



Reservoir Compartmentalization

5-6 March 2008

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Wednesday 5 March	
08:30	Registration and coffee
09:00	Welcome and opening
Session 1 Introduction: impacts & approaches (Chair: Steve Jolley)	
09:10	Mike Bowman (BP) <u>KEYNOTE</u> : Tackling the challenges & minimizing the impacts of compartmentalization on reservoir performance
09:40	Mark Bentley (TRACS) <u>KEYNOTE</u> : Reservoir compartments: beyond fault seal
10:10	Tea / Coffee
Session 2 Detection I - fluids & pressures (Chair: Quentin Fisher)	
10:40	Craig Smalley and Ann Muggeridge (BP) <u>KEYNOTE</u> : Reservoir Compartmentalization: Get it Before It Gets You
11:10	Caroline E Gill, Mike Shepherd & John J Millington (Shell) Compartmentalisation from Chemistry: New Insights into the Nelson reservoir from produced water sample analysis
11:30	E Chuparova, T Kratochvil, J Westrich, C Guillory, J Bikun, J Kleingeld, A Kornacki (Shell) Integration of Time-Lapse Fluid Geochemistry, Well Logging and Seismic to Monitor Reservoir Connectivity
11:50	Rachel H Páez, John Lawrence, Herb Hyatt, Adam Bucki (ExxonMobil) Changes in Fluid Density: Different Compartments or Gravity Segregation? Understanding Compartmentalization in Near-Critical Fluids
12:10	H Justwan, K Petersen, S Dreyfus, S Rochford (ExxonMobil) Characterization of Static and Dynamic Reservoir Connectivity for the Ringhorne Field through Integration of Geochemical and Engineering Data
12:30	General Discussion
12:40	Lunch
Session 3 Detection II - pressures & 4D integration (Chair: Steve Jolley)	
13:40	Jan Einar Ringås, Torbjørn Skille, Eirik Vik and Hans Borge (StatoilHydro & Sintef Petroleum Research) The Smørbukk Field – compartmentalized before the production start-up. What happened?
14:00	Stephen A O'Connor, Richard E Swarbrick, Phillip Clegg & David T Scott (GeoPressure Technology Ltd) Vertical and lateral seal efficiency: controls on pressure and fluid distribution, Halten Terrace, offshore Mid-Norway

14:20	R S J Tozer and A M Borthwick (BP) Variation in fluid contacts in the Azeri Field, Azerbaijan: sealing faults or hydrodynamic aquifer?
14:40	Thomas Røste, Jorunn Tyssekvam, Anita Moen, Kristina Rigland, Guillaume Lescoffit, Kjell Johan Rosvoll, Ola Skjæveland, Tone Endresen, Vidar Hauge (StatoilHydro) The benefits of using 4D seismic for optimizing infill wells placement in a compartmentalised reservoir – Cases from the Heidrun field
15:00	Mirosław Gainski, Paul Freeman, Alan MacGregor and Ferry Nieuwland (BP) The Schiehallion Field: Detection of reservoir compartmentalisation and identification of new infill targets using 4D seismic surveys and dynamic production data
15:20	General Discussion
15:30	Tea / Coffee
Session 4 Stratigraphic Compartmentalization (Chair: Bruce Ainsworth)	
16:00	Bryan Bracken (Chevron) <u>KEYNOTE</u> : Techniques in Defining Siliciclastic Reservoir Architecture and Compartmentalization: Short-Comings and Opportunities
16:30	Tom McKie, Mette Kristensen and Steve Jolley (Shell) Stratigraphic and structural compartmentalization in the Triassic Heron Cluster reservoirs, Central North Sea
16:50	Fawke, A, Hansen, B H, Høias, A, Samuelsen, B T, and Walker, R (StatoilHydro) An integrated approach to understanding the stratigraphic heterogeneities and structural compartmentalisation of a lower coastal plain reservoir in the Norwegian Sea
17:10	Erik Scott, Francois Gelin, Tim Goodall, Ed Perry, Else Leenaarts, Simon Gould, Dave Bateman, Steve Jolley (Shell) Sedimentological control of fluid flow in the Forties Sandstone Member, Pierce Field, Central North Sea, UK
17:30	General Discussion, notices/instructions
18:00	Wine Reception

Thursday 6 March	
08:30	Registration and coffee
08:50	Re-connect
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09:00	Graham Yielding, Peter Bretan, Bret Freeman (Badley Geoscience Ltd) <u>KEYNOTE</u> : The Dark Art of 'Fault Seal Calibration' – a review
09:30	Francesco V Corona, J Steve Davis, Susan J Hippler, and Peter J Vrolijk (ExxonMobil) Multi-Fault Analysis Scorecard: Success of Stochastic Approach in Fault Seal Prediction
09:50	R W Krantz, D L Van Nostrand, P S D'onfro, J Deprang, P Jonklaas, K H Northey, P J Perfetta, T L Campbell and L H Wright (ConocoPhillips) An Integrated Approach to Characterizing Faults at Kuparuk Field, Alaska: the Key to Maximizing Reserve Depletion
10:10	Mark Reynolds and Sylvie Delisle (Total) Fault Zone Property Calibration: A North Sea Case Study
10:30	Silje S Berg, Eirik Vik, Tor Anders Knai, & Jan Einar Ringås (StatoilHydro) Fault parameter uncertainty in reservoir models: ranking effects of parameters on flow response in a history matched dynamic model
10:50	General Discussion
11:00	Tea / Coffee
Session 6 Multi-component Compartmentalization (Chair: Peter Vrolijk)	
10:30	Joseph Hovadik & David K. Larue (Chevron) <u>KEYNOTE</u> : Structural and Stratigraphic Controls on Reservoir Connectivity
12:00	Bruce James, Wayne Bailey, Andrew Murray, and Trey Meckel (Woodside) Reservoir Connectivity at the Sunrise Giant Gas Field: A Multifaceted Study
12:20	Bill Richards, Peter Vrolijk, John Gordon, Brent Miller (ExxonMobil & Petro-Canada) Reservoir Connectivity Analysis of a Complex Combination Trap: Terra Nova Field, Jeanne d'Arc Basin, Newfoundland, Canada
12:40	M E Meurer, J C Burger, S K Oppert, P J Vrolijk, J W Snedden (ExxonMobil) Fault impact on sweep patterns: Predicting effective cross-fault connections and comparing with 4D saturation change
13:00	General Discussion
13:10	Lunch

Session 7 Modelling (Chair: Mark Bentley - TBC)	
14:10	Tom Manzocchi, Andrew Heath, Bala Palananthakumar, Conrad Childs and John Walsh (FAG, UC Dublin) KEYNOTE: Sensitivity of petrophysical and geometrical fault representation on field production – a comparative study
14:40	S D Harris, R J Knipe, S Freeman, Z Khatir, A Brown, R K Davies and A Li (RDR Ltd) The influence of fault geometric and property uncertainty modelling on reservoir compartmentalisation
15:00	Ron D Thompson, Yongshe Liu, Peter D’Onfro (ConocoPhillips & Stanford University) Fault Property Modelling and Impact on Fluid Flow
15:20	Alan Irving¹, Emmanuel Chavanne², Vincent Faure³, Philippe Buffet³, Eurico Barber³ (¹Total E&P UK, Geoscience Research Centre, ²Total SA, Geoscience Technologies, ³Total E&P UK) An uncertainty analysis workflow for structurally compartmentalised reservoirs
15:40	General Discussion / Debate “Reservoir Compartmentalization” (Chair: Convenors)
16:40	Final Wrap-up and Notices

Posters
<p>Victor Bense, Mark Person, Peter Sauer, Niel Plummer, Nils Cremer and Stefan Simon (University of East Anglia; Indiana University; US Geological Survey & Erftverband) Aquifer compartmentalization in the Lower Rhine Embayment, Germany</p>
<p>Glenn W Davies and Mike Tohill (BP) The Use of Pre-Production Data to Assess the Risk of Reservoir Compartmentation in a Deep Marine Turbidite Reservoir</p>
<p>J Steve Davis, Francesco V Corona, Peter J Vrolijk and Susan J Hippler (ExxonMobil) The Impact of Structural and Stratigraphic Uncertainty in Fault Seal Analysis</p>
<p>D Duggan, D Waltham, M Krus and S Maclean (Midland Valley Exploration & Royal Holloway University of London) Compartmentalized reservoirs – modelling stacked turbidite flows and the effect on the formation of petroleum reservoirs</p>
<p>Giger, S, Clennell, B, Beekman, F, Wassing, B B T, van Wees, J D and ter Heege, J H (CSIRO Petroleum & TNO-NITG) Factors influencing the formation of clay smears and associated changes in fluid transport properties across fault zones – an integrated numerical and experimental study</p>
<p>Ilsa M Kerscher, Francesco V Corona, Susan J Hippler and Charles W Kiven (ExxonMobil) Multi-fault Analysis Success Story - Total Pay Prediction in a Mature Field: An Example from South Texas, USA</p>
<p>Sofie Nollet, Steffen Giese, Gisa Kleine Vennekate, Janos Urai and Peter Vrolijk (ExxonMobil & RWTH Aachen) Finite element modeling of faulting in sand-clay layered sequences</p>
<p>Matthew Pachell, Bob Quartero, Ross Deutscher and Justin Forai (Talisman Energy) Contractional Tectonics and Reservoir Connectivity: A Case Study from the Bighorn Gas Field of West Central Alberta</p>
<p>Elodie Sallet and Christopher Wibberley (UMR CNRS Valbonne & Total) Evolution of brittle deformation and fault growth in high porosity sandstone: the Bassin du Sud-Est, Provence, France</p>
<p>Schueller S, Braathen A (Centre for Integrated Petroleum Research, University of Bergen) Statistical distributions of deformation bands and organization of fault damage zones in siliciclastic reservoirs</p>
<p>Wilfrido Solano-Acosta, Andrew R Thomas, Robert Lander, Robert M Reed and Marek Kacwicz (Chevron; Geocosm Ltd & University of Texas at Austin) Quantitative Modeling of Quartz Cementation along Cataclastic Fault Zones, Offshore Louisiana, Gulf of Mexico</p>
<p>Larry Sumpter, Kenneth Petersen, John Snedden, Mike Sweet and Peter Vrolijk (ExxonMobil) Early Recognition of Potential Reservoir Compartmentalization</p>
<p>J Underschultz, J Strand, P Bretan, B Freeman and G Yielding (CSIRO Petroleum & Badley Geoscience Ltd) Across-Fault Seal Capacity Calibration between different aquifers</p>
<p>Boyan K Vakarelov and R Bruce Ainsworth (University of Adelaide) Are Ancient Shallow Marine Stratigraphic Models Oversimplified? Potential Compartmentalization Lessons from Holocene Regressive Systems</p>
<p>F F N van Hulten (Energie Beheer Nederland B.V.) Geological factors influencing compartmentalization of Rotliegend gas fields in the Netherlands</p>
<p>J P Wonham, M Cyrot, T Nguyen, J Louhouamou and O Ruau (Total) Integrated Approach to Geomodelling and Dynamic Simulation in a Complex Carbonate Reservoir, N'Kossa field, offshore Congo</p>

