Evaluation of the Potential for Shale Gas Exploration in the Fika Shales of the Gongola Basin, Upper Benue Trough, Nigeria*

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Abstract

The development of shale gas and oil in unconventional plays onshore North America and Northern Europe has significantly impacted the finances and the energy security of the host countries. Lately, the interior basins of Nigeria have seen a resurgence of interests with the main focus being on conventional plays in these frontier areas. In this study, we document the shale gas potential and prospectivity of the Cretaceous Upper Benue Trough.
Geochemical analysis of outcropping shales of the Cretaceous Fika Formation, Upper Benue Trough indicates that the organic richness of this formation is prospective. High TOC values, greater than the minimum threshold of 0.5%wt are documented in the analyzed samples. S_1 and S_2 yields were obtained to complement the organic carbon content results. The results indicate that the Fika Formation shales contains fair to rich bonded hydrocarbons, as revealed by the S_2 vs TOC plot, with the presence of type II oil prone, and type III gas prone type kerogen also detected. T_{max} values from the Rock Eval pyrolysis range between 422°C and 436°C, suggesting immature to early mature source rocks at the sample locations.

Petrographic and mineralogical analysis of the samples indicates high silica content (> 30%) and relatively low swelling clay in the samples, and suggests that the Fika Formation may be highly frackable. The integration of petrographic and organic geochemistry analysis of this formation as shown in this study suggests that the potential for a viable shale gas plays exist in the interval. Other factors like local stress regimes, timing and depth of burial in the deeper parts of the trough, and proximity to water filled aquifers may however prove to be critical for a successful campaign.

Introduction

The extraction of unconventional hydrocarbons from shale onshore North America and Northern Europe has significantly impacted the finances and the energy security of the host countries. Lately, the interior basins of Nigeria have seen a resurgence of interests with the main focus being on conventional plays in these frontier areas. In this study, we document the shale gas potential and prospectivity of the Cretaceous Upper Benue Trough.

Exploration and production of unconventional hydrocarbons involves the extraction of gas reservoired within organic rich shales, through a combination of horizontal drilling and hydraulic fracturing, also called fracking. Like in the conventional realm, hydrocarbon production from these shales is largely a function of organic content and thermal maturity. However, unlike in the conventional production of hydrocarbons where organic rich shales are classed as the "source rocks", the shales contain locked up kerogen within its micropores (Smith, 2010). Due to the low permeability of shales, the kerogen "sits there" underexplored, or unexplored in most cases. Hydraulic fracturing is carried out by injecting high pressured fluid down the horizontal well bore, which then creates artificial fractures within the shale formations.

The exploration for shale gas and oil in Nigeria has not been seriously considered, probably as a result of its vast proven hydrocarbon resources in conventional plays, both onshore and offshore Niger Delta. There extensive amounts of Cretaceous – Tertiary source rocks in Nigeria, with gas estimates of 184 TCF, Nigeria belongs to the elite league of the largest gas producers in the world.

There has been renewed interests in the Nigerian inland basins in response to the oil discovery in the Muglad Basin of Sudan, and the Termit, Doseo, and Doba Basins of Chad Republic (Abubakar et al., 2008), which are all genetically linked to the Central African Rift System. Several authors, including Akande et al. (1998), and Obaje et al. (2004a) have documented a similar tectonic history for the Benue Trough and the aforementioned basins (Figure 1).

Raji et al. (2013), Jarvie et al. (2004, 2007), and Gale et al. (2007) all documented some of the most important ingredients for shale gas exploration. They include source rocks, with TOC's greater than the minimum threshold of 0.5%wt with oil or gas generative potential, and must be thermally mature. The mineralogy must contain over 30% quartz, some carbonate, and preferably, brittle rock fabric. The presence of microporosity and pore throats in the shales, detectable under scanning electron microscope, would also provide an insight into the detailed shale mineralogy.

