Source Rocks at Svalbard: An Overview of Jurassic and Triassic Formations and Comparison with Offshore Barents Sea Time Equivalent Source Rock Formations*

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Abstract

The Svalbard Archipelago, located in the Arctic region, holds source rocks of great importance to the understanding of the Petroleum systems in the Barents Sea and the Circum-Arctic Region. Vast Mesozoic sedimentary successions are exposed on the major islands. The key targets of this study were to identify the source rock potential and describe the organic matter (OM) in terms of total organic carbon contents (TOC), hydrocarbon potential, organic facies, and level of maturity in more detail and from more varied localities than previously accomplished. Forty-nine outcrop samples, mostly shales and mudstones, representing Triassic and Jurassic formations from four different locations at Svalbard have been analysed geochemically.

The results indicate that both Jurassic and Triassic sediments have potential for oil and gas generation, and the best source rocks at Svalbard lie within the Triassic Botneheia Formation. Most samples from the Botneheia Formation at the Blanknuten locality are characterized by high TOC (5-10%) and high hydrogen index (HI) (445-609 mg HC/g TOC) values, suggesting excellent source rocks with Type II kerogen. Most samples from the Botneheia Formation at the Muen locality have also very good TOC values (2.4-6.2%), but significantly lower HI values (124-184 mg HC/g TOC), indicative of gas prone Type III kerogen. These results suggest that the organic rich Botneheia Formation at Muen has currently lower generating capability than its analogue at the Blanknuten locality, and this difference is mainly attributed to maturation. The Muen samples are also defined by higher production index (PI) values than the Blanknuten samples, and typical values range from 0.1-0.3 at a T_{max} of 448-457°C for the Muen samples, and this compares to PI values of 0.04-0.06 at a T_{max} of 439-446 °C for the Blanknuten samples. This suggests that the Muen samples are presently at a "late-oil-window-maturities" and therefore have already generated and expelled significant proportions of oil, due to their elevated PI values. Still they are capable of generating gas, while the Blanknuten samples are today only at an early "oil-window-maturity-stage". The samples from the Upper Jurassic Agardhfjellet Formation at the Myklegardfjellet/Agardhbukta locality are characterized by 2.2-5.9% TOC, 77-121 mg HC/g TOC HI, and 452-465 °C T_{max} values, implying gas prone Type III kerogen which are presently within the "late oil window maturity".

Isotope and biomarker data suggest that the source rock facies is marine for most samples with additional organic matter input from terrestrial flora for some of the Jurassic samples. The poster presentation includes a comparison between these Triassic and Jurassic formations at Svalbard, with time equivalent offshore Barents Sea Steinkobbe (1.5-9% TOC) and Hekkingen (3-16% TOC) formations.

Introduction

The Svalbard Archipelago comprises all Islands in the area 74-81°N, 10-35°E (Steel and Worsley, 1984) (Figure 1). The largest Islands are Spitsbergen, Nordaustlandet, Barentsøya and Edgeøya. Although most of Svalbard is permanently covered by glaciers and inland ice, coastal and mountain exposures, quite surprisingly, made Svalbard one of the best places to study geological features ranging in age from Precambrian to the Palaeogene. Thus, Svalbard has been a key area for geological research for more than a Century (Steel and Worsley, 1984; Mørk and Worsley, 2006). The Mesozoic sedimentary successions that have been exposed on the major islands of the Archipelago have been divided into three major lithostratigraphic units or Groups (e.g. Buchan et al., 1965; Parker, 1967; Forsberg and Bjorøy, 1983). These lithostratigraphic units comprise organic rich successions of fine-grained shales and mudstones, which are important petroleum source rocks (e.g. Krajewski, 2013). At Svalbard, mature source rocks are known from the Triassic (e.g. Botneheia Formation), Jurassic (e.g. Agardhfjellet Formation) and from the Lower Cretaceous Carolinefjellet Formation. All these sediments represent source rocks with varying hydrocarbon (HC) generation potential, ranging from gas to oil prone. Time-equivalent sediments in the Barents Sea are also confirmed source rocks. The Middle Triassic Botneheia Formation makes the best petroleum source rock at Svalbard and it has received special attention (e.g. Bjorøy et al., 2010). Previous studies indicated up to 10% TOC values for this formation (Mørk and Worsley, 2006). The Triassic succession at Svalbard varies greatly in thickness, where the successions generally thin eastwards. In eastern Svalbard, the potential of the Botneheia Formation as source rock varies from moderate to very good. Coals in Svalbard are also known in several formations from Devonian to Tertiary, and especially the latter has been mined since the 1900s. Recent findings indicate the presence of migrated bitumen in sandstones and carbonaceous mudstones of Triassic to Cretaceous ages (Olaussen, 2014).

Samples and Analytical Methods

Forty-nine outcrop samples (38 Triassic, 10 Upper Jurassic and 1 sample from the Lower Jurassic) were collected for this study from outcrops at several localities (Muen, Blanknuten, Myklegardfjellet/Agardhbukta and Festningen) at Svalbard (Figure 1). Most of the samples are shales and mudstones from the Triassic (Botneheia, Tschermakfjellet, Vikinghøgda) and Jurassic (Agardhfjellet/Agardhbukta) formations. Surface and weathered material was removed from the samples prior to crushing. Total organic carbon (TOC) and Rock-Eval pyrolysis was carried out on all samples. The pulverized samples were extracted on Soxtec extraction system unit, following the procedures proposed by the Norwegian Industry Guide to Organic Geochemical analyses (Weiss et al., 2000). This was carried out by using extraction solvent consisting of 93 vol% dichloromethane (DCM) and 7 vol% methanol (i.e. volume ratio, 93:7). Subsequently, the extracts were analysed by Gas chromatography-Flame ionization detector (GC-FID) for bulk compositional data and Gas chromatography-Mass spectrometry (GC-MS) for biomarker analyses. Moreover, on selected samples determination of stable carbon isotope composition of saturated and aromatic hydrocarbon fractions and determination of vitrinite reflectance were carried out.

Results and Discussion

Solvent Extracts of Rocks

Figure 2 is a photo of the organic extracts showing systematically varying colours, suggesting variation in the organic matter richness. The samples from the Botneheia Formation at the Blanknuten locality are darker compared to the others. Extracts from the Vikinghøgda Formation are much lighter in colour and apparently low in extractable organic matter content.

Hydrocarbon Potential and Kerogen Type

The quantity of organic matter is usually expressed as total organic carbon (TOC) (Hunt, 1996). The TOC values for most of the studied samples are above 1.0 wt% (Figure 3). Only five samples contain TOC values of lower than 1.0 wt%, indicating that most samples contain values above the minimum TOC requirement for oil or gas forming rocks (Hunt, 1996). Higher TOC values were in general observed from the Botneheia Formation at the Blanknuten locality with values up to 9.87 wt%, and the average value is 4.62 wt%. The TOC content of the samples from the Botneheia Formation at Muen locality ranges from 1.34 to 6.21% wt%, and the average value is 3.44 wt%.

The TOC content of the samples representing the Jurassic Agardhfjellet Formation varies between 2.5 and 5.86 wt%, except for one sample with only 0.86 wt% TOC. Bjorøy and Vigran (1980) concluded that the upper part of the Agardhfjellet Formation has a "good" to "rich" potential and is thus a source for oil and gas, whereas the lower part has a "good potential" and is a source for gas. It is interesting to compare this hydrocarbon generation potential and other organic matter aspects of the Agardhfjellet Formation to its time-equivalent Hekkingen Formation in the Barents Sea. The latter with up to 16 wt% TOC is the best source rock in the Barents Sea (Smelror et al., 2001).

TOC values for 3 samples from the Vikinghøgda Formation, varies from 0.07 to 0.94 wt%, with an average value of 0.45 wt% and represents the lowest values in the sample set. Five samples representing the Tschermakfjellet Formation contain TOC values in the range 1.15 to 2.32 wt% with an average value of 1.60 wt%. In this study, the Upper Triassic De Geerdalen Formation is represented by one sample and its TOC content was found to be 1.54 wt%. The TOC content of a Lower Jurassic sample from the Festningen locality was 1.58 wt% TOC.

From Figure 3, it can be seen that most samples from the Botneheia Formation at Blanknuten locality are "very good" to "excellent" source rocks, whereas samples from the same formation at Muen locality are classified as "fair" to "good". The samples from the Upper Jurassic Agardhfjellet Formation and all samples from the Festningen area, presently, are fair to good source rocks (Figure 3). Samples from the Vikinghøgda Formation, with very low TOC and S2 values, are plotted as "poor" source rocks.

