The geology of geomechanics: petroleum geomechanical engineering in field development planning

M. A. ADDIS

Rockfield Software Ltd, Ethos, Kings Road, Swansea Waterfront SA1 8AS, UK
Tony.Addis@rockfieldglobal.com

Abstract: The application of geomechanics to oil and gas field development leads to significant improvements in the economic performance of the asset. The geomechanical issues that affect field development start at the exploration stage and continue to affect appraisal and development decisions all the way through to field abandonment. Field developments now use improved static reservoir characterization, which includes both the mechanical properties of the field and the initial stress distribution over the field, along with numerical reservoir modelling to assess the dynamic stress evolution that accompanies oil and gas production, or fluid injection, into the reservoirs.

Characterizing large volumes of rock in the subsurface for geomechanical analysis is accompanied by uncertainty resulting from the low core sampling rates of around 1 part per trillion (ppt) for geomechanical properties and due to the remote geophysical and petrophysical techniques used to construct field models. However, some uncertainties also result from theoretical simplifications used to describe the geomechanical behaviour of the geology.

This paper provides a brief overview of geomechanical engineering applied to petroleum field developments. Select case studies are used to highlight how detailed geological knowledge improves the geomechanical characterization and analysis of field developments. The first case study investigates the stress regimes present in active fault systems and re-evaluates the industry’s interpretation of Andersonian stress states of faulting. The second case study discusses how the stress magnitudes and, potentially, stress regimes can change as a result of production and pore pressure depletion in an oil or gas field. The last case study addresses the geomechanical characterization of reservoirs, showing how subtle changes in geological processes are manifested in significant variations in strength. The studies presented here illustrate how the timely application of petroleum geomechanical engineering can significantly enhance field development, including drilling performance, infill drilling, completion design, production and recovery.

Gold Open Access: This article is published under the terms of the CC-BY 3.0 license.

Geomechanical analysis is based on a comparison of rock mechanical properties and strengths with the stresses acting in situ. When the magnitudes of the stresses acting in the rock are lower than the yield strength, the rocks behave elastically and deformations are small. However, if the changes in stress resulting from excavation during drilling, or from pore pressure or thermal variations exceed the compressive yield, peak or pore collapse strengths, the rock will fail through shearing or compaction, leading to non-linear irreversible deformation. If, on the other hand, the stresses become tensile, fracturing of the formation can occur.

A brief timeline of the important developments in geomechanical engineering applied to oil and gas extraction (Fig. 1) shows that these issues have been pursued since the earliest days of widespread hydrocarbon extraction, attracting the attention of some of the most notable figures in the industry.

The geological expression of the geomechanical, or structural, processes that are responsible for the development of many oilfields include folding, faulting, fracturing and diapirism. The stress regimes and strains accompanying these deformations can control the present day initial stresses and textures in many reservoirs. However, oil field developments lead to geomechanical changes, including the following:

1. rock excavation during drilling results in wellbore stability and sand production problems;
2. removing pore fluid and pressures from the rock results in compaction and subsidence;
3. injection into the reservoirs increases the pressure and induces thermal changes, which result in rock fracturing or shearing to enhance the natural geologically controlled permeability. This is accompanied by significant changes in the reservoir and overburden stresses and strains.

In short, field development activities, from drilling to stimulation, perturb the initial geological conditions. It is the job of the petroleum geomechanical engineer to characterize the initial stress regime and the material properties, including the strength of rocks, to predict and plan for any changes in

From: TURNER, J. P., HEALY, D., HILLIS, R. R. & WELCH, M. J. (eds) 2017. Geomechanics and Geology. Geological Society, London, Special Publications, 458, 7–29.
First published online June 28, 2017, https://doi.org/10.1144/SP458.7
© 2017 The Author(s). Published by The Geological Society of London.
Publishing disclaimer: www.geolsoc.org.uk/pub_ethics
either of the stress magnitudes or deformations accompanying the field development. The perturbations can be small and linear in nature, going unnoticed in many developments. However, when large changes occur, the response of the formations may become non-linear, or plastic, leading to safety breaches and lost production, costing billions of dollars in design changes in the worst-affected fields. As the industry pushes for increased efficiency, greater safety and improved economics in increasingly challenging fields, all aspects of the development are expected to deliver improved field performance, including the discipline of geomechanics.

The application of geomechanics to oil and gas field development has become increasingly common over the past 40 years, with asset teams in the more challenging and larger field developments adopting geomechanical engineers as a permanent part of the team. The growth of unconventional oil and gas developments has accelerated this trend because the need to hydraulically fracture reservoir formations, or to shear the natural fracture network, to generate artificial reservoir permeability relies on geomechanical knowledge of the mechanical properties and initial stresses, as well as on the evolution of the reservoir stresses during field development.

The continual adoption of geomechanical engineering in the industry is difficult to judge quantitatively. However, a good indicator of the level of integration of petroleum geomechanics in the industry is the number of papers published annually by the Society of Petroleum Engineers (SPE) and stored in the SPE library containing the term ‘geomechanics’ in the publication title (Fig. 2).

The number of publications increased gradually through the 1990s, with a significant increase around 2000, predating the successful development of shale gas in the USA in 2004 or the increase in US shale oil production after 2010. This measure of industry uptake does not take into account different aspects of geomechanical analysis, such as compaction, hydraulic fracturing and wellbore stability, which have been used by the industry for a much longer period than that indicated in Figure 2. Compaction and subsidence has attracted considerable activity and interest since the late 1950s, with the notable examples of the Wilmington, Ekofisk, Groningen and the Central Luconia fields, demonstrating the extent to which reservoirs are dynamic during the field development. Wellbore stability and sand production have been a focus in the industry since the late 1970s, particularly after 1979 when four seminal wellbore stability papers were published (Bradley 1979a, b; Bell & Gough 1979; Hottman et al. 1979). These presaged a step change in drilling inclined, high-angle, extended and horizontal wells, both onshore in the Austin chalk, the North Slope of Alaska, and offshore in the North Sea and Gulf of Mexico in the 1980s and early 1990s. Figure 2 reflects the uptake of the now-accepted discipline of geomechanics into field development.

Numerous textbooks comprehensively address both the theory and application of geomechanical engineering to field planning (Charlez 1991, 1997; Fjaer et al. 2008; Zoback 2008; Aadnoy & Looyeh 2011). This paper, in contrast, presents an individual view and geomechanical insights from significant field developments, with emphasis on the geological...
Stress estimation in fault blocks: the limitations of using the Andersonian system

Stress magnitude estimation in the absence of field data

Subsurface stress magnitudes and orientations differ considerably from passive basins and margins to extensional basins and compressional regimes, with wide variations within these structural regimes. The determination of present day subsurface stresses centres around the estimation of the two horizontal total stress magnitudes and directions; the vertical total stress is typically assumed to be equal to the weight of the overburden.

The magnitudes of the two horizontal total stresses ($\sigma_{H}$, $\sigma_{h}$), which result solely from the weight of the overlying column of rock or sediments ($\sigma_{v}$), have been calculated in civil engineering using linear elastic theory since Terzaghi (1943). This approach considers ‘passive basin’ stresses, expected in flat-lying strata in geologically passive environments, where no horizontal compression or extension occurs and the magnitudes of the two horizontal stresses are equal. The horizontal stress in such a simple case is caused by an element of rock trying to expand laterally against the adjacent elements. The horizontal stress magnitude is therefore directly related to the vertical effective stress ($\sigma'_{v}$) and the Poisson’s ratio of the formation. Eaton approach was formulated for passive basins (Eaton 1969) yet, in the absence of area-specific data or measurements, it is commonly used by the industry as a first approximation regardless of the geological environment.

