Understanding of Petroleum Systems from Palaeo-Petroleum Present in the Fingerdjupet Sub-Basin of the Bjørnøya Basin, Norwegian Barents Sea*

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Abstract

The Norwegian Barents Sea was for some time considered a gas-province due to significant uplift and the discoveries of Alke, Albatross and Snøhvit, but the recent advents of the Goliat and Johan Castberg oil discoveries followed by the Gohta oil discovery in 2013 has resulted in renewed optimism and work to understand better the “Petroleum Systems” of the region. Our angel of investigation to this is in part the residual oil in dry wells in the region. The present case study involves the study of residual oil and petroleum inclusions in core samples from reservoir sandstones of exploratory wells 7321/7–1, 8–1 and 9–1 in the Fingerdjupet Sub-Basin in the Barents Sea. Gases from inclusions were studied on disintegrated samples and extracted bitumen samples were analyzed by Gas Chromatography - Flame Ionization Detector (GC-FID), Gas Chromatography - Mass Spectrometry (GC-MS) and Thin Layer Chromatography - Flame Ionization Detector (TLC-FID). The isoprenoid to n-alkane ratio from GC-FID and distribution of sterane isomers from GC-MS suggest the palaeo-oil to have been sourced from the Upper Jurassic Hekkingen Formation. The relation between isoprenoids ratio (Pr/Ph) and aromatic hydrocarbons (MDBT/MPHEN) also point to such a marine source rock facies. Vitrinite reflectance calculated from aromatic hydrocarbons and sterane isomers shows that expulsion of petroleum from source rock took place in a single event of migration at maturity =0.8%Rc, which is typical for the early to middle part of the oil window. Composition of gases from inclusions of the Late Triassic Fruholmen Formation and the Middle Jurassic Stø Formation reservoirs show with C_2+ wetness between 13 to 22 % classifying the gas as condensate to oil associated and the butane ratios ($i\text{-}C_4/n\text{-}C_4$) fall in the range of 0.5 reflecting un-altered petroleum. We found a lateral variation in the Middle Triassic reservoir (Snadd Formation). In well 7321/7–1 this formation show inclusions with a

drier gas composition (C_2+ =5 %) and with higher butane ratio (=1.0) and an abnormally high polar fraction (50 %) representing biodegradation. However, this same formation in the well 7321/9–1 contain un-altered petroleum (i-C_4/n-C_4=0.5) with higher wet petroleum components (14 %), illustrating the complexity of the Triassic formations. The level of maturation and the proven migration history of these wells suggest that the possibility is high for commercial oil discoveries up-dip in the general region.

Introduction

The Norwegian Barents Sea was for some time considered a gas province due to significant uplift and owing to gas discoveries like the Alke, the Albatross and the Snøhvit fields, but the later to follow advents of the Goliat (2000) and Johan Castberg (2011) oil discoveries, followed by the Wisting and Gohta (2013) oil discoveries has resulted in renewed optimism and need for revision of the “Petroleum Systems Understanding” of the region. The Mesozoic rocks having varying degree of reservoir quality are present in the Norwegian Barents Sea. Residual oil saturation may exist in wells classified as dry, and petroleum inclusions can represent a further means of examination of palaeo-petroleum, which existed previously in traps. In this present study petroleum inclusions and residual oil in the core samples was investigated from three wells 7321/7-1, 8-1 and 9-1. Core samples were selected from the Mesozoic reservoir sections from these so-called dry wells drilled in the Fingerdjupet Sub-Basin of the Bjørnøya Basin of the Norwegian Barents Sea as shown in Figure 1.