Hunt (1996) described the relative ability of source rocks to generate petroleum, and this is defined by kerogen quantity (TOC) and quality (high or low in hydrogen). As shown in Figure 4 and Figure 5, there is a clear variation typically in the hydrogen index (HI) values between the Botneheia samples from the Muen area and the Botneheia samples from the Blanknuten area. The majority of the Botneheia samples from Blanknuten display HI values well above 300 mg HC /g TOC whereas, samples from the Muen locality are below 200 mg HC / g TOC. Peters and Cassa (1994) suggested that HI values between 300 and 600 mg HC/g TOC as oil prone Type II kerogen. Accordingly, most samples from the Botneheia Formation at the Blanknuten locality appear to be potentially oil prone with kerogen characterized as Type II (Table 1, Figure 4, and Figure 5), and possibly even Type I. A few samples from this locality indicate mixture of Type II and III kerogens (Figure 5).

About 92% of the Botneheia samples from the Muen locality, with HI ranging from 124 to 184 mg HC/g TOC, are representing gas prone Type III kerogen, but one sample (sample 13, HI = 306) seems to favor Type II kerogen. The variation in kerogen types between the Botneheia samples at Blanknuten and Muen, shown in Figure 5, is most likely related to thermal maturity, rather than to variation in kerogen type associated with depositional environment and organic input. As discussed later, the Muen samples are thermally more mature compared to the Blanknuten samples and this is furthermore, supported by Rock-Eval and biomarker data (Figure 6, Figure 7, Figure 8, Figure 9, and Figure 10).

The samples from the Tschermakfjellet Formation contain gas prone Type III kerogen. The Jurassic samples of the Agardhfjellet Formation with hydrogen index much lower than that of the Botneheia Formation, display hydrogen indices of still higher than 50 (the minimum value of HI for a sample to generate gas, Peters and Cassa, 1994), but lower than 200, thus plotted as gas prone type III (Figure 4 and Figure 5).

Maturity

Figure 6 is a cross plot of HI against T_{max}, which is used to describe the petroleum generating thermal range of the studied source rock samples. The T_{max} values for all, but one sample, range between 435 to 466 °C (Figure 6), indicating that nearly all samples are within mature petroleum-generating thermal range and values vary significantly from lower maturity (lower T_{max} values) in the samples of the Botneheia Formation at the Blanknuten locality, to higher maturity (higher T_{max} values) in the samples from the Agardhfjellet, Tschermakfjellet formations and Botneheia Formation at Muen. Figure 7 is a cross plot of production index (PI) versus T_{max} and illustrates the significant variation in thermal maturity observed between the Botneheia Formation at Blanknuten and the Botneheia Formation at Muen. Biomarker maturity parameters obtained from GC-MS analyses (Figure 8) is consistent with maturity data from Rock-Eval in that, samples from the Blanknuten locality are lower in maturity compared to the other samples (Figure 9 and Figure 10).

Organic Facies

The n-alkanes and isoprenoids (Pristane and Phytane) peaks identified from the GC-FID (Figure 11) were used in facies interpretation (Figure 12 and Figure 13). Figure 14 is a plot of stable carbon isotope values for the saturated and aromatic hydrocarbon fractions of 11 selected samples and shows the depositional environments of the samples.

Summary and Conclusions

Assessment of source rock at Svalbard by geochemically analyzing 49 outcrop samples (38 Triassic, 10 Upper Jurassic, and 1 Lower Jurassic) has been carried out. The outcrops represent the following Formations: Botneheia, Tschermakfjellet, De Geerdalen, Vikinghøgda (all Triassic) and Agardhfjellet (Upper Jurassic). The key targets of this study were to identify the source rock potential and describe the organic matter (OM) in terms of total organic carbon contents (TOC), hydrocarbon potential, organic facies, and level of maturity. Regarding total organic carbon content, except two samples (both from the Vikinghøgda Formation) all contain TOC value of nearly 1.0 or above 1.0 wt%. On average, the Botneheia samples at Blanknuten contain the highest TOC content among the sample set.

The potential of the samples to generate hydrocarbon and the type of kerogen varies. Most samples from the Botneheia Formation at Blanknuten locality are excellent oil-prone source rocks with kerogen Type II, as indicated by hydrogen index of above 300 mg HC/g TOC. In contrast, the same formation at Muen is mainly gas prone plus possibly some oil. This variation is attributed to maturity and not to kerogen type with respect to depositional facies, i.e. (open) marine for both localities. Rock-Eval and biomarker data strongly support the variation in maturity level between the Botneheia Formation at Muen and the Botneheia Formation at Blanknuten. Maturity at Muen is higher than at Blanknuten. The reason for this is not clear, thus more work is recommended.

The organo-facies depositional setting of the Middle Triassic sediments in the Barents Sea and Svalbard, in general, was marine with some input from terrestrial. Geochemical correlation with time equivalent Steinkobbe/Kobbe formations in the Barents Sea indicate that, the organic matter in the Botneheia Formation were derived from 'anoxic to dysoxic' conditions, compared to 'anoxic' depositional setting of that in Steinkobbe Formation at the Svalis Dome and 'dysoxic to oxic' depositional setting of that in the Kobbe Formation from the Nordkapp Basin and Bjarmeland Platform. The organic matter in the samples of the Kobbe Formation in the Hammerfest and Bjørnøya Basins were deposited at more or less similar depositional setting to that of the Botneheia Formation.

The quality of the organic matter in the Agardhfjellet Formation varies locally. The present data suggest that the Agardhfjellet Formation is currently a gas prone source rock with Type III Kerogen and maturity of this organic matter is towards the late stage of the oil window. The depositional setting for the sediments of the Agardhfjellet Formation was a marine with possible input from terrestrial environment. This indicates that the organic matter input was from aquatic and terrestrial precursors and, that it was more terrigenous compared to the Hekkingen Formation in the Barents Sea. The organic matter in the Upper Triassic De Geerdalen and Tschermakfjellet formations is derived from Type III gas prone source rocks indicating input from land material deposited in a terrestrial environment. The quantity and quality of the organic matter in the Vikinghøgda Formation is very low, probably due to over maturation. The data from three samples indicate little or no potential source rock quality for this formation.

The GC-MS data suggest that the Triassic samples are characterized by high hopane and homohopanes contents and lack of bisnorhopanes, and appearance (and relative amount) of tricyclic terpanes vary strongly, seemingly not only controlled by maturity. The samples from the Botneheia Formation are characterized by higher tricyclic terpanes including the C_{28} and C_{29} tricyclic terpanes, often associated with Triassic age source rocks/oils. However, C_{28} and C_{29} peaks were not detected on several samples of the Steinkobbe and Kobbe formations.

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Figure 1. Map of Svalbard showing the locations of the samples indicated by red circles followed by numbers 1-5.

Figure 2. Soxtec extracts sorted according to the color of the extractable organic matter (EOM). The upper row represents the Botneheia Formation at the Blanknuten locality, which clearly contain more EOM than the other samples. Triassic carbonaceous samples of the Vikinghøgda Formation appear to contain lower EOM as these extracts have lighter colours.

