Note on the importance of hydrocarbon fill for reservoir quality prediction in sandstones

Ann M. E. Marchand, P. Craig Smalley, R. Stuart Haszeldine, and Anthony E. Fallick

ABSTRACT

Oil emplacement retarded the rate of quartz cementation in the Brae Formation deep-water sandstone reservoirs of the Miller and Kingfisher fields (United Kingdom North Sea), thus preserving porosity despite the rocks' being buried to depths of 4 km and 120°C. Quartz precipitation rates were reduced by at least two orders of magnitude in the oil legs relative to the water legs. Important contrasts in quartz cement abundances and porosities have emerged between the oil and water legs where reservoirs have filled with hydrocarbons gradually over a prolonged period of time (>15 m.y.). The earlier the hydrocarbon fill, the greater is the degree of porosity preservation. Failure to consider this phenomenon during field development could lead to overestimation of porosity and permeability in the water leg, potentially leading in turn to poor decisions about the need for and placement of downflank water injectors. During exploration, the retarding effect of oil on quartz cementation could lead to the presence of viable reservoirs situated deeper than the perceived regional economic basement.

INTRODUCTION

Models published recently allow prediction of quartz cementation and concomitant porosity loss in quartzose sandstones (Walderhaug, 1996; Bjørkum et al., 1998; Lander and Walderhaug, 1999; Oelkers et al., 2000). In these models, quartz cementation is regarded as a three-step process. Silica is sourced internally from quartz dissolution at stylolites, diffuses across short distances, and precipitates onto clean quartz surfaces (Walderhaug, 1996; Bjørkum et al., 1998; Oelkers et al., 2000). Precipitation is regarded as the rate-limiting step controlling the quartz cementation process. Subsequently, this approach was coded into a commercial

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Stuart Haszeldine has been attempting to understand sandstones for the past 15 years. The combined techniques of basin modeling, isotopic microanalysis, fluid inclusions, and petrography have produced some understanding of the interaction between the timing of burial, cementation, and hydrocarbon charge. His current work examines porosity preservation, porosity creation, and deep geopressured reservoirs. He likes field work and cycling with his son.

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numerical model for prediction of quartz cementation, compaction, and estimation of porosity called Exemplar (Lander and Walderhaug, 1999).

The interaction of hydrocarbon emplacement with quartz cementation remains a matter of debate. Walderhaug (1994) reasoned that as long as sandstones remain water wet, quartz precipitation rates would not be affected by hydrocarbon emplacement. Oil-filled inclusions in authigenic quartz and comparable quartz cement volumes in water and oil legs of some reservoirs have been used to support this argument (e.g., Ramm, 1992; Walderhaug, 1994). In Exemplar, quartz cement volumes in sandstones are calculated by using quartz precipitation rates that were empirically derived from data from the Norwegian Continental Shelf. Because the calculated quartz precipitation rates for this data set are similar for oil- and water-leg samples (Walderhaug, 1994), similar quartz cement volumes are predicted in oil and water legs where the model is used on petrographically and texturally similar samples. Many investigators, however, have observed diagenetic variations within reservoirs that were ascribed to oil charge (e.g., Macaulay et al., 1992; Emery et al., 1993; Marchand et al., 2000; Souza and McBride, 2000). In the Miller field (North Sea), Marchand et al. (2001) demonstrated that when oil displaced formation water from the pore space in the sandstones at around 40 Ma, the quartz precipitation rate was reduced by at least two orders of magnitude (i.e., 10^{-22} mol/cm^2 s in the presence of oil compared with 10^{-20} mol/cm^2 s in the presence of water during burial from 3 to 4 km and temperatures of 100–120°C). This retarding effect of oil on quartz cementation in the Miller field led to contrasts in quartz cement abundances in the oil and water legs of the reservoir. Attempts to predict quartz cement abundances in this oil field using Exemplar were successful only for the water leg of the reservoir and not for the oil leg; oil-leg quartz cement abundances were systematically overestimated by, on average, 6.5 ± 4.4%.

Because quartz cement is a major porosity-occluding phase in many deeply buried reservoir sandstones, accurate prediction of the abundance of this authigenic mineral is important for correct prediction of porosity and permeability. Failure to consider the retarding effect of hydrocarbons on quartz cementation could result in serious underestimation of oil-leg porosities. As a consequence, errors in field-volume calculations in the appraisal stage and erratic assessments of reservoir performance (e.g., aquifer influx) during the production stage of oil fields may occur.

In this article, we outline a case study of a well-documented area in the North Sea where three different scenarios of hydrocarbon emplacement interacting with quartz cementation can be identified within one hydrocarbon system: the Brae Unit 2 reservoir in the Miller field received an early, gradual oil fill; the Brae Unit 1 reservoir in the Kingfisher field received an equally early but rapid hydrocarbon fill; and the Brae Unit 2 reservoir in the Kingfisher field received a recent oil charge. We report the results of quantification of the effect of hydrocarbons on quartz cement volumes,

precipitation rates, and porosity in each of these reservoirs. Because of the contrasting filling histories of the reservoirs studied, our results can be extrapolated to other quartz-rich, deeply buried exploration targets where a quantitative understanding of the impact of hydrocarbons on quartz cementation could improve reservoir quality prediction.

