formation is light grey to grey, laminated to thin bedded, moderately hard, fissile and cleaved (Khan 2000). In well sections the Surma Group as a whole represents an argillaceous formation. Shale and siltstone form the most dominant rock types. They contain numerous thin and thick beds of fine to medium grained sandstones. The sandstones contain all of the hydrocarbons so far discovered in the Bengal Basin in Bangladesh. Both shale and siltstone are often sandy and contain paper thin bands of sandstone. Calcareous material frequently forms a part of the matrix (Khan 2000). The top of the Surma Group constitutes a predominantly shaly unit, designated as the ‘Upper Marine Shale’, which represents a 230-m thick pelitic sequence marking the last marine incursion, and is probably the sole seismic marker horizon throughout the Sylhet Trough. In well Beani Bazar-1X it is 233 m thick and composed of grey to dark grey claystone, slightly firm to soft, with traces of pyrite, mica and carbonaceous material, thin laminations of fine grained sandstone and siltstone. In Atgram 1X well, this shaly unit is eroded.

TOC of the Surma Group ranges between 0.2 and 1.8% (Curiale et al. 2002). From samples of eight gasfields Farhaduzzaman et al. 2012 describe the organic matter to be dominated by terrestrial type III kerogen with lesser amount of type II (marine). TOC ranges are given between 0.16 and 0.9 wt % for the Bhuban Formation and 0.15-0.55 wt % for the Bhoka Bil Formation. The vitrinite reflectance from shale intervals ranges between 0.56 and 0.76% in the Bhuban Formation and from 0.48 to 0.76 in the Boka Bil Formation, representing immature to early oil mature. A further study for the Patharia Structura in Northeast Bangladesh (Hamid 2000) describes the Lower Bhuban Formation to be in the early oil maturity stage at depths between 4680 and 5685 m. The wet gas zone is seen below 7000 m.