Session 1

**Introduction: impacts &
approaches**

Chair: Steve Jolley

Tackling the challenges & minimizing the impacts of compartmentalization on reservoir performance

Dr Mike Bowman, Head of Discipline Appraisal & Pre Development, BP Exploration, Houston, Texas, USA

As an industry we have been poor at identifying and predicting the effect of reservoir compartmentalization on fluid flow throughout field life. In the context of harder to find reserves and rising development costs it is vital to have a well-rounded strategy in-place. One of today's challenges is to improve our predictive capability of compartmentalization. There are many situations where compartmentalization unexpectedly impacts development; we still have some way to go before we have work flows and practices that enable consistent prediction of the impact of faults, fractures, stress and other reservoir heterogeneities ahead of the drill bit.

Historically we have relied too heavily on 'single complex' linear modeling approaches to understand the impact of compartmentalization. We are now beginning to place greater emphasis on dynamic signals from production data. Evidence is mounting that as fields deplete they evolve mechanically over production time scales leading to changes in fault behaviour, stress configuration, compaction and compartmentalization; commonly not predicted at start-up. Our challenge is to develop workflows which integrate an appropriate range of geological models coupled with dynamic data, combining these with analytical approaches to enable real-time updates of the evolving reservoir & fluid system to improve our models and their predictive power. This will enable more informed decisions at every stage of field life.

A number of examples will be described from the BP portfolio to illustrate some of the approaches being used to capture and model subsurface response.

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Reservoir compartments: beyond fault seal

Mark Bentley, TRACS International, Aberdeen, Scotland

Suspicion of reservoir compartmentalisation often leads naturally to a discussion of faults and fault seal, particularly in clastic reservoirs and especially when sub-seismic faulting is anticipated. Although this discussion is important (understanding fault seals is as complex as it is significant for forecasting performance) it is only part of a broader picture and over-enthusiasm for structural solutions to compartmentalisation may cause a broader, more correct solution to be missed.

This introduction offers a broad technical template for viewing reservoir compartmentalisation - context for thought as the conference papers unfold. The template has three aspects: one capturing generic compartment types, one distinguishing probabilistic from deterministic description of those types and one involving time.

Generic classification can be divided neatly into structural, stratigraphic and diagenetic phenotypes. Structural compartments encompass faulting and fault seal, further understanding on which comes from unravelling fault seal processes and intertwining these with fault network geometries. Stratigraphic compartments may be as simple as reservoir/non-reservoir layering or as subtle as sand connectivity in low net-to-gross systems. Diagenetic compartments may run disconformably across structural and stratigraphic boundaries and are arguably have been best appreciated by carbonate sedimentologists or groups working in low permeability reservoirs. Combinations of these phenotypes, convolved with differing significance for different fluid fills completes the descriptive picture.

The second aspect concerns how we understand and model this collection of compartmentalising phenomena. Can we describe them largely deterministically, as we would need to for the planning of a single well, or are these features which require probabilistic prediction? A woefully incomplete reservoir description emerges from a tendency to take an either/or approach to deterministic and probabilistic features. A good example in the structural field comes from an analysis of fault seal mechanisms on an interpreted fault network (deterministic) without consideration of the (probabilistic) sub-seismic fault population. In the stratigraphic field a comparable example would be simple percolation theory, which predicts critical levels of net sand presence, below which compartmentalisation will occur. On a first pass, these levels can be simply calculated assuming a random distribution of net; adding deterministic sand correlations suppresses the net sand level at which compartments occur. In this case the interpreted degree of compartmentalisation links directly to the degree of deterministic interpretation.

The third aspect is time, as a change in reservoir pressure or reservoir fluid type during the field life cycle may cause the emergence of reservoir compartments where previously there were effectively none (or visa versa).

It is argued here that a positive outcome in the description of reservoir compartments not only needs to look beyond the issue of fault seal to build a broader description integrating with the other causes of reservoir compartmentalisation, it also needs an appreciation of which aspects of this broad picture can be described deterministically and which should be described probabilistically. Add in the dimension of time and these compartments become dynamic features, changes in which need to be predicted.

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Session 2

Detection I - fluids &
pressures

Chair: Quentin Fisher

Reservoir Compartmentalization: Get it Before It Gets You

Craig Smalley and Ann Muggeridge, BP Exploration and Production

Reservoir compartmentalization caused by sealing faults or depositional discontinuities can have an adverse effect on oil or gas recovery factors by reducing the efficiency of drainage (connectedness to a producing well) and sweep (between injectors and producers). Many under-performing field developments have had unidentified (or under-estimated) compartmentalization as a root cause. Thus it is vital to characterize reservoir compartmentalization as early as possible in field life, ideally during appraisal, before truly diagnostic dynamic data become available.

One early sign of compartmentalization is disequilibrium in the fluid system in different parts of the reservoir, recognized by variations in pressure, fluid contacts and fluid chemical or physical properties. However hydrocarbon reservoirs are dynamic on a geological timescale: some reservoirs are still filling and others may not yet have had sufficient time to settle back to equilibrium. In order to get maximal quantitative information from a suite of compartmentalization indicators, it is necessary first to appreciate the time scales for each property to revert back to equilibrium. Without this understanding it can often appear that some data are contradictory, leading to valuable data being excluded as apparently unreliable.

This paper quantifies the interplay between fluid properties (density, viscosity), sizes of compartments (length scale) and fluid equilibration processes (flow driven by pressure or density differences, diffusion) to reveal which combinations of indicators may be suited to different types of reservoirs over different timescales. Use of analytical models, calibrated against numerical simulations, has revealed some overall patterns, independent of equilibration process, from which rules-of-thumb can be derived that enable different types of data to be integrated, giving a more reliable and quantitative prediction of compartmentalization.

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Compartmentalisation from Chemistry: New Insights into the Nelson reservoir from produced water sample analysis

Caroline E Gill, Mike Shepherd & John J Millington, Shell UK Exploration and Production, Aberdeen

The Nelson Field is located in blocks 22/11, 22/6a and 22/12a in the UK Central North Sea. Nelson is a simple dip closed structure and is one of a series of Paleocene Forties Sandstone Member oil accumulations on the Forties Montrose High. The Nelson Field has been in production for over 12 years. As the field matures the focus for well location has shifted to more detailed analysis of a multidisciplinary dataset using a variety of conventional and original methods. This project has been termed the Nelson LTRO project: Locate The Remaining Oil. The principal aim of the Nelson LTRO project is to identify oil accumulations that will be left behind in the reservoir given the current development plan. One facet of the project is the use of produced water chemistry samples in order to further understand connectivity in the different parts of the Nelson reservoir.

Step changes in formation water composition can be used as indicators of reservoir compartmentalisation and to distinguish laterally restricted and laterally extensive shales, both in the oil and water leg (Smalley et al., 1995). The Nelson Field shows variation in chloride ion concentration both vertically and laterally within the reservoir. Vertical variation can be detected by changes in produced water chemistry after water shut off events at known laterally extensive shale horizons. Lateral variation can be detected by variation between macrofacies on a fieldwide scale.

The observed variations in chloride ion concentration suggest that there is a level of compartmentalisation both laterally and vertically within the Nelson Field which has restricted pore water mixing on a geological timescale. These discrete formation water chemistry signatures as characterised by chloride ion concentration variations may reflect discrete cells the boundaries of which are baffles or barriers to hydrocarbon flow. As such, the baffles or barriers are likely to prevent migration of hydrocarbons and are important in identifying flow zones within the field.

Smalley, P.C., Dodd, T.A., Stockden, I.L., Raheim, A. & Mearns. 1995. Compositional heterogeneities in oilfield formation waters: identifying them, using them. *Geological Society Special Publication 86*.

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Integration of Time-Lapse Fluid Geochemistry, Well Logging and Seismic to Monitor Reservoir Connectivity

E Chuparova, T Kratochvil, J Westrich , C Guillory, J Bikun, J Kleingeld, , A Kornacki

The paper will present two case studies in Auger Blue and Auger Pink reservoirs, deep water Gulf of Mexico (DW GOM), to illustrate the integration of several time-lapse (4D) techniques to monitor dynamic reservoir connectivity. Time-lapse geochemistry, pulsed neutron logging (PNC) and seismic provide information of different nature and at different scale, which when integrated allow for higher level of confidence and better optimization of reservoir management decisions to be made.

Time-lapse geochemistry results are based on sets of fluid samples collected pre-production and over a period of up to eight years of production. Results from several time-lapse pulsed neutron logs and seismic surveys pre-production and at different stages of production will be discussed. Auger Pink is a compositionally graded reservoir, and the integrated time-lapse approach will illustrate complex drainage pattern and fluid compositional characteristics. Auger Blue case study will illustrate evidence for dynamic communication and drainage between different reservoirs, starting after five years of production.

