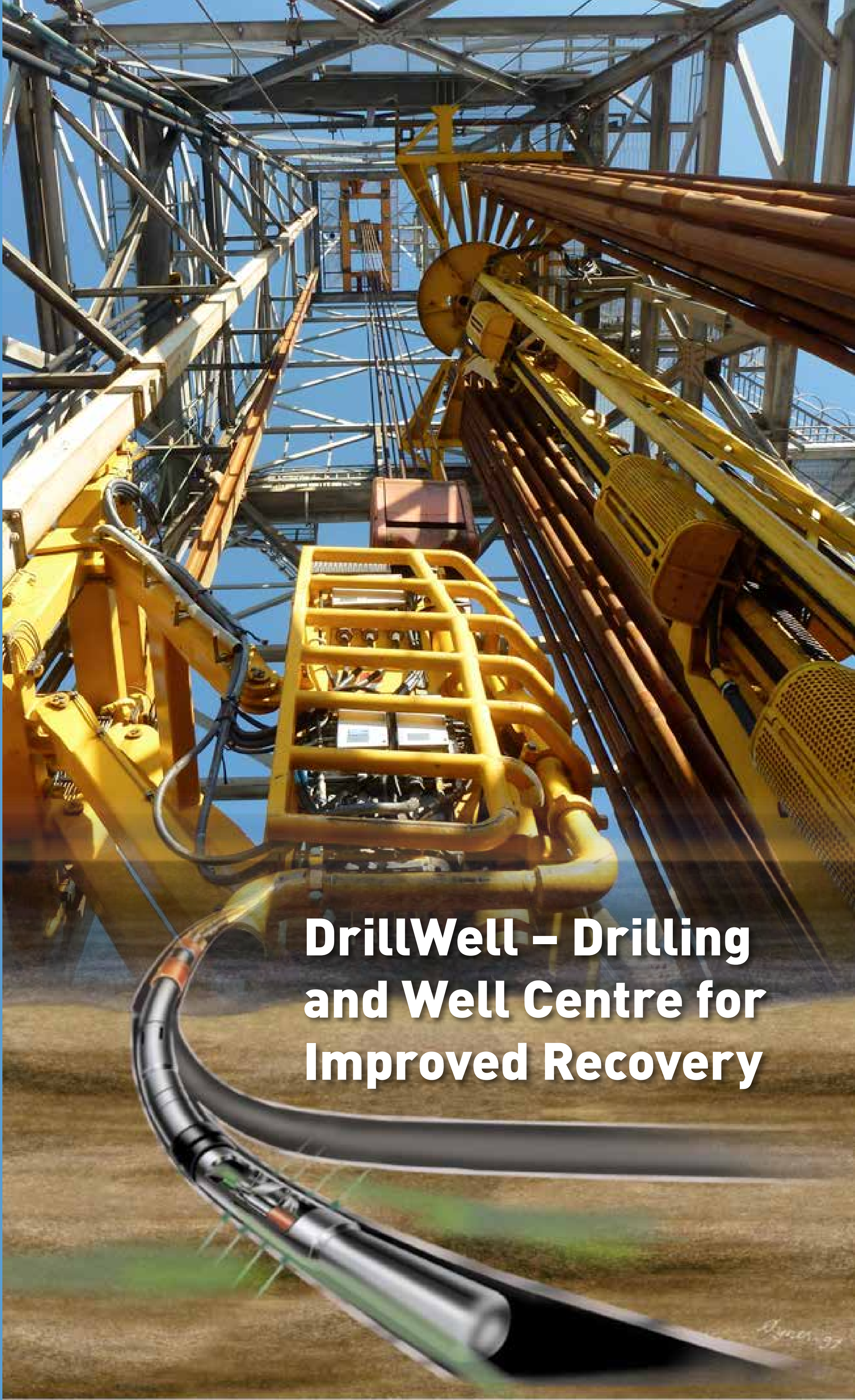
Annual Report 2013



DrillWell – Drilling and Well Centre for Improved Recovery

sfi Centre for Research-based Innovation

Established by the Research Council of Norway

IRIS

SINTEF

UiS

NTNU – Trondheim
Norwegian University of Science and Technology

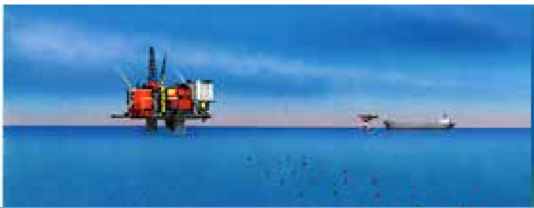
DrillWell
DRILLING AND WELL CENTRE FOR IMPROVED RECOVERY

Introduction

The Drilling and Well Centre for Improved Recovery (DrillWell) is an industry-driven collaboration and innovation environment with the industrial partners funding, prioritizing and directing R&D efforts towards their requirements and challenges. Six industry partners are funding the Centre with NOK 30 million annually.

The Centre is also funded with NOK 10 million annually by the Research Council of Norway (RCN) as a Centre for Research-based Innovation (SFI), over an eight year period.

The Centre was fully established and became operational in June 2011.



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Vision

Unlock petroleum resources through better drilling and well technology.

Objective

The Centre's objective is to **improve drilling and well technology** providing **improved safety** for people and the environment and **value creation** through better **resource development, improved efficiency in operations** and **reduced cost**.

Cost reduction

Innovative drilling and well technology is needed to reduce exploration and development costs, as well as well plugging and abandonment.

Improved recovery

Improved wells at lower cost will imply higher recovery of oil and gas by increasing the number of wells and their productivity.

Efficient field development

Improved wells at lower cost will imply cost-efficient field development. Today the wells represent 50-60 % of the field development cost.

Technology gaps

The Centre is focusing on a number of technology gaps:

- Formation and well integrity prediction, monitoring and control
- Monitoring and control of well temperature, pressure and multiphase flow in complex wells
- Real-time drilling and well data utilization
- Integration of subsurface and surface drilling and well data
- Imaging ahead of and around the wellbore during drilling
- Updating of earth model while drilling
- Intra-field well monitoring for optimized field drainage and well integrity
- Low cost well intervention
- Cost-efficient and safe plugging and abandonment of wells (P&A)

Way to the market

To ensure that the developed technology and solutions will be commercially available in the market, the realization of R&D results is to be performed through associated projects. These projects will be developed outside the Centre´s activities, and aim at a targeted development and qualification process in cooperation with the service industry and smaller companies (SMEs) in order to produce commercially available products/services.

Collaborative environment

There is a strong interaction between the scientists at the Research Partners and the supervisors and specialists in the Industry Partners. The oil companies are directing the work through the Board, the Technical Committee and specialists monitoring and guiding each research area.

DrillWell Partners

Research partners

SINTEF

UiS

NTNU – Trondheim
Norwegian University of Science and Technology

IRIS

The Research Council of Norway

sfi Centre for Research-based Innovation

Industry partners

Statoil

ConocoPhillips

TOTAL

DETNORSKE

TALISMAN ENERGY

wintershall

Programmes and projects

Drilling and Well Centre for Improved Recovery

Programme 1 Safe and efficient drilling operations for cost reduction	Programme 2 Drilling solutions for improved recovery	Programme 3 Well solutions for improved recovery
Projects • Rate of penetration management and improvement • Formation integrity • Managed pressure drilling • Determining changes in oil-based mud during well control situations	Projects • Geosteering and deep imaging • Flexible earth model	Projects • Well integrity • Plugging and abandonment • Water shutoffs and intelligent well completions

In the following it should be kept in mind that this represents a snapshot of the results at the present time, and that the visions and motivation for the programmes and projects mostly extend far beyond what are the ongoing activities and results at any point in time. The visions and motivation reflect the ambitions we have for the DrillWell Centre.

IRIS office

SINTEF Petroleum office


UiS campus


NTNU campus

Programme 1
Safe and efficient drilling operations for cost reduction

Programme 1 addresses technologies and methods to avoid drilling-related problems and improve safety and drilling performance. Three projects are continued from 2012:

- ROP management and improvement
- Formation Integrity
- Managed Pressure Drilling in depleted reservoirs

In addition a fourth project was started in 2013:

- Determining changes in oil-based mud during well control situations

The diversity of these projects reflects not only the broad knowledge among the partners, but also a variation in project objectives spanning from industrial prototypes to fundamental research.

Industrial prototypes have been developed through the project "ROP management and improvement" and has in 2013 been applied during drilling of an Extended Reach Drilling (ERD) well in the North Sea. The transient cuttings transport model developed in 2012 has been used to analyse hole-cleaning in real time and was used as a part of the decision basis when drilling the ERD well to target depth. More information can be found in SPE 163492 "Real-Time Evaluation of Hole Cleaning Conditions Using a Transient Cuttings Transport Model".

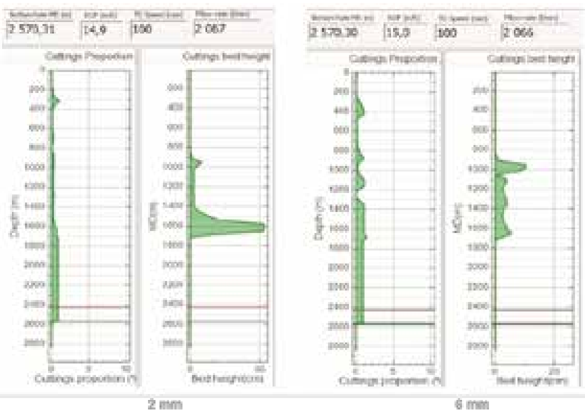


Figure 1: Cuttings concentration and cuttings bed height for two different cuttings particle size and cuttings bed erosion conditions.

Among the fundamental research in Programme 1 several sub-projects have been initiated related to ROP Management and Improvement. In addition, a new project in Programme 1; "Determining changes in oil-based mud during well control situations" study the change in density and viscosity for a representative selection of oil-based muds for different levels of gas saturation and pressures. In addition, the methane absorption of different base oils is to be evaluated.

ROP Management and Improvement

Motivation

The ability to optimize the rate of penetration while drilling is essential to reduce the drilling cost and avoid well problems. A significant potential for improvement exists.

When drilling a well the rate of penetration (ROP) is mainly affected by (1) bit properties, (2) weight exerted on the bit, (3) rotational speed of the bit, (4) formation properties, and (5) pressure difference between the well and the formation.