Methodology

Various geochemical methodologies were applied on the core samples from these exploration wells to get better understanding of petroleum systems. The disintegrated core samples were finely crushed to obtain the gases (C_1 to C_5 hydrocarbons) from the petroleum inclusions, and the gas was analyzed by Gas Chromatography - Flame Ionization Detector (GC-FID). The microscopic study of petroleum inclusions was also carried out to describe the type of fluid present in the inclusions (Karlsen et al., 1993; 2004; Nedkvitne et al., 1993). The disintegrated samples were extracted by a Soxtec extraction unit to get the bitumen from the core samples. The extracted bitumen samples were analyzed by GC-FID, Gas Chromatography – Mass Spectrometry (GC-MS), and Thin Layer Chromatography – Flame Ionization Detector (TLC-FID) as developed by Karlsen and Larter (1991) and later modified by Bhullar et al., (2000). The North Sea Oil (NSO-1) from the Oseberg Field of Norwegian North Sea (Dahl and Speers, 1985) was used as a reference sample in geochemical analyses. The ratios of isoprenoids to n-alkanes calculated from GC-FID results of bitumen extracts were plotted in a Shanmugam (1985) diagram (Figure 2A), which illustrates the residual petroleum present in all the Mesozoic reservoirs was generated from a source rock of marine origin, most likely of the Upper Jurassic, which is typical source rock in the Norwegian Continental Shelf. The relative percentages of C_{27}, C_{28} and C_{29}

sterane isomers from GC-MS data (Figure 2B), also suggests that a marine source rock facies (Hekkingen Formation in the Norwegian Barents Sea) is responsible for petroleum generation in the region.

Discussion

The maturity of the samples was calculated from GC-MS data where aromatic hydrocarbons and sterane isomers categorize the samples from well 7321/7-1 to have a higher maturity than bitumen form well 8-1, while the well 9-1 has a relatively lower maturation level, as shown in Figure 3A. The ratios of steranes (20S+R and 22S+R), as used by Mackenzie (1984), indicate the extent of isomerization (Figure 3B). The samples show that the bitumen is clearly fully mature and represent mostly expulsion of petroleum at maturities of the early to middle part of the oil window (≥0.8 Ro %) which is positive to future petroleum exploration in the region.

The composition of light hydrocarbons (C1 to C5 hydrocarbons) from GC-FID results of crushed sand grains is a vital tool in order to determine the type of gas and petroleum in the traps at the time of entrapment. The gases from all the samples show Bernard parameter value less than 100, which clearly illustrate the thermogenic origin of gas (Bernard et al., 1977). In the well 7321/7-1, two reservoir sections have different gas compositions signalizing different sub-reservoirs. The Middle Jurassic reservoir (Stø Formation) contains C_2+ wet gas components of hydrocarbons making up 14 to 19 % (Jamil, 2012), indicating clearly that a condensate to oil associated gas (Schoell, 1983) whereas the Middle Triassic Reservoir (Snadd Formation) in the well 7-1 represents dry thermogenic methane gas of about 95 % (Figure 4B) (C_2+ contents of only 5%) with an abnormally high butane and pentane isomers ratios which concludes the process of biodegradation. This reservoir section also contains a rich polar fraction as shown in TLC-FID analyses that also support the model with in-reservoir biodegradation (Connan, 1984). The Late Triassic reservoir unit (Fruholmen Formation) in the well 8-1 contain C_2+ hydrocarbons ranges from 17 to 22 % (Figure 4B) showing that a condensate to oil associated gas existed at one time in the reservoir.

The well 7321/9-1 contain three reservoir units, the Late Jurassic (Fuglen Formation), the Middle Jurassic (Stø Formation) and the Middle Triassic (Snadd Formation), where all these sandstone units contain 14 to 19% of C_2+ hydrocarbons (Figure 4B) modified from Schoell (1983).

The reservoir units also contain normal butane ($i\text{-}C_4/n\text{-}C_4$) and pentane ($i\text{-}C_5/n\text{-}C_5$) isomers ratios (Figure 4A) which shows un-altered petroleum (Horstad et al., 1992). The composition of the gas varies in the inclusions in the Middle Jurassic sandstone (Stø Formation) in wells 7-1 and 9-1 indicate the complexity of the Middle Jurassic reservoir in the Fingerdjupet Sub-Basin.

The microscopic study of fluid inclusions in cleansed sands and thick sections was conducted to support the entrapment of hydrocarbon fluids. Two different reservoir sections were selected in order to compare the quartz overgrowth formation and to investigate any potential fluorescent oil inclusion present in the samples. The fluid inclusions are more developed in the Middle Jurassic reservoir of well 9-1 as compared to the Middle Triassic unit as shown in Figure 5.