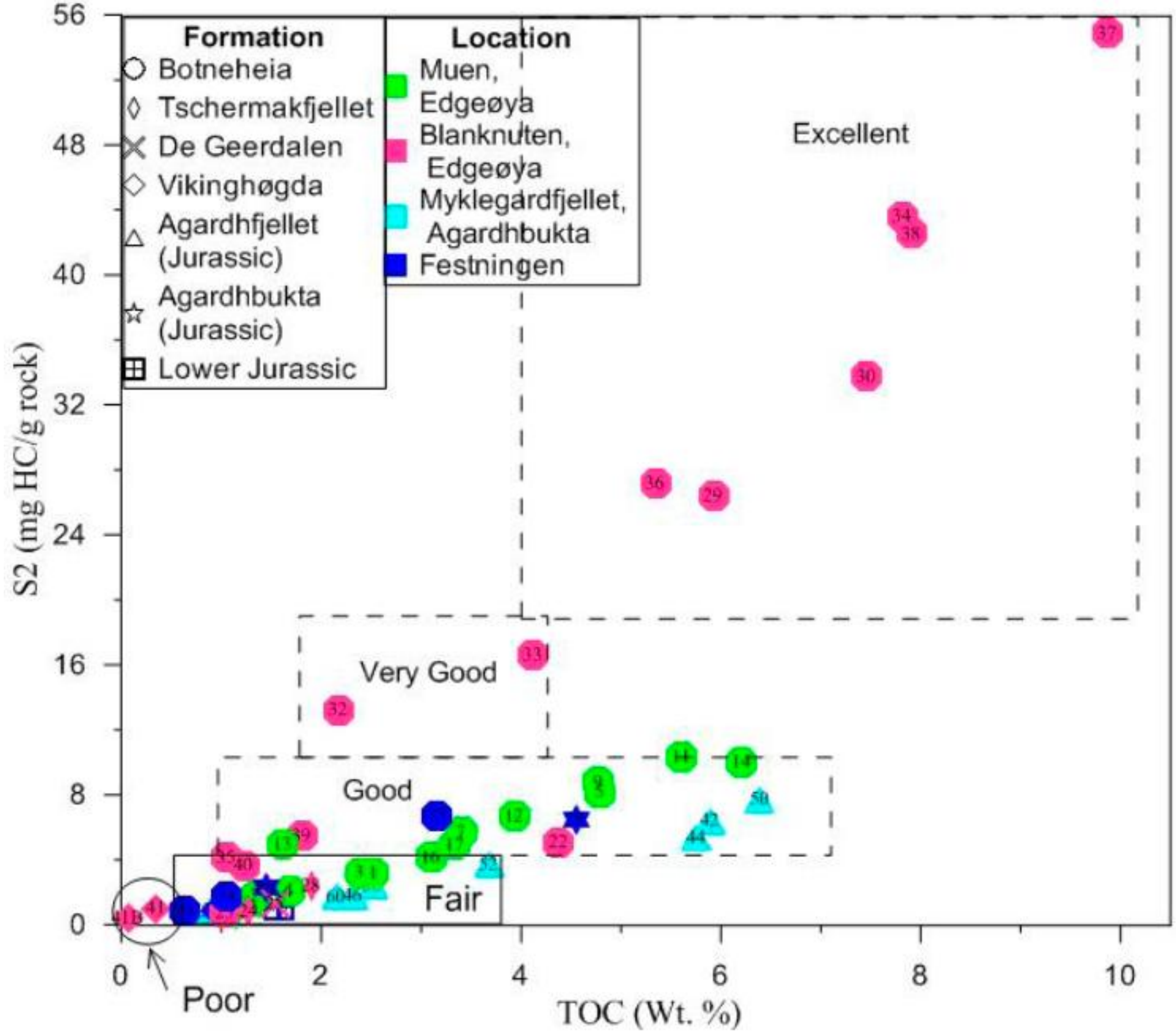


Figure 3. Total organic carbon (TOC, wt%) plotted against S2 (mg HC/g rock), showing differences in hydrocarbon generation potential of the samples. The numbers on the sample symbol indicate sample code.

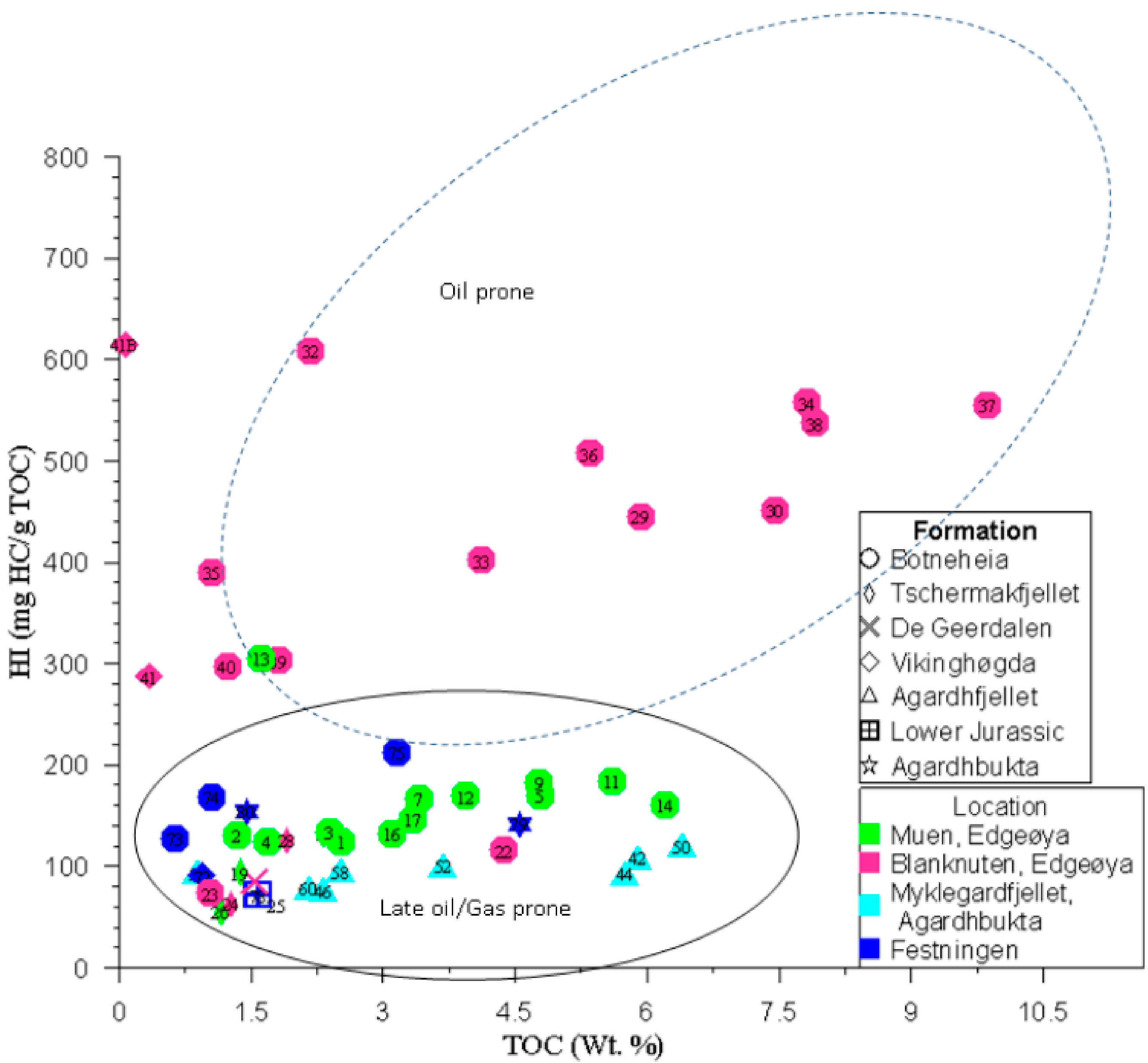


Figure 4. Cross plot of hydrogen index (HI) against total organic carbon (TOC), showing the main hydrocarbons, the samples presently can generate.

