Recognising the Limits of Reservoir Modelling - and how to overcome them

4-5 March 2015

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Oral Presentation Abstracts (Presentation order)
Wednesday 4 March
Session One
Keynote Speaker: Upscaling from Nano- to Macroscale: Is It Possible?

Philip Ringrose, Statoil ASA & NTNU, NO-7005 Trondheim, Norway

The estimation of large-scale flow behaviour in subsurface rock formations inevitably involves a degree of upscaling (or re-scaling) from smaller-scale measurements. Typically, we start with a few measurements of rock samples (with lengthscales of a few cm) and some records of flow rates and pressures in test wells (lengthscales ~100m), and then attempt to estimate how the whole reservoir will flow (length scales ~1-10km). Over the last few decades various formalisms to handle these scale transitions have been developed, under the broad theme of multi-scale modelling. These multi-scale modelling approaches range from highly probabilistic methods to more deterministic process-based approaches, but all rely on some form of effective medium theory.

Example multi-scale models ranging from the nano-scale to the macroscale

Process-based approaches, in which deterministic aspects of the rock medium are defined using a series of multi-scale geological models, have proven to be quite successful at giving useful estimates of large-scale flow behaviour. We review these multi-scale process-based approaches with reference to two published case studies: (a) modelling a North Sea oil reservoir using a pore-to-field process-based approach, (b) modelling a CO₂ storage site using multi-scale fracture-flow models. In the North Sea oilfield example, multi-scale modelling of...
pore-types and lithofacies were upscaled as a set of directional water-oil relative permeability curves which had a significant impact on waterflood sweep patterns at the field scale, consistent with field observations. In the CO₂ storage site example, modelling of fractures at the core-scale and the near-wellbore-scale was used to estimate the stress-dependent flow patterns at the full-field scale, consistent with surface monitoring data. In each case, the multi-scale approach provided useful predictions, but also revealed some of the challenges and limitations of multi-scale modelling over the large range of length-scales involved (from mm to km). How many scales should be modelled? Are the models at any one scale representative of the natural variations in rock properties? These challenges can to some extent be handled using the multi-scale REV concept, where models of Representative Elementary Volumes (REVs) are established at a series of nested lengthscales based on statistical analysis of rock property data. Although it is not always possible to establish a convincing REV at each scale, the approach allows natural rock variability to be organised in terms of the key lengthscales which influence any particular multi-phase fluid displacement process (e.g. water injection, gas injection, or pressure depletion).

So far, most of these multi-scale approaches have started at the pore-scale-REV (lengthscales of order 50μm), and assume that molecular (or nano-scale) processes are constant and spatially invariant. Chemical reactions between rock surfaces and fluids are, however, known to vary both temporally and spatially (e.g. wetting behaviour of oils or dissolution-precipitation reactions between CO₂ and minerals). It is therefore natural to extend multi-scale flow-modelling approaches into the nano-scale domain. While this presents significant new challenges, we argue that upscaling from nano- to macro-scale is indeed possible and beneficial. The key issue is to identify the most important molecular-scale processes and to capture them (as simplified functions) within a multi-scale REV framework. Emerging examples of the explicit inclusion of molecular-scale processes in multi-scale flow modelling include: (a) variable-salinity waterflooding, where the effectiveness of the low-sal or high-sal water flood depends on the spatial distribution of clays, and (b) CO₂ injection projects where CO₂-brine reactions depend on the spatial distribution of carbonates and clays.
Geological Weaknesses in Geomodelling

Richard Steele and Karl Stephen

1 Tullow Oil
2 Heriot-Watt University

Key aspects of the core methodology and underlying mathematics of geomodelling have not changed in 20 years. We still use variogram-based methods, whether two-point or multi-point, for distributing rock types and properties. We still prefer to have grid cells that are orthogonal or nearly so. We have a lot more computing power and, if the number of lines of code is a measure, 50 times the functionality. But there are important aspects of geomodelling that were, frankly, embarrassing then and remain embarrassing now. “Embarrassing” here means that the model geology is a misrepresentation of the actual rocks to an extent that introduces significant error in calculating flow. Some are discussed here and a list of others is offered.

In most models, permeability heterogeneity is assumed to occur only at a length scale of several grid cells. We represent heterogeneity at this scale because we can. But when closely-spaced measurements are made at outcrop, it turns out that the range of the bed-parallel variogram of porosity or permeability is smaller than a typical grid cell – in most cases less than 20 m. Most of the variance is inside the grid cell and cannot be modelled by standard methods.

In lots of depositional environments, sand beds pinch out and shales merge. In lots of depositional environments, flow-limiting shales are organised and not parallel to the model layering. Flow-expediting coarse layers may have organised dip too, or are arranged into threads. All these geological geometries are hard to represent in geological models, so are ignored or merged and smeared into a caricature of the reservoir that fails to represent the flow structure.

We are commonly unable to predict fluid breakthrough with any accuracy. The arrival and progression of unwanted fluids is an important factor in field development planning and economics. But it’s a history-matching parameter or the output of an uncertainty study where the answer ranges from “next Thursday afternoon” to “never”. Pathways that lead to fluid breakthrough very often depend on the hard-to-model geology mentioned above or the unknowable geology of the precise geometry of connections between flow units away from the wells. This is hard to guess with any convergence, so it is glossed over, merged and smeared into a model reservoir that will flood much more smoothly than reality.

For each facies in a model the geologist and reservoir engineer must think very carefully about what size should be the grid cell and what’s inside it, recalling that the cell is commonly a factor of 108 larger than a core plug. Is it possible to represent the effective permeability by simple averaging or is a more elaborate upscaling required? Likewise for relative permeability: is it realistic simply to apply the curves derived from core plug measurement? And what should be the pattern and severity of cell-to-cell variation? We advocate much more uniformity within facies.

This is not intended as a manifesto for sophistication. Sophisticated is not the same as clever. Clever can mean simple. To borrow previously-coined terms, the integrated modelling team must avoid over-modelling and work to mitigate under-modelling. To do this, the team must be aware of the weaknesses of the process and the susceptibility of their field.
It Ain’t What You Do, It’s the Way That You Do It: Decision-Led Modelling Workflows for Mature Fields

Richard Oxlade & Mark Bentley, AGR TRACS International Ltd, Aberdeen, UK

Standard modelling workflows often let us down when it comes to supporting decisions in mature fields. The models tend to become large and unwieldy, the integration of production data is time-consuming and the incremental nature of the data accumulation means models tend to become ‘patched’. Models are commonly passed hand-to-hand between practitioners to the point that ownership is lost. The update and maintenance of the ‘field model’ becomes a job in itself, often separate from the process of managing the mature field. The modelling process thus reaches a technical limit, and loses its value.

We argue that successful modelling and simulation in mature fields requires a different generic workflow, building on concepts of front-end loading and design, with much of the work and the thinking done before significant modelling work is undertaken. This goes significantly beyond the idea of holding a project framing session. We use the analogue of the Forth Rail Bridge as a reference, the cantilevers representing short periods of team-based working and the nodes between the cantilevers representing meeting points when the disciplines come together to compare findings and plan for the next work segment.

The generic content of each node and cantilever is predictable:

- **Node** - problem definition (‘frame’)
- **Cantilever** - data review
- **Node** - definition of uncertainties – the long list
- **Cantilever** - analysis of significant uncertainties – root cause analysis
- **Node** – review result and short list
- **Cantilever** - initial static/dynamic models to test commercial sensitivity
- **Node** - decision on modelling – worth it or not?
- **Cantilever** – the larger modelling exercise, or not

Work in the early cantilevers is short – measured in days or weeks. The early modelling choices are not known at the outset – the problem has to be defined, deconstructed and worked - and hence the study plan is not constructed at the kick-off (the ‘framing’), as too little is known at this point. The outcome may be that detailed full-field models are not required to support the decision at hand; potentially modelling is not required at all.

An example is given from a mature field in which standard modelling workflows proved incapable of delivering useful technical support for decision-making. Work commenced and it quickly became apparent that the static-dynamic iteration of a full-field model at the resolution needed to capture production behavior was time consuming - too time-consuming to support...
the decision on infill drilling which the asset team was required to make. The technical limit of the default modelling process was reached. The initial, traditional modelling plan was therefore abandoned in favour of a multi-scale approach with static-dynamic iteration on small sectors combined with coarser full-field material balance and volumetric work. There was no ‘field model’ but many models, each addressing part of the problem. The decision-point was reached in time for the corporate planning cycle (just), was supported by the models and the wells have subsequently been drilled successfully. A traditional, detailed, history-matched full-field model was not required and was never built. The technical limit was overcome.
Decision Driven Modeling: Building the “Right” Models at the Appropriate Scale

Charlotte Martin & Walter Morrison, Shell International E&P, Houston, Texas, USA.

In the past 15 years there has been a significant increase in the computing power and software capability available to Development and Production Geologists which has led to progressively more fine scale and complex geological models. This increasing level of modeled detail is linked to a fundamental belief that if heterogeneity can be captured in a geologically “realistic” way that history matching will be easier and forecasting will be more robust. It takes significant time to build a finely detailed static model and when project deadlines are tight the focus of the sub-surface team tends to be on a single geological model. Uncertainties then tend to be analyzed in the dynamic realm only.

In the Shell organization models are required to be Decision focused i.e. tools for decision making in the business. The decision focus is established by undertaking integrated structured data analysis and planning phases prior to model building. Following community norms a significant number of sub-surface teams in Shell have been building highly detailed models for both development and field management purposes. These models tend to be facies-based, conditioned to well data and use available seismic data as trends. A smaller number of teams have focused on building coarser scale models at the seismic loop resolution and using the seismic data as hard conditioning data. Over the past two years a sample of both these geological model scales have been evaluated to delineate the time taken for model building and the resultant decision making ability. The long term aim of the study has been to define what model scale supports which business decisions and to therefore assist geologists in the building of the “right” suite of models at the appropriate scale rather than a single, highly detailed, sub-surface realization. When thorough data analysis and planning are undertaken the model building phase can be significantly reduced thus speeding up project delivery and improving the business focus of the sub-surface work.