Several uplift and exhumation events in the Tertiary Period resulted in fracturing of the cap rocks on traps in the Barents Sea. Additionally, the uplift exposed deeper stratigraphy at shallower levels, which decreased the temperature and pressure resulting in gas expansion and phase separation (Sales, 1997). This gas expansion and phase separation may have triggered dismigration of oil from most of traps in the region. On the other hand, non-uniform stages of uplift in the basin differentially affected the sealing capacity and the dismigration. The cap rock may in cases also leak or bleed off gas from the trap, while retaining some oil, and uplift may mobilize oil from deeper down in the migration avenues so that uplifted traps may recharge. Thus, uplift is not necessarily only destructive to traps of the region (Ohm et al., 2008).

Conclusions

Conclusively, this study has found irrefutable proof of migrated gas and residual migrated oil in the three investigated wells and this shows that source rock units in the region generate the mature hydrocarbons that accumulate in multiple reservoir units of the Fingerdjupet Sub-basin. It could be possible, in future exploration to investigate in particular up-dip traps, which may still hold long distance migrated oil-legs in Sales Type III, traps which are more resilient to uplift than traps with thicker and tighter cap rocks. Hence, several positive elements of “Petroleum System” model are coming together to optimistically indicate the potential for further and successful exploration for petroleum in this general region.

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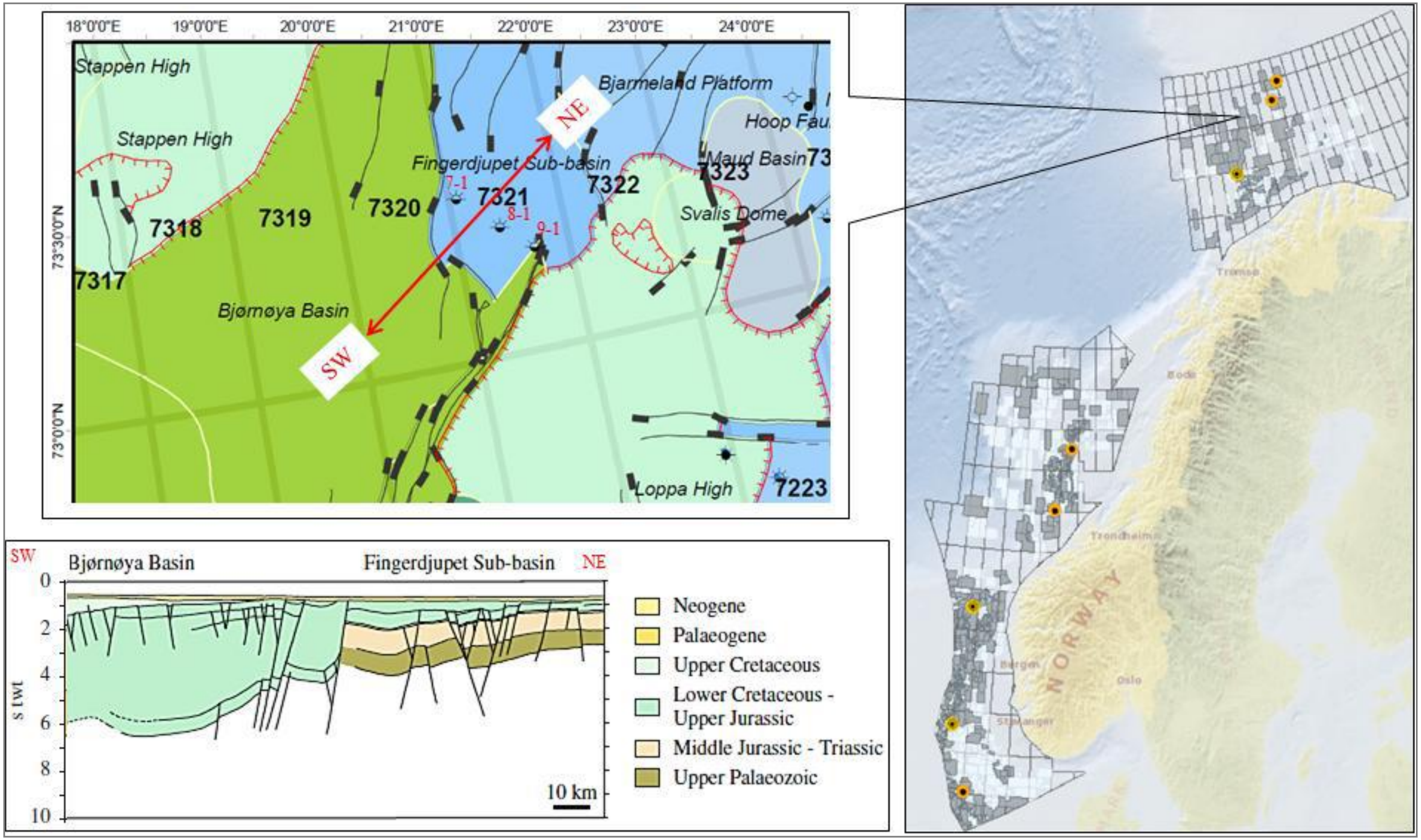

