

Charging and Connectivity of Fractured Basement Reservoirs in the West of Shetland (North Atlantic, UK) - Insights from Oil Geochemistry Studies*

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Abstract

The West of Shetland (WoS) continental margin of the United Kingdom is characterized by multiple sub-basins separated by basement ridges. The fractured Precambrian basement is thus in contact with Late Jurassic Kimmeridge Clay Formation (KCF) source intervals in many sub-basins. Even though source rock extracts are too scarce to represent regional facies variations adequately, the data available allow the distinction of at least three KCF types in three different sub-basins, showing that KCF source intervals may display noticeable geochemical differences across the WoS. Oil has been sampled in the Precambrian basement on the Rona, Clair and Judd crustal highs and is produced from younger sandstone reservoirs in most of the major oil fields of the region. The first oil charge(s) in the shallow sandstone reservoirs are frequently very severely biodegraded, with the reservoirs having received later charges in several areas. Additionally, reservoir fluids are commonly fractionated due to later episodes of gas migration through the accumulations. Three main groups of fluids can be distinguished across the WoS based on their geochemical compositions (e.g., distribution of terpane biomarkers). In some areas, the different (altered) charges of the reservoir fluids appear to have a contrasting maturity but display comparable source characteristics, suggesting that the successive charges were expelled by the same kitchens at different maturity stages. In other areas, however, the fluids show contradictory maturity and source indicators, which suggest that they have mixed sources. The identification of fluid mixtures is however made more difficult by the very severe biodegradation of the first fluid charge(s) that strongly affects typical geochemical parameters. Moreover, subtle geochemical differences in the compositions of the fluids could stem from KCF facies variations within the basin from which the fluids are sourced, or indicate that the fluids have sources located in different sub-basins, or both.

The location of several oil fields along crustal highs, and the evaporative fractionation of the basement oil in the Clair Ridge basement suggest that the fractured basement forms the migration pathway for some of the largest sandstone accumulations in the region. By contrast, in the area of the Lancaster oil field on the Rona Ridge, the fractured basement has retained hydrocarbon fluid charges because it is capped by an efficient seal, amongst other factors. The Lancaster Field is thought to have received oil charges from at least two surrounding sub-basins, with oil-

mature charges probably sourced partly from the East Solan sub-basin (south of the Rona Ridge) and late oil- to gas-mature fluids being charged from the Faroe-Shetland Basin (north of the Rona Ridge). Consistently, traps on the northern edge of the ridge (Whirlwind) are charged with late oil- to gas-mature fluids probably originating mainly from the Faroe-Shetland Basin. Rather than fractionating the emplaced oil, the mature fluids migrating to the Lancaster connected reservoir basement appear to become dissolved in the oil. Accumulation of oil into the basement seems to offer protection from the processes of biodegradation and evaporative fractionation, which are widespread in the region. Ongoing geophysical and geochemical studies are attempting to investigate the mechanism(s) involved.

Introduction

Fractured basement plays, while potentially challenging to produce, can offer major advantages and have a fundamental role in charging oil accumulations in conventional reservoirs in multiple rift margins such as the West of Shetland (WoS) on the continental shelf of the United Kingdom. In this region, fractured Precambrian Basement highs are flanked by sub-basins ([Figure 1](#)) and placed in contact with oil-prone Late Jurassic Kimmeridge Clay Formation (KCF) source rock intervals.

The KCF constitutes the main regional source rock, although it has been suggested that Mid. Jurassic sources may at least contribute to waxy oils in some fields (i.e., Foinaven; Scotchman et al., 2006). Three discoveries and a proven oil field have been discovered to date since 2009 by Hurricane Energy plc in the fractured basement of the Rona Ridge, a prominent NE-SW-trending basement high acting as a structural feature separating the Faroe-Shetland, West Shetland and East Solan basins ([Figure 1](#)). Basement oil had previously been observed further NE on the Clair Ridge in the large Clair Field, and has been recovered further southwest on the Judd High. Planning the appraisal and development of basement fields requires a thorough understanding of the connected fracture network, the charging mechanism and charge history. Mapping the networks of connected fractures is challenging; however, Hurricane has developed a geophysical workflow that identifies areas where reservoir properties are predicted to be elevated. After a number of successful well tests from the basement reservoir at the Lancaster Field, a phased field development approach is now undertaken with first oil anticipated in the first half of 2019. Flowed fluids and oil stains have been systematically analyzed for parallel geochemical studies. The main results of these geochemical investigations are presented here for the first time.

Method

This detailed geochemical investigation of the south Rona Ridge basement plays is presented in the context of a regional geochemical study of the WoS. An extensive petroleum geochemistry database has been compiled partly using data produced by the APT Laboratory (Norway) and made public by the UK Oil & Gas Authority (<http://data-ogauthority.opendata.arcgis.com/datasets?t=Geochemistry>). Geochemical data from Shell in the WoS, also made public by the OGA, have also been compiled in this database, as well as data published by Scotchman et al. (1998) and Rooney et al. (1998). The second major part of the dataset has been acquired since 2007 for source rocks, oil stains and flowed fluids from the Rona Ridge by Hurricane plc and interpreted by IGI Ltd. These data are from 11 wells in the Lancaster and Solan fields and the Whirlwind, Lincoln, and Halifax discoveries. The full database comprises geochemical analyses of rock extracts from 40 wells, of flowed fluids from 28 wells and of oil stain extracts from 71 wells distributed across the WoS region. The range of geochemical data used in this work is summarized for fluids in [Table 1](#).

Results and Discussion

Integrity of fluids in the WoS

Several, but not all, WoS oil fields are located along SW-trending crustal highs. Fluids are produced mainly from sandstones of Paleozoic to Tertiary ages: Carboniferous-Devonian (Clair Field), Triassic (Strathmore), Jurassic (Solan) and Paleogene (e.g., Foinaven, Schiehallion, Cambo, Tormore, Laggan). The reservoir fluids are very frequently altered due to microbial biodegradation or to physical evaporative fractionation, the effects of both processes being often difficult to distinguish especially since they are not necessarily mutually exclusive. Briefly, biodegradation is the degradation of petroleum compounds by aerobic or anaerobic microbes at the Oil-Water Contact (OWC) (e.g. Head et al., 2003). Microbes degrade some classes of compounds more readily than others, resulting in the removal of the former before the latter become significantly depleted (e.g. Huang and Larter, 2005). Characteristically, light hydrocarbons are removed at lower biodegradation levels than are heavier ones (e.g. Peters et al., 2005), with gasoline-range hydrocarbons (C_6 to C_{10}) being typically affected first. Similarly, *n*-alkanes are more readily degraded than branched, cyclic or aromatic compounds. In moderately biodegraded fluids, the removal of the light hydrocarbon fraction (gasoline-range [C_6 - C_{10}] and eventually diesel-range [C_{11} - C_{16}] hydrocarbons) is visible on Whole Oil Gas Chromatograms (WOGCs), as illustrated for the oil from 204/28-1 in [Figure 2](#). In moderately to highly biodegraded fluids, the ratio of pristane (Pr) to the normal alkane nC_{17} increases because the former is relatively more resistant to biodegradation (e.g. 204/20A-7 in [Figure 2](#)).