Geologically, the assumption of a passive basin is inappropriate for the majority of oil and gas accumulations, which are more commonly found ‘on structure’ and associated with compressional or extensional geological environments. Horizontal stress anisotropy occurs in these structural regimes when a significant difference is observed between the magnitudes of the maximum and minimum total horizontal stresses, $\sigma_{H}$ and $\sigma_{h}$, respectively. Two different approaches are used to estimate the magnitudes of these stresses from geological considerations. The first imposes a horizontal strain on the formations, whereas the second considers a constant horizontal stress, or stress gradient, compressing or extending the formations – strain v. stress horizontal boundary conditions. Both methods commonly rely on the assumption of isotropic formation properties.

The strain boundary, or deformation boundary, approach results in different horizontal stress magnitudes in different lithologies, calculated from both the Poisson’s ratio and the horizontal stiffness (Young’s modulus) of the formations. This method

Fig. 2. Publications in the Society of Petroleum Engineers OnePetro library with ‘geomechanics’ in the paper title (up to the first quarter of 2016).
requires estimates of the present day strains applied to the formation in the two horizontal directions, which are either obtained empirically through calibration with any available stress data from the field, or through numerical modelling. The stress boundary method, on the other hand, results in lithology-dependent horizontal stress magnitudes controlled by the contrasts in Poisson’s ratio between formations. Two common stress boundaries include a constant stress gradient (or effective stress ratio, $\sigma_v/\sigma_h$), which is determined by calibration with any existing stress data from the field, or on the assumption of active faulting.

**Andersonian fault systems**

The assumption of active faulting relies on estimates of the relative magnitudes of the two horizontal stresses and the vertical stress consistent with the Andersonian stress system for faulting (Anderson 1905, 1951). In this approach, for a given pore pressure, the relative total stress magnitudes required to generate different faulting systems are considered to be:

- normal faulting: $\sigma_v \geq \sigma_H \geq \sigma_h$ (where $\sigma_H = \sigma//$)
- strike-slip faulting: $\sigma_H \geq \sigma_v \geq \sigma_h$ (where $\sigma_v = \sigma//$)
- thrust faulting: $\sigma_H \geq \sigma_h \geq \sigma_v$ (where $\sigma_h = \sigma//$)

where compressive stresses are considered to be positive and $\sigma//$ is the stress oriented parallel to the strike of the fault.

The stress magnitudes associated with these fault systems require that basins are at the limit equilibrium for faulting – that is, on the point of slip, where the stresses required to activate the faults are either the maximum compressional stresses in thrust and strike-slip regimes, or the minimum extensional stresses in normally faulted basins. The following case study illustrates that the measured stresses, particularly the magnitude and orientation of the minimum total stress, are not always consistent with the deformational style of faulting and the assumed stress regime.

**Case study 1. Cusiana field, Colombia: identifying the stress regime acting in an active thrust fault environment**

The Cusiana field in Colombia is located in the foothills of the Andes at the deformation front, where the foothills reach the Llanos plain, and consists of an anticlinal structure bounded by two thrust faults, the Yopal and Cusiana faults (Fig. 3). The underlying Cusiana fault defining the structure of the field is active, as observed in the ground movements and deformation in buildings prior to the start of the field development. The movement on the main fault blocks consists of thrust deformation with little or no strike-slip motion.

Severe wellbore instability was encountered by BP while drilling the first exploration well (Cusiana 1) and subsequent appraisal wells on the Cusiana structure (Skelton et al. 1995). Cusiana 1 was the first well to successfully reach the Mirador reservoir in the region, despite the attempts of several operators. The wellbore instabilities were most common, and challenging, in the overburden that included the Leon and Carbonera formations. The Carbonera Formation was particularly challenging to drill because it consists of four layers of strong sandstone units where mud losses and where hole were experienced, with hole sections generally in-gauge or slightly under-gauge, separated by more shale-rich units, which experienced severe breakouts in the early exploration and appraisal wells. In one example, a four-arm caliper tool measured breakouts that had extended the wellbore to $>1$ m ($>40$ inches) in diameter in one direction, with essentially an in-gauge 31 cm (12¼ inch) borehole diameter in the perpendicular direction (Addis et al. 1993; Last et al. 1995). These early wellbore stability problems led to significant non-productive time drilling the wells, numerous sidetracks and lengthy drilling programmes.

Cusiana, as an anticlinal structure bound by active thrust faults, was expected to have a typical thrust fault stress system, where the minimum stress is oriented vertically and equal in magnitude to the overburden stress (Anderson 1905, 1951; Hubbert & Willis 1957). Analysis of the wellbore stability problems confirmed that the maximum horizontal stress direction, as determined from breakout orientations, was perpendicular to the strike of the fault, consistent with pure dip-slip (plane strain) thrust deformation. However, the analysis of leak-off test and mud loss data indicated that the minimum stress magnitudes were similar to those expected in passive basins, and considerably smaller in magnitude than the vertical stress. This had significant implications for optimizing the stability of the inclined wells required to develop the field from a number of limited drilling pad locations and any hydraulic fracture stimulation of the reservoir.

**Analytical stress analysis**

This unexpectedly low magnitude of minimum horizontal stress was explained using a simple isotropic linear elastic analysis of relatively undeformed fault blocks bound by active faults in plane strain conditions (no strike-slip deformation). This approach showed that it is possible for active thrust faults to exhibit a 90° rotation of the minimum stress acting on the fault blocks, from vertical pre-faulting to horizontal post-faulting (Addis et al. 1994). This
rotation of the minimum stress direction resulted from low fault friction, which causes the magnitude of the horizontal total stress acting parallel to the fault ($\sigma_h$) to drop below the magnitude of the vertical total stress ($\sigma_v$) post-faulting. The stress calculations are shown in Figure 4.

The $y$-axis of Figure 4 shows the magnitude of the horizontal ‘plane strain’ stress ($\sigma_h$) in the fault blocks aligned parallel to the strike of the thrust fault, relative to the magnitude of the vertical stress ($\sigma_v$). If this $\sigma_h/\sigma_v$ ratio $>1$, the minimum stress is oriented vertically, as expected for thrust faults.
A ratio \( < 1 \) indicates that the horizontal stress oriented parallel to the strike of the fault is the minimum stress (\( \sigma_h = \sigma_{//} \)) and a strike-slip stress regime exists, even though the fault deforms as a thrust fault. This ratio is plotted for different fault friction angles on the \( x \)-axis and for formations with different Poisson’s ratios, shown as the contours on the plot.

Figure 4 illustrates that for an active thrust fault at the point of slip, with plane strain deformation, fault blocks consisting of different lithologies, as in the Carbonera Formation in Cusiana, could have lithology-dependent stress regimes: a sandstone with a low Poisson’s ratio may have a minimum stress oriented horizontally, while a juxtaposed shale characterized by a higher Poisson’s ratio may have a minimum stress oriented vertically. In other words, the stresses in the sand layers within the Carbonera Formation are inconsistent with Anderson’s stress regime for the formation of a thrust fault, whereas the stress system in the shale conforms to these pre-faulting stresses.