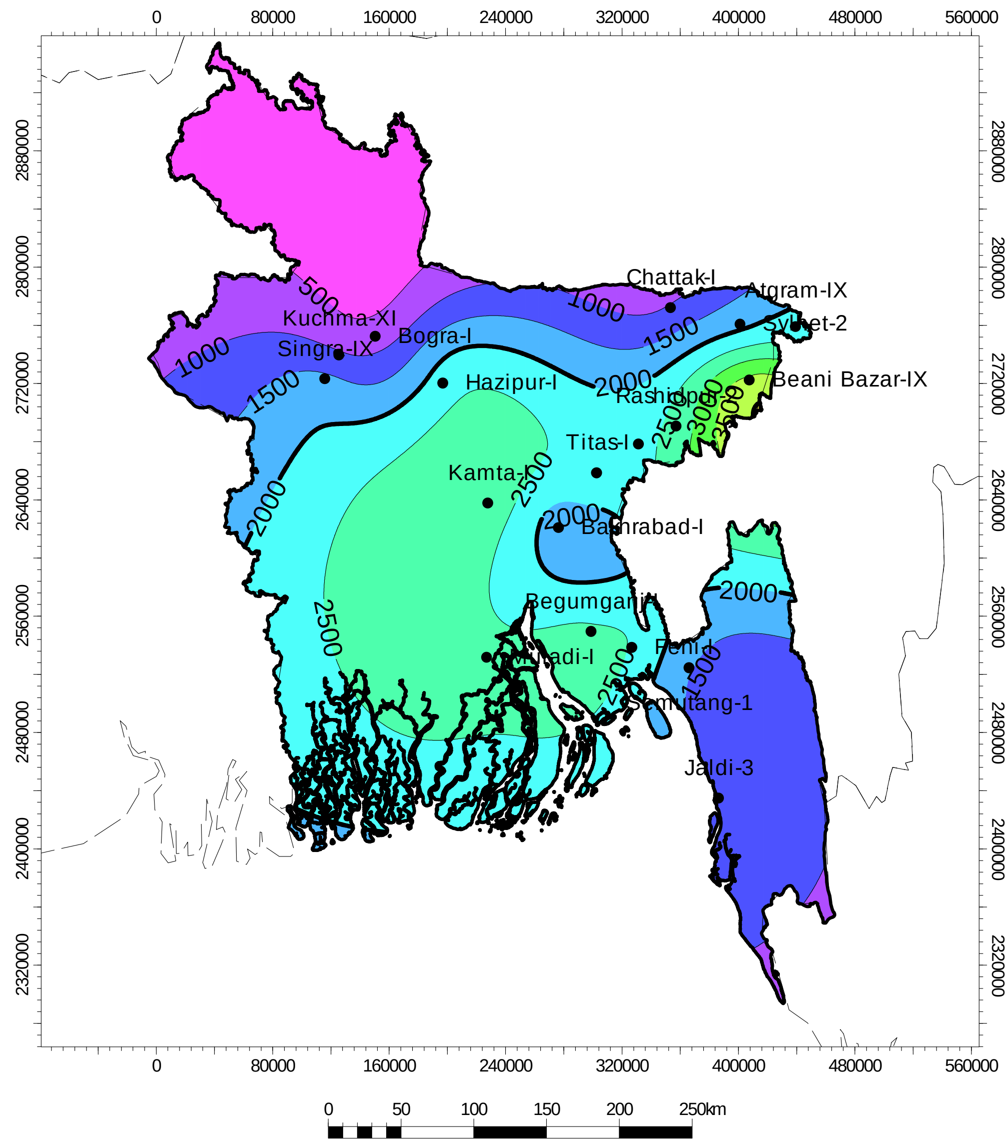

Figure 4-12 Depth map at Top Bhuban Formation

(Data source: Uddin & Lundberg 2004), Map projection: UTM 46N

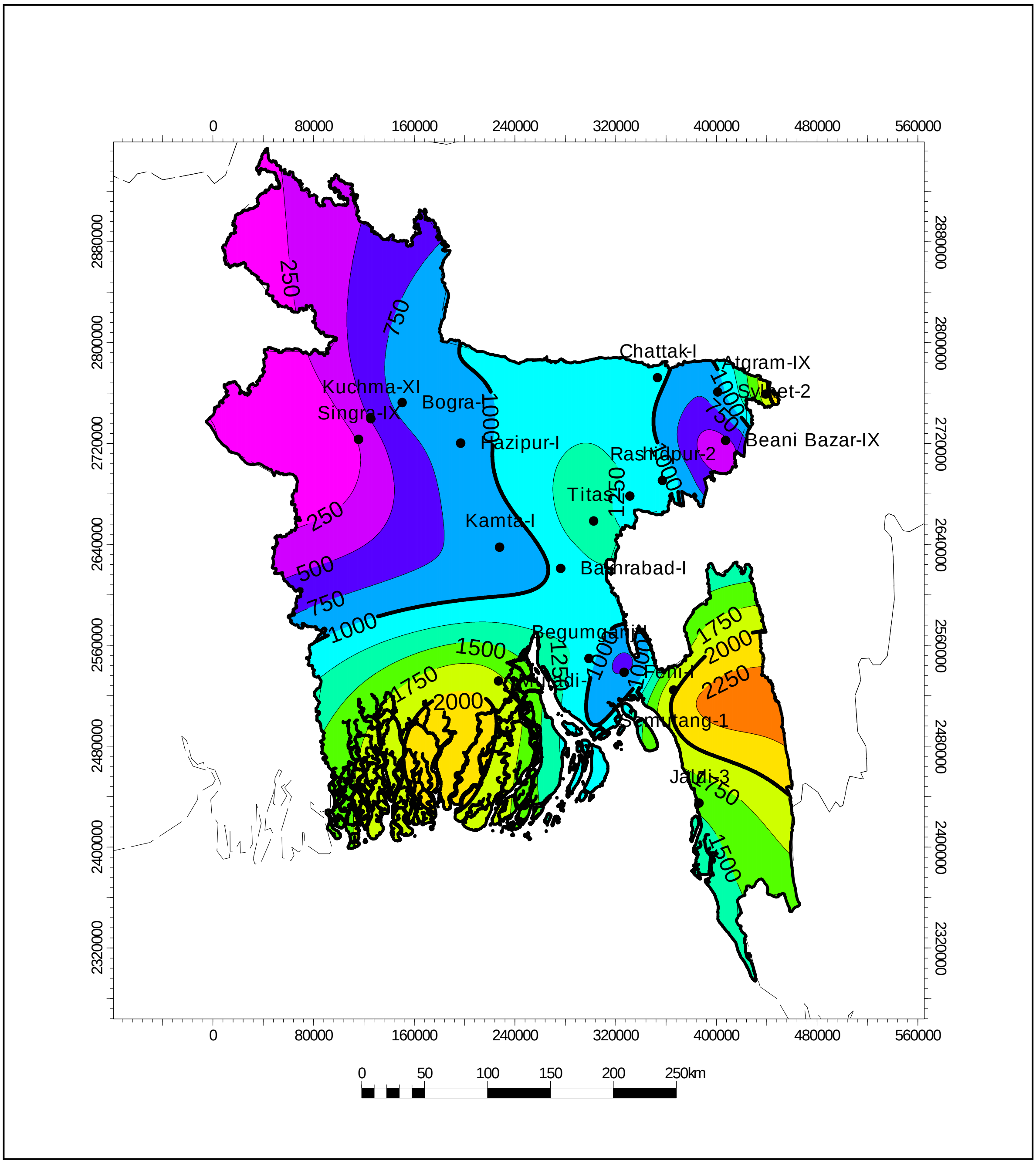

Figure 4-13 Thickness map of the Bhuban Formation

(Data source: Uddin & Lundberg 2004), Map projection: UTM 46N

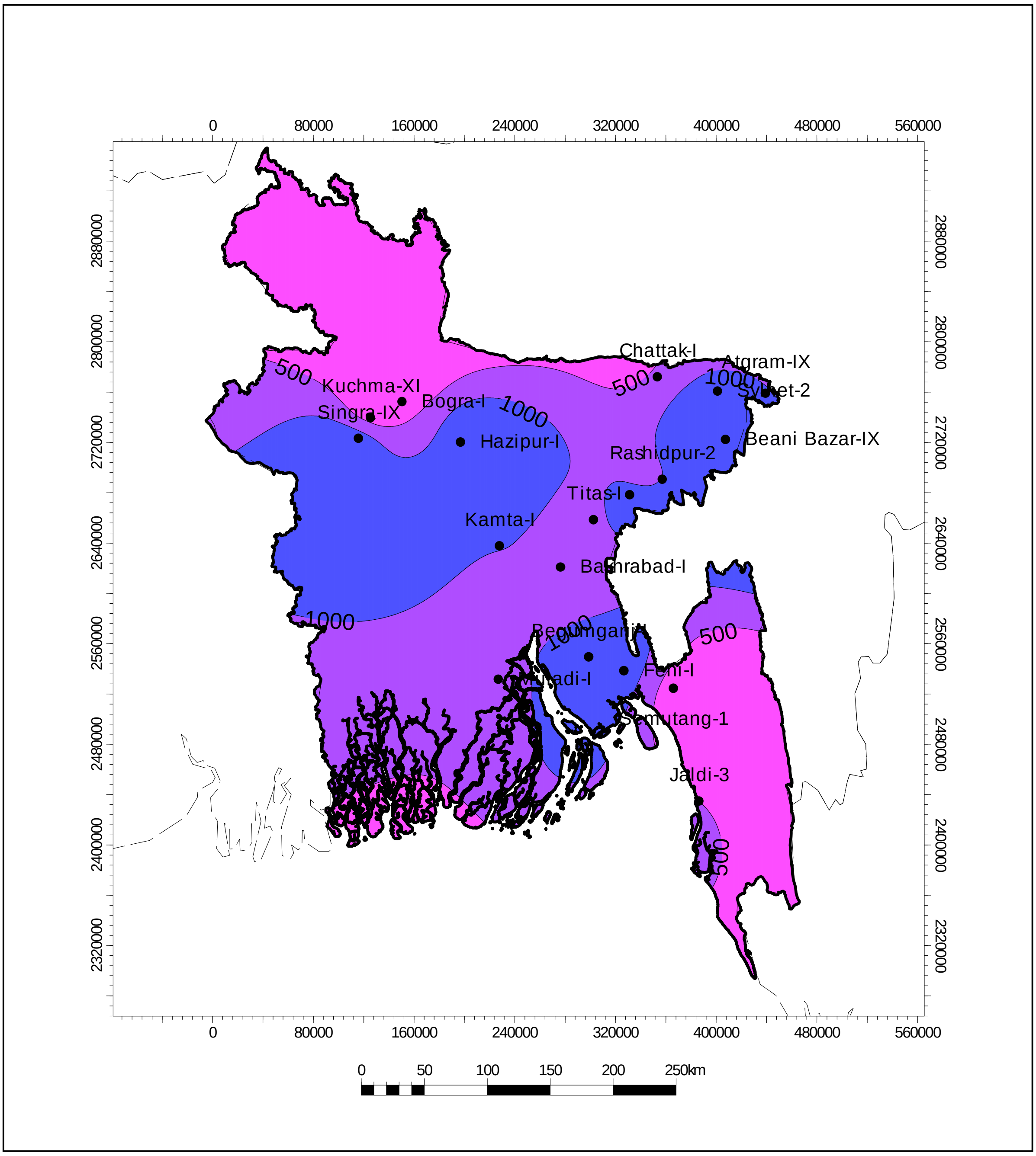

Figure 4-14 Depth map at Top Boka Bil Formation

(Data source: Uddin & Lundberg 2004), Map projection: UTM 46N

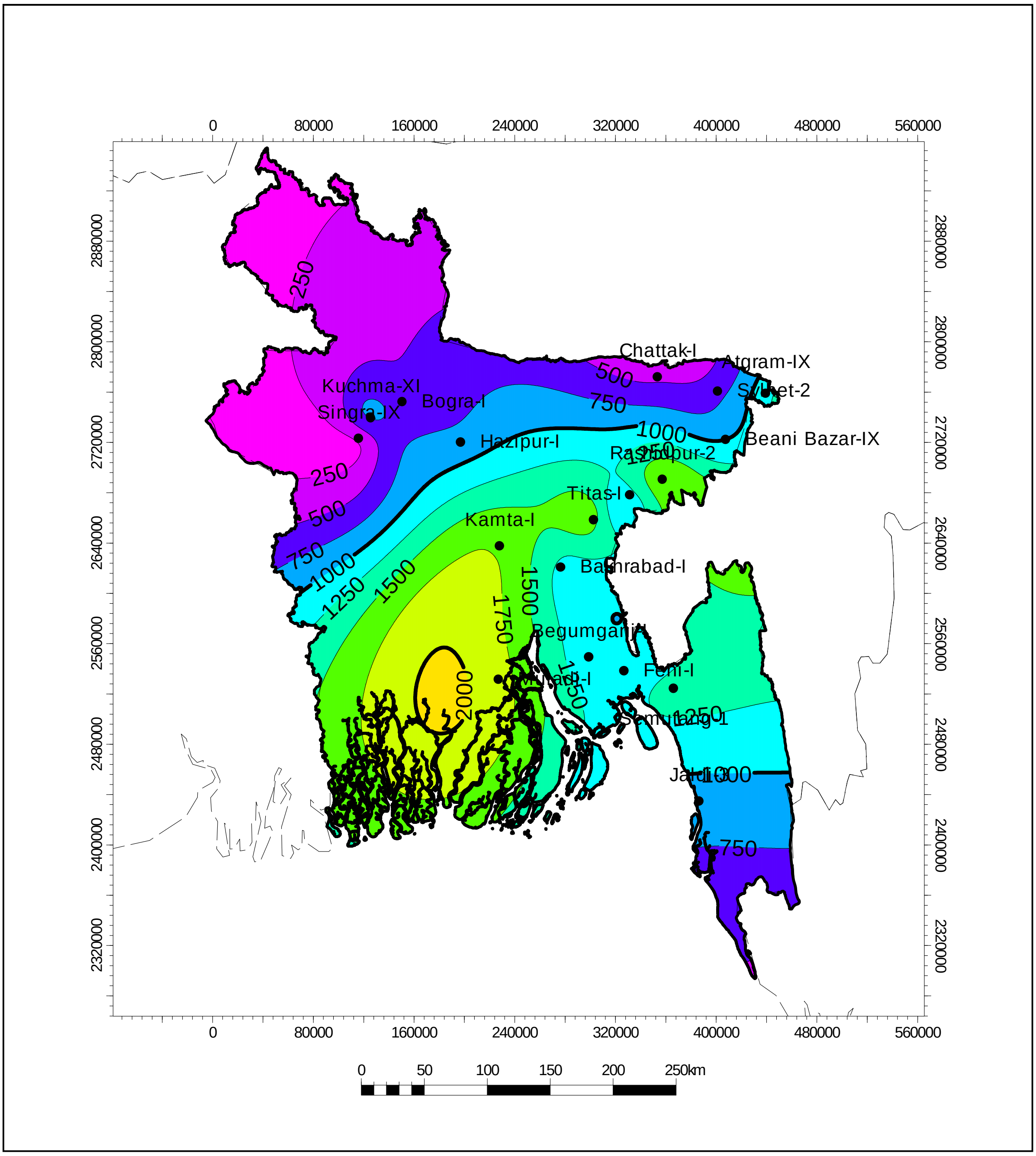

Figure 4-15 Thickness map of the Boka Bil Formation

(Data source: Uddin & Lundberg 2004), Map projection: UTM 46N

4.5 Pliocene and Quaternary

In the stable shelf region the Jamalganj Formation is unconformably overlain by the Dupi Tila Formation that was deposited in a fluvial and prograding delta-shelf environment. It consists of light grey to yellowish grey clayey sandstone, siltstone and claystone with minor gravel. The formation is 280 m thick. Separated by another unconformity, the Dupi Tila Formation is overlain by Barind Clay and Dihing Formations. The Dihing Formation is formed by coarse sand and sandstone, siltstone and claystone with some pebble beds. The Barind Clay predominantly consists of yellowish to reddish brown clay, silty clay and silty sand with minor pebble. Thickness of the Barind Group is about 200 m. The depositional environment resembles the Dupi Tila Formation.

In the Sylhet Trough the Tipam Group unconformably overlies the Surma Group, subdivided into the Tipam Sandstone and Girujan Clay Formations. The Tipam Sandstone comprises coarse grained, cross-bedded sand and pebbly sand, with common carbonized wood fragments and coal interbeds, interpreted as braided fluvial systems. The Girujan Clay is composed mainly of mottled clay, accumulated in subaerial conditions as lacustrine and fluvial overbank deposits. Unconformably overlying the Tipam Group, the Dupi Tila Sandstone comprises a sandy lower unit and Dupi Tila claystone an upper argillaceous unit. The sediments of the Lower Dupi Tila Formation are similar to the Tipam Sandstone, except that they tend to be poorly consolidated. Sediments of the Lower Dupi Tila Formation are characteristically fine to medium-grained sandstones, commonly silty and containing lignite fragments and fossil woods, with intercalation of mottled clay horizons. The fining-upward sequences of the Lower Dupi Tila Formation, with alternating channel and floodplain deposits, have been interpreted as meandering river. The younger Pleistocene sediments of the Dihing Formation have been identified only locally as relatively thin subaerial deposits unconformably overlying the Dupi Tila Group. A huge thickness of sediment (nearly 7 km) has been deposited in the Sylhet Trough from Mid-Pliocene onward that could be due to the Mio-Pliocene uplift of the Chittagong– Tripura Fold Belt and the Himalayas.

In the Chittagong-Tripura Fold Belt the Tipam Group and Dupi Tila Formation overlie the Surma Group. They are probably Plio-Pleistocene in age and range in thickness from 1100 to 1600 m. The Tipam Group represents braided stream coastal to fluvial deposits, whereas the Dupi Tila Formation represents deposits of meandering river systems. A 100–200 m thick and rather patchy clay deposits (Girujan Clay) sometimes divides the two members.

The Quaternary in the Bengal basin was marked by a general regression presumably due to voluminous sediment influx from the highlands. Much of the present geomorphic landscape of the Bengal basin and the regions surrounding it developed during this time. Pleistocene and Holocene deposits are represented on land by areas of red clay deposits, a coastal coral bed and several small sand bodies, but voluminous deltaic deposits of this age are restricted to the offshore regions of the Bay of Bengal.

5 Data Base

Principally there are three types of data sets, which will be useful to establish shale plays. These are:

- Regional and General Geological Data
  Recent Study: the TOR refer to a recent study confirming the potential for shale gas in Bangladesh (Khan, A.H. et al. 2011)

  Existing reports, maps and publications: stratigraphy, facies developments, regional thickness variations, structural framework, basin development, etc.
- Drill Data

  General Review: number and location; target layers, thickness and parameters measured and analysed
- Geophysical Data

  Wireline log data (in particular Gamma Ray logs)

5.1 Regional and General Geological Data

The used data are cited in the reference list (chapter 10).

5.2 Borehole Data

Relevant maturity and TOC data are listed in Appendices 11.2.1 and 11.2.2 respectively. Maturity samples were available for seven wells, TOC from 9 wells.

5.3 Wireline Logs

The data collection was focussed on the scanning of Gamma Ray logs from seven key wells. A listing of the measured depth intervals in feet and meter with the respective graphic file are contained in Appendix 11.3. The graphic files in tif-format are contained on the report´s data CD.

6 Evaluation Parameters

Since the successful start of shale gas operations in the USA, the important parameters of shale plays are well known and have been employed for many studies of shale plays world-wide. The parameters can be subdivided into three groups, viz. quality of source rock for oil and gas formation, current location and quality of source rock conducive to reservoir stimulation. The latter is less critical for conventional gas deposits, but is very important in the context of shale gas. Table 6-1 lists evaluation parameters and their significance (after TNO 2009 and eia 2013).

Table 6-1 Evaluation Parameters and Significance.

Parameter **Source Rock**	**Significance**	**Comments**
Gas and HC Formation		
Extent and Thickness	**Very important**	yields finally volume of GIIP
Thermal Maturity	**Important**	vitrinite reflectance; R_0 1-1.3 wet gas, R_0 >1.3 dry gas
TOC	**Very important**	minimum 2 %; regional changes
Type of Kerogen	**Important**	marine sediments are preferred to terrestrial coal-bearing strata.
Content of gas	**Very important**	free and adsorbed and/or hydrocarbons
Current Setting		
Geographic Location	**Very Important**	Limited to onshore portion of a basin due to economic reasons
Burial depth	**Important**	controls gas pressure; shallow depth low pressure and higher water content; deep depths cost intensive and reduced

		permeability
Seal	**Important**	possible losses
Structural Framework (fracture system, stress regime)	**Important**	controls breakage of seal and possible expulsion; controls on stimulation
Gas pressure	**Important**	
Water content and composition	**Moderate**	
Quality Stimulation		
Modal composition of shale (qtz, clay, carb)	**Very Important**	Marine shales have low clay mineral content but high in brittle minerals as quartz, feldspar and carbonate. Brittle shales respond favourably to hydraulic stimulation. Shales deposited in non-marine settings (lacustrine, fluvial) tend to be higher in clay, more ductile and less responsive to hydraulic stimulation.
Composition of clay minerals	**Important**	
Porosity and permeability	**Moderate**	

During exploration for conventional HC deposits detailed studies of source rocks are often not done and hence focus has to be on available key parameters, which will be discussed in more detail below.

Volumes of shales would be calculated using thickness and extend of the strata using published data and wells.

6.1 Key Parameters

Data from shale plays in the USA and Canada suggests the following key parameters with cut-off values (TNO 2009 and eia 2013):

Parameters	Value	
Burial depth	>1 km and < 5 Km	current burial depth between 1000 and 5000 m.
Thickness	> 20 m	minimum thickness required.
TOC	> 2 wt.%	total organic carbon is the amount of carbon bound in an organic compound. It is one of the parameters, which is generally determined in source rocks analysis. A lower cut-off of 2 % can be deducted from empirical values of shale plays world-wide. Higher values do indicate higher potential.
Type of Kerogen (OM)	II	in known shale gas plays organic material comprises mainly type II, i.e. being sedimented under marine conditions and consisting of plant, spores, exines, resins and bacterially degraded algal matter. Marine-deposited shales tend to have lower clay content and tend to be high in brittle minerals such as quartz, feldspar and carbonates. Brittle shales respond favorably to hydraulic stimulation. Shales deposited in non-marine settings (lacustrine, fluvial) tend to be higher in clay, more ductile and less responsive to hydraulic stimulation.

Maturity (vitrinite reflectance)	>0.8< 3.3 % R_0	vitrinite is a primary component (maceral) of coal and many sedimentary kerogens. Vitrinite reflectance (R_0 or VR) is a key method for identifying the maximum temperature history of sediments in sedimentary basins. Increase in vitrinite reflectance indicates exposure to higher temperatures. Hence, temperature ranges corresponding to those of hydrocarbon generation (i.e. > 60°C to < 180°C) can be determined: onset of oil generation corresponds to 0.5-0.6 % $R_{0;}$ termination of oil generation 0.85 - 1.1 % $R_{0;}$ onset of gas generation ('gas window') 0.8 - 1.3 % $R_{0;}$ termination 3.0 % R_0.

7 Evaluation of Shale Gas Plays in Bangladesh

7.1 Screening

The following stratigraphic units with principle shale gas potential have been identified:

- Gondwana Group (Kuchma and Paharpur Formations)
- Jaintia Group (Tura Sandstone and Kopili Shale)
- Barail Group (Jenum Shale)
- Surma Group (Bhuban and Boka Bil Formations)

The screening results in accordance to chapter 6.1 are shown in the following.

Maturity and TOC ranges are derived from the compiled well data (Appendix 11.2.1 and 11.2.2)

Shaly units of Pliocene-Pleistocene or Holocene age were not further screened since these are too shallow for shale gas extraction, mostly unconsolidated soft clays and mudstones and immature for gas generation.

Values for shale thickness describe continuous shale intervals as based on quick-look evaluations from the available Gamma Ray logs, i.e. Kuchma-X1 for the Gondwana Group, Bogra-1 for the Tura Sandstone and the Kopili Shale. For the Jenum Shale no decent log coverage was available. Thus, no shale thickness has been assigned. For the Boka Bil and Bhuban Formations a number of logs are available. Since the TOC and Maturity screening had already shown unfavourable conditions, no further detailed evaluations to assign the shale thickness on a well to well basis were conducted. However, the available logs show high Gamma Ray readings extending up to some 100 m in thickness in the Bhuban Formation. In places, where the Upper Marine Shale is present in the Boka Bil Formation it reaches a thickness of some 230 m.

Gondwana Group

Parameters	Burial depth	Shale Thickness	TOC	Type of Kerogen (OM)	Maturity (vitrinite reflectance)
Favourable	>1 km < 5 Km	> 20 m	> 2 wt.%	II	0.8 > R_0 < 3.3 %
Gondwana Group	0.2 to > 5 km	4 m	0.9 – 9.9	II and III	0.89 -1.80

Tura Sandstone

Parameters	Burial depth	Shale Thickness	TOC	Type of Kerogen (OM)	Maturity (vitrinite reflectance)
Favourable	>1 km < 5 Km	> 20 m	> 2 wt.%	II	0.8 > R_0 < 3.3 %
Tura/Cherra Sandstone	0.2 to > 5 km	32 m	0.4-4.3	III	0.43 – 0.47

Kopili Shale

Parameters	Burial depth	Shale Thickness	TOC	Type of Kerogen (OM)	Maturity (vitrinite reflectance)
Favourable	> 1 km < 5 Km	> 20 m	> 2 wt.%	II	0.8 > R_0 < 3.3 %
Kopili Shale	0.2 to > 5 km	36 m	0.6-4.7	II	0.46-0.56

Jenum Shale

Parameters	Burial depth	Shale Thickness	TOC	Type of Kerogen (OM)	Maturity (vitrinite reflectance)
Favourable	> 1 km < 5 Km	> 20 m	> 2 wt.%	II	0.8 > R_0 < 3.3 %
Jenum Shale	0.2 to > 5 km	Not evaluated*	0.8-3.7	II	0.46-0.56

* no decent log coverage available

Bhuban Formation

Parameters	Burial depth	Shale Thickness	TOC	Type of Kerogen (OM)	Maturity (vitrinite reflectance)
Favourable	> 1 km < 5 Km	> 20 m	> 2 wt.%	II	0.8 > R_0 < 3.3 %
Bhuban Formation	0.2 to 4	Up to some 100 m	0.2 to 1.7	III and (II)	0.43 to 0.49

Boka Bil Formation

Parameters	Burial depth	Shale Thickness	TOC	Type of Kerogen (OM)	Maturity (vitrinite reflectance)
Favourable	> 1 km < 5 Km	> 20 m	> 2 wt.%	II	0.8 > R_0 < 3.3 %
Boka Bil Formation	0.2 to 3.5	Up to some 230 m	0.1 to 0.9	III and (II)	0.38 to 0.65

One of the most important findings of this study is that low maturity values exclude all Formations of Tertiary Age for being suitable for economic shale gas production in the Bengal Basin.

This assessment is based on the following facts:

1. In none of the geochemical samples down to 4877 m (Jenum Shale in Atgram-1X) favourable maturity values greater than 0.8% have been reached;
2. Geochemical evaluations from several boreholes place the minimum depth for the beginning of gas generation (Ro>0.6%) at depths between 3900 and 4975 m, averaging to some 4000 m (Figure 7-1);
3. Compiled maturity vs. Depth trends indicate that the 0.8% threshold will be reached at depth below 5000 m (Figure 7-2). These findings are in line with BOGMC 1986 (Figure 7-3).