In severely biodegraded fluids such as the 204/25a-8Y oil, almost all resolvable hydrocarbon peaks are removed, resulting in a large rise of the WOGC baseline reflecting the presence of an Unresolved Complex Mixture (UCM). Severely biodegraded fluids can contain characteristic 25-norhopane biomarkers ($\sim C_{27}$ - C_{34}), which are one of the products of the biodegradation of hopane biomarkers, and only occur in very severely biodegraded fluids (Bennett et al., 2006). The plot of 25-norhopane/ C_{30} hopane vs. Pr/ nC_{17} in [Figure 2](#) shows that some fluids are non-biodegraded (low ratios). The 204/25a-8Y oil, by contrast, is severely biodegraded (high ratios). Most fluids represent mixtures of severely biodegraded charges (high 25-norhopane/ C_{30} hopane) and later charges that have been moderately to highly biodegraded (variable Pr/ nC_{17} values), with the effects of biodegradation being different if the later charges consist of light fluids or of black oils.

The plot of toluene/*n*-heptane vs. *n*-heptane/methylcyclohexane ([Figure 3](#)) shows the effect of biodegradation and evaporative fractionation on the composition of gasoline-range hydrocarbons of the fluids. Evaporative fractionation refers to “the complex of phenomena involved in the separation of gas from oil in the subsurface” (Thompson, 1987), with the removal of the gas fraction evolved from the liquid, and its migration to other traps (or no trap). This results in characteristic alteration of the compositions of both migrated (gas) and residual (liquid) phases. As a gas phase forms in the reservoir, hydrocarbon compounds will partition variably between the gaseous and the liquid phase, depending on their molecular weight (lighter compounds are more volatile). Additionally, C_3 - C_{10} range hydrocarbons have variable affinities for gas or liquid phases depending on their molecular configuration (normal, aromatic, branched and/or cyclic). Within C_7 hydrocarbon compounds, for example, *n*-heptane (nC_7) or methylhexanes tend to partition more favorably in the gaseous phase compared to methylcyclohexane (MCH) and the aromatic toluene, which become relatively enriched in the residual liquid (Thompson, 1987; 1988).

Within the group of non-biodegraded oils ([Figure 2](#)), the composition of C_7 gasolines are typical of migrated fluids in Lancaster and Whirlwind basement samples ([Figure 3](#)). Most other non-biodegraded fluids contain non-altered gasoline-range hydrocarbons (fluids are mostly from the

north, along the Flett Ridge). The gasoline compositions of all other WoS fluids hint at their alteration, whether due to biodegradation (e.g. many Foinaven oils) or evaporation leaving the residual liquid enriched in aromatic compounds such as toluene (e.g. most Clair oils). These alterations affect geochemical source and maturity indicators but, if unraveled, they also provide valuable information on hydrocarbon fluid migration and charging episodes.

Sources, maturity and migration of fluids in the WoS

The Late Jurassic KCF, the main oil-prone marine source in the region, displays subtle differences in composition in different sub-basins of the WoS. The distribution of terpane biomarkers is especially distinguishable in KCF extracts from the Faroe-Shetland, West Shetland and East Solan sub-basins and these differences are visible in the composition of basement oils on the highs flanking these basins ([Figure 4](#)). Briefly, KCF extracts in the Faroe-Shetland Basin (“KCF 1”) show progressively increasing extended hopanes peaks from C_{35} to C_{31} and an absence of 28,30-bisnorhopane. A similar feature characterizes the oil from the Judd High basement. By contrast, the KCF extract from the West Shetland Basin (“KCF 2”) and Clair oils contain 28,30-bisnorhopane. This compound also occurs in the “KCF 3” extract from the East Solan Basin and in the Rona Ridge oils (e.g. in the basement in Lancaster). However, the KCF 3 type fluids also show markedly higher C_{35}/C_{34} extended hopane ratios and a ratio of C_{29}/C_{31} hopane lower than 1 as opposed to a value > 1 for fluids from KCF1 or KCF2 sources. Three main groups of oils are hence identified as groups 1 to 3 corresponding to KCF source facies found in the Faroe-Shetland, West Shetland and East Solan sub-basins, respectively. Note however that there are insufficient data to show that these source facies are exclusively restricted to these basins. Furthermore, no potential source rock extracts are available in the Foinaven/Judd, northernmost Faroe-Shetland and Faroe sub-basins ([Figure 1](#)).

In [Figure 5](#), which shows a plot of the source-sensitive ratios of C_{29}/C_{31} hopanes vs. 28,30-bisnorhopane/ C_{30} hopane for all WoS fluids, data are separated in three groups. The terpane biomarker composition of most oils from the Rona Ridge area share characteristics of the East Solan Basin KCF 3 source and form “Group 3” oils. Variations of 28,30-bisnorhopane/ C_{30} hopane ratios in Group 3 oils do suggest, however, that some samples may incorporate contributions from other sources (e.g. similitude with Group 2 fluids). Fluids from “Group 1” and “Group 2”, which correlate approximately with KCF 1 and KCF 2 source types, respectively, form smaller sub-clusters. The formation of “sub-groups” can result from slight geochemical variations of the KCF source in different areas, or from fluid mixtures. Although source rock extract data are too scarce to support reliable source-oil correlations, the separation of the Group 1 fluids into three sub-groups may reflect KCF 1-type source variations because the fluids are from different areas (1a=Flett Ridge, 1b= Westray/Corona Ridges and 1c= Foinaven/Faroe-Shetland Basin).

It is unclear if the fluids from the Foinaven and the Clair areas, forming the sub-groups 2a and 2b, respectively, have a similar but slightly distinct source (presumably from the Faroe-Shetland Basin) or if they represent different fluid mixtures. Here, the Clair Field oils (sub-group 2b) are tentatively interpreted to have mixed sources: a KCF 2-type source and a KCF 1-type source. These may be located, respectively, in the West Shetland Basin (see GC-MS traces in [Figure 3](#)) and in the northern Faroe-Shetland Basin. Alternatively, the distinct sources may reflect compositional variations in different areas of the KCF within the large Faroe-Shetland Basin. Interestingly, the two oils exhibiting the lowest 28,30-BNH/ C_{30} hopane ratios (i.e. higher contribution of Group 1 fluids from the Faroe-Shetland basin) are located at the southwest and northeast extremities of the Clair field, with these areas probably possibly constituting charging points for the field (wells 206/4-1 and 206/12-1 labeled on [Figure 5](#)).