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**Changes in Fluid Density: Different Compartments or Gravity Segregation?
Understanding Compartmentalization in Near-Critical Fluids**

Author: Rachel H Páez, ExxonMobil Production Company

Co-Authors: John Lawrence, ExxonMobil Upstream Research Company (Reservoir Engineering), Herb Hyatt, ExxonMobil Development Company (Reservoir Engineering), Adam Bucki ExxonMobil Exploration Company (Geophysical Applications)

The maturing business landscape in West Africa as led to different questions regarding fluid predictions. Initial business focus on finding “oil” has evolved into finding hydrocarbon “commodity.” Infamous predictions of “Oil versus Gas” have evolved into predicting “Dual phase versus single phase (or anything in between!).” There is no silver bullet to fluid predictions; technology has evolved and the integration of geoscience with reservoir engineering is as critical in an exploration scale as a production scale in assessing the full value of deep-water hydrocarbons. On the exploration scale, where there is limited data to determine reservoir compartments, near-critical fluids are particularly challenging to predict. Appropriate capture of the range of possible outcomes, rather than deterministic scenarios, in fluid prediction are as critical as reservoir properties such as thickness, NTG, or porosity and have a direct impact on interpretations of reservoir connectivity. Within a 850 m window of burial, oils can have a range of 350 scf/stb to 2800 scf/stb and condensate yields can vary from quite dry at bbls/mcf to single phase condensates with up to 200 bbls/mcf.

Density differences between condensates and volatile oils are minor as fluids fluctuate in temperature or pressure within the hydrocarbon column. This poses a challenge to seismically-based methods to predict ‘gas’ vs ‘oil.’ Interpretations of reservoir connectivity hinge on understanding the phase relationship of the reservoir fluids. A key factor in successful predictions is understanding pressure regime of target reservoirs, and tying the range of fluid properties in with the range of rock properties to ground truth with the seismic to eliminate scenarios.

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Characterization of Static and Dynamic Reservoir Connectivity for the Ringhorne Field through Integration of Geochemical and Engineering Data

¹H Justwan, ¹K Petersen, ¹S Dreyfus, ²S Rochford

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²ExxonMobil Exploration and Production Norway AS, Sandnes, Norway

The Ringhorne Field, located in the Norwegian South Viking Graben, is producing oil from the Early Jurassic Statfjord Formation and the Paleocene Ty Formation. Analysis of reservoir pressures and PVT data suggested limited inter-compartment oil leg communication already during the exploration and appraisal phase. An integrated study was initiated in order to assess the connectivity of fluids in the potential reservoir compartments at Ringhorne.

Pre-production water and oil samples have been analyzed by ion chromatography, high resolution gas chromatography, mass spectrometry, as well as a novel trace metal technology. Integration of detailed geochemical data with engineering data such as pressure and bulk fluid properties allowed the establishment of a reservoir charge model and a static reservoir compartmentalization model. Routine sampling and analysis of produced oil and water samples and integration with production pressure data and fault transmissibility modeling allows the evaluation of dynamic reservoir connectivity within the oil and water legs.

All gathered static data suggest that there are four separate fluid compartments at Ringhorne. The time-lapse geochemistry data collected to date further suggest that fluid communication is limited on a production time-scale. Time-lapse water data are also used to determine water injection efficiencies and communication within the water legs of the compartments.

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Session 3

**Detection II - pressures & 4D
integration**

Chair: Steve Jolley

The Smørbukk Field – compartmentalized before the production start-up. What happened?

Jan Einar Ringås¹, Torbjørn Skille², Eirik Vik¹ and Hans Borge³

¹StatoilHydro ASA, Research Centre Trondheim, Trondheim, Norway

²StatoilHydro ASA, Stjørdal, Norway

³Sintef Petroleum Research, Trondheim, Norway

Exploration and appraisal wells on the deeply buried Smørbukk Field, offshore Mid-Norway indicated a strongly segmented field, both stratigraphically and laterally. Some thin reservoir zones indicated from geochemical analysis lateral communication, but having different hydrocarbon-water contacts and varying water pressure gradients. Mapped faults were therefore extended below seismic resolution in order to separate the field into static pressure segments.

Following the production start-up, pressure responses due to production were observed in wells located in segments supposed to be isolated from the production wells. These observations triggered the idea of a possible hydrodynamic pressure regime resulting in a tilted hydrocarbon-water contact across the field. A semi-regional pressure simulation study based on the overpressure distribution showed that large amounts of formation water flow through the Smørbukk area today. The modelled fluid fluxes could explain the observed differences in hydrocarbon-water contacts, and thereby a tilt towards the north eastern part of the field. Later production drilling has confirmed deep hydrocarbon-water contacts in the north eastern part.

A study of a production test performed in an appraisal well located in the southern part of the field indicated extensive lateral communication northwards within a thin reservoir zone. A re-entry into the appraisal well confirmed pressure communication to the production wells. A decision was therefore made to connect this appraisal well to a gas injection template.

An improved understanding of the hydrodynamic pressure regime in the Smørbukk area thus helped us in 1) predict deep contacts in the north eastern part of the field and 2) improve the drainage strategy of thin reservoir zones.

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Vertical and lateral seal efficiency: controls on pressure and fluid distribution, Halten Terrace, offshore Mid-Norway

Stephen A O'Connor, Richard E Swarbrick, Phillip Clegg & David T Scott, GeoPressure Technology Limited, Durham, UK

In the Halten Terrace area, fault activity significantly affects the Jurassic (and Triassic) strata and appears to be the dominant control on the distribution of overpressures into discrete pressure cells. However, the integration of pressure data and regional mapping has identified pressure compartments that vary both laterally across the area and also vertically. The intertidal Lower/Middle Jurassic Bat and Fangst Group reservoirs show evidence of increases in overpressure with depth as well as decrease (or reversals), implying preferential pressure loss in certain reservoir units. Some of the pressure cells have systematic overpressure variation across them, implying hydrodynamic fluid flow within cells where faults are also acting as baffles. When pore pressures are high, all Jurassic reservoirs are at similar pressure in the cell, implying that in these areas fault seal capacity is high.

What emerges is a more complete understanding of the role of vertical and lateral seals and their control on the distribution of pressures and fluids in the Halten Terrace area. The implications are significant in terms of the up-dip migration of hydrocarbons, the trapping potential of faults and the potential for tilted hydrocarbon-water contacts.

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Variation in fluid contacts in the Azeri Field, Azerbaijan: sealing faults or hydrodynamic aquifer?

R S J Tozer, A M Borthwick, BP Exploration & Production, Sunbury on Thames, UK

The Azeri Field in the South Caspian Sea, offshore Azerbaijan, is a periclinal anticline 20 km in length containing multiple stacked reservoirs of Pliocene age. Appraisal wells that were drilled at the eastern end of the structure identified multiple oil-water contacts and fluid pressure gradients in both of the principal reservoirs, the Pereriv B and D. At the time, these data were interpreted to indicate the local presence of compartments at the eastern end of the field as a result of sealing faults within the aquifer. This local compartmentalisation seemed to be in marked difference to the majority of the field where pressure connectivity had been observed.

A new analysis of the pressure data shows that aquifer pressures at sea level datum define a simple water potential gradient for both the Pereriv B and D. As a result of this, the oil-water contact in both reservoirs is gently inclined towards the NNE. The precise inclination and orientation of the oil-water contact for each reservoir has been determined geometrically using free-water level and oil-water contact coordinates from around the field, and the inclined oil-water contact for the Pereriv B provides a good fit to the observed contact determined from seismic amplitudes. The new analysis provides confidence that the reservoir is less likely to be compartmentalised due to faulting, and consequently the conceptual geological model for the eastern end of the field is now more consistent with the observations made in the rest of the field.

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The benefits of using 4D seismic for optimizing infill wells placement in a compartmentalised reservoir – Cases from the Heidrun field

Thomas Røste, Jorunn Tyssekvam, Anita Moen, Kristina Rigland, Guillaume Lescoffit, Kjell Johan Rosvoll, Ola Skjæveland, Tone Endresen, Vidar Haugse - Heidrun Petek, StatoilHydro

Contact author: Thomas Røste, thros@statoilhydro.com

Heidrun is an oil and gas field located on the Halten Terrace, in the Norwegian Sea. The reservoir is compartmentalised by a complex network of faults associated with several stratigraphic barriers. Forecasting the drainage pattern of the different reservoir compartments has proven difficult, as communication across segment bounding faults and across the stratigraphy can be hard to predict. This is one of the key uncertainties when choosing infill wells locations.

Seismic monitoring has therefore become an important part of the reservoir management plan on the Heidrun field. Several time-lapse repeated seismic surveys have been acquired using Q-marine technology. The uppermost reservoirs on the south flank have been seismic monitored in 2001 and 2004 with great success. In 2006, the entire field was covered for the first time, including all the reservoir formations. The repeatability is quite high and time-lapse inversion has become an important interpretation tool; clear 4D effects have been mapped in large parts of the field.

Recent work on wells in planning phase has proven the interest of 4D at a rather fine scale (500 m or so). Examples from two well planning processes will be shown.

The first example will look into the placement of a producer that was relying on pressure support from an existing water injector. Measurements in a neighbour well showed no pressure increase in the actual injection interval. Interpretation of 4D data has allowed us to identify a possible water flow in shallower layers and helped us to understand the fluid movement across neighbouring faults. This was valuable in terms of well placement and economic forecasts.

The second example will look at fluid front movement within a reservoir compartment, and how this can help interpreting intra-segment faults.

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The Schiehallion Field: Detection of reservoir compartmentalisation and identification of new infill targets using 4D seismic surveys and dynamic production data

Mirosław Gainski, Paul Freeman, Alan MacGregor and Ferry Nieuwland, BP Exploration, Aberdeen, UK

The Schiehallion oil field lies in water depths of up to 500m and is situated on the United Kingdom continental shelf some 200km west of the Shetland Islands. Schiehallion was discovered in late 1993. Production started in 1998. The current development scheme totals 21 producers and 22 water injectors.