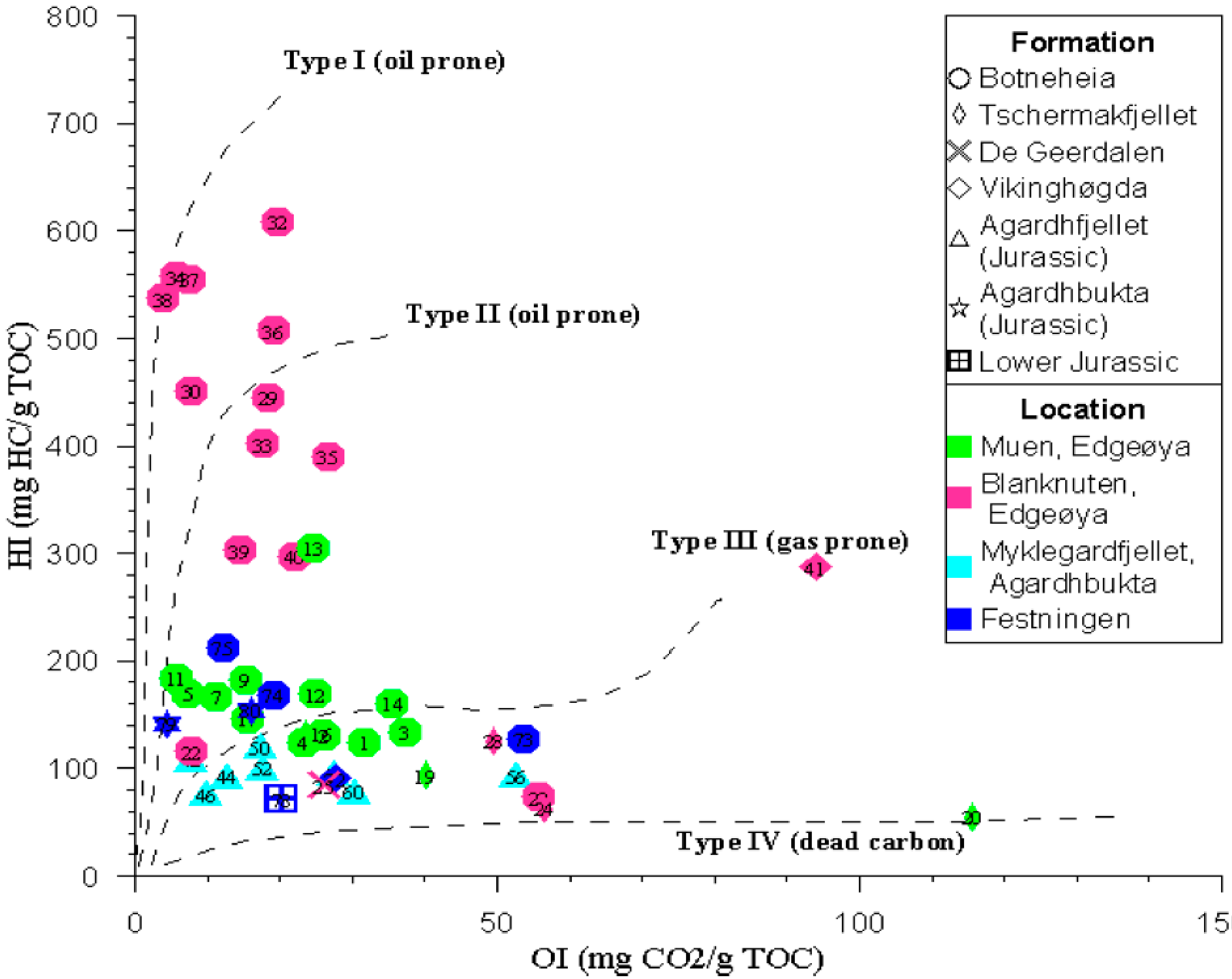


Figure 5. Modified van Krevelen diagram with hydrogen index (HI) plotted against oxygen index (OI). Most samples from the Blanknuten locality of the Botneheia Formation show higher HI values (HI = greater than 300) and thus oil prone. The rest of the samples show lower HI values capable only of generating gas.

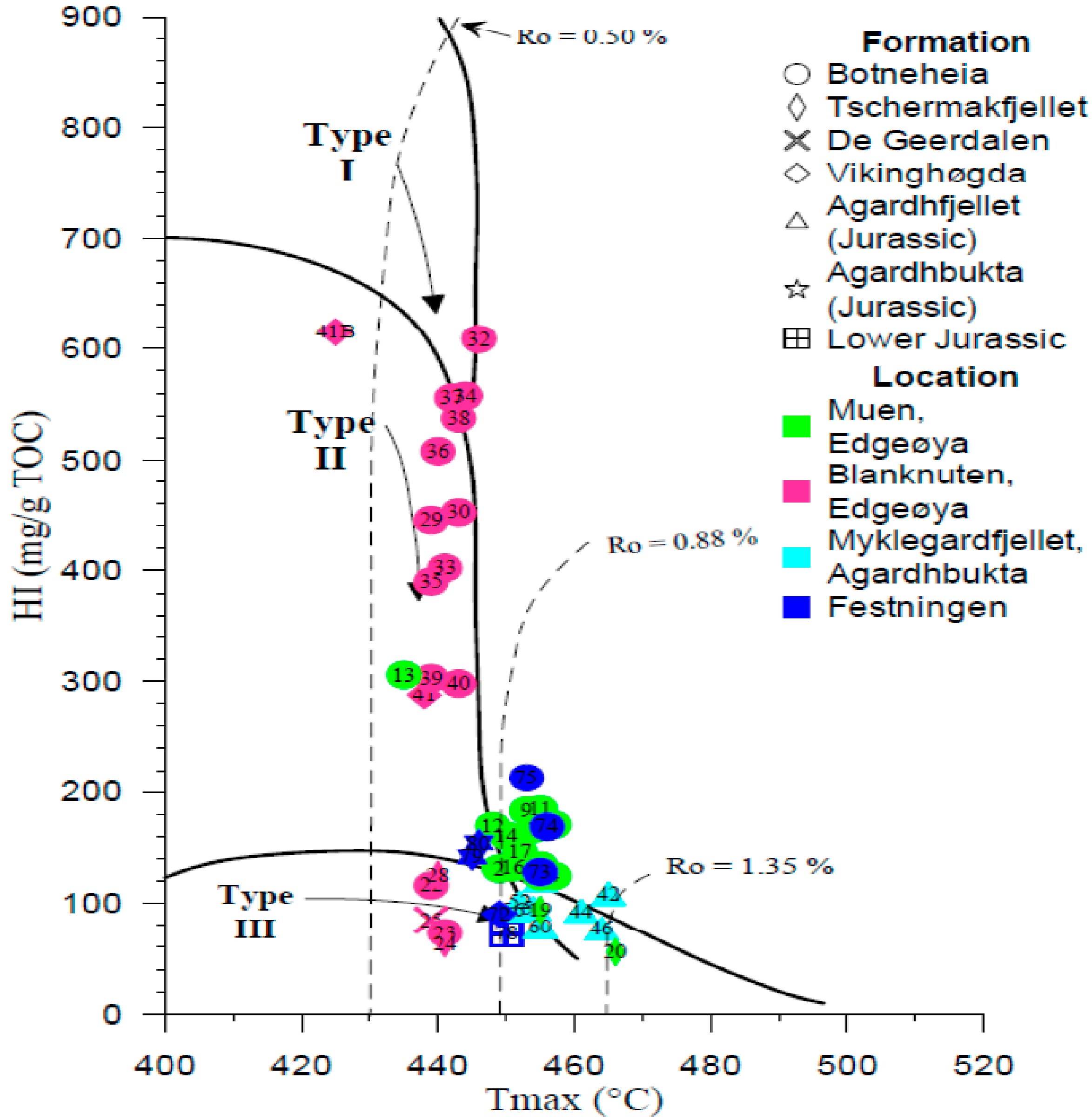


Figure 6. Rock-Eval data Hydrogen Index (HI) plotted against T_{max}. All samples (except 1) are within the oil window maturity. Those samples from the Botneheia Fm at Blanknuten show early oil window maturity whereas, most samples from the Botneheia Formation at Muen locality together with the other samples are in the moderate to late oil maturity stages.

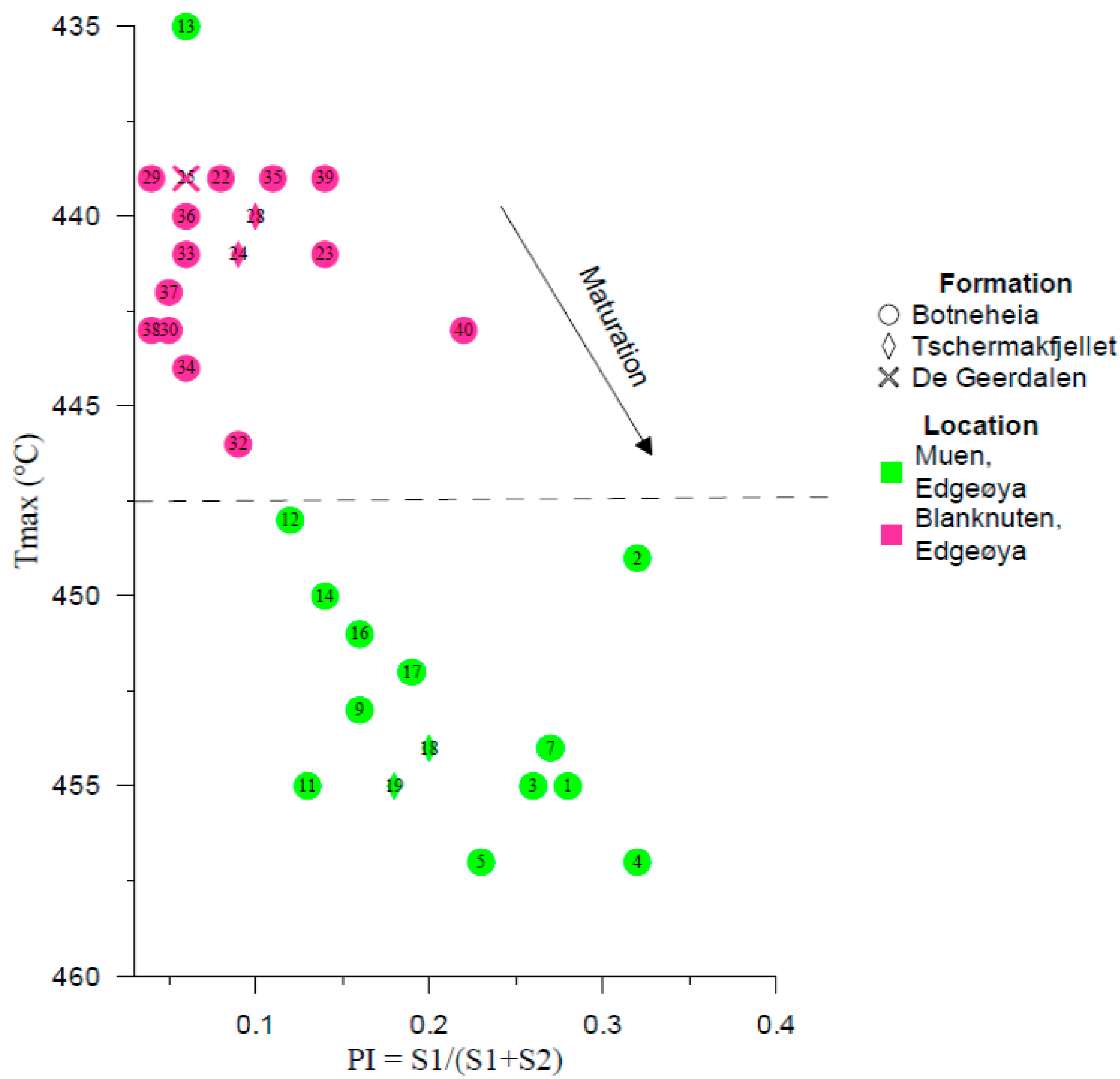


Figure 7. X-Y plot of production index (PI) vs. T_{max} for samples at Muen and Blanknuten areas, both from the Botneheia Formation. The figure shows a clear variation in T_{max} and PI between these sample groups. The maturity at Muen is higher than the maturity at Blanknuten. Note how sample 13 from Muen is plotted, also in Figure 6. This sample reflects lower maturity than all other samples from the Botneheia Fm at Muen.