Figure 1. Regional map of offshore Norwegian Continental shelf (right side) and map of the study area where the Fingerdjupet Sub-basin is located in the Norwegian Barents Sea (top left side) (NPD factmaps, 2014) along with the NE-SW geological cross-section (bottom left side) displaying the structural elements and stratigraphic distribution of the Mesozoic reservoir units (Faleide et al., 2010).

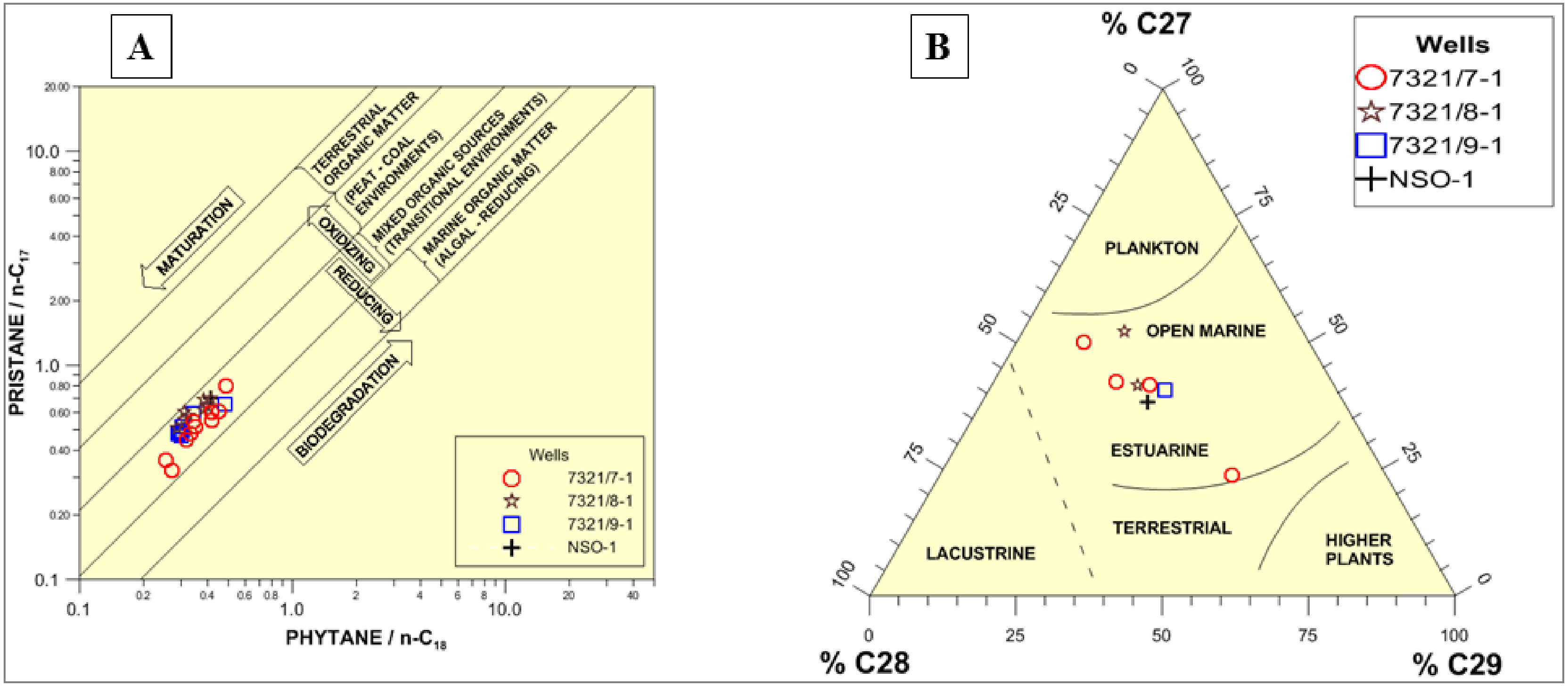

Figure 2. (A) Shanmugam diagram (Shanmugam, 1985) showing the isoprenoids to n-alkanes ratios categorizing the samples with respect to depositional environment, and all the core samples from the dry wells are suggestive of a marine source rock facies. In figure (B) modified from Shanmugam (1985), the distribution of sterane isomers shows that the bitumen samples from the dry wells generally lie in the “open marine environment” which is also representing the typical Hekkingen Formation of the Upper Jurassic age in the Norwegian Barents Sea.