During early years of production it became apparent that the field development plan would have to be updated to account for poorer than predicted connectivity between mapped sand bodies. As a result the number of wells required to maximise the recovery has more than doubled to that specified in the original development plan, and is expected to increase as the Field matures. Continuous collection of bottom hole pressure data from permanently installed gauges, well testing and production logging (PLT) supported by the regular time-lapse (4D) seismic programme are used to update and run reservoir models. This data integration results in improved understanding of the reservoir, well connectivity and compartmentalisation. This paper discusses Field compartmentalisation and shows an example of a recently drilled compartment which was successfully identified following detailed subsurface work. The analysis involved integration of dynamic well data with 4D seismic, revised geological models and reservoir simulation. Two newly identified targets were drilled and completed successfully with one well using down-hole flow control technology.

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Session 4

Stratigraphic Compartmentalization

Chair: Bruce Ainsworth

Techniques in Defining Siliciclastic Reservoir Architecture and Compartmentalization: Short-Comings and Opportunities

Bryan Bracken, Chevron Energy Technology Company, San Ramon, California, USA

The common goal of reservoir geologists is to characterize internal and external reservoir properties with sufficient resolution so that fluid flow pathways are “mapped”, production behavior predicted, and hydrocarbon production maximized. Accurate characterization of the connectivity and compartmentalization of permeable reservoir (= reservoir flow-unit architecture) is required. For the last several decades it has been widely held that the use of sedimentary-process and sequence-stratigraphic analysis would help resolve reservoirs architecture. However, the impact of these techniques in our most important reservoir systems has been limited because they are based on non-dynamic depositional facies models and an incomplete understanding of the range of possible reservoir architectures and scales. More accurate prediction and assessment of reservoir compartmentalization in the subsurface can be accomplished by 1) using depositional facies models and definitions of reservoir flow units and intra-reservoir barriers linked to sequence stratigraphic context and 2) use of appropriate dynamic engineering data sets to validate interpretations of reservoir connectivity and continuity. Three subsurface examples of fluvial and shallow marine reservoirs will be used to illustrate the opportunities and value of integrating static and dynamic data and using dynamic facies models that are linked to sequence stratigraphic context.

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Stratigraphic and structural compartmentalization in the Triassic Heron Cluster reservoirs, Central North Sea

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The Heron Cluster, located in the UK Central North Sea, comprises the Heron, Egret and Skua oilfields and forms part of the 'Eastern Trough Area Project' - an integrated development of seven Shell and BP operated fields. The reservoirs in these fields are classified HPHT, with initial pressures and temperatures of 9,300-12,900 psi and 300-350 F respectively. All produce from the Triassic alluvial Skagerrak Formation. The performance of these fields is heavily influenced by the effects of structural and stratigraphic compartmentalization, as indicated by both static geological data and dynamic production data.

Oil geochemistry and residual salt analyses indicate significant fluid variations both between wells and vertically within individual wells. Material balance calculations suggest production from restricted connected volumes, locally from a subset of the range of oils present. Lateral variations can be ascribed to prominent structuration within these fields, but the mud-prone intervals causing stratigraphic compartmentalization are more subtly expressed.

Structural compartmentalization by faults has two origins. Early (syn-halokinetic) grounding of Triassic 'pods' between salt swells during salt withdrawal has resulted in zones of intense faulting along the zone of contact of the pod and the underlying basement. This occurs in Skua and the nearby, undeveloped Seagull discovery. Subsequent salt ridge growth, possibly in the Jurassic, has resulted in a more pervasive fault pattern in Egret for example.

Stratigraphic compartmentalization occurs across several shale-prone intervals that are correlatable across the region. In some cases these appear to mark the boundaries to major changes in fluvial depositional style, provenance and floodplain drainage, suggesting an extrinsic control. This is most apparent in the relatively unfaulted Heron Field, but can be demonstrated in all fields in the Cluster. Whilst some faults have large throws which offset the reservoir sequence, smaller faults are present, which juxtapose the sands above and below the shale prone sequence. Fault property averaging algorithms (e.g. shale gouge ratio), indicate that the sands should communicate across the juxtapositions, implying that the fluids and draw-down pressures should equilibrate between upper and lower reservoir sands. However, the differences in fluid geochemistry and pressure differences caused by draw down are preserved despite the presence of these faults. This indicates that for these faults, the deformation mechanism was probably dominated by clay smear, in which the shale prone sequence is smeared down the fault planes without losing its coherence. Thus, stratigraphic compartmentalization between the upper and lower sands is preserved.

Recent analysis of 4-D seismic data from Skua suggests that a twt difference signal is localised in extent around the single (horizontal) producer in the field. The interaction between structural and stratigraphic compartmentalization are critical to understanding this anomaly. The compartment defined by the 4D signal appears to be defined by the subcrop of a regional compartmentalizing shale in combination with large throw faults related to pod grounding. Unlike Egret, where fault seal is breached by c. 6000psi depletion across faults, the fault seal in Skua appears to be robust. This may be due to the compartmentalization being dominantly defined by stratigraphic seals, which are also seen to be robust against differential depletion in Heron.

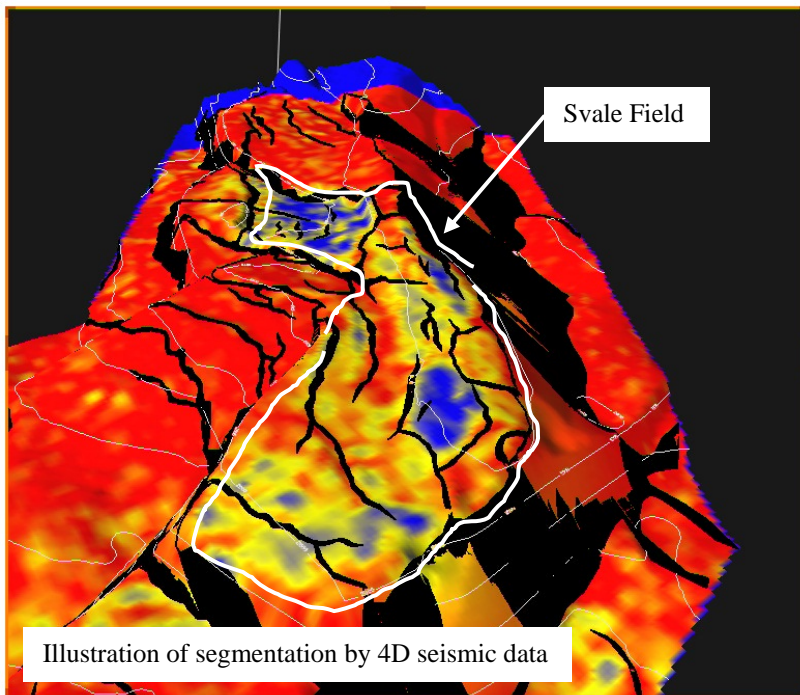
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An integrated approach to understanding the stratigraphic heterogeneities and structural compartmentalisation of a lower coastal plain reservoir in the Norwegian Sea

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The Svale Field is a subsea satellite discovered in 2000 and tied back to the Norne FPSO. The main reservoir is the oil filled Lower Jurassic Åre Formation, interpreted to be deposited in a coastal plain environment. The reservoir is heterolithic in nature, resulting in lithological flow barriers between the different reservoir units and extreme variations in permeability.

The field was developed in 2005 with an understanding of the compartmentalisation based upon core and image log data, formation pressure data and an interference test between the two exploration wells. A geological facies model was built to incorporate the reservoir heterogeneities and to best simulate reservoir production. The drainage strategy comprises two downflank water injectors and three production wells towards the top of the structure. To facilitate production optimisation in a heterolithic reservoir, 'smart' completions (DIACS) were installed in the production wells.



Production and 4D data have given a more complex picture of the structural compartmentalisation and stratigraphic heterogeneities of the subsurface.

Downhole pressure data has confirmed different degrees of communication between the injectors and producers in the different reservoir zones. Seismic 4D data has supported this, giving a better understanding of the compartmentalisation and an improved history match for the field.

Integration of the geological model, simulation model, 4D and other seismic data, well pressure and production data, image and well log data has given an enhanced understanding of the compartmentalisation of the field and allows for a more appropriate drainage strategy.

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Sedimentological control of fluid flow in the Forties Sandstone Member, Pierce Field, Central North Sea, UK

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The Pierce Field in the Central UK North Sea is a twin diapir structure that produces out of the turbiditic Paleocene Forties Sandstone Member. Different hydrocarbon–water contacts encountered in the wells around both diapirs have been variously ascribed to a tilted OWC or else some form of stepped (compartmentalized) contact. Recent reinterpretation of the structure, sedimentology and fluid geochemistry, has indicated that the 3D architecture of the reservoir is the prime control on fluid contacts and production flow.

While faults are present on both South and North Pierce they are not extensive and do not appear to play a major role in the compartmentalization of the field. From production data, pressure communication can be inferred around North Pierce and around the majority of South Pierce, the main exception being a fault block in the southeast of the diapir. Geochemical fingerprinting of the hydrocarbons in Pierce show families of oils that do not appear to be related to fault patterns, but most likely reflect the fluid flow through the 3D architecture of the reservoir and filling history.

The Forties Sandstone Member was emplaced by turbidity flows influenced by pre-existing seafloor topography that funnelled the flows into discrete sediment corridors and into the Pierce area. The rising twin diapirs further influenced the flows by forming a small salt withdrawal basin between the diapirs that captured sediment as well as enough seafloor topography to prevent the bulk of the flows from depositing significant amount of sand over the crest. With the bulk of the high permeability sands being deposited in a rim around the diapirs aquifer support and water injection does not always travel structurally higher but follows the channelized sands.

NOTES

Session 5

Fault Seal

Chair: Sylvie Delisle

The Dark Art of 'Fault Seal Calibration' – a review

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Calibration is a necessary step in the workflow for prediction of fault seal because there is no direct way to detect the hydraulic behaviour of a fault at the scale of a hydrocarbon trap. Over the last 20 years two general approaches have been developed:

- i) Simple algorithms which attempt to capture a salient feature of the fault zone (e.g. CSP, SSF, SGR). Then look at known trap-bounding faults to find a relationship between the algorithm and the presence or strength of a seal (sub-surface calibration).
- ii) Measurement of hydraulic properties of fault-zone samples (lab calibration). Then map these results onto the appropriate parts of trap-bounding faults.