STUDY AREA

We studied the impact of oil emplacement on quartz cementation in the Upper Jurassic Brae Formation deep-water sandstones of the Miller and Kingfisher fields in the South Viking Graben, North Sea. Interbedded and overlain with Kimmeridge Clay source rock, the sandstones currently host a complex of oil and gas condensate reservoirs in chronostratigraphically different members. The oil reservoirs in both fields are located in the Brae Formation Unit 2 sandstones (Figure 1). A structural saddle separates the oil accumulations, but they share a common aquifer. Oil-water contacts in the Miller field and Kingfisher field Unit 2 reservoirs are at 4090 and 4030 m below seabed, respectively (Rooksby, 1991). The gas condensate reservoir in the Kingfisher field is located in the shallower Brae Formation Unit 1 sandstones (Figure 1).

This reservoir is separated from the Brae Formation Unit 2 oil reservoir by about 25 m of Kimmeridge Clay mudstones. The gas-water contact is located at 3993 m below seabed. Geochemical studies of hydrocarbons in the Brae Formation Unit 2 sandstones showed that the oil is locally derived from Kimmeridge Clay in the vicinity of the reservoirs (Mackenzie et al., 1987). The gas condensate in the Unit 1 reservoir, however, is thought to have migrated from source rock deeper in the graben to the east of the Kingfisher field (Mackenzie et al., 1987).

APPROACH

To minimize the effects of facies and texture on sandstone porosity, we sampled a total of 103 oil- and water-leg samples, which are as similar as possible in their mineralogical and textural composition, from 10 different wells across the Miller and Kingfisher fields (Table 1). Mineralogical compositions of the sandstone samples were determined by thin-section point counting (500 counts/section), and mean grain size was estimated by measuring the apparent long axis of 100 randomly selected quartz grains per thin section. The standard deviation of the grain-size measurements was used as a measure of sorting. Overall, the sandstones
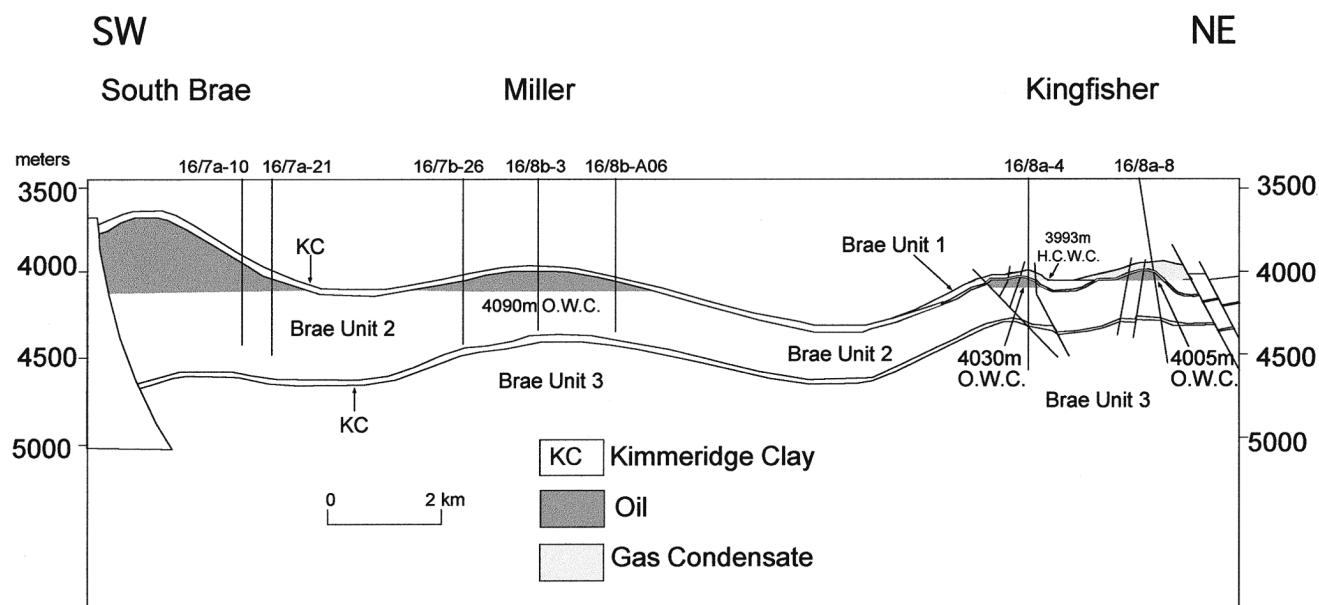
Figure 1. Structural profile across the South Brae–Miller-Kingfisher fields (North Sea). Both the Miller and Kingfisher fields have an anticlinal field structure. The Brae Unit 2 oil reservoirs in the Miller and Kingfisher fields are separated by a structural saddle but still have a communal aquifer. The gas condensate reservoir in the Kingfisher field is located in the shallower Brae Unit 1 sands. O.W.C. = oil-water contact; H.C.W.C. = hydrocarbon-water contact.