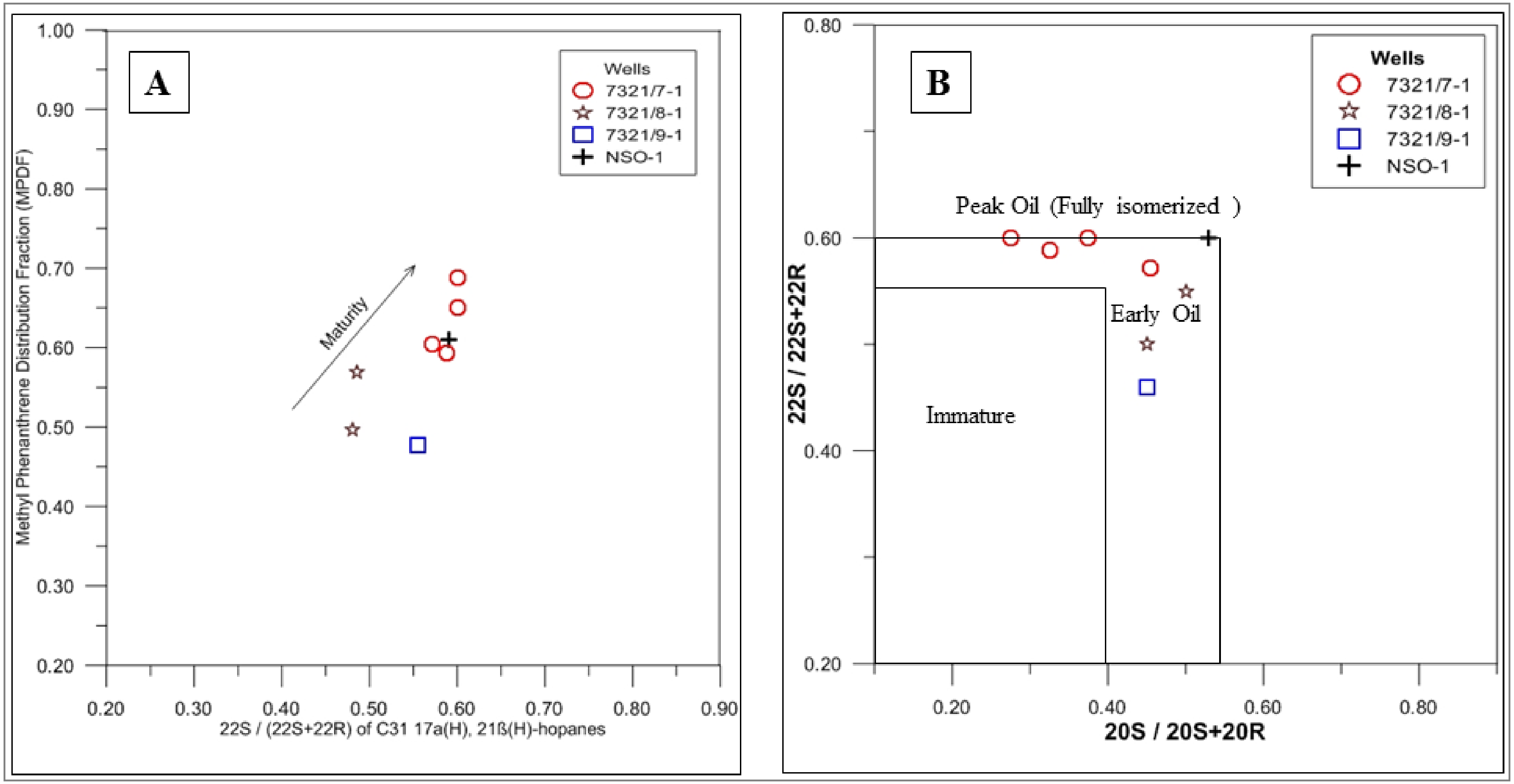

Figure 3. (A) Maturity comparison of studied wells based on aromatic hydrocarbons and hopane values from GC-MS results that shows that well 7-1 has a higher maturity than well 8-1, while well 9-1 lies at relatively lower maturation level. (B) Represents the samples with respect to sterane isomers (20S/22S) where all the samples lie in the early to peak oil phase of petroleum generation. The parameter 22S shows fully isomerization at a value of 0.6 while parameter 20S has an equilibrium value of isomerization at 0.55 (Peters et al., 2005).