It is also noteworthy that the basement oil from the Whirlwind Discovery, on the northern edge of the Rona Ridge, displays very similar hopane characteristics to the Clair oils, suggesting that it may also have mixed Group 1 and Group 2 fluid sources. Both sources are most likely located in the Faroe-Shetland Basin, because the prospect could not be charged with Group 2 fluids from the West of Shetland Basin, as they would have to migrate downdip. Within oils from sub-group 2a, which are predominantly from the Foinaven, Schiehallion and Judd High areas, a thorough comparison (not shown) of alteration, source and maturity indicators suggests that some fluids correspond to oil-mature charges that have frequently been severely biodegraded while others (sub-group 2a*) have subsequently received charges of migrated and highly mature condensates (i.e. Group 1 fluids).

Plots of maturity-related geochemical ratios for the heavier hydrocarbons fraction (C_{21} to C_{29}), for gasoline-range hydrocarbons (C_7) and for light hydrocarbon gases (C_2 - C_3) are provided in [Figure 6](#), [Figure 7](#), and [Figure 8](#), respectively. The comparison of the maturity of different fluid fractions aims at identifying mixed charges and gas migration (in oil reservoirs). [Figure 6](#) uses ratios of the concentration of side-chain shortened aromatic steroids to that of their heavier precursors to assess the maturity of the higher molecular weight fraction of the fluids, with the ratios increasing with maturity. The plot of $(C_{21}+C_{22})/(C_{21}-C_{29})$ triaromatic steroids (TAS) vs. $(C_{20}+C_{21})/(C_{20}-C_{28})$ monoaromatic steroids (MAS) is particularly useful for biodegraded fluids, because these aromatic biomarkers are more resistant to microbial degradation than the saturated hydrocarbon biomarkers (e.g., steranes, Head et al., 2003). The WoS fluids show a clear trend for increasing maturity from oil-mature Group 3 oils (e.g. Lancaster) to mid to late oil-mature Group 2 and Group 1 fluids, with the most mature sample being the gas-mature condensate from the Tormore Field on the Flett Ridge (Group 1). The Group 2 fluids showing an increased maturity incorporate later charges of migrated condensates (sub-group 2a*). The maturity of the fluids in the Foinaven/Schiehallion area is indicated on the map in [Figure 6](#), with a distribution suggesting later charges of gas-mature fluids from the north/northwest. [Figure 7](#) plots the heptane ratio against the isoheptane ratio, both involving C_6 - C_7 hydrocarbons whose composition, while dependent on source and maturity, is also readily altered because of biodegradation or evaporative fractionation (e.g. Thompson, 1987).

The composition of C_7 hydrocarbons is altered for the large majority of the WoS fluids, with most Group 1 and especially Group 2 fluids showing signs of biodegradation and evaporative fractionation. The compositions of the non-altered fluids are typical of late oil to gas-mature fluids (for Type II sources such as the KCF). These samples occur only in a few locations: Paleocene sands in Cuillin (204/19-2) and Tormore (205/05a-1) and basement oils on the Judd High and Rona Ridge (204/23-1 and 205/21a-4). In Lancaster (205/21a-4), only one sample seems non-altered, whereas most samples show increased heptane ratios, a feature common in migrated gas condensate fractions. It suggests that the basement oil has received charges of high maturity migrated fluids. This hypothesis is supported by the enrichment in ^{13}C of ethane and propane ([Figure 8](#)). In the plot of $\delta^{13}C$ -propane vs. $\delta^{13}C$ -ethane (after Berner and Faber, 1996), the maturity curve indicates the expected maturity of a -31‰ VPDB oil prone source rock for a given pair of $\delta^{13}C$ -Ethane and $\delta^{13}C$ -Propane values. The gas in the Lancaster oils appears to have mixed thermogenic sources, with overall late oil to gas window maturity ($\sim 1.3\%Ro$) which indicates that a gas-rich fluid has been dissolved in the oil in the basement reservoir. It is possible that this fluid has also charged the Whirlwind volatile oil field in the north. Isotube gases in the Halifax basement show even higher ^{13}C enrichment and are clearly gas-mature. The Rona Ridge thus appears to be charged partly with mid-mature oil from the East Solan sub-basin, on its southern edge, and largely with late oil to gas-mature charges from the Faroe-Shetland Basin in the north of the Lancaster field and in the Halifax and Whirlwind areas. The high maturity of the Halifax and Whirlwind

fluids suggests that perhaps the KCF source intervals are more mature in this area of the Faroe-Shetland Basin than further southwest near the Lancaster and Judd High areas.

Summary and Conclusions

Summary maps showing the source ([Figure 9](#)) and maturity ([Figure 10](#)) of the WoS region are presented. A comparison of the distribution of fluid groups and maturity across the WoS suggests that basement highs separating sub-basins might channel the migration of fluids expelled from different kitchens on different sides of the ridges. However, further structural geology studies are needed to identify migration paths. Some structures, such as the Rona Ridge in the Lancaster/Lincoln area, have retained oil charges because, amongst other factors, they are overlain by effective seals. By contrast, in the Clair Ridge the fluids appear to migrate through the basement into shallower sandstones, as indicated by the obvious evaporative fractionation of the Clair basement oil. The on-going combined geophysical and geochemical study of charging and connectivity of the Rona Ridge basement is expected to yield further insight into how hydrocarbon fluids migrate and accumulate in these fractured reservoirs and to help understand better how they become largely protected from biodegradation and evaporative fractionation.

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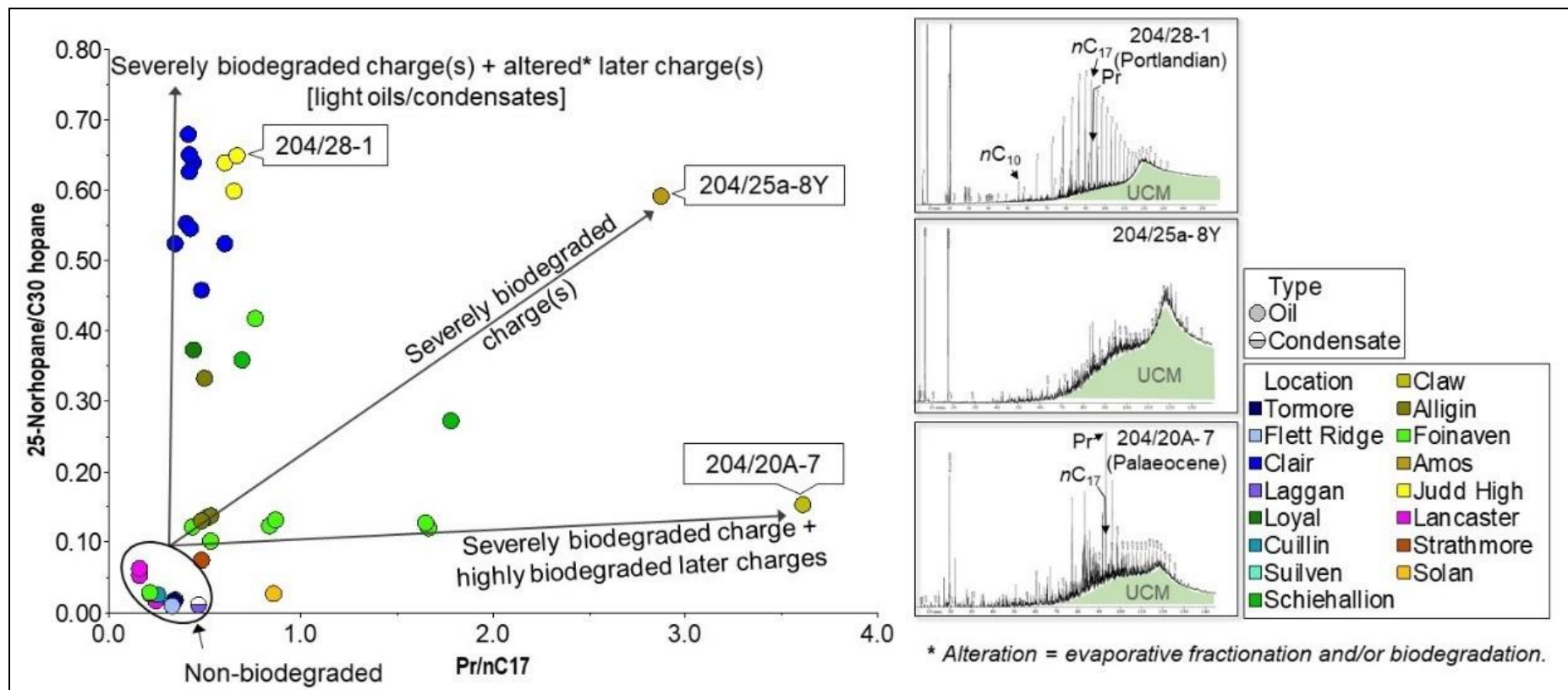