This paper will present results of the model analysis study to demonstrate the time taken to build geological models at the coarse and fine scale, and the ability of these models to evaluate key sub-surface uncertainties. Examples of models at different scales will be used to show the importance of multi-scale modeling in the decision making process. The positive impact of integrated data analysis and planning prior to model building will be demonstrated across a range of green and brownfield projects from around the globe.
NOTES
Stretching the Limits of Reservoir Modelling: An Integrated Approach from the Peregrino Field, Brazil

Gustavo Haruki Saka¹, Eduardo Castro¹, Cássio Pettan¹, Andrew McCann¹, Xavier van Lanen²

¹Statoil do Brasil
²Statoil ASA

The Peregrino Field is a heavy oil field, offshore Brazil (Figure 1), producing from Upper Cretaceous sandstones. The heterogeneous reservoir is predominately deposited by gravity-flow processes and the primary targets are multi-Darcy channel and lobe sands (F1).

Figure 1: Peregrino Field Location

The reservoir knowledge prior to development drilling (from 2010) was based on limited well data (1 wildcat & 6 appraisal wells). The first development wells and production experience (from 2011), revealed a different picture of the reservoir than modelled previously. The F1 sand continuity, distribution and thickness had been overestimated and water breakthrough came faster than predicted. While drilling 10 wells per year, there was a need to regularly update the reservoir model efficiently, incorporating new well and production data, to be able evaluate the drainage strategy and support optimal well placement, as well as to evaluate possible IOR/EOR measures and generate field production prognoses.

The Peregrino asset team adopted a ‘Big-Loop’ workflow that merges all steps from static reservoir modelling to dynamic simulation and history matching.

The workflow enables the rapid incorporation of new data, as well as analysis of alternative geological scenarios and property parameters, in order to screen multiple realizations and filter out the best production data-matched among them. Integration between the reservoir characterization and simulation allows a fine-tuning match with historical data, changing not only parameters like connection factors, skin factor and relative permeability curves but also changing geological scenarios, facies volume fractions or incorporating deterministic sand bodies into the stochastic model, for example.

This is implemented through an automated chain that is repeatable and updatable and where consistency is ensured throughout. The core of the integration is a workflow manager (Figure 2) that controls all modelling steps from depth conversion to simulation in batch mode, in addition to running sensitivity screening and assisted history matching. The sensitivity
screening is achieved through a workflow manager that allows changes in parameters (e.g. OWC, facies fraction) and scenarios (e.g. velocity models, different facies modelling approach or conditioning), in order to re-run the entire workflow.

Figure 2: Workflow overview

Perhaps most significantly, the efficient modelling process allows more time for analysis of the results and the possibility to test various hypotheses, with the goal of understanding their geological implications.

As an example, the F1 facies distribution is initially steered by weakly correlated seismic inversion data and the fraction controlled by well observations. The ability to locally change facies fractions in the model, performing hundreds of realizations to evaluate the results against water-cut and pressure data, improves not only the history match, but also influences the conceptual understanding of sand distribution in the field. Another example is the incorporation of deterministic F1 sand bodies, interpreted from well and seismic data. The ability to merge stochastic models with these deterministic bodies improves not only the history match (Figure 3) but also the predictability of the model.

Figure 3: Improved history match (Peregrino well) through the incorporation of deterministic sand bodies.
Recognising the Limits of Reservoir Modelling - and how to overcome them

This approach has enabled the delivery of up to three updated and history matched model versions per year to support the business of the asset. The efficient integration of data and technical disciplines has given greater confidence in the results and a better understanding of the strengths and weaknesses of each model.
Buzzard Field Stage 2 Modelling Workflow: Closing the Loop on Static Uncertainties Using Workflows and Olyx Trend Analysis

Ben Seldon, BG Group

Close-the-loop modelling testing reservoir characterization against production performance is frequently desired and rarely delivered. The BG Group has developed a new stage to its uncertainty modelling and simulation workflow loop to allow the team to screen and learn from trends in probabilistic modelling results prior to entering the full dynamic simulation loop.

The Buzzard field is located in the Outer Moray Firth, Central North Sea. It is volumetrically significant with expectation volumes of 1.4 B bbl STOIIP and production rates of 200 K bopd. It is in its 8th year of production completing the first development phase in mid-2014. Reservoirs are characterized as deepwater turbidite deposits ranging from complex, slump and structure bounded flows to open, unconfined sheets.

The need to test the validity of geological models of these complex turbidites steered the team towards probabilistic characterization of facies and property fractions and geometries. Once built the plumbing of these models were tested against drilling pressure data (RFT/RCI) and then simulated against production history. Acceptable ‘screened’ models were then analysed using the Olyx plugin to determine trends between input parameters and quality of match. These learnings were then fed back into the next iteration of the loop.

The use of this screening stage prior to handing over the reins to the simulation engineer yields the following advantages:

- Front end loading draws the reservoir engineer into the discussion early and ensures only dynamically valid models are progressed
- Improves the geomodellers understanding of realistic probabilistic ranges in facies and property modelling with a fast turn around
- A step change improvement in the history match of the field.
Wednesday 4 March
Session One
The practice of reservoir modelling as typically used in the oil and gas industry can be a cumbersome and unsatisfactory process. Modelling tools impose unfortunate compromises that distort our understanding of behaviors in subsurface geologic systems (rocks and fluids). Properties and their distributions in reservoir models are commonly adjusted to achieve history matches but the solutions are non-unique, provide only limited insights to reservoir behavior, and, alone, do little to strengthen the scientific basis for prediction. Many sophisticated research efforts have pursued geostatistics, modelling and visualization techniques to overcome these shortcomings but continue to ignore root causes that lead to ineffective applications of reservoir models. In this broad overview, we share geoscience, engineering and computational perspectives on key factors impacting the effectiveness of reservoir models and examine opportunities for improvement and new paradigms.

Opportunity 1. Asking more from reservoir models. As reservoir modelling has become an integral and routine component of industry workflows there is an increasing risk of simply “ticking the box” (modelling for comfort) as opposed to using models to learn about the reservoir and explore possibilities. Commercial software emphasizes workflow efficiency over considered design. The first keyboard stroke can significantly diminish the opportunity to think clearly about the reservoir in a wide, concept-driven context. There are many factors to consider, including the purpose of the model, the questions being addressed, the level of detail sought, the hard data and soft conditioning required, the error and uncertainties in data, and the tolerance achievable in model outputs. The value of sketching conceptual models (whether on paper or tablet) should not be underestimated as a communication tool, a means to quickly explore a wide range of model concepts, and as a mechanism to think through problems and opportunities from the perspectives of multiple disciplines. Short circuiting discussions of model opportunities and design not only undermines modelling objectives, but commonly results in the under-utilization of modelling tools. Opportunities for users to gain distinct insights relevant to different disciplines may also be missed.

Opportunity 2. Populate the reservoir system not the reservoir discipline. Historically the geologic content of geocellular models tends to be dominated by discipline-based inputs. Seismic stratigraphers define stratal geometries, structural geologists disrupt these with discrete faults and proxies for natural fracture networks, sedimentologists and petrophysicists evaluate rock and fluid properties, while engineers relate the resulting reservoir flow behavior to data measured at wells. Each of these components is considered at a given scale appropriate for its representation in the model and the scales emphasized by different disciplines are not the same. While the reservoir modeler attempts to combine multi-disciplinary perspectives on reservoir content, our tools and practices rarely reinforce a holistic perspective in which the reservoir system is viewed as more than the sum of its parts. For example, a combination of stratigraphic and structural geologic insight is required to see the stair-stepping motion along competing flow pathways between super-k stratigraphic zones and cross-cutting fractures; the reservoir engineer on the other hand may try to adjust production indices to
improve the agreement between simulated and observed well performance. In our experience, a similar bias arises in the development of reservoir models based on outcrop analogues. The outcrop that contains analogous features for combined depositional, diagenetic and structural realms in the subsurface is extremely rare. Accordingly, models based on individual outcrops commonly fall short of representing the key interactions between geologic elements in the reservoir system of interest and are rarely used to investigate how certain geological features that can be quantified in the outcrop impact flow. Reservoir models have the potential to facilitate a systems approach, in which the interaction of different geologic elements (e.g. drawn from different analogues) is investigated to characterize reservoir behaviors, if carefully designed with an experimentalist’s mindset.

**Opportunity 3. Novel proxies – getting geology into models.** The multi-scale nature of the systems that we deal with raises the question of whether or not we are selecting appropriate methods to represent geology in models. There are many efforts afoot to connect or nest simulations across multiple scales using discrete representations of geologic characteristics, but these still do not necessarily capture patterns and scale of heterogeneity in the reservoir. Spatial statistical and data analysis tools used in other disciplines allow such patterns (e.g. clustering or regular spacing of channelized sandbodies and fractures) to be identified across multiple scales in geologic data, and offer potentially powerful tools to inform reservoir modelling studies. In addition, the static and dynamic domains defined by separate model components can be radically different from those defined by a knowledge of the relative impacts of geologic elements on flow at different scales, or of the combined impacts of geologic elements on flow, as emphasized in the systems approach discussed earlier.

**Opportunity 4. What’s really in your model?** The development of reservoir models, particularly early in the life of a field is challenged by sparse data in terms of both quantity and spatial density. This leads to inherent model uncertainty which should be explored and propagated when basing reservoir development decisions on models. Methods to populate models of the subsurface by stochastic and geostatistical approaches are largely driven by locally derived information, such as from well logs and core, combined with seismic images of variable quality. Again, there is an inherent multi-scale problem as routine core analysis is measured on plugs the size of a flashlight battery while wireline data from logs is derived at the decimeter scale. Yet, both data sources are used to populate grid cells in static and dynamic models that have the size of a ballroom which, in itself, is much smaller than the seismic wavelength. This tends to drive an early emphasis on sparse information and loss in heterogeneity, which then anchors later perspectives on model development and opportunities. Nothing in the final model currently reminds us of the weak constraints and the assumptions we used in its construction, or the implicit assumptions about heterogeneity above a certain scale. Once removed from the hands of its developer, there is a risk of a single model becoming the solution (false accuracy). Today’s technology can assist users by guiding complex processes, reflecting and expressing the level of data uncertainty during interactive model building, interpretive visualization and analysis of reservoir datasets. Examples include sketch-based interface modelling (SBIM), multi-scale and multi-dimensional visualization and analytics, and interaction technologies (e.g., augmented or mixed reality, multi-touch display devices, smart assistants).