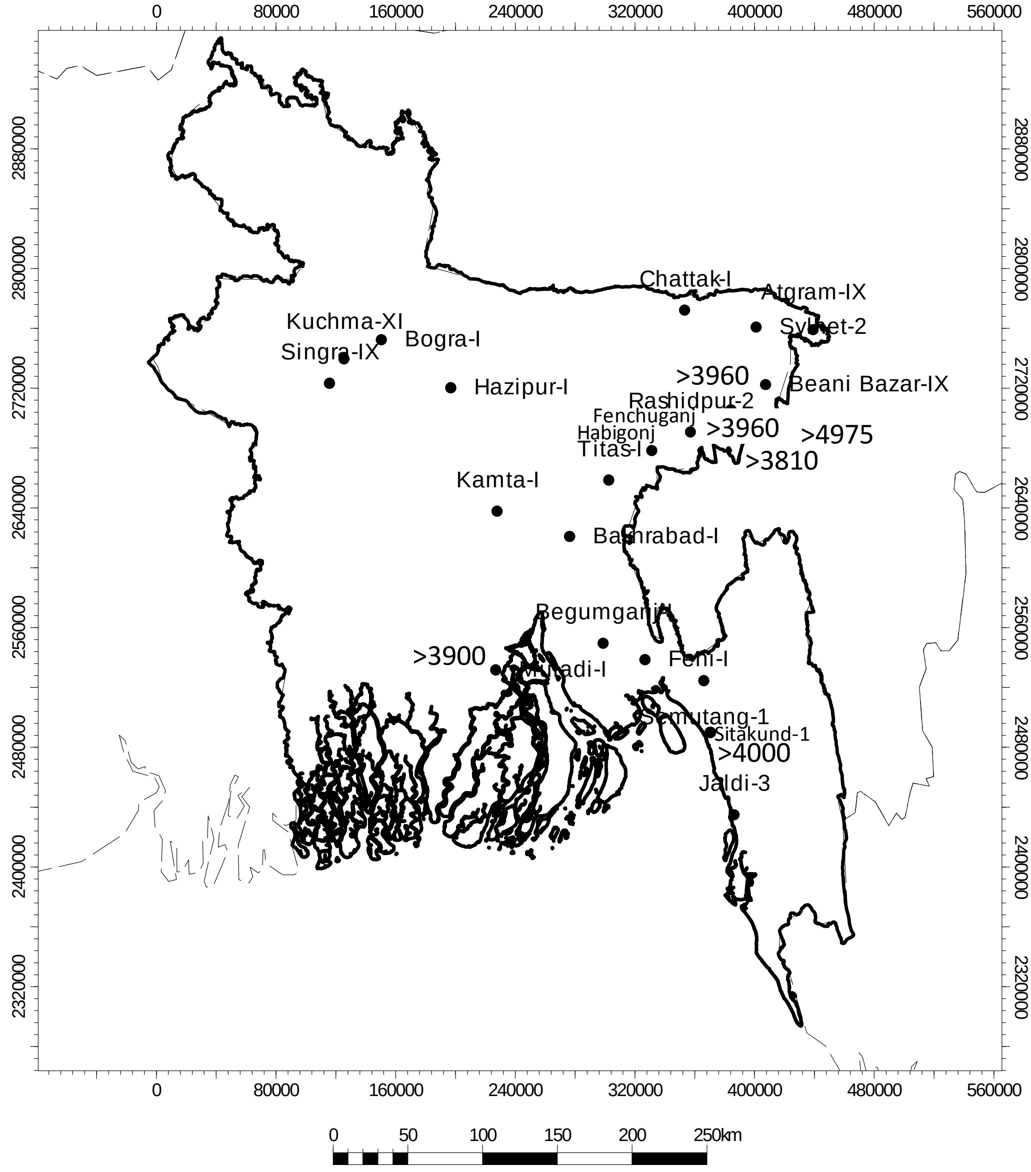

Figure 7-1 Minimum depth of gas window for the Tertiary rocks based on geochemical well reports

Map projection: UTM 46N

(Source: Compilation for this report)

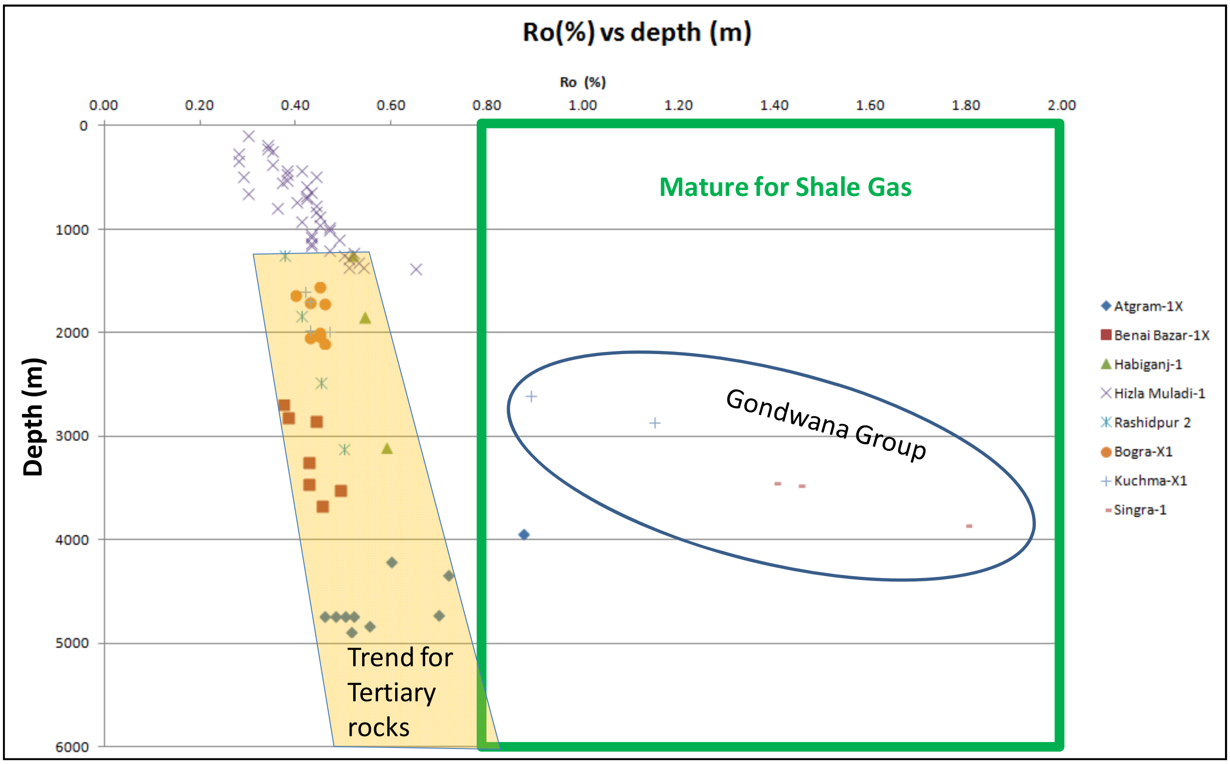

Figure 7-2 Maturity vs. Depth trends from compiled data

Data Base: Compilation for this study (Appendix 11.2.1)

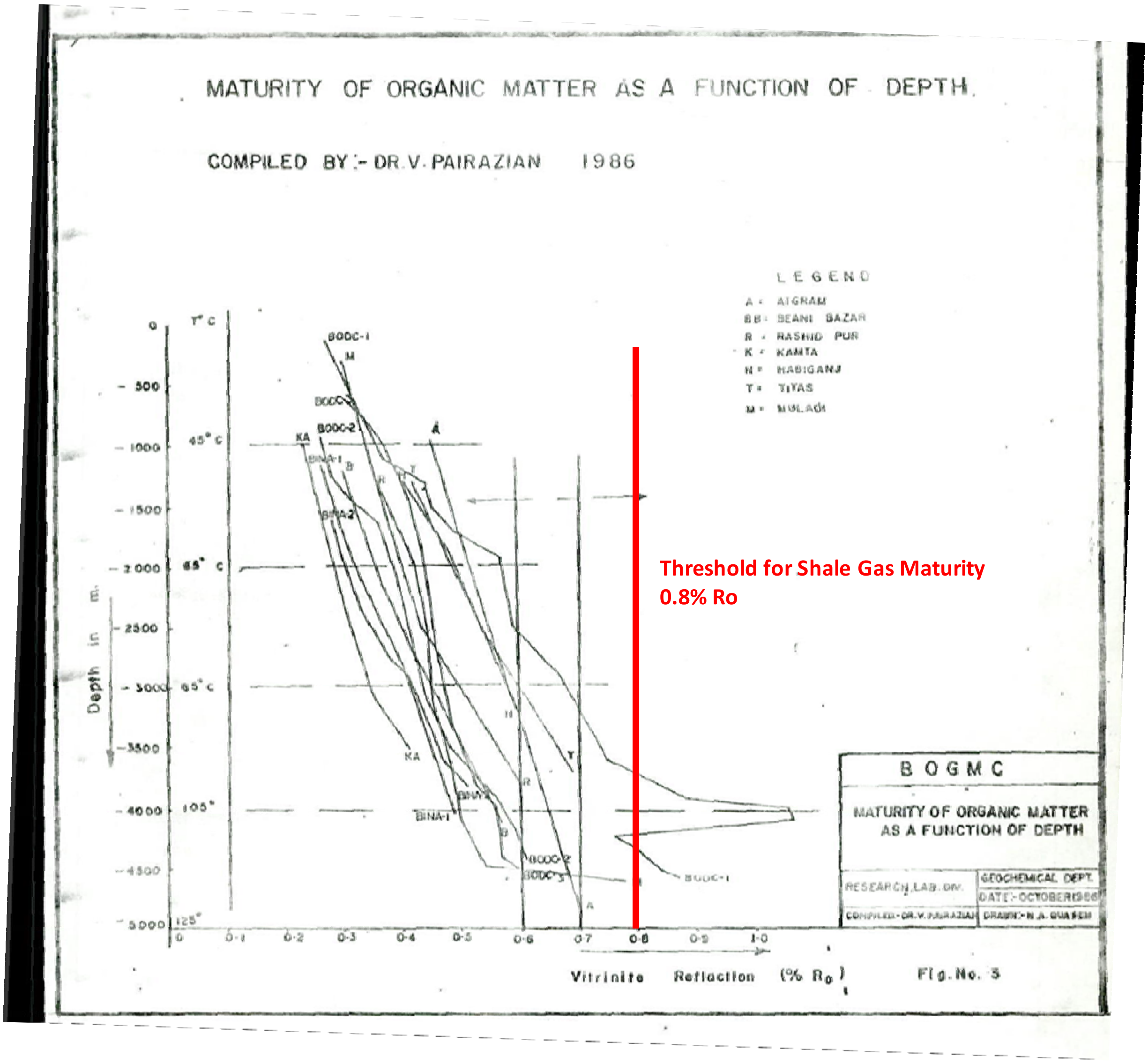

Figure 7-3 Maturity vs. Depth graph for the Bengal Basin

(After: BOGMC 1986)

In contrast to the Tertiary shales only the Gondwana Group in the stable shelf region has reached favourable maturity (Figure 7-4). The reason for the increased maturity is the deep burial prior to the uplift between Middle Jurassic and Early Cretaceous (Frielingsdorf et al. 2008).

According to the mapping by Islam & Eickhoff 2001 the sub-basins of Singra-Kuchma and Sherpur are situated within the required depth window (Figure 7-5).

However, the Gamma Ray Log from Kuchma-X1 Figure 10-1) clearly indicates that the shale content stems from intercalated intervals which do not exceed 4 m in thickness. These thin layers do not allow sufficient shale gas extraction. A further restriction may arise from the TOC distribution. Though one maximum TOC value of 9.88% has been recorded, the remaining four samples are in a range of just 1.2 to 1.5%. In addition it should be noted that the Gondwana sediments in Kuchma-X1 were production tested by drill stem test without hydrocarbon shows.

From these findings it is concluded that the Gondwana Group in the sub-basins of Singra-Kuchma and Sherpur does not provide a valid shale gas play.

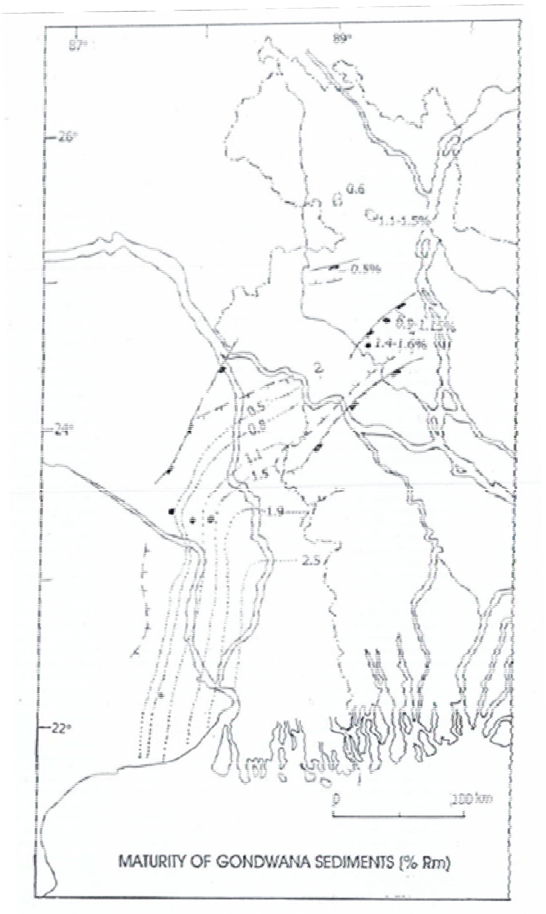

Figure 7-4 Maturity of the Gondwana Group

(Source: Islam & Eickhoff 2001)

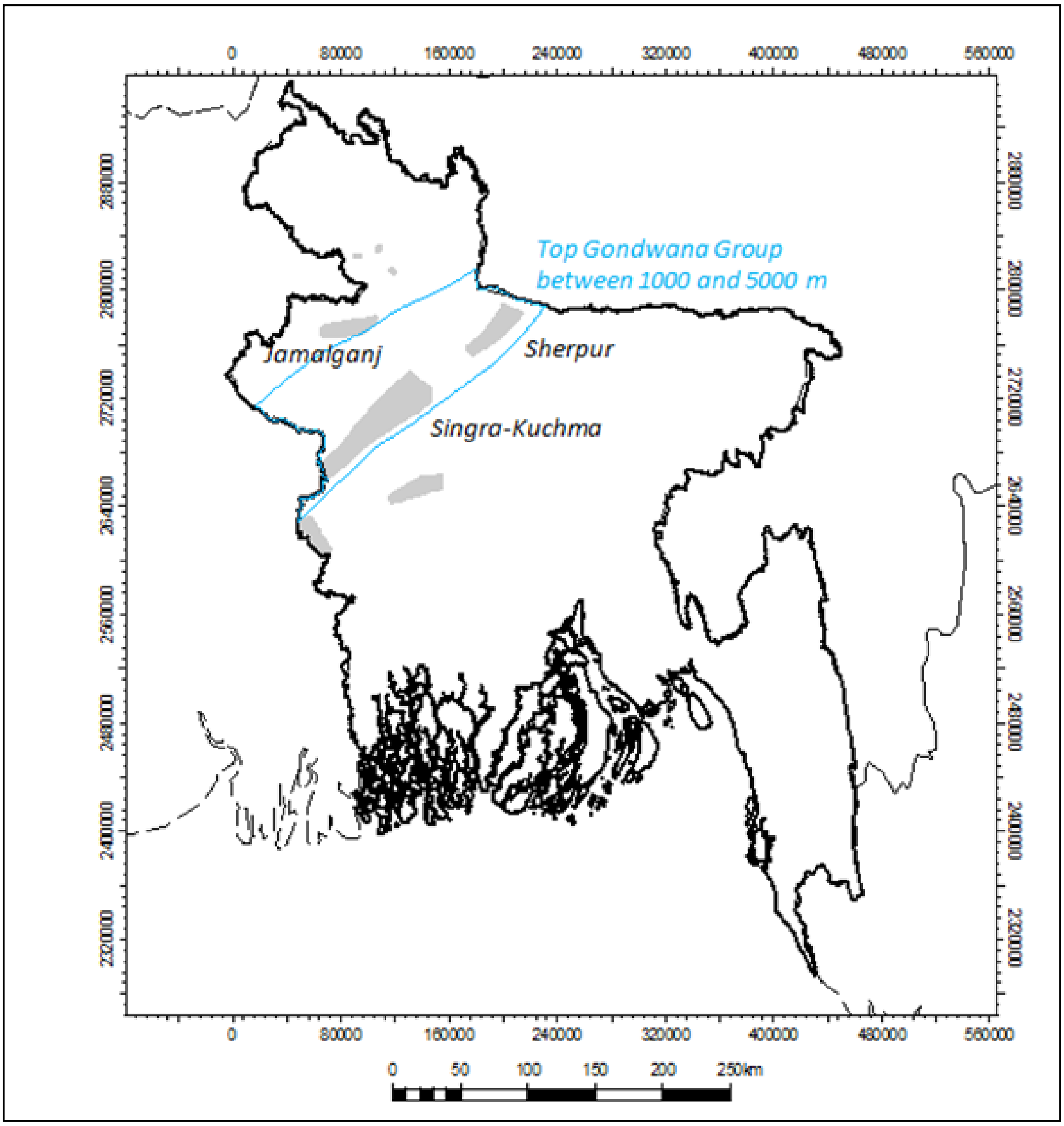

Figure 7-5 Gondwana Group in favourite depth setting

Map projection: UTM 46N

:

8 Comparison with Selected Shale Plays in Asia

It has been further evaluated how the Singra-Kuchma and Sherpur sub-basins compare with the Damodar Valley Basin in East India, for which a risked GIIP of 27 Tcf has been estimated by eia 2013. The comparison has been made because at first glance the Bangladesh sub-basins appear to show resemblance with the Damodar Valley Basin.

