Long-timescale interaction of CO_2 storage with reservoir and seal: Miller and Brae natural analogue fields North Sea

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Abstract

The Miller oilfield may form the first UK offshore CO_2 storage site. We have examined sandstones from the Miller reservoir and mudrocks, which form the vertical seal, using techniques adapted from investigations of oilfield reservoir quality. The present-day distribution of natural CO_2 suggests emplacement up a fault to the west, bounding the basin. A scoping study of equilibrium geochemical modelling, with enforced reducing chemistry, predicts that CO_2 addition makes little change to the assemblage of minerals present, but could produce changes of mineral ratios. Carbonate cement is common in the reservoir. Stable isotope analyses provide a fingerprint of C and O origins, and show no difference from standard burial cementation trends. The physical distribution of calcite, however, shows an increase from north to south – possibly due to CO_2 filling, and a horizontal alignment that we interpret as a paleo gas-water contact. Fluid inclusions fossilise samples of ancient fluid, these suggest an input of high salinity water when the reservoir was at cool to moderate temperatures (ie shallow to medium burial depths). Mudrocks above the reservoir show enrichment in kaolin compared to the same mudrock distant from CO_2. Stable isotope analyses of mudrock carbonates, including a low CO_2 comparison well, show a trend similar to the sandstones. Prediction of C, O isotope values in calcites formed from current CO_2 is unlike these measured values. We interpret that there is no direct evidence of abundant ancient CO_2 leakage vertically, although reduced reservoir pressures show that leakage has occurred – possibly laterally. CO_2 seems to have been retained for about 120 million years, with little mineral trapping in the reservoir or seal.

Keywords: seal, integrity, CO_2 leak, isotope, carbonate

Background

Depleted oil or gas fields, naturally rich in CO_2, provide an immediate opportunity for long-term CO_2 storage within the UK. Costs and legislative problems in such sites could be partially offset by storing CO_2 as part of Enhanced Oil Recovery. The Miller oilfield is planned, by British Petroleum and Scottish and Southern Energy, to be the world's first offshore development of CO_2 storage linked to onshore power generation by shift of natural methane gas to hydrogen and pre-combustion separation of CO_2. This field is part of the same geological province, with naturally high CO_2 contents of up to 20mol% in the oils, which hosts Statoil's Sleipner West, where CO_2 is supplied to the SACS offshore storage demonstration. These hydrocarbon fields are buried to about 4km. This examination of reservoir sandstones and seal mudrocks in the Miller oilfield, has the aim of estimating: 1) the geological age at which natural CO_2 was charged, 2) the effect of CO_2 on mineral growth in reservoir or seal during millions of years of contact at temperatures up to 140 C, 3) evidence of ancient CO_2 leakage.

Methodology

We have approached this study by using multiple techniques normally deployed during investigations of hydrocarbon reservoir quality, and which give an insight into the distribution of minerals in the oilfield, and especially their post-depositional (diagenetic) growth during burial of the sediments at geological timescales. Our approach is to use the present day fluid distribution, and present day mineral assemblages to provide information on fluid origins (especially CO_2), on ancient geochemistry – and how CO_2 may have produced signatures in minerals grown during or consequent on its presence. This paper represents an interim report on our work in progress.

We have used existing data from a EU sponsored THERMIE project [1], as well as our own standard petrographic and wireline techniques for assessment of reservoir quality in hydrocarbon fields, in which our group is long-experienced [2]. Isotopic analyses have been taken from samples of publicly available rock core.

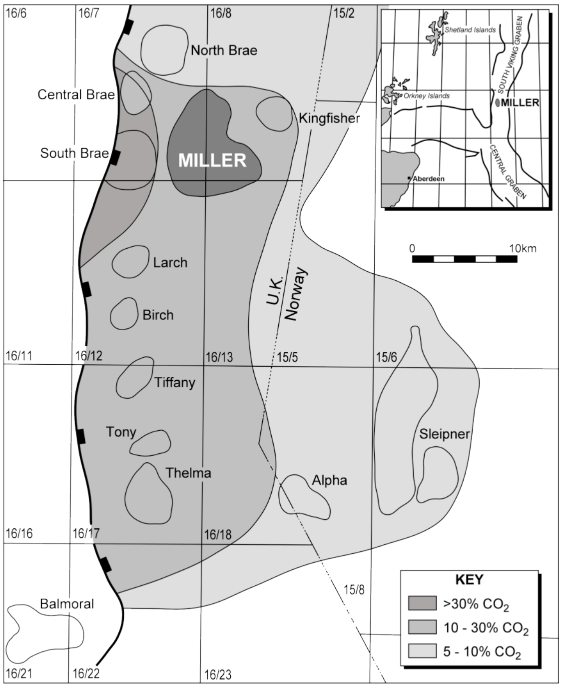

Figure 1 Location of Miller, showing relationship to Brae and Sleipner, and mol% CO_2 in oils.