**Opportunity 5. Introducing a global perspective.** An emphasis on the need for subsurface data constraints and techniques to interpolate between wells may de-emphasize the value that can be realized from global perspectives. In an era of crowd-sourced information, our IT capabilities are ever increasing and should be readily able to complement local subsurface constraints with global context for the systems that we are modelling. Geoscience currently lacks the equivalent
Recognising the Limits of Reservoir Modelling - and how to overcome them

of a project involving large, high-dimensional data (i.e., data samples containing multiple attributes, such as a Genome project. In these scenarios, computational tools support the (semi-)automated compilation of relevant statistics and knowledge for the DNA of a given geology. Even without community efforts, the cost of high-performance computing is small compared to drilling wells. Today’s computing powers can provide early first order constraints in the absence of more detailed information, a gut check for reasonableness, and maintain an open aperture for multiple scenarios (i.e. “what could you plausibly put in the model?” rather than “what do you know?”). Knowledge of the frameworks and evolutionary patterns that give rise to distinct geologic combinations can provide early insights to the nature of distinct flow domains in the subsurface. Global perspectives can also support compare-and-contrast studies that help to move reservoir modelling away from the realm of glorified stamp collecting: we learn little from a dogma that insists every reservoir is unique.

**Opportunity 6. Fast exploration of model concepts.** With an expanded set of scenarios, we need methods to capture them quickly into models and to prioritize them. Recent advances highlight, for example, sketch-based interface and modelling (SBIM) techniques as a means to rapidly translate geologic concepts into 3D surface and grid-based models for further characterization and simulations, and are discussed in another presentation at this meeting. In addition, there are technology opportunities to accelerate decision making (e.g., ranking earth models) via computational methods that give an approximate but adequate dynamic behavior. If 20 models are constructed, we want to know how similar or different they could be in their dynamic response without time-consuming upscaling and full-physics simulation work. Beyond this, we identify capabilities in pattern recognition that could readily support comparisons between new models and scenario libraries of reservoir models developed as crowd-sourced repositories. These in turn help to reinforce the global perspectives discussed above.

**Opportunity 7. New software paradigms.** A further opportunity resides in moving to new software paradigms that currently limit adoption of technologies from other fields. Commercial software is dominated by a relatively small pool of vendors and the industry workforce commonly resists the adoption of new software. Those pursuing novel methods have significant barriers to entry. Our models tend to operate at the field and field-sector scale when, ideally, we want to take advantage of interactive multi-scale modelling, visualization and analytics capabilities to achieve deeper insights to the way that different processes operate and interact across 10+ orders of magnitude. As noted above, tools to support (almost) real-time updating of models based on well information and process-based modelling on the production timescale could continually refine geometries and properties. Systems could troll networks identifying any and all relevant data for the model and support modelling hubs that facilitate interfaces between reservoir models and many other analyses and simulations. It is therefore a matter of harnessing these computational resources rather than relying on the idea that “a model must be able to run on a desktop in a few hours”.

**Opportunity 8. Training a new generation of reservoir analysts.** The last opportunity is “people”. In our experience, it is the breakdown in communication among people (and their silos) that is the single greatest limitation for reservoir modelling. Entrenched fiefdoms prevent boundary spanners from operating in multiple worlds; protectionism routinely limits opportunities to acquire cross-disciplinary datasets; and arcane jargon interferes with cross-disciplinary understanding. We believe that open minds and hybridized skill sets offer substantial uplift for reservoir modelling and that traditional divisions of geoscience training are not necessarily optimal for future generations of reservoir modelers (and other industry roles). Universities will play an integral role in equipping young geoscientists with the fundamental skills that are
necessary to become truly interdisciplinary and quantitative reservoir modelers, with special technical skills obtained later on through professional training courses.
Innovative Integration of Subsurface Data and History Matching Validation to Characterize and Model Complex Carbonate Reservoir with High Permeability Streaks and Low Resistivity Pay Issues, Onshore Abu Dhabi

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Complex carbonate reservoirs provide many challenges for characterization and modeling not least because diagenetic overprints may lead to increases in heterogeneities on a small scale. This study examines a complex carbonate reservoir from onshore Abu Dhabi where diagenetic overprints have led to the development of high permeability streaks. Additional complication is the presence of a low resistivity pay (LRP), where analysis of resistivity logs has resulted in the calculation of high water saturation which contradicts production tests that confirm dry oil.

This study used a combination of core, thin section, MICP, well logs and dynamic data to develop a holistic and robust reservoir characterization and reservoir model. A methodology was developed specifically to characterize and model the subsurface conditions identified in this field due to the simultaneous existences of high permeability streaks and LRP intervals. The methodology included:

1) detailed core, thin section and lithofacies description;
2) palaeoenvironmental interpretation;
3) high resolution sequence stratigraphy (HRSS) interpretation;
4) diagenetical analysis;
5) reservoir rock typing (RRT);
6) assessment of the relationship between lithofacies, diagenetic processes, and RRT;
7) saturation height function (SHF);
8) integrated static model building, and;
9) flow simulation and history match validation.

Three lithofacies were identified using faunal content, texture, sedimentary structures and Dunham Classification. The depositional setting varied from lagoon to shoal. Reservoir Rock Typing (RRT) defined seven rock types based on capillary pressure trend, pore throat distribution and porosity-permeability. HRSS interpretation recognized three 5th order highstand sequences that separated by two transgressive sequences. This has then allowed the identification of the origin of the high permeability streaks and the spatial distribution within the sequence stratigraphic framework. Detailed geological modeling was then integrated with dynamic data to provide a robust dynamic simulation validation. The combination of static and dynamic modeling can then be used to more accurately calculate OOIP and optimize the current reservoir management plan ensuring optimal sweep efficiency and recovery.
Cameia Field - Deepwater Pre-salt Kwanza Basin, Angola: Challenges in Modeling a Multi-scale Pore System Lacustrine Microbialite Reservoir

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Introduction

Appraisal and development of pre-salt lacustrine microbialite reservoirs in the South Atlantic present a number of reservoir description and modeling challenges: there are few (if any) modern or ancient analogues, lithologies and facies are complex, pore sizes range from nanopores to vugs and fractures, and since they are located in deepwater, the details of the reservoirs will be revealed slowly and development planning uncertainty must be managed.

Cameia is a giant condensate field in one of these reservoirs, and will be the first deepwater pre-salt development in Kwanza Basin, Angola. Cobalt International Energy, (operator) and partner Sonangol Pesquisa & Produção, discovered Cameia in 2012. The field is located in approximately 1700 m of water, and lies about 100 km offshore Angola in block 21.

Sedimentology

Cameia pre-salt sediments are principally interbedded chert, dolomite, and limestone. There are a number of lithologies, as shown in Figure 1, but the most important depositional and reservoir facies is microbial boundstone. This microbial boundstone may be composed of chert, limestone or dolomite, or mixtures of these mineralogies. Subordinate reservoir facies include dolomite and calcite packstones and grainstones. Non-reservoir facies are essentially all carbonate mudstone, which has occasionally been dolomitized. The interbedding of cherts, limestones and dolomites is probably related to changes in lake water chemistry as various ion-bearing fluids entered through vents and springs along faults at the lake floor. Textural evidence from core, and petrographic and isotope data, suggest that reef-building bacteria secreted silica directly from lakes, which had alkaline water chemistries that were similar to modern East African rift lakes.

Core and seismic evidence suggests that the microbial boundstones formed mounded organic buildups that have lengths and widths on the order of 1 – 2 km, and are 50 – 200 m thick. Subordinate packstone and grainstone reservoir is interpreted to have been deposited around and between mounds. Although these mounds may be resolved on seismic, their internal distribution of reservoir properties is uncertain, and analogue data to guide this distribution is lacking.

Pore systems

Petrographic and isotopic evidence from Cameia indicates that diagenesis started early (before compaction) and continued through hydrocarbon charge. Petrographic study, as well as log analysis and capillary pressure data, indicate that a number of pore types and ranges in pore sizes are present in Cameia reservoir. A spectrum of pore sizes, from nanopores (pore throat radius <0.10 microns) to megapores (pore throat radius >50 microns) are present. Numerous millimeter- to centimeter-sized vugs are visible in core and image logs as well. Finally, much of the chert microbialite reservoir has suffered compaction-related fracturing that appears to terminate at boundaries with limestone or dolomite beds.

Scales of measurement
Recognising the Limits of Reservoir Modelling - and how to overcome them

The range of pore sizes impacts petrophysical measurements as well, as vertical and lateral investigation limits vary by logging tool type, and many tools cannot resolve large vugs and fractures. Furthermore, core measurements often sample only the small- to medium-sized pores, even if full-diameter core analysis is used. The only measurement technique that samples the entire range of pore sizes is well testing, but this technique presents particular problems for defining intervals contributing to flow, quantifying contribution from these intervals, and for net pay determination.

Field development planning and modeling approach

Development planning for the Cameia field is progressing rapidly, and contemplates a Floating Production Storage and Offloading facility with subsea wells and wet trees, with 1st Oil in 2017.

This presentation will describe the range of techniques used to describe the Cameia reservoir, including the evolution of 3D static modeling approaches as additional log, core and well test information has been acquired in the field. The pore systems described earlier impose a large positive impact on reservoir quality and well deliverability, and early production data from similar reservoirs in pre-salt Brazil is encouraging. In addition, the Cameia reservoir fluid has many forgiving physical and chemical properties that will aid recovery. Nonetheless, the relative contribution of the different pore sizes during production, as well as sweep, remain uncertain. Therefore, although a great deal has been learned about the Cameia reservoir from the three wells drilled and evaluated thus far, a flexible and phased development approach has been selected to respond effectively to a wide range of outcomes during development drilling and early production.

Figure 1. Cameia reservoir lithologies

- Cameia Mound reservoir is a mosaic of chert (microcrystalline silica), limestone and dolomite
- Pore types and sizes are variable, and typical of carbonate reservoirs, even though mineralogy may be silica
- Mineralogy and porosity is dependent on depositional environment and lake chemistry

The author acknowledges the kind permission of Sonangol E.P. and Cobalt International Energy, Inc. to make this presentation.
Building a Reservoir Model for a Complex Coal Seam Gas Play, Surat Basin, Australia

Leon Erriah, Zana Williams and Colin Zimmer, QGC, a BG Group business

Four multi-billion dollar LNG projects are currently underway in Queensland, Australia. These are primarily underpinned by the Jurassic Walloon Subgroup in a world class coal seam gas (CSG) play in the Surat Basin. Approximately 40% of Queensland’s domestic gas supply is sourced from the CSG production out of the Walloon Subgroup (WSG), with production starting in early 2006. The project represents a world first CSG production into the lucrative Asian LNG market.

