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GEOCHEMICAL EVALUATION OF TAYARAT'S PROSPECTIVITY IN BURGAN FIELD

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The Tayarat Formation of the Aruma Group is part of a shallow-water carbonate platform complex deposited across the interior of the Arabian Shield during the Maastrichtian Stage of the Cretaceous System. The Tayarat carbonates span the depositional spectrum from subtidal marine to lagoonal, with the dominant reservoir facies being developed within dolomites deposited in a subtidal setting. The Tayarat (-2700 TVDSS), which is roughly 800 feet thick in the area, can be sub-divided into lower and upper carbonate units separated by an intervening shale. The upper unit has generally better reservoir characteristics.

As an on-going project Kuwait Oil Company's – Greater Burgan Studies Team is conducting a comprehensive geochemical studies of the Tayarat Formation in selected wells. The objective is to assess the chemical and physical properties of the fluids that are present in the Tayarat Formation. Geochemically, the results to date suggest that there are two types of hydrocarbons found in the Tayarat Formation: (1) very heavy/ viscous indigenous oil and (2) more recently re-migrated medium gravity oil from underlying lighter oil reservoirs.

Very heavy/ viscous indigenous oil (API 3-17°):

The degradation of the hydrocarbon's physical and chemical properties is as a results of on-going secondary processes such as water washing, biodegradation and loss of volatiles. The extent of these secondary effects varies with aerially and with depth. The hydrocarbons found on the northern side of Burgan Field has been severely degraded (API 3-10°). Whereas, the southern side shows only moderate to extensive alteration of the oils (API 10-17°). These observations have been supported by the absence of *n*-alkanes, and the presence of a distinctive hump on the finger print analyses. As a consequence, Tayarat oils are relatively rich in sulphur, yielding an average sulphur content of 5% by weight. In addition, the SARA analyses of the severely degraded oils show the abundance of resins and aromatics at the expense of the asphaltenes and saturates. Therefore, it is believe that the physical properties of Tayarat oils are probably controlled jointly by the presence of polars and sulfur.

Re-charged medium gravity oil (API ~26°):

An east-west trending deep seated fault in the south of Burgan Field might be the conduit for on-going re-migrating of lighter hydrocarbons from the deeper reservoirs such as the Wara and/or Burgan. The volumetric contribution of this fault in bringing lighter oil to shallower depths until recently was poorly understood. Unfortunately, recent well data suggests that the fault's contribution is minor. Here, finger print analyses illustrate the recharging and removal of the lightest *n*-alkane ends (gasoline group). The n-C_7/ MCH vs. n-C_7 ratio demonstrates the presence of on-going evaporative fractionation process which is responsible for preferential migration of the lightest species. SARA results show the dominance of saturate and aromatic fractions at the expense of NSO's. Finally, the sulfur content is notably lower than in the indigenous Tayarat heavy oil.

Generally, the pristane/ phytane ratios of both types of oils found in the Tayarat Formation are < 1, a characteristic generally indicative of oils generated from a source rock deposited in an anoxic environment. An oil-oil correlation was made for the different gravity oils based on finger-printing, biomarkers for saturates and aromatics, and carbon isotopic compositions. The results of this study are in agreement, suggesting that both types of oil are source related and may have been generated from marine shale/ carbonate source rock rich in sapropelic organic matter (Type II kerogen), deposited in anoxic-dysoxic environment.

Finally, the PY-GC results for the heavy, altered Tayarat oils are believed to show a reasonably good correlation with the unaltered oils found in the Burgan Formation.

PETROLEUM SYSTEM ANALYSIS OF THE TRIASSIC SEQUENCE IN CENTRAL AND EASTERN SAUDI ARABIA

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Compared to the Jurassic and the Paleozoic, the Triassic sequence of Saudi Arabia has not heretofore been invoked as a significant petroleum system. However, Triassic oil and gas–condensate has been recovered throughout the Arabian Peninsula. Sharland *et al.,* (2001) identified potential petroleum source rocks in dark limestones and dolostones of late Triassic age from Syria and Iraq. Hassan (1989) reports high Total Organic Carbon (TOC) contents of up to 5% for the Middle Triassic Gulailah Formation in the Ghasha field, offshore the United Arab Emirates with thermal maturities attaining levels that are transitional from oil to wet-gas generation. Triassic gas shows are common in eastern Saudi Arabia, Bahrain and the United Arab Emirates (Loutfi and Abdel Sattar, 1987). In Qatar, commercial gas accumulations in the Middle Triassic Jilh Formation were reported. The giant Sarakhs gas field in northeastern Iran is probably sourced from the late Triassic and early Jurassic Elika and Kashaf Formations.