Figure 2. Plot of the ratios of 25-norhopane/C₃₀ hopane (17 α ,21 β) versus pristane/nC₁₇ for West of Shetland fluids, showing the biodegradation of ~C₂₇-C₃₀ (hopanes) and ~C₁₇-C₁₉ hydrocarbons and evidencing several charges. The Whole Oil Gas Chromatograms (WOGCs) illustrate the presence of several charges of severely to moderately biodegraded fluids.

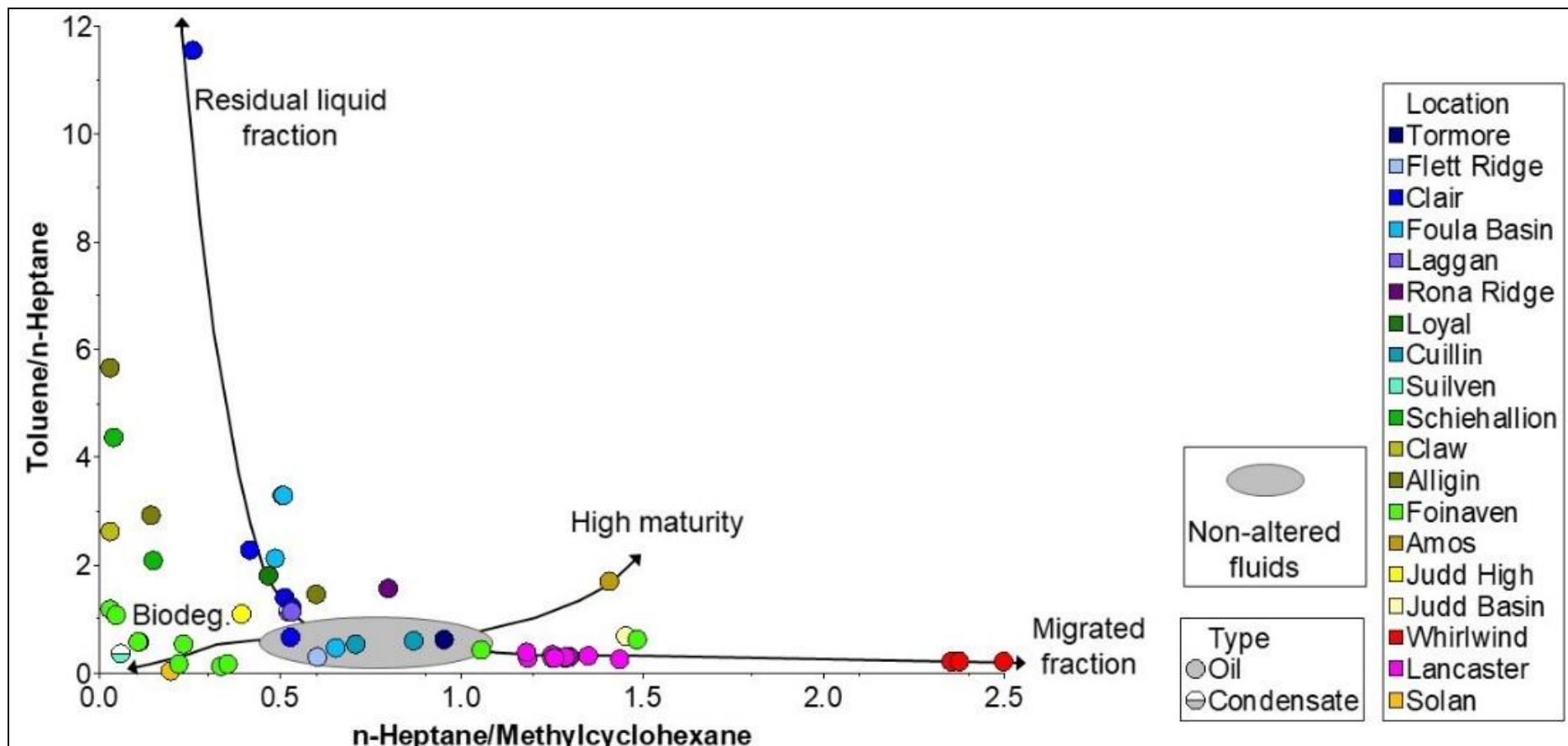


Figure 3. Plot of the ratios of toluene/ nC_7 versus nC_7 /methylcyclohexane (after Thompson, 1987) identifying non-altered gasoline-range hydrocarbons by contrast to fluids having experienced biodegradation or evaporative fractionation (migrated gas and residual liquid fractions).