In excess of $50 billion Australian dollars has been invested, underpinned by a significant amount technical work. Part of the development activity includes the atypical approach of constructing reservoir models for CSG reservoirs. Industry examples of CSG field development show that analytical approaches have been preferred for unconventional plays with only a few references related to numerical modelling approaches for CSG reservoirs. We believe the complexity and risk profile associated with LNG exporting requires subsurface groups to aid the business via comprehensive forecasting, uncertainty analysis and also on critical commercial decisions.

The Jurassic Walloon subgroup is a highly heterogeneous stratigraphic section of interbedded fluvio-lacustrine sands, muds and coals. The WSG has been deposited across a massive area (> 1000 km2) and their properties vary laterally over short distances. The average pay thickness is ca. 30cm, with individual plies coalescing into seams up to 5m thick in some places. This thinly bedded reservoir nature presents a significant challenge in characterising the reservoir section vertically in the static model.

Connectivity and permeability are key reservoir parameters in the geological static model construction. Spatial understanding of the coal seam connectivity has been gained primarily by well data, sedimentological interpretation of core data and also via analogues, where applicable. The sparse 2D seismic dataset allows for delineation of major features across the Surat basin; however smaller scale structural features that contribute to potential disconnection of the coals exist. With the seams (cumulatively ca. 30m of net pay in each well) interspersed sporadically throughout a 400-450m section, the propagation of reservoir properties between wells becomes even more challenging. This is coupled with the very complex two-phase nature of a coal seam gas play, making the dynamic model equally as difficult to calibrate and predict using existing industry toolkits.

Reservoir models have been constructed using integrated datasets including petrophysical log data, core data; including sedimentological descriptions, gas content measurements from desorption, saturation measurements from adsorption and also drill stem test information. This presentation aims to summarise the key inputs and workflows adopted for building large full field reservoir models across QGC (BG Group) Surat Basin acreage. It aims to detail the approach in building these complex models and also addresses shared conventional reservoir challenges of managing datasets at different scales and also understanding uncertainty.

Philosophically, it will address the benefits and pitfalls of the numerical modelling approach with a focus on critically understanding the 3D geometry and distribution of the different facies. We will also deliver key messages around data management for fields with vast amounts of data, and the need for calibration to production data for a reservoir model in an unconventional CSG play.
Recognising the Limits of Reservoir Modelling - and how to overcome them

Snapshot of 3D Facies model across sector in Surat Basin
Characterising and Capturing Patterns of Sandbody Distribution and Connectivity in Models of Channelised Sandstone Reservoirs

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It has long been known that channelised sandstone reservoirs can exhibit sandbody distributions that reflect autogenic behaviours such as avulsion, compensational stacking and clustering. Such sandbody distributions do not conform to either reservoir-wide stratigraphic layers or to stochastically generated random distributions. They are thus poorly captured by typical reservoir modelling methods, which, in the absence of strong seismically derived constraints, assume a reservoir-wide, sequence stratigraphic framework within which lateral variations in facies are conditioned to user-defined trends and sparse well data.

We present outcrop data from a large, play-scale succession of alluvial-to-coastal plain strata (late Cretaceous Blackhawk Formation (Wasatch Plateau, central Utah, U.S.A.), which demonstrates diverse distributions of channelised fluvial sandbodies at reservoir scale. Comparison with process-based numerical models of fluvial stratigraphic architecture imply the predominance of an avulsion-generated pattern of sandbody distribution that includes an element of compensational stacking on the upper coastal plain and alluvial plain. On the lower coastal plain, localized clustering of channelized sandbodies is interpreted to have formed by a combination of low-amplitude sea-level fluctuations and avulsion of deltaic distributary channels.

These outcrop data were used to construct object-based reservoir models that mimic the sandbody dimensions, abundances and distributions observed in different stratigraphic intervals and palaeogeographic locations with low to moderate net-to-gross ratios (11-32%). Two descriptive spatial statistical measures, raster-based lacunarity and point-based L function, were used to characterise sandbody distribution patterns in the outcrop data and in the object-based reservoir models. Lacunarity is sensitive to sandbody abundance and net-to-gross ratio, while L function identifies clustering, random and regular spacing of sandbodies. In common with previous studies, the connected fraction of sandstone in the 3D reservoir models increases with increasing net-to-gross ratio and with increasing range of sandbody orientations, but there is significant stochastic variation around both of these trends. In addition, low net-to-gross reservoir models in which sandbodies exhibit a high degree of clustering have a lower connected fraction of sandstone than models with regular, random or weakly clustered sandbody distributions, because the clustered sandbodies are widely spaced and thus tend to be isolated. Thus, connected sandstone fraction could be overestimated if avulsion-generated sandbody clusters are not identified and replicated in models of such reservoirs.

The wider implications of this work are that current stratigraphic models and industry-standard geostatistical tools are both inadequate to capture autogenic patterns of channelised sandbody distributions, even where conditioned to well data. The result is models that are inherently unable to assess the full range of potential sandbody connectivities (and associated sweep patterns and recovery estimates) in channelised sandstone reservoirs. Solutions will likely require a combination of process-based stratigraphic forward models and new spatial statistical tools, both of which will need to be ground-truthed against high-quality sedimentological and stratigraphic datasets.
NOTES
Structural Models for Reservoir Estimation: How Scale Matters.

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Structures are recognized to have a primary impact on hydrocarbon reserve estimation, reservoir dynamics and production prediction. Scaling issues are common problems encountered by reservoir geologists. Dealing with structurally complex reservoirs raises two scaling issues. (1) A downscaling problem: due to the resolution of the seismic image used to conduct reservoir studies, only large-scale structures can be interpreted, while the fault continuity, segmentation and linkage are uncertain. However, these subseismic structural features may significantly impact the fluid flow behavior and therefore has to be taken into account in the reservoir modelling process. (2) An upscaling problem: fine-scale structures, e.g. relay zones smaller than the reservoir grid cell resolution, can be quantified by using field analog data but cannot be directly integrated in flow simulation grids. An upscaling strategy is therefore required. We propose to use stochastic methods to deal with these scaling issues.

A stochastic fault network simulation method (Cherpeau et al., 2010; Julio et al., 2013) is adopted to deal with seismic resolution issues. This method proposes to sequentially simulate faults and fault connections by taking into account seismic observations. By doing so, different subseismic fault segmentation and linkage configurations can be generated leading to the investigation of different production scenarios.

However, when fault structures are below the reservoir grid resolution, another strategy has to be adopted. In the case of fault relays, we propose to use an object-based geostatistical method to simulate their position along the fault plane. The fault relay equivalent dynamic property is then upscaled at the reservoir grid scale using a renormalization method.
Thursday 5 March
Session Three
Recognising the Limits of Reservoir Modelling - and how to overcome them

Keynote Speaker: When Geostatistical Reservoir Models Become Unfit For Purpose (And Ways to Avoid This)

Michael Pyrcz and Richard Sech, Chevron ETC

Geostatistical modeling methods are widely used to model oil and gas reservoirs. Their selection is motivated by demands such as: (1) data conditioning with integration of data of variable scale and type for sparse and dense data settings, (2) integration of geologic mapping away from wells encoded as nonstationarity models, (3) reproduction of statistics and heterogeneity models derived from local observations and geologic conceptual models, (4) representation of uncertainty through multiple equiprobable realizations and methods to communicate uncertainty, and (5) efficiency. The evolution of geostatistical techniques has enabled practical workflows that, paired with various geological and engineering constraints, have improved decision making in the presence of subsurface uncertainty.

Yet, there are fundamental limitations of geostatistical approaches that must be considered in designing reservoir modeling workflows. For example, stationarity is the assumption that the input statistics are invariant under translation. Each geostatistical reservoir model imposes stationarity over a range of scales. This must be understood and best practice is to maximize geologic mapping to relax this assumption, but this often degrades the uncertainty model if uncertainty in the geologic mapping itself is not considered. Also, consider that the spatial features reproduced in geostatistical simulation are limited to a reduced set of input statistics represented by the two point semivariogram, multiple point statistics or geometric parameters for objects. Beyond these limited spatial statistics the geostatistical realizations tend toward maximum entropy, which is associated with maximum discontinuity of extreme values. Given the importance of connectivity of permeability extremes to the formation of flow barriers, baffles and conduits, this attribute often has significant consequences on the simulated flow response. Finally, all geostatistical simulation methods include an inherent conditioning priority. Contradictions in model inputs are settled by compromise and simulation models may not honor all input data; there are limitations.

There are opportunities to improve the practice of geostatistical reservoir modeling through expert guidance and implementation of new technology. Essential to expert practice is an appreciation of the numerics and resulting behavior and limitations of each simulation method. This will optimize choice, implementation and design of entire project workflows. An understanding of limitations such as those discussed above drives the practitioner to the integration of more descriptive nonstationarity models to improve characterization of flow significant features and to broaden their toolkit of simulation methods to meet project goals. Emerging technologies that produce more complicated heterogeneity patterns through advanced statistical characterization or integration of depositional process have been proposed, and some leading examples of these will be demonstrated.
Rapid Reservoir Modelling – Efficient and Intuitive Prototyping of Geological Concepts and Reservoir Models

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Constructing or refining complex reservoir models is challenging and time-consuming. The lack of an intuitive set of modelling and visualization tools that allows rapid prototyping of reservoir models significantly increases the challenge. Conventional workflows, facilitated by commercially available software, have remained essentially unchanged for the past decade. These workflows are slow, requiring months from initial model concepts to flow simulation or other outputs; moreover, many model concepts, such as large scale reservoir structure and stratigraphy, become fixed early in the process and are difficult to retrospectively change, often because the model must be re-gridded if structure and/or stratigraphy change. Uncertainty is often quantified by changing rock properties assigned to grid blocks within a fixed structural and stratigraphic framework, which may significantly under-estimate, or fail to identify the true cause of, uncertainty. Traditional reservoir modelling workflows are poorly suited to rapid prototyping of a range of reservoir model concepts and testing of how these might impact on reservoir behaviour.