As the well is drilled deeper, the ROP is greatly limited by the ability to transport the cuttings out of the well. The drilling mud has several purposes and one of the most important is to transport the cuttings. If cuttings are not removed sufficiently, the movement of the drill string will be obstructed, and may result in a situation where the drill string eventually becomes stuck. This increases the cost of drilling the well due to lost productive time, and potentially loss of equipment if one does not succeed in freeing the pipe. A so-called pack off due to improper hole cleaning may also result in a situation where drilling mud is lost to the formation. In some cases this may cause underbalance above the depth of the fracture and might aggravate to a severe loss of well stability or an influx of formation fluids.

The problem of finding the optimum flow rate can be very challenging. On the one hand, the frictional pressure loss caused by the mud flow cannot be too high in order to prevent formation fracturing; this sets an upper constraint on the flow rate. On the other hand, the flow rate needs to be sufficient to transport the cuttings. These two constraints are contradictory, especially for long wells with highly inclined sections.

Project description and results

As mentioned in the introduction, "ROP Management and Improvement" has developed a real-time software system for evaluation of cuttings transport during drilling. The system uses available measurements and calculates critical flow rates to determine whether the cuttings are being transported sufficiently or not. The calculations are complex and take into account the geometry of the well, rotation of the drill string, mud flow rate, and the properties of the drilling mud and formation rock. In the model, the cuttings bed can be settled and eroded along the wellbore based on the prevailing operational parameters.

Based on the experience when using the transient cuttings transport model in 2013, several sub-projects have been conducted in the project.

One of them is on drilling fluid visco-elastic properties: Drilling fluids should usually exhibit low resistance to flow during circulation and spontaneously thicken and grow elastic structure during static conditions. Colloidal particles such as polymers and clays are added to oil- and water-based drilling fluids to provide the desired shear thinning and yield stress characteristics. Sag and settling of weighting particles are drilling problems that have received considerable attention over the last two decades and are now believed to be at least partly correlated to low shear rate and the nearly static flow behaviour of drilling fluids, i.e. the microstructure and low shear rate viscosity of the fluid. Recent sag cell and sag flow loop experiments suggest that these problems occur at shear rates lower than those directly accessible by standard oilfield viscometers.

Measurements made with steady rotational shear and dynamic oscillatory strain have been made for a number of oil- and water-based drilling fluids using an Anton Paar MCR 302 scientific rheometer.

As expected, it has been found that the drilling fluid viscosity increases with augmenting pressures and decreases with higher temperatures. In most cases, the drilling fluids exhibit more pronounced sensitivity towards temperature than pressure. The microstructure of the oil-based drilling fluids exhibits a clear elastic behaviour under small strain deformations. The shear moduli of these gel structures increase as functions of time according to a power law behaviour for more than 90 minutes, indicating progressive spontaneous struc-

Figure 1: Left: The components of the double-gap cylinder pressure cell used for measurements of viscosity and shear stress at pressures up to 200 bar. Right: The pressure cell is shown mounted in the MCR 302 rheometer.

turing of the fluid. The water-based drilling fluids are generally less viscous than the oil-based samples and have significantly weaker but more flexible gel structures characterized by lower shear moduli. Based on findings in a previous experimental study, the oscillatory strain measurements of most oil-based drilling fluids indicate good robustness towards static sag.

A second topic that has been conducted in "ROP Management and Improvement" has been studying the factors influencing the estimation of downhole pressure. In any drilling operation, it is important to maintain the pressure in the well within the geopressure margins (above collapse and pore pressure, and below fracturing pressure). The downhole pressure management consists primarily of selecting the operational drilling parameters (flow-rate, pump acceleration, rotational and axial velocities and accelerations of the drill-string) in such a way that the well pressure stays within the geopressure margins in the part of the well that is open to the formation. Alternatively, the pressure may be actively controlled by adjusting one of the parameters that influences the hydrostatic pressure, like the well head pressure in a back-pressure MPD (Managed Pressure Drilling) method or the level of the interface between the blanket and drilling fluid in a DG (Dual Gradient) method.

In practice, the downhole pressure is only sparsely measured in time and depth. With traditional mud pulse telemetry, it is only possible to have sensors in the direct vicinity of the MWD (Measurement While Drilling) tool, and because of the low communication bandwidth, the measurement sampling interval is seldom better than half a minute. Even with the best downhole telemetry system available for drilling (wired pipe data transmission), the sampling interval is about a few seconds and multiple pressure sensors along the wellbore are usually at distances of 500 metres or more. Considering that the speed of sound in drilling fluids is usually more than 1000 m/s, with currently available downhole pressure instrumentation it is not possible to capture any of the transient pressure pulses that may cause problems during a drilling operation. To compensate for that deficiency, mathematical models can be used for pressure predictions to fill the gaps, in space and time, between the downhole and surface pressure measurements.

However there are external factors that influence the accuracy of such models. For instance, the actual wellbore position is derived from indirect measurements: the inclination, the azimuth and the measured depth at the time of measurement. These measurements can be biased by systematic errors that can result in a miscalculation of the position of the well. As a consequence, over- or under-estimation of the actual vertical depth of the well may introduce discrepancies in the estimation of the downhole pressure along the whole borehole.

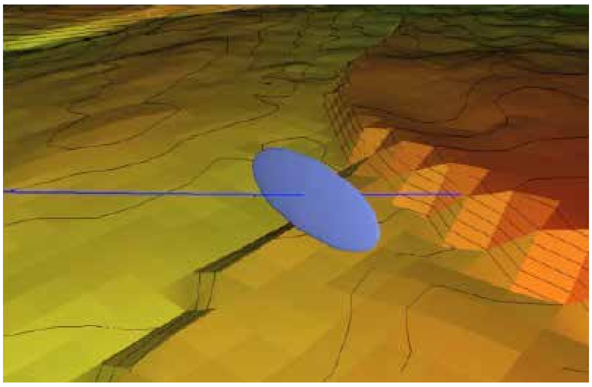


Figure 2: Ellipsoid of uncertainty at certain depth of a deviated well.

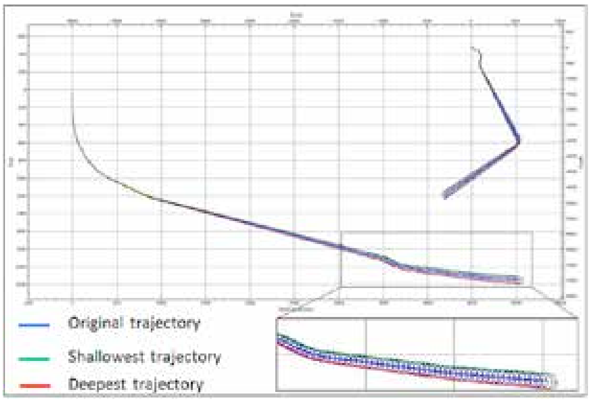


Figure 3: Reconstruction of shallowest and deepest trajectories.

Other sources of inaccuracies are the actual temperature gradients along the annulus, the real proportion of cuttings in suspension, the presence of gas in the drilling fluid, the variations of borehole size due to cuttings beds or hole enlargements. Any of these elements influence the accuracy of the pressure prediction made by models, especially at some distance from the downhole measurement location. A methodology has been developed to quantitatively estimate the influence of these factors on the pressure estimation accuracy.

Conclusions

The transient cuttings transport model has been incorporated in a prototype real-time software system and used in monitoring and analysis during drilling of a North Sea ERD well. The results are very promising, and show that estimation of cuttings accumulation and settling can be done in real time. This system may contribute to prevent severe drilling problems.

Several sub-projects have been conducted to improve the accuracy of transient well flow models for real-time applications. Among these are studies on variations in mud prop-

erties, such as visco-elastic properties (mentioned above) and also on lubricity properties. The study on factors influencing the estimation of downhole pressure (also mentioned above) indicates the sensitivity from uncertainties in wellbore position, mud density and thermo-physical properties. A fourth sub-project has been developing a hook load correction model for draw-works. The model shows that surface weight on bit may vary by two tonnes while drilling one stand of 30 metres just due to the effect of the weight of the drill-line and the tension applied by the mud hose on the top-drive. This model is described in a coming paper to be published at the OMAE 2014 to be held in June in San Francisco, California, USA.

Formation integrity

Motivation

Drilling costs could be significantly reduced by better control of borehole stability, which is becoming increasingly important for deviated wells, long-reach wells, and small drilling margins in over-pressured formations or during infill drilling. Uncertainties in the stress state, in particular the horizontal stresses, often prohibit accurate borehole stability assessment and mud weight determination. The stress state of a formation has a strong impact on rock strength and proximity to failure. Lost circulation, for example, is directly related to the minimum principal stress. The minimum principal stress can be determined most reliably by extended leak-off tests (XLOT) but the modelling and interpretation of such tests is not straightforward, especially for deviated wells or complex stress states. To date, there are no modelling tools available for the simulation of XLOT in more complex settings.

Project description

The main goal of the project is the development of a numerical XLOT simulation tool that allows for improved interpretation of XLOT data, thereby reducing the uncertainties in stress estimates. Since XLOT is based on near-well hydraulic fracturing, the numerical tool, with some modifications, may also find applications in the modelling of hydraulic-fracture stimulation or wellbore strengthening. The XLOT simulation tool is based on a «modified discrete element model» coupled to a reservoir simulator (MDEM) and a «well-flow simulator» (WEMOD). MDEM was developed at SINTEF, and the WEMOD tool was developed by IRIS. The two models are coupled to simulate injection-induced pressure build-up in the well, leak-off into the formation during hydraulic fracture initiation and propagation, and pressure decline during shut-in and controlled flow-back.