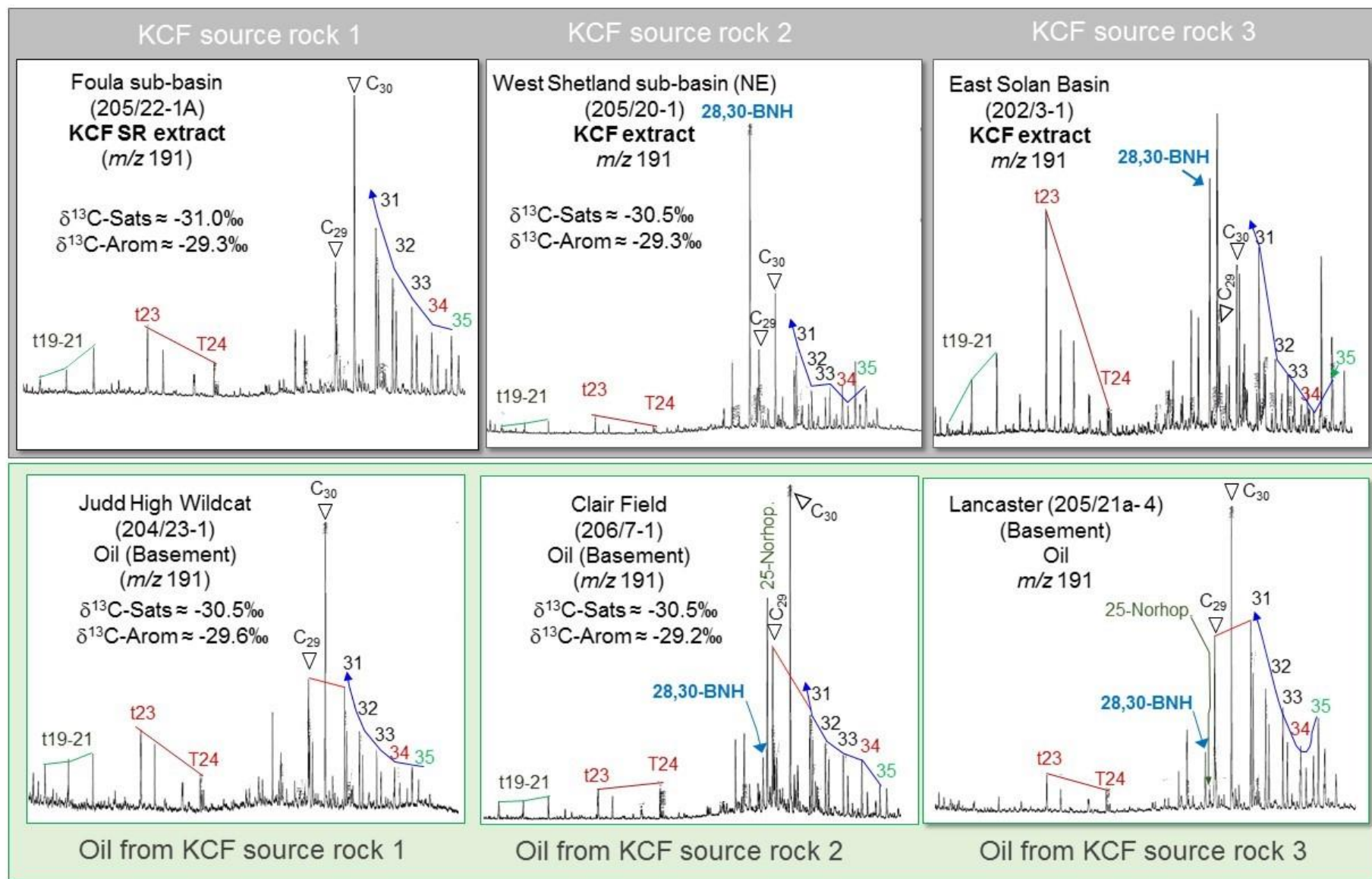


Figure 4. Oil-source correlations showing the distribution of terpanes (m/z 191 GC-MS traces) for three main Kimmeridge Clay source rock formations identified across the West of Shetland region and three basement oils having compositions that correlate with these sources.

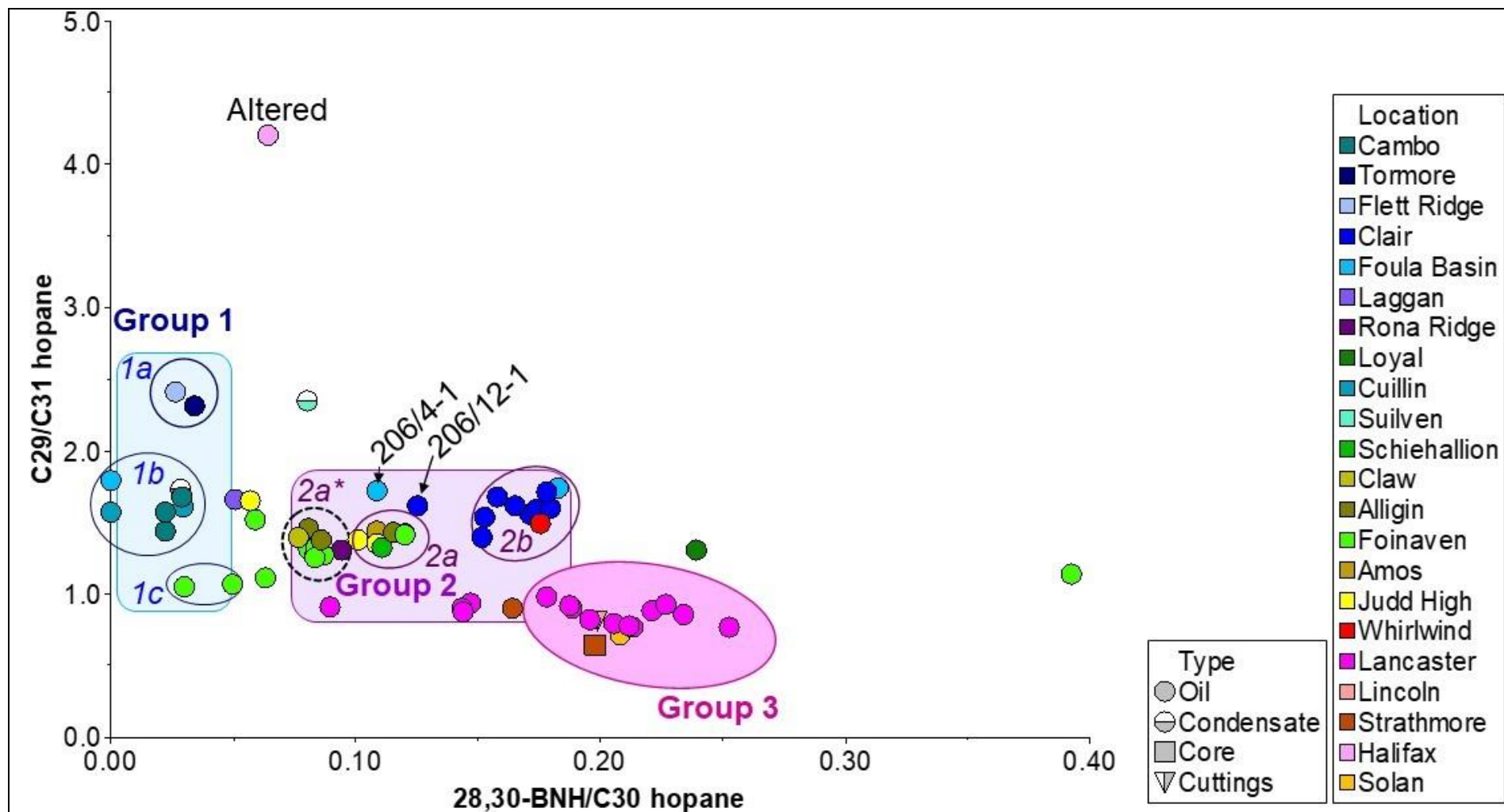


Figure 5. Plot of the ratios of norhopane ($17\alpha,21\beta$)/homohopane versus 28,30-bisnorhopane/hopane ($17\alpha,21\beta$) for West of Shetland fluids. The fluids separate in three main groups, but smaller clusters within fluid groups may reflect slight facies variations (Group 1 fluids) and/or mixed sources (Group 2 fluids?).