**Numerical stress models**

The conclusions of this analytical approach were supported by a finite difference numerical model of the Cusiana structure (Fig. 5). BP’s numerical simulation of tectonic deformation in the three Cusiana blocks involved gravitational loading due to the weight of the overburden. Horizontal tectonic movement was then introduced by displacing the Yopal thrust fault overlying the Cusiana structure by 100 m (330 ft) to the SE and displacing the underlying Cusiana thrust fault by 20–25 m (65–82 ft). This ratio of displacements matched the observed fault-throw ratio on the fault surface. The results of this numerical approach illustrate the relatively low horizontal stress magnitude (\( S_h \)) oriented parallel to the strike of the thrust faults (Addis et al. 1993; Last et al. 1995), in line with the analytical estimates.

While drilling additional wells on the Cusiana structure, these low minimum horizontal stress magnitudes of 14.7–17.0 kPa m\(^{-1}\), (0.65–0.75 psi/ft) and vertical overburden stresses of 23.8–24.7 kPa m\(^{-1}\) (1.05–1.09 psi/ft) were repeatedly observed across the field (Last et al. 1995).

The analytical estimates of horizontal stress magnitudes, illustrated in Figure 4, assume a simple flat-lying fault block geometry. However, in reality, rollover anticlines defining the Cusiana field result in non-horizontal and non-vertical principal stresses. Last & McLean (1996) described the stress rotation based on numerical modelling of the Cusiana structure and the impact on wellbore stability analysis.

This additional complexity does not seem to significantly influence the minimum horizontal stress magnitude in Cusiana: The stresses used to model the stress rotation in Cusiana by Last & McLean (1996) were equivalent to 31.7:24.9:15.8 kPa m\(^{-1}\) (1.4:1.1:0.7 psi/ft) for the maximum horizontal stress, vertical stress and minimum horizontal stress gradients, respectively.

**Model validation with additional measurements during late field development**

More reliable data on the stress magnitudes became available during the completion and stimulation of the Cusiana development wells. The low-permeability Mirador reservoir underlying the Carbonera Formation was hydraulically fractured and the stress measurements obtained during these stimulations again largely support the earlier stress estimates, indicating stress gradients in the sandstone reservoir of \( \sigma_h = 23.8 \) kPa m\(^{-1}\) (1.05 psi/ft), \( \sigma_v = 24.9–28.3 \) kPa m\(^{-1}\) (1.1–1.25 psi/ft) and \( \sigma_\perp = 13.1–17.6 \) kPa m\(^{-1}\) (0.58–0.78 psi/ft) (Osorio & Lopez 2009).

Microseismic data measured during reservoir stimulation confirmed the development of vertical hydraulic fractures. The microseismic events were aligned with the maximum horizontal stress (NW–SE) direction determined from breakout analysis and were oriented perpendicular to the strike of the fault planes (Osorio et al. 2008). This again indicates that the minimum stress magnitude is oriented horizontally and parallel to the strike of the thrust fault (\( \sigma_h \)). It also consistent with the analytical and numerical modelling, is apparently at odds with the common interpretation of stress regime associated with the Andersonian thrust deformation of the faults.

**Business impact**

Despite the very severe drilling problems experienced in the early exploration and appraisal wells on the Cusiana field, the efforts taken to understand the complexity of the stress field allowed the development team to better address the wellbore instability and to improve well design and drilling practices. This led to a significant improvement in performance in this challenging field, with the non-productive time reducing from 47% in 1993 to 27% in 1996 (Last et al. 1998).

**Stress evolution from numerical sandbox modelling of thrust fault systems**

The transformation of the stress state in the compressional thrust fault blocks, pre- and post-faulting (Fig. 4), results from low fault friction, either initial or residual friction. In the latter case, the maximum
compressive stress required to initiate the thrust fault plane exceeds that required to mobilize the fault plane at large strains, the difference between peak strength and residual strength. Using Sibson’s characterization of faulting styles (Sibson 1977, 2003), this may be more common at relatively shallow depths in a ‘brittle’ zone, where strain softening rock behaviour might be expected, rather than at great depths with larger confining pressures, where the fault planes may display perfect plasticity during rock failure.

The results of the finite difference numerical modelling of Cusiana (Fig. 5) only considered the late-stage movements on existing fault planes with an existing structure. However, simulations of sandbox experiments that consider the formation and

---

**Fig. 5.** BP’s finite difference simulation of the Cusiana field stresses. Analysis was made on sections oriented NW–SE, parallel to the tectonic compression. The maps show the three principal stress magnitudes for one of the sections. In general, $S_{H_{nw-se}} > S_v > S_{h_{sw-ne}}$. From Addis et al. (1993), reproduced with permission of Schlumberger.
development of fault planes show similar results; Crook et al. (2006) present such numerical models for extensional faulting. A large strain finite element numerical modelling code was used to simulate a compressional sandbox experiment. The material being compressed laterally was sandstone, with a characteristically low Poisson’s ratio and the elastic and Mohr–Coulomb properties shown in Table 1. The sandstone properties assigned to the numerical sandstone are representative of high porosity sands.

The compressional numerical experiments considered both high and low fault frictions (Fig. 6). The total stress magnitudes for the three stresses ($\sigma_v$, $\sigma_H$, $\sigma_h$) are shown by the colour scales, where red indicates low compressive stresses and blue shows high compressive stresses. The scale for the top row of figures differs from the scale for the figures in the middle and bottom rows by an order of magnitude. The sandbox models simulated in this numerical modelling consist of a uniform formation compressed by the left-hand boundary, with a static right-hand boundary.

The top panels (Fig. 6) show the calculated initial stress conditions due to gravitational loading, prior to compression, where the two horizontal stresses have similar magnitudes and distributions, equivalent to passive basin conditions. The observed differences at the boundaries reflect the friction assigned to the sides of the sandbox.

The panels in the middle row show the vertical stress, compressional maximum horizontal stress and the minimum horizontal stress (perpendicular to the plane strain boundary, $\sigma_h = \sigma_{\parallel}$) after the sandbox experiment had undergone compressional strain. This middle row of simulations uses the sand properties shown in Table 1, which are elasto-plastic, and the friction angle remains constant at 36°, independent of the amount of strain or slip developed on the failure planes. From the analytical solutions presented in Figure 4, these simulations with a sand Poisson’s ratio of 0.25 would result in the vertical stress as the minimum principal total stress ($\sigma_3 = \sigma_v$).

The bottom panels again present the three stresses, but for conditions where the sandstone has been assigned frictional properties that reduce as the plastic strain on the failure planes develops. This approach reproduces a fault plane mobilizing residual friction as the fault slips. The properties assigned to this post-peak residual friction are shown in Table 1 in parentheses for the friction

### Table 1. Summary of sandstone properties used in the numerical sandbox simulations

| Property                   | Value   |
|----------------------------|---------|
| Young’s modulus (Pa)       | $1.5 \times 10^5$ |
| Poisson’s ratio            | 0.25    |
| Density (g cm$^{-3}$)      | 1.7     |
| Effective plastic strain   | 0       |
| Cohesion (Pa)              | 140     |
| Friction angle (°)         | 36      |
| Dilatation angle (°)       | 30      |

**Fig. 6.** Numerical simulations of a sandbox experiment illustrating the stress development post-failure. Top row: passive basin conditions, gravitational loading with no lateral compression. Middle row: gravitational loading with lateral compression – sandstone with constant friction angle. Bottom row: Gravitational loading with lateral compression – sandstone with residual friction angle.
angle, where the friction angle drops from 36 to 28° as the failure plane develops more plastic strain. Using the analytical solution in Figure 4, this lower fault residual friction should result in the minimum principal total stress becoming oriented horizontally (σ₃ = σ₀ = σₒ //). These numerical sandbox simulations show that the maximum horizontal stress develops as expected, accompanying the lateral compression. The stress contours outline the developed shear failure bands. The vertical stress is bound by the free surface in the y-axis direction, but shows variations resulting from the development of the shear failure bands.