The description as provided in eia 2013 is summarized here:

The Damodar Valley Basin is part of a group of basins collectively named the “Gondwanas”, owing to their similar depositional environment and Permo-Carboniferous through Triassic deposition. The “Gondwanas,” comprising the Satpura, Pranhita-Godavari, Son-Mahanadi and Damodar Valley basins (Figure 8-1), were part of a system of rift channels in the northeast of the Gondwana super continent. Subsequent tectonic activity formed the major structural boundaries of the Gondwana basins, notably the Damodar Valley Basin. Sedimentation in the Early Permian was primarily glacio-fluvial and lacustrine, resulting in significant deposits of coal. As such, the majority of exploration in the Damodar Valley has focused on the coal resources of the basin, which account for much of India’s coal reserves. However, a marine incursion deposited a layer of early Permian Shale, called the Barren Measure Shale in this basin (Figure 8-2). TOC of that interval is assumed to range between 3% and 6% averaging 3.5%

Along with the Cambay Basin, the Damodar Valley Basin has been set as a priority basin for shale gas exploration by the Indian government. In late September 2010, Indian National Oil and Gas Company (ONGC) spudded the country’s first shale gas well, RNSG-1, in the Raniganj sub-basin of the Damodar Valley. The well was completed mid-January 2011, having reportedly encountered gas flows from the Barren Measure Shale at approximately 5,600 ft depth. Detailed well test and production results are not publicly available. This well was the first of a proposed four-well R&D program in the basin.

The main and vital difference to the setting in Bangladesh is the presence of some 75 m thick marine shale – the Barren Measure Shale - for which no equivalent can be found in Bangladesh.

For this study we screened as well other sub-basins in Bangladesh as namely the Khalaspir and Barapukuria regions for the existence of thick shale sequences. It was intended to investigate whether away from Kuchma-X1 well indications for thicker shale intervals similar to the Barren Measure Shale can be inferred. The result was negative. Both basins do not show any thick and lateral extensive shale intervals (Figure 8-3 and Figure 8-4).

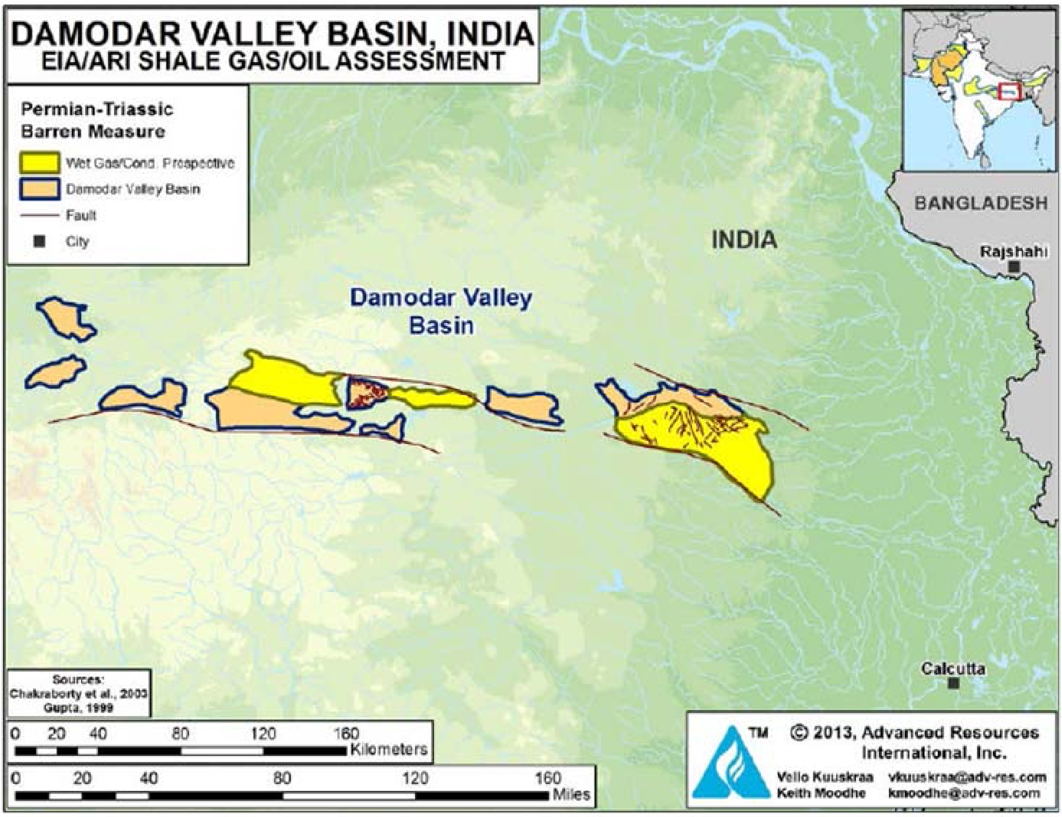

Figure 8-1 The “Gondwana“ Damodar Valley Basin in India

(Source: eia 2013)

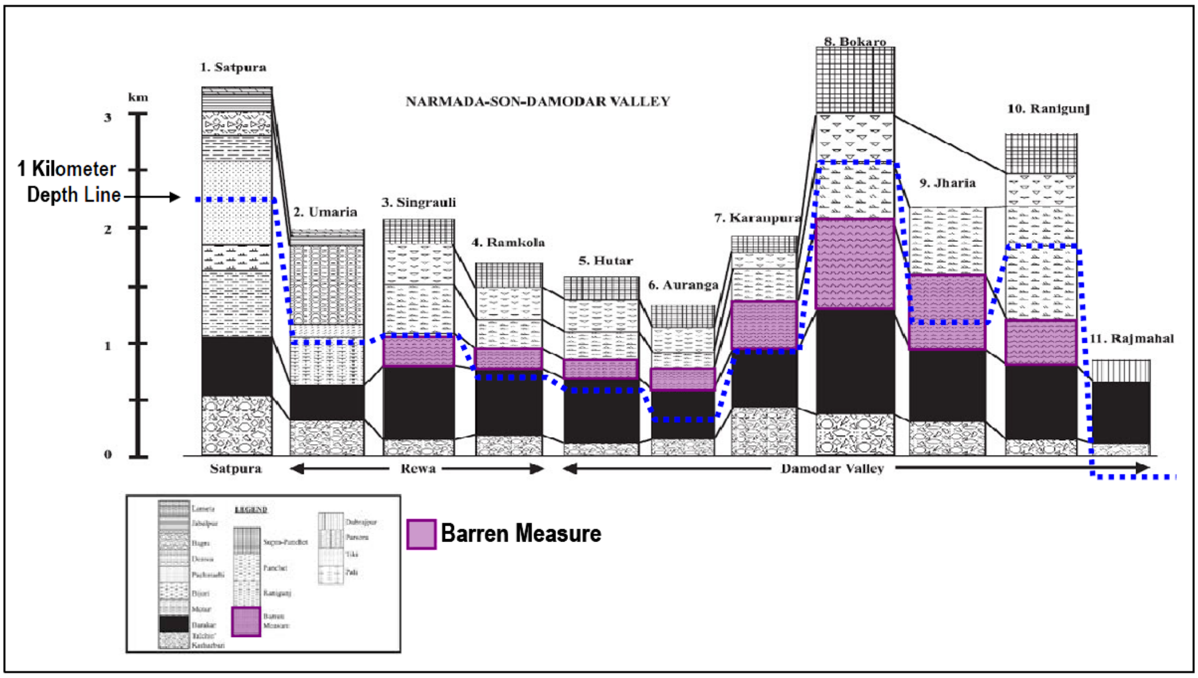

Figure 8-2 Regional Stratigraphic Column of the Damodar Valley Basin

(Source: eia 2013)

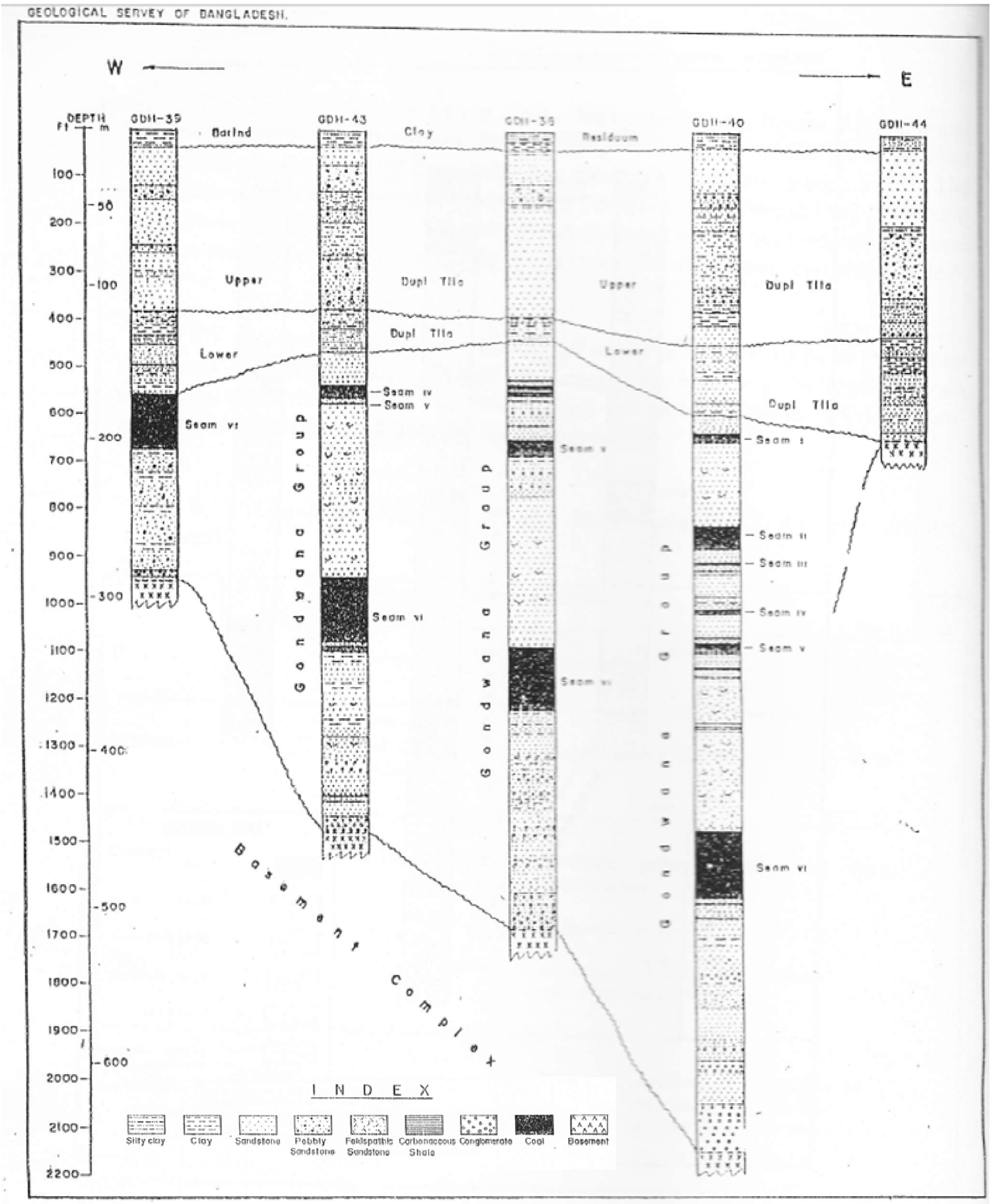

Figure 8-3 Stratigraphy of the Barapukuria Basin

(Source: Geological Survey of Bangladesh 1996)

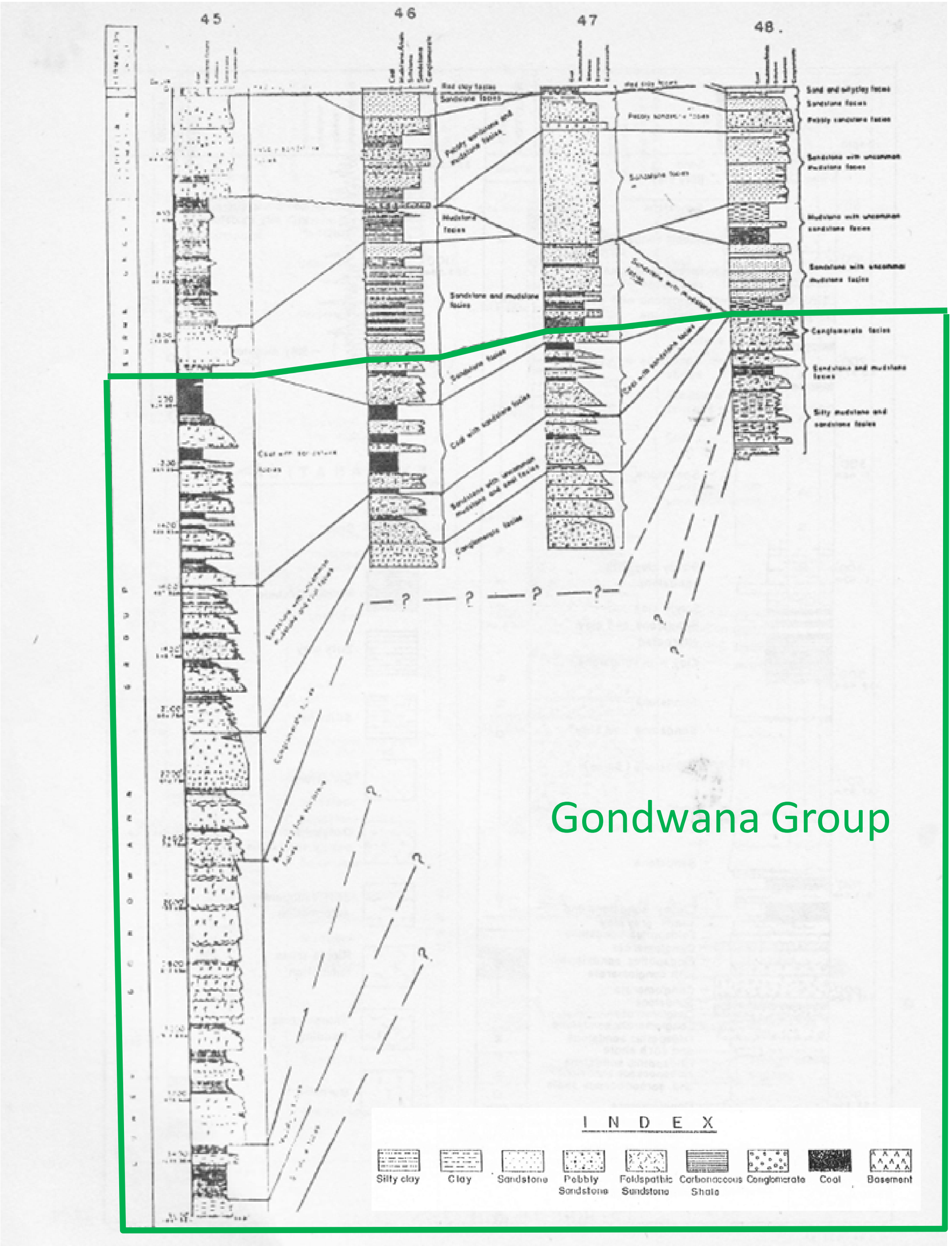

Figure 8-4 Stratigraphy of the Khalaspir Basin

(Source: Geological Survey of Bangladesh 1992)

9 Conclusions

This preliminary study on shale gas potentiality in Bangladesh reveals that no valid shale gas plays exist in Bangladesh. In the Tertiary sediments shale intervals exceeding 20 m in thickness may occur in places in the Kopili, Jenum and Tura Sandstone Formation, but they reach maturities at depths deeper than 5000 m, thus being not economic for extraction. The basins of the Gondwana Group have favourable maturity, but contain only thin shale sequences. Furthermore, the TOC is a critical factor. The conclusion contradicts earlier work, which described potential for shale gas and lists substantial volumes of contained gas in the basins. However, it did not combine all key factors affecting the potential.