Table 1. Overview of Wells and Depth Intervals Sampled in the Brae Formation Reservoirs of the Miller and Kingfisher Fields*

Field	Reservoir	Well	Sample Depth (m)	Number of Samples	Detrital Quartz (%)	Feldspar (%)	Rock Fragments (%)	Detrital Clay (%)	Other (%)	Grain Size (μm)	Sorting**
Miller	Brae Unit 2	7b-A03	4022–4070	35	88.2 ± 3.7	2.9 ± 0.7	3.2 ± 1.6	3.5 ± 2.3	2.2 ± 2.6	318 ± 66	0.65 ± 0.19
		8b-3	3989–4116	6	86.3 ± 3.5	3.0 ± 1.4	4.8 ± 1.8	2.2 ± 0.7	3.7 ± 2.1	328 ± 71	0.68 ± 0.07
		7b-24	4045–4113	11	87.5 ± 2.6	3.9 ± 0.9	2.9 ± 1.6	2.8 ± 1.2	3.0 ± 1.7	321 ± 43	0.69 ± 0.08
		8b-5	4086–4145	3	87.1 ± 0.3	1.5 ± 0.6	5.4 ± 0.7	3.2 ± 2.9	2.8 ± 1.7	385 ± 22	0.65 ± 0.04
		8b-A06	4065–4112	5	89.6 ± 1.9	2.1 ± 0.7	4.7 ± 1.5	1.8 ± 1.0	1.8 ± 0.7	354 ± 69	0.59 ± 0.09
		7b-26	4101–4186	3	89.0 ± 2.5	2.6 ± 0.6	3.2 ± 0.7	2.5 ± 0.5	2.7 ± 0.9	405 ± 43	0.66 ± 0.02
		7b-28	4080–4085	7	87.3 ± 5.2	3.1 ± 1.8	2.1 ± 1.0	2.4 ± 0.9	5.1 ± 3.1	400 ± 71	0.68 ± 0.05
		8b-A10	4094–4105	4	84.8 ± 4.0	3.0 ± 0.3	2.7 ± 0.3	3.2 ± 1.3	6.3 ± 2.8	373 ± 28	0.78 ± 0.07
Kingfisher	Brae Unit 1	8a-8	3886–3955	16	82.5 ± 3.7	2.9 ± 0.5	3.7 ± 1.3	6.3 ± 2.2	4.6 ± 1.4	300 ± 40	0.63 ± 0.05
Kingfisher	Brae Unit 2	8a-4	3990–4126	13	82.2 ± 2.1	1.6 ± 0.5	3.3 ± 1.0	7.0 ± 1.9	5.9 ± 2.1	325 ± 35	0.69 ± 0.06

*Average (± standard deviation) mineralogical compositions, grain sizes, and sorting are indicated for each interval.
**Sorting is quantified as the standard deviation of grain sizes (Folk, 1966).

are quartzose or sublithic/arkosic arenites in composition and are medium grained and moderately sorted (Table 1). Quartz cement is the main diagenetic phase (3–15%), and authigenic minerals other than quartz are restricted to less than 2% kaolinite, calcite, and pyrite.

We obtained minimum temperatures of quartz cementation by measuring the homogenization temperatures of fluid inclusions in quartz cements with a modified U.S. Geological Survey gas flow Fluid Inc. stage mounted on a Leitz Metallux 3 microscope. It would be expected that if hydrocarbon emplacement prevented continuation of quartz cementation, then water-leg samples would yield some higher temperature inclusions than oil-leg samples. Also, if the time of hydrocarbon emplacement were different in the three reservoirs studied, then this difference should be reflected in quartz growth temperatures.

We constrained the approximate time of onset of quartz cementation in the different reservoirs by combining fluid-inclusion temperatures with burial and temperature history modeling of the reservoir and source rocks (using the BasinMod 1-D modeling package). The BasinMod program uses stratigraphic data, thermal conductivities, and heat flow as input values. Heat flow values were derived from bottom-hole temperatures (with standard corrections) measured in wells. The results were calibrated with measured vitrinite reflectance data. BasinMod also allows a hydrocarbon maturity window to be plotted onto burial history curves. For Brae Unit 2 reservoirs in the Miller and Kingfisher fields, source rocks enclose the reservoirs, and, consequently, migration distances are short (Figure 1). Therefore, timing of source rock maturation can be used as an indication of the timing of hydrocarbon emplacement (it is, in fact, the most recent time of emplacement, because oil could have been generated earlier downdip and migrated updip into the reservoir). The maturity window for the interbedded Kimmeridge Clay source rock suggests that oil emplacement in Miller field sediments started at or before approximately 40 Ma, when the Brae Formation was buried to a depth of about 3 km and about 105°C (Figure 2A). The Kimmeridge Clay in the Kingfisher field started generating oil from around 15 Ma onward (Figure 2B). At this time, the Brae Unit 2 reservoir in this field had reached temperatures of around 110°C (Figure 2B).