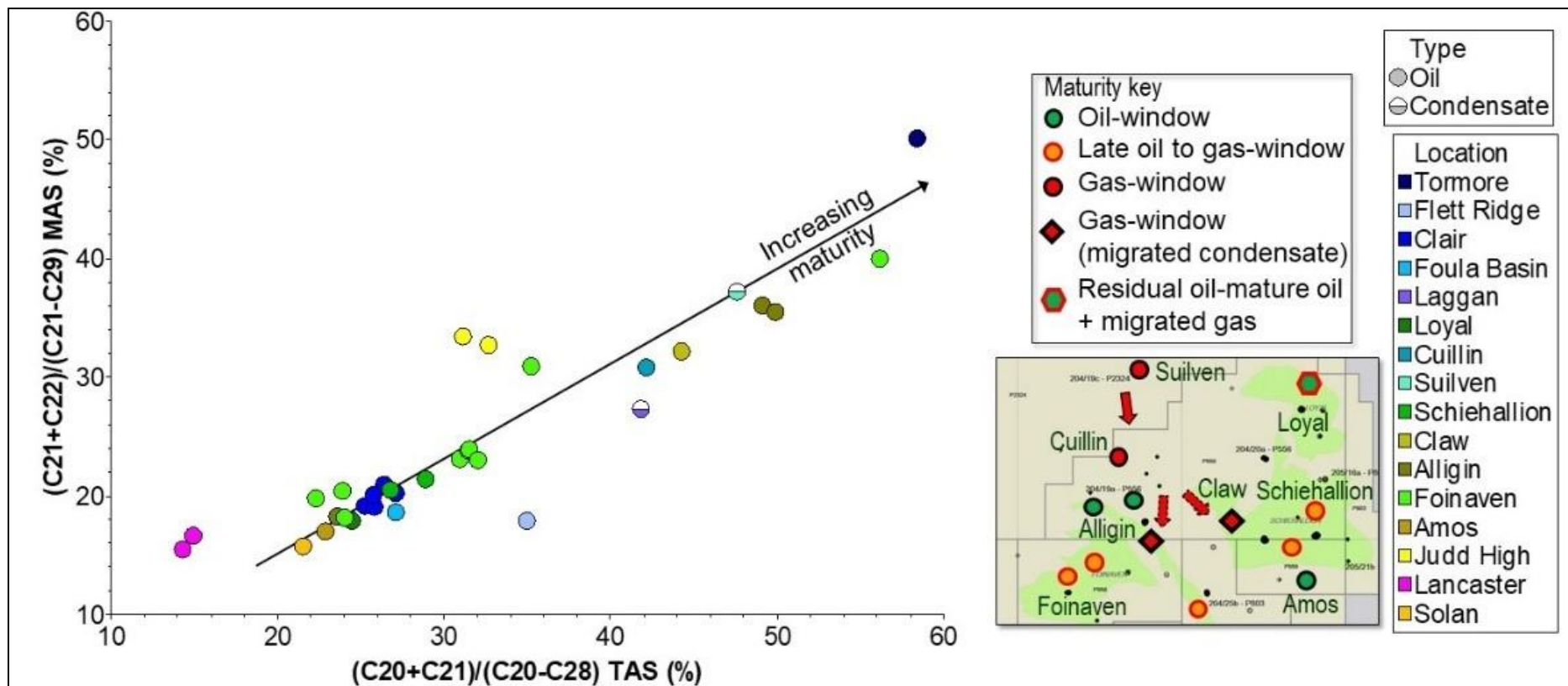


Figure 6. Plot of the ratios of $(C_{21}+C_{22})/(C_{21}-C_{29})$ MonoAromaticSteroids versus $(C_{20}+C_{21})/(C_{20}-C_{28})$ TriAromaticSteroids indicating the maturity of C_{20} - C_{29} hydrocarbons. Insert = Detail of the maturity of fluids in the Foinaven and Schiehallion areas showing inferred migration trends.