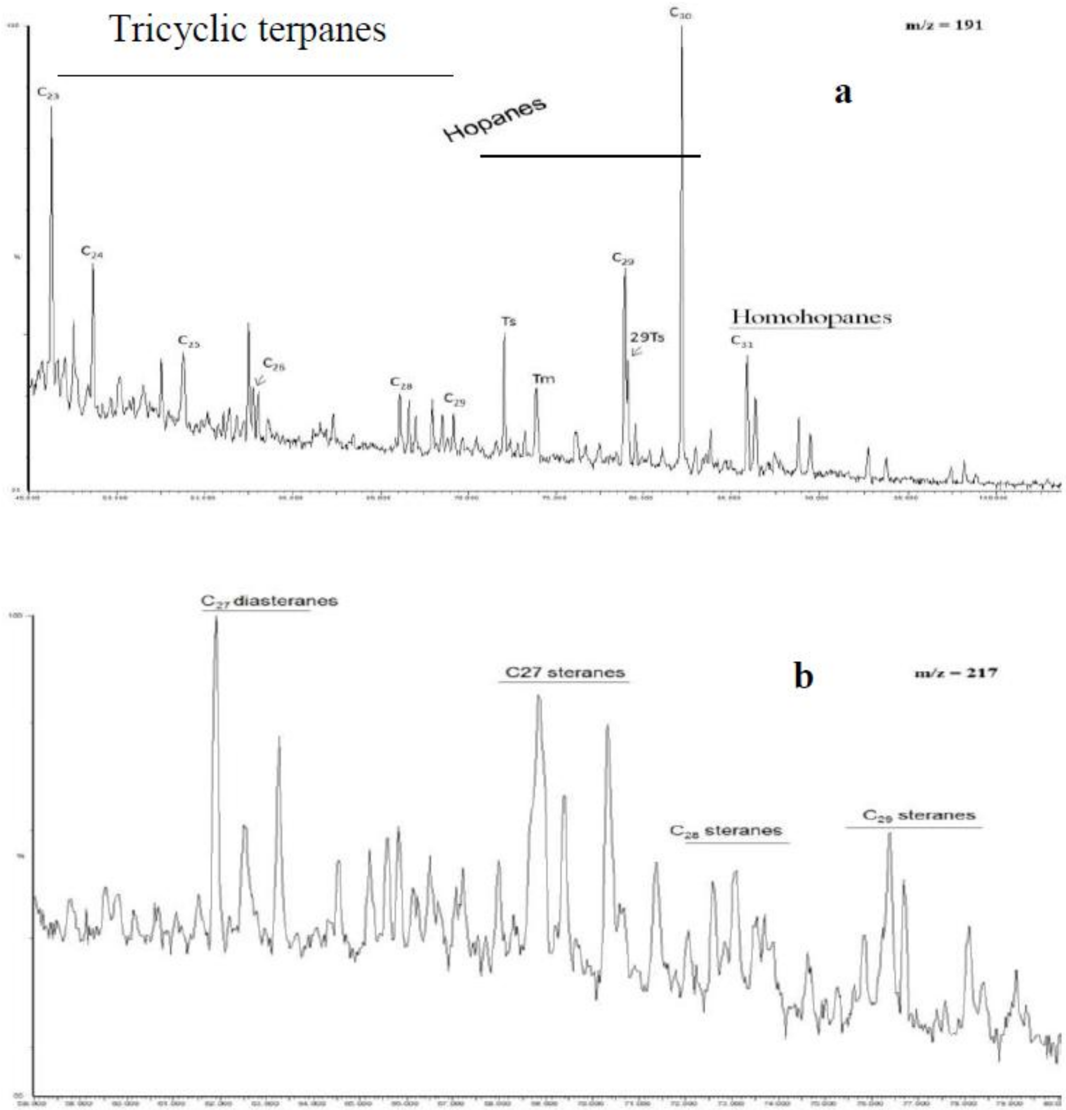


Figure 8a and b. m/z 191 and m/z 217 GC-MS chromatograms of a sample representing the Botneheia Fm at Blanknuten. Note the higher tricyclic terpanes including the C_{28} and C_{29}, often associated with Triassic age. Comparison of m/z 191 chromatograms of the Botneheia Formation with that of time equivalent Steinkobbe and Kobbe formations in the Barents Sea (Abay et al., 2014) indicate that in general, the Middle Triassic Barents Sea samples contain low concentrations of tricyclic terpanes and the C_{28} and C_{29} peaks were not available in significant concentration in several samples of the Steinkobbe and Kobbe formations (Abay et al., 2014).

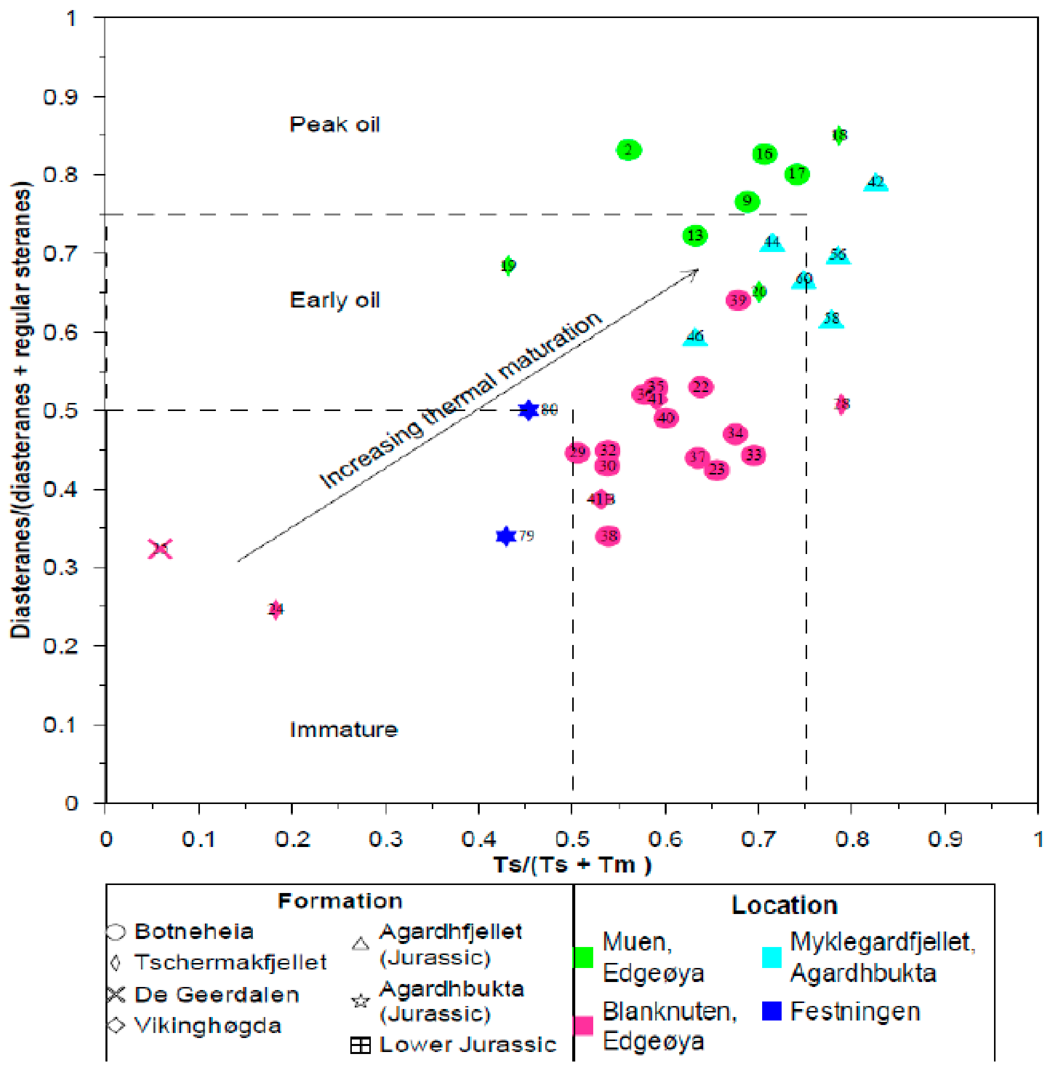


Figure 9. A cross plot of Ts/ (Ts + Tm) and diasteranes/(diasteranes + regular steranes), illustrating the maturity of the samples. The ratios on the axes increase with maturity, and they are valid for the whole oil window. The maturity trend from the biomarkers is more or less similar to that from the Rock-Eval (Figure 6 and Figure 7). Samples such as 80, 79 (Agardhbukta Formation, both Jurassic), 25 (De Geerdalen Fm, Triassic) and 24 (Tschermakfjellet Formation, Triassic) are plotted more or less in the same relative position as in Figure 6. However, these samples (80, 79, 25 and 24) together with some samples (42, 44, 46 and 50) from the Agardhfjellet Formation might have been influenced by source facies/depositional environment, i.e. more oxidized/terrestrial environment as seen from the facies cross plots in Figure 12, Figure 13 and Figure 14.