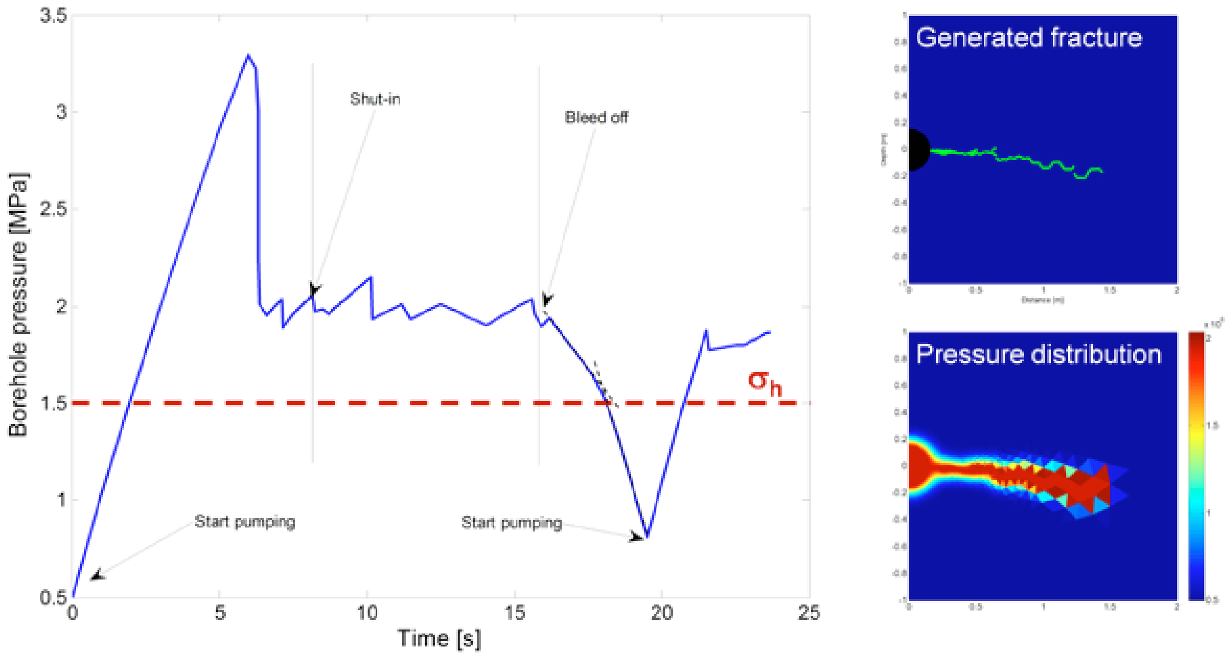


Figure 1: Preliminary XLOT simulation results obtained by 2D MDEM showing a typical pressure response in the wellbore: Pressure build-up during injection, pressure drop to a nearly constant fracture-propagation pressure after fracture initiation, small pressure changes during a shut-in phase due to the small leak-off rate, gradual pressure decrease during a flow-back phase with a marked change in slope when the pressure drops below the minimum horizontal stress, i.e. at fracture closure; pressure build-up during a second injection cycle showing fracture re-opening at a significantly lower stress. Images of the generated fracture and the fluid-pressure distribution in the horizontal plane at the end of the shut-in phase are shown on the right.

In a first step, hydraulic fracturing will be modelled in two dimensions (2D), allowing for XLOT simulations in simple geometries and stress states. The ultimate goal, however, is a 3D XLOT simulator that can be used to model fracture propagation in 3D, including fracture twisting, around deviated wells or in rotated stress fields. It is especially fracture twisting that is expected to have a strong impact on XLOT and its interpretation. Temperature and chemical effects (fluid-rock interaction), and elasto-plastic rock properties are to be included in the model.

The first results of a 2D XLOT simulation for a low-permeability formation and an anisotropic stress state are shown in the figure below. The model takes into account the dependences of the fracture permeability on both fracture aperture and shear displacement. The plan is to calibrate the fracture-permeability relations by matching simulated XLOT data to field data.

Numerical modelling of hydraulic fracturing in low-permeability formations such as shale is particularly difficult because of the intimate coupling of the hydraulics and fracture mechanics; small changes in the volume injected into the fracture will have large effects on fracture growth. Very small time steps are needed especially around fracture initiation, which results in long simulation times. Before starting with 3D simulations it is therefore recommended to use parallel computing.

Conclusions

The first XLOT simulation results are promising. Most issues and numerical problems were solved last year. In the coming year, we will focus on model calibration by matching XLOT field data, and carry out a sensitivity study to investigate the impact of different parameters (stresses, rock properties, injection rates) on XLOT.

Managed Pressure Drilling in Depleted Reservoirs and Long Wells

Motivation

Managed Pressure Drilling (MPD) is a drilling process that offers the ability to control the well pressure faster and more precisely than conventional drilling in order to compensate for pressure variations. The intention is to prevent influx from the formation, losses to the formation, or any instability problems. MPD techniques can assist drilling by allowing smaller margins between pore pressure or collapse pressure and fracture pressure.

Project Description and Results

The focus in 2013 has mainly been to describe the factors that influence the ability to perform safe and efficient Managed Pressure Drilling (MPD) in Extended Reach Drilling (ERD) wells. MPD is defined by the International Association of Drilling Contractors (IADC) as *"an adaptive drilling process used to more precisely control the annular pressure profile throughout the wellbore."* The objectives of MPD are *"to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly."* However, the ability to control wellbore pressure "more precisely" for a specific drilling operation is limited by several factors. In this work we have categorized the factors into the following groups:

Surface and downhole equipment	Drilling mud	Wellbore geometry	Measurements
Well flow models	Downhole conditions	Performance of operating procedures	Pressure control method

Figure 1: Factors affecting the ability to control wellbore pressure.

During 2013 the project has evaluated how pressure control is affected and constrained by these factors. For some of the factors, recommendations or requirements that are necessary to accomplish safe and efficient MPD are suggested.

The work is based on experience from MPD operations and supported by simulations using advanced in-house well flow models. The intention has been to produce guidelines for both the planning and execution phase. More details can be found in the papers SPE 167856 *"Possibilities of Using Wired Drill Pipe Telemetry during Managed Pressure Drilling in Extended Reach Wells"* and *SPE 169211 "Back-Pressure MPD in Extended-Reach Wells - Limiting Factors for the Ability to Achieve Accurate Pressure Control"*.

Conclusions

MPD is a valuable tool for drilling wells with reduced pressure margins. This will allow wells to be drilled which might otherwise not be possible. However, it is crucial to understand the factors that influence the ability to control pressure precisely. Following simulations using transient well flow models the project has demonstrated the effect of using improved downhole instrumentation, through wired drill pipe, the effect of change in operational procedure (ramp down time) during connection, and the effect of choosing different choke control strategies. Although the focus of this project has been on ERD wells, many of the factors that influence pressure control are related to back-pressure MPD in general and would be useful also when planning and executing non-ERD wells.

Determining changes in oil-based mud during well control situations

Motivation

The understanding of kick and oil-based mud (OBM) interaction is essential for the planning and operation of safe drilling. Leaking of gas from a reservoir into the drilling mud will even occur in overbalance situations; this is more pronounced the higher the pressure. In order to characterize the gas loading into the OBM and the potential severity of gas release during depressurization, it is essential to determine the gas loading capability and its impact on rheology as a function of OBM and process conditions.

Project description and results

The first task for the project is the determination of the gas loading capability and rheology at HPHT-conditions; max 1000 bar and 200 °C. Two different OBMs in terms of base oil are investigated; a «normal mineral» base-oil; EDC 99DW/ OBM: EMS-4600, and a «linear paraffin» base-oil; Sipdrill 2.0/ OBM: EMS-4400, fluids supplied by MI-Swaco. A key issue is to determine the difference in the characteristics of the OBMs with respect to gas loading and rheology at HPHT conditions.

The project work in 2013 has included the planning, design, commissioning and calibration of the HPHT-experimental facility, comprising gas feed pump and supply, specially designed gas-liquid mixing device, and rheometer and densitometer designed for HPHT conditions.

The first results on the differences in base oil and OBM characteristics are planned by Q2 2014 and Q4 2014, respectively.

The second task of the project concerns the determination of the gas rate at which base oils (BO) absorb reservoir gas. A gas absorption cell has been designed together with measurement methodology for determining the gas absorption rate, swelling of the liquid and effective viscosity and density as a function of the gas loading of the BO. As in task 1 a key issue is the comparison of the gas absorption characteristics between the two types of BOs; «normal mineral»- and «linear paraffin»-type. The test cell components are under construction and first test results are scheduled for Q3 2014.

Conclusions

The experimental results will give valuable insight in gas loading capabilities, kinetics and the rheology of OBMs at HPHT conditions, in particular this will reveal differences between two OBMs widely in use, one made of a «normal mineral» base-oil; EDC 99DW (OBM: EMS-4600), the other made of a «linear paraffin» base-oil; Sipdrill 2.0 (OBM: EMS-4400).

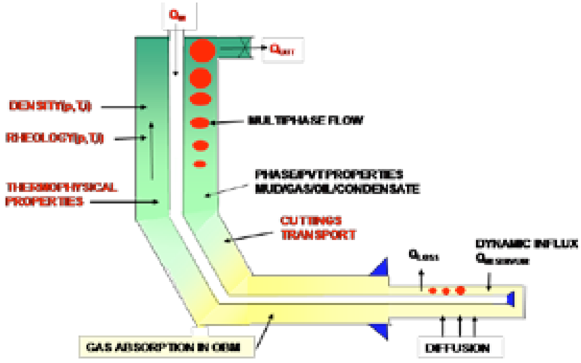


Figure 1: Gas absorption in OBM and identification of key parameters potentially affected.

Programme 2
Drilling solutions for improved recovery

Programme 2 addresses optimal well placement and geometry and effective earth model management for improved recovery of oil and gas.

Geo-steering and deep imaging

Motivation

High resolution deep imaging and geosteering have the potential to greatly improve oil recovery by being able to optimize the well placement in the reservoir and the well construction process.

Project description and results

The objective is to develop methods and algorithms for deep imaging (imaging ahead and around the wellbore) and geosteering in order to improve well placement and geometry, support the decision-making process while drilling, and make optimum use of data acquired during drilling.

Geo-steering

During 2013, a decision analytic framework to support high quality geosteering decisions was proposed. Three key components have been identified: Descriptive Analytics, Predictive Analytics, and Decisions Analytics (Figure 1).

The project investigated the Ensemble Kalman Filter (EnKF) performance when assimilating different types of observations into a geosteering problem. Azimuthal deep resistivity data, acoustic data, and a combination of both have been used as observed data. Sensitivity studies of the EnKF performance with different intrinsic parameters (for example the ensemble size, the observation noise level, the optimization time interval) were performed. The results confirmed the robustness of the EnKF approach. The best results were obtained with deep resistivity data.

A more sophisticated inversion method, the iterative EnKF, has also been tested with azimuthal deep resistivity data. Preliminary investigations (Figure 2) indicated that in certain circumstances and despite the higher computational cost, the use of the iterative EnKF can constitute a good alternative to conventional EnKF.

Joint estimation of reservoir boundaries and resistivity properties with the EnKF approach using synthetic directional resistivity data was also initiated (Figure 3). The derived results suggested that the uncertainty of the estimate of the boundaries is generally higher than the case in which the resistivity of different regions of the formation is assumed to be known.

In addition, the work included the implementation of a Bayesian inference technique to consistently update ahead-of-the-bit reservoir uncertainties while behind-the-bit data are gathered in real time and provide a robust approach for making high-quality geosteering decisions.