It is concluded that shale gas production will not replace the foreseeable decline in conventional gas production in Bangladesh. However, very limited potential may still exist because of three reasons: (1) the data review has been restricted to historic data, (2) recent results of activities, including exploration data from international oil companies, were not available, and (3) the potential of large areas are based on interpolation between widely spaced wells and remain untested by drilling.

10 TOR for Future Phases of Work and Recommendations

The current study does not support any economic shale gas plays in Bangladesh. This status should be regularly checked and verified because of technology advance and availability of new exploration data. If these data reveal an increase in potential, then additional drilling may be justifiable. Meantime future phases of work have to focus on other plays. In the context of this study DMT recommends to evaluate the potential for Coalbed Methane (CBM) hosted in the Gondwana Group. Its general potential has been demonstrated for the Jamalganj basin by Imam et al. 2002.

Together with this study the shale sequences in the Gondwana Group should be studied in detail together with the gas content in order to validate the assessment of this report and achieve a more detailed estimate. This will be also important in the view of future improved exploitation technology and economic parameters, which may make it possible to exploit thin shale units.

Exploration for CBM differs from conventional and other unconventional gas reserves. The prospectivity of a basin depends on whether sufficient gas has been generated through time from the coal, either through thermogenic or biogenic processes. Thermogenic gas generation is strongly linked to burial depth, and therefore to the tectonic history of the basin.

- The higher the **cumulative coal seam thickness** the higher the gas-in-place will be, because the adsorbed gas present in the coal reservoir is directly linked to the amount of coal present.
- The **structural style** of the basin is important for the continuity of the coal seams. In tectonically active areas, coal seams were often buried deeper than they are at present resulting in low present-day porosity and permeability due to irreversible compaction during burial. Major faults could have displaced coal seams and make coal seams discontinuous.
- The **reservoir properties** of a coal bed are quite complex. Permeability as a crucial factor is determined by the internal fracture (cleat) system, which is in turn largely controlled by the tectonic regime. The cleat network may be formed at an earlier stage of geological history under influence of the stress regime prevailing at that time.
- Present-day permeability strongly depends on present-day **in-situ stress directions** which are likely to be different compared to those during formation of the cleats.
- The most productive wells have permeabilities ranging between 0.5 and 100 millidarcies. Because permeability decreases with depth, coalbed-methane production may be limited to **depth**s less than 1500 to 1800 m, depending on local conditions.
- **Hydrodynamic conditions** strongly affect coalbed-methane producibility and include both the movement of meteoric water basin-wards, which is important for biogenic gas production, as well as the migration of fluids from deeper parts in the basin. Hydrogeological conditions have to be identified for delineating prospective CBM plays. These and other factors like formation pressure are especially important at the dewatering-phase of CBM-production.

The evaluation of the described factors requires comprehensive data collection and thorough analysis to assess the potential of unconventional reservoirs. The following methods will have to be applied to explore unconventional deposits:

- Seismic survey

  Seismic data acquisition comprising measurements of seismic lines (2D seismic) and/or volumes (3D seismic). Generally, in a 2D survey lines will run perpendicular to the strike of the strata with selected lines running parallel to the strike for delineation of faults. Preferably, 2D seismic lines should run through existing drill holes allowing to tie-in its information. The type of measurement (2D or 3D) as well as the geometrical and frequency parameters will have to be selected according to the local geological scenario. Data processing is essential step to provide an accurate image of the subsurface. If seismic lines are already existing, state of the art data processing of these data may improve the quality considerably. Since unconventional gas reservoirs are commonly thin and deeply buried, sophisticated processing methods are required to resolve the structural setting of these targets. In case of CBM, seismic surveys will have to be complemented by cored drill holes, because coal seams at greater depth and with limited thickness typically fall short of what can be resolved by seismic techniques. Experienced interpreters may enhance migration models using further information, e.g. well data or other geological data, to define geological elements more accurately and possibly determine flow paths or trap formations for deposits.

- Drilling

  A reasonably accurate assessment of the quantity of methane can only be performed based on drilling results and here – at least at early stages of exploration – by analysing core samples, including potential sidewall coring. Drilling can be executed prior, parallel to and/or after the seismic survey depending on previous knowledge of geological conditions. Based on the seismic and well data, a geological block model will have to be set-up in order to allow a preliminary assessment of the methane potential. This model will show the geological structure as well as data on grade, depth, shape of methane distribution and other quality parameters. Number and types of boreholes required will depend on the existing knowledge and the stage of exploration. For CBM, in many cases earlier data are available because exploration on coal has preceded. CBM well sampling and testing is to some extent identical with shale gas and comprises the following:

  - gas content of coal cores / desorption test of coal cores
  - gas composition
  - porosity and permeability tests (under pressure) of coal
  - density
  - porosity/permeability of host rock (sandstone) for potential water flow
  - adsorption isotherm
  - proximate & ultimate analysis
  - coal petrography
  - cleats and cleat orientation (e.g. xrd)
  - formation pressure and stress
  - injectivity
  - mechanical properties
  - water analysis
  - temperature
  - fluid sensitivity
  - production testing

- Well logging

  Well logging may help to provide information to some of the critical parameters as there are: porosity (permeability), layer thickness, OM (TOC, type of kerogen), mechanical properties, local stress, fracture systems and shale mineralogy. Regarding well logging for unconventional gas, the different types of potential deposits require different logging programmes.

  A logging programme for CBM mainly consists of the standard tools for coal exploration (gamma-ray, density, calliper) completed by acoustic image to receive information on fracture/cleat content and local tension field (calculated from breakouts). The logging program may be extended by sonic and resistivity as well as special tools and programs as hydraulic fracturing, formation tests or formation pressure. All logs may be joined together in a program for reservoir analysis which provides information on shale, sand, carbon, water and of the gas content of the coal seam.

  Beyond applying well known standard methods used in conventional gas exploration, logging for shale gas should at least include logs to acquire the following parameters:

  - Lithology/ mineralogy
  - TOC
  - Porosity and matrix perm
  - GIP (adsorbed and free)
  - Robust clay quantification independent of kerogen
  - Matrix density
  - Robust identification of complex clay mineralogy

  Ideally, the content of organic material, free and adsorbed gas, permeability, porosity, mineralogy and elastic properties of the formation can also be calculated. Again, these data should be complemented by core data. As the main production will result from fractures (naturally and artificial), respective information can only be provided by image logs (acoustic, resistivity). To enhance the logging results special probes have been developed and interpretation programmes have been improved.

- Microseismic monitoring

  The viability of CBM and shale gas reservoirs often depends on hydraulic fracture stimulation and re-stimulation programmes. Monitoring of microseismic events allows evaluating hydraulic fracture propagation for real-time assessment of the fracturing process. To improve 3D hydraulic fracture modelling and treatment optimization, it is necessary that the location and growth of hydraulic fractures is assessed in terms of fracture azimuth, length, and height. Microseismic monitoring can be applied in boreholes as well as with surface arrays.

- Hydrogeology

  The production from unconventional gas deposits is also connected with hydrological issues. Typically, unconventional gas production requires pumping of major amounts of formation water to reduce the pressure below hydrostatic. The influence on the neighbouring geological units and especially on aquifers must be considered for example in terms of storativity and conductivity. Furthermore, the hydraulic effects of faults are of special interest. Numerical models calculate water flow, solute, gas und heat transport in groundwater systems.

A typical programme could be dived into several steps. In the exploration phase the most significant and accessible coals will be defined to identify suitable project locations including a reviewing of the geology and existing data (wells, seismic surveys etc) and a core well drilling programme to determine in particular coal quantity and quality, gas quantity and quality, gas saturation and permeability. Selected areas may initially be covered by 2D seismic lines. In case of favourable results either a 3D seismic survey for better resolution or a direct investigation by cored holes will be carried out. Sources of information in this phase include cores and logs from previous and actual wells, seismic data, outcrop information (if available), aerial photographic studies, published regional geological studies and regulatory agencies. Data will then be interpreted through a purpose-built geological model.

This could be followed by an appraisal programme to confirm the initial results and to carry out a pilot testing programme to assess the production potential and to optimise the development strategy. A pilot scheme is designed usually with a minimum two well programme that forms the basis of a mini-development of the project. Surface engineering requirements and installation issues will be resolved and site access and construction planned. Additional key parameters include drainage area, fluid properties, reservoir quality and distribution, stimulation requirements, completion options and produced water utilisation or disposal. An extended period of production testing will be carried out to allow for a longer-term production modelling of the project assessing the projected daily production volumes of the project, and the decline curve to gauge the longevity of the producing field.

11 References

Alam, K.H. et al. (1990): Geological Map of Bangladesh. Geological Survey of Bangladesh, Geological Map 1:1,000,000; Dhaka, Bangladesh

Alam, M. et al. (2003): An overview of the sedimentary geology of the Bengal Basin in relation to the regional tectonic framework and basin-fill history. Sedimentary Geology, 155, p. 179-208.

Aminul Islam, M. (2009): Diagenesis and reservoir quality of Bhuban sandstones (Neogene), Titas Gas Field, Bengal Basin, Bangladesh. Journal of Asian Earth Sciences, Elsevier, Vol. 35, Iss. 1, p. 89 – 100.

Bangladesh Oil, Gas and Mineral Corporation (BOGMC), Research Laboratory Division, Geochemical Department (1986): Hydrocarbon source rock evaluation in the Bengal Basin (Part – II). 33 p.

Curiale, J.A. et al. (2002): Origin of petroleum in Bangladesh. AAPG Bulletin, 86 (4), p. 625-652.

Farhaduzzaman, Md. et al. (2012): Source rock potential of organic-rich shales in the Tertiary Bhuban and Boka Bil Formations, Bengal Basin, Bangladesh. Journal of Petroleum Geology, 35(4), p. 357-376.

Frielingsdorf, J. et al. (2008): Tectonic subsidence modelling and Gondwana source rock potential, Northwest Bangladesh – modelling of Kuchma, Singra and Hazipur wells. Marine and Petroleum Geology, 25, p. 553-564.

Geological Survey of Bangladesh (1992): Geology of the Khalaspir Coal Basin. Records of the Geological Survey of Bangladesh, 6 (5), 80 p.

Geological Survey of Bangladesh (1996): Geology and coal deposit of Barapukuria Basin, Dinajpur District, Bangladesh. Records of the Geological Survey of Bangladesh, 8 (1).

Gustavson Associates (2011): Final Updated Report on Bangladesh Petroleum Potential and Resource Assessment 2010.

Hamid, M. (2000): Application of Lopatin´s TTI method in evaluating organic matter maturity: a case study for Patharia Structure, Surma Basin, Bangladesh. Bangladesh Geoscience Journal, 6, p. 37-51.

Imam, M.B. et al. (2002): Coalbed methane prospect of Jamalganj coalfield, Bangladesh. The Arabian Journal for Science and Engineering, 27, 1A, p. 17-27.

Islam, Sk. A. & Eickhoff, G. (2001): Occurence and hydrocarbon source rock potential of Gondwana sediments in West-Bangladesh. BMZ Project No.1996.2280.4, Promotion of Bangladesh Petroleum Exploration Company Ltd. (BAPEX), skill development. 12 p.

Khan, F.H. (2000): Geology of Bangladesh. University Press Limited, Dhaka, Bangladesh, 207 p.

Khan, A.H. et al. (2011): Shale gas prospects in Bangladesh. HCU Report, 11 p.

Noor Alam, Md., Nakayama, K., Toshifumi, M. and Yohroh, T. (2006): Petroleum System of Bengal Basin in Bangladesh. 6th Int. Conf. & Exposition on Petroleum Geophysics "Kolkata 2006". 8 p.

Paul DD. and Lian HM. (1975): Offshore tertiary basins of south-east Asia: Bay of Bengal to South China Sea. Proceedings 9th World Pet Congress, Vol. 3, Applied Science Publishers, London, p. 107 – 121.

Reimann, K.-U. (1993): Geology of Bangladesh. Gebrüder Bornträger, Berlin, 160 p.

TNO Report (2009): TNO-034-UT-2009-00774/B – Inventory non-conventional gas. TNO, Netherlands, 187 p.

Uddin, A. & Lundberg, N. (2004): Miocene sedimentation and subsidence during continent–continent collision, Bengal basin, Bangladesh. Sedimentary Geology 164, p. 131–146.

USGS-Bangladesh Gas Assessment Team (2001): U.S. Geological Survey-Petrobangla Cooperative Assessment of Undiscovered Natural Gas Resources of Bangladesh. USGS Bulletin 2208-A. Wandrey, CJ (ed.), 119 p.

U.S. Energy Information Administration (eia) (2013): Technically recoverable Shale Oil and Shale Gas resources: an assessment of 137 shale formations in 41 countries outside the United States, Washington DC, 730 p.

