

EVALUATION OF THE PETROLEUM SOURCE POTENTIAL OF THE KHOMAN FORMATION IN THE ABU GHARADIG BASIN, WESTERN DESERT, EGYPT

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Hydrocarbon occurrence and source rock characteristics of the Late Cretaceous Khoman Formation in the Western Desert of Egypt were studied in 13 wells. During the Late Cretaceous, Tethys was closing and a major transgression covered most of the northeast margin of Africa resulting in anoxic deposition of organic-matter-rich shelfal shale and limestone over much of the region. The Khoman Formation is dated as Late Santonian to Maastrichtian and is split into two members, "A" and "B". The lower "B" Member consists of shale and organic-rich limestone, while the upper "A" member consists of open-marine chalky limestone with chert bands. The Khoman Formation is stratigraphically equivalent to the Brown/Duwi limestone which is a major source rock in the Gulf of Suez and the northern Red Sea area.

Regionally, the Khoman Formation is a source rock of marginal quality (TOC's 0.5-2.0 wt. % ; S₂ 2-12 mg HC/g rock). High TOC's up to 6.7 wt. % are only observed in one well. Kerogen composition and pyrolysis data indicate that the Khoman Formation is an oil-prone, Type II source rock. Previous petroleum systems characterizations of the Western Desert by other workers overlooked the Khoman Formation as an active source rock and believed it to be immature over most of the basin. However, in this study, integration of a variety of maturity parameters (pyrolysis data, vitrinite reflectance and kerogen composition) proves that the Khoman reached a maturity close to peak generation. Because most of the measured vitrinite reflectance values (up to 0.72 Ro%) are not statistically robust, those results are backed up by the pyrolysis T_{max} data which generally range between 420°C and 450°C and exhibit a steady increase with depth suggesting that the Khoman source rocks reach the oil window at 3000 m. In addition, under UV the fluid-rock relationship and the occurrence of exsudatinite indicate in-situ generation.

In Khoman extracts, the high diasterane/sterane ratio and the low C₂₄ tetra-/C₂₆ tricyclic terpanes, C₂₉/C₃₀ hopanes, and dibenzothiophene/phenanthrene ratios suggest the hydrocarbons are derived from source rocks containing abundant clay minerals. The high sterane/hopane, the low tricyclic diterpane distribution and the presence of C₃₀ 24-*n*-

propylcholestane indicate that the hydrocarbons extracted are derived from source horizons containing primarily marine organic matter. In addition, the C₂₉ sterane and the aromatic steroids maturity parameters suggest that the bitumens were expelled in the very early oil window. The biomarker and carbon-specific isotope data for the extracted bitumens differ from the values found for commercial oils recovered in the basin (which are believed to have been sourced by the Cenomanian-Turonian Abu Roash "F" source rocks), indicating that no commercial accumulations of Khoman-sourced oil have yet been found. The source potential of the Khoman Formation is limited by its relatively low organic carbon content (a characteristic which separates the Khoman from more prolific, time-equivalent sources from elsewhere in the world, such as the Austin Chalk or the Barnett Shale).