We calculated quartz precipitation rates with Exemplar software for a random selection of 20 oil- and water-leg samples from the Miller field and 10 samples
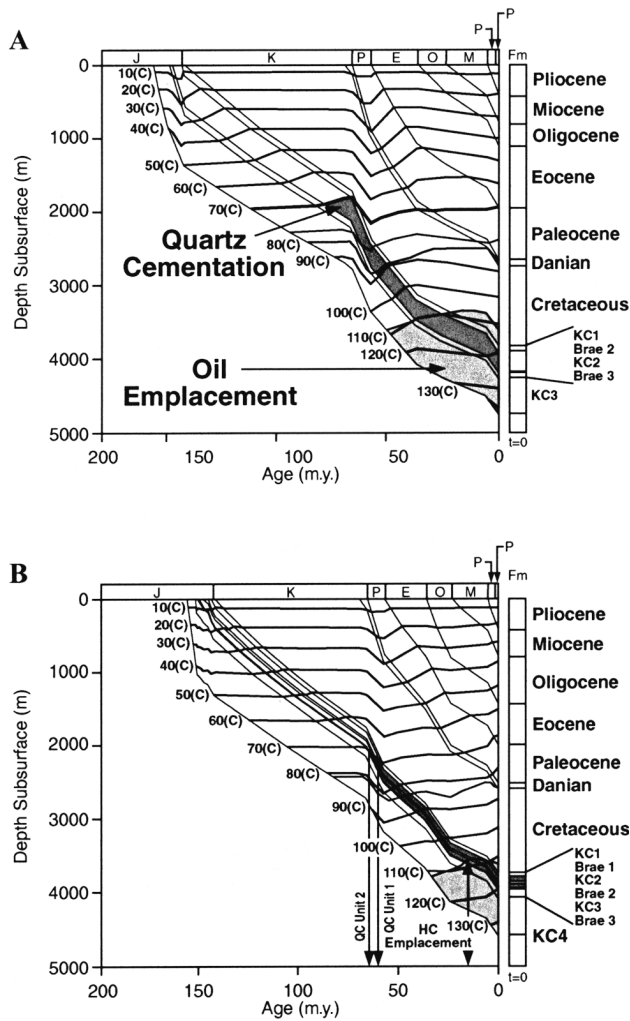
Figure 2. Burial histories combined with isotherms for the (A) Miller field (modified after Marchand et al., 2001) and (B) Kingfisher field. Quartz cement (QC) precipitated in all three reservoirs studied from 70°C onward (see Figure 3). Oil emplacement (shaded light gray) in the Brae Unit 2 reservoirs in the Miller and Kingfisher fields occurred around 40 and 15 Ma, respectively.

each from the Brae Unit 1 and Unit 2 reservoirs in the Kingfisher field. In Exemplar, quartz cement volumes are calculated as the sum of a series of integrals over small time steps (Walderhaug, 1994; Lander and Walderhaug, 1999):

$$m = \int_{t_0}^{t_1} A_1 r(t)dt + \int_{t_1}^{t_2} A_2 r(t)dt$$
$$+ \ldots + \int_{t_{n-1}}^{t_n} A_n r(t)dt \qquad (1)$$

where m is moles of quartz cement precipitated per cubic centimeter of sandstone, A is the surface area of

quartz grains in square centimeters per cubic centimeter of sandstone, t is the time in seconds (t_0 and t_n are the times when quartz cementation starts and terminates, respectively), and r is the rate of quartz precipitation (mol/cm^2 s). Quartz cementation time t and surface area A are derived from burial history modeling and petrographic data, respectively. Parameters that influence surface area A (such as grain size, sorting, sandstone composition, and grain coatings) are also important inputs; these are documented in Table 1. Quartz precipitation rates are calculated as a logarithmic function of temperature that was empirically derived using data from the Norwegian Continental Shelf (Walderhaug, 1994). This temperature dependence of quartz precipitation rates is expressed by the Arrhenius equation,

$$\ln r = \ln B - E_a/RT \qquad (2)$$

where r is the quartz precipitation rate (mol/cm^2 s), B is the preexponential or frequency factor, E_a is the activation energy (J/mol), R is the gas constant (J/K mol), and T is temperature (K). Default reaction kinetics, derived using data from the Norwegian Continental Shelf (Walderhaug, 1994), are $E_a = 58$ J/mol and $B = 5 \times 10^{-12}$. According to Walderhaug (2000), optimal fit between measured and modeled quartz cement volumes is not always obtained with the default reaction kinetics because of inaccuracies in temperature histories and the quartz surface area function A in the program (equation 1). We also have noticed a grain-size dependence in other studies, which indicates that these kinetic parameters are not universally applicable. Therefore, we fine-tuned the reaction kinetics E_a and B (equation 2) to achieve a good match between the predicted and measured amounts of quartz cement in the water-leg samples of the reservoirs in the Miller and Kingfisher fields ($E_a = 58$ J/mol and $B = 2.8 \times 10^{-12}$ for the Miller field; $E_a = 58$ J/mol and $B = 3.8 \times 10^{-12}$ for the Kingfisher field).