Geological Setting

The Miller oilfield (Fig. 1) is of Upper Jurassic age, deposited as submarine fan sandstones in a deep marine setting. The reservoir sandstones are laterally equivalent to the Brae Formation reservoirs in South and Central Brae. Oil is trapped by the Kimmeridge Clay Formation mudrocks, which also source the oil. The top-reservoir is buried to about 4.0km, at a temperature of 140 C, and is only partly overpressured, compared to other fields at similar depth in the North Sea Viking Graben. The Miller and Brae sandstones are unusually poor in feldspar (compared to other North Sea Upper Jurassic reservoirs), and these sandstones are also poor in diagenetic clay [3]. This natural CO_2 province includes the following fields : Miller; North-, Central-, South-, and East- Brae fields; Kingfisher; Tiffany; Toni; Thelma; Larch; Birch; Oak; Elm; and Pine.

Results

CO_2 distribution

Miller field contains up to 20 mol% CO_2 in the oil. CO_2 content in water is less well recorded as separator gas during water testing, and is 60 - 70 mol%, equating to equilibrium solubility and partitioning. A map of CO_2 distribution (Fig 1), shows that the highest CO_2 concentrations are in the South Brae field adjacent to the Graben boundary fault, with progressively less CO_2 eastwards to Miller, and then to Kingfisher and Sleipner. This suggests that CO_2 could have charged up the fault system, and migrated eastwards.

Geochemical modelling

We wished to test if CO_2 enhancement would enforce geochemical reactions of rock-forming minerals, to sequester CO_2 by production of new mineral precipitates. We used Geochemists

Workbench software, with a mineral assemblage representing the bulk reservoir: quartz, muscovite (as a proxy for illite), calcite (early concretion), pyrite, kaolinite, albite, K-feldspar, haematite. We equilibrated a closed system with seawater, to represent depositional pore-fluids, and then heated progressively to 140C. We suppressed production of dolomite and witherite (as these are not observed in the reservoir today), but permitted precipitation of dawsonite and chlorite. Aluminium from kaolin dissolution is balanced by illite/phengite precipitation. Crucially, we forced the Eh (oxidation state) to be very reducing (-350mV), to account for the reactive effects of organic material and oil. We undertook one simulation with no CO_2 present, and one identical simulation with CO_2 present (Fig.2) – so that results could be compared.

Published simulations of CO_2 effect on deep North Sea reservoirs (based on the Utsira sand from Sleipner), have predicted [4] the formation of dawsonite ($NaAlCO_3(OH)_2$), and of magnesite ($MgCO_3$). However this predicted mineralogy is not confirmed in natural oifields [5]. Our modeling here does not precipitate dawsonite as part of an equilibrium assemblage, and we ascribe this to the reduced environment in the presence of organic material, oil. We find minimal difference of final mineralogy between the two simulations, although the pathways to that assemblage differ. We predict growth of quartz, calcite, albite, illite and pyrite. Consequently, we have (below) sought evidence of ancient calcite growth as a record of CO_2 interaction.