Methodology

The database for this research consists of organic geochemical data from Cretaceous shales in the Ashaka Cement Quarry of the Gongola Basin, Upper Benue Trough. The samples were collected at about 10-20 cm from the surface in order to minimize the effect of subareal weathering. These samples were further subjected to thin section microscopy and scanning electron microscopy.

Geochemical Analysis

Geochemical analysis was carried out in GHGeochem Laboratory in Liverpool, UK. These analyses include LECO TOC and Rock Eval Pyrolysis. S_1, S_2, and S_3 were derived to determine the generative potential of the organic matter in the shales. IGI's p:IGI-3 software was used to plot and interpret the geochemical results, by plotting the raw data and derived ratios into its dedicated interpretative graphs. R_o was calculated from T_{max}, using the formula from Zdanaviciute and Lazauskiene (2009), 0.0180 T_{max} -7.16.

Shale Mineralogy

For the shale mineralogy, the analyses carried out include petrographic description by conventional optical procedures with reference to Adams and Mackenzie (1998), which allows for identification of mineralogy, rock fabric and micro structures. The Scanning Electron Microscopy provides higher resolution semi-quantitative mineralogy. This was carried out at the University of Derby Petroleum Geoscience Department. The scanning electron microscope uses an electron beam instead of a light beam used in optical microscopy. Here, the high energy electron beam strikes the surface of the slide, and produces secondary emitted elecron stream in form of reflections from the electron-indiced excitation of the minerals present (Reed, 1996). From the point of view of shale gas exploration, high quartz (SiO_2), and carbonate content is preffered as this will help the rocks frack under hydraulic pressure.

Results

Geochemical Analysis

The Rock Eval pyrolysis results from the analyzed Fika shales from the Upper Benue Trough generally has fair TOC contents, with none exceeding 1%wt. The HI values range between 65-548, which indicates the samples analyzed are generally gas or oil prone, with fair to good generative potential as obtained from the S_2 yield (Peters, 1986). For the kerogen typing, the HI was plotted against the T_{max} (Figure 2) and the samples trends towards Type II (oil and gas-prone) kerogen, which is associated with marine/lacustrine source rocks, and the Type III (gas-prone) kerogen, which is essentially, associated with terrestrially derived source materials. The T_{max} values range between 427°C and 436°C (Figure 3) indicating that the analyzed samples are within the immature to early mature threshold, with minor hydrocarbon generative potential (D'Elia, 2009). This suggests low maturity for the shales at the sample location.

Mineralogical Analysis

The shales are calcareous and black to darker grey with carbonate nodules observed in hand specimen and on polished petrographic thin sections. The fabrics are finely laminated to non-laminated and moderately bioturbated. The fossil fragments seen in thin sections and in hand samples are much larger than silts

The SEM results (Figure 4) show that the analysed shales generally contain Al_2S_3, SiO_2, K_2O, FeO, SO_3, O, CO_2 in different weight proportion. It is composed of clay (3.97-12.81 wt %), quartz (> 30%), and amorphous dead organic carbon (average 44%) and pyrite (average 4%). Some samples contain some percentage of siderite.

Discussion and Conclusion

The HI values indicate that the Fika shales consists essentially of oil and gas prone kerogen. According to Dow (1977), thermal maturity of organic matter depends on the thermal stress to which they are exposed to, therefore, the T_{max} values, which provides information on maturity alongside the Vitrinite indicate that the analysed samples fall within the immature to early mature window, with minor hydrocarbon generative potential. These shales have been correlated, and reported to be stratigraphically equivalent to the Fika shales in the Nigerian sector of the Chad Basin (Obaje, 2004b), which can be as thick as 415 m in some parts (Alalade and Tyson, 2010). Gebhardt (1997) reported anoxic/dysoxic conditions were prevalent in the basin at this which may be attributed to the high TOC values reported in this study. Judging by the average source potential values (S_2 = 10.5) the Fika shales have high generative potential for hydrocarbon.