12 Appendices

12.1 Borehole Formation Tops

SL NO.	Borehole	Area	Borehole Surface Location		Elevation							
			Longitude	Latitude				Formation				
			Deg-Min-Sec	Deg-Min-Sec	GL	KB	Total Depth		Tops	Tops	Age	Lithology
					(m)	(m)	(m)		(m)	(ft)		
1	Beani Bazar -IX	Sylhet	85-56-10	32-39-50	21,02	27,32	4109	Surface	0	0	Plio-Pleistocene	Loose and Unconsolidated sands
								Tipam	2003	6570	Late Miocene	Unconsolidated sands and sandstones
								Boka Bil	2631	8631	Middle Miocene	Alternating of Sand and Shale/Claystone
								Bhuban	3063	10050	Middle Miocene	Alternating of Sand and Shale/Claystone
2	Bakhrabad-1	Brahmanbaria	90-52-23	23-38-08	5,26	11,7	2838	Dupi Tila,	0	0	Plio-Pleistocene	Loose and Unconsolidated sands
								Tipam,	838	2750	Pleistocene	sand with some lignite streaks
								Boka Bil	1789	5870	Miocene	Alternating sandstones and sandy shales
								& Bhuban	2502	8210	Miocene	Shale and Siltstone
3	Rashidpur-2	Moulavibazar	91-36-26.01	24-18-32.87	66,07	73,87	4596	Dupi Tila	0	0	Plio-Pleistocene	Loosely & Unconsolidated sands
								Tipam	314	1030	Pleistocene	sandstones
								Boka Bil	1036	3400	Miocene	sandstones & Shales
								Bhuban	3344	10970	Miocene	Mainly shales, silty, with rare sandstones
								Jenam(Barail Group)	4237	13900	Oligocene	Mainly shales, silty, with rare sandstones
4	Habiganj-1	Habiganj	91-22-47	24-13-55			3505	Alluvium	0	0	Recent	Loose sand
								Dupi Tila	1250	4101	Plio-Pleistocene	loose quartz, sand, silt
								Tipam,	1350	4429	Pleistocene	loose quartz, sand, silt
								Boka Bil	1650	5413	Middle Miocene	sandstones, shales and siltstones
								Bhuban	3060	10039	Lower to Middle Miocene	calcareous sandstone, interbeded grey shales
5	Titas-1	Brahmanbaria	91-07-7.8	23-59-42.7	12,19	15,24	3758	Alluvium	0		Recent	loose sand
								Girujan Clay			Plio-Pleistocene	clay
								Tipam			Pleistocene	loose quartz sand
								Boka Bil			Middle Miocene	sandstones, shales and siltstones
								Bhuban			Middle Miocene	calcareous sandstone, shales with laminated silt
								Barail			Oligocene to Lower Miocene	calcareous sandstone, shales with laminated silt

SL NO.	Borehole	Area	Borehole Surface Location		Elevation							
			Longitude	Latitude				Formation				
			Deg-Min-Sec	Deg-Min-Sec	GL	KB	Total Depth		Tops	Tops	Age	Lithology
					(m)	(m)	(m)		(m)	(ft)		
6	Sylhet-2	Sylhet	802034m	2947625m			2819	Alluvium			Recent	Loose sand
								Dupi Tila,			Plio-Pleistocene	massive clay, locally interbedded with sand
								Tipam,			Pleistocene	loose quartz sand
								Boka Bil			Miocene	Thinly laminated shale, siltstone and sandstone
								Bhuban			Miocene	calcareous sandstone, shales laminated with silt
7	Kailas Tila-1	Sylhet	92-01-06	24-51-13			4139	Dupi Tila	0	0	Plio-Pleistocene	Loose sand
								Tipam	220	722	Pleistocene	Clay and sandstone
								Boka Bil	2300	7546	Middle to Late Miocene	shale, siltstone and sandstone
								Bhuban	2900	9514	Middle Miocene	calcareous sandstone, shales laminated with silt
8	Semutang-1	Chittagong	91-45-53	22-50-40	50,3	53,6	4088	Tipam	0	0	Upper Miocene	Sandstones, alterations of grey shales & Siltstones
								Boka Bil	250	820	Middle to Upper Miocene	Alterations of shales, sandstones and siltstones
								Bhuban	1551	5089	Lower to Middle	Interclations of shales & siltstones
9	Begumganj-1	Noakhali	581189.7m	2863036m			3655	Alluvium	0	0	Pliocene to Recent	Clay
								Dupi Tila	250	820	Upper to Lower Miocene	sandstones with pebbles of quartz
								Girujan/ Tipam	1050	3445	Middle to Upper Miocene	Clay and sandstone
								Boka Bil	1800	5906	Lower to Middle Miocene	Shale with sandstones
								Upper Bhuban	2400	7874		Alteration of Sandstones and Shales
10	Hazipur X-1	Mymensingh	89-59-04	24-31-23	11,82	16,82	3816	Recent Subrecent	0	0	Recent	dominant sand
								Dupi Tila	245	804	Plio-Pleistocene	dominant clay
								Boka Bil	1393	4570	Miocene	dominant clay
								Bhuban	2247	7373		
								Barail	3130	10269	Oligocene	
11	Atgram-IX	Sylhet	E92-15-30	N25-03-10	51,23	6,36	4961	Younger	0	0	Quaternary	Gravel, Pebble, Loose quartz
								Dupi Tila	110	360	Plio- Pleistocene	Sandstone & soft claystone
								Boka Bil	911	2990	Miocene	Sandstone, silstone with lignite
								Bhuban	1442	4730	Miocene	Sandstone, silstone & claystone
								Renji	3975	13040	Oligocene	coarse sandstone with minor shales
								Jenam	4712	15460	Oligocene	carbonaceous shales/ siltstones

SL NO.	Borehole	Area	Borehole Surface Location		Elevation							
			Longitude	Latitude				Formation				
			Deg-Min-Sec	Deg-Min-Sec	GL	KB	Total Depth		Tops	Tops	Age	Lithology
					(m)	(m)	(m)		(m)	(ft)		
12	Bogra-XI	Bogra	89-30-11	24-47-55	11	16,5	2187	Recent- Sub recent	0	0	Recent	Sand
								Dupi Tila	37	120	Pliocene	Clay and Siltstone
								Boka Bil	217	712	Miocene	Clay
								Bhuban	782	2565	Miocene	Sandstone- Clay
								Bhuban	1186	3890	Miocene	Shale and Sandstone
								Kopili	1593	5227	Oligocene- Upper Eocene	Sandstone and Shale
								Kopili shale	1756	5760	Oligocene- Upper Eocene	Shale
								Sylhet Limestone	1766	5795	Middle - Upper Eocene	Limestone
								Cherra	1977	6486	Lower Eocene - Paleocene	Under Clay and Shale
								Cherra	2102	6897	Lower Eocene - Paleocene	Sandstone
								Basement Complex	2145	7039	Pre-Cambrian	Gneiss
13	Fenchuganj-2	Sylhet	91-57-22.9	24-36-47	39,6	47,6	4977	Dupi Tila	290	951	Middle Pliocene	sandstone
								Tipam	890	2920	Early Pliocene	sandstone
								Boka Bil	1180	3871	Miocene	Upper Marine Shale & sandstone
								Bhuban	2220	7283	Middle- Late Miocene	silty shale with interclation sandstone
								Barail	4820	15814	Oligocene	Laminated shale & Sandstone
14	Kamta-1	Dhaka	90-29-38	23-52-53	5,52	10,3	3615	Modhupur Clay	0	0	Pleistocene	Red to brown clay
								Dupi Tila	15	49	Upper- Lower Pliocene	Sand with little clay & quartzite pebbles
								Girujan Clay	414	1358	Middle - Upper Miocene	Clay & trace sand layers
								Tipam	650	2133	Middle - Upper Miocene	Sandstone with trace clay layers
								Boka Bil	1030	3379	Middle-Lower Miocene	Shale, sandstone, alteration of sand/shale
								Bhuban	2740	8990	Middle-Lower Miocene	sandstone and shale alterations
15	Kuchma-X1	Bogra	89-16-15	24-41-34			2875	Recent- Sub recent	0	0	Recent	Sands
								Dupi Tila	58	190	Plio-Pleistocene	Clays, sands and siltstones
								Surma? (Group)	1090	3575	Miocene	Sandstones, Clay-Shales and Siltstones
								Barail?	1606	5270	Oligocene	Sandstones, Clay-Shales and Siltstones
								Kopili	1766	5794	Upper Eocene	Clays-Shales
								Sylhet Limestone	1774	5820	Middle- Lower Eocene	Limestones
								Cherra	1970	6464	Paleocene- Upper Cretaceous	Sandstones, Claystones and Shales
								Rajmahal trap	2312	7586	Lower Cretaceous	Basaltic Lava flows
								Lower Gondwana	2381	7811	Lower Triassic or Upper Permian	

SL NO.	Borehole	Area	Borehole Surface Location		Elevation							
			Longitude	Latitude				Formation				
			Deg-Min-Sec	Deg-Min-Sec	GL	KB	Total Depth		Tops	Tops	Age	Lithology
					(m)	(m)	(m)		(m)	(ft)		
16	Hizla-Muladi-1	Barisal	90-29-15.5	22-56-24.24	2,51	6,84	4732	Recent-Subrecent	0	0	Recent	Clay
								Dupi Tila	303	993	Pleistocene	Silty shale & sandstone
								Tipam	701	2299	Pliocene	Silty shale, sandstone & Shale
								Boka Bil	1201	3940	Miocene	Shale, Silty shale, sandstone & Siltstone
								Bhuban	2866	9403	Miocene	shale & sandstone
17	Feni-1	Feni	91-24-17.5	22-56-29.3	5,7	10	3200					
18	Singra-1	Nator	E909244yds	N88544yds	9,1	15,5	4100	Alluvium	0	0	Recent to Sub-recent	Alluvium
								Dupi Tila	10	33	Plio-Pleistocene	Gravel, Sandstone & Shale with few peat beds.
								Surma (Group)	1285	4216	Plio-Pliocene	Sandstone & Shale
								Barail	2001	6565	Oligocene	Sandstone with Shale beds.
								Kopili	2121	6959	Upper Eocene	Shale
								Sylhet Limestone	2126	6975	Middle Eocene	Limestone with Shale beds.
								Cherra Sandstone	2340	7677	Paleocene	Sandstone, shale, coal and claystone
								Shibgonj trap	2717	8914	Late Cretaceous	Sandstone (Trap-Wash) with shale
								Rajmahal trap	2830	9285	Lower Cretaceous	Basalt with intra-trapen Sandstone
								Gondwana	2900	9514	Upper Permian	Sandstone with coal and carbonaceous shale.
19	Jaldi-1	Chittagong	92-0-36	22-0-48	37	41	2300	Dupi Tila	0	0	Plio-Pleistocene	Sandstone & Shale
								Tipam	7	23	Pliocene	Sandstone & Shale
								Boka Bil	118	387	Miocene	Alteration of Sandstone & Shale
								Bhuban	1293	4242	Miocene	Sandstone, Shale & Siltstone
20	Shahbajpur-1	Bhola	90-45-13.8E	22-27-55.7	3,3	10,2	3631	Alluvium	0	0	Recent	loose sand
								SB Sequence I (Dupi Tila)	480	1575	Pleistocene?	Shale with occassional interbedded sandstone
								SB Sequence II (Tipam)	1505	4938	Plio-Pleistocene?	Shale with occassional interbedded sandstone
								SB Sequence III (Boka Bil)	2010	6594	Miocene	Alteration of Sand and Shale
								SB Sequence IV (Bhuban)	2750	9022	Miocene	Sand and Shale

12.2 Summary of Geochemical Well Reports

Area	Tectonic Setting	General Comments	TOC %	Ro %	Reference	Additional Remarks
Bogra	NW Shelf	1396 to 1707; Barail (Oligocene)	0.21 t 0 .95		Hydrocarbon Source Rock Evaluation	
		1987 to 2095; Cherra Fm (Paleocene)	0.67 to 50.6 (Coal)	0.40 to 0.46	in the Bengal Basin (Part-II), Dr. V.V. Pairazian, Nov '86, P17	
Kuchma 1	NW Shelf	1594 Bhuban	0.39	0.42	Hydrocarbon Source Rock Evaluation	
		1672 to 1738; Cherra	1.69 to 16.34	0.47	in the Bengal Basin (Part-II), Dr. V.V. Pairazian, Nov '86, P17	
		2556 to 2869; Gondwana	**1.43 to 60 .57**	**0.89 to 1.15**		
Singra 1	NW Shelf	1800 to 1804 Bhuban	0.29 to 0.36		Hydrocarbon Source Rock Evaluation	
		2000 to 2004 Barail	0.23 to 0.26		in the Bengal Basin (Part-II), Dr. V.V. Pairazian, Nov '86, P17	
		3451 to 3863 Gondwana	1.2 to 1.5	1.45 to 1.80		
Hazipur	East of Hinge Line	2945 to 3133; Bhuban	0.47 to 1.18		Hydrocarbon Source Rock Evaluation	
		3658 to 3803 Gondwana	0.51 to 0.55		in the Bengal Basin (Part-II), Dr. V.V. Pairazian, Nov '86, P18	
Atgram IX	Surma Trough	Upto 609 m section is immatur;	Below 3600 m 0.5% to 1.95 %	0.45 at 1188m to	Geochemical Report of Atgram, P5,6,7	Tmax between 400-430 deg immature zone
		Upto 3200 m early thermal maturity		0.70 at 4876		Oil zone is 430 -460 deg Oil -prone
		for oil generation.				Atgram -403 -440 deg Just mature Kerogen
		Kerogen is gas prone humic kerogen				terrestrially derived.
		below 3600 m depth				Generation potential below 3650 m
						is fair to very high.
Beani Bazar IX	Surma Trough	Early mature zone between 1500-1800 m	below 3650, 0.57 - 0.88%		Petroleum Geochemical Evaluation of the 5032-12154 feet	Tmax 425 - 430 deg
		and middle maturity enters below 3000 m.			interval of the Petrobangla Beani Bazar Well-XI, Drilled	Inertinite & Fusinite is the common kerogen
		Fully mature sediments will			onshore N.E. Bangladesh, Project No.S/II/801/124	
		occur below 4267 m.			10th July'81, table 2, 3" Rock Eval Pyrolysis data"	
		Gas generation from suitable				
		organic matter will				
		occur below 4000 m.				
Fenchuganj 2	Surma Trough	Ro% is above 0.5% below 4000 m.	1085-1900m 0 .46-0.88%	Above 0.5% below 4000m	Petroleum Geochemical Evaluation of Sedimentary sequence	Type III Kerogen.
		Interval between 2175 - 5280	1900 - 2466m .29-.63	(Fig. 6)	of the interval 1190m-4937m of Fenchuganj well-2,	
		considered as early mature.	2466 - 3800 - 0.5- 0.75		A.H.M Shamsuddin, S.I Khan, M.A. Sattar, M. Ahmed	
			3860 -4580 m .25 - .50		October-89, P13,31	
Habiganj 1	Surma Trough		0.32 -0.49 between 1250 to 3100m	Maturity at 1280 m 0.40%	An Organic Geochemical Evaluation of the 4117-10202 feet	
				to 0.59% at 3100 m	interval of Habiganj-1 well, Project no. S/II/812/31, Table-2	
Muladi 1	Hatia Trough		Upto 1700 m Average 0.26%	From 1800 -3600m Average 0.43%	An Organic Geochemical Evaluation of the 302-4532m	
			1800 -3200 m Average 0.29%	From 3690 -4530 Average	interval of Hizla-Muladi Well-1, Table 1,2 & 3	
			3300-4530 m Average 0.25	0.49%		
Sitakund 1	Chittagong -Tripura	Section of 3560-3905 may be termed as	Below 3000 m Average 0.78%	0.38 at surface to 0.60 at 2450 m	Geochemical Evaluation of Sedimentary sequence in	Above 3000 m Kerogen is mostly Type III.
	Fold Belt	fair to good for HC generation	above the sediment is lean	Measured Ro decreased to 0.52	Sitakund well-1 to study their Source rock potential	Interval between 3545 to 3900 m is Type III
			and less than 0.5%	indicating repeatation of younger	and depositional Environment.	Kerogen admixed with small proportions of
				sediment due to faulting.	A.H.M Shamsuddin, S.I Khan, M.A. Sattar, M. Ahmed, T.A	Type II proponents. Similar organic matter
				It increses again to 0.72% till	Safranov, June-88, P-11-14,	may be capable to generate large volume of
				4005 m.		gases together with fair amount of oil.
Titas-1	Chittagong –Tripura		0.32 -0.70 %	0.42% at 1300 m to about 0.69%	An Organic Geochemical Evaluation of the 4227-12239 Feet	
	Fold Belt			at 3730 m	interval of Titas Well-1, Table-1	