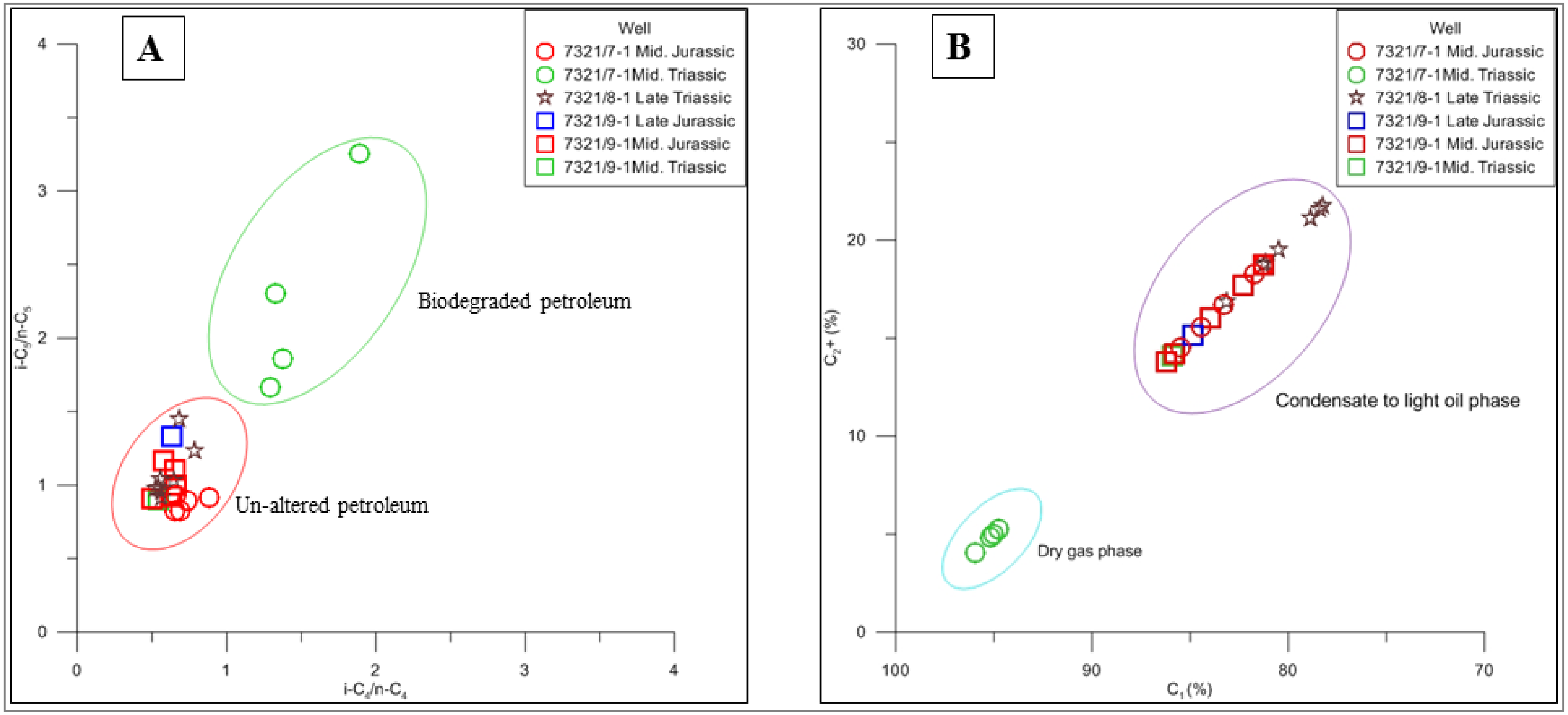

Figure 4. (A) Butane and pentane isomers were used to classify the dataset into un-altered and biodegraded gas samples form the GC-fid results. Most of the samples from the Mesozoic reservoirs show no signs of transformation or bacterial degradation except the Middle Triassic reservoir of well 7-1. (B) Demonstrate gas analysis results in order to determine the phase of petroleum where the Middle Triassic samples from well 7-1 represent dry gas while all other reservoirs shows wet gas which is clearly condensate associated or even