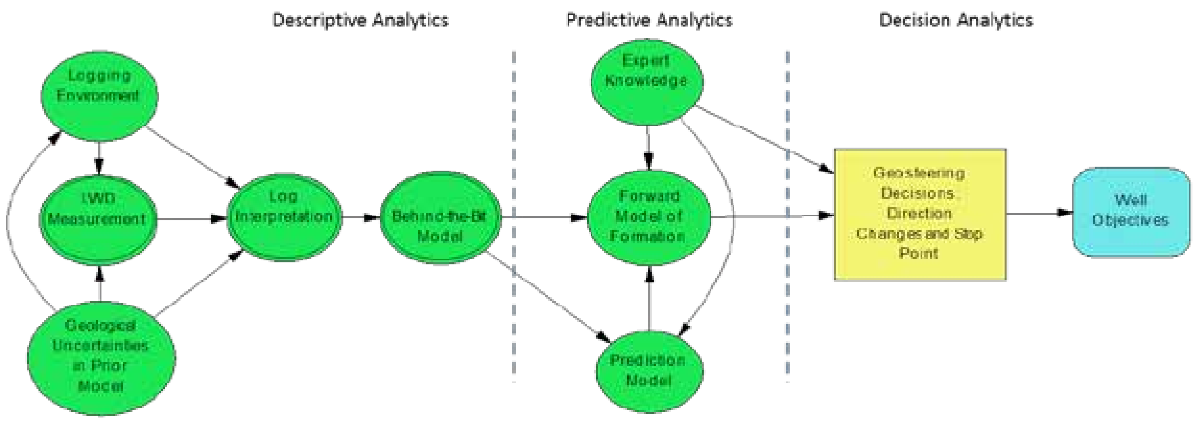


Figure 1: Influence diagram representing a geosteering decision problem.

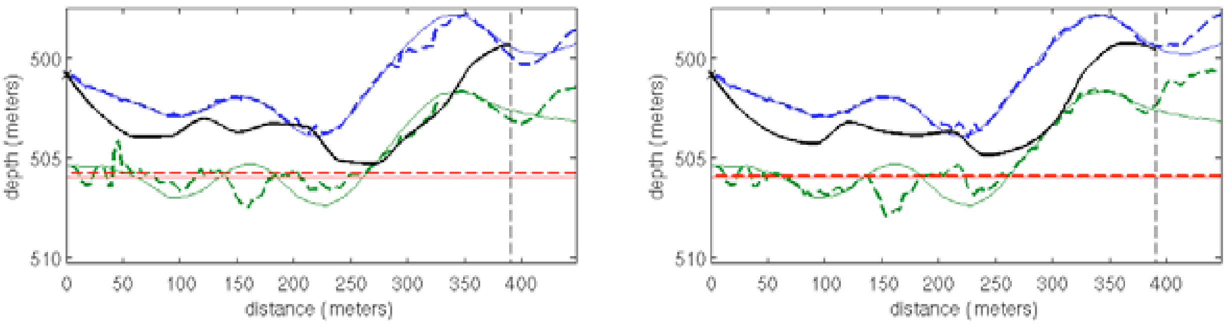


Figure 2: True (solid curves) and estimated (dashed curves) surfaces, with blue and green for the reservoir boundaries, and red for initial water-oil contact (WOC). The black curve represents the optimized well path, while the vertical black dashed line indicates the last place where the resistivity data are recorded. Left: results of EnKF; Right: results of iterative EnKF.

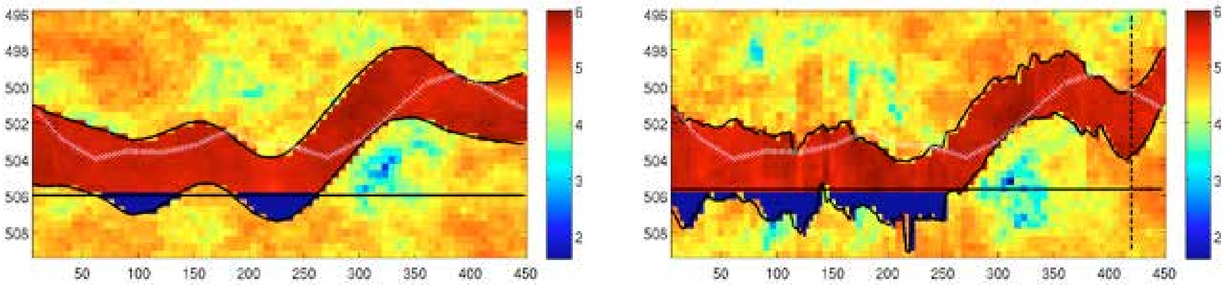


Figure 3: Left: True reservoir boundaries and initial WOC (black) and the surrounding EM resistivity field (colour) in logarithmic scale, together with the optimized well path (white crosses); Right: as on the left panel, but for one of the ensemble estimates and the associated optimized well path. Again, the vertical black dashed line indicates the last place where the resistivity data are recorded.

Deep imaging

During 2013, the project investigated the performance of a seismic waveform-based method (Full waveform inversion (FWI)) when updating the subsurface seismic image during drilling. This included evaluating the ability of the method to detect geological features ahead of and around the drill bit for different acquisition configurations and at different scales (Figure 4), with particular focus on the case of wellbore seismic with sources and receivers placed along the drill string.

Sensitivity studies of the FWI performance to different parameters including the quality of the initial model, the acquisition set up, the frequency bandwidth of the source signal, the presence of noise, and the effect of attenuation were performed. For these different cases, the results suggested that the method can provide a significant update of the seismic velocity model around the drill bit. It can also provide clear indications about the presence of a fault ahead of the drill bit. However, the prior knowledge about the subsurface, the acqui-

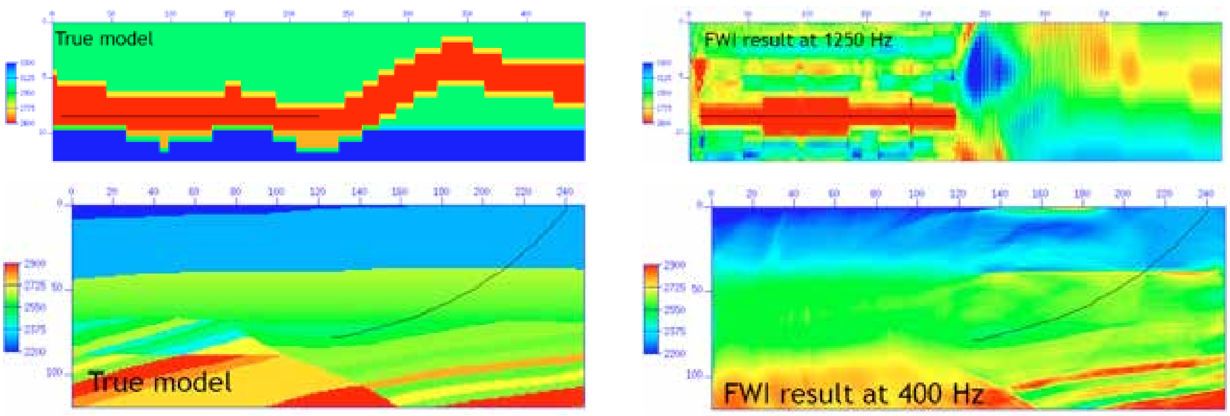


Figure 4: Examples of FWI results in the case of wellbore seismic with sources and receivers placed along the drill string. The black curve represents the well path.

sition setup, and the frequency content of the source signal have a substantial imprint on the quality of the obtained results.

In addition, method adaptations to the requirements of fast model update during drilling have been initiated. They particularly include developments to take into account the available prior information about the subsurface, and perform a target oriented inversion. In this context, an advanced inter-source type of interferometry by multi-dimensional deconvolution is very useful when one only has noise sources in the subsurface (for example drill-bit noise). This has been derived and tested on simple cases.

Conclusions

The work performed confirmed the considerable potential for making better-quality geosteering decisions. The development of a consistent analysis framework and the combination of advanced modelling tools with the new hardware developments coming from the industry will enable optimal use of the data acquired while drilling to improve predictions.

Flexible Earth Model

Motivation

The increased amount of measurements available in real time while drilling with wired pipe opens new possibilities for the optimization of well placement. The continuous stream of new information reduces uncertainty and allows revisions of the geological interpretations made prior to the drilling operation. This requires effective interpretation, integration and utilization of the new information within the timeframe set by the on-going drilling operation. Current three-dimensional earth modelling tools have limited capabilities for local alterations that enable effective integration of newly acquired information. Model modifications are complex and labour intensive, and the time needed for updating the model exceeds the time available during drilling operations.

The aim of the project is improved support for decision-making processes while drilling, by using the most current and precise information obtained during the drilling operation for model updates, thus aiming at maintaining an at all times up-to-date earth model.

Project description and results

Structural modelling in real-time while drilling requires methods for effective, local updates of geological structures such as layer boundaries and faults in the earth model. This is not possible using existing 3D earth modelling tools and methodologies. The project's objective is to develop new methods for more effective earth model management, particularly aimed at supporting decisions for optimal well placement in real-time based on the most recent information received during the on-going drilling operation.

The complexity when managing existing earth models is mainly a result of their application of a single and globally defined grid for storing physical properties (often denoted the 'geological grid'). This strategy effectively inhibits all types of local updates of the geological structure, except very simple ones. Any update of some complexity, say the insertion of a new layer or a new fault, dictates a time consuming global re-construction of the geological grid as well as a re-run of the existing workflows to re-generate the properties over the new grid.

In contrast, in our newly developed gridless approach we split the sub-surface volume into separate sub-regions (e.g. layers and fault blocks). Each sub-region is handled individually and completely independently of the other sub-regions. This is enabled by the application of a set of flexible and effective mathematical transformations, as depicted in the figure below. Each such transformation links a sub-region bounded by the geological structure with an associated function used to represent the properties within this sub-region. This allows separate management of the geological structure and the properties, as well as individual handling of each property within a sub-region. As a result, local updates of both the geological structure and the prop-

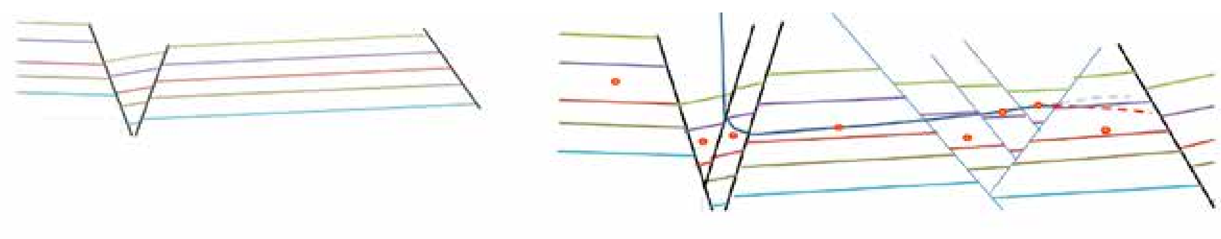


Figure1: An illustration of how we aim to continuously update the pre-drill earth model to the left in a series of local modifications based on new information interpreted while drilling.