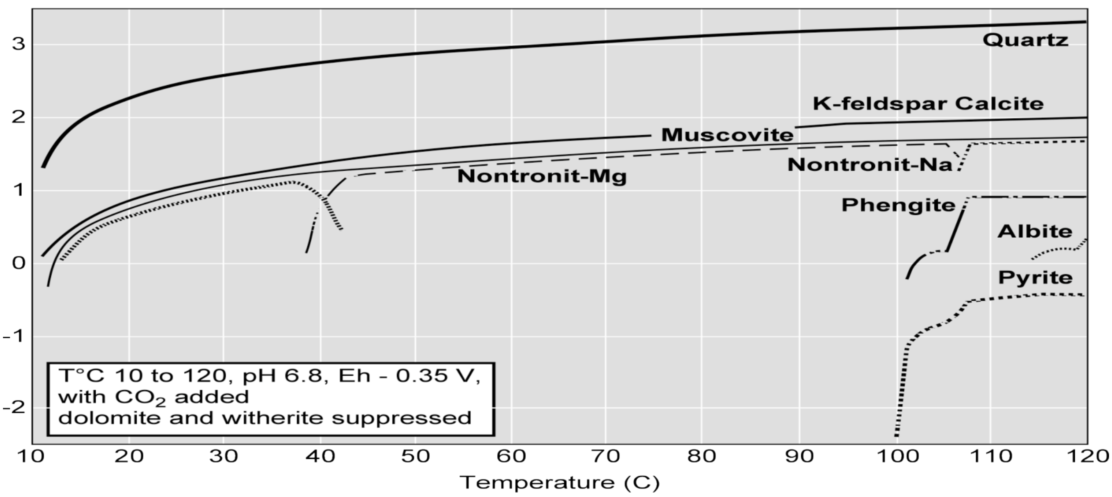

Figure 2 Result of Geochemists Workbench simulation of Miller reservoir sandstone, with CO_2 and forced -350mV oxidation state.

Ancient fluids

From the THERMIE project [1], we have fluid inclusion measurements. These record the salinity and temperature of small samples of fossil fluid entombed within quartz crystals. These show that very high salinity fluids existed in the past, up to 26 wt% NaCl equivalent (which is almost at halite saturation), at temperatures of 70 to 95C. Present day salinity in Miller is about 7 - 8.0wt%NaCl equivalent, which our geochemical modelling shows is too saline to be derived from a closed system. This strongly implies that an input of very saline fluid occurred, and this was very likely at temperatures cooler than 70C as fluid inclusions within quartz overgrowths do not exist to record the lower temperatures. We infer that CO_2 and saline fluids could have charged together, ascending from Permian evaporite sediments known to occur vertically below Miller. These fluids also carried high levels of Ba, Sr, Mg, Na, Cl. From the geological history of the reservoir, this equates to a CO_2 charge from more than 120 Million years ago, up to 70 Million years ago.

The virgin reservoir pressures on Miller and South Brae were close to hydrostatic [6]. These are much lower than geographically nearby oilfields, which are elevated about 50% above hydrostatic. We infer that fluids from Miller and Brae have leaked, to reduce geopressure.

Reservoir sandstones

We examined the distribution of calcite cements in the reservoir, using standard wireline logs from boreholes on Miller, via the CDA database (courtesy of Malcolm Rider, GeoSciences Edinburgh). We focused on of zones of concentrated carbonate cementation (examination of dispersed carbonate cement is currently underway). Some of these “concretions” appear to form a horizontal layer parallel to, but 50m deeper than, the present-day oil-water contact. We interpret this to indicate preferential growth of concretions at a palaeo water contact – potentially of an ancient charge of CO_2, which migrated eastwards from Brae, overfilled the reservoir, and has gradually leaked since then. Our preliminary compilations of concretion growth thickness, expressed as a percentage of sand thickness in 9 wells, suggest that within the higher, southern, part of the Miller field, concretionary calcite cement is less abundant (0-10%), relative to the deeper northern oil zone (17 - 70%), whereas the water zones contain 3 -15% uniformly throughout the field. Several of these concretion cements are known to fill poorly compacted sediment, and so they formed during very shallow burial. Controls which operated to affect concretion growth could include: 1) an oil or CO_2 gas charge at very shallow burial to slow or halt concretion growth in an oil or gas zone at the shallow crest of the field, whilst growth continued in the water zone; 2) CO_2 – related dissolution of early formed concretions, 3) preferential growth of concretions along a CO_2 charge route. We are currently compiling carbonate thickness data from additional wells, and undertaking more detailed isotopic analyses and petrography to test between these possibilities.