EARLY, GRADUAL OIL FILL

Oil emplacement began in the crestal areas of the Miller field around 40 Ma when the reservoir was buried to 3 km (Figure 2A). Although quartz cementation had started in the crest of the reservoir from around 70 Ma, when the sandstones were buried to approximately 2 km and approximately 70°C (Figure 3A), the resulting quartz cement abundances before oil
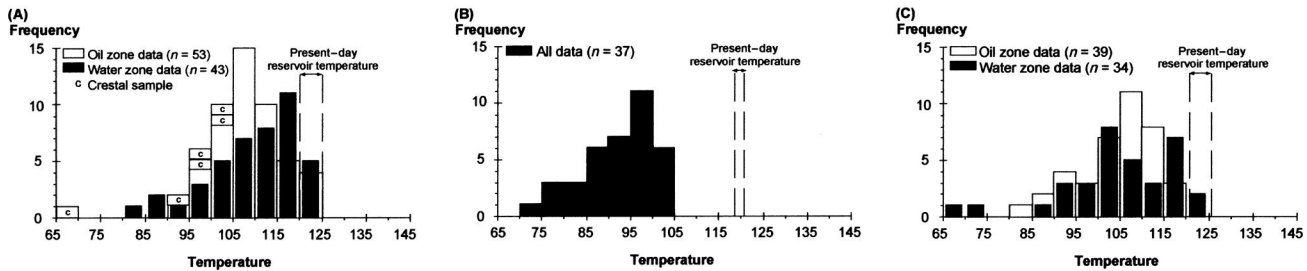
Figure 3. Histograms of homogenization temperatures (T_h) measured in aqueous fluid inclusions in quartz cement. (A) The T_h data from the Brae Unit 2 reservoir in the Miller field suggest that oil-leg cementation (histogram peak between 105 and 110°C) is retarded to aquifer cementation (peak histogram between 115 and 120°C). (B) The T_h data from the Brae Unit 1 reservoir in the Kingfisher field suggest that quartz cementation was halted when the reservoir was buried to temperatures of 95–105°C (maximum measured temperatures). (C) The T_h data from the Brae Unit 2 reservoir in the Kingfisher field suggest quartz cementation over identical periods of time in oil and water legs (similar fluid-inclusion temperature ranges).

emplacement (40 Ma) in the crest are low (<5%) (Figure 4A). This finding is regarded as a consequence of the slow rate of quartz precipitation at lower temperatures (e.g., Walderhaug, 1996; Marchand et al., 2001). The highest fluid-inclusion temperatures measured in crestal samples are 95–105°C (Figure 3A). This temperature range coincides with reservoir temperatures around 40 Ma, when oil first entered the reservoir (Figure 2A). Increasing quartz cement abundances from the crest of the field toward the oil-water contact at 4090 m (from <5 to 10% quartz cement) (Figure 4A) and fluid-inclusion temperature data that approach present-day reservoir temperatures (120°C) (Rooksby, 1991) (Figure 3A) suggest a gradual oil fill over a prolonged period of time (Marchand et al., 2001), with the degree of porosity preservation related to the proportion of time spent with an oil fill.

Exemplar predictions of quartz cement abundances and porosity are acceptable for water-leg samples (Figure 4A). For oil-leg samples, however, quartz cement abundances are typically overestimated and porosities underestimated (Figure 4A) using the water-leg kinetic parameters. Because oil- and water-leg samples are texturally and mineralogically similar and underwent an identical burial history, Marchand et al. (2001) concluded that the rate of quartz precipitation in the oil leg was lower than in the water leg of the reservoir because of the oil fill itself: there were no viable textural, mineralogical, or burial history–related explanations. The average rate of quartz precipitation in oil-leg samples of the Miller field was derived from Exemplar by reducing the rate of quartz precipitation in the model after oil emplacement (40 Ma until the present) in individual samples until their simulated quartz cement abundance agreed precisely with their measured values. The calculated rates of precipitation, averaged over the period since oil emplacement to the present day, are lower in every oil-leg sample (average $1.5 \pm 1.8 \times 10^{-21}$ mol/cm^2 s) compared with the water-leg samples (average $6.3 \pm 0.9 \times 10^{-20}$ mol/cm^2 s) (Figure 4A). There is a clear trend of a decreasing rate upward from the oil-water contact to the reservoir crest (Figure 4A). Quartz precipitation rates after oil emplacement are zero in some samples near the field crest (Figure 4A). The variation in calculated quartz precipitation rates through the oil leg of the Miller field can be explained by the reservoir filling history. The calculated quartz precipitation rate for each sample in Figure 4A assumed that quartz had continued to grow in the oil leg after oil filling at 40 Ma, albeit at a reduced rate. However, oil charging did not occur instantaneously at 40 Ma; it happened gradually over millions of years (Marchand et al., 2001). Thus, a better explanation is that the gradient of decreasing quartz cement upward through the oil leg is not caused by a decreasing cementation rate but by an increasing proportion of time spent at (almost) zero cementation rate.