The discovery of significant amounts of hydrocarbons in Triassic reservoirs provides a unique opportunity to study the petroleum potential of the Triassic System using standard geochemical screening and correlation techniques. Firstly, we have determined the source rock potential on selected core and cutting samples from the Minjur, Jilh and Sudair Formations using TOC and Rock-Eval analyses. Secondly, oil-oil and oil-source correlations have been completed on a suite of Jilh reservoired oils and source rock samples to assess the origin of the oils and their possible correlation to Triassic source rocks. For comparison, we also analyzed representative Jurassic and Paleozoic oils.

Although source bed thickness is limited, the Middle and Upper Triassic sequences contain excellent oil-and gas-prone source rocks with organic carbon contents of up to 7.4% and Hydrogen-Index (HI) values up to 700 mg/g TOC. However, the petroleum potential is quite small compared to the well-known Jurassic and Silurian petroleum systems. Visual kerogen revealed that the samples mainly contain amorphous organic matter. Vitrinite reflectance and other thermal maturity parameters indicate that these sequences are thermally mature only in Eastern Saudi Arabia. Oils in Triassic reservoirs have a number of distinctive characteristics compared to Qusaiba (Paleozoic) and Hanifa (Jurassic) sourced oils. Typical features of many Jilh reservoired oils are Pristane/Phytane ratios between 0.8 and 1.2, relatively high abundances of the C_{34} homohopanes and occasionally high gammacerane indices which suggests source rock deposition under restricted, sometimes hypersaline environmental conditions. Carbon isotope and biomarker data of the Triassic fluids suggest generation from localized middle and upper Triassic source rocks with limited areal extent. All these data verify the existence of a minor Triassic petroleum system in eastern Saudi Arabia (see Figure 1).