In the middle row of Figure 6, the minimum horizontal stress (σᵢ = σₒ //) is of a similar magnitude to the vertical stress. In the relatively undeformed fault blocks, next to the right-hand boundary of the figures, the minimum horizontal stress slightly exceeds the magnitude of the vertical stress, in line with the Andersonian description and the analytical estimates in Figure 4. This is consistent with the stress system responsible for the formation of the fault planes.

The results from the last suite of simulations are shown in the bottom row, where the friction angle of the sands was reduced as the failure planes developed. These simulations show that once residual friction is developed and the fault plane friction is sufficiently reduced, the stresses generated in the relatively undeformed fault block on the right-hand boundary of the simulations has the minimum horizontal stress oriented parallel to the strike of the fault with a magnitude lower than the vertical stress (σ₃ = σ₀ = σₒ //). These simulations again support the field data as well as the analytical and numerical models used to explain the anomalously low magnitudes of horizontal stress acting in the Cusiana field. The earlier discussion of the stresses present in the Cusiana active thrust fault is also evident in other compressional thrust faulting regions, such as the Canadian Rockies (Woodland & Bell 1989) and the highlands of Papua New Guinea (Hennig et al. 2002), which also indicate minimum horizontal stress magnitudes significantly lower than the vertical stress magnitude (σ₃ > σ₀ = σₒ //). The common interpretation and application of the Andersonian stress system should therefore be treated with caution in similar structural regimes.

**Stress regimes in active normal faulting systems**

This discussion has focused on thrust fault environments, but many fields are developed in normally faulted regimes. The analytical approach described in Figure 4 was applied to normal faulting and a similar picture emerged: stress rotations in the undeformed fault block can also accompany normal fault development.

In Figure 7, the y-axis again plots the ratio of the horizontal stress acting parallel to the strike of the normal fault, which is normally assumed to be the intermediate stress, relative to the magnitude of the vertical stress (σₒ ///σᵥ). The horizontal stresses are always less than the vertical stress in this normal faulting extensional environment and the values on the y-axis are always < 1. The relative magnitude of this ‘fault-parallel’ horizontal stress (σₒ //) is again plotted for different values of fault plane friction and formation Poisson’s ratios.

This plot also shows the magnitude of the extensional horizontal stress acting perpendicular to the strike of the fault plane relative to the magnitude of the vertical stress; the fault mobilization curve. This is the horizontal total stress required to mobilize or slip normal faults for given fault friction angles.

Figure 7 shows that in fault blocks defined by normal faults with no strike-slip component, but with high fault friction angles, isotropic formations with high Poisson’s ratios are likely to have minimum horizontal stresses acting perpendicular to the strike of the fault, in line with expectations of the pre-fault stress state. By contrast, in formations with low Poisson’s ratios and in the presence of faults with low friction, in the area below the fault mobilization curve, the minimum horizontal stress magnitude may be re-oriented parallel to the normal fault (σ₃ = σ₀ = σₒ //), which again contrasts with the Andersonian fault system required to form the faults.

**A note on stress polygons**

The stress polygon (Anderson 1951) and its modification (Zoback 2008) is commonly used in the petroleum industry for the stress estimation of faulted environments. It can be used to illustrate this rotation of the minimum horizontal total stress and the non-coincidence of the principal stress and deformational axes when low friction or weakening on the fault occurs during slip or for formations with contrasting Poisson’s ratios.

Figure 8a shows the standard stress polygon for the Andersonian stresses required to generate the main faulting types for a fault friction of 30°, while Figure 8b illustrates the analytical estimates for formations with low Poisson’s ratios (= 0.1) for the stress states presented in Figures 4 and 7 for thrust and normal faulting, respectively. The stress polygons show for plane strain conditions that thrust fault deformations can result in stress magnitudes normally attributed to strike-slip faulting and that for thrust and normal fault deformations
the minimum stress may become oriented parallel to
the fault plane ($\sigma_3 = \sigma_h = \sigma_f$). Figure 8c, calculated using a Poisson’s ratio of 0.35, demonstrates
that a continuum of stress states may not occur
between faulting styles for the plane strain condi-
tions presented in Figures 4 and 7. Figure 8 illus-
trates that a range of different properties and sizes
of the stress polygons exists depending on the values
of the fault friction angle and Poisson’s ratio for a
specified vertical total stress and pore pressure.

Discussion of Andersonian systems and
post-faulting stress regimes

Anderson (1905, 1951) described the relative stress
magnitudes required to generate normal, strike-slip
and thrust faults, specifically up to the point when
the faults form, not post-faulting. Anderson used
the phrase, ‘Suppose now that the stresses are so
great as to lead to actual fracture’. That describes
the stress regime acting up to the initiation and gen-
essis of the fault, but does not address the stress
regimes that could develop after the faults have
formed, stating that, ‘The effect of all faulting is
to relieve the stress and bring conditions nearer to
… the standard state’, i.e. closer to isotropic condi-
tions. The assumption of a minimum stress equal to
the vertical stress in a thrust fault regime, or perpen-
dicular to normal faulting, may therefore be incor-
correct under certain conditions.

The decrease in stress after fault formation can
be explained by the well-documented large post-
peak ‘brittle’ or weakening response that accompa-
ies the formation of a well-defined discontinuity
(Bishop 1974; Sibson 1977; Mandl 2000). This
‘brittle’ or weakening response as the fault develops
leads to low residual friction at large strains due to a
number of possible contributing mechanisms,
including: grain disaggregation, a large clay con-
tent, or low effective normal stresses resulting
from high ‘undrained’ pore pressures on the fault
plane, accompanying the shear stress build-up and
deformation. This is akin to the undrained mechan-
ical response described by Skempton’s ‘A’ pore
pressure coefficient (Skempton 1954; Yassir 1989).

This section has considered only simple compres-
sional or extensional events. However, geological
history is commonly complex, involving multiple loading events that affect the current
day stresses. Stress inversion events are well docu-
mented in the Tertiary of the North Sea (Biddle &
Rudolph 1988), the NW Shelf of Australia (Bailey
et al. 2016) and globally (Cooper & Williams
1989; Buchanan & Buchanan 1995). Stress inver-
sion also plays a part in the development of the

Fig. 7. Variation of the minimum horizontal stress magnitude acting in intact fault blocks oriented parallel to a
normal fault, normalized by the vertical stress magnitude, for different friction angles on the normal fault (Addis
et al. 1994). © 1994, Society of Petroleum Engineers. Reproduced with permission of SPE. Further reproduction
prohibited without permission.
Fig. 8. Comparisons of stress polygons with (a) standard Andersonian faulting for stress conditions leading up to fault development; (b) possible stress conditions post-fault development in formations with low Poisson’s ratios (¼0.1); and (c) possible post-fault conditions in formations with high Poisson’s ratios (¼0.35).
Cusiana field, where the bounding Cusiana fault was originally a margin extensional fault, which was later reactivated during the Andes compression. Consequently, the inclination of the Cusiana fault may not be consistent with the typical angular relationship of failure planes relative to the maximum horizontal stress ($\beta = 45^\circ - \phi/2$) for thrust fault development, but may be more representative of normal faulting. To account for the differences in the dip between the actual fault plane after fault formation and the expected fault orientation resulting from rock failure, Wu et al. (1998) refined the earlier calculations for stresses resulting from normal and thrust faults for plane strain conditions. These equations represent a simplified analytical approach to estimate the impact of stress inversion on the stresses acting in fault blocks away from the immediate vicinity of the fault planes.