The sandstones situated at the field crest would have been filled by oil at 40 Ma. These sands experienced virtually no further quartz cement growth after oil emplacement, so clearly the cementation rate in the crestal part of the reservoir was (almost) zero ever since oil filling. Parts of the Brae Formation located progressively deeper below the crest (i.e., closer to the oil-water contact) have spent progressively less time filled with oil. The increasing quartz cement abundances in the deeper oil-leg samples are related to the relative amount of time they have spent filled with oil (almost zero cementation rate) compared with their
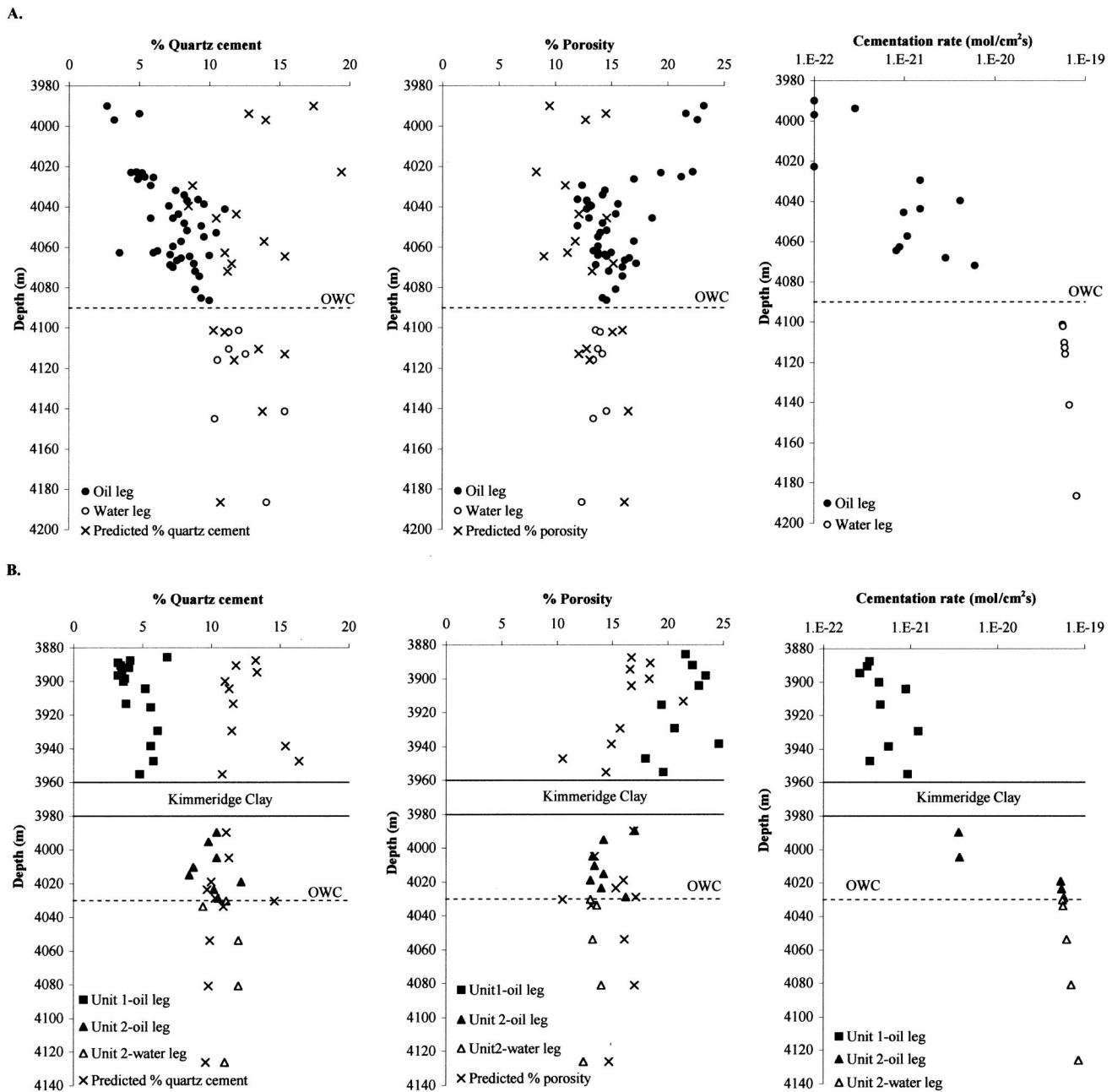
Figure 4. Plotted vs. depth, from left to right, quartz cement abundances determined by scanning electron microscopy–based cathodoluminescence (SEM-CL) and image analysis (%); core He porosities (%); and calculated quartz precipitation rates (mol/cm² s) for (A) the Miller field (modified after Marchand et al., 2000, 2001) and (B) the Kingfisher field. (A) The Brae Unit 2 reservoir in the Miller field received an early (40 Ma), but gradual, oil fill with low quartz cement abundances and high porosities preserved only in the crestal areas of the reservoir. Predicted quartz cement abundances and porosities (crosses) are erratic across the reservoir oil leg. This is because, in reality, quartz precipitation rates are at least two orders of magnitude lower for every oil-leg sample compared with aquifer samples. Samples yielding zero as quartz precipitation rate have been plotted as 1×10^{-22} because log zero cannot be plotted. (B) The shallower Brae Unit 1 reservoir in the Kingfisher field received an early (30 Ma), but rapid, hydrocarbon charge with low quartz cement abundances and high porosities preserved throughout the reservoir. Predicted quartz cement abundances are overestimated and porosities underestimated (crosses). Quartz precipitation rates are low throughout the reservoir. The deeper Brae Unit 2 oil reservoir in the Kingfisher field received a recent, probably still ongoing, oil charge with negligible differences in quartz cement abundance and porosity above and below the oil-water contact (OWC) as a consequence. Predicted amounts of quartz cement and porosity (crosses) are more accurate. Quartz precipitation rates in oil legs are comparable to precipitation rates in the aquifer.

time spent in the aquifer (so-called normal cementation rate).