Thin section microscopy, combined with the scanning electron microscopy revealed the shale minerology. The analysed shales contain high quartz content as well as carbonates, which are key parameters to the process of hydraulic fracturing. The shale mineralogy reveals high silica contents in some parts, particularly along the laminae and occasionally, within the fractures. Alongside revealing the mineral abundance and the clay mineralogy, scanning electron microscopy revealed the microporosity to be greater than 6%.

In terms of the environmental impact assesment, especially on the contamination of water filled aquifers, further research is being carried out. Several other scientists globally are investigating the effect of hydraulic fracturing on triggering shallow earthquakes, as experienced in Blackpool, UK, 2011.

From the analysis done so far, the following conclusions can be drawn:

- The HI vs T_{max} plots suggest that the samples contain Type II oil prone kerogen and Type III gas prone kerogen.
- The sampled shales have good source rock potential in terms of its organic carbon content, but have low thermal maturity, within the early stage of hydrocarbon generation.
- The observed mineralogy seems conducive for hydraulic fracturing.
- The potential for shale gas exploration at the sampled location is unlikely, but would serve as a good analogue for the subsurface shale, especially in areas with higher paleo-burial might increase chances.

Future work

- Extensive geochemical analysis on borehole samples across the basin.
- Thermal and burial history models across the basin be carried out.

- Access to geophysical seismic data to further understand the structural complexities and resource estimation.

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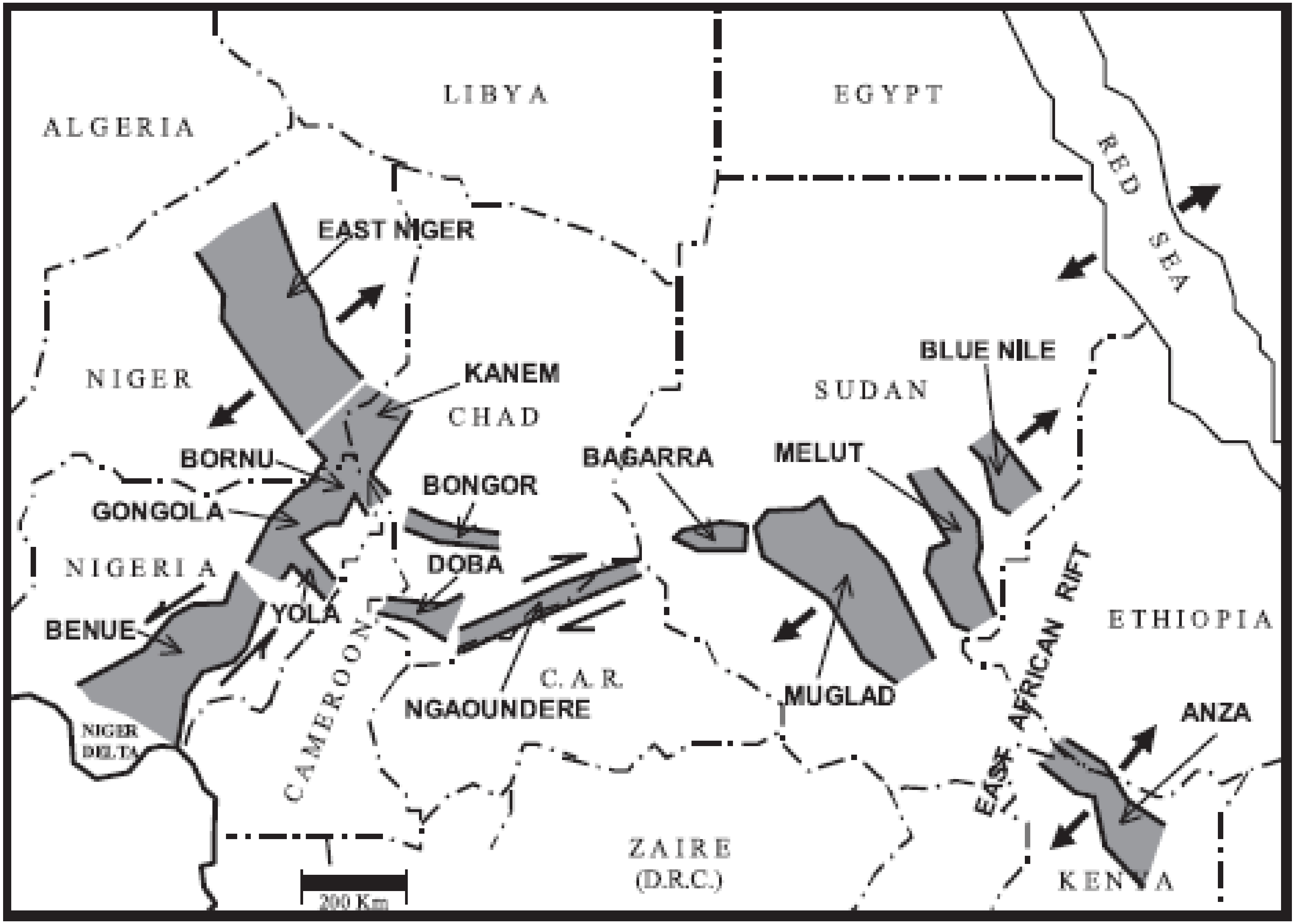