As a further consideration, the normal assumption of vertical and horizontal stresses, while a common assumption for flat-lying formations, does not apply in these compressional environments, where faulted and folded formations predominate. The subvertical principal stress orientation in these folded environments is, as a first approximation, taken to be normal to the bedding planes in moderately inclined and folded beds. The presence of faulting provides additional complexity and local rotations occur based on the orientation of the fault, the relative movements on the fault blocks and the fault friction angles which are best evaluated using numerical models (Thornton & Crook 2014). These folded formations and rotated stress systems have a significant impact on wellbore stability for inclined wells in these compressional environments (Last & McLean 1996).

Other geological processes have a significant impact altering the stress systems acting in relatively passive environments, most notably associated with salt intrusions, where stress rotations in the horizontal plane are observed from breakout analysis (Yassir & Zerwer 1997) and those in the vertical plane are calculated using numerical methods (Peric & Crook 2004).

To conclude, the stress regimes described by Anderson for the onset of different faulting styles, specifically normal and thrust faulting, are calculated to persist in relatively undeformed fault blocks if the formations have a high Poisson’s ratio and/or large fault plane friction. The stress states acting in fault blocks deviate from the pre-faulting Andersonian stress states for formations with low Poisson’s ratios and for faults with relatively low friction, either initially or as a result of strain weakening and low residual friction angles. This suggests that at depths within the zone of interest for hydrocarbon exploitation, fault blocks containing younger, less compact and less cemented formations, which are more likely to behave in an elastoplastic manner, and bound by faults with high fault friction could be expected to have stress systems compatible with the Andersonian system of stresses required for the formation of the faulting styles. In contrast, older or more competent formations, bound by faults with low fault friction (drained or undrained), may have post-faulting stress systems that are not consistent with the original pre-faulting stress states.

This has significant implications for stress analysis in petroleum field development and for the selection and interpretation of stress estimation methods. These estimation methods are often lithologically constrained, e.g. breakout analysis predominates in more shale-rich formations, whereas minifract and differential strain curve analysis are more common in sandstones and limestones. There are also implications for strain-based indicators of fault movement, such as seismic moment analysis ‘beach balls’, which may not always represent the existing stress field throughout these active fault systems.

**Neotectonic natural fracture development accompanying compression and extension**

Evidence of strain accompanying faulting on a geological timeframe includes the occurrence of extensional vertical fractures or steep hybrid fractures in compressional environments. These neotectonic fractures are oriented perpendicular to the deformation front, with the minimum horizontal stress aligned parallel to the strike of the thrust fault plane ($\sigma_h = \sigma_s$), as described by Hancock & Bevan (1987) for a number of foreland basins. The formation of these near-vertical natural fractures oriented parallel to the maximum horizontal stress direction is again inconsistent with a common interpretation of compressional thrust stress regimes, where the minimum stress is expected to be vertical.

The rotation of the minimum stress from vertical at the onset of thrust faulting to horizontal during the development and displacement of the thrust fault, discussed in the preceding sections, may provide a prerequisite condition for the development of the subvertical neotectonic natural fractures. These are observed over hundreds of kilometres in the forelands and hinterlands of orogenic belts and at distances greater >500 km from the compressional deformation front (Hancock & Bevan 1987). Numerous examples are presented by Hancock & Bevan (1987), from southern England, northern France and the Arabian platform, along with the vertical $J_2$ joint set of the Marcellus Shale in the Appalachian basin reported by Engelder et al. (2009). In the absence of this post-faulting stress rotation, these neotectonic fractures have been considered to be restricted to shallow depths and attributed...
to significant uplift and elevated fluid pressures, or lateral elongation in the forelands parallel or sub-parallel to the fault strike or orogenic margin, in order to produce the necessary tensile effective horizontal stresses to form the fractures.

For normally faulted environments, similar observations have been discussed by Kattenhorn et al. (2000), where vertical natural extensional fractures occur oriented perpendicular to the strike of the normal fault plane, again contrary to the common interpretation of stress states associated with normal faults. Kattenhorn et al. (2000) discuss the field occurrence of these fractures and assess the conditions required for their formation, primarily considering the elastic stress perturbation around faults. However, one prerequisite for their formation is considered to be \( \sigma_h = \sigma_v \), which Kattenhorn et al. (2000) refer to as a condition where \( \delta > 1 \); \( \delta \) is redefined here (where compressional stresses are considered positive) as the ratio of the fault-perpendicular to fault-parallel horizontal stresses \( (\sigma_f/\sigma_h) \) acting remote from the fault plane (Fig. 7). The stress estimations presented here and discussed in Addis et al. (1994) enable us to predict which formations are likely contain such fractures and why these may not extend into adjacent formations of different mechanical properties.

The lithological control on the minimum horizontal stress becoming parallel to the fault strikes is consistent with observations of neotectonic fractures being more prolific in low Poisson’s ratio formations, e.g. sandstones and limestones (Hancock & Engelder 1989), and less clay-rich formations (Engelder et al. 2009).

In the formulations presented, the minimum horizontal stress does not become tensile, a requirement for the development of new tectonic joints as described by Hancock & Bevan (1987), Hancock & Engelder (1989) and Engelder et al. (2009) for compressional regimes and by Kattenhorn et al. (2000) for normal faulting environments. Mechanical conditions such as elevated fluid pressures and/or high deviatoric stresses leading to ‘extension fractures’ (Engelder et al. 2009) or extension parallel to the fault plane may be required to make this minimum effective horizontal stress tensile.

**Stress evolution during field production and the impact on infill drilling**

The compressional stress regime discussed in the previous sections for the Cusiana field considers the relative total stress magnitudes present at the start of production, which have developed over a geological timeframe and are considered to be relatively static, although fault movements are known to perturb this static condition. Production and injection in a field cause the total stresses to vary with the changes in the reservoir pore pressure on an almost daily basis. This dynamic stress environment not only exists in the reservoir, but also in the surrounding formations. It has a significant technical and economic impact on field planning, drilling, stimulation and production of these fields, especially for depleting high pressure–high temperature (HPHT) fields.

The effect of production and reservoir pressure depletion on the minimum total stress magnitude was first documented by Salz (1977), who showed a linear relationship between the change in the total minimum horizontal stress magnitude and the change in the average reservoir pressure \( (d\sigma_h/dP_p) \) in the Vicksburg Formation in south Texas, where the stress depletion response was shown to be:

\[
\frac{d\sigma_h}{dP_p} = \gamma_h = 0.53
\]

A large number of subsequent studies on different fields have described similar decreases in the magnitude of the minimum horizontal stress accompanying depletion (Teufel et al. 1991; Engelder & Fischer 1994; Addis 1997a, b; Hillis 2003). Little attention has been given to the changes in the magnitude of the maximum horizontal total stress with pore pressure, which is normally assumed to change with the same depletion ratio as the minimum horizontal total stress \( (\gamma_h = \gamma_h) \). The change in the vertical total stress with pore pressure \( (\gamma_h) \) has received more attention as a result of the increasing use of field-wide geomechanical numerical modelling and the cross-correlation with four-dimensional seismic velocity changes, which are used to monitor the vertical stress and strain changes resulting from depletion-driven reservoir compaction and subsidence (Kenter et al. 2004; Molenaar et al. 2004).