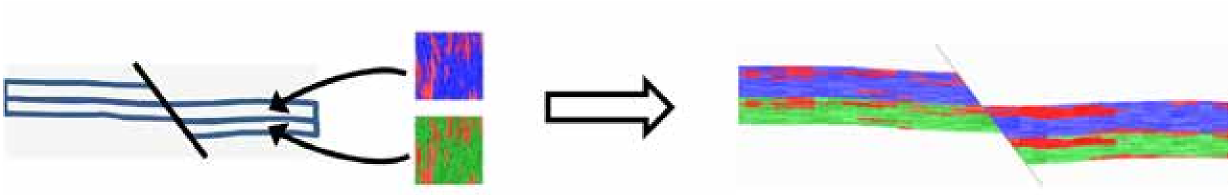
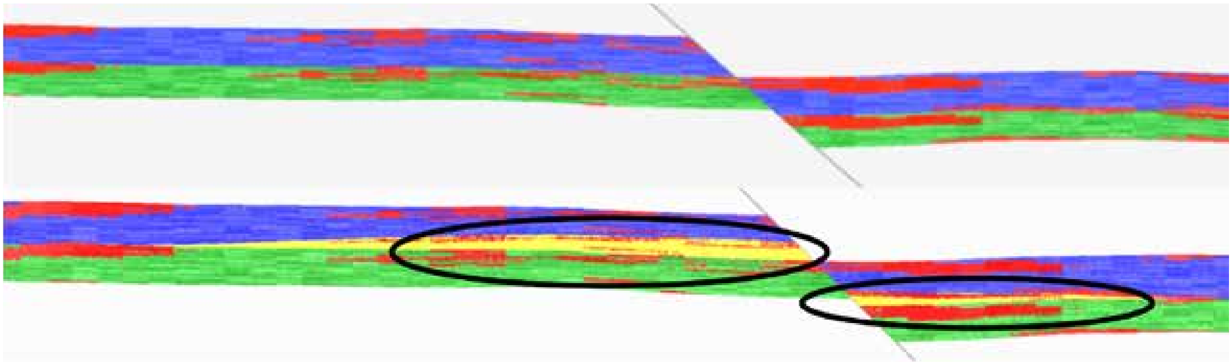


Figure 2: The geological structure and the properties are individually managed. They are linked only when required to produce the earth model (or local parts of it).



Figures 3: The earth model is locally updated when inserting a new layer (in yellow). Only the top layer (in blue) is modified, the bottom layer (in green) is retained. Using existing earth model technologies, such updates dictate a global re-construction of the entire numerical representation.

erties in the earth model are enabled. Moreover, the resolution of each property within each sub-region can be separately controlled and adapted to the requirements of each property.

Effective methods for real-time control of the geological structure in the reservoir model, based on the new information acquired while drilling, is important for the support of optimal well placement. Current approaches for managing the reservoir geometries are mainly based on time consuming manual control with the mouse pointer. This is too ineffective to be used for real-time control. Our current main focus is therefore to develop automatic methods, based on geological parameters and geological rules.

Effective management of several scales in the earth model geometries would be a major step towards more effective earth modelling. Multi-scale methods have been successfully applied in other scientific disciplines. Current methods for structural modelling are single scale, requiring that the modeller decides a particular scale before the model construction starts. If another scale is required, the model must be entirely re-constructed. Moreover, well placement support requires control on a finer scale than the scale at which reservoir modelling normally is conducted. Well logs obtained while drilling enable the identification of sub-seismic geometries, e.g small faults and fine-scaled stratigraphic features, which should be taken into consideration when guiding the placement of the well. But using existing methodologies it is not possible to shift between different scales. Furthermore, with improved control of model scale, one could aim for massive reductions in time spent for model computations by focusing on the volumes relevant to the task at hand. Improved computational efficiency is a pre-requisite for the support of real-time operations.

In 2013 we developed the main principles of a novel method for automatic multi-scale management of the fault network and layering. To our knowledge this is the first approach for automatically handling geological structure in a level-of-detail fashion. It is currently being implemented in a 2D software prototype aiming at demonstration of the fundamental principles. We aim at applying the strategy for several purposes, most importantly real-time structural modelling while drilling including local updates (e.g. insertion of new faults and layers), uncertainty modelling ahead of the bit and a reduction in the earth model resolution away from the bit. We expect that visualization could also be made more effective by applying such methods.

Conclusions

The current developments aim at enabling effective decision support for optimal well placement while drilling. The present focus is on validation and demonstration of the fundamental principles of the recent developments, and on exploring new functionalities that capitalize from the advantages offered by the new approach.

Programme 3
Well solutions for improved recovery

Wells are an invariable prerequisite for the recovery of hydrocarbons. Any technical progress that makes it technically and financially possible to drill more wells and ensure effective, reliable, long-lasting functionality of existing wells is therefore a valuable contribution to improve oil recovery.

Life-cycle well integrity

Motivation

During production, failure of well barriers may lead to leakages from the well. As a consequence, the well may be shut-in or abandoned, thereby causing a significant production loss. Maintaining well integrity throughout the life-cycle of the well is therefore important in order to improve recovery.

Project description and results

The best way to ensure well integrity during production is to include emphasis on well integrity already in the well planning phase. By having such an initial life-cycle well integrity approach, several problems and costs can be avoided during production and also after well abandonment. In this project, the emphasis has been put on well barriers - to understand why well barriers fail, and also on well design - to understand how initial well design influences the long-term well integrity.

Influence of thermal cycling on cement sheath integrity

One of the most important well barrier elements is the annular cement sheath. Well temperatures cycle up and down as a part of normal production operations, and this thermal cycling in the well can have a detrimental effect on the integrity of the cement sheath.

A tailor-made laboratory set-up has been built to study the effect of thermal cycling on the integrity of different annular sealants such as cement. A major finding so far has been that the cement sheath integrity during thermal cycling is dependent upon casing centralization – the cement is more likely to fail when the casing is not centralized. From X-ray Computed Tomography (CT) analyses it is seen that the debonding and cracks initially present in the cement sheath enlarge during thermal cycling, and that this occurs more rapidly when the casing is not centralized.

Good casing centralization is therefore important during well construction – not only for optimal cement placement, but also for maintaining well integrity during production.

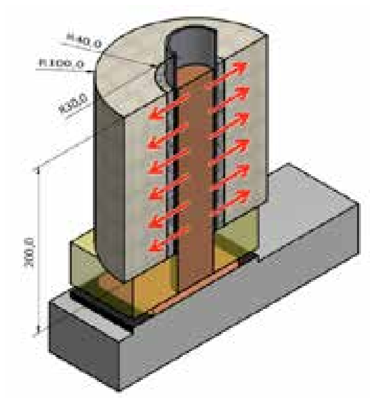


Figure 1: Schematic illustration of experimental set-up for thermal cycling tests (Albawi et al. 2014, OTC 24587, and De Andrade et al. 2014, IADC/SPE 168012).

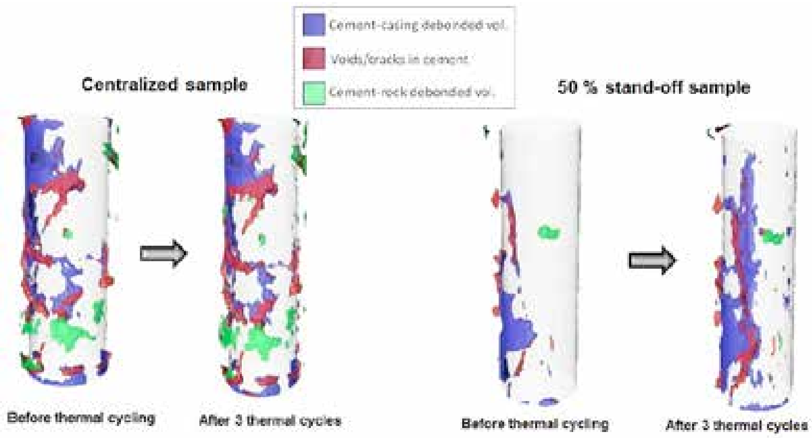


Figure 2: Computed Tomography (CT) visualizations of cement sheath integrity before and after thermal cycling. There is significantly more change in the 50 % stand-off sample (De Andrade et al. 2014, IADC/SPE 168012).

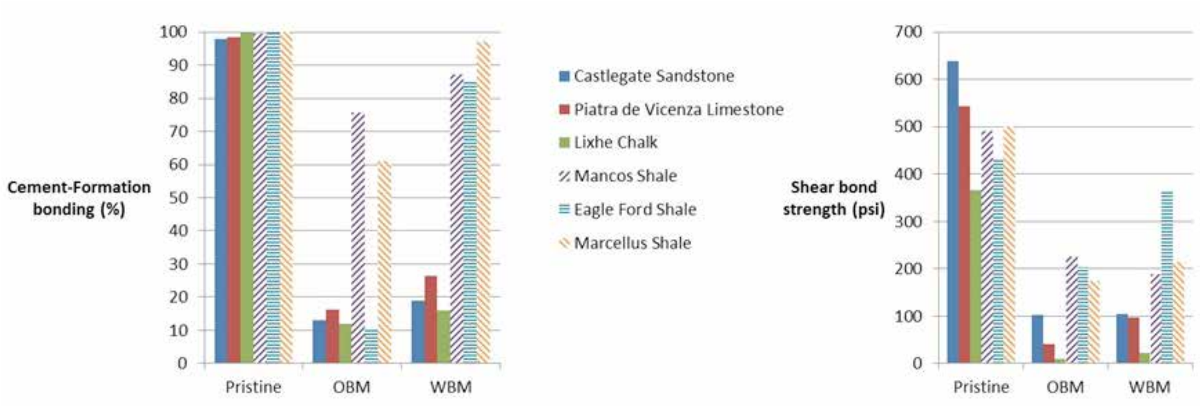


Figure 3: Quantification of cement-formation bonding and measurement of shear bond strength for six different rocks with and without drilling fluids (Opedal et al. 2014, SPE 168138).

Cement-formation bonding

A typical failure mode in the cement sheath is the formation of microannuli, which can be formed both during primary cementing and during production. Drilling fluids present in the wellbore will influence microannuli formation and cement bonding.