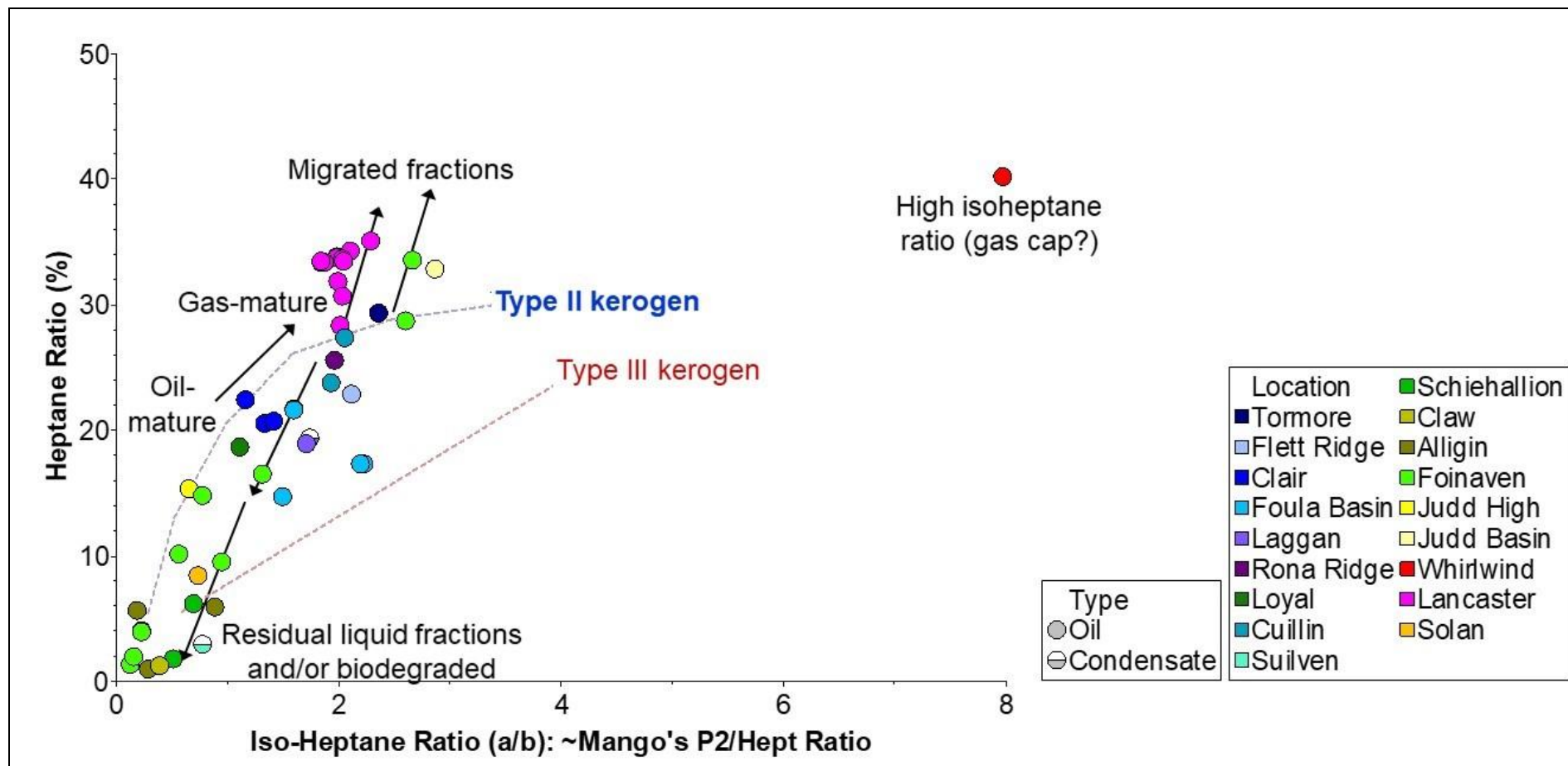


Figure 7. Plot of the heptane ratio versus the isoheptane ratio showing the maturity and alteration of C₆-C₇ hydrocarbons (after Thompson, 1987).

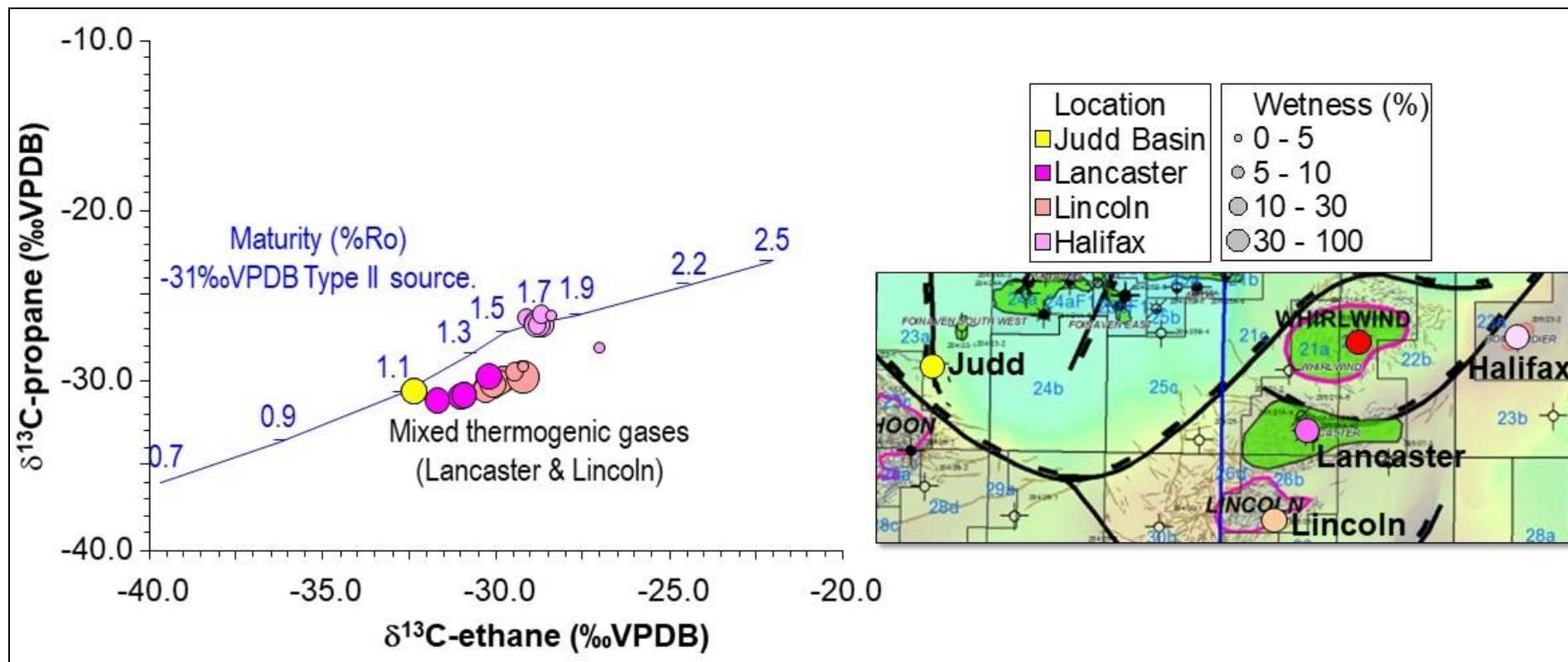


Figure 8. Plot of the stable carbon isotope composition of propane versus ethane indicating the expected maturity of the Kimmeridge Clay source rock (after Berner and Faber, 1996). Insert = Location of the samples in the south Rona Ridge oil fields.