12.2.1 Maturity Samples

Atgram-1X			
Depth(feet)	depth(m)	Ro (%)	Formation
12928	3940	0.88	Renji
13810	4209	0.60	Renji
14200	4328	0.72	Renji
15479	4718	0.70	Jenam
15516	4729	0.48	Jenam
15522	4731	0.52	Jenam
15528	4733	0.46	Jenam
15531	4734	0.50	Jenam
15840	4828	0.56	Jenam
16000	4877	0.52	Jenam

Benai Bazar-1X			
depth (feet)	depth (m)	Ro(%)	Formation
8830	2691	0.38	Boka Bil
9240	2816	0.38	Boka Bil
9334	2845	0.44	Boka Bil
10640	3243	0.43	Bhuban
11351	3460	0.43	Bhuban
11540	3517	0.49	Bhuban
12040	3670	0.45	Bhuban

Habiganj-1			
depth (feet)	depth (m)	Ro (%)	Formation
4117	1255	0.52	Dupi Tila
6072	1851	0.55	Boka Bil
10200	3109	0.59	Boka Bil

Hizla Muladi-1			
depth (feet)	depth (m)	Ro(%)	Formation
302,80	92,29	0,30	Recent-Subrecent
606,40	184,83	0,34	Recent-Subrecent
700,70	213,57	0,34	Recent-Subrecent
773,00	235,61	0,35	Recent-Subrecent
882,00	268,83	0,28	Recent-Subrecent
1077,00	328,27	0,28	Dupi Tila
1201,00	366,06	0,35	Dupi Tila
1398,50	426,26	0,38	Dupi Tila
1402,95	427,62	0,41	Dupi Tila
1516,70	462,29	0,38	Dupi Tila
1605,15	489,25	0,44	Dupi Tila
1610,35	490,83	0,29	Dupi Tila
1700,65	518,36	0,38	Dupi Tila
1800,00	548,64	0,37	Dupi Tila
1917,95	584,59	0,42	Dupi Tila
2108,50	642,67	0,43	Dupi Tila
2150,00	655,32	0,30	Dupi Tila
2216,00	675,44	0,42	Dupi Tila
2293,00	698,91	0,42	Dupi Tila
2405,40	733,17	0,40	Tipam
2502,85	762,87	0,44	Tipam
2603,40	793,52	0,36	Tipam
2713,00	826,92	0,44	Tipam
2866,00	873,56	0,45	Tipam
3026,25	922,40	0,41	Tipam
3119,10	950,70	0,45	Tipam
3216,80	980,48	0,47	Tipam
3300,25	1005,92	0,47	Tipam
3420,00	1042,42	0,43	Tipam
3502,00	1067,41	0,43	Tipam
3602,00	1097,89	0,49	Tipam
3692,00	1125,32	0,43	Tipam
3791,00	1155,50	0,43	Tipam
3930,00	1197,86	0,47	Tipam
4007,00	1221,33	0,52	Boka Bil
4099,00	1249,38	0,50	Boka Bil
4205,10	1281,71	0,51	Boka Bil
4339,15	1322,57	0,53	Boka Bil
4458,66	1359,00	0,51	Boka Bil
4462,46	1360,16	0,54	Boka Bil
4530,72	1380,96	0,65	Boka Bil

Rashidpur 2			
depth (feet)	depth (m)	Ro (%)	Formation
4109	1252	0.38	Boka Bil
6006	1831	0.41	Boka Bil
8111	2472	0.45	Boka Bil
10227	3117	0.50	Boka Bil

Bogra-X1			
depth (ft)	depth (m)	Ro (%)	Formation
5098	1554	0.45	Bhuban
5341	1628	0.4	Kopili
5581	1701	0.43	Kopili
5600	1707	0.46	Kopili
6519	1987	0.45	Cherra
6663	2031	0.45	Cherra
6683	2037	0.43	Cherra
6873	2095	0.46	Cherra

Kuchma-X1			
depth (ft)	depth (m)	Ro (%)	Formation
5230	1594	0.42	Surma
5548	1691	0.43	Barail
6460	1969	0.43	Sylhet Limestone
6509	1984	0.47	Cherra
8530	2600	0.89	Lower Gondwana
9390	2862	1.15	Lower Gondwana

Singra-1			
depth (ft)	depth (m)	Ro (%)	Formation
11322	3451	1.4	Gondwana
11391	3472	1.45	Gondwana
12674	3863	1.8	Gondwana

12.2.2 Total Carbon Content (TOC) Samples

Atgram-1X			
depth(feet)	depth(m)	TOC(%)	Formation
510	155.448	0.19	Dupi Tila
1740	530.352	0.18	Dupi Tila
3750	1143	0.24	Boka Bil
3900	1188.72	0.32	Boka Bil
4020	1225.296	0.35	Boka Bil
4200	1280.16	0.26	Boka Bil
4550	1386.84	0.25	Boka Bil
4700	1432.56	0.33	Boka Bil
4880	1487.424	0.29	Buban
5040	1536.192	0.42	Buban
5130	1563.624	0.29	Buban
5220	1591.056	0.32	Buban
7010	2136.648	0.33	Buban
7016	2138.4768	0.41	Buban
7209	2197.3032	0.45	Buban
7260	2212.848	0.33	Buban
7500	2286	0.18	Buban
7565	2305.812	0.39	Buban
7760	2365.248	0.44	Buban
7911	2411.2728	0.44	Buban
8020	2444.496	0.4	Buban
8120	2474.976	0.39	Buban
8316	2534.7168	0.44	Buban
8400	2560.32	0.43	Buban
8585	2616.708	0.53	Buban
8620	2627.376	0.59	Buban
8671	2642.9208	0.47	Buban
9000	2743.2	0.4	Buban
9050	2758.44	0.37	Buban
9133	2783.7384	0.3	Buban
9233	2814.2184	0.31	Buban
9240	2816.352	0.46	Buban
9355	2851.404	0.36	Buban
9360	2852.928	0.36	Buban
9480	2889.504	0.35	Buban
9710	2959.608	0.34	Buban
9885	3012.948	0.42	Buban
9995	3046.476	0.26	Buban
10000	3048	0.29	Buban
10100	3078.48	0.36	Buban
10500	3200.4	0.34	Buban
10507	3202.5336	0.43	Buban
10600	3230.88	0.33	Buban
10700	3261.36	0.32	Buban
10709	3264.1032	0.35	Buban
10728	3269.8944	0.22	Buban
10800	3291.84	0.67	Buban
11000	3352.8	0.92	Buban

Atgram-1X			
depth(feet)	depth(m)	TOC(%)	Formation
11137	3394.5576	0.55	Buban
11200	3413.76	0.35	Buban
11255	3430.524	0.58	Buban
11300	3444.24	0.37	Buban
11400	3474.72	0.32	Buban
11426	3482.6448	0.37	Buban
11480	3499.104	0.5	Buban
11500	3505.2	0.33	Buban
11552	3521.0496	0.53	Buban
11600	3535.68	0.35	Buban
11696	3564.9408	0.33	Buban
11700	3566.16	0.49	Buban
11702	3566.7696	0.15	Buban
11708	3568.5984	0.65	Buban
11720	3572.256	0.59	Buban
11730	3575.304	0.46	Buban
11742	3578.9616	0.47	Buban
11800	3596.64	0.89	Buban
11900	3627.12	0.89	Buban
11982	3652.1136	0.47	Buban
12000	3657.6	0.52	Buban
12078	3681.3744	1.2	Buban
12100	3688.08	0.38	Buban
12200	3718.56	0.44	Buban
12286	3744.7728	0.66	Buban
12300	3749.04	0.38	Buban
12348	3763.6704	0.57	Buban
12400	3779.52	0.43	Buban
12408	3781.9584	0.37	Buban
12468	3800.2464	0.32	Buban
12500	3810	0.41	Buban
12510	3813.048	1.35	Buban
12546	3824.0208	1.29	Buban
12568	3830.7264	1.7	Buban
12590	3837.432	1.25	Buban
12600	3840.48	0.57	Buban
12714	3875.2272	1.3	Buban
12747	3885.2856	1.14	Buban
12750	3886.2	0.52	Buban
12800	3901.44	1.015	Buban
13085	3988.308	1.12	Renji
13100	3992.88	0.375	Renji
13110	3995.928	1.55	Renji
13168	4013.6064	1.89	Renji
13200	4023.36	0.56	Renji
13206	4025.1888	0.76	Renji
13242	4036.1616	2.49	Renji
13280	4047.744	1.23	Renji
13300	4053.84	0.59	Renji
13350	4069.08	1.37	Renji

Atgram-1X			
depth(feet)	depth(m)	TOC(%)	Formation
13450	4099.56	0.46	Renji
13550	4130.04	0.87	Renji
13600	4145.28	0.51	Renji
13680	4169.664	1.17	Renji
13750	4191	0.54	Renji
13800	4206.24	0.59	Renji
13871	4227.8808	1.52	Renji
13890	4233.672	0.89	Renji
14200	4328.16	0.96	Renji
14420	4395.216	1.03	Renji
14670	4471.416	0.84	Renji
14732	4490.3136	1.02	Renji
14750	4495.8	0.81	Renji
15370	4684.776	0.94	Renji
15440	4706.112	0.79	Renji
15479	4717.9992	1.02	Renji
15516	4729.2768	0.75	Jenam
15531	4733.8488	0.87	Jenam
15840	4828.032	1.89	Jenam
15900	4846.32	2.11	Jenam
16000	4876.8	2.7	Jenam
16160	4925.568	3.74	Jenam
16210	4940.808	3.62	Jenam
16280	4962.144	2.93	Jenam

Beani Bazar-1X			
depth(feet)	depth(m)	TOC(%)	Formation
5032	1534	0.65	Plio-Pleistocene
6160	1878	0.28	Plio-Pleistocene
6454	1967	0.17	Plio-Pleistocene
7090	2161	0.33	Tipam
8290	2527	0.34	Tipam
8680	2646	0.57	Boka Bil
8735	2662	0.70	Boka Bil
8740	2664	0.61	Boka Bil
8830	2691	0.67	Boka Bil
8950	2728	0.63	Boka Bil
9040	2755	0.68	Boka Bil
9140	2786	0.73	Boka Bil
9240	2816	0.74	Boka Bil
9327	2843	0.86	Boka Bil
9334	2845	0.82	Boka Bil
9440	2877	0.72	Boka Bil
9640	2938	0.67	Boka Bil
9740	2969	0.85	Boka Bil
9940	3030	0.72	Boka Bil
10040	3060	0.88	Boka Bil
10199	3109	0.39	Bhuban
10240	3121	0.56	Bhuban
10340	3152	0.38	Bhuban
10440	3182	0.43	Bhuban
10540	3213	0.43	Bhuban
10551	3216	0.46	Bhuban
10573	3223	0.48	Bhuban
10640	3243	0.47	Bhuban
10740	3274	0.45	Bhuban
10840	3304	0.42	Bhuban
11040	3365	0.49	Bhuban
11140	3395	0.49	Bhuban
11240	3426	0.43	Bhuban
11341	3457	0.42	Bhuban
11351	3460	0.38	Bhuban
11440	3487	0.48	Bhuban
11484	3500	0.35	Bhuban
11540	3517	0.44	Bhuban
11640	3548	0.40	Bhuban
11740	3578	0.40	Bhuban
11840	3609	0.41	Bhuban
11940	3639	0.44	Bhuban
12150	3703	0.42	Bhuban
12154	3705	0.57	Bhuban

Habiganj-1			
depth (feet)	depth (m)	TOC (%)	Formation
4117	1255	0.47	Dupi Tila
4128	1258	0.49	Dupi Tila
6072	1851	0.43	Boka Bil
10200	3109	0.32	Bhuban

Hizla -Muladi-1			
depth (feet)	depth (m)	TOC (%)	Formation
302.80	92.3	0.74	Recent-Subrecent
606.40	184.8	0.10	Recent-Subrecent
700.70	213.6	0.32	Recent-Subrecent
773.00	235.6	0.41	Recent-Subrecent
882.00	268.8	0.08	Recent-Subrecent
989.00	301.4	0.09	Recent-Subrecent
1077.00	328.3	0.48	Dupi Tila
1079.00	328.9	0.11	Dupi Tila
1132.00	345.0	0.10	Dupi Tila
1201.00	366.1	0.24	Dupi Tila
1398.50	426.3	0.28	Dupi Tila
1402.95	427.6	0.27	Dupi Tila
1516.70	462.3	0.25	Dupi Tila
1605.15	489.2	0.47	Dupi Tila
1610.35	490.8	0.33	Dupi Tila
1700.65	518.4	0.12	Dupi Tila
1800.00	548.6	0.36	Dupi Tila
1915.00	583.7	0.30	Dupi Tila
1917.95	584.6	0.25	Dupi Tila
2108.25	642.6	0.28	Dupi Tila
2150.00	655.3	0.26	Dupi Tila
2213.00	674.5	0.10	Dupi Tila
2216.00	675.4	0.12	Dupi Tila
2293.00	698.9	0.31	Dupi Tila
2405.40	733.2	0.36	Boka Bil
2502.85	762.9	0.39	Boka Bil
2603.40	793.5	0.27	Boka Bil
2713.00	826.9	0.33	Boka Bil
2866.00	873.6	0.22	Boka Bil
3026.25	922.4	0.25	Boka Bil
3119.10	950.7	0.48	Boka Bil
3216.80	980.5	0.23	Boka Bil
3300.25	1005.9	0.35	Boka Bil
3420.00	1042.4	0.30	Boka Bil
3502.00	1067.4	0.24	Boka Bil
3602.00	1097.9	0.40	Boka Bil
3692.00	1125.3	0.18	Boka Bil
3791.00	1155.5	0.05	Boka Bil
3930.00	1197.9	0.26	Boka Bil
4007.00	1221.3	0.29	Boka Bil
4099.00	1249.4	0.31	Boka Bil
4205.10	1281.7	0.24	Boka Bil
4339.15	1322.6	0.09	Boka Bil
4458.66	1359.0	0.34	Boka Bil
4462.46	1360.2	0.29	Boka Bil
4530.72	1381.0	0.15	Boka Bil

Rashidpur-2			
depth (feet)	depth (m)	TOC (%)	Formation
4109	1252	0.45	Boka Bil
4112	1253	0.45	Boka Bil
6006	1831	0.28	Boka Bil
8111	2472	0.35	Boka Bil
10227	3117	0.19	Boka Bil

