Petroleum source rock characteristics of the Tertiary Bhuban Formation of the Bengal Basin, Bangladesh

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Summary
The present study investigates the hydrocarbon source potential of the Bhuban Formation shales. Organic geochemical and petrographical methods were used to analyze 11 drill core samples from 4 gas fields of the basin. The kerogen was identified to be mainly of Type III. Vitrinite is the dominant maceral group observed in the analyzed Bhuban samples followed by liptinite and inertinite. Vitrinite reflectance, Tmax and other biomarker parameters indicate a maturity range from pre-oil window to mid-oil window. The analyzed Bhuban shales are ranked as poor to fair source rocks with good gas generation potential.

Introduction
Bangladesh is located at the northeastern corner of Indian subcontinent. It is extended to Bay of Bengal. Several authors have already published on different aspects of the Bengal Basin (Imam and Saw, 1987; Curiale et al., 2002; Islam 2009; Farhaduzzaman et al., 2012). In this present paper, the petroleum source rock properties of the Tertiary Bhuban Formation shale have been evaluated on the basis of organic geochemical and petrographical methods.

Methodology
A total of 11 Bhuban shale core samples were collected from 4 wells of 4 different gas fields located in Deep Basin unit. The samples have been crushed to fine powder and subsequently analyzed using a Weatherford Source Rock Analyzer (equivalent of Rock-Eval). Approximately 15g of the powdered samples have also been extracted using a Soxhlet apparatus. The recovered EOM were separated by means of column liquid chromatography into aliphatic, aromatic and polar fractions. The polished shale blocks were used for petrographic study. The Leica CTR 6000 microscope equipped with ultraviolet light sources was used for the present study.

Results and discussion
The analyzed samples are mostly shown to possess poor source rock potential whilst two samples have fair potential based on classification by Peters and Cassa (1994). The recorded TOC value ranges from 0.26 to 0.61 (wt.%). S2 value ranges from 0.22 to 1.41 mg HC/g rock. HI value varies from 60 to 232 mg HC/g TOC and it shows considerable variation which indicates Type III kerogen mixed with minor amount of Type II. The Tmax ranges from 429 to 441 °C which correspond to the
range of immature and early oil window for hydrocarbon generation (Figure 1). The measured vitrinite reflectance value ranges from 0.57 to 0.71 (%Ro) which are in good agreement with the maturity interpretation deduced from the Tmax. The hydrocarbon yield measured from the extractable organic matter ranges from 26 to 139 mg HC/g TOC. The petrography (Figure 2) and biomarker parameters based on TIC, m/z 191 and m/z 217 fragmentograms also support this kerogen typing and maturity assessment.

**Figure 1** The analyzed samples correspond to immature to early mature oil window and being predominantly of Type III kerogen as shown by cross-plot of hydrogen index vs. Tmax.

**Conclusions:** The extracted organic matter of the studied Bhuban shale samples is dominated by Type III kerogen with minor Type II kerogen. The studied Bhuban Formation shales are immature to early mature for hydrocarbon generation. The hydrocarbon generation potential has been deduced as poor to fair quality, the majority of which possess poor oil-generating potential.
Figure 2 (A) Dominantly found moderately reflecting Type III vitrinite (vt) which is associated with bitumen staining (bs) and white color inertinite maceral inertodetrinite (id). (B) Yellow fluorescent narrow Type II liptinitic maceral cutinite (ct); Greenish yellow fluorescent Type II resinite (rs) found in the study area.

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