Seal strength is typically described by Hg-air threshold pressure in the lab or static pressure differences in the subsurface (e.g. hydrocarbon buoyancy pressure). Different workers have variously parameterised seal strength as a linear, log-linear or stepped function of fault-zone composition. Further uncertainty is introduced when converting the calibrated seal strength to potential hydrocarbon column height, because of the variability of subsurface hydrocarbon fluids (capillary properties and density).

Using exploration and appraisal examples, some of the assumptions in this workflow are critically assessed in order to suggest uncertainty ranges that should pragmatically be applied in fault seal predictions.

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Multi-Fault Analysis Scorecard: Success of Stochastic Approach in Fault Seal Prediction

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Multi-fault analysis is an ExxonMobil proprietary approach for analyzing stratigraphic uncertainty and variability on cross-fault leakage of hydrocarbons in faulted traps. Stratigraphic variability is simulated by stochastically constructing 1-D stratigraphic columns that satisfy assumptions of mean seal thickness and proportion (i.e., N:G). This juxtaposition-based method provides quantitative prediction of hydrocarbon contact levels through a complex system of structural spills and juxtaposition leak points in traps with stacked reservoir systems and one or more faults. The results are used as direct input to assessment risking and sizing and/or to rank and grade hydrocarbon prospects and leads. This methodology does not account for dip leak along fault zones or additional hydrocarbon column supported by capillary fault gouge, although the effects of gouge are considered later in the assessment process, if necessary. However, our observations in post-drill analyses indicate that these factors may be secondary compared to cross-fault juxtaposition.

Validation of the Multi-fault analysis technology was carried out at ExxonMobil in pre-drill evaluations followed by post-drill comparisons of 41 faulted exploration prospects from 1994-2001. Of the 41 prospects, 29 were valid tests in which we made 22 successful predictions (76% Success Rate). Of the 22 successful predictions, 11 were discoveries and 11 were dry wells. Some of the dry wells were drilled on the basis of there being sealing fault-zone material to trap economic hydrocarbon volumes. The seven Multi-fault prediction failures comprise four predicted successes that were failures and three predicted failures that were successes. Most of the Multi-fault prediction failures can be attributed to data quality and uncertainty; however, some of the predicted failures that were successes may be associated with sealing fault-zone material.

Fault-zone materials can produce important seals in hydrocarbon traps, and clear examples have been recognized in our post-drill analyses. These examples are accepted only after all plausible geologic interpretations that account for juxtaposition seal are rejected. However, these analyses also show that capillary gouge seals control only a small portion of hydrocarbon traps, and that these occurrences are unpredictable. We find far greater benefit in questioning and testing our structural and stratigraphic interpretations and their impact on fault-juxtaposition seal, benefits which sometimes accrue in later field development or production. We favor the Multi-fault approach simply because we think it addresses the first-order questions of fault-seal analysis (geometry of permeable connections and the uncertainty upon which those assessments are based), and the methodology forces us to honestly consider alternative geologic interpretations.

NOTES

An Integrated Approach to Characterizing Faults at Kuparuk Field, Alaska: the Key to Maximizing Reserve Depletion

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The Kuparuk River field, located on Alaska's North Slope, is the second largest oil field in North America (6 BBOOIP). Discovered in 1969, with start-up production in 1981, this field has produced over 2 billion barrels of oil from lower Cretaceous sandstones. With over 1200 wells drilled to date and peak production in 1992, the Kuparuk River field is currently in decline. 3D seismic interpretation reveals a high density of intra-reservoir faults, including over 6000 mapped at the full-field scale. Key challenges in an asset management strategy at Kuparuk include maximizing reserves depletion while diligently managing LOC (Lease Operating Costs). Fault characterization, understanding fault-fluid behavior, and predicting reservoir compartmentalization are critical to accessing the remaining resource and value within the Kuparuk River field.

Numerous lines of evidence indicate that many faults provide barriers or baffles that compartmentalize the reservoir. Early drilling found different oil-water contact depths. Production history revealed limited drainage areas. Infill drilling tapped into fault blocks with near-original oil saturation. Detailed well interaction studies show a lack of communication between fault separated injectors and producers. Pressure domains are bounded by mapped faults. Recent 3D seismic shows dramatic amplitude patterns separated by obvious faults.

Over the past 20 years various approaches to fault characterization have had mixed success. Early efforts to derive simple predictive rules (fault strike, throw thresholds) failed. More detailed fault characterization efforts have proven more successful, but time-consuming. Business needs have promoted an integration of multidisciplinary approaches to assigning fault properties that can be scaled to fit the area of investigation and number of faults in question.

Based on detailed studies and lab tests of core samples, we have established relations between fault displacement, lateral stratigraphic variation, flow units, and fault seal potential. These can be applied to individual faults or the entire field. A second approach derives fault properties from observed well interactions and from detailed analysis of production and injection history. Rapid injector-producer response implies open faults; delayed or no response suggests faults that are baffles or barriers. A third method interprets the amplitude patterns seen in the new 3D seismic as a response to fluid saturations and/or to reservoir pressure distribution. Thus contrasting amplitudes across faults suggest seal, and local amplitudes "spilling" through fault relays reveal lateral leak points.

The integration of these three methods allows for the generation of new infill opportunities and for a reduction of the associated risks and uncertainties, while greatly increasing the number of faults that have been characterized. Thus we have included more sophisticated fault properties in all stages of reservoir development planning, from screening for under-produced reserves to well planning to reservoir modeling. Recent drilling supports the integrated approach and provides additional feedback to the fault characterization.

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Fault Zone Property Calibration: A North Sea Case Study.

Mark Reynolds and Sylvie Delisle, Total E&P UK Ltd., Geoscience Research Centre, Aberdeen, UK

Fault zone properties are now routinely estimated as part of the reservoir characterisation workflow. Whether these properties are then used for exploration, appraisal or production modelling it is important that we have confidence in the values being predicted. The best way to improve our confidence is through a process of calibration, where predicted values are compared against observed cross fault pressure and fluid differences.

A recently drilled well in the northern North Sea Alwyn field provided an example for which fault zone capillary entry pressure could be calibrated at a Statfjord-Statfjord reservoir juxtaposition window. In this case hydrocarbons are present in the footwall block but at the same depth in the hanging wall only water is observed, providing an indication of cross-fault buoyancy pressures.

Three different SGR-based algorithms were compared during this study, two from published sources and one from Total's internal work. At the Statfjord-Statfjord juxtaposition window, all three algorithms were able to predict the required fault zone capillary entry pressure for the first fault under consideration and suggested that a second fault might be leaking, indicating possible future exploration targets.

This study allowed greater confidence to be gained in the application of different entry pressure algorithms when quantifying reservoir compartmentalisation during exploration and production fault seal analysis.

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Fault parameter uncertainty in reservoir models: ranking effects of parameters on flow response in a history matched dynamic model

Silje S Berg, Eirik Vik, Tor Anders Knai, & Jan Einar Ringås, StatoilHydro ASA, Research Centre Trondheim, Trondheim, Norway

Drainage strategies for fields in tail production rely heavily on understanding how geological and petrophysical properties effect fluid flow. We present an analysis of fault property modelling uncertainties and the resulting dynamic responses in a mature, heterogeneous, fluvial reservoir (Statfjord Fm., Statfjord Field). The aim is to identify important parameters for oil production in a history matched model. This "history approach" is different from most reservoir parameter studies, since the common method is to assess the effect of different parameters by running models in prediction mode.

The input model is a 4000x3500x250 m³ sector of the full-field model, with 27 intra-reservoir faults and 75x75x4m³ grid blocks. Flux boundary conditions are tuned to match the full-field model. Within this restricted framework, where the simulation runs are controlled by production history, 5 input parameters are varied in an experimental design: Fault permeability, Vshale, fault throw, fault thickness algorithm, and clay smear potential threshold. The preliminary results show that fault throw has significant impact on the simulation results and is the overall most important factor. Another conclusion is that identification of parameter uncertainty is not trivial and that work can be done to reduce the uncertainty in some of the parameters.

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Session 6

Multi-component Compartmentalization

Chair: Peter Vrolijk

Structural and Stratigraphic Controls on Reservoir Connectivity

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David K. Larue, Chevron San Joaquin Valley Business Unit, Bakersfield CA*

The connectivity of a reservoir to a well bore represents a fundamental initial condition for drainage of an oil or gas field. The size of the static connected volume is a function of the stratigraphic and structural architecture of the reservoir.

The most important stratigraphic factor affecting connectivity is a net-to-gross threshold which determines whether a reservoir is highly or poorly connected. Other factors that affect connectivity are the presence of continuous mudstones, and the 2D or 3D nature of geobodies. Structural compartmentalization through faults, folds and aquifers can limit volume support needed for connectivity: as the size of the geobodies approaches compartment size, connectivity is typically less predictable. Static reservoir connectivity can thus be visualized in three dimensions, with axes of net-to-gross, support volume, and static connectivity. This 3D plot can be sub-divided into zones that will give insights into potential for the reservoir to be compartmentalized and resulting impact on well count.

Static connected volumes do not predict flow performance, but are a component in predicting flow performance. To more completely address predictions of flow performance, dynamic connectivity is sometimes considered. However, dynamic connectivity, which is dependent of fluid type, permeability heterogeneity, time and other factors, confuses connectivity with tortuosity and sweep- and displacement-efficiency and is possibly best avoided.