Figure 1. Map of Central and West African Rift System, showing the relationship between the Nigerian Benue Trough and other basins in the system (Obaje et al., 2004).

Rock-Eval Hydrogen Index vs T-max

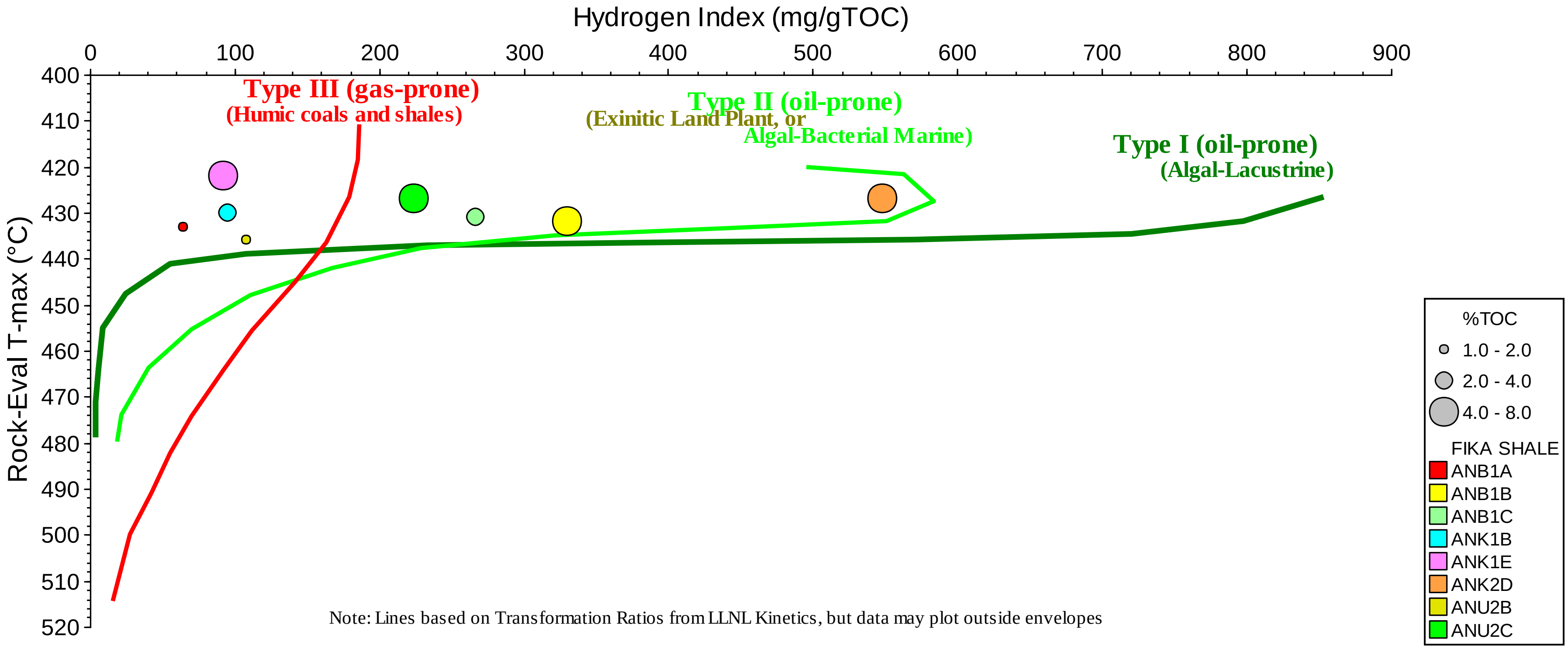

Figure 2. Showing that Type II (oil-prone) kerogen is associated with marine/lacustrine source rocks with moderate hydrogen/carbon (HC) ratio, whilst the Type III (gas-prone) is essentially associated with terrestrial land plant with lower HC ratio.