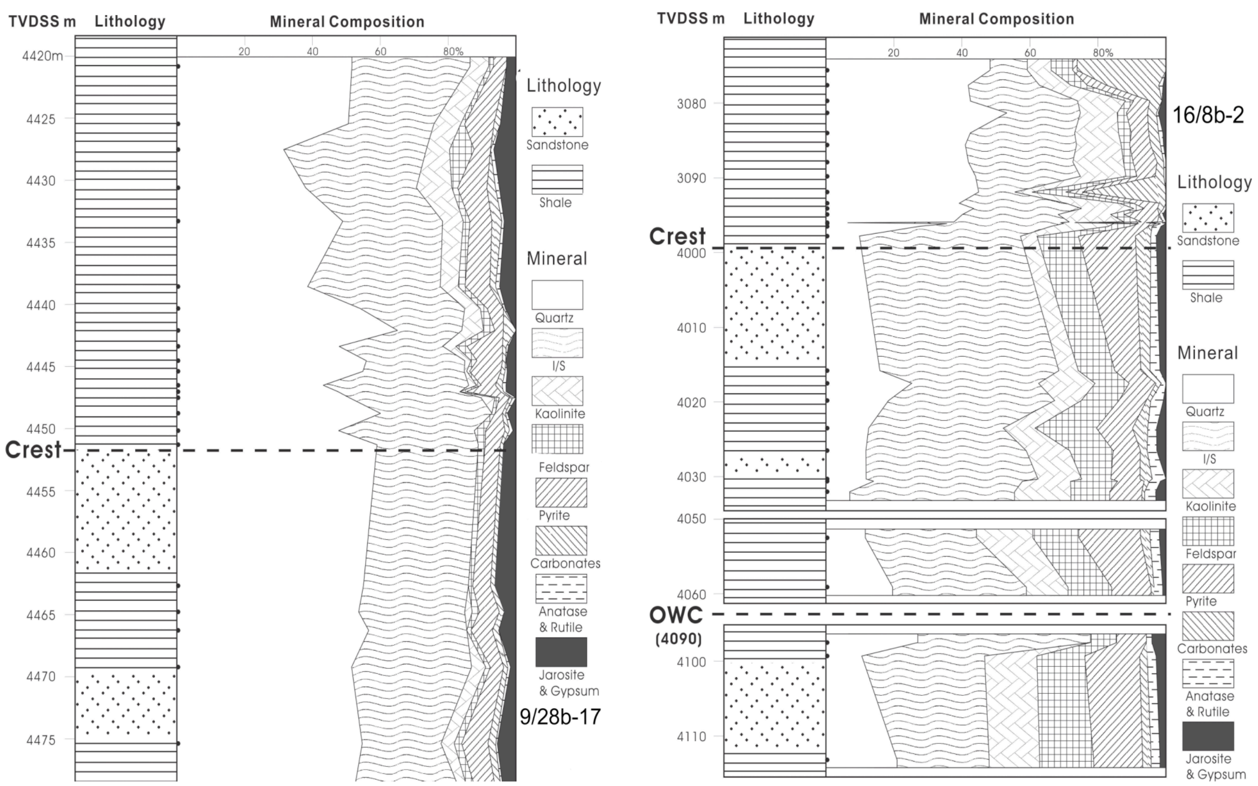

Figure 3 X-Ray Diffraction of mudrock mineralogy (not sandstone) in low CO_2 comparison well 9/28b-17, and high CO_2 Miller well 16/8b-A2. The high CO_2 well shows more calcite, more kaolin, and less feldspar in the seal.

Mudrock seal

We undertook X-Ray Diffraction analyses of mudrocks from several wells on the Miller oilfield (Fig. 3), to identify and semi-quantify mineralogy. These wells are compared to analyses made in an identical way from mudrocks from the same stratigraphic interval overlying the reservoir sandstone, in a 'comparison' borehole. This is more than 20km distant, in an area with 'normal' CO_2 levels, ie less than 5 mol% in water. The control borehole shows no change in mineralogy vertically above the reservoir. By contrast some wells on the field show depleted feldspar, enhanced kaolin and enhanced calcite above the reservoir, relative to the control well, and relative to mudrock layers within the reservoir. This could be caused by CO_2-induced reaction of feldspar to kaolin + calcite in the mudrock seal.