Geological factors which influence the dynamic response of the minimum horizontal total stresses to reservoir pressure changes include:

1. the reservoir dimensions;
2. the reservoir structure (anticlinal, inclined, flat-lying);
3. the mechanical property (elastic) contrasts between the reservoir and overburden formations;
4. pore pressure depletion – the radius of influence, drainage radius or reservoir compartmentalization;
5. pressure cycles, depletion followed by injection (Santarelli et al. 1998, 2008);
6. faulting style and stress regime;
7. location on the structure.

These factors contribute to the range of the stress depletion ratios observed globally, which typically
vary between $\gamma_h = 0.4$ and 1.0, with the most common being in the range $\gamma_h = 0.6$–0.8. Teufel et al. (1991) showed for the Ekofisk field that the horizontal stresses on this domal field decrease at the same rate for wells located at the crest and the flanks of the field, at a rate of $c. \gamma_h = 0.8$. The nearby chalk fields show similar stress depletion ratios for the minimum horizontal stress. Geological factors also control the vertical stress changes accompanying depletion, ranging from $d\sigma_v/d\Delta P = \gamma_v = 0$ for flat-lying, laterally extensive reservoirs to $\gamma_v = 0.2$ for anticlinal or highly inclined reservoirs (Molenaar et al. 2004). Molenaar et al. (2004) predict that the vertical total stress changes accompanying the depletion of the Shearwater field, in the high pressure–high temperature region of the central North Sea, are dependent on the location of the well on the structure of the inclined reservoir blocks.

The variation of the maximum horizontal stress with depletion is not known and is only estimated through analytical (Addis 1997a) or numerical modelling, given the challenges of determining the magnitude of the maximum horizontal stress from field measurements. The assumption that $\gamma_H$ varies in a similar manner to the minimum horizontal stress might be a reasonable assumption for flat-lying reservoirs exhibiting a passive basin type depletion response. This is unlikely to be the case for anticlinal or faulted reservoirs.

**Case study 2. Brent field, North Sea: the impact of depletion on infill drilling**

The difficulty in estimating the magnitude of the stress depletion coefficient for the minimum horizontal stress ($\gamma_h$) manifested itself during the analysis of drilling challenges which were encountered during the infill drilling of the Brent field during the early 2000s. Brent had been on production since 1976, with the later stages of production benefiting from pressure support through water injection. In January 1998, the water injection was halted over the majority of the field and the reservoir pressure allowed to decrease through reservoir blow-down aimed at recovering remaining bypassed oil and gas. The average pressure depletion rate of the field was 3.4 MPa a$^{-1}$ (500 psi/year).

Infill drilling of high-angle sidetracks from existing wellbores during 1999 began to encounter severe mud losses, which had not been observed with the earlier drilling. A post-well review identified the cause of the mud losses as a reduction in the fracture gradient of the wells, resulting from the decrease in the minimum horizontal stress accompanying the depletion (Addis et al. 2001). The losses were stress-related; the most severe losses corresponded to the lowest reservoir pressures and with wellbores drilled in the direction of the maximum horizontal stress direction i.e. predominantly NW–SE (Figure 9).

The infill drilling sidetracks targeted small pockets of bypassed oil on the eastern flanks of Brent, which were isolated from the main reservoir by

---

**Fig. 9.** Breakout (minimum horizontal stress) directions for the Brent field. Orange and pink denote borehole elongation in vertical wells and deviated wells, respectively; blue and green denote possible borehole breakouts in vertical wells and deviated wells, respectively. Rose diagrams are not to scale. After Boylan & Williams (1998). © 1998 Society of Petroleum Engineers. Reproduced with permission of SPE. Further reproduction prohibited without permission.
faulted compartments – the crestal slump faults (Struijk & Green 1991) (Fig. 10). These wells were low-cost sidetracks, c. £1 million per sidetrack, designed to access 1–2 million bbls of oil per well, but the mud losses and other non-productive time were making the sidetracks uneconomic (Davison et al. 2004).

As a result of the mud loss review, a number of operational changes were adopted to continue drilling the sidetracks, as outlined in Addis et al. (2001) and Davison et al. (2004). An early priority was to establish the stress depletion constant for Brent.

**Stress depletion response**

During the planning stages, the depletion coefficient for the minimum horizontal total stress was assumed to be $\gamma_h = 0.7–0.75$, based on data obtained from laboratory tests of the Brent sandstone and the simple passive basin assumption for horizontal stress decrease. Such estimates are commonly used as a first approximation, but they ignore the geology and the geological controls of stress and stress evolution accompanying depletion and injection.

The relationships used for estimating the horizontal stress magnitudes for faulted environments, post-faulting, illustrated in Figures 4 and 7 for thrust and normal faulting regimes, allow the horizontal stress depletion responses ($\gamma_h$) to be estimated for these different faulted environments (Addis 1997a). Given that the eastern flank of Brent was normally faulted, with slump faults, the stress depletion response might be controlled by the stresses acting in the presence of the normal faults. However, the estimates for these normally faulted conditions did not significantly differ from the passive basin values. This simple approach also does not account for the present day stress regime. The maximum horizontal stress direction, oriented perpendicular to the breakouts (Fig. 9), indicates that the horizontal stresses have rotated since the initiation of the faults because they are currently aligned oblique to the strike of the faults.

The dynamic response of the reservoir to pressure changes does not respond in isolation. The reservoir has a predominantly shale overburden, providing a contrast in the average elastic material properties between the reservoirs and the shale overburden. The impact of this modulus contrast on the reservoir stress depletion response was estimated using a semi-analytical model based on the Eshelby ellipsoidal inclusion approach (V. Dunayevsky, pers. comm. 2001), which resulted in an estimate of the stress depletion coefficient of $\gamma_h = 0.61–0.62$ for the horizontal total stresses and $\gamma_v = 0.01–0.02$ for the vertical total stress changes. The initial estimate of the stress depletion response and this update used core-based mechanical property measurements and considered uniform reservoir pressure changes across the field. Subsequently, an elastic finite element model was built and populated with the calculated reservoir pressures from a dynamic reservoir engineering model of the Brent field, leading again to stress depletion estimates for the minimum horizontal total stress in the region of $\gamma_h = 0.60–0.61$ over the majority of the field, but with lower values towards the flanks of the field (J. Emmen pers. comm. 2001).

These stress depletion estimates showed a reduction in the minimum horizontal total stress and in the fracture gradient of between 60 and 70% of the pore pressure decline for these high-angle sidetracks. However, predicting the observed stress depletion responses of reservoirs globally for different geological conditions had proved difficult at the time due to the range of factors affecting the depletion response (Addis 1997b).

Consequently, the approach taken to estimate the depletion constant, and the reduction in the fracture gradient with depletion, was based on an analysis of
the field data. The only available data reflecting the change in the fracture gradient and the minimum horizontal total stress during the depletion stage of the Brent field development since 1998 were the mud loss occurrences. These are imprecise measurements, but in the absence of actual stress measurements, such as mini-fracture tests, they can be used as an operational estimate.