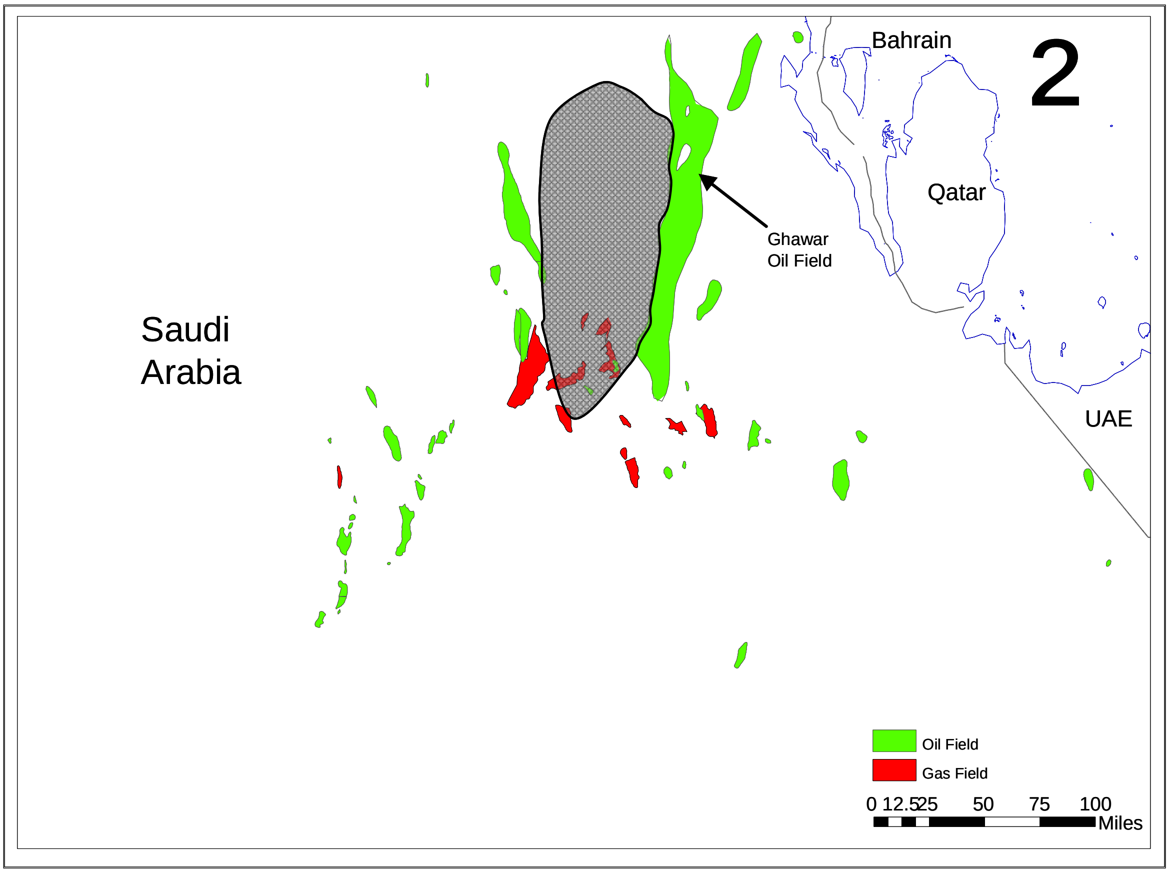

Figure 1. Map view showing the major oil and gas fields in Saudi Arabia. As illustrated by dark shading, this is the general region in which Triassic oils have been recovered.

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COALBED GAS OF BIOGENIC ORIGIN IN THE MIOCENE SOMA BASIN (WESTERN TURKEY)

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The Neogene Basins of Turkey contain as much as 9 billion tons of lignite-rank coal (Şengüler, 2001; Tuncalı et al., 2002). The Miocene Soma Basin, a rift basin trending NE-SW in the Aegean Extensional Province (EAP) of Western Turkey, is estimated to contain at the least one billion tons of lignite and about half of this reserve is present at depths greater than 600 m (Turkish Coal Enterprises, 2006). Miocene marl/limestone units and Pliocene clastics and volcanic tuffs overlie the Miocene coals of the Soma basin. In the Soma Basin, Turkish Coal Enterprises (TKİ) has conducted open cut coal mining and underground coal mining activities for several decades in the Northern and Central part of the basin, respectively. Recently, coal exploration activities have been extended to the Southern part of the basin by means of exploratory drillings. In this context, two boreholes encountering a coal seam (M2) up to 20 m thick were evaluated. The M2 coal seam was encountered between 900 and 940 m depth in two boreholes drilled approximately 1 km apart. Wellhead gas content was measured on coal cores following the USBM method (Diamond and Levine, 1981). Additionally, coal was placed in hermetically sealed canister and desorbed gas was analyzed in laboratory for chemical composition (by FTIR gas analyzer) and ^{13}C isotope (by GC-IRMS). Coal characterization was completed by means of Rock Eval (RE) Pyrolysis, Proximate and Ultimate analyses, as well as microscopic analyses for typing of macerals and vitrinite reflectance measurements.

The wellhead gas content measurements (six core measurements from two boreholes) indicate that as much as 4 m^3 gas / ton coal is present in the coal recovered from 900 to 940 m below the surface. The rank of coal based on vitrinite reflectance measurements is lignite to sub-bituminous (0.40 to 0.45 % Ro); supported by RE Tmax values of 420 ^0C. TOC content of the coal samples vary between 53 to 73 %. The composition of the gas is dominantly methane (more than 99.4 %) and the $^{13}C/^{12}C$ isotope ratio of methane is 61 to 65 per mil. Considering the chemical composition of the gas and the del ^{13}C isotope of the methane, the source of the coal gas is biogenic probably generated by bacteria that are introduced to the coal seam by fresh water following mainly the normal faults bordering the graben structure. The maceral analyses show that coal samples on average contain more than 60 %

huminite/vitrinite. Hydrogen Index values derived from RE analyses range from 220 to 360; supporting the results of microscopic observations suggesting dominant huminite/vitrinit occurrence. Adsorption on the internal coal surface is considered as the primary mechanism of gas storage in coals and the surface area, which controls the gas adsorption capacity, is in general a function of the micro-pore volume (Levy et al., 1997; Crosdale et al., 1998).

The vitrinite/huminite maseral content has positive correlation with gas sorption capacity (Levy et al., 1997); meaning that at a given pressure, the higher percentage of micro-pore dominated huminite/vitrinite the more gas adsorption capacity. In this context, the Miocene Soma lignites have good micro-pore properties in respect to gas adsorption.

Coalbed gas potential of Zonguldak hardcoal basin in Turkey was extensively studied and the results reported (Yalçın et al., 2002 for a review). In this study, however, we report the first findings on occurrence of coalbed gas of biogenic origin in Turkey. Preliminary evaluation, based on limited analyses and results summarized above, on gas potential of the Miocene Soma Basin is encouraging, yet further investigations are underway. In case, further research support the economic feasibility for biogenic coal gas, a good justification and ground will have been established for conducting similar studies for other coal-bearing Neogene basins in Turkey.

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