Stable C, O isotope signatures in calcite

We have attempted to discover signatures of CO_2 from Miller in the calcites from the reservoir and from the overlying mudrocks. We have plotted existing data [1] from concretions in sandstone, with our own new data from mudrocks in Miller and from the comparison well (Fig. 4). All these data fall on a similar, unusually linear, trend. This trend would conventionally be interpreted as a 'normal' diagenetic pattern, which records the co-evolution of temperature and porewater ($\delta^{18}O$), with bacterial and decarboxylation process ($\delta\,^{13}C$) during burial. Superimposed are our calculations (arrow) of the predicted C, O isotope values of calcite formed at mid-burial (70-90C) from present day -8.3 $\delta\,^{13}C$ CO_2 in Miller. The observations and predictions do not coincide, suggesting that calcites in reservoir and seal were not dominated by CO_2 derived from Miller. This implies that the calcites in the mudrock do not record leakage of CO_2 vertically (Fig. 5) through the Kimmeridge Clay Formation seal.

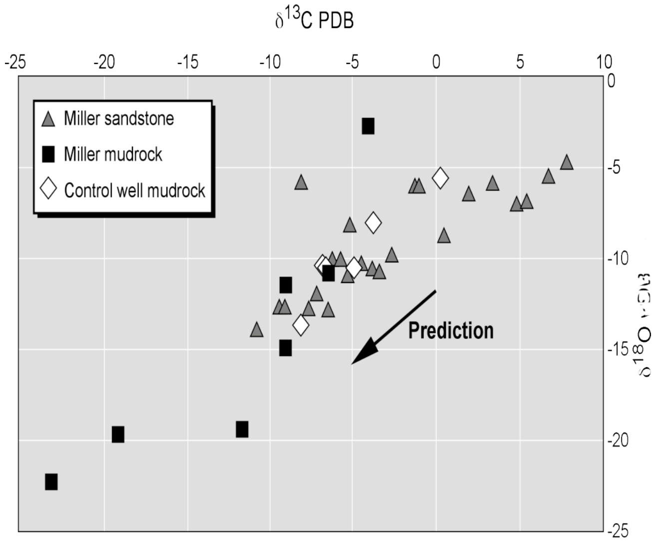

Figure 4 Preliminary C, O isotope data from Miller sands, mudrocks, and control well. Superimposed arrow is the predicted C, O isotope values of calcite formed at 70-90C from present day CO_2 in Miller.

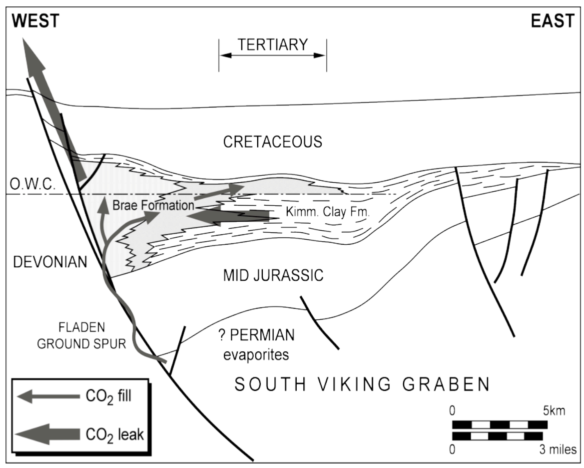

Figure 5 Cartoon of Miller and Brae, showing interpreted pathway of CO_2 charge, and pathway of CO_2 leakage.

Conclusions

1) Natural CO_2 is reservoired with black oil in the Miller oilfield 4km deep beneath the North Sea. This field forms part of a CO_2-rich sub-province, and may provide the first opportunities for CO_2 storage with Enhanced Oil Recovery in the UK offshore.

2) Scoping geochemical simulations of the reservoir interaction with CO_2 suggests that definitive signatures of mineral change are not to be expected. Dawsonite, predicted in some previous geochemical simulations of CO_2 storage, is not a stable phase in Miller field. Our simulations suggest that oil forces a reduced oxidation state and thus makes dawsonite unstable.

3) The distribution of calcite cements suggests that the reservoir was, at one time, filled with more CO_2 or oil than now. CO_2 charge may have been up the western graben boundary fault, possibly 120 - 70 Ma.

4) Although some mineral changes in mudrock seal above the reservoir may have been induced by CO_2, such CO_2 did not isotopically dominate the precipitation of carbonate in the seal. There is no mineralogical evidence of vertical CO_2 leakage, although reduced reservoir pressures suggest that lateral leakage may have occurred during geological timespans.

5) There is no definitive evidence of extensive reaction of natural CO_2 with reservoir or seal, to form permanent mineral storage.

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