Linking Diagenesis to Sequence Stratigraphy: A Better Approach to Unravel and Predict Reservoir-Quality Evolution of Sandstones

Morad, Sadoon[1], Marcelo Ketzer[2] (1) Uppsala University, Uppsala, Sweden (2) PUCRS-Pontifícia Universidade Católica do Rio Grande do Sul, Porto Alegre, Brazil

Linking diagenesis and sequence stratigraphy is proposed here for better elucidation and prediction of the reservoir quality of paralic and shallow-marine sandstones. The employment of this approach is possible because parameters, which are relevant for post-depositional alterations of reservoir quality of sandstones, can be obtained from sequence stratigraphic analyses, i.e. changes in the rates of relative sea level changes and sediment supply. These parameters include: (i) pore-water chemistry (marine, meteoric and brackish), (ii) detrital composition, particularly regarding the proportion of intra-basinal grains (e.g., mud intraclasts, bioclasts, and glaucony), (iii) residence time of sediments under certain geochemical conditions, (iv) amounts and types of organic matter, and (v) degree of bioturbation. Establishment of the links between diagenesis and sequence stratigraphy will thus enhance the assessment and prediction of the spatial and temporal distribution, volume, texture, and composition of the near-surface diagenetic alterations within: (i) lowstand, transgressive, highstand and falling-stage (forced regressive wedge) systems tracts, and (ii) in the vicinity of key sequence stratigraphic surfaces that include marine-flooding surfaces (i.e., parasequence boundaries), transgressive surfaces, maximum-flooding surfaces , and sequence boundaries, because these surfaces record rapid changes in the relative sea level, and hence marked changes in the five parameters outlined above. These near-surface diagenetic alterations will constrain, and thus allow the prediction of reservoir quality evolution pathways of deeply buried sandstones, such as tight gas reservoirs. Integrating diagenesis into sequence stratigraphy can, in some cases, aid stratigraphic correlation and the recognition of major sequence stratigraphic surfaces and eventually systems tracts.

Reservoir Effectiveness Prediction in Palaeozoic Reservoirs of the northern Murzuq Basin, Southwest Libya: An Integrated Approach

Cubitt, Chris[1], Tim Conroy[2], Andrew Buffin[2], Mark Partington[2], Georgia Boyd[2], Stuart King[3], Adel Obeidi[4] (1) Woodside Energy Ltd, Perth, Australia (2) Woodside Energy Ltd, Perth, (3) Woodside Energy (NA) Ltd, Tripoli, Libya (4) Woodside Energy North Africa Ltd, Tripoli, Libya

Reservoir quality prediction and characterisation, is a key risk in the exploration and development of NC210 and NC151 concessions in the northern Murzuq Basin, south west Libya. Outcrop ,wireline, core and cuttings analyses have been integrated to gain an understanding of the geology, petrophysical properties, and ultimately reservoir effectiveness of the Palaeozoic Memouniat, Tahara, Acacus and M'rar formations.

Six hundred metres of core were described and sampled with respect to ichnofabrics, depositional environments and reservoir rock properties. The core based results together with field outcrop observations were then integrated into a sequence stratigraphic framework based on parasequence stacking patterns and stratal surfaces derived from wireline logs. Subsequently geological, models were constructed for each productive unit allowing the reservoir effectiveness of each facies to be modelled and predicted in a “geologically realistic” manner.

Cuttings analysis or “Rock Typing” was then performed on approximately 850m of cuttings over key intervals identified from core analysis. The Rock Typing technique, first described by Sneider et. al. (1983) and Esther et. al. (1984), is a semi-quantitative technique which discriminates rocks into distinct groupings, or “Rock Types” according to key visual attributes.

Having benchmarked the rock typing results against known DST and core based petrology analyses potential flow rate estimates were then calculated using locally derived permeability height/reservoir pressure/flow rate cross plots. From these estimates it was then possible to risk reservoir effectiveness and potential formation deliverability at both a prospect and field scale over the entire NC210 and NC151 concessions.

A New Method for Permeability Prediction in Reservoir Sandstones

Walderhaug, Olav[1], Arild Eliassen[1], Nils Einar Aase[1] (1) Statoil ASA, Stavanger, Norway

Permeability is commonly the critical reservoir parameter for economic production from deeply buried reservoir sandstones. However, permeabilities predicted from permeability versus porosity trends are often highly uncertain as permeability for a given porosity may vary by a factor of up to around ten thousand. Methods for permeability prediction based upon grain size information and the volumes and morphologies of detrital and diagenetic components have also been put forward, but are not easy to use due to the very complex input data required.