We present a new reservoir modelling approach termed Rapid Reservoir Modelling (RRM) that allows such prototyping and complements existing workflows. In RRM, all reservoir geometries that describe geological heterogeneities (e.g. faults or sedimentologic features) are modelled as discrete volumes bounded by surfaces, without reference to a predefined grid. These surfaces, and also well trajectories, are created and modified using intuitive, interactive techniques from computer visualisation, such as Sketch Based Interface Modelling (SBIM). Input data can be sourced from seismic, geocellular or flow simulation models, outcrop analogues, conceptual model libraries or blank screen. RRM outputs can be exported to conventional workflows at any stage. Meshing of the models within the RRM framework allows rapid calculation of key reservoir properties. We demonstrate the RRM workflow using a number of examples.

This work allows, for the first time, application of rapid prototyping methods in reservoir modelling. Such methods are widely used in other fields of engineering design and allow improved scoping of concepts and options prior, or in addition, to detailed modelling. SBIM can be used on a range of hardware architectures, including table tops and surface PCs, fostering collaboration within integrated asset teams.
Automated History-Matching of Small-Scale Heterogeneities Using Stochastic Surface-Based Property Models

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Clastic reservoirs often contain centimeter- to decimeter scale heterogeneities that can act as barriers or baffles where they are lined by low-permeability lithologies and aligned perpendicular to the flow (Jackson and Muggeridge, 2000). The characterization and reservoir modelling of such heterogeneities have been extensively studied over a range of depositional environments including: siltstone units between lobes in turbidite reservoirs (e.g. Pyrcz et al., 2005; Prelat et al., 2009); mudstone-lined clinoforms in shallow-marine reservoirs (e.g. Sech et al., 2009; Jackson et al., 2009); and shales deposited as part of fluvial point bars in fluvial reservoirs (e.g. Willis and Tang, 2010; Hassanpour et al., 2013). A variety of object-based methods have been proposed to explicitly capture the distribution of such heterogeneities in reservoir models (e.g. White et al., 2003; Alpak and van der Vlugt, 2014). However, despite this modelling effort towards their efficient representation in geological models, heterogeneities at this scale are often not explicitly captured in simulation models. This is because they typically occur over lengthscales smaller than a single simulation grid block, as the simulation model is built at a coarser scale than the geological model for computational efficiency. Heterogeneities are therefore captured implicitly in flow simulations using effective petrophysical properties or transmissibility multipliers, or are not captured at all, even when such heterogeneities have been shown to strongly influence hydrocarbon recovery.

A new parameterisation which consists of two steps is proposed. First, the heterogeneity between geological objects is represented by attaching stochastically generated properties belonging to the heterogeneity, such as thickness and permeability, to the surface representing the stratigraphic object. For example, low permeability shale packages that occur at the base of channels are attached to stratigraphic surfaces that bound the volume of specific channel intervals. This in itself is advantageous, as surfaces are not created using an underlying geological or simulation grid, thus allowing for increased flexibility and efficiency in reproducing complex distributions, geometries, hierarchies and interactions of geological features in the subsurface. A grid however, is required to solve the governing flow equations. Such a grid can be conditioned to the surface framework or generated without reference to the surfaces. In the second step, the heterogeneity is represented in flow simulations by directly modifying the transmissibility calculated between cells at each simulation time step, using the heterogeneity property information attached to the surface template.

This parameterisation is validated via a synthetic fluvial reservoir simulation model, using an automated history matching method to assimilate production history. In this reservoir model, we focus on the small-scale heterogeneity associated with shale packages at the base of fluvial channels; however the method can be applied to other small-scale heterogeneities in simulation models, such as fault zone properties. The resulting flow simulation models demonstrate the value of the method over conventional approaches when applied to a history-matching problem. The update of heterogeneity parameters such as thickness and permeability improves the history match and production forecast in comparison to using traditional implicit techniques relying on the update of transmissibility multipliers. Furthermore, the new method shows an improvement in the update of the underlying geological model in comparison to the
traditional approaches. These results indicate that traditional implicit methods of representing heterogeneity in simulation models may fail to capture the fluid movement in the reservoir, resulting in some automated history-matching techniques failing to produce reliable models for forecasting future production.

References

Fast Iteration - Geoscientists and Engineers Working in Harmony

Liz Chellingsworth, Pete Kane and Tian Xia, AGR TRACS

A history matched model is a beautiful thing – or is it? A matched oil rate or water cut profile may look satisfying but if the reservoir engineer has bent and twisted the geological model beyond all recognition then the validity of both geological and simulation model should be called into question.

There is often an expectation in reservoir teams that history match ‘fixes’ should be applied in the simulator and not at the geological modelling stage. By adopting an iterative, integrated approach right from the start of the reservoir evaluation, we explore the possibility of bringing together data, concepts and learnings from analogue fields into an integrated reservoir model. By tuning the various elements within the bounds of the (reliable) data and (appropriate) concepts, mutually acceptable ‘fixes’ can be implemented in the geological model, the simulation model or both. When this process occurs quickly through close collaboration between geoscientists and engineers, we talk of Fast Iteration.

We use a case study from a Paleocene turbidite field in the North Sea to illustrate the Fast Iteration process. In the example we have a sparse well stock and the seismic data represent a limiting factor to sand prediction. Thus we used geological concepts to model sand extent away from the wells, utilizing an innovative attribute to implement those conceptual models. Early feedback from the dynamic analysis also guided sand prediction, in particular the connection in the water leg. Through an integrated, iterative process we obtained a history match from a reservoir model that honoured all the static and dynamic data but was not limited by the imperfect seismic data. Crucially once we obtained ‘the answer’ we tested various alternative realisations – all of which also honoured the input data – to ensure we had explored the full range of outcomes. This process included trying to ‘break the match’ to investigate where the tipping point lay and what static or dynamic parameters controlled the history match. We demonstrate that when geoscientists and engineers work together in harmony, the history matched reservoir model really is a thing of beauty.

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The Snorre field, situated on the Tampen Spur is one of the largest producing fields on the Norwegian shelf, with the largest remaining oil reserves, and one of the longest life expectancies. The reservoir consists of a highly faulted fluvial reservoir. Ever since the dawn of 3D geological modelling the development of and the production of the fluvial reservoir of the Snorre field has been one of the driving forces in developing the way the oil industry is assessing hydrocarbon reservoirs. Now after more than 20 years of production the complexities of the reservoir are more evident than ever before. The Snorre asset is now building a new common workflow for generation of models for flow simulation and geological evaluation. This workflow marks a move away from the use of the base case, and the introduction of multiple realisations, in the reservoir evaluation of the Snorre field. This change is made with the aim of shedding light on the influence of the key geological uncertainties on the production profiles in a much more direct way. The goal of the workflow is to be a living workflow that can generate tailor made high quality reservoir models in well planning, and to be used to make better decisions for how to produce from the field, both on a short and long time horizon.

In the process of developing this workflow a number of recent in house developments within reservoir modelling are being implemented. These developments can be summarised into the following key elements:

- Automatic generation of multiple scenarios of both the structural framework and the flow properties of the reservoir to be taken on into flow simulation to make production forecasts
- Modelling of channel belts directly at the simulation scale. This is done in tandem with a multiscale upscaling to ensure correct representation of the flow properties at the simulation scale
- Paving the way for conditioning to 3D and 4D seismic data
- A simplified fault seal methodology that is an ideal meeting ground for the reservoir engineers and the geologists to ensure that both geological knowledge and the understanding of the production behaviour is preserved in the model

With the introduction of this workflow the Snorre asset is taking a long step forward in the way one does history matching, especially in including uncertainty in the reservoir geology, and therefore making better production profiles. The new workflow however exposes quite clearly that there is still no substitution for proper geological understanding, and there are still many areas that are difficult to understand, and the understanding of these areas will require the willingness to go back to the input data, and in some instances challenge the existing understanding both of the production data and the geological data available.
NOTES
Integrated Static and Dynamic Uncertainty Workflows for Field Development Planning: an Example from the Jackdaw Discovery, Central North Sea.

D.J. Ryan, J. Opata, J. Luchford, S. Taheri, A. Kononov, N. Lee and A. Hall, BG Group

Integrated static and dynamic uncertainty workflows are a powerful tool for quantifying subsurface risks and guiding decisions during field development planning. A multi-disciplinary workflow that incorporates geophysical, geological and production uncertainties has been developed for the Jackdaw discovery, a High Pressure, High Temperature, gas-condensate field in the central North Sea.

As a result of high well costs and the challenges of operating in extreme sub-surface conditions at depths approaching 19000 ft (5800 m), the exploration and appraisal programme, conducted between 2005 and 2012, was recognised as being unable to resolve various key uncertainties. In order to progress the development through the decision chain and provide key stakeholders with a robust, reasoned and accurate resource range, a key element in evaluating overall value, the sub-surface team developed innovative approaches to dealing with and quantifying the key uncertainties.

This workflow draws on a geological model built with PETREL with uncertainty parameters defined within MEPO. In addition to modification of geological and petrophysical parameters, each realisation runs additional nested workflows. The first of these nested workflows modify the structure of the grid to account for gross rock volume and seismic interpretation uncertainty. The second workflow automatically calibrates the generated static model to the available drill stem test data.

Each model realisation is simulated with ECLIPSE, with results sent back to MEPO for statistical analysis and the generation of probability distribution curves for both GIIP and reserves. Sensitivity analysis reveals the key uncertainty on in place volumes in both the appraised and un-appraised fault blocks are the gas-water contacts. However recovery from the reservoir is largely controlled by abandonment pressure and permeability. The reservoir comprises a bimodal permeability system that is primarily controlled by depositional facies. High permeability turbidite or gravity flow deposits are found within a background of low permeability, bioturbated shelfal sand. The shelf sand facies has core measured permeabilities of 0.005-1 mD (air permeability). As a result of this low permeability, uncertainty around the Klinkenberg correction factor and vertical permeability can significantly impact recovery.
Thursday 5 March
Session Four
Keynote Speaker: Predictability in Reservoir Performance Forecasting

Mike Christie, Heriot-Watt University

The challenges that we face in designing efficient means of oil recovery share many similarities to other complex science and engineering challenges such as weather forecasting, radioactive waste disposal and ocean circulation modelling. A fruitful source of ideas for advancing our ability to predict oil recovery accurately is to examine solutions found in other scientific fields. This talk will illustrate some techniques developed in other fields that have the potential to both improve our ability to quantify uncertainty in, and optimise our ability to increase, recovery of hydrocarbon from reservoirs.
NOTES
Decision Driven Integrated Reservoir Modelling: It’s Application to Field Development Planning and Well and Reservoir Management

John Brint and Tim Woodhead, Shell Global Solutions Upstream International, 1 Altens Farm Road, Nigg, Aberdeen AB12 3FY, UK

Optimal Integrated Reservoir Modelling (IRM) for development planning and well and reservoir management requires the holistic integration of sub-surface work and its iterative testing against economic outcomes. The workflow should be scaled and naturally iterative allowing the addition of detail to models where it is shown to be required. It allows for an audit trail and evergreen approach – modelling from exploration to operations.