Several laboratory experiments have been performed in order to further understand cement-formation interactions and cement-formation bonding in particular. Different rock samples have been cemented with and without drilling fluids present and the quality of the cement-formation bonding has been characterized by X-ray Computed Tomography (CT). The results show that the bonding percentage correlate relatively well with the measured shear bond strength, and that both the rock type and drilling fluid type are important.

Reliability of Downhole Safety Valves

An important well barrier element during production is the Downhole Safety Valve (DHSV). Understanding of the reliability of these valves and selection of optimal inspection intervals is crucial for maintaining well integrity during production. Published literature on the reliability of DHSVs, as well as past experience and lessons learned from qualification testing performed at Ullrigg, have been used to point at main reliability challenges for DHSVs. This information is important for improved predictions on when and how failures occur.
A framework for the selection of inspection intervals has been developed, based upon the approach that different situations call for different decision principles. For example, in some situations, decisions could be based on a need to minimize costs, whereas in other situations the ALARP principle should be used as a decision basis. (ALARP - As Low As Reasonably Practicable).

This decision framework will be used together with field data on DHSV failures provided by operators, where the

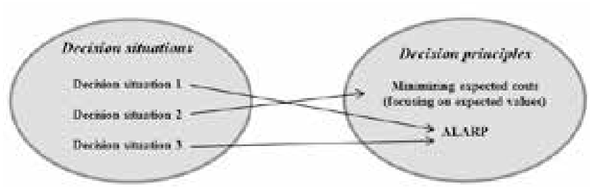


Figure 4: With respect to reliability and selection of inspection intervals of well barrier elements such as DHSVs: Different decision situations call for different decision principles (Abrahamsen and Selvik 2013, ESREL Conference).

objective is to give recommendations on the selection of optimal inspection intervals for DHSVs.

Conclusions

A good understanding of well barrier failure modes and the influence of well design on long-term well integrity is important in order to ensure well integrity throughout the life-cycle of the well.

Plug & Abandonment

Motivation

Thousands of wells need to be plugged and abandoned on the NCS in the next few decades, and this will be both time-consuming and very costly. As most plug and abandonment (P&A) operations currently require a drilling rig, it is important to find less time-consuming and more cost-effective methods, since these drilling rigs should be used to drill new wells and thereby improve recovery.

Project description and results

There are several important problem areas in P&A. For this project, two main topics have so far been selected; permanent plugging materials and P&A of subsea wells.

Portland cement is currently used as the plugging material in most P&A operations. There are however some situations where cement is not so suitable and there is a need for availability and qualification of alternative plugging materials for use in P&A operations.

P&A of subsea wells usually require semi-submersible rigs, which have high day rates. Since P&A operations can be very time consuming, it can be quite costly to plug and abandon subsea wells. Also, these semi-submersible rigs should preferably be used to drill new wells. It is therefore important to find ways to make P&A operations less time-consuming and more cost-effective, and to move parts of or all of the operation to Light Well Intervention Vessels (LWIV).

Long-term integrity of plugging materials

One of the most important requirements for permanent plugging materials is long-term integrity at downhole conditions. Ageing tests are currently ongoing where four different plugging materials are exposed to different downhole chemicals at elevated temperature and pressure. Two different cement systems, one polymer-based material, and one geopolymer are currently tested, and the objective is to determine the long-term integrity of these materials.

The results so far have found that all the materials are affected by most of the chemical environments, but in different ways.

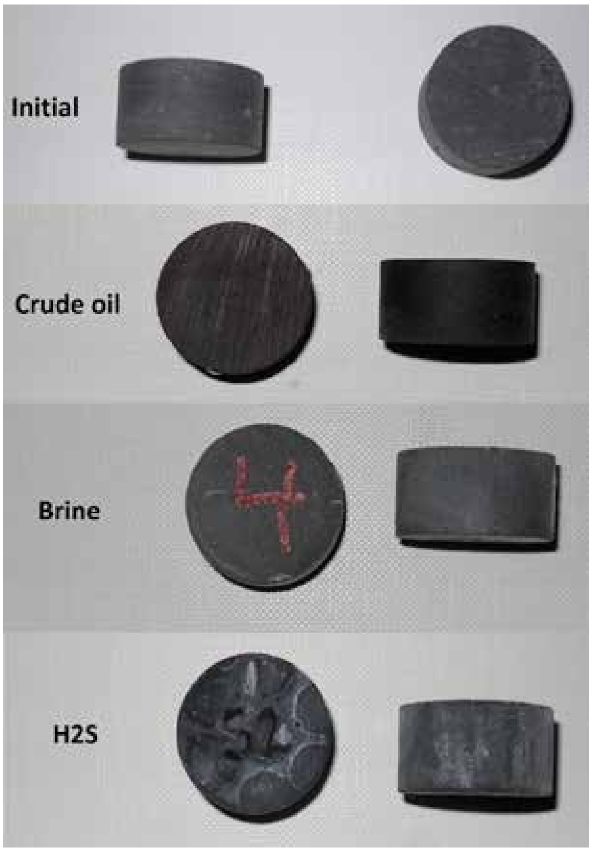


Figure 1: Cement samples after exposure to downhole environments at elevated temperature and pressure.

Geopolymers as potential plugging materials

Geopolymers are a type of inorganic, rock-like materials that can be seen as «artificial stone», and are based upon different raw materials such as fly ash, kaolinite

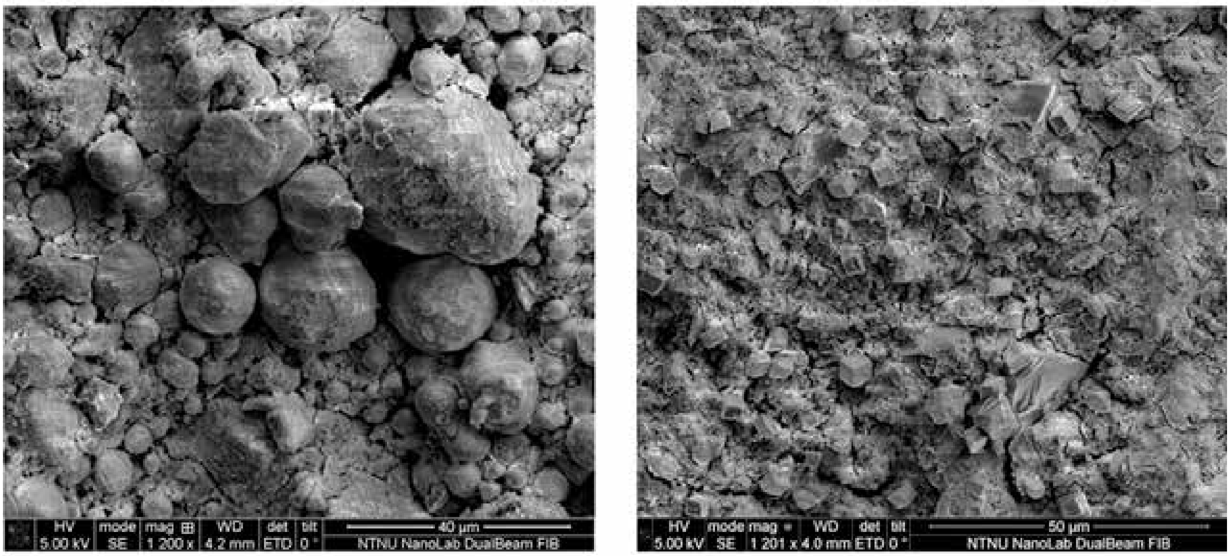


Figure 2: Scanning electron microscopy (SEM) images of two different geopolymers (Khalifeh et al. 2014, SPE 169231).

and various rocks. They are prepared by suspending small particles of the raw material in water and then adding different chemicals that start a chemical reaction where the solid geopolymer is formed. By varying the type of raw material and chemical additives, various types of geopolymers with different properties can be obtained.

Since the objective of P&A is to «restore the cap rock», the rock-like nature of geopolymers makes these materials potentially very suited to be permanent plugging materials. Work is currently ongoing where different types of geopolymers are prepared and evaluated as potential plugging materials. Rheological properties of the suspension and mechanical properties of the set material are determined, and the emphasis has so far been on controlling strength development and kinetics during the curing process.

Tubing left in hole

Significant time during P&A operations is spent on removing steel tubular from the well. If the tubing could be left in the well instead of removed, considerable time and cost could be saved – especially for subsea wells since a rig is required for tubing removal. By leaving the tubing in hole, parts of the P&A operation can be performed rig-less.

Full-scale tests have been performed where the objective was to determine if it is possible to obtain a good cement seal when tubing is left in hole. Here, 7" tubings were cemented in 9 5/8" casings with and without control lines and cable clamps.

For visual confirmation of the cement quality, the casing strings were cut through at several places. Inspection showed perfect cement placement at all cuts, i.e. no canals or assemblies of fluid were seen, including the area around the control lines. No cracks could be seen in the cement. Pressure tests however showed that microannuli were present. Additional tests are planned in order to expand the test matrix and elaborate further.

Cost and time estimation of subsea multi-well P&A campaigns

Given the large number of wells to be abandoned in the near future, there is a need for structuring the cost and time estimation for large field P&A campaigns. Wells can be categorized based upon well type and abandonment complexity, and the P&A operations can be planned and performed in multi-well campaigns in order to optimize time use and improve cost efficiency. For example, similar operational activities for different wells can be performed by the same rig or perhaps by an LWIV if possible, thereby optimizing and reducing total time expenditure.

Figure 3: Full scale tests to determine if a good seal can be obtained after P&A when tubing is left in hole.

Figure 4: Cut strings with tubing cemented inside casing with and without control lines.

A probabilistic approach has been developed to forecast distribution curves for the duration of multi-well P&A operations. Unexpected events, learning effects, and dependency between sub-operations inside a single well and between wells have been included in the model. Monte Carlo simulations are used to provide non-biased estimates of the total outcome in the form of probability distribution curves. The output is statistical values of estimated time and cost that can be used for budgetary planning and to improve decision making during planning of multi-well P&A campaigns.

Ref: Moeinikia et al. 2014, IADC/SPE 167923 and Moeinikia et al. 2014, SPE 169203.

Conclusions

Considerable time and costs can be saved during P&A operations with increased focus on research and development of new methods and technologies.

Production Optimization through the use of Water Shutoffs and Intelligent Well Completions

Motivation

There is great potential for improving oil recovery by (a) a controlled reduction of the produced water cut from individual zones in oil producing wells and (b) an effective utilization of deployed smart (or advanced) wells.

Secondary and tertiary (EOR) applications require the use of fluids which are injected to displace formation oil, accelerate oil production, reduce residual oil saturation, and increase oil recovery. The injected fluids (water, chemicals, gas, etc.) should be utilized efficiently to achieve these objectives, and produced fluid composition should be optimized with respect to the quantity and quality of the unwanted (water and/or free-gas) fluids.