EARLY, RAPID HYDROCARBON FILL

Quartz cement and porosity distributions in the Brae Unit 1 reservoir in the Kingfisher field illustrate the case of a reservoir that received an early and rapid hydrocarbon fill with high porosity preservation (25–30%) and low quartz cement abundances (<5%) throughout the reservoir (Figure 4B). Placing an accurate time constraint on hydrocarbon emplacement in the Brae Unit 1 reservoir is difficult. The maturity of the deep source rocks from which hydrocarbons were expelled could not be modeled because of the lack of information about the distal kitchen area. However, the observation that no precipitation of quartz cement occurred at temperatures higher than 100–105°C in this reservoir (Figure 3B) does indicate that hydrocarbons were present at least from 30 Ma onward, when the reservoir was buried to 3 km (Figure 2B).

Exemplar predictions of quartz cement abundances and porosity using water-leg kinetics from the other wells (no water-leg samples were available from this well) are not successful (Figure 4B). There are discrepancies between predicted and measured quartz cement abundances and porosities in the Brae Unit 1 reservoir: quartz is overpredicted by 8.2 ± 2.2% and porosity is underpredicted by 7.8 ± 2.1%. Average quartz precipitation rates over the period since hydrocarbon charge until the present day, derived from the Exemplar simulation results using a similar methodology to that described for the Miller field, are very low throughout the Brae Unit 1 reservoir: 5.8 $\times 10^{-22}$ ± 3.3 × 10^{-22} mol/cm^2 s (Figure 4B). These calculated oil-leg precipitation rates are greatly reduced compared with normal expected rates in water-filled rocks ($\sim 10^{-20}$) at these temperatures (100–120°C).

RECENT OIL FILL

Quartz cement and porosity distributions in the Brae Unit 2 reservoir in the Kingfisher field illustrate the case of a reservoir that received a recent oil fill. Kimmeridge Clay in the Kingfisher field started generating oil around 15 Ma when the Brae Unit 2 reservoir in this field was buried to temperatures of 110°C (Figure

2B). A consequence of a recent, possibly still ongoing, oil charge is that there is negligible difference in quartz cement abundances above (average 10.0 ± 1.2% in the oil leg) and below (average 11.1 ± 1.2% in the water leg) the present-day oil-water contact (Figure 4B). The recent oil emplacement in the reservoir also is reflected in fluid-inclusion temperature measurements. Measured fluid-inclusion temperatures are similar to present-day reservoir temperatures (~120°C) in oil-leg as well as in water-leg samples (Figure 3C), suggesting that quartz cement has precipitated fairly recently in the oil and water legs.

Exemplar predictions of quartz cement abundances and porosity are acceptable for both oil- and water-leg samples using the same water-leg kinetics (Figure 4B). Oil emplacement was simulated with Exemplar from 15 Ma, and average quartz precipitation rates were calculated as described in a preceding section. The quartz precipitation rates in the oil and water legs of the reservoir are statistically indistinguishable (average 3.5 × 10^{-20} ± 2.8 × 10^{-20} mol/cm^2 s and 6.6 × 10^{-20} ± 1.2 × 10^{-20} mol/cm^2 s, respectively) (Figure 4B), although there is a suggestion of lower rates of quartz precipitation in the very crestal area of the reservoir where oil charged first (Figure 4B).

DISCUSSION

Does Oil Halt Cementation?

Quartz cementation is generally regarded as a three-step process (dissolution, transport, and precipitation). According to Renard et al. (2000), between 0 and 3 km burial, the slowest step dictating the overall rate of quartz cementation is precipitation. This is because at shallow depths, transport by diffusion is fast relative to the kinetics of precipitation, which are slow because of the low temperature. At greater depths (>3 km), the kinetics of quartz precipitation are accelerated by an increase in temperature, and the limiting step becomes diffusional transport along the grain contacts (Renard et al., 2000). Worden et al. (1998) hypothesized that quartz cementation also becomes transport controlled where oil is present in the pore space of a sandstone, with the degree to which diffusion is retarded dependent on water saturation.

The Brae Formation reservoirs in the Miller and Kingfisher fields provide excellent examples of the effect of oil emplacement on quartz cementation.

Where oil emplacement occurred first (i.e., the structural crest of Miller field and the Brae Unit 1 reservoir in the Kingfisher field) and oil saturations have thus been high the longest, porosities are highest and quartz cement abundances are also lowest. In the Brae Unit 2 reservoir of the Kingfisher field, where oil filled downflank parts of the reservoir quite recently, calculated rates of quartz precipitation are indistinguishable in the oil and water legs of the reservoir.