oil associated suggesting that such gas existed with oil in the kitchen area and the oil may have migrated farther up-dip into nearby structures – Gussow (1955) style.

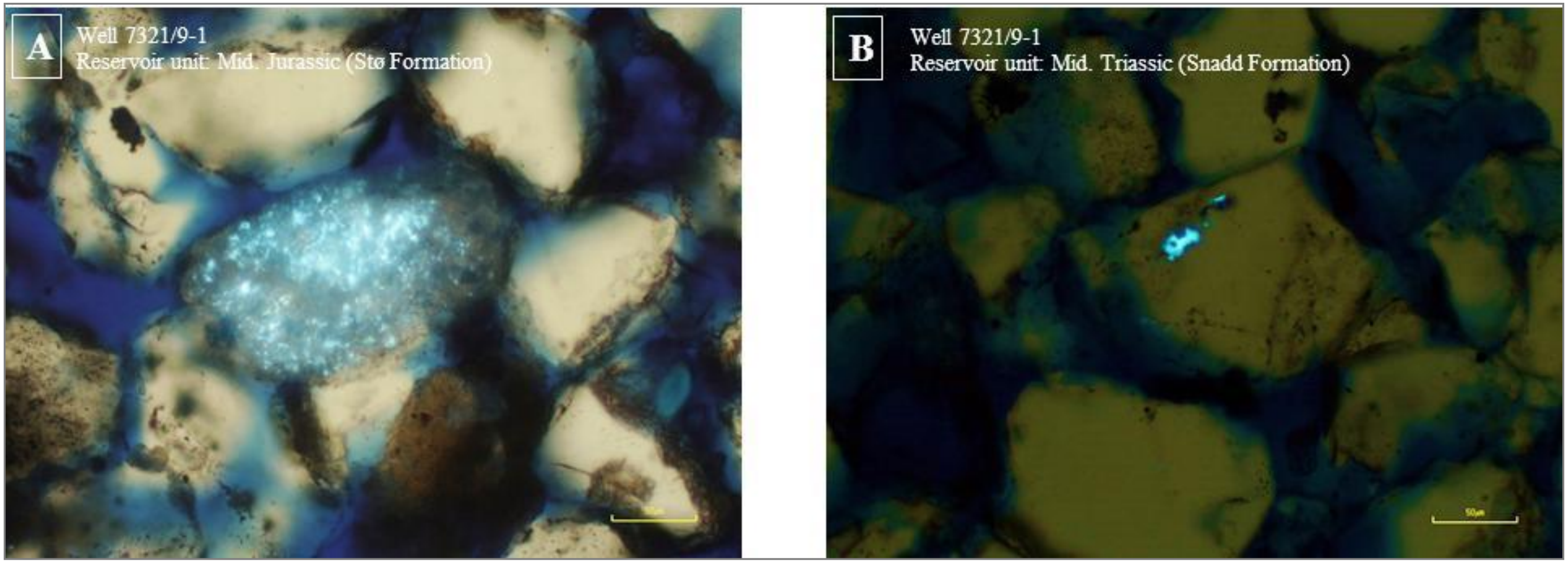

Figure 5. Fluid inclusions study from well 9-1 with a scale of 50μm where the Middle Jurassic reservoir section (A) show oil type fluorescent inclusions (here in albitized plagioclase but also in quartz), while the Middle Triassic reservoir (B) show only few fluorescent hydrocarbon inclusions (shown here in quartz), but with very well developed quartz overgrowths.