Bogra-1				
depth (feet)	depth (m)	TOC(%)	Formation	Shale/Coal
4580	1396	0.95	Bhuban	Shale
4600	1402	0.62	Bhuban	Shale
4619	1408	0.15	Bhuban	Shale
4659	1420	0.21	Bhuban	Shale
5098	1554	0.77	Bhuban	Shale
5341	1628	0.48	Kopili	Shale
5581	1701	0.87	Kopili	Shale
5600	1707	0.62	Kopili	Shale
6519	1987	3.05	Tura/Cherra	Shale
6637	2023	0.67	Tura/Cherra	Shale
6663	2031	4.26	Tura/Cherra	Shale
6683	2037	10.5	Tura/Cherra	Coal
6873	2095	50.6	Tura/Cherra	Coal

Kuchma-X1				
depth (feet)	depth (m)	TOC (%)	Formation	Shale/Coal
5230	1594	0.39	Bhuban	Shale
5486	1672	1.08	Kopili	Shale
5548	1691	0.55	Kopili	Shale
5584	1702	1.12	Kopili	Shale
5643	1720	4.65	Kopili	Shale
5702	1738	1.22	Kopili	Shale
6460	1969	0.44	Sylhet Limestone	Shale
6509	1984	1.69	Tura/Cherra	Shale
6660	2030	16.24	Tura/Cherra	Coal
6818	2078	4.15	Tura/Cherra	Shale
8386	2556	9.88	Lower Gondwana	Shale
8530	2600	60.57	Lower Gondwana	Coal
8868	2703	23.6	Lower Gondwana	Coal
9390	2862	29.81	Lower Gondwana	Coal
9413	2869	1.43	Lower Gondwana	Shale

Singra-1			
depth (feet)	depth (m)	TOC (%)	Formation
5906	1800	0.29	Bhuban
5919	1804	0.36	Bhuban
6562	2000	0.26	Barail
6575	2004	0.23	Barail
11322	3451	1.2	Gondwana
11391	3472	1.5	Gondwana
12674	3863	1.5	Gondwana

Hazipur-X1			
depth (feet)	depth (m)	TOC (%)	Formation
9662	2945	1.18	Bhuban
10233	3119	0.6	Bhuban
10266	3129	0.54	Bhuban
10249	3124	0.47	Bhuban
10279	3133	0.82	Barail
12001	3658	0.51	Barail
12477	3803	0.55	Barail

12.3 Geophysical Borehole Logs

Inventory of scanned Gamma Ray logs:

Borehole	Scan File (*.tif)	Measured Interval			
		from (m)	to (m)	from (feet)	to (feet)
Atgram 1	271	1920	3310	6300	10860
	272	1917	3307	6290	10850
	273	3242	3806	10636	12486
	274	3255	3825	10680	12550
	275	698	923	2290	3028
	276	698	1006	2290	3300
	277	661	1673	2170	5488
	278	689	1670	2260	5480
	279	1652	1915	5420	6284
Beani Bazar 1	698	1268	3716	4160	12190
	699	1274	3716	4180	12190
	700	3694	3999	12120	13120
	701	3676	4006	12060	13142
Bogra 1	9017	73	2196	240	7204
	9018	24	2195	80	7200
Kuchma 1	12398	85	1398	280	4588
	12399	88	2722	290	8930
Kutubdia 1	40	48	230	158	754
	41	177	1286	580	4220
	42	1183	3117	3880	10228
	43	3036	3153	9960	10346
	44	21	287	68	940
	45	49	463	160	1520
Singra 1	1270	250	1510	820	4954
Sylhet 2	12639	143	2809	470	9215

Scan File refers to graphic file name (available on data CD)

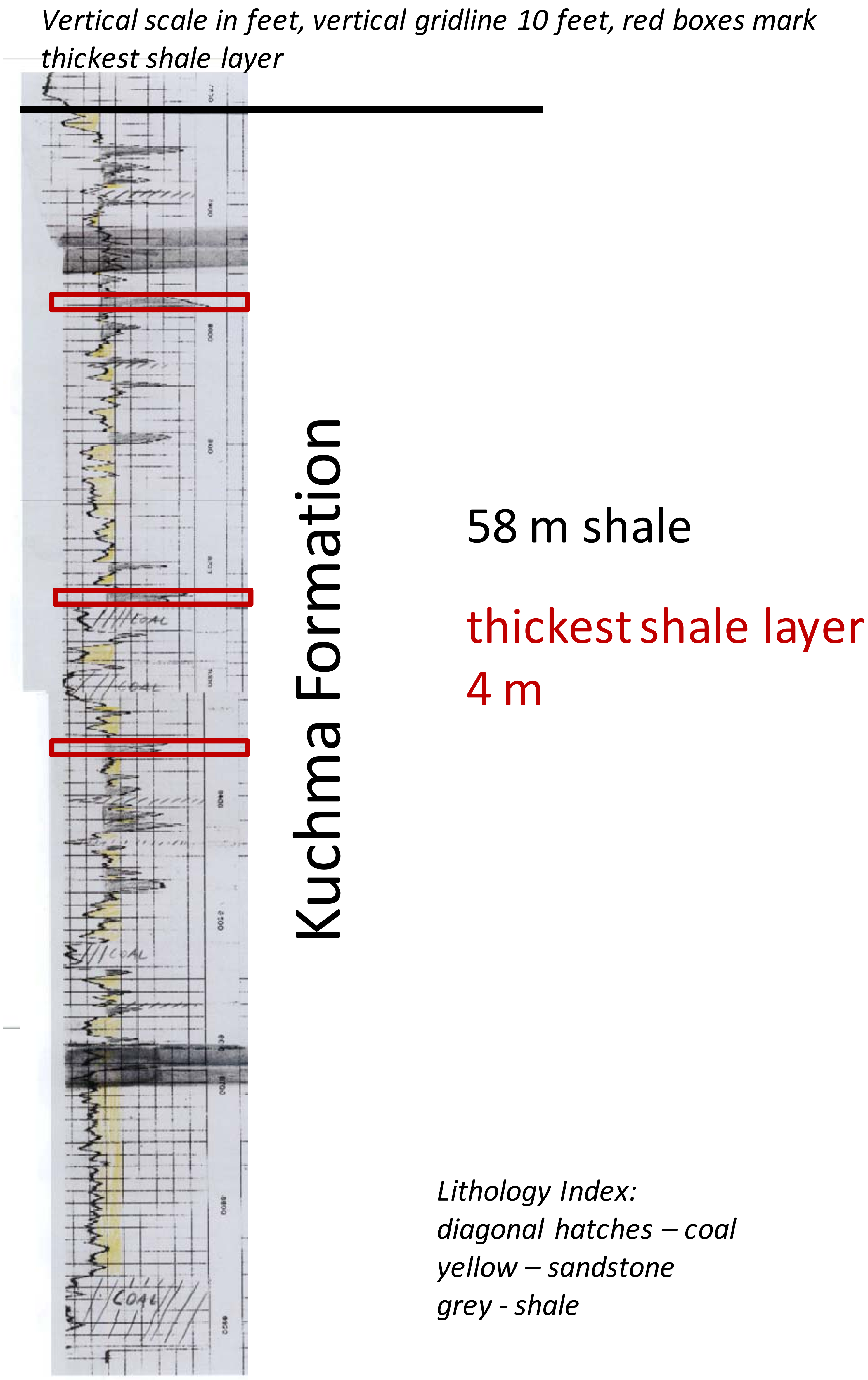

Figure 10-1 Kuchma-X1, Gamma Ray Typelog, Kuchma Formation, Lower Gondwana Group

(Source: scan file 12399.tif)

Vertical scale in feet, vertical gridline 10 feet, red box marks thickest shale layer

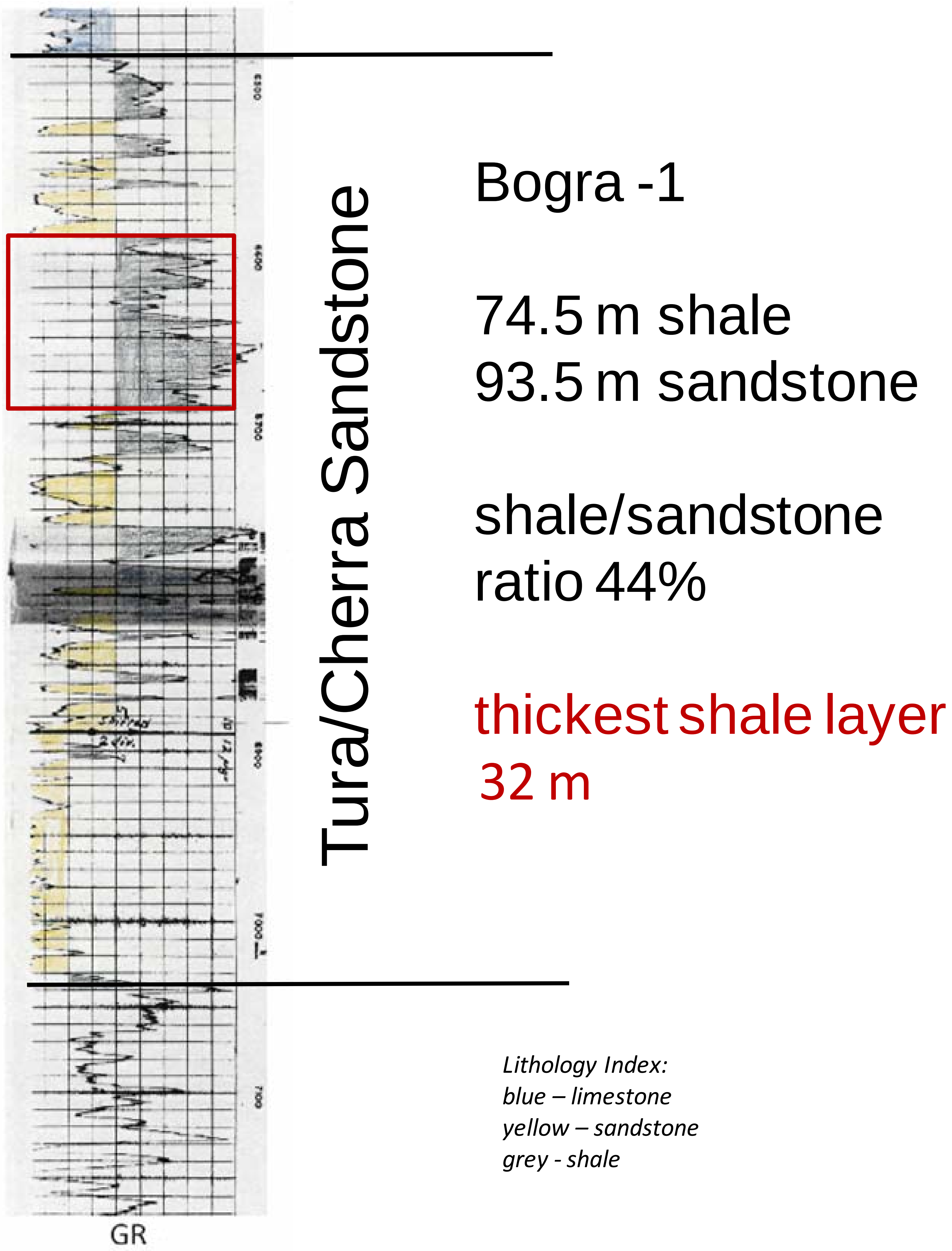

Figure 10-2 Bogra-1, Gamma Ray Typelog, Tura/Cherra Sandstone, Jaintia Group

(Source: scan file 9017.tif)

Vertical scale in feet, vertical gridline 10 feet, red box marks thickest shale layer

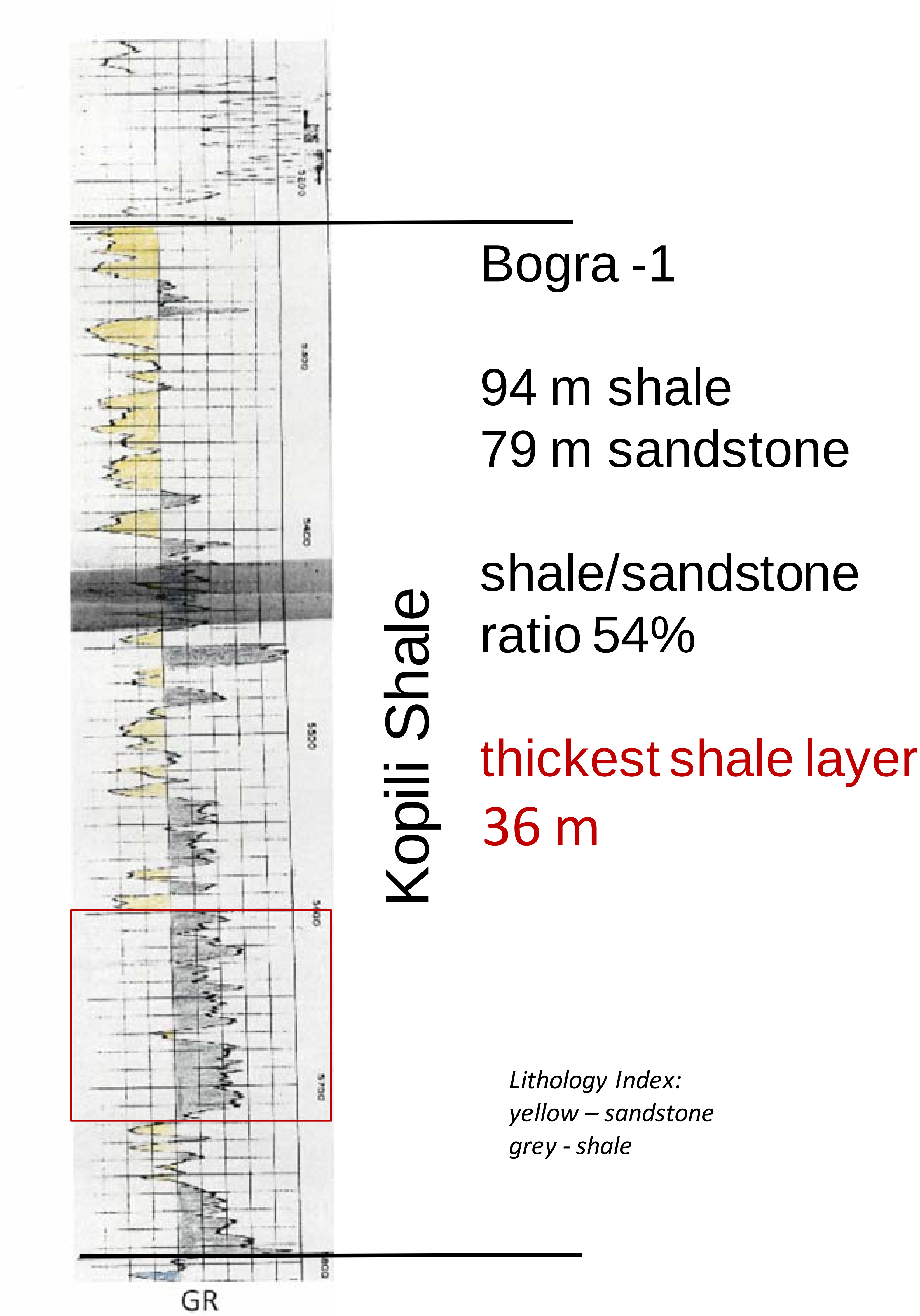

Figure 10-3 Bogra-1, Gamma Ray Typelog, Kopili Formation, Jaintia Group

(Source: scan file 9017.tif)

Essen, December, 2013

(B Loske)

(Dr. EB Teigler)