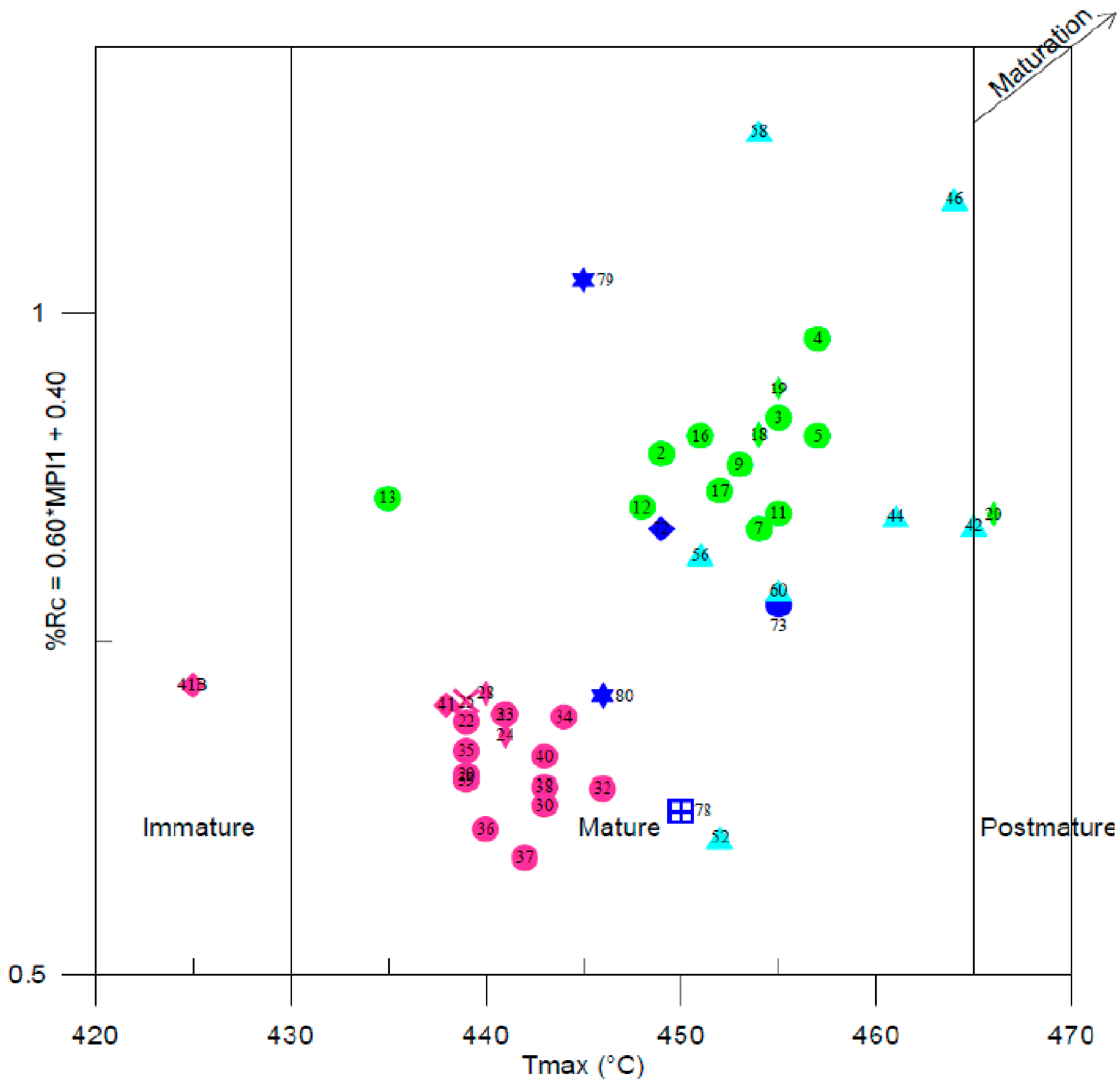


Figure 10. Cross plot of the maturity parameters T_{max} vs. vitrinite reflectance, calculated from MPI 1: %Rc = 0.6*MPI 1+0.4 (Radke and Welte, 1983), showing the difference in maturity of the samples. The Botneheia samples from the Blanknuten locality are lower in maturity compared to those from the Muen locality and to most of the other samples. MPI 1 is Methylphenantrene index 1 (Radke et al. 1982).

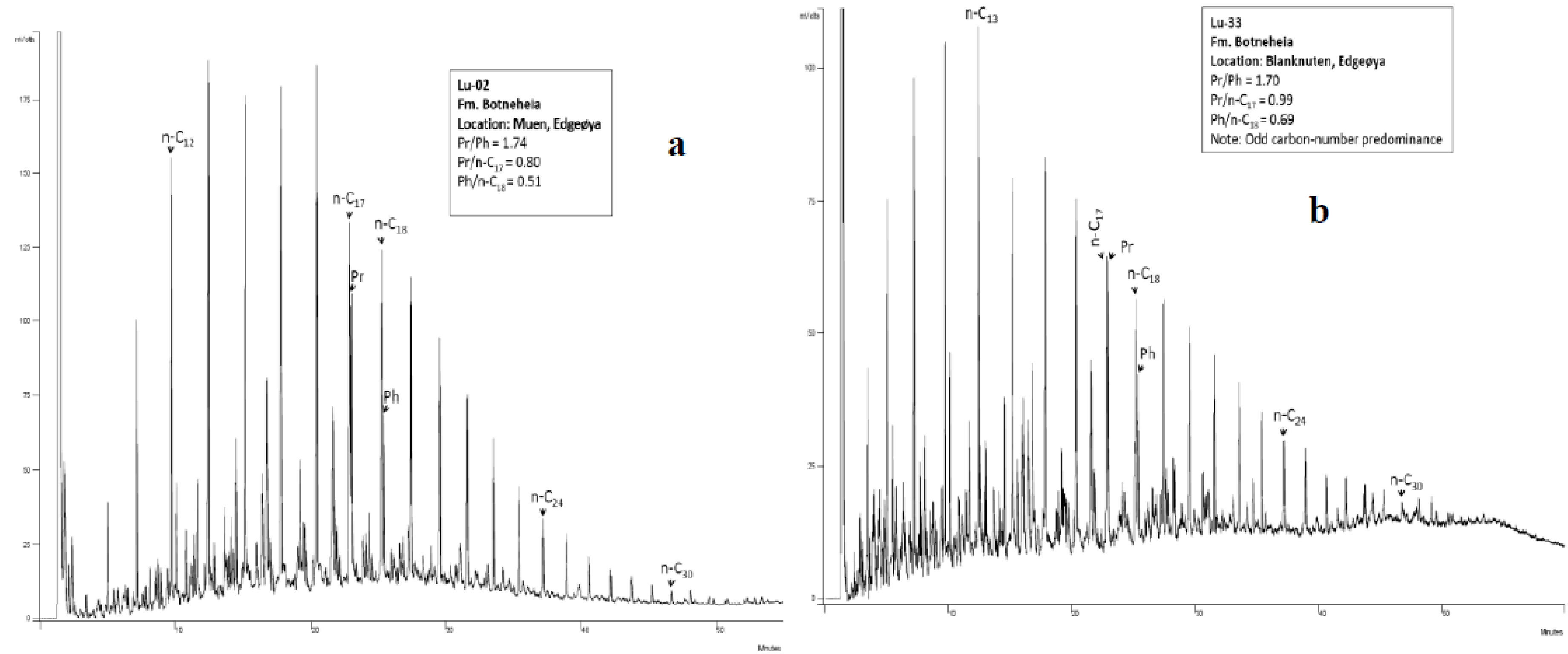


Figure 11 a and b. Examples of GC-FID chromatograms of samples from the Triassic Botneheia Fm at Muen and Blanknuten localities, respectively.