The emphasis for IRM in Shell is a focus on a broader description of uncertainty rather than ever-increasing attention to detail and complexity. It allows reservoir understanding to be built up systematically, starting from simple high level interpretations to which detail is added where this is shown to be critical to a development decision. This is consistent with the need to accelerate cycle times and provide more robust steer to field development decisions.

Our aim is to describe the reservoir by multiple geological concepts. Each concept needs to be screened against available data and then ranked against the relevance for development decisions. Reservoir and geological concepts can only be eliminated from the uncertainty ranges, expressed as dynamic model parameters, when negated by data, or when they have no impact on the development decisions.

By application of our IRM process we aim to reduce model building effort so allowing more time to be spent on analysis, decisions and integration. This helps avoid model anchoring to one base case and allows the discrimination between development concepts that can be progressed and those that require further appraisal.

Our IRM process is focussed on decision-driven workflows. Examples will be shown on how a decision driven approach to modelling is undertaken, including the definition of a modelling strategy.

We need to continue the move in IRM from a lengthy linear exercise to a repeatable iterative loop that incorporates model sufficiency with the dynamic response and the economic impact together.

We will demonstrate how our approach aims to capture a wide range of uncertainties, avoid anchoring on a base case whilst working at the appropriate scale to ensure we make realistic promises and forecasts.
NOTES
"Envelope of Outcomes" Method for Forecast S-Curve Generation

Ed Stephens, AGR

In a multiple deterministic modelling workflow, a dilemma for evaluating development projects is how to assign likelihood to the outcome distribution. This is especially problematic where history matching is required since the conditioning from the dynamic model is a coupling of the input parameter values, so preventing an a priori unbiased model selection.

The challenge is to interpret a set of forecasts from particular history matched models as a single probability S-curve and chance of success. Common approaches suffer from a number of drawbacks: i) ranking on match quality or history match sensitivities may not reflect the key sensitivities for the forecast, especially if the development is targeting undrained areas or changing the recovery process; ii) model set asymmetry also complicates analysis e.g. when greater effort is to be focussed on downside case models; and iii) treating all realisations as equiprobable is susceptible to bias from clustering of results, e.g. if a small number of outliers identifies a decision critical uncertainty.

The ‘Envelope of Outcomes’ method treats the outcomes as a single set, through a scatter plot of incremental recovery vs. in place volume. The data points represent the particular forecast results from each realisation and there is normally a tendency for greater recovery for models with higher in place volume, but subject to conditioning of the previous production/pressure history. The vertical scatter of the results represents the uncertainty in outcome due to architecture and/or dynamic parameters. The interpreted probability S-curve is based on an envelope following the slope of the upper and lower bounding results in the set, without necessarily picking a ‘mid case’ trend. These are combined to a two-variate probability distribution ‘heat map’ from which the S-curve is derived by integration.

The key advantages of the method are:

- The envelope is relatively insensitive to clustering or selectivity within the set, as long as at least one of the models has explored the decision critical uncertainty.
- The distribution of results can highlight areas where there may be under sampling that might be require additional realisations.
- The envelope is an efficient communication of the relation between actual results from the deterministic models, judgement of what the model set as a whole means in terms of the unknown reality and how these are related to project chance of success.

The method is illustrated by two field cases, with consent of the operators, with multiple deterministic model based evaluation of the proposed further development.
Recognising the Limits of Reservoir Modelling - and how to overcome them

S-curve of outcomes

- Envelope of outcomes
  - Slope and width define distribution of *interpreted* outcomes range
  - Slope: trend vs. STOIIP
  - Width: range vs. architecture

- Heat map
  - $\text{Prob(Volume)}$ follows static volumetric analysis
  - $\text{Prob(Architecture)}$ peaked in the centre, noting we evaluated ‘extremal’ parameter combinations

- S curve
  - $\text{Prob} < R = \text{area} \times \text{heat below } R$

$$P(x) = \sum_{R<x} \text{Heat}(R, V)$$

Incremental recovery vs. STOIIP

$$P(3 \text{ MMb}) = \sum_{R<3} \text{Heat}(R, V)$$
Recognising the Limits of Reservoir Modelling - and how to overcome them

Reservoir Modeling For Flow Simulation: Surface-Based Representation of Geologic Heterogeneity and Space- and Time-Adaptive Unstructured Meshes

Matthew Jackson, Gary Hampson, Chris Pain and Gerard Gorman, Department of Earth Science and Engineering, Imperial College London

The widely accepted workflow currently employed in reservoir modeling typically yields models in which the spatial resolution of the grid, defined early in the modeling process, dictates the spatial resolution at which geological and flow features can be captured. Moreover, the geometry of the grid is restricted by the requirement of k-orthogonality, to be consistent with the ‘Two-Point Flux Approximation’ (TPFA) invoked in commercial flow simulation software. Despite the popularity and longevity of this workflow, it is well known that key geologic heterogeneities, and key aspects of flow, are often not captured in the resulting simulation models. The problem with using k-orthogonal (typically pillar) grids of a given spatial resolution is that they often provide a poor representation of geologic heterogeneity; moreover, in conventional reservoir simulation models, the same fixed grid resolution is used throughout a given reservoir zone yet in many production scenarios, higher grid resolution is required in specific regions of the model where gradients in a property of interest (e.g. pressure, saturation, concentration) are large, and lower resolution is acceptable elsewhere. A more efficient use of computational effort is to adapt the grid in space and time to be refined where necessary. In this paper, we describe a new approach to reservoir modeling and simulation that employs:

1. Surface-based modeling (SBM) of geologic heterogeneity, without reference to a pre-defined grid.
2. Unstructured, non k-orthogonal meshes to discretize the rock volumes defined by the surfaces, and a Control-Volume-Finite-Element-Method (CVFEM) to solve the governing flow equations.
3. Dynamic adaptive mesh refinement (AMR) to focus computational effort on regions of the reservoir where it is required (e.g. Fig. 1).

Fig. 1. 2D slice through an example 3D immiscible two-phase flow simulation using the methods reported here. Snapshot in time showing (A) dynamic adaptive mesh refinement (AMR) to capture (i) high permeability features (‘fractures’ shown in purple) embedded in a low permeability background, and (ii) the location of the waterfront; (B) water saturation (high values in red), with injection over the left-hand face. As the waterfront advances through the model, AMR allows its complex geometry to be accurately captured. This is an extremely challenging problem to capture using conventional reservoir modelling methods employing fixed, k-orthogonal grids and the TPFA but is easily handled by the methods reported here.
In our approach, geological heterogeneities are represented as discrete volumes bounded by surfaces, regardless of whether the heterogeneities are structural, stratigraphic, sedimentologic or diagenetic in origin. Within these discrete volumes (termed ‘geologic domains’), the petrophysical properties are constant. This is equivalent to a grid-based approach, in the sense that petrophysical properties within grid cells are constant; however, in our approach, properties are constant within geologically meaningful domains, rather than cells of arbitrary size and shape. The surface-based modeling methodology is, in principle, simple: numerous surfaces are used to represent (i) fault surfaces, (ii) stratigraphic surfaces, (iii) boundaries between facies associations, and/or facies types within facies associations, and/or rock types or lithologies within facies types, (iv) boundaries between different regions of diagenetic modification of rock properties, and (v) fracture surfaces. The surfaces are ranked into a hierarchy based upon relationships that specify which surfaces truncate, are truncated by, or conform to, other surfaces and are generated using deterministic or stochastic techniques developed at Imperial College (IC) and elsewhere; these techniques are analogous to those used in conventional geologic modeling, except here the model is built without reference to an underlying grid.

The resulting surface-based geologic model is discretized for flow simulation using an unstructured, tetrahedral mesh that honors the architecture of the surfaces and allows heterogeneity over multiple length-scales to be explicitly captured using fewer cells than conventional grids. Multiphase flow is simulated using CVFEM in an open-source code developed at IC (IC-FERST). Computational costs are reduced through (i) efficient and massive parallelization and (ii) dynamic AMR, in which mesh elements may be split or amalgamated (h-adaptivity) or element vertices may be moved (r-adaptivity) during simulation, using libraries developed at IC and incorporated in IC-FERST. Within each geologic domain, the unstructured mesh coarsens and refines to capture key flow features, whilst preserving the surface-based representation of geological heterogeneity (e.g. Fig. 1). When adapting the mesh, it is not necessary to calculate new values of effective permeability (or other petrophysical properties) from some underlying fine-scale distribution, because AMR is applied within domains with uniform properties. This key step allows dynamic AMR to be applied without introducing a large computational overhead in up-, cross- or downscaling permeability each time the mesh changes; indeed, the computational cost of AMR is far less than that of a fixed mesh yielding the same solution accuracy (Fig. 2).

We demonstrate a number of distinct advantages to a surface-based approach to reservoir modeling in conjunction with an adaptive, unstructured mesh simulator:

1. The geologic model can be constructed without reference to a pre-determined grid, and is the same as the simulation model except that the latter has a mesh that discretizes the geological domains.

Figure 2. Computational cost of high resolution static mesh (c. 2 million nodes), adaptive mesh yielding the same solution accuracy (c. 25,000 nodes maximum), and static low resolution mesh (c. 25,000 nodes) yielding much lower accuracy, for the problem shown in Fig. 1. The overhead of AMR is small.
2. Computational costs are reduced, because complex geometries can be represented in simulation models using fewer cells, and surfaces are less expensive to generate and manage than large grids.

3. An unstructured mesh can better capture complex reservoir architectures than a conventional pillar grid, because the geometry and dimensions of the mesh elements are more flexible.

4. The mesh resolution varies in space to better capture heterogeneity, with higher resolution in model regions with complex architectures.