We have developed an alternative approach where permeability is predicted with an equation containing only three variables: porosity, grain size, and a packing parameter that tends to remain quite constant within individual sandstone units. Comparison of the packing parameter with mercury injection and petrographic data suggests that the packing parameter reflects the dominant pore throat diameters in the sandstones. Testing of the equation on numerous data sets from the Norwegian continental shelf shows a good fit between measured and calculated permeabilities. Moreover, our experience with the new method shows that being able to focus on only three parameters when evaluating permeability rather than on a large range of petrographic and diagenetic factors, greatly reduces the time and money spent on such studies.

Our work also indicates that, contrary to conventional wisdom, moderate amounts of diagenetic illite do not have a significant impact on permeability. Our results are also consistent with the previous conclusion of other workers that the flow through a sandstone is controlled by an interconnected array of packing flaws surrounding more closely packed domains.

Porosity Preservation by Inhibition of Quartz Cementation: Microquartz Versus Hydrocarbons

Bonnell, Linda[1], Richard E. Larese[2], R. H. Lander[1] (1) Geocosm, Austin, TX (2) Clastic Petrology Consultant, Durango,

CO

Our group has been investigating the influence of hydrocarbons and microquartz on quartz cementation. Both of these factors have been called upon to explain the occurrence of high porosity zones in the Miller Field in the UK North Sea (Marchand, et al., 2000, 2001, 2002 invoke hydrocarbons whereas Aase & Walderhaug, 2005 invoke microquartz). In an independent examination of samples from 4 Miller Field cores, we found that microquartz coated sandstones have significantly lower quartz overgrowth cement than nearby samples lacking such coatings.

To test whether microquartz coatings can inhibit quartz overgrowth development, we used a hydrothermal reactor to induce quartz cementation in Miller Field samples. The samples had both microcrystalline quartz coatings and naked quartz surfaces at grain contact scars. While large quartz overgrowths formed on naked contact scars, surfaces covered by microcrystalline quartz showed only minor growth suggesting that microquartz inhibits "normal" quartz growth because it grows at much slower rates.

To test the potential inhibition of quartz cementation by hydrocarbons, we also conducted quartz growth experiments in the presence of hydrocarbons at varying water saturations. Experiments were conducted at 350°C and 250°C. The 350°C experiments showed a strong dependence between quartz growth rate and water saturation. However, in the 250°C experiments the quartz cementation rate did not decline with decreasing water saturation. We hypothesize that the different results of the 350° and 250° experiments reflect a change in the rate limiting step for quartz cementation between these two temperatures and that the experiments conducted at 250°C are more likely to reflect natural conditions.

Prediction of Mechanical Compaction During Deep Burial

Fisher, Quentin[1], Tony Crook[2], Christine Souque[1] (1) Rock Deformation Research Limited, Leeds, United Kingdom (2) Rockfield Software Limited, Swansea, United Kingdom

Mechanical compaction of siliciclastic sediments is usually thought to be restricted to shallow burial depths. Pervasive mechanical compaction of sand-rich reservoirs involving porosity collapse and grain-fracturing may, however, occur during deep burial resulting in a dramatic reduction in reservoir quality. Reservoirs particularly prone to mechanical compaction are those that have high porosity and medium to coarse grain-size, which become exposed to high mean effective stresses. The requirement of high effective stresses and high porosity means that late stage mechanical compaction is usually confined to reservoirs that are very deeply buried and have been rapidly buried under low geothermal gradients. Diagenetic modelling provides a good indication as to which sandstone reservoirs would be susceptible to mechanical compaction during deep burial. However, the extent of grain-fracturing varies as a function of structural position. Studies of several outcrop examples that have experienced pervasive porosity collapse have shown that grain-fracturing is sometimes more pervasive in tightly folded sandstones than those that show less signs of macroscopic deformation. Here we show how sophisticated geomechanical modelling using a commercial finite element simulator (Elfen) may be used to predict regions within deeply buried reservoirs in which porosity collapse is most likely to have occurred.

