Geochemistry of reservoirs, an introduction

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We believe this is the first collection of papers to be devoted entirely to reservoir geochemistry, which is an area of growing scientific and economic importance. The main aim of reservoir geochemistry is to understand the distributions and origin(s) of the petroleums, waters and minerals in the reservoir and account for their possible spatial and compositional variation. This is ideally related to basin history and location of source-rock kitchens and migration pathways.

As well as being of interest in its own right, reservoir geochemistry has many important practical applications during petroleum exploration, appraisal and development. The most important uses are related to proving or disproving connectivity between different regions of a particular well or horizon. During exploration, reservoir geochemistry can indicate the direction from which a field filled, pointing the way for future wells. During production, studies of variations in composition with time may also be made, although this is a little studied area at present.

Published accounts of the origins and applications of reservoir fluid differences appear to be relatively recent. England et al. (1987) noted the phenomenon and were probably the first to relate it to migration and subsequent time-scales of in-reservoir mixing. Workers, particularly in the USA, have developed the use of ‘gas chromatography (GC) fingerprinting’ to distinguish different oil families, often in reservoirs with numerous thin hydrocarbon-bearing intervals (Kaufman et al. 1990). Effects due to the Earth’s gravitational field were first considered by Sage & Lacey (1939). An extensive bibliography is presented by Larter & Aplin (this volume).

Although many techniques can be used to study the fluids in a reservoir, the most useful for reservoir geochemistry appear to be:

(1) For hydrocarbons
- conventional and high resolution gas chromatography–mass spectrometry
- high resolution chromatography (‘GC fingerprinting’)
- gas analysis and isotope determination
- fluid inclusion studies
- type analysis on extracts of (to locate/study) tar mats
- thermovaporization (to eliminate conventional core extraction steps)

(2) For waters
- conventional multi-element analysis
- oxygen/hydrogen isotope determinations
- strontium isotope ratios (especially on core)

Note, however, that other available non-geochemical data should also be included in any interpretations.

In order to classify the articles in a volume of this kind, we have attempted a broad split between (a) more general reviews and discussions of techniques, and (b) papers with a greater case study flavour.

General reviews and new techniques

Larter & Aplin give a comprehensive and readable review of the current ‘state of the art’, discussing the origins and natures of water and petroleum heterogeneities in reservoirs and their rates of dissipation over geological time. They also provide a useful account of the growing importance of statistics, which is vital for finding real (as opposed to imaginary) differences in the large datasets often collected. Finally, they discuss the importance of interactions between organic compounds and formation waters during migration.

Bjørlykke et al. review the geochemistry of North Sea and Gulf Coast formation waters. They emphasize the thermodynamic and kinetic controls on the possible reactions involving, for example, dissolved potassium and potassium-containing minerals. These factors are vital when considering the complex interactions involved during the emplacement of petroleum in reservoirs which may be simultaneously undergoing diagenesis.

Anissimov discusses geochemical criteria of value in reservoir characterization and in particular the inorganic compounds in formation waters. This short paper is illustrated by the use of benzene and
dissolved hydrocarbon gas in formation waters as an aid to exploration in the Volgograd Region.

Smalley et al. show how measurements of $^{87}\text{Sr}/^{86}\text{Sr}$ isotope ratios (on residual salts redissolved from cores) can be used to detect potential reservoir flow barriers. The possible heterogeneity in formation water resistivity/salinity is also discussed; this can potentially have a large influence on reserve estimates made from wireline logs.

Philp et al. move the focus of attention to high molecular weight organic compounds (with more than 40 carbon atoms). These are often neglected because they are difficult to analyse. However, as they often precipitate as solids in the reservoir pore space, they can have a serious effect on recovery. Pipes and valves may also be blocked in the well or at the surface. Wilhelms & Larter continue the high molecular weight theme, with a discussion of the tar mats found in marine-sourced oils in the North Sea and North America. Various formation mechanisms are discussed, with the authors favouring those in which tar mats are formed from stable asphaltene precursors. The precursors can be precipitated as tar mats by thermal degradation of a migrating oil (e.g. Ula Field, Norwegian North Sea) or an increase in dissolved gas content (Oseberg Field, Norwegian North Sea). Li et al. describe a study of pyrolic nitrogen compounds in the measurement of approximate migration distances in reservoired oils. The method exploits the differences in relative oil/water fractionation of a family of these compounds. If successfully developed, ‘migration’ parameters could become a valuable new addition to the geochemist’s standard ‘source’ and ‘maturity’ parameters.

**Case studies**

Case studies are important because they let us test our theories against natural systems and provide details of the approach used by oil companies during field development and appraisal.

Two papers make good use of fluid inclusions found in authigenic cements. Inclusions can reveal the fluids present during key stages of reservoir development. By their use, McNeil et al. are able to constrain the temperature and salinity of the fluids responsible for cementation in the Rotliegend Sandstones of the Southern North Sea. The presence of methane in the inclusions shows that cementation occurred predominantly in the presence of gaseous hydrocarbons. Oxtoby et al. present a detailed study of the relative abundances of petroleum-bearing inclusions in cores from the Ula Field of the Norwegian North Sea. They deduce that filling was synchronous with cementation, and they relate the local maxima in petroleum-containing inclusions to the way in which the field filled with oil. The relationship of their work to the variable oil–water contact in Ula is also covered.

Horstad et al. discuss the variations in geochemical properties in a number of fields in the Tampen Spur region of the Norwegian North Sea. They identify five main charging systems, and suggest the presence of an additional carrier bed. This new concept has been tested by two exploration wells, one of which has successfully tested hydrocarbons.

England et al. show how a reservoir simulator can be used to interpret variations in fluid density, which are often observed in oil accumulations. If one can estimate the approximate time available since the reservoir filled, then the strength of internal flow barriers can be estimated. The method is illustrated by a case history from the Forties Field (UK North Sea).

Karlsen et al. present an extensive study of 33 petroleum from the Haltenbanken area of the Norwegian North Sea. They use organic geochemistry to group the oils according to their source rocks, taking maturity into account. Stoddard et al. give a good example of sharp variations in geochemical properties observed in several wells from the Eldfisk Field in the Norwegian North Sea. They relate these measurements on core extracts to barriers located by RFT pressure logging. This gave the authors a chance to test their geochemical discontinuities against the likely position of production barriers. Mason et al. stress the role of biodegradation in their study of Tertiary reservoiroed North Sea oils. The relationship to meteoric water influx and oxygen budget is discussed. Finally Aplin & Coleman show how $\text{H}_2\text{S}$ production can change during the life of a producing field. Geochemical data, including isotopic measurements, were used to shed light on the possible mechanisms involved in this economically important process.

**Discussion**

This book gives a snapshot of academic and industrial reservoir geochemistry. We think that we can detect a growing maturity in this new area of geochemistry. In the future, we expect to see the following trends develop:

1. further comparisons of production data with predictions (e.g. of barriers) made by reservoir geochemistry, which will allow the reliability of geochemical predictions to be tested;
2. the collection of larger datasets and the application of sophisticated statistical analysis in order to identify real groupings and to measure success rates objectively;
(3) increased cooperation between reservoir geochemistry and engineering/modelling disciplines, including the increased application of reservoir flow simulators over geological timescales;

(4) the development of cheaper, faster and novel analytical methods, particularly on core samples (e.g. thermal extraction GC and GCMS, Compound Specific Isotope Analysis);

(5) an increased interest in water/oil/mineral interactions and the relation between organic and inorganic reservoir geochemistry;

(6) further attempts to relate reservoir geochemistry to rock 'wettability' (an important factor in oil recovery).

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References