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Reservoir Connectivity at the Sunrise Giant Gas Field: A Multifaceted Study

Bruce James, Wayne Bailey, Andrew Murray, and Trey Meckel, Woodside Energy Ltd., Perth, Australia

The Sunrise gas field, Timor Sea, covers an area >900 km². The field consists of two main reservoirs, a laterally extensive upper shoreface unit and a lower unit comprising incised fluvial valleys, separated by a laterally extensive layer of low-permeability sands, silts, and shales. The trap is distinctive in a regional context in that it is heavily faulted, bounded by faults that reach the seabed, and is only recently formed, constraining hydrocarbon charge to the last 500K years.

Reservoir connectivity is a key development uncertainty, as data from 5 widely spaced appraisal wells present contradictory evidence against and for compartmentalisation. For example, the gas column appears to be in pressure equilibrium and there is extraordinarily good mixing of light end hydrocarbons over distances as large as 10 km laterally, as well as vertically between the major reservoir units. However, there are lateral variations in condensate-gas ratio, gas-water contact, and aquifer gradients, suggesting the potential for compartmentalisation.

The paper presents an interdisciplinary investigation into geological- & production-timescale compartmentalisation at Sunrise, based on stratigraphic, structural, and geochemical, analyses as well as mixing over geological time. Multidisciplinary study is essential to being able to understand compartmentalisation in such a large, dynamic field, sampled by a limited data set.

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Reservoir Connectivity Analysis of a Complex Combination Trap Terra Nova Field, Jeanne d'Arc Basin, Newfoundland, Canada

Bill Richards (ExxonMobil Canada), Peter Vrolijk (ExxonMobil Upstream Research Company), John Gordon (Petro-Canada), Brent Miller (Petro-Canada)

Terra Nova Field in the Jeanne d'Arc Basin, offshore Newfoundland, is a heavily block-faulted, structural, stratigraphic and diagenetic combination trap. The Terra Nova anticline plunges northward from the low-side of the basin bounding Voyager Fault system to the high-side of the trans-basin Trinity Fault. About 1 billion barrels STOOIP is reseroired in stacked, braided fluvial sandstones (Tithonian syn-rift Jeanne d'Arc Formation) which are of variable quality and extent due to onlap, cementation & facies transitions. The Jeanne d'Arc Basin has a prolific Kimmeridgian source of oil & gas that underlies four major reservoir/topseal couplets. Of the four major fields in the basin, Terra Nova is unusual in that it lacks a gas leg and in that significant hydrocarbons are confined to one major reservoir interval. At the Jeanne d'Arc reservoir level, the highest part of the Terra Nova anticline is wet while the lowest part has the deepest contact and longest oil column. Aquifer pressures vary between hydrostatic and significantly overpressured (~7000 kPa). The objective of this talk is to show that this apparently anomalous and counter - intuitive distribution of fluids, pressures and contacts can be explained by systematically considering: (1) the geometry of the reservoirs, seals and source rocks, (2) the connections between reservoir compartments (controlled by stratigraphic & fault juxtapositions), (3) fluid buoyancy and (4) capillary and mechanical leak. This type of approach, used historically by the Operator, Petro-Canada, and formalized as 'Reservoir Connectivity Analysis' (RCA) at ExxonMobil, is effective in understanding and predicting fluid behaviour at multiple scales: basin, field, producing fault block and individual sandstone. This type of analysis continues to be important at Terra Nova after almost seven years of development & delineation drilling and six years of production.

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Fault impact on sweep patterns: Predicting effective cross-fault connections and comparing with 4D saturation change

M E Meurer, J C Burger, S K Oppert, P J Vrolijk, J W Snedden, ExxonMobil Upstream Research Company

Predicting the impact of faults on fluid flow in a producing field requires understanding of stratal geometries, rock type and quality, fault displacement, and likelihood of shale smear or cataclasis within the fault itself. We present results of detailed 3D fault juxtaposition analysis, used to predict (qualitatively) the effectiveness of cross-fault connections. We used this approach in combination with seismic volume-based methods to identify the most favorable fluid flow paths between wells. Our predictions support and refine independent predictions from geologic analysis and well interference testing. Favorable comparison with anomalies observed in seismic monitor surveys and with field production history, supports our conclusion that sweep pattern is consistent with absence of low permeability fault zone material. Our method quickly identifies elements that exert strong control on reservoir connectivity, and can be applied relatively early in field life-- we obtained results using interpreted faults, stratigraphic surfaces, and depositional environment maps. Results demonstrate that understanding fault impact on sweep patterns requires concurrent evaluation of cross-fault connections and the geometry and connectivity of the full reservoir system in which they are embedded. This successful example also demonstrates that the approach can lead to earlier and more accurate qualitative predictions of fault fluid flow behavior. Applying this workflow during early development of fields with risk of production-timescale fault compartmentalization has the potential to improve early reservoir modeling strategies and development plans.

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Session 7

Modelling

Chair: Mark Bentley (TBC)

Sensitivity of petrophysical and geometrical fault representation on field production – a comparative study

T Manzocchi, A E Heath, B Palanathakumar, C Childs and J J Walsh, Fault Analysis Group, University Collage Dublin, Dublin, Ireland

Even when geologically-based methods are used to determine fault rock permeabilities and thicknesses for input into flow simulators, a wide range of simplifying assumptions regarding fault structure and content are still present. We address many of these assumptions by defining quantitative and flexible methods for realistic parameterisation of fault-related uncertainties, and by defining automated methods for including these effects routinely in full-field flow simulation modelling. Fault effects considered include the two-phase properties of fault rocks, spatial distributions of naturally variable or uncertain single-phase fault rock properties and fault throws, and the frequencies and properties of sub-resolution fault system or fault zone complexities including sub-seismic faults, normal drag and damage zones, paired slip surfaces and fault relay zones. Innovative two-phase or geometrical up-scaling approaches implemented in a reservoir simulator pre-processor provide transmissibility solutions incorporating the effect, but represented within the geometrical framework of the full-field flow simulation model. The solutions and flexible workflows are applied and discussed within the context of a sensitivity study on two faulted versions of the same full-field flow simulation model and reveal significant influence of some of these generally-neglected fault-related assumptions and uncertainties.

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The influence of fault geometric and property uncertainty modelling on reservoir compartmentalisation

S D Harris, R J Knipe, S Freeman, Z Khatir, A Brown, R K Davies, A Li, Rock Deformation Research Limited, School of Earth and Environment, University of Leeds, Leeds, UK

Efficient methods are required to optimise the fault juxtapositions and property distributions within reservoir simulation models and to assess the likely impact of the uncertainty on reservoir compartmentalisation relative to the required tolerances. The fundamental issues are that the seismic-based model could: tend to overestimate the throw on the main slip surfaces; not include drag effects or secondary faults; ignore deformation within the host as well as within the main fault zone.

This may result in an underestimation of the bulk reservoir connectivity and the connections between different layers. The true connectivity would probably allow many more pathways than the geocellular model can physically represent.

Compounded with the geometric effects, the application of simple fault rock property estimates will create errors. Single intrinsic permeability values with specific fault thickness relationships will fail to model the true range. This is important because the fluid flux distributions will be dominated by the high-transmissibility regions that generally form a relatively small proportion of the fault area.

The composite effect of geometric and property complexities and spatial variabilities means that simple models will tend to underestimate communication across faults. This observation may be counteracted by multiphase flow effects in zones of higher water saturations.

Fluid flow simulations have been performed on representative reservoir permeability and fault rock property distributions to quantify the impact of varying geometry and property values. These have been contrasted against those values typically produced from simple models using existing software systems. This approach has enabled the development of algorithms for creating modified grids that better model the flow across fault zones within compartmentalised reservoirs.

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Fault Property Modeling and Impact on Fluid Flow

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The Kuparuk oil field on the Alaskan Arctic plain is a heavily faulted field in which about 5200 faults have been mapped. Those faults can act as barriers, baffles or conduits to fluid flow. Consequently, the fault seal situation is critical for fluid flow simulation.

This paper discusses work aimed at building geologically-driven, high-resolution fault property models and investigating the impacts of different fault seal property models on fluid flow. A workflow for building fault property models and studying their impacts on flow simulation is proposed. Fault seal analysis from two commercial products, RMS and TrapTester, are compared using ConocoPhillips in-house reservoir simulator PSim. This workflow is tested using the data from one drill site area in the Kuparuk oil field.

Different fault property methods are investigated. The results demonstrate that some of the fault-related parameters, like shale smear, are sensitive while others, like faulting depths, are not. For this test area and these rocks it was found that the transition from the faults being open (high fault transmissibility multipliers) to being sealed (low fault transmissibility multipliers) took place over a very narrow fault permeability range. These results provide us good references for the practical fault seal analysis and flow simulation with faults.

The information from injector-producer interaction, seismic amplitude change over time of production and fault throw values are important qualitative information related to fault seal. That information is incorporated into flow simulation through fault transmissibility multipliers.

Using what has been learned, it is possible to run appropriate fault seal analysis on all of the 900+ modeled faults for the entire Kuparuk field. Those faults or fault segments for which the qualitative information indicates either open or sealed conditions are explicitly honored. For all unevaluated fault segments or those for which the qualitative information indicates the fault segment to be a baffle, the fluid flow performance of the fault segment is controlled by the fault transmissibility calculated via fault seal analysis and transmissibility calculations done in RMS.

NOTES

An uncertainty analysis workflow for structurally compartmentalised reservoirs

Alan Irving, Total E&P UK, Geoscience Research Centre, Aberdeen, UK

Despite their significance, structural uncertainties are often neglected in workflows for assessing uncertainty on connected volumes and forecast production for compartmentalised reservoirs. An approach is proposed that integrates structural and property uncertainties to generate multiple equiprobable model realisations. Geometric parameters that may be simulated include fault and horizon shape and location, fault displacement and fault pattern, while property variables include fault zone architecture and permeability. The effects of multiphase fault rock properties and sub-seismic faults can also be investigated.

The workflow is integrated with commercial 3D geomodelling software, which provides the framework for managing parameter definition and simulating realisations. Different static connectivity measures can be used to rank realisations before selected models are submitted for flow simulation. Sensitivity of forecast production to individual parameters can be efficiently assessed using experimental design.