**Business impact**

The reservoir pressure estimates at the time of the mud loss, the differences in well trajectory and operational effects such as temperature, swabbing and surging were analysed, which led to an operational bound of $\gamma_0 = 0.4$ for the decline in the minimum horizontal total stress (fracture gradient) with depletion. This much slower rate of minimum horizontal stress decline formed the basis for new well planning and, along with operational improvements, resulted in continued infill drilling in the Brent reservoir and significant improved recovery of reserves (Davison et al. 2004).

This Brent case study demonstrates the shortcomings of using simple model assumptions about stress and stress variations and the need to include geologically realistic models calibrated to field data measurements. If the early, higher, stress depletion estimates had been used for planning purposes, the infill well drilling could have been prematurely curtailed, with a loss of tens of millions of barrels of oil production and reserves recovery.

**Strength differences resulting from cementation and facies variations**

The previous sections have focused on the relative magnitudes of the in situ stresses for different faulted geological environments and the variation in the stress magnitudes in the reservoir accompanying depletion. Field development must also address the second element of geomechanical analysis: formation mechanical properties and, foremost among these, the strength of the reservoir rock.

Numerous relationships are used by the industry to estimate the strengths and mechanical properties of different lithologies from log-based geophysical measurements, as collated and summarized by Khaksar et al. (2009). These generic trends are invaluable, because measurements on reservoir formations are often limited by the available core. For a typical exploration well, core taken across the hydrocarbon-bearing interval may range from 20 m to over 100 m for larger reservoirs. Mechanical testing of 15–20 core sample intervals from the reservoir formation would be a typical sampling density per well. Given that the determination of mechanical rock properties on cores obtained from more than two to three exploration and appraisal wells is uncommon in a field, gives a total number of sample points of 40–60. More testing may occur in larger fields, but this is rarely done.

Table 2 shows calculations of sampling densities for typical geomechanical reservoir characterization for different well lengths or for a reservoir sector. A sampling rate for one well in a reservoir sector of 3 km radius corresponds to a sampling density $<1 \times 10^{-12} (<1 \text{ ppt})$. This very low sampling rate illustrates why the use of petrophysical well logs and three-dimensional seismic data, in combination with calibrated rock strength trends, are crucial in interpolating the measured rock properties across the entire reservoir and overburden, and underpin any three-dimensional geomechanical analysis of the field.

The use of these generic strength trends, however, introduces considerable uncertainty when estimating reservoir rock strength profiles for detailed geomechanical analysis because the correlations are generally ‘one-parameter’ correlations (e.g. unconfined compressive strength v. porosity). By contrast, Coates & Denoo (1980) and Bruce (1990) presented an equation to describe the dependence of sandstone strength on two primary factors (stiffness and clay content) based on a collation of earlier test data:

$$C_0 = 0.026 \times 10^{-6} \frac{2 \cos \phi}{1 - \sin \phi} EK(0.008V_{\text{clay}} + 0.0045[1 - V_{\text{clay}}])$$

where $C_0$ = unconfined compressive strength (psi), $\phi$ = angle of internal friction, $E$ = Young’s modulus.

**Table 2. Illustration of the sampling densities for geomechanical analysis in wells and reservoir sectors**

| Sampling Points          | Well Length (m) | Reservoir Radius (m) | Sampling Density |
|--------------------------|-----------------|----------------------|-----------------|
| Reservoir interval sampling | 15–20          | 100                  | 0.011–0.015     |
| Total well depth sampling | 15–20          | 3000                 | $3 \times 10^{-4}$–$5 \times 10^{-4}$ |
| Reservoir (sector) sampling | 15–20          | 100                  | $0.4 \times 10^{-12}$–$0.6 \times 10^{-12}$ |

Based on standard mechanical samples 7.5 cm long.
modulus (psi), $K = \text{bulk modulus (psi)}$ and $V_{\text{clay}} = \text{fractional volume of clay minerals}$

Plumb (1994) followed this approach, attributing the primary petrophysical controls of sandstone strength to porosity and clay content. Plumb (1994) described a number of characteristics of empirical strength curves for sandstones, including a transition from a grain load-bearing skeleton throughout the sandstones at low porosities and clay contents, to a predominantly matrix load-bearing structure at porosities $> 30–35\%$. This forms an upper bound for the unconfined compressive strengths of relatively clean load-bearing sandstones. For the lower porosity grain load-bearing sandstones, Plumb (1994) showed that the strength reduces with increasing clay content. Additional developments to define multi-parameter strength correlations include the work of Tokle et al. (1986) and Raen et al. (1996).

Improved accuracy of both the strength, and any subsequent analysis, requires strength and mechanical property measurements on the reservoir core materials to calibrate these generic correlations. Ideally, mechanical property characterization tests are performed on each reservoir facies or reservoir layer to identify potential strength variations. In practice, the number of tests possible is limited by the available length of cores cut through the reservoir.

Case study 3: Lunskoye Sakhalin Island, Eastern Russia: the impact of strength variations on completion design

An example of how detailed lithological and strength variations impact geomechanical design is shown in the completion design for the reservoir sandstones in the Lunskoye field, offshore Sakhalin Island, eastern Russia. The Lunskoye gas field consists of 10 layers of the Daghinsky sandstone (layers I–X) with porosities of 15–30% and permeabilities ranging between 2 and 3000 mD. The Daghinsky Formation, of Miocene age, was deposited under cyclic repetitions of transgressive and regressive episodes along a fluvial-dominated delta system. The Upper and Middle Daghinsky sandstones form the Lunskoye reservoir, with the Upper Daghinsky (I–IV) described as a non-coal-bearing shallow marine, inter- to mid-shelf formation with minor deltaic influence and shoreline-parallel sand bodies. The Middle Daghinsky (V–XII) has been described as being deposited in a coal-bearing delta plain environment. The sandstone reservoir has a thickness of c. 400 m true vertical depth, each Daghinsky layer being separated by thin, fine-grained siltstone layers. Between Daghinsky layers IV and V is a field-wide siltstone layer c. 20 m thick (Ross et al. 2006).

The wells in this reservoir were planned as open-hole completions using either slotted or pre-drilled liners. However, the likelihood of sand production was high with these completions and would have led to significant production delays. The wells were re-designed and completed using a selective perforation technique, which involves shooting perforations across the higher strength sandstones and avoiding the high porosity, weaker sand-prone intervals. However, sufficient interval has to be perforated to deliver the 8.5 million m³ per day per well (300 mmscf per day per well) of gas to meet the liquefied natural gas contract (Addis et al. 2008; Gunningham et al. 2008). This approach to the lower sandface completion design requires a rock testing programme to define a rock strength profile through the reservoir as the basis of the selective perforation design.

Strength v. porosity correlations

For the Lunskoye development and completion design, rock mechanics tests consisting of unconfined compressive strength tests, thick walled cylinder tests and petrophysical characterization tests were performed on the available cores from three reservoir layers. Even though the data were sparse, two strength trends were identified, with samples from the deeper sandstone layers exhibiting higher strengths than those from the shallower layers.

The strength v. porosity trends are shown in Figure 11, indicating that the deeper sandstones are c. 10 MPa (100 bar) stronger than the shallower sandstones for porosities between 15 and 25%. The differences in the strength were not readily explained by differences in texture or clay content. However, following the drilling of a new appraisal well, a spectral gamma ray log indicated that the cements in the different layers differed in geochemical composition.

