Evaluation of Lower Cretaceous Saar Formation as petroleum system in the Western Central Masila Basin, Republic of Yemen

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The Saar Formation is an attractive petroleum exploration target in the deeper part of the Masila Basin because it is favorably positioned with respect to source and seal units. Saar petroleum system was identified in the western central Masila Basin (Figure 1). During Early Cretaceous the sea level rose on a flat ground, resulting in marine transgression and sedimentation of widespread shallow marine carbonates of Saar Formation (Beydoun et al., 1998). These deposits unconformably overlie the Naifa Formation. In general, the Saar Formation is composed mainly of limestone, with some mudstone and sandstone, which were deposited in a restricted marine environment (Figure 2; King, 2003; Canadian Oxy Oil Company, 2001 “personal communication”). Oil companies classified this formation into lower Saar carbonate and upper Saar clastic (Canadian Oxy Oil Company, 1999, 2000 and 2001 “personal communication”). The lower unit of the Saar is characterized by the predominance of limestone, dolomite, mudstone, and marl. The upper part is mainly sandstone and limestone facies (Canadian Oxy Oil Company, 1999, 2000 and 2001 “personal communication”). Shale samples from Saar Formation were analysed using organic geochemical analysis (Rock-Eval pyrolysis, bitumen extraction and biomarker distributions). An assessment, based on organic facies characteristics, has been carried out on these sediments, in order to distinguish, characterise and evaluate source rock deposited in marine deposition setting. The Saar shale samples generally contain TOC values less than 2.0 wt% and have been fair to good hydrocarbon potential. Kerogen is predominantly Type III with minor Type III-II. Tmax values range from 430 to 443°C, indicating that the Saar samples are thermally mature for hydrocarbon generation. Biomarker approach here has been able to interpret the depositional environment of the Saar Formation in the Masila Basin. Biomarker parameters such as Pr/Ph, Pr/C17, Ph/C18, Tm/Ts and C29/C30 hopane rations appear to reflect variation in depositional conditions and source input. Although there is a marine-derived organic matter in Saar sediments, whereby the Saar shale were deposited in a suboxic marine condition.

Reservoir rock characterization was conducted on the Lower Cretaceous Saar Carbonates using integrated results (petrographic, core and well log analyses). The Saar reservoir is composed mainly of carbonate rocks dominantly dolomite and limestone (Figure 3). The Saar carbonate rocks have good reservoir quality, where porosity reaches up to 8% as indicated by fracture and vuggy pores (Mohammed, 2011; Figure 3). However, the hydrocarbon potentiality is relatively low due to high water saturation, which was calculated from well log analysis (Mohammed, 2011; Figure 4). Saar carbonate reservoirs are sealed by shales and massive carbonate beds within the Saar Formation (Canadian Oxy Oil Company, 2000; PEPA, 2004 “personal communication”).

References

Figure 1: Location map of Masila Basin, showing the study area (East Shabowah Oilfields).

Figure 2: Regional stratigraphic nomenclature of Masila Basin, Republic of Yemen and showing Saar Formation (modified after King, 2003; Canadian Oxy Oil Company, 2001 “personal communication”).
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Figure 3: Features of petrographic reservoir characterization of the core samples studied from the Upper Saar Carbonate reservoir in NWATOF-001 well.

Figure 4: The corrected log datasets (left) and the litho-saturation cross-plot (right) illustrating vertical variations of the petrophysical characteristics of the Saar Formation studied in the KH 3-07 well.