The implementation of the workflow is illustrated using a faulted North Sea reservoir, in which multiple scale structural heterogeneities are poorly constrained by the available seismic, log and core data. This leads to considerable uncertainty on connected volumes, with implications for history matching and infill well planning. Case-specific and more general conclusions can be drawn about the effect of different parameters; potential improvements and extensions to the workflow are discussed.

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Poster Presentations

Aquifer compartmentalization in the Lower Rhine Embayment, Germany

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Faults that are part of the Roer Valley Rift System compartmentalize groundwater flow systems in the Lower Rhine Embayment. However, we hypothesize that these faults cutting through the unconsolidated sediments of the Lower Rhine Embayment act as combined conduit-barrier systems. In such systems fluid flow vertically along faults will be enhanced while across-fault fluid flow is impeded. We proposed that this dual behaviour can be understood by assuming the simultaneous shear of sand as well as the smear of clay along the fault plane. The barrier properties of faults in the Lower Rhine Embayment are reflected in strong hydraulic head gradients that are enhanced by groundwater extractions that are impacting regional scale groundwater flow. Preliminary, idealized models show that these head drops can coexist with vertically enhanced fluid migration. However, hydraulic head data alone are not sufficient to demonstrate this behaviour. For this purpose we have collected a suite of groundwater samples for detailed hydrochemical analyses. These samples are analyzed for stable isotope ratios, trace metals and groundwater ages are being determined (¹⁴C and T/³He dating). The results of these analyses are integrated using three- and two dimensional hydrogeological models that are used to calculate transient hydraulic head, temperature and groundwater age distributions.

The Use of Pre-Production Data to Assess the Risk of Reservoir Compartmentation in a Deep Marine Turbidite Reservoir

Glenn W Davies and Mike Tothill, BP Exploration

As the industry moves to resource exploitation in progressively more challenging environments, the importance of gaining an early understanding of uncertainties becomes more critical.

In the subsurface, one of the principal uncertainties is reservoir compartmentalization. With increasing costs, particularly in the deep water environment, it becomes important to assess these uncertainties whilst minimising expenditure and controlling well numbers.

This paper describes the assessment of compartmentalization risk in two turbidite reservoirs exhibiting different architectural styles. The assessment is made by integrating a range of pre-production data, both static and dynamic. In particular, an extensive data set from pre-production interference tests was gathered as wells were completed. The reservoir model has been history match against these dynamic data – before first oil. This has reduced the uncertainty of poor connectivity and confirmed the selection of the development scheme.

The Impact of Structural and Stratigraphic Uncertainty in Fault Seal Analysis

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Uncertainty in fault seal analysis derives from imperfect stratigraphic and structural input models. The primary impact of imperfect inputs is misprediction of where permeable layers and sealing layers are juxtaposed across faults. Misprediction of juxtapositions can lead to erroneous interpretations, and predictions, of hydrocarbon distributions, fluid pressures, and flow behaviors in the subsurface, which in turn lead to over or under-assessment of discovered resources, poorly designed field development plans, and poor reservoir management in producing fields.

Fault seal analyses start with predictions of cross-fault juxtapositions by combining structural geometry with stratigraphic architecture. In our experience, starting with carefully constructed geometric and stratigraphic models to evaluate juxtapositions of low and high capillary entry pressure rocks across faults obviates the need to introduce higher uncertainty predictions regarding the presence, distribution, and quality of capillary sealing material in a fault zone. For example, two commonly observed phenomena, offset hydrocarbon contacts and different fluid pressures across faults, lead to hypotheses about sealing materials in fault zones. Often we find that, within the range of structural uncertainty and assumptions, juxtaposition models can be built that satisfy the observations and are testable within the seismic data from which they are derived. Further, recognition that common geometric elements associated with juxtaposition windows (e.g., breakover at the base of a juxtaposition window) can yield both offset contacts and different fluid pressure regimes across faults, reduces the need for ad hoc prediction of fault zone sealing materials. An advantage of the juxtaposition approach to fault seal analysis is that it frequently guides revised geologic interpretations that can be tested by drilling and examination of seismic data. The distribution and quality of fault zone materials is rarely directly tested.

Compartmentalized reservoirs – modelling stacked turbidite flows and the effect on the formation of petroleum reservoirs

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The need for improved understanding of the generation of compartmentalized petroleum reservoirs is increasing as easily extracted oil is removed from existing reservoirs; while the increased price of oil means that small traps are becoming increasingly viable. In order to improve the identification of sweet-spots for well locations and to better evaluate the potential hydrocarbon reserves, better visualisation of reservoirs in 3 dimensions is needed, as well as an understanding of the interaction between depositional surface and syn-depositional sediment distribution.

Structural modelling has been part of the exploration workflow for decades. The ability to restore complex surfaces to their palaeo-geometry at depositional time allows geoscientists to visualise the morphology of the depositional surface. Using this surface as a palaeo-seabed, it is possible to model the interactions between this surface and the deposition of turbidites. Results from a mass flux particle flow model will be presented which demonstrate the importance of modelling stacked turbidite flows rather than a single thick turbidite deposit. A 10m thick turbidite deposit covered by 1m of pelagic fine grained deposits (max total thickness 11m) will be compared to deposits resulting from 10 successive turbidity currents, separated from each other by 0.1m fine grained pelagic sediments (max total thickness 11m). In both cases the distribution of well sorted, high net to gross sands will be identified, allowing improved reservoir visualisation and a better understanding of the 3-dimensional shape of the potential reservoir to be achieved.

Numerical modelling and scenario comparison of flow architecture within the palinspastic framework allows technical uncertainty and risk to be minimised in decision making.

Factors influencing the formation of clay smears and associated changes in fluid transport properties across fault zones – an integrated numerical and experimental study

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We present preliminary results of a combined experimental and numerical study, which aims to identify the controlling factors, and their respective contributions, in the development and spatial continuity of clay smears.

Analogue experiments were conducted in a large, direct-shear apparatus, capable of deforming rock samples of approximately 10'000 cm³ in volume to up to 10 cm displacement. The sample box was specially designed to allow measurement of permeability during deformation. The sample blocks, containing a shale layer sandwiched between reservoir sandstone units, are produced synthetically using a Carbonate In-situ Precipitation System (CIPS). The CIPS technique allows the production of samples with known and easily adjustable chemical (composition) and physical (strength) properties, and also ensures reproducibility of a reference starting material.

The experimental program is complemented by numerical modelling using two different finite element software packages (Plaxis, Diana) as well as a discrete element package (PFC2D). Input parameters were given by the starting material and the analogue experiments. The results of the numerical modelling, notably the evolving stress-distribution with displacement and coupling between simulated fault evolution, clay smear and fluid flow, are then compared with changes of mechanical and fluid flow properties as measured in experiments to provide a basis for a new fault seal algorithm.

Multi-fault Analysis Success Story - Total Pay Prediction in a Mature Field: An Example from South Texas, USA

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ExxonMobil's proprietary juxtaposition analysis technology, Multi-fault Analysis (MFA), was developed to address stratigraphic uncertainty and variability via stochastic treatment of sand and shale bed stacking. Results can be used as input to risking and sizing (including well specific pay and column height predictions) and/or as a relative prospect ranking tool. This presentation will provide a case example of applying MFA to faulted traps in South Texas. The objective interval is characterized by thinly interbedded sands and shales with a net to gross ranging from 15 to 60%. The total reservoir thickness under closure is ~1400' (more than 100 sand beds), however <10% of the reservoir beds contain hydrocarbons, indicating a very leaky system. Using stratigraphic parameters from nearby well logs and fault throws from structure maps to create a juxtaposition model, MFA successfully predicted hydrocarbon distribution over a 4100' interval in a development drillwell. MFA is now being used to rank and size opportunities in untested fault blocks.

Finite element modeling of faulting in sand-clay layered sequences

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Predicting fault zone properties in the subsurface is still a major challenge with important implications for across fault-fluid flow predictions on both geologic and production time-scale. A key to this problem is a good understanding of the influence of geologic boundary conditions on the fault zone geometry.

In this paper, we present the results of a study on localization in sand and sand-clay layered sequences using a finite element method. The finite element method uses constitutive material properties and adaptive remeshing to accommodate localization and large deformations. The geometry, boundary conditions and dimensions of the numerical model were based on analogue sandbox models with a basement fault. In order to model the sand and clay with constitutive material properties, geotechnical laboratory tests were done, resulting in a detailed material characterization.

A qualitative comparison of the fault zone geometry in the numerical models with those in analogue sandbox experiments show that the finite element model produces realistic results, in agreement with geomechanical principles. The modeling results also show that the material properties at the time of faulting and the NTG highly influence the fault zone structure and thus impact the sealing capacity of the fault.

Contractional Tectonics and Reservoir Connectivity: A Case Study from the Bighorn Gas Field of West Central Alberta

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The Bighorn gas field of West Central Alberta, Canada produces from thrust Mississippi and Devonian limestones and dolostones. The field contains 49 wells and has produced over 132 BCF of gas since 2000. The main reservoir is a 90 m thick, normally pressured, dolomitized crinoidal and peloidal packstone to grainstone that has matrix porosities of 3-6% and permeabilities of 0.1-10 md. As these are poor quality reservoir rocks, the best performing wells also intersect several fracture sets which increase overall well productivity. While the reservoir is laterally continuous across the Bighorn field, the structural geometry changes significantly from north to south; the north is dominated by a large, single Devonian-detached thrust sheet and the south by multiple smaller Mississippian-detached thrust sheets.

Initial reservoir pressures obtained from PTA, RFT, SG, and DST tests from 30 wells suggest that all imbricate sheets are connected above a common aquifer and, with some exceptions, plot on a single gas gradient. Anomalous pressure points indicate several factors such as reservoir depletion, inadequate build up periods, mechanical packer failures, and sub-seismic reservoir compartmentalization.

Low permeability/porosity reservoir rocks, dramatic lateral changes in structural geometries, and large distances between wells generally produce reservoir compartmentalization. However in the Bighorn area, these factors are subordinate to fracture connectivity which has resulted in lateral pressure communication across the entire 30 km strike length of the field as well as vertical pressure communication across thrust sheets. This conclusion is important on several technical and economic levels that include planning future well locations, determining single well OGIP estimates, capital requirements for future field development, and total producible reserves estimates.