Petrographic Characterization of Chemical Reactions in Clastic Diagenesis

Milliken, Kitty[1], Anthony J. Park[2] (1) University of Texas, Austin, TX (2) Sienna Geodynamics & Consulting, Inc, Bloomington, IN

Two classes of diagenetic reactions can be identified, based on a constellation of petrographic characteristics. Reaction rate-limited processes (including precipitation of authigenic phases and dissolution of detrital phases) are volumetrically significant and at the microscale show significant evidence of nucleation difficulty and restriction of reaction to highly specialized sites. At larger scales the products of these reactions have spatial distributions that are prominently governed by temperature. Within very broad limits, individual reactions of this type can be described using empirical kinetic rate laws, without reference to other simultaneously occurring reactions. In contrast, transport-limited minerals are typically cements that are volumetrically less significant than the products of reaction-limited reactions and do not exhibit any strong thermal controls on their spatial distribution. Instead, transport-limited minerals reflect local variations in solutes, and thus require the use of kinetic reaction rate laws combined with a description of transport phenomena in order to describe or predict their behavior.

The validity of this petrography-based but phenomenology-descriptive model is tested using a quantitative model Balance that implements kinetic and thermodynamic reactions, advective and diffusive mass-transfer processes, and a dynamic texture model. The model is applied to sediments of the Gulf of Mexico sedimentary basin, for which an extensive database of petrographic and chemical analyses is available. The results show coherent and consistent trends between petrographic observations and simulation predictions, and suggest extensive mass exchanges between shales and adjacent sandstones.

Reservoir Quality Controls in Permo-Carboniferous Sandstones of Saudi Arabia

Franks, Stephen G.[1], William J. Carrigan[1] (1) Saudi Aramco, Dhahran, Saudi Arabia

Deep Permo-Carboniferous sandstones (Unayzah Reservoir) of Saudi Arabia contain large reserves of sweet natural gas. The reservoirs consist of sandstones and siltstones deposited over a 40-50 million year period in a variety of environments as the Arabian Plate moved from high to low latitudes: periglacial aeolian and fluvial, hot-arid aeolian, hot-humid marginal marine. Stratigraphy is complex, correlation is difficult, and reservoir quality prediction is uncertain at best.

Porosity and permeability vary significantly at all depths of burial. Plots of thousands of core plug data, however, suggest two end-member trends. One trend is dominated by coarser, relatively clean sandstones variably cemented with quartz overgrowths. A second trend consists of finer, more feldspathic sandstones dominated by diagenetic fibrous illite. For any given porosity, permeability is typically an order-of-magnitude (or more) greater in the quartz trend than in the illite

trend. Therefore, interpretation of seismic or log porosity signatures requires additional information to ascertain whether the porosity is accompanied by sufficient permeability to be productive.
Fluid inclusion analysis combined with kinetic modeling help constrain timing of quartz cementation, and by inference, timing of illite cementation. Although there is evidence of early hydrocarbon charging, no examples of hydrocarbon-preserved porosity have been identified. Anomalously high porosity and permeability are instead due to early grains coats (either clay or microquartz) associated with pedogenesis. Pedogenesis also destroys reservoir quality below thick soil horizons where infiltrated (illuviated) clays and oxides plug porosity for ten's of feet in dune and fluvial sandstones that otherwise would have been excellent reservoirs.

A Model for Fibrous Illite Nucleation and Growth in Sandstones

Lander, R. H.[1], Linda Bonnell[1] (1) Geocosm, Austin, TX

We have developed a model for the formation of fibrous illite in sandstones based on the kinetics of crystal nucleation and growth which, in turn, are controlled by temperature and supersaturation state. Nucleation occurs on pore walls and micaceous materials are considered to be favorable substrates. Reactants include kaolinite and, optionally, K-feldspar. Particle dimensions are tracked through geologic time as are K-Ar dates and $\delta^{18}O$ values. The model is integrated with Touchstone's compaction, quartz cementation, microporosity, and permeability models.
We tested the model on quartzose Jurassic sandstones from offshore Norway and on lithic Miocene sandstones from offshore southeast Asia. Maximum sample temperatures from basin modeling range from 108-172 °C and 154-173 °C, respectively. We assumed Al and K mass balance on the thin section scale with kaolinite and K-feldspar reactants and that the saturation state is controlled by equilibrium with these phases and quartz. The model generally matched measured illite, kaolinite, and K-feldspar abundances in both datasets using identical model parameters other than the temperature histories and the compositions and textures of the host sandstones.
Predicted illite K-Ar dates for the Norway samples are within the published range of ~30-60 Ma for samples in the region with comparable maximum temperatures. Although no illite particle size data are available from the analyzed samples, modeled crystallite thicknesses are comparable to published values of ~40-120 Å from Jurassic North Sea samples with similar temperature histories.
Predicted illite K-Ar dates for the southeast Asia dataset trend with the measured values of 7-14 Ma but are 2-4 m.y. too young. The model results, however, are comparable to the measurements if it is assumed that minor detrital contaminants are present in the analyzed samples. Calculated $\delta^{18}O$ values are within 1□ of the measured values assuming a constant water value of □4□$\delta^{18}O$ SMOW.