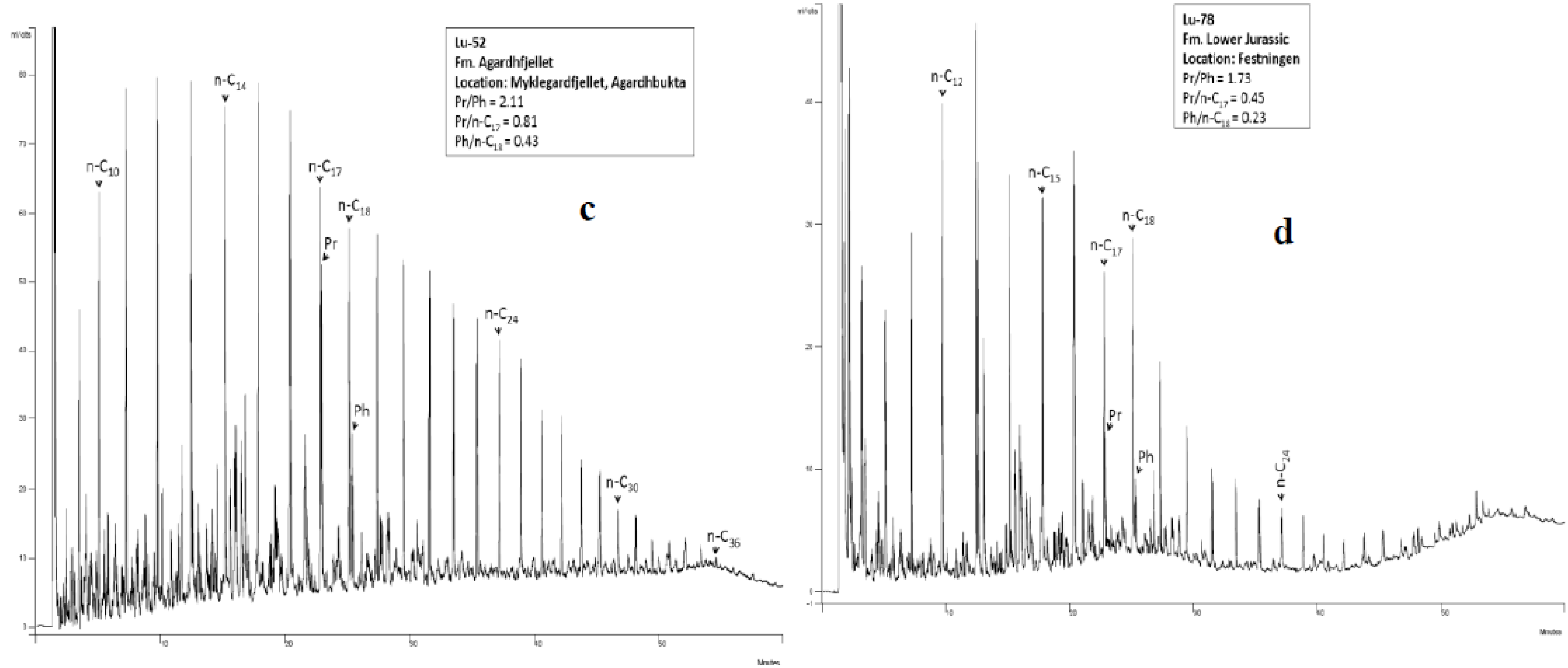
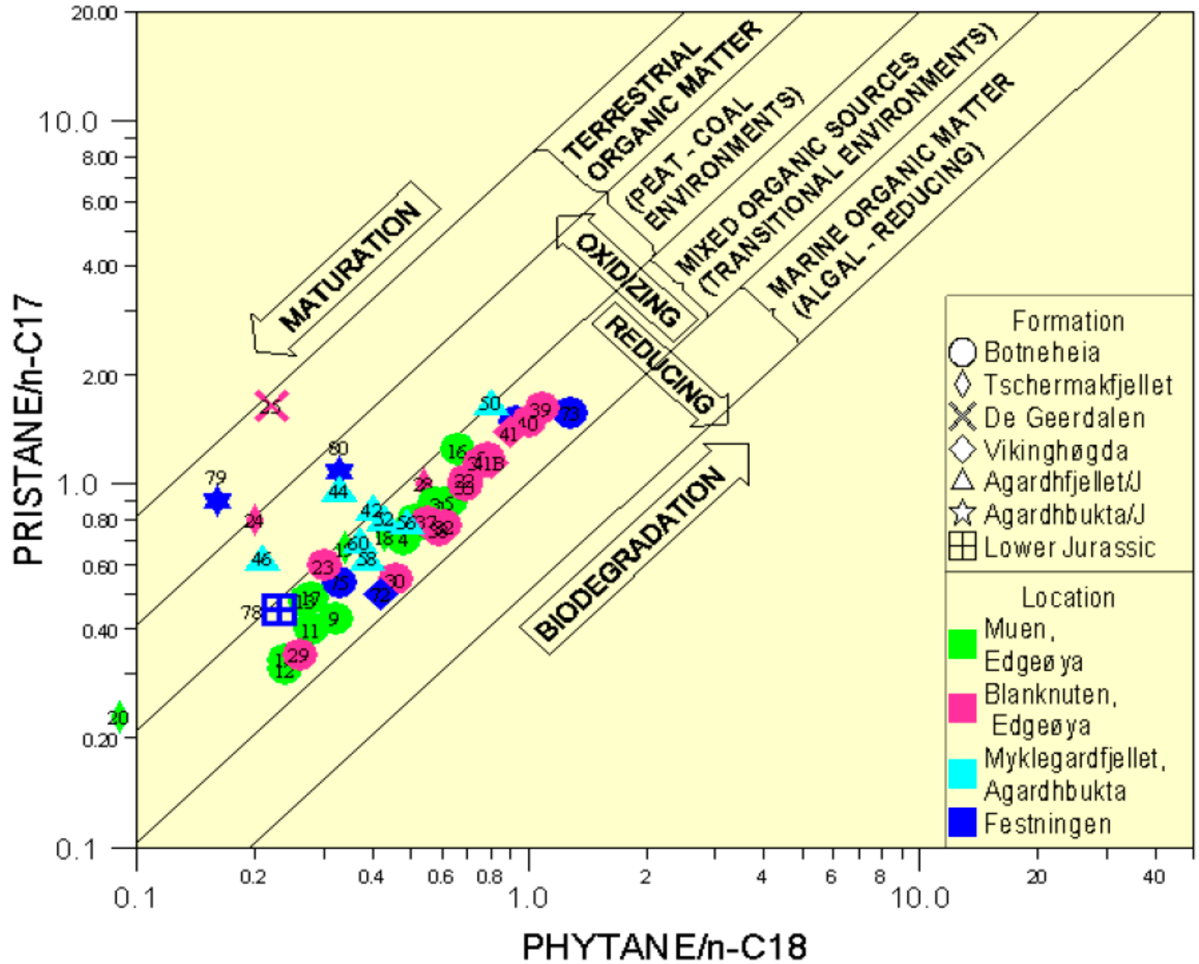


Figure 11c and d. Examples of GC-FID chromatograms of samples from Upper Jurassic and Lower Jurassic formations.



(modified from Shanmugam, 1985)

Figure 12. Logarithmic plot of ratios of pristane to n-C_{17} (Pr/n-C_{17}) and phytane to n-C_{18} (Ph/n-C_{18}), illustrating the possible depositional settings of the samples. The Botneheia samples from the Blanknuten area are plotted in the same setting as that from the Muen locality, suggesting that the variation in Kerogen Type between the Botneheia Fm at Muen and Blanknuten (Figure 5) is due to maturity and not source facies. Sample 20 from the Tschermakfjellet Formation at the Muen locality is the most mature sample in the data set. Sample 20 also has the highest T_{max} value (T_{max} = 466 °C). The Agardhbukta samples (79 and 80) and samples from the Agardhfjellet Formation, both Jurassic, are terrestrially influenced. The sample from the De Geerdalen Formation (sample 25) clearly suggests input from terrigenous organic matter. Comparing the Botneheia Samples with time equivalent Middle Triassic formations in the Barents Sea indicate that the Stein Kobbe Formation was deposited in a more anoxic setting where as the Kobbe Formation was deposited in a more oxic environment (Abay et al., 2014).