Evolution of brittle deformation and fault growth in high porosity sandstone: the Bassin du Sud-Est, Provence, France

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Fluid circulation in the crust and in particular hydrocarbon migration in reservoirs is highly dependant on fault geometrical and hydromechanical properties. Understanding the evolution of these properties during fault growth and network development is of major importance in fluid flow prediction. This question is important for high porosity sandstone, where brittle deformation is typically expressed by a large number of small-displacement (mm – cm) cataclastic deformation bands (CDBs), and ultracataclastic fault zones of larger (metre-scale) displacement. CDBs and faults which affected high porosity sandstone induce a significant permeability reduction, which poses problems for hydrocarbon production in faulted reservoirs.

This contribution is based on field and laboratory data of CDBs and ultracataclastic fault zones, obtained on a structural reservoir analogue, the Cretaceous high-porosity sands in the Bassin du Sud Est (Provence, France). This complete field and multi-scale study is based on 3 main research axis: (i) A complete and systematical field study based on scan lines totalling a length of 717 meters; (ii) A microstructural and a statistic porosity and granulometry analysis based on samples extracted from the outcrops previously mapped in detail. (iii) A permeability study based on the same samples. The different analysis methods provide evidence for a transition in growth mechanism and petrophysical properties from thin CDBs to larger ultracataclastic fault zones, which form preferentially in contexts where a previous generation of CDBs already exists.

The results suggest the influence of previous structural heritage on further fault network growth. Thus a knowledge of the complete tectonic/deformation history is fundamental in predicting the properties of CDBs and ultracataclastic fault zones in high-porosity sandstone reservoirs.

Statistical distributions of deformation bands and organization of fault damage zones in siliciclastic reservoirs

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In siliciclastic reservoirs, normal fault damage zones contain small-scale structures, mainly deformation bands that can substantially modify fluid flow properties. This study focuses on the geometry of damage zones of an outcrop-based database. The aim is to derive statistical distributions of deformation bands and trends characterizing the geometry of damage zone that can then be implemented in reservoir modeling.

Processing of 150 scan-lines of damage zones reveals a logarithmic decrease of the deformation band number away from the fault core as well as a fractal deformation band spatial distribution responsible for the clustering of the structures. Results show a non-linear relationship between the damage zone width and the throw of the fault. Parameters such as the footwall and hanging-wall positions, the degree of lithification, or the folding of the damage zone are also analyzed, regarding the damage zone width and the distribution of deformation band density in the media. Combining the width-throw relationship and the distribution of deformation band densities allow to build a statistical damage zone, which can be divided into different facies according to the deformation band density degree. These facies can be linked to strain intensity or petrophysical properties in the reservoir.

Quantitative Modeling of Quartz Cementation along Cataclastic Fault Zones, Offshore Louisiana, Gulf of Mexico

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A Miocene well in offshore Louisiana, Gulf of Mexico, was used to model the effects of diagenetic quartz cementation in a cataclastic zone and adjacent undeformed reservoir. Core descriptions, petrographic modal analyses, high-resolution scanning electron microscopy (SEM) elemental maps, and cathodoluminescence (CL) images were collected and digitally processed for mineral identification. Extensive digitization resulted in composite images representing the areas with and without deformation. The undeformed areas were modeled to represent cementation processes under 'normal' conditions, while deformation bands were modeled separately to quantify the contrast in quartz cementation rates between deformed and undeformed zones.

Touchstone modeling results suggest that measured quartz cement from deformation bands can be represented by a combination of low activation energy (52.2 kJ/mol) and relatively recent deformation. In contrast, higher activation energy (56 kJ/mol) is necessary to account for measured quartz cement in the undeformed zone. The studied samples indicate that temperature and timing were not sufficient to destroy the reservoir properties despite significant cementation occurring along the deformation bands. However, more intense cementation observed along deformed zones compared to those along undeformed areas may account for reservoir compartmentalization.

Early Recognition of Potential Reservoir Compartmentalization

Larry Sumpter, Kenneth Petersen, John Snedden, Mike Sweet and Peter Vrolijk, ExxonMobil

Compartment identification is important in the exploration and exploitation of oil and gas resources and may have a significant impact on the estimation of in-place and/or recoverable reserves, as well as the placement of exploration, development and production wells. In this paper we discuss causes and indicators of compartmentalization with examples from many different fields. We define a compartment as a trap containing no identified barriers that would allow the contact between two fluids to reach equilibrium at more than one elevation. Notably, under our definition compartmentalization can be achieved by separating the lighter fluid (gas or oil) into two columns above a spill point or the heavier fluid (oil or water) into two columns below a breakover point - separation of both fluids is not required. Compartmentalization can be caused by lateral flow barriers, such as faults, reservoir pinch-out or truncation, or it may be caused by simple structural closure along the top or base seal surface. Since we associate compartmentalization with a potential change in fluid contact elevation, we consider any conclusive indicator of contact elevation, such as well logs or pressure data, to be a "hard indicator" of compartmentalization. We also recognize "soft indicators", which warn of possible compartmentalization, but by themselves do not conclusively demonstrate it. We consider most seismic data (e.g., DHI), geochemical data and early production data to be soft indicators, but this data can be extremely valuable in compartment analysis, as well as in understanding or predicting the dynamic behavior of the reservoir. Causes (geologic features) of compartmentalization can usually be recognized before most indicators (such as well data) are available, and will therefore provide the earliest warning of the potential for compartmentalization.

Across-Fault Seal Capacity Calibration between different aquifers

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The use of Shale-Gouge-Ratio (SGR) methods to predict fault-seal capacity relies on a calibration against field examples. Existing calibrations have plotted across-fault pressure difference or buoyancy pressure against SGR to define a fault-seal failure envelope. Recent work on hydrodynamics has provided insight on fine-tuning the calibration methodology. In particular we examine the hydrodynamic implication for fault seal capacity where hydrocarbons are trapped on both sides of a fault zone of finite width.

When hydrocarbons are reservoired on both sides of a fault, at different pressures, then the hydrocarbon saturation must be discontinuous across the fault. For hydrocarbon leakage to occur across the entire width of the fault zone, the hydrocarbon pressure must exceed the threshold pressure on the side of the fault zone that is adjacent to the highest formation water pressure that is present. The calculated SGR should therefore be calibrated by using the difference between the hydrocarbon pressure (on either side of the fault) and the formation water pressure from the side of the fault with the highest hydraulic head (i.e. highest aquifer pressure).

By using this modified approach an improved calibration data-set can be generated in cases where hydrocarbons appear to be juxtaposed across a fault.

Are Ancient Shallow Marine Stratigraphic Models Oversimplified? Potential Compartmentalization Lessons from Holocene Regressive Systems

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Geomorphologic and oceanographic studies of shallow marine systems typically show levels of heterogeneity that are not described in their ancient counterparts.

Late Holocene systems appear to have been affected by numerous localized pulses of regression and transgression, caused by short term changes in sediment supply, physical oceanographic conditions or relative sea level. As a result, the depositional elements that build modern regressive systems (e.g., mouthbar sets, beach ridges, tidal bars, distributary channels) tend to occur on scales of hundreds of metres to several kilometres rather than tens of kilometres. This scale of stratigraphic architecture will have a first-order control on reservoir connectivity and reservoir properties .

Modern shorelines also tend to be influenced by mixed depositional processes. They are rarely dominated by just one river, wave, or tidal process. Since individual depositional elements can occur across a large range of physical oceanographic conditions, the processes dominating a shoreline are best reflected in the frequency of occurrence of depositional elements rather than the presence of individual elements.

We present a series of 2D and 3D models and case studies that illustrate how such findings can aid in the prediction of stratigraphic architecture in ancient systems, improve field development planning and ultimately the prediction of reservoir compartmentalization and performance.

Geological factors influencing compartmentalization of Rotliegend gas fields in the Netherlands

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After the discovery of the Groningen field, almost fifty years ago, more than 250 gas fields have been discovered in the Netherlands. A study of most of these fields shows that connected volumes of many of the fields can be smaller than expected from volumetric evaluation. Seismic uncertainty can be an explanation for the discrepancy, but there can also be a geological explanation. Most fields are found in the Permian Rotliegend and good drainage is expected because the reservoirs are relatively thick and homogeneous. Minor faulting is not supposed to cause drainage problems, but this study shows that it is likely in a number of cases. Twenty three Rotliegend fields with connectivity problems have been studied. With this analysis a number of areas can be outlined that share a risk for fault seal and therefore problems with connected volumes. Fault seal analysis is important to understand compartmentalization but did not explain all discrepancies. It is not always successful because lateral fault movement may be an important factor in a number of areas. Areas with high clay content have also lower connected volumes. A better understanding of the connectivity problems can outline areas for appraisal and near field exploration.

Integrated Approach to Geomodelling and Dynamic Simulation in a Complex Carbonate Reservoir, N'Kossa field, offshore Congo

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The Lower Sendji Carbonate (Albian age) of the N'Kossa field, offshore Congo is a typically complex mixed siliciclastic-carbonate reservoir for which an understanding of geological and reservoir parameters can significantly assist the management of hydrocarbon production. The reservoir is a thick succession of interstratified dolomite, limestone, sandstone and shale lithologies in the order of 400m thick. These deposits, laid down in a restricted environment during an early phase of Atlantic Ocean spreading, show a lateral variability across the field that reflects the influence of salt movement and extension during deposition.

Challenges to production include the great variability of the reservoir properties, the presence of many vertical barriers, complex lateral connection between fault-bounded compartments and the need for appropriate pressure support to the existing critical reservoir fluid via injection into both the gas cap and the water leg.

Recent studies which include a dynamic synthesis to assess production mechanism and identify key heterogeneities reveal the importance of a geological understanding of stratigraphy and early dolomitisation gathered from many studies of more than forty wells that penetrate the field.

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