SOURCE ROCK POTENTIAL COMPARISON OF LOW-MATURE TRIASSIC–EARLY CRETACEOUS SEDIMENTS OF NORWEGIAN BARENTS SEA AREAS AND SVALBARD

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The Norwegian Barents Sea including Svalbard is a prolific hydrocarbon province. Petroleum exploration began in the Norwegian Barents Sea in the 1980s. While most wells drilled are either dry or contained non-commercial gas, a number of commercial discoveries have been made in the last five years. The discovery of Wisting, Gohta and Alta in 2013 and 2014 sparked a renewed research interest on oil properties (Duran *et al.* 2013; Killops *et al.* 2014; Lerch *et al.* 2016), but not on source rocks. Moreover, in the past, a presumption of equal lateral source rock properties prevailed within equivalent age units: e.g. the Botneheia, Steinkobbe and Kobbe formations. In part, this assumption was made because most geochemical analysis performed on source rocks had focused on data from exploration wells from the Hammerfest Basin where most of the source rocks are mature and thus the organic matter is highly reduced. It has therefore been problematic to ascertain the hydrocarbon potential and kerogen type pertaining to the original input organic matter.

This article describes the total organic carbon and Rock-Eval data of mostly immature to early mature sediments from the Early Triassic to the Early Cretaceous intervals collected from several shallow drilling holes from the Norwegian Barents Sea areas (i.e. Svalis Dome, Nordkapp Basin, Bjarmeland Platform) and from outcrop in Svalbard in order to determine the source rock potential and kerogen type. Data from time-equivalent formations are compared to eachother in order to examine the lateral variations in source properties.

The results from the investigated samples (Early Triassic to the Early Cretaceous) as a whole showed a wide lateral variation in source rock potential and kerogen type. The organic contents in the Middle Triassic Botneheia (n = 19) and Steinkobbe (n = 30) formations from Svalbard and Svalis Dome, respectively, are similar and range from 2 to 7%. Van Krevelen diagram suggest that the Botneheia Formation contains Type II organic matter, whereas Type II/III is more typical of the Steinkobbe Formation. By contrast, the Kobbe Formation samples (n = 15) collected from the Nordkapp Basin and Bjarmeland Platform have poor to fair hydrocarbon potential (TOC < 5%), and are dominated by Type III kerogen. In the Hammerfest Basin, the Middle Triassic Kobbe Formation samples from exploration wells show good hydrocarbon potential with kerogen Type II/III. These differences indicate that the equivalent Botneheia/Steinkobbe/Kobbe formations had changed from more oil-prone in Svalbard and at Svalis Dome areas to more gas-prone on the Bjarmeland Platform and in the Nordkapp Basin areas.

Our results also indicate that TOC contents in the Late Jurassic Hekkingen Formation samples (n = 21) from Nordkapp Basin and Bjarmeland Platform range from 7 to 19%. The hydrogen index for the Hekkingen Formation samples changes from Type II on the Bjarmeland Platform to Type II/III in the Nordkapp Basin samples. For the Lower Cretaceous Kolje Formation samples (n = 6) from the Nordkapp Basin our results indicate moderate

TOC, varying from 1.20 to 3.65%. However, Hydrogen indices varying from 23 to 66 mg HC/g TOC, in general, suggest Type IV/III kerogen and therefore are non-generative.

Most of the Svalis Dome and Nordkapp Basin samples are immature (i.e. $T_{max} < 430°C$), and the Svalbard Botneheia samples are early mature. The fact that such sediments have never or poorly drained make them ideal for constructing rankings of source rock potential and determining the kerogen type with respect to the inherited organic matter type, prior to maturation (Espitalié *et al.* 1987; Cornford 1998; Dahl *et al.* 2004).

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