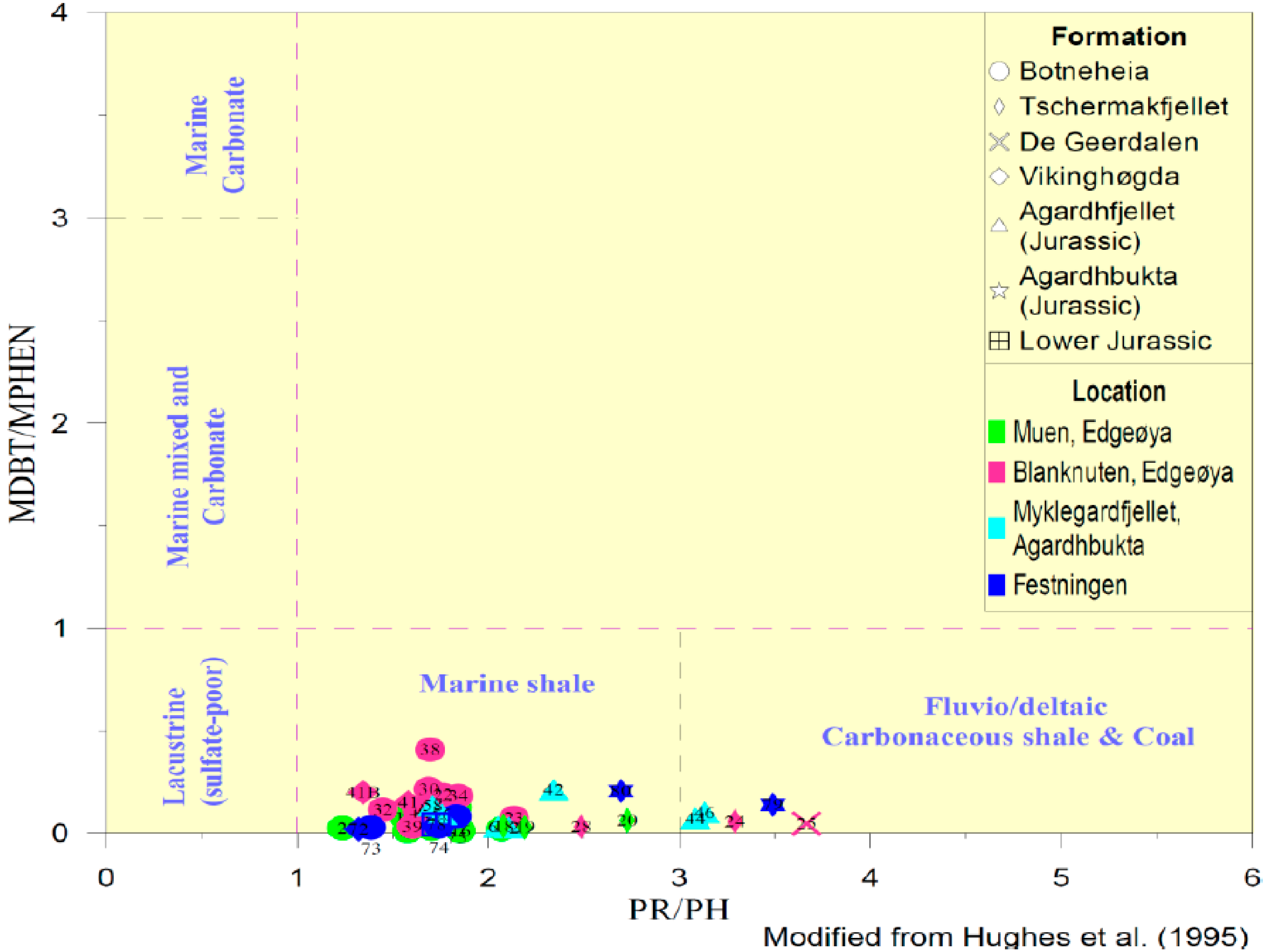


Figure 13. Cross-plot of ratios of pristane / phytane (Pr/Ph) vs. the sum of methyl-dibenzothiophenes (MDBT) / the sum of methyl-phenanthrenes (MP), showing the possible depositional facies of the studied samples.

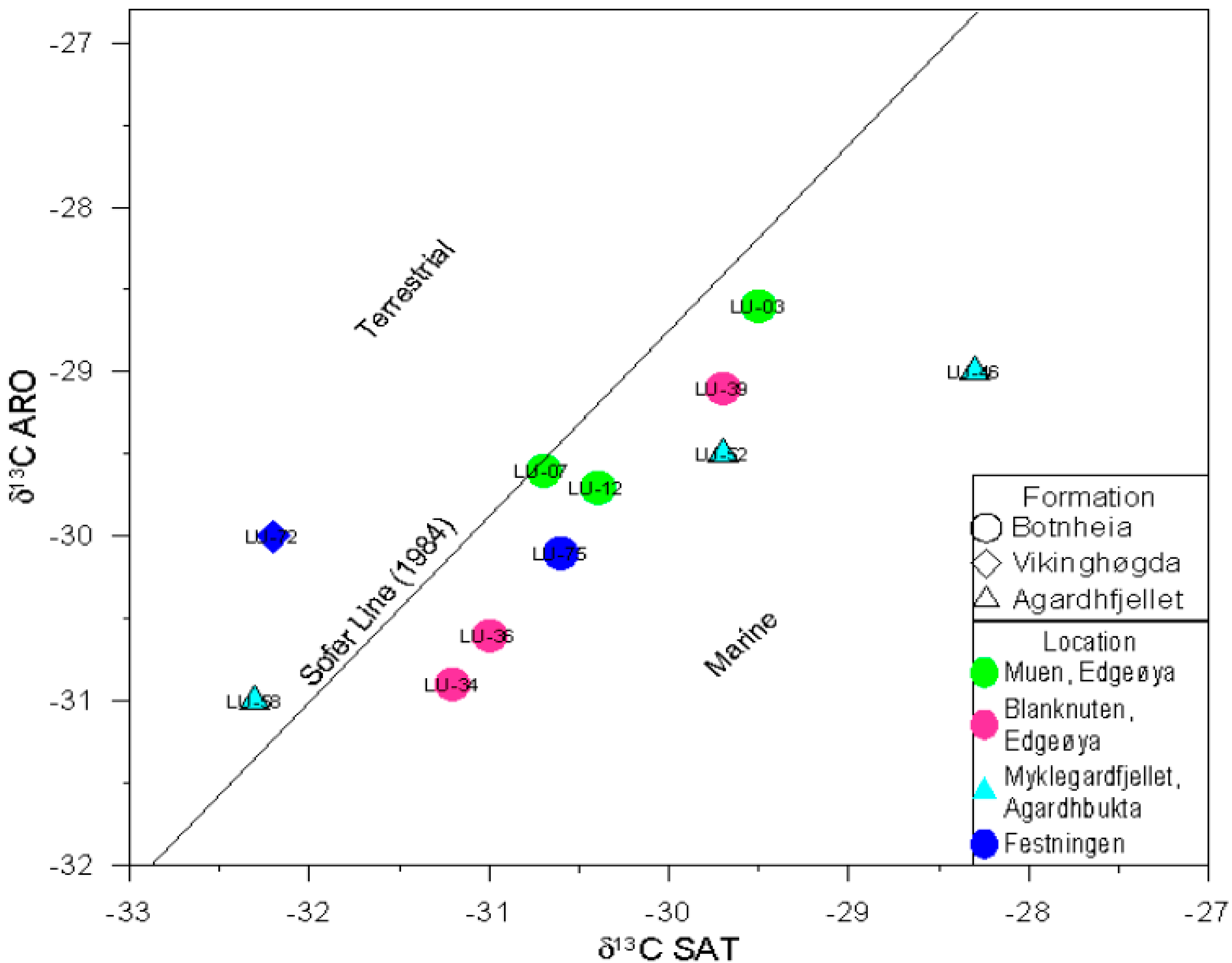


Figure 14. A cross plot of stable carbon isotope values of the saturated and aromatic fractions for the extracts, showing the depositional setting of the organic matter that sourced the hydrocarbon. Most samples indicate a marine setting but they are plotted very close to the marine/terrestrial transitional environment.

Formation (locality)	TOC (wt%)	S2 (mg HC/g rock)	S2/S3	T_{max} (°C)	HI (mg HC/g TOC)	Kerogen Type	Main HC
Botneheia (Blanknuten) #11	5 (1.1-9.9)	25	47	442 (439-446)	460 (298-609)	II	Oil
Botneheia (Muen) #11	3.6 (1.3-6.2)	6	11	453 (448-457)	152 (124-184)	III	Gas
Agardhfjellet (Myklegardfjellet) #7	4.1 (2.2-6.4)	4	7	458 (452-464)	96 (77-121)	III	Gas
Tschermakfjellet #4	1.4 (1.2-1.9)	1.3	1.6	441 (440-466)	85 (56-126)	III/IV	None

Table 1. Quality/type of kerogen and the type of expelled hydrocarbon (after Peters and Cassa, 1994). Numbers are average of the total sample numbers (#). Values in bracket indicate range.