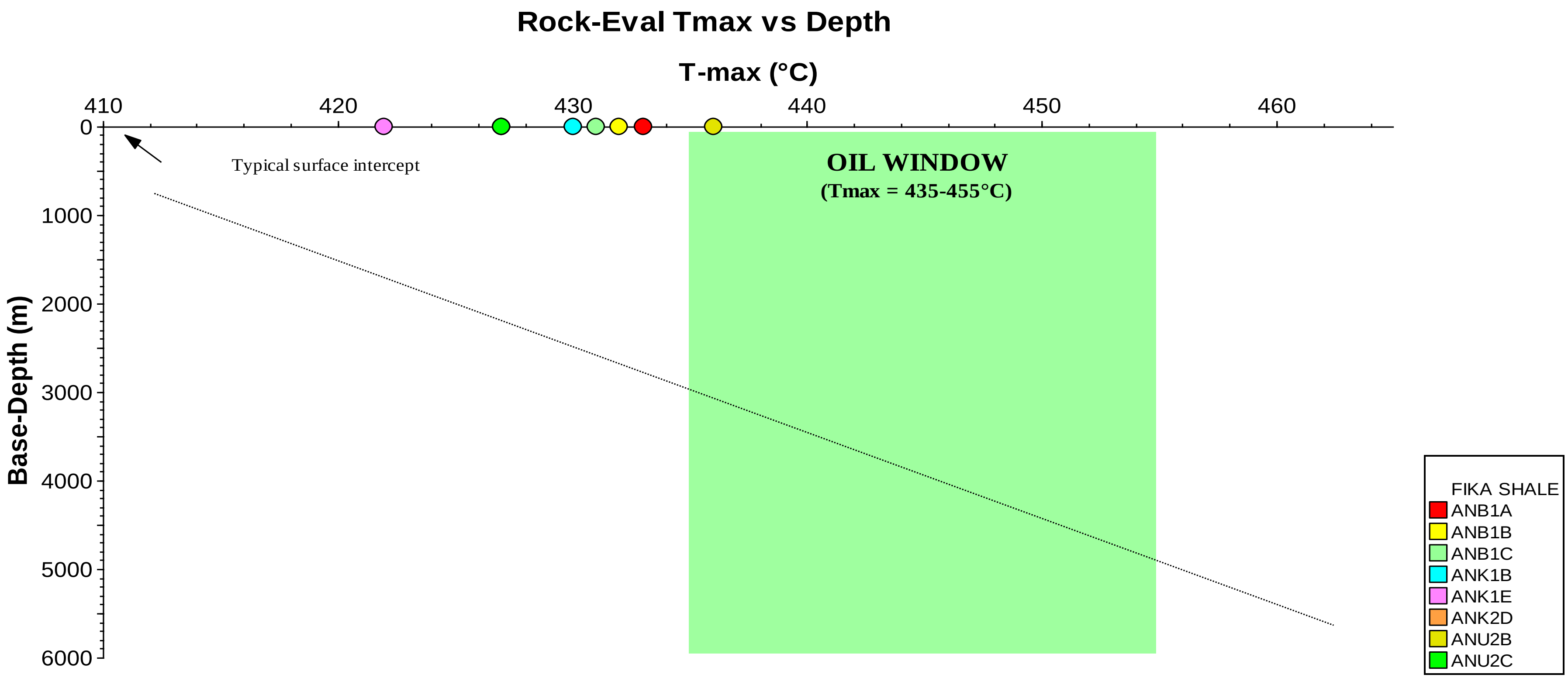

Figure 3. Maturity plot derived from Rock-Eval T_{max} showing that the analyzed samples are within the immature to early mature oil window.