5. The mesh resolution varies in time to better capture fluid flow, with higher resolution in model regions with steep gradients in pressure, velocity or saturation. Conventional simulation grids have fixed resolution, which limits the resolution at which fluid flow can be captured in the model.

Although not yet a finished product, this new workflow shows great promise for improved reservoir modeling, allowing complex geological and flow features to be better captured in reservoir simulation models at lower computational cost.
NOTES
High Resolution Modeling: A Step-Change in Asset Team Integration

Banks, C.J., Zhienkulov, M., Schlumberger Information Solutions, Kirkhill House, Dyce Drive, AB21 0LQ.

The effectiveness of an oilfield asset team is dictated by the ability of different disciplines to integrate to develop a unified vision of the subsurface. This necessitates a seamless flow of data, interpretation and concepts from seismic interpretation, through static geological modelling to simulation.

The addition of seismic interpretation functionality to geological modelling software has enabled the Geologist and Geophysicst to collaborate in a single 3D environment. However, the computational requirement of upscaling for reservoir simulation, has hitherto prevented effective collaboration between Engineers and Geoscientists.

When a “coarse grid” (500K to 1 million cells) is the end point, Geoscientists may restrict the scientific resolution of their models in the initial model build. This makes it difficult to accurately model complex structures and high frequencies of vertical and lateral resource heterogeneity (thin beds, facies interfingering) that would better be captured in multi-million cell grids.

The next generation of reservoir simulators can accurately simulate fluid flow and test field development strategies at the fine-grid scale (1 million – 10’s of millions of cells). This removes the bottle neck for passing on scientific information and resolution from Geoscientist to Reservoir Engineers. Static and dynamic models effectively become one.

With a single grid being used by all disciplines, combined uncertainty analysis can be run on the assets unified vision of the subsurface. This gives a better quantification of risk, empowering better decision making during the life cycle of the field.
Poster Presentation Abstracts
All Simulation Models are Wrong - But Geological Well Test Modelling Can Still Be Useful.

Patrick W. M. Corbett, *Institute of Petroleum Engineering, Heriot-Watt University*

Over the last two decades it has become increasingly feasible to study single well geological models at high enough resolution in order to generate synthetic well test responses from numerical simulations. These models – referred to as geological well test models - are useful in driving the understanding and mapping of the geological variation (as quantified by porosity and permeability contrasts) in the near-well bore region enabling many workflow steps: matching well test data, eliminating unlikely geological scenarios, ranking geological scenarios, enforcing dynamic – static integration, providing PLT calibration of geological models, testing reservoir model calibration and improving history matching. The increasing ability to do these models is driven by the development of fine scale models and the ability to consider complex geological geometrical-systems in 3-D. The understanding of the classic well test radial composite and linear flow models in the presence of significant vertical and lateral cross-flow is becoming better understood. However, there are a number of workflow and cultural issues preventing these models being more widely used and it is expected that these will fade over the coming years as geologist get more involved with near-well bore modelling and the software allows these models to be more easily accommodated within the commercial time-frames of industry projects. The geological type curve models are particularly relevant to understanding the dynamics of complex clastic (braided fluvial systems) and carbonate systems where the industry could be challenged to improve recovery factors. Fractured reservoirs, with complex matrix-fracture interactions, are also ‘falling’ to geological modelling and geological well testing approaches. Geological well test modelling as a sub-discipline of geengineering will become an increasingly easy way to understand near well regions of reservoirs and encourage the geoscience community to engage more effectively with the well testing community. This approach is considered to be useful for improving the understanding of reservoir performance and should lead to quicker and more useful reservoir models.
A Model is only as Good as the Data Put into It: Identifying Inter Reservoir Sands.

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Considerable research has gone into improving software, algorithms and multipliers for reservoir modelling in the petroleum industry. However, all these improvements still rely on the quality of data going into the model. Sand on sand contacts within reservoirs are incredibly difficult to identify on logs or seismic unless there is a significant change within the sand such as a mud baffle, cementation surface, major change in sand characteristics etc. Elemental chemistry does have the potential to identify sand on sand contacts, however in clean reservoirs even this can be hindered due to large amounts of Si (from Quartz) diluting the elemental signal.

An alternative method of looking at how sands vary within a reservoir is through the use of heavy mineral and detrital zircon analyses. Heavy mineral analysis and detrital zircon geochronology are commonly used as sediment provenance tools within academia. However, to be fully effective, provenance studies require sizeable data sets, which until recently have been too time consuming for provenance to be a routinely used tool in the oil industry. New methods enabling rapid, reliable data to be gathered now enable provenance to be a valuable tool in a commercial setting. Heavy mineral analysis gives insights into lithological composition of the source geology, with detrital zircon geochronology providing information on the ages of initial igneous source rocks. Furthermore, analysis of zircon geochemistry (e.g. U and Th ratios) can differentiate isochronous source units and the morphology of individual zircons provides insight on sediment reworking history. However, to be fully effective, provenance studies require sizeable data sets. However, to be fully effective, provenance studies require sizeable data sets, which until recently have been too time consuming for provenance to be a routinely used tool in the oil industry. New methods enabling rapid, reliable, data to be gathered now enable provenance to be a valuable tool in a commercial setting.

Traditionally in academia, provenance data have been utilised to identify large scale regional trends in sands. This paper illustrates, through the use of case studies from the West of Shetlands area, how provenance data sets produced quickly and cost effectively can be utilised to identify sand on sand boundaries and variations within reservoirs that are otherwise invisible. Therefore, this enables a fuller understanding of reservoir units, reservoir stratigraphy and reservoir quality, which will provide data of hitherto unseen resolution to be presented to reservoir modellers.
The Impact of Fine-Scale Reservoir Geometries on Streamline Flow Patterns in Submarine Lobes: Outcrop Analogues from the Tanqua Depocentre (Fan 3 & Unit 5)

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Capturing multiscale heterogeneities within deep-water stratigraphy can help to improve reservoir models and therefore recovery factors. The use of outcrop analogues is a key tool within this process for gaining knowledge on detailed sedimentary architectures and facies relationships. The sand-rich submarine fan systems of the Tanqua depocentre allow a detailed study of individual submarine lobes. An advanced geological reservoir model of a terminal lobe complex of Fan 3 (Skoorsteenberg Formation) was constructed using ReservoirStudio™, which permits realistic architectures and facies distributions of both lobe and channel bodies to be captured. Available data from the Glinne gas field, a similar sand-rich submarine fan system in the northern North Sea, was used to construct petrophysical property models. Artificial injectors and producers were implemented at various locations in the system. By the use of streamline analysis (RMS²012TM) the effects on fluid flow were tested between i) traditional lobe deposit models with vertically stacked facies belts that mimic coarsening-upwards in all locations, and ii) deterministic models that include lateral facies changes with dimensions and distributions constrained from previous field data from the Karoo.

The findings show that the lobe architecture model employed has a significant influence on the predictability of the breakthrough time within reservoirs. Channelized lobe areas show the best connectivity, but the presence of channels at the well location becomes less important within the more deterministic lobe models due to lobe axis amalgamation. Within channelized lobe areas, the sand proportions of submarine lobe deposits and the level of facies detail within the channel infill have a major influence on fluid-flow behaviour. Breakthrough time becomes up to 75% shorter with added flow barriers such as mud-clast conglomerate lags and mud-bearing banded sandstones.

The implementation of sedimentary detail and the use of realistic sedimentary concepts on the architectural scale are shown to be vital in accurately capturing multiscale reservoir heterogeneities, which will help to improve predictions of reservoir recovery.
Fig. 1: Plan view of a terminal lobe complex facies model based on Fan 3 in the Tanqua depocentre. The various locations of artificial injector and producer pairs are indicated.

Fig. 2: Photo-panel of the ‘Ongeluks River’ section of Fan 3, showing a distributive channel system cutting through lobe-like deposits (top) & a simplified facies model of the same section (below).
Use of Seismic Attributes in the Modeling of Pore Systems, Water Saturation and Permeability of Carbonate Reservoirs

Noelia Rodríguez Morillas¹, Taoufik Ait-Ettajer¹, Mudaham Zen¹, Laurent Fontanelli²

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The 3D modeling of water saturation (Sw) and permeability (K) in carbonate reservoirs is a complex task due to the complexity of the pore network. This pore network is defined by the presence of multiple pore systems. Each pore system is defined by its bulk volume (Bv), its minimum entry pressure (Pd), that allows the fluid to enter and exit the pores, and the variability of the pore throat diameters (G) that control the access to the pores. Classical approaches for the modeling of Sw cannot take into account the coexistence of multiple pore systems (Clerke, 2003), and the computation of the permeability cannot be performed using classical poro-perm relationship as each pore system contributes to the global permeability.

Thomeer (1960), Swanson (1981) and Clerke (2003) proposed different approaches to improve the modeling of Sw and K. Those approaches are restricted to the zone of the wells where laboratory measurements such as Mercury Injection Capillary Pressure (MICP) were performed. The following equations show the relation between the pore system parameters and Sw and K:

\[ Sw = 1 - e^{\frac{G}{Pc}} \]
\[ K = a \times G^b \times \left(\frac{Bv}{Pd}\right)^2 \]

where Pc is the capillary pressure, a and b are constants.

Recent studies (Ait-Ettajer, 2012, 2014 and Sung, 2013) proposed the use of Sequential Gaussian Simulation, in order to interpolate the pore systems in 3D while honoring the well data and the variogram parameters. One of the limitations of those methods is the high level of uncertainty, due to the limited number of conditioning data.

In our paper we propose to improve the previous approaches by enhancing the interpolation of the pore system parameters in 3D, using seismic attributes. In fact, some seismic attributes such as Shear Impedance (Zs) are correlated to the presence of water, which is governed by characteristics of the pore system and the distance to the free water level (FWL).

The proposed process is described below with examples from a Tertiary carbonate reservoir.

The first step of the process consists in defining the different geological units based on sequence stratigraphy. Those units are correlated throughout the reservoir. In our example, we restrict our study to the upper unit of the reservoir. In this zone, the MICP data showed 3 main pore systems as shown in figure 1.
In the second step of the process, we assess the relationship between Zs and percent of pore system. Figure 2 shows that there is a correlation between the trend of Zs and the trend of the second and third pore systems. This correlation can be explained by the fact that for a given distance to the FWL and for a given porosity value, the second pore system has more probability to be filled with hydrocarbon, and the third pore system has more probability to be filled with water.