The view, held by some, that oil emplacement has little or no effect on quartz cementation is based on examples of reservoirs that do not show a significant difference in volumes of cement between oil and water legs and on the occurrence of oil-bearing fluid inclusions entrapped in quartz cement (e.g., Walderhaug, 1996; Bjørkum et al., 1998). The cement volume argument only holds if it is supported by quantitative information on oil emplacement and temperature history, because we have shown that the relative timing of oil emplacement is crucial. If oil emplacement were a recent event in a reservoir, as is the case in the Brae Unit 2 reservoir in the Kingfisher field, then there would be no reason for rocks in the oil and water legs to have significantly different quantities of quartz cement. The petroleum fluid-inclusion argument is, in fact, only proof that some oil was present at the time that quartz cement was growing, but this is not conclusive evidence that cement can continue to grow at irreducible water saturations (Worden and Morad, 2000). We agree with the hypothesis of Worden et al. (1998) that entrapment of petroleum in inclusions in quartz cements most likely occurs where water saturation in the reservoirs is still high and silica diffusion rates are not significantly reduced by the presence of hydrocarbons (e.g., during the earlier stages of oil emplacement or on migration routes). The relationship between quartz cement abundance and petroleum emplacement times in the Brae Formation reservoirs indicates that, with rising oil saturation, quartz precipitation in the oil-leg sandstones was strongly inhibited by oil emplacement compared with the underlying aquifer sandstones.

The question remains whether natural gas also can preserve porosity in sandstones. Although no gas reservoir was examined in this study, examples are available in the literature that may illustrate the inhibiting effect of gas on diagenesis. For example, Houseknecht and Spötl (1993) and Spötl et al. (1996) reported that after accumulation of gas in the Spiro Sandstone (Arkoma basin, United States), reservoir quality below the gas-water contact was reduced by high-temperature quartz diagenesis, whereas porosity was preserved in the gas leg. These results may indicate that gas has a similar effect as oil on quartz cementation. Indeed, the commonly lower irreducible water saturations in gas accumulations compared with oil could mean that gas is even more effective at inhibiting quartz cementation.

Implications for Reservoir Quality Prediction

The retarding effect of oil or gas on quartz cementation has been noted by several researchers in reservoirs other than the Brae Formation (e.g., Macaulay et al., 1992; Emery et al., 1993; Houseknecht and Spötl, 1993; Souza and McBride, 2000). If quartz cement abundances and porosity in such reservoirs are predicted using existing modeling packages without considering the retarding effect of hydrocarbons on quartz cementation, then large errors in predicted results can occur, that is, overestimation of cement and underestimation of porosity and permeability. This is particularly so wherever reservoirs have been at high temperature and hydrocarbon filled for a prolonged period of time (cf. the oil legs of the Miller and Kingfisher fields) (Figure 4). Quartz cement abundance and porosity predictions for the structural crest of the reservoir in the Miller field and the Brae Unit 1 reservoir in the Kingfisher field were particularly unsuccessful because these areas were hydrocarbon filled the longest (Figure 4). Predictions for the Brae Unit 2 reservoir in the Kingfisher field are good because this reservoir experienced only a recent oil fill (Figure 4).

During exploration, porosity and permeability may be estimated based on regional patterns of variation with depth. Because shallower parts of a basin tend to be drilled up first, the regional database may be skewed toward fields with little quartz cement and fields that received late (or no) hydrocarbon charge. Porosity in deeper prospects may be estimated by extrapolating the regional porosity-depth trend to greater depths, but this would be incorrect if those deeper oil or gas prospects had received an earlier oil or gas charge. A direct consequence of not considering lower oil-leg quartz precipitation rates is that oil-leg porosity predictions for early filled fields could be greatly underestimated (Figure 4) during exploration. Early filled accumulations could clearly retain viable reservoir properties, although they might be deeper than the regional porosity or permeability cutoffs.

Very commonly, the earliest well(s) in a field are drilled toward the structural crest to maximize the chance of a discovery. The porosity encountered in such a crestal oil discovery well may not be representative of the rest of the field because quartz cementation could increase dramatically downflank into the water leg if the reservoir is within the quartz cementation window. This could result in errors in field-volume calculations, affecting the decision to proceed with appraisal. Furthermore, there is the possibility that the aquifer may be yet more cemented and have poorer porosity and permeability compared with the reservoir itself. This could lead to overestimation of the degree of aquifer pressure support to an oil field (or aquifer influx to a gas field), leading to an underestimation of the need for artificial pressure support (water injection). This number of required injectors might be further underestimated if the injection performance were based on reservoir properties from the oil leg that were much better than for the water leg.

Optimal predictions of reservoir quality in potentially quartz-cemented reservoirs thus require an understanding and quantitative modeling of the pressure (for modeling compaction), temperature (quartz cementation potential), and reservoir filling history (for cement retardation). This emphasizes the need for reservoir quality analysis to be integrated with basin modeling.

CONCLUSIONS

1. Quartz precipitation rate is retarded by at least two orders of magnitude in hydrocarbon-filled reservoirs at 120°C, that is, quartz cementation is effectively stopped in the presence of hydrocarbons.
2. The retarding effect of hydrocarbons on quartz cementation is not explicitly modeled in current commercial software packages. As a result, cementation modeling of reservoirs that have been hydrocarbon filled for a prolonged period of time yield oil-leg quartz cement abundances that are too high and porosities and permeabilities that are too low.
3. Correct predictions of quartz cement abundances and porosity are of great importance in exploration (risk of reservoir effectiveness) and the appraisal stages of deeply buried clastic oil fields. An underestimation of oil-leg porosity could lead to some viable prospects being overlooked because they lie below a regional porosity cutoff.

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