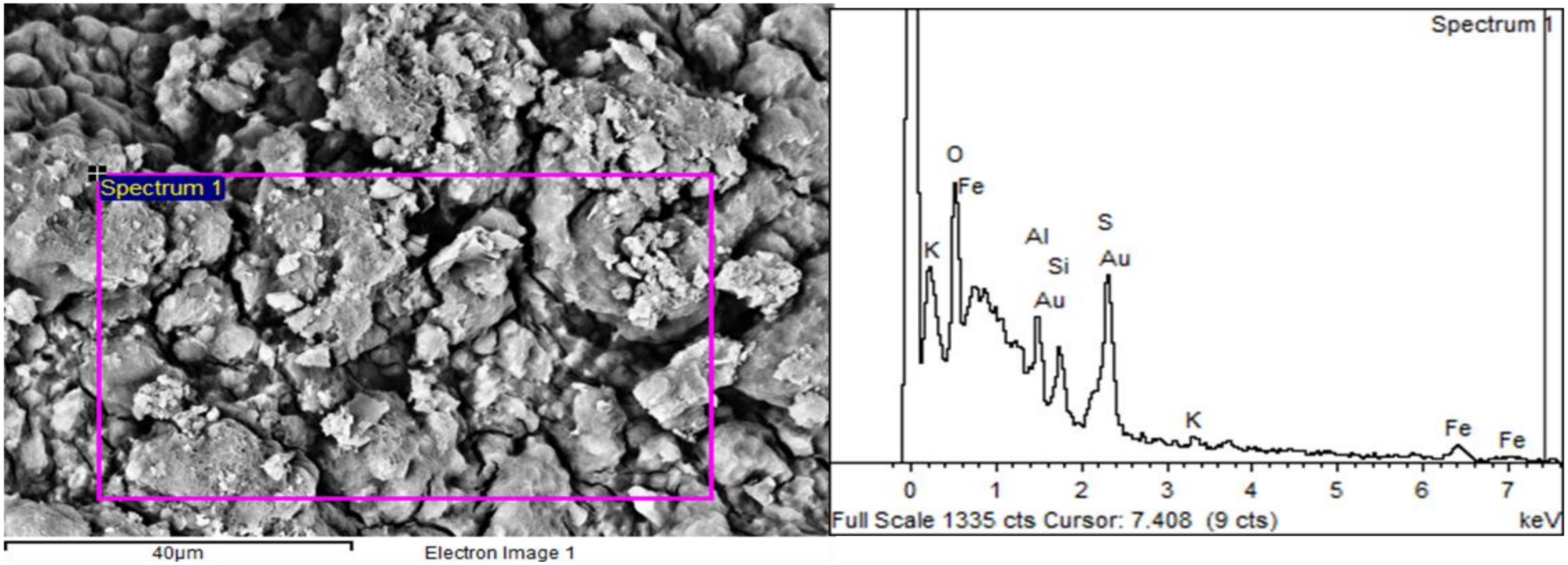

Figure 4. SEM image showing pyrite rich shale with large pore throats connecting pores. This sample is composed predominantly of clay, quartz, pyrite, and mica.