Diagenetic Mineral Reactions Related to Hydrocarbon Migration as a Tool in Deep Clastic Reservoir Prediction – Evidence from Permian Red Bed Reservoirs of the Central European Basin System

Gaupp, Reinhard[1], Robert Schöner[2] (1) University Jena, Jena, Germany (2) Friedrich-Schiller-University Jena, 07749 Jena, Germany

Red bed sandstones are important hydrocarbon reservoirs worldwide. In sedimentary facies types with high primary porosity and permeability, diagenetic processes are major control of reservoir properties during deep burial. Organic rich fluids, which may have positive and/or negative effects on reservoir properties, are omnipresent in areas where one prospects for oil and gas reservoirs. To evaluate the importance of organic maturation products during clastic diagenesis, we compared the diagenetic evolution of deeply buried Permian red bed sandstones from areas with and without hydraulic contact to hydrocarbon source rocks in the Central European Basin System. The comparative study of petrography, authigenic mineral chemistry, burial and thermal evolution of reservoir and source rocks suggests that major diagenetic processes are controlled or at least influenced by organic maturation products. Important diagenetic features are spatially related to the presence of maturing hydrocarbon source rocks: the bleaching of red beds, major dissolution events, pervasive illite/chlorite formation, impregnation of pore surfaces with bitumen and formation of late Fe-rich cements. The spatial coincidence of these processes, their timing with respect to organic maturation and the presence of paleo oil (bitumen) suggests that they trace paleo hydrocarbon migration pathways. Cementation patterns can be strongly reorganized in areas affected by hydrocarbon fluids. Other deep basinal compartments, which were not in hydraulic contact to organic rich source rocks, often preserve relatively early burial cements. Combination of 3D-seismic data with conceptual models of HC migration related pore space modification is an aid in reservoir quality prediction.

A Multiple Model Technique for Evaluating the Potential Hydrocarbon Volumes and Risk of an Exploration Prospect

Swarbrick, Chris F.J.[1], Rob S. Kimmel[1], Steve D. Jenkins[1], Peter Leiggi[2], Paul M. Harris[3] (1) Tengizchevroil LLP, Atyrau, Kazakhstan (2) Chevron Energy Technology Company, San Ramon, CA (3) Chevron Energy Technology Company, San Ramon,

Potential hydrocarbon volumes and geologic risk of an exploration prospect are usually assessed using a single geological model describing the likely structure, reservoir, seal and hydrocarbon charge. However a single model may not adequately capture the wide range of alternate models which could exist within the constraints of the available data. Although the probability of these other models occurring may be relatively small, their impact on the probabilistic distribution of potential hydrocarbon-in-place volumes may be significant.
To assess potential hydrocarbons volumes and geologic risk of a Paleozoic carbonate buildup in the southern Pricaspian Basin, Kazakhstan, suites of conceptual reservoir and seal models were developed to adequately depict the spectrum of potential scenarios which could exist within the data constraints. The workflow consisted of 1) estimation of the probabilities for each reservoir and seal model, 2) calculation of volumes for each reservoir-seal combination, and 3) generation of a cumulative probability curve relating resource volumes to their probability of occurrence. Model

probabilities were also used to calculate the appropriate geologic risks for reservoir and seal failure.

We found the multiple model technique to be very effective in capturing, evaluating and ranking a wide range of geologic concepts and divergent expert opinions. The technique has the additional advantage that the calculated risk incorporates most possible outcomes, not just the risk associated with a single geologic model. We believe the multiple model technique can be applied to other prospects which have a wide range of geologic outcomes for two or more key play elements.