This project is designed to address the means to control/minimize the production of the unwanted formation/injection fluids and maximize oil production through the use of chemical and mechanical means in existing and newly drilled wells.

Project description and results

Chemical Water Shutoff Technology

Inorganic fluids, such as for example silicates, are also used to manage water production and optimize

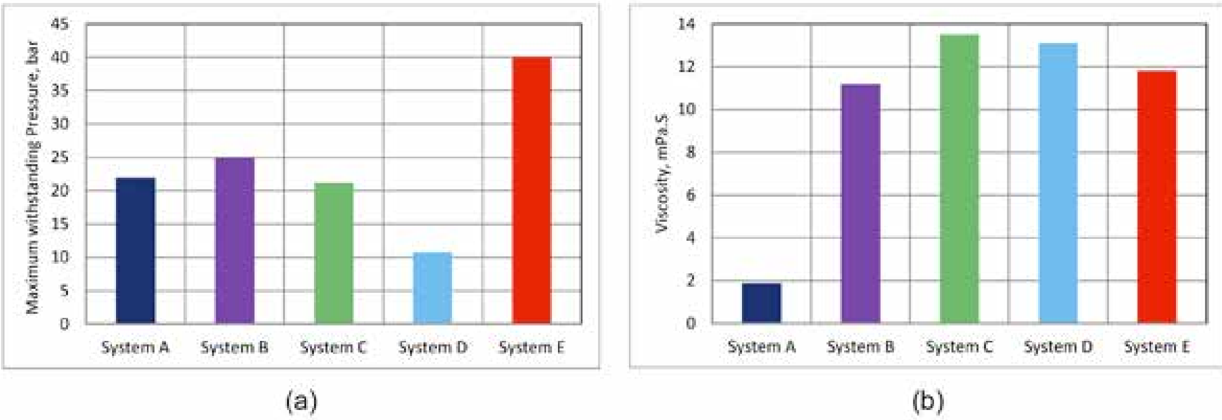


Figure 1. Gel maximum withstand applied pressure, and (b) fluid system pre-gelation viscosity.

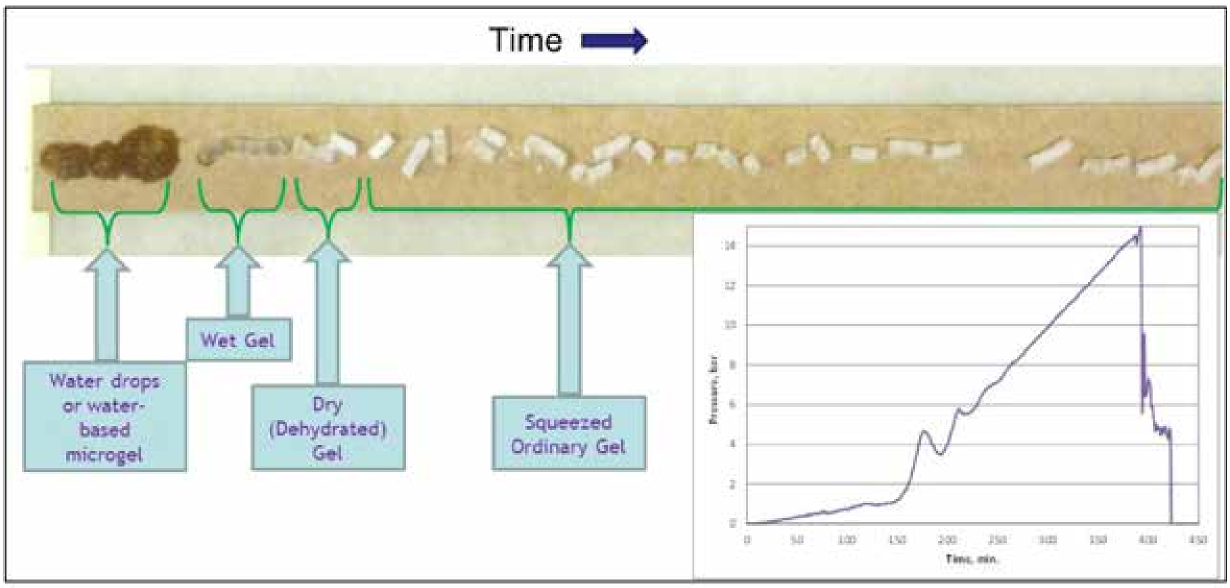


Figure 2. Gel portions squeezed out of the tested tube during the maximum withstand applied pressure test.

oil production rates and recovery factors through the precise placement of gel systems into the reservoir at a preselected location. This can be achieved in several ways such as: (a) isolating a watered-out layer, (b) diverting injected fluids into previously unswept regions, (c) adjusting well injectivity/productivity index in layered systems, and (d) modifying layer/region oil and water productivities.

Commercial inorganic systems have been investigated in achieving some of the above-mentioned possibilities. Laboratory tests included investigations of gelation time, filterability/injectivity, strength tests (maximum withstand pressure), fluids system viscosity prior to gelation. Mixtures of selected chemicals are also tested for obtaining increased pre-gelation fluids system viscosity and improved post-gelation gel strength. Figure 1 illustrates tube-test (Fig. 1a) and bulk-fluid (Fig. 1b) measurements for five fluid systems with System E providing both good viscosifying effects, to minimize fluid crossflow during gelation in the formation or through the treated wellbore, and strong gel which can withstand post-gelation applied pressures due to reconvened water or EOR fluids injection. Figure 2 displays the gel extruded through the test tube by applying fluid pressure; the measured applied pressure vs. time, indicating the ability of gel to withstand this pressure, is shown at the right-bottom portion of Figure 2.

Intelligent Well Completions

Smart well completions can be used to delay injected fluid breakthrough, and manage water/gas production while improving sweep efficiency and maximizing oil recovery factors at late stages of the life of a field. The extended Brugge field model was used to study (a) how one should manage smart well completions to effectively minimize water production and maximize financial gains, and (b) the impact of uncertainty and reservoir geology on smart well completions added value compared to traditional wells. The model consisted of both fluvial and non-fluvial layers; five deviated producers equipped with smart completions in different layers are used to control water production. The geological uncertainty is taken into account by using an ensemble of realizations of the reservoir properties. Both reactive and proactive control strategies are considered for the management of smart wells. The latter is achieved by optimizing oil production over a certain time period; several optimization procedures are examined and their influence on both wells and field fluid production is investigated and evaluated. In the smart completions operation strategy a water cut threshold is assigned to each completion, which is shut-in when this threshold is reached. The assigned water cut thresholds were optimized.

A reliability study is performed to assess oil production losses from a potential malfunction of smart

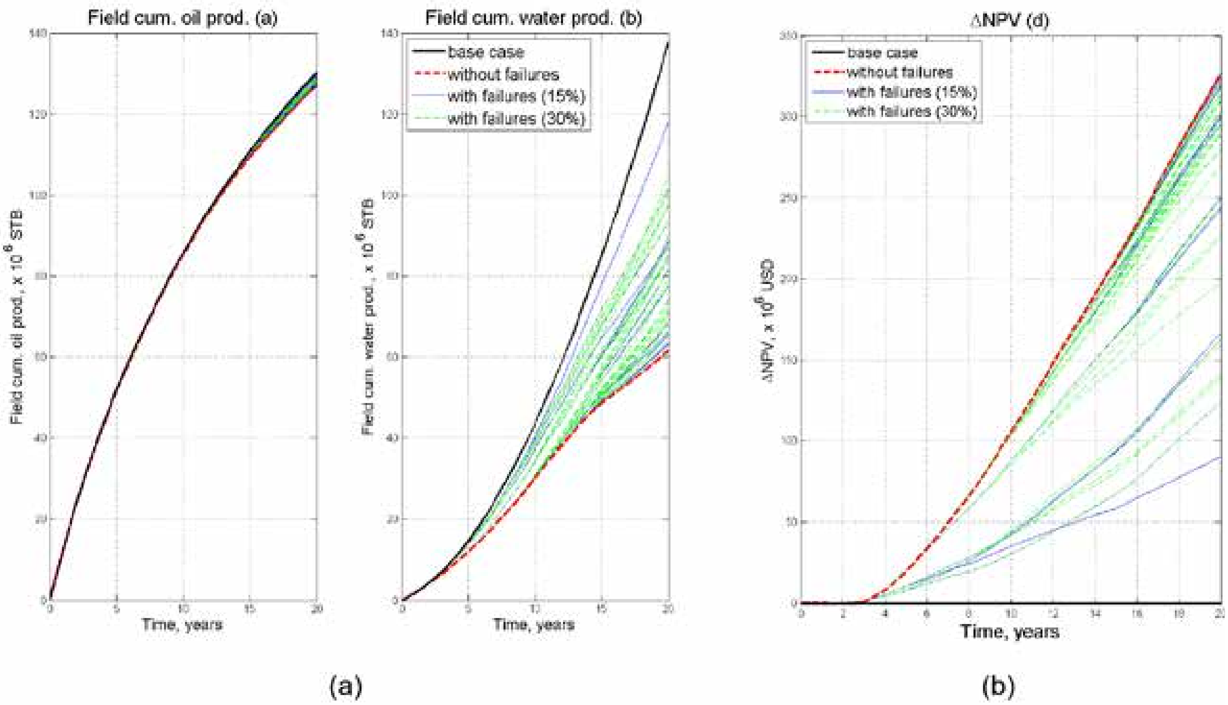


Figure 3. Reliability study results: (a) field cumulative oil and production vs. time, (b) incremental NPV of smart-well completions against traditional wells vs. time.

completions. Profiles of field cumulative oil and water production are shown in Figure 3 for the base case (conventional wells), an optimized smart-well completions operational strategy in the absence of ICV failures, and with 15 % and 30 % failure probability. Figure 3b illustrates that, even for the most pessimistic cases, smart completions are still capable of providing an added value significantly higher than the smart completion installation cost of USD 2 million per well used in this study.

The following can be stated from these results: (a) smart wells provide the ability to effectively manage oil production while minimizing water production even when accounting for geological uncertainties, (b) generally, proactive control strategies are more effective than reactive ones, and (c) depending on the reliability of the installed downhole devices, potential malfunctions of smart well completions could decrease the incremental NPV against traditional wells.

Details of this study are included in the paper SPE 169223 by Valestrand, Khrulenko and Hatzignatiou presented at the SPE Bergen One Day Seminar, Bergen, Norway, 2 April, 2014.

Conclusions

Effective, cost-based and environmentally friendly solutions and improved technology could provide significant boosts in the produced oil volumes, and thus ultimate oil recovery, while reducing water production from oil producing wells.