During the last step of the process, we select the most adapted geostatistical approach for building pore systems percentage using Zs as external drift. The selected approach is Sequential Gaussian Simulation with External Drift (SGS_ED). This method allows incorporating many covariates, and it is less demanding of variograms. The output of the SGS_ED is a 3D distribution of the proportions of each pore system. The remaining parameters (Pd, G) will be distributed using SGS with collocated co-kriging with the proportion of each pore system, as described in Ait-Ettajer et al., 2014. The 3D distribution of Sw and K will be performed using the equations presented above. The picture below shows the distribution of the proportion of the second pore system in 3D (Figure 3).

In conclusion, we showed that the incorporation of seismic attributes allows a better control of the 3D modeling of water saturation and permeability in carbonate reservoirs, thanks to a better control of the distribution of the different pore systems.
Getting Inside a Gas Reservoir: Using Outcrop to Test Numerical Flow Simulators and Understand the Impact of Heterogeneity on Fluid Flow Behaviour

Andrew Newell¹, Andrew Butcher¹ and Gareth Williams²

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Sedimentary basins that are now areas of tectonic uplift and erosion often expose former hydrocarbon reservoirs. Where the reservoirs are terrestrial red-beds the former presence and movement of hydrocarbons are often indicated by grey or white bleaching that provides a very graphic illustration of fluid flow pathways within heterogeneous aeolian and fluvial deposits (Beitler et al. 2003; Bowen et al. 2007). Modern digital geological fieldwork methods which include terrestrial laser scanning (Fig. 1) and outcrop permeametry now make it a relatively straightforward task to construct high-quality static geological models of these former hydrocarbon reservoirs parameterised for flow simulation. Attempting to model the bleached finger-print of fluid flow movement within the palaeo-reservoir provides a bench-mark of flow-simulator performance and a real understanding of much sedimentological heterogeneity is required in a static geological model. This talk illustrates the process and outcomes using new unpublished work on some spectacularly exposed mixed aeolian-fluvial palaeo-reservoirs of the Cutler Formation along the Salt Wash Graben Fault in SE Utah, USA.

Fig. 1 Laser scanned outcrop of the Sherwood Sandstone which has been converted to a static reservoir model for a CO₂ injection simulation (Newell et al. in press)
Utilising 2D Probability Trends as Areal Constraint for the Reservoir Properties Distributions in A1000 Reservoir, "Ajot" Field, Offshore Niger Delta

Afuye Taiwo. J, and Ehinola Olugbenga. A, Department of Geology, University of Ibadan, Ibadan, Nigeria

The interpretation of depositional environment and the reservoir properties, properties modeling and property prediction for field development planning are characterised by subsurface uncertainties. There are reduced well data and absence of core data for the derivation of estimates of subsurface parameters; which form input to the process of populating trends to constrain the extrapolation of properties which increase these uncertainties.

An Areal Geological Concept; 2D Trends (Probability) Map of the A1000 Reservoir was built based on the geological interpretation of the depositional environments as interpreted from the well logs, provides areal coverage for the models. The 2D Trends Map generated was used to guide the distribution of reservoir properties away from well control/coverage. The Stochastic approach uses Sequential Indicator Simulation (SIS) and Sequential Gaussian Simulation (SGS) algorithms in PETREL™ Modeling software for building the facies and petrophysical models respectively and as well, incorporating this 2D Trends Map and tested modeling parameters like variograms, kriging, cell sizes and layering to determine which set of parameters ultimately produced the most geologically reasonable model of the A1000 reservoir thus minimising the subsurface uncertainties.

The results of the properties models show that regions showing good facies, higher porosity, higher permeability, lower shale volume, lower water saturation values of the A1000 reservoir as optimal location for development wells placement from the static modeling perspective.

Quality Check Tests show that reservoir properties models built are consistent and honoured the geological interpretation of the depositional environments. This approach will enable optimal development well placement, STOIIP estimate and eventually leading to successful dynamic Modeling of the reservoir.
Improving the Accuracy of Geological Models through Geometric Restoration and Forward Modelling In Move

E. Macaulay, J. F. Ellis and A. Vaughan, Midland Valley Exploration, 2 West Regent Street, Glasgow.

Accurate geological models provide the starting point for any meaningful reservoir simulation. Interrogating geological models through geometric restoration and forward modelling are well-established techniques to test a model’s validity and accuracy. Geometric restoration involves retro-deforming models to their pre-tectonic geometries and attempting to fit them back together; overlapping fault blocks and loss of material are common indicators that an interpretation is not structurally valid and needs to be improved. Forward modelling involves reproducing the present positions and geometries of horizons by simulating deformation and the region’s geological evolution.

In recent years, the geometric restoration and forward modelling workflows in Move have been significantly enhanced. In this presentation, we provide an overview of these improved workflows by investigating the validity of two geological models and refining the interpretation. An interpreted cross section from Wheeler Ridge in California (Mueller and Suppe, 1997) is block restored, revealing a significant space problem in the retro-deformed horizon geometries. The pre-tectonic horizons are then reconstructed and forward modelled using the Fault Parallel Flow algorithm to produce a structurally valid, balanced interpretation. An additional benefit of utilizing this workflow is the ability to distinguish different fault timing scenarios.

The validity of a 3D geological model from the North Sea is also interrogated using geometric restoration. Unfolded fault bounded blocks are fitted back together using the jigsaw restoration workflow within Move, identifying areas of misfit caused by incorrect fault interpretations. Fault-related deformation is then forward modelled to better understand the structural evolution of the region and extending the interpretation into poorly constrained areas.

Strain accumulated during the forward modelling can also be calculated and used to predict fracture distributions. Fracture orientations and intensities derived from the calculated strain have been used to generate a Discrete Fracture Network, which is analyzed to determine the secondary porosity and permeability in the reservoir unit.

Fault damage zones in porous sandstones with porosity higher than 12% - 15% commonly display complex networks of mm to cm thick tabular deformation bands surrounding a fault core at the footwall, hanging wall, and fault tips. Deformation bands may cause order-of-magnitude permeability reductions which impair subsurface fluid flow (Antonellini and Aydin, 1994; Sternlof et al., 2004; Fossen and Bale, 2007; Rotevatn et al., 2009). These damage zone architectures surrounding the fault core are normally not included in conventional reservoir modeling workflows. The present study gives an example of how to include fault damage zone properties in reservoir models and the sensitivity of reservoir performance to some modeling parameters.

A multi-scale modeling workflow is applied to incorporate damage zone heterogeneity of different scales into a synthetic reservoir model (Figure 1). The distribution of heterogeneity at meter scale, caused by the variation of deformation band density (number of deformation bands crossed along scanlines per meter) in damage zones, is captured using a combination of fault facies (Tveranger et al., 2005; Braathen et al., 2009) and truncated Gaussian simulation (Fachri et al., 2013a, 2013b). Three fault facies were defined in the damage zone based on deformation band density (high, medium and low density); undeformed rock constituting a fourth facies. An empirical model for spatial distribution of these facies was based on spatial analysis of band densities recorded in 106 scanlines across damage zones of extensional faults in porous sandstone outcrops in Egypt, Utah, UK, France, Netherland and Svalbard (Schueller et al., 2013). Effective permeability of individual fault facies were calculated using fine-scale mini-models for each facies, in which deformation bands and undeformed rock between deformation bands were rendered explicitly. Deformation band networks are generated using an algorithm originally developed for stochastic modeling of subseismic/secondary faults. Input data regarding deformation band orientation, displacement, and length-displacement scaling relationship are based on published outcrop studies.

As good 3D outcrops of faults are rare, it is difficult to obtain good empirical field-datasets which allow quantification of variogram ranges for modeling purposes, especially in fault-parallel direction. Fluid flow simulations were carried out to investigate the effect of changing variogram ranges on model performance. Our results show that model performance with respect oil recovery, water cut, oil production rate, field pressure and flow behavior is not influenced by changes in fault-parallel variogram ranges. Changing variogram range in fault-perpendicular direction causes only slight changes in reservoir response.

The effect of upscaling the fault damage zone was also investigated. Results show that the upscaling of damage zone properties does not affect flow performance. The upscaled models do, however, display a difference in the remaining oil distribution at the end of production. The causes that give rise to these differing flow simulation results are discussed.
Recognising the Limits of Reservoir Modelling - and how to overcome them

Figure 1. Workflow overview. (A) Explicit representation of deformation band network of each fault facies. (B) Distribution of fault facies in the fault damage zone. (C) Oil saturation at different production time.

References
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In the interests of health, safety and welfare you and your guests are requested to heed the instructions detailed below at all times and particularly in the event of an emergency situation.

If your event booking has been made on behalf of a third party, please ensure that this information is passed onto the relevant organiser or attendees.

IN THE EVENT OF A FIRE
1. Sound the Alarm
2. Call the Fire and Rescue Service by dialing 999
   999 from any Internal phone
   Report the exact location of the fire
3. Warn others in the vicinity of the danger
4. On the arrival of the Fire and Rescue Service indicate the location of the fire

ON HEARING THE ALARM
5. Leave the building by the nearest exit and gather to the assembly point (As detailed for each venue plan)
6. If possible a roll-call should be made. It is vital to make sure that the premises are completely evacuated.
   If there is the slightest doubt inform the Fire and Rescue Service on their arrival

THE EMERGENCY SIGNAL IS A CONTINUOUS SOUNDING KLAXON

The means of escape and the firefighting equipment on site will have been checked prior to your arrival.

During an evacuation persons must not use the lift in the King’s College Conference Centre.

On the sound of the alarm a member of University Security personal will be called to the venue.

You and your guests will not be allowed to re-enter the building unless permission has been given by the emergency services.
VENUE FIRE SAFETY INFORMATION
The following plans detail the area in which your event will take place.

Each plan clearly details fire exits and escape routes.

You should ensure that responsible persons in your party become familiar with fire safety arrangements.

If you have any questions regarding safety arrangements please contact your events co-ordinator.

ELPHINSTONE HALL
Fire Assembly Point – King’s Lawn (Directly in front of the venue)
Fire Alarm Test Times – Wednesdays 08.30am
THE LINKLATER ROOMS

Fire Assembly Point – King’s Lawn (Directly in front of the venue)
Fire Alarm Test Times – Wednesdays 08:30am