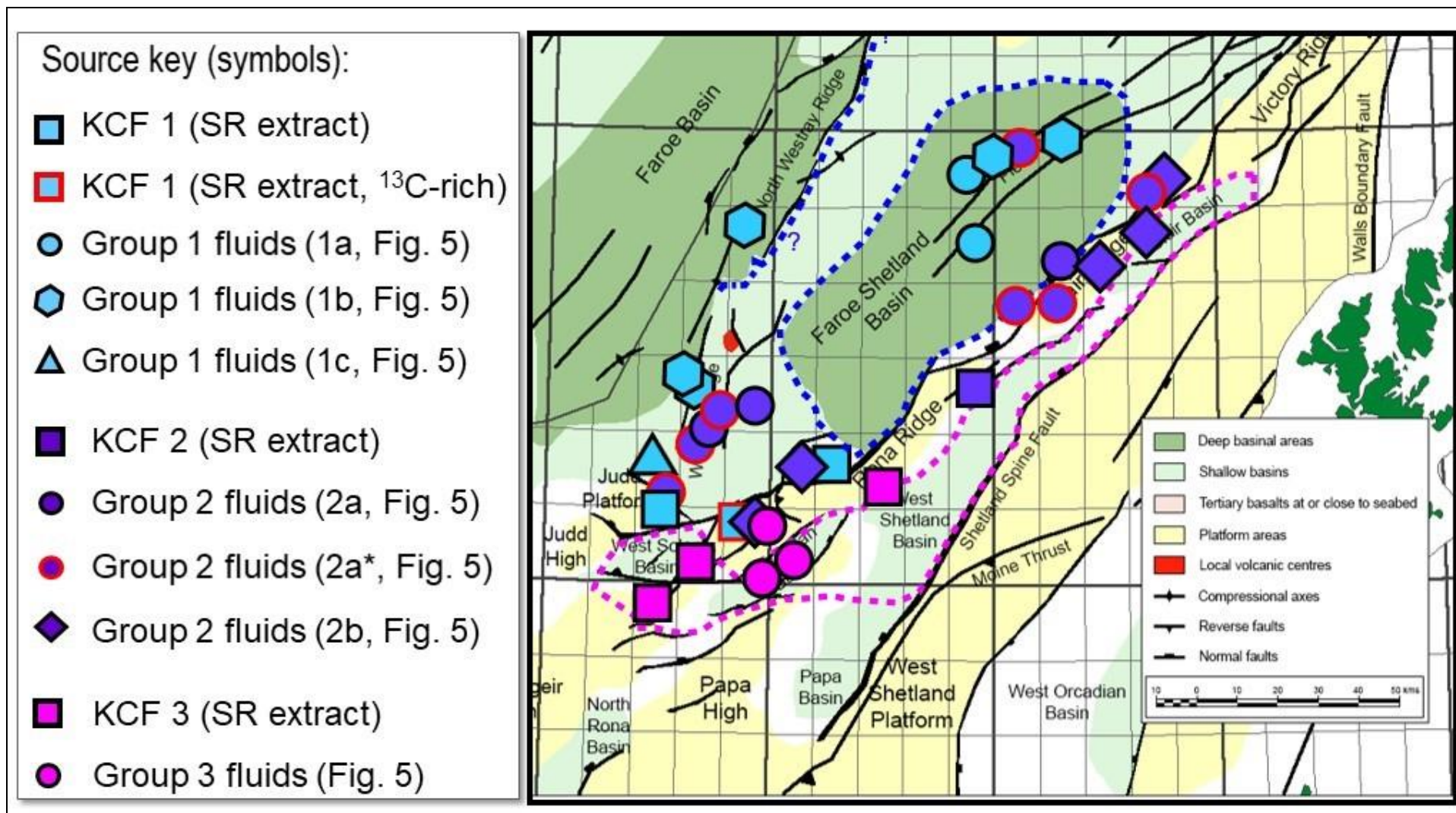


Figure 9. Summary map of fluid sources in the West of Shetland. The distinct Kimmeridge Clay Formation (KCF) source types identified in this study and indicated by color-coded squares. All other symbols refer to groups of fluids, with colors indicating oil groups and symbol shapes corresponding to tentative sub-groups identified on [Figure 5](#).

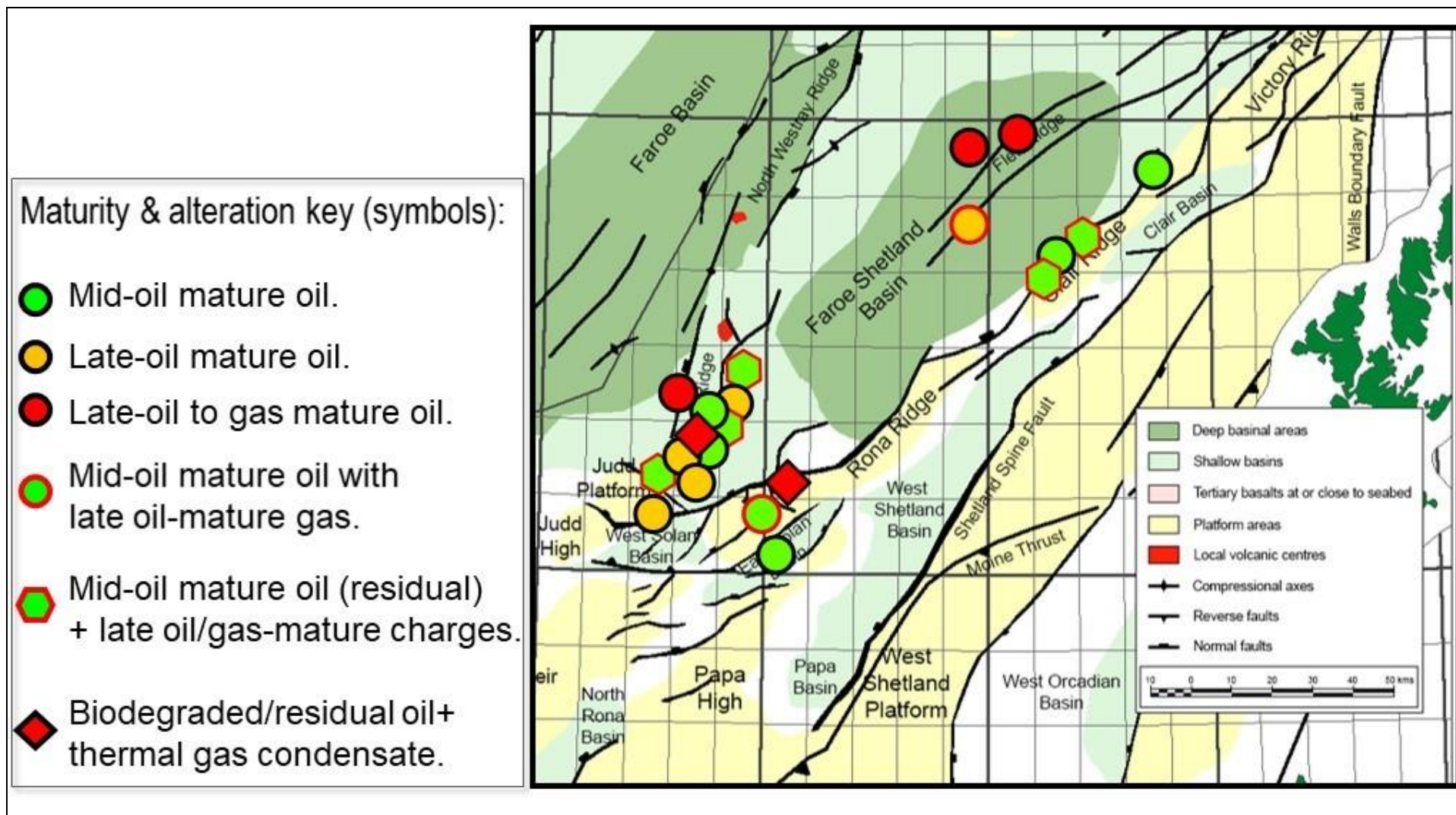


Figure 10. Summary map of fluid maturity in the West of Shetland. Symbol types and colors are indicative of the state of alteration and maturity of the fluids, respectively.

No. of samples	Location/oil field	Fluid type	Reservoir ages	Source/Lab	C ₁ -C ₅	C ₆ -C ₁₀	$\delta^{13}\text{C}$ (‰VPDB)	Biomarkers
104	Oil fields on the Rona, Flett, Westray & Judd ridges	Oil	Precambrian basement to Paleocene sands	APT, Hurricane, Scotchman et al. (1998) & Rooney et al. (1998), Expro, Shell/OGA	4	64	70	56
2	Strathmore & Lincoln	Oil stain extracts	Precambrian basement & Triassic	Hurricane	0	0	2	2
2	Suilven & Laggan	Condensate	Paleocene	APT	0	2	2	2

Table 1. Number of fluid samples and geochemical data available.