- The initial project work forms the basis for the next project phase that is focusing on the development of new fluids for controlling water production in wells located in matured, heterogeneous reservoirs which are producing substantial water volumes along with the produced oil.

Academy

The Centre organizes projects for MSc and PhD students to work on industry defined topics.

PhD students and post-doctoral fellows are employed by the University of Stavanger and NTNU.

Seven PhD students are engaged, three of these are female. During 2013, sixteen MSc students were involved in the research projects.

Papers from scientists and PhD students have been presented at high level conferences in Houston, Amsterdam, Dubai, London, Helsinki and Bergen.

The Centre will also include structured competence development in collaboration with and for the oil companies. The first course planned is "Life cycle well integrity".

International cooperation and network

There is a scientific cooperation with University of Texas at Austin in deep imaging and geosteering and with University of Houston within Managed Pressure Drilling.

The Centre's scientists and PhD students have an extensive network to the international research community at prominent universities:

- University of Texas
- Texas A&M University
- University of Houston
- University of Tulsa
- University of Southern California, Los Angeles
- University of California, San Diego
- University of Calgary
- MINES ParisTech
- University of Clausthal
- Delft University of Technology
- University Simon Bolivar, Department of Energy Conversion and Transport, Venezuela
- Sharif University of Technology, Tehran
- Amirkabir University of Technology (Tehran Polytechnic)
- Petroleum University of Technology, Iran
- Research Institute of Petroleum Industry, Iran
- Shiraz University, Iran
- NIOC-IOR Research Institute, Iran
- Curtin University, Perth
- Chulalongkorn University, Department of Mining and Petroleum Engineering, Bangkok

Conference and journal papers

A total of 8 papers were presented at international conferences in Houston, Amsterdam, Dubai, London, Helsinki and Bergen in 2013. One paper has been accepted for the SPE Drilling and Completion Journal.

Governance

The Board has representatives from the Industry Partners as well as the Research Partners. The Chair of the Board is elected from industry and industry governance is secured through voting rules giving one vote to each industry member and one joint vote to the research partners. The Research Council joins the Board as observer.

A Technical Committee (TC) is an advisory body to both the Board and the Centre Manager, and has a coordinating responsibility across programmes and projects.

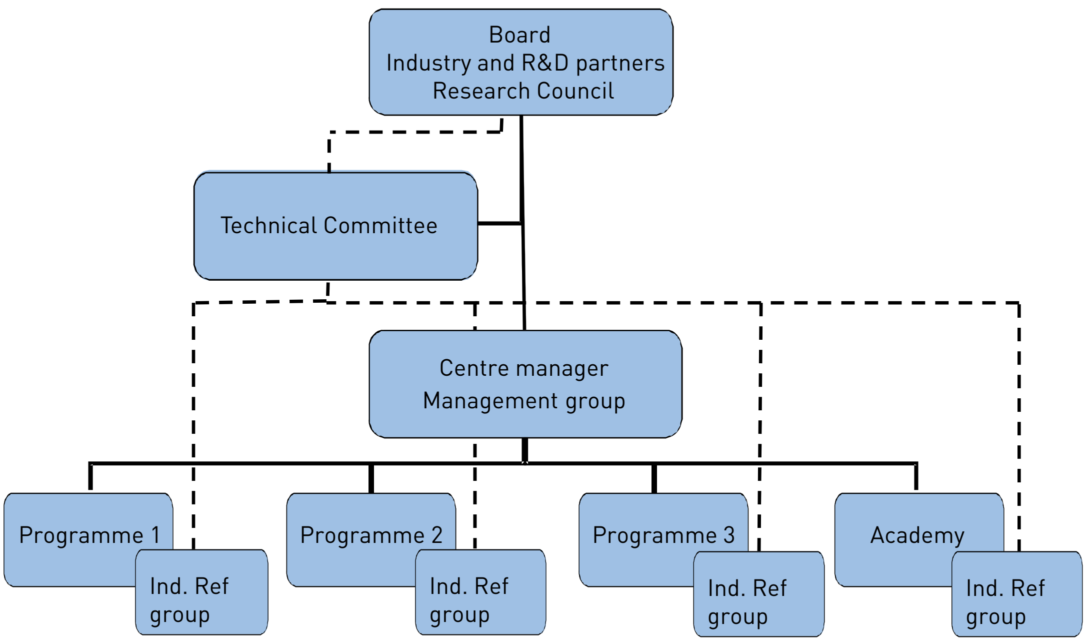
Project-based Reference Groups (RG) with technical specialists from the oil companies are established and provide advice and project supervision.

The industry involvement through the Board, the Technical Committee and the Reference Groups is essential for the innovation process. Innovation comes from intensive cooperation between industry experts and R&D people.

Project research management and coordination is provided by both Programme Managers and Project Managers.

A Score Card developed jointly by the Partners is used for industrial evaluation of each project and of the Centre as a whole three times a year. This gives valuable feedback to the project and Centre's management and is used to direct the R&D for innovation.

Centre organisation



Budgets and financial matters

The Centre has a budget of NOK 42 million per year, funded by NOK 10 million from the Research Council of Norway, NOK 30 million from the participating oil companies and NOK 2 million from the Research Partners.

Seminar

A seminar with 57 participants from the participating oil companies, the Research Council and the Research Partners was successfully organized at Clarion Hotel, near Stavanger. A similar seminar will be arranged in 2014, while a conference with external participation is planned for 2015.

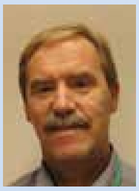
People in DrillWell

– Drilling and Well Centre for Improved Recovery

Board and Technical Committee

Board members:


Halvor Kjørholt, Statoil, Chairman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Harald Blikra, Talisman


Rune Teigland, TOTAL


Torgeir Larsen, Wintershall


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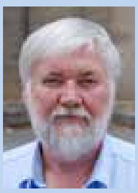
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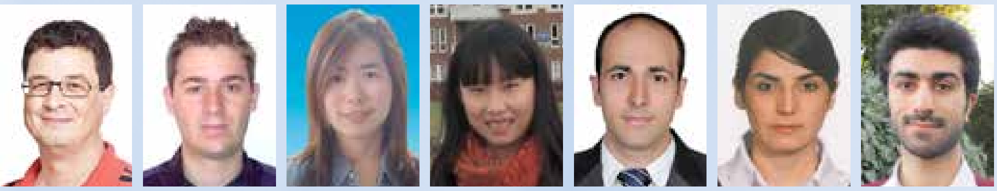
PhD students



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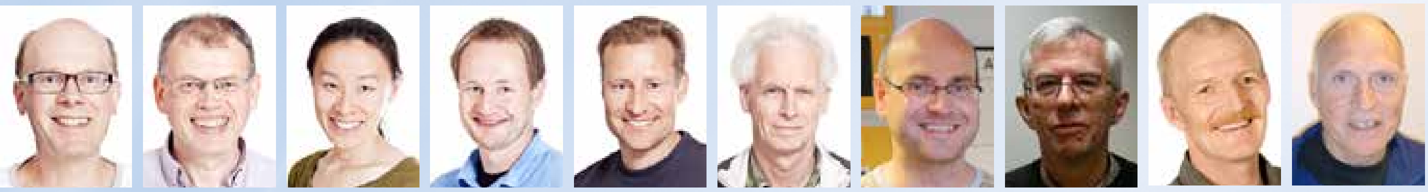

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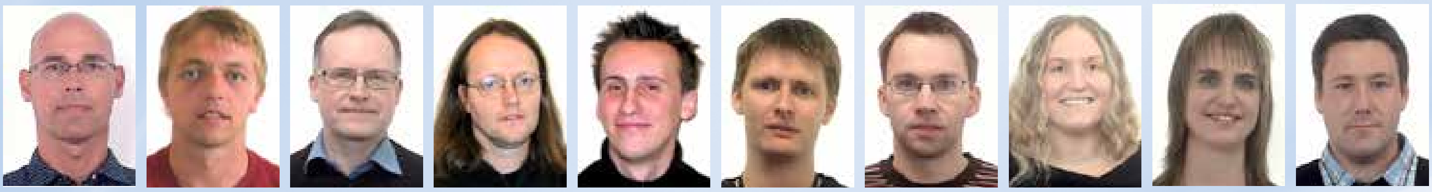

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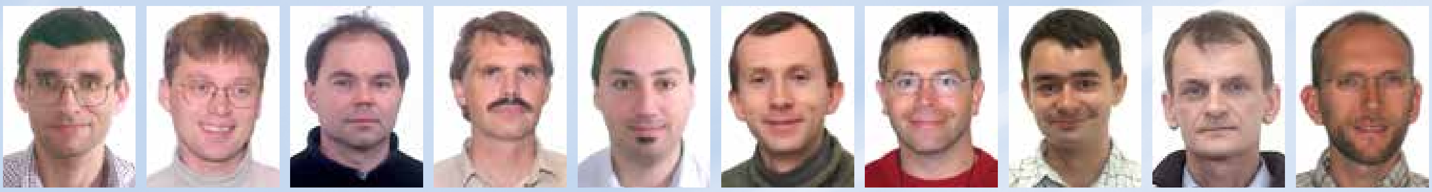

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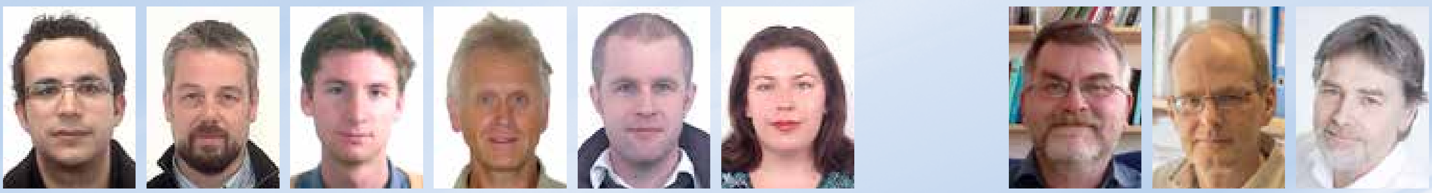

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Pål Skalle NTNU

Annual Report 2013

DRILLING AND WELL CENTRE FOR IMPROVED RECOVERY

Vision

Unlock petroleum resources through better drilling and well technology.

Objective

Improve drilling and well technology providing **improved safety** for people and the environment and **value creation** through better **resource development, improved efficiency in operations** and **reduced cost**.

- Cost reduction
- Improved recovery
- Efficient field development

Contact persons

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Produksjon: www.fagtrykk.no Miljømerket trykkeri, lisensnr. 241 811