The different geochemical compositions of the cements identified in the Lunskoye reservoir were used to explain the strength variations observed from the laboratory mechanical testing programme and the two rock strength (thick walled cylinder v. porosity) trends. The final selective perforated completion design was based on the two strength correlations applied to the different reservoir layers contained in the subsurface model. The model was discretized down to intervals 2 m true vertical depth thick in the three-dimensional static reservoir model, resulting in significantly more of the lower Daghinsky layers being selectively perforated in the completion design and contributing to greater production than would have been possible by using the lower strength or an average strength trend.
Business impact

The first phase of well drilling on Lunskoye used this selective perforating scheme for completing the wells, based on real-time reservoir data obtained from logging while drilling (LWD) to update the reservoir model, which enabled a customized, well-specific, selective perforating design for each of the wells drilled. As a result, the completions successfully delivered the required gas production sand-free for the start-up of the liquefied natural gas development (Zerbst & Webers 2011).

From this example we demonstrate that identifying strength differences in reservoir sandstones can lead to significantly less conservative completion designs and larger operational limits for production, leading to increased production and recovery. The higher strength sandstones are able to withstand larger drawdown pressures and depletions, with improved production and recovery.

Scratch testing of core with subtle lithological variations

Similar variations in rock strength have been observed in other reservoirs around the world, resulting from subtle geological influences. For example, reservoir facies differences in a North Sea field, observable in core, but not discernible from well logs, required two strength correlations to mechanically characterize the reservoir, with the higher strength facies on average 45 MPa (450 bar) stronger than the weaker strength facies for 15–20% porosity sandstones.

The sensitivity of strength to both depositional and diagenetic factors has been based on coarse sampling using plugs from cores, which introduces sampling bias into any analysis. Recent developments with the use of scratch tests, which provide a continuous measure of strength along the entire core, together with ultrasonic measurements, provide a means to use strength to identify different facies in far more detail than with sporadic core plugs (Germay & Lhomme 2016).

Figure 12 shows an example of scratch test based strength estimates over a 400 m long core section, showing a large scatter of data when plotted against the corresponding log porosity. When re-analysed using a clustering scheme, four different facies are identified, enabling unique strength correlations to be established for the different facies. Both standard strength measurements on core plugs and the more detailed measurements of strength obtained from the scratch tests provide independent evidence for the use of facies-based strength correlations for detailed completion design.

Concluding remarks

The contribution of geomechanical engineering to a range of field planning issues, from exploration through to the development and abandonment of oil and gas fields, has seen a continued increase since the 1980s. The uptake of geomechanics has relied on analytical models and, more recently, sophisticated numerical models to address the design optimization of field developments. These range from pore pressure and stress estimation, wellbore stability, sand production and completion design, reservoir management issues of compaction and subsidence and four-dimensional field monitoring to hydraulic fracturing and natural fracture.
stimulation. The use of analytical models has been effective, but the availability of field data in the case studies discussed in this paper highlights the limitations of the models, which can oversimplify the industry’s view of the subsurface. What is required is both improved modelling and increased geological input into the models.

The use of field data to help characterize the stress state in both the Cusiana and Brent fields, for both the initial field conditions and during production and depletion, has led to novel explanations of the initial stress state with respect to the faulting style and the stress depletion response of the reservoirs. These data, along with improved models and geomechanical subsurface characterization, have led to significant improvements in the field developments.

Core sampling and mechanical testing strategies commonly result in very low sampling rates, down to <1 ppt of the reservoir volume. This highlights the reliance on establishing strength- and property-based correlations to enable petrophysical and geophysical extrapolation of the core measurements away from the well and across the field for subsurface geomechanical characterization. This low sampling density increases the uncertainty of any analysis, which can be managed, but not eliminated, with intelligent calibration of the data based on sound geological models. Nevertheless, analysis still benefits from adequate sampling and laboratory...
measurements, as shown in the Lunksoye completion design, and from the more detailed strength measurements obtained from scratch tests.

Field-wide porosity distributions derived from the three-dimensional seismic attribute analysis used to generate three-dimensional reservoir strength and mechanical property distributions typically rely on generic correlations for the translation from porosity to strength. The Lunksoye case study shows that significant strength differences measured on similar sandstones within the same reservoir arise from subtle geological changes. As such, future three-dimensional reservoir characterization would benefit from a facies level or unit description for any detailed geomechanical analysis and completion design.

Advanced numerical modelling is a practical approach to improving our visualization and understanding of subsurface geomechanical conditions and their evolution with drilling and production. This move away from the more simplistic models used in the industry to date is facilitated by the availability of more complex material models and increased computational power. However, models need data. This paper has shown how additional measurements throughout the lifetime of a field, from early characterization to the monitoring and surveillance of developments, allow asset teams to assess the validity of the subsurface models and react in a timely manner to optimize field development plans.

Understanding the geomechanical issues addressed here has led to operational changes with considerable financial impact on field developments. It has meant the difference between stable wells and unplanned drilling costs, continued drilling v. field shutdown, and between sub-optimum and improved reserves recovery. As we move into increasingly challenging environments, geomechanics is proving to be an essential key to economically unlocking additional reserves.

The field studies presented here, and the field improvements implemented as a result of these analyses and recommendations, rely on entire asset teams. The ideas and observations presented here are also the result of numerous discussions with supportive colleagues and I acknowledge the contributions of Mike McLean, Nigel Last, Dick Plumb, Philippe Charlez, Mike Cauley, Chris Kuyken, Victor Dunayevsky, Mark Davison, Mike Gunningham, Philippe Brassart, Jeroen Webers, Cor Kenter, Nick Barton, Axel Makurat and Najwa Yassir and the numerous researchers, operational and asset engineers with whom I have had the pleasure of working. The GSL paper reviewers, Paul Gillespie and Miltiadis Parotidis, also made excellent recommendations, helping to improve the paper, and in pointing out the possible impact of stress rotations during faulting on the formation of neotectonic fractures. I acknowledge the support of Rockfield Software Limited in preparing this paper and the support and invaluable suggestions of Najwa Yassir while reviewing and editing this paper.

References

Aadnoy, B.S. & Looyeh, R. 2011. Petroleum Rock Mechanics: Drilling Operations and Well Design. Gulf Professional Publishing, Houston, TX.

Addis, M.A. 1997a. Reservoir depletion and its effect on wellbore stability evaluation. International Journal of Rock Mechanics and Mining Sciences, 34, 423.

Addis, M.A. 1997b. The stress depletion response of reservoirs. Paper SPE 38720-MS, paper presented at the 72nd SPE Annual Technical Conference & Exhibition, 5–8 October 1997, San Antonio, TX, USA.

Addis, M.A., Last, N.R., Boulet, D., Ramisa-Roca, L. & Plumb, R.A. 1993. The quest for borehole stability in the Cusiana field. Oilfield Review, 5, 33–43.

Addis, M.A., Last, N.C. & Yassir, N.A. 1994. Estimation of horizontal stresses at depth in faulted regions, and their relationship to pore pressure variations. Paper SPE 28140, presented at the 1994 SPE/ISRM Rock Mechanics in Petroleum Engineering Conference, 29–31 August 1994, Delft, the Netherlands. Reproduced in SPE Formation Evaluation, 11, 11–18.

Addis, M.A., Cauley, M.B. & Kuyken, C. 2001. Brent in-fill drilling programme: lost circulation associated with drilling depleted reservoirs. Paper SPE/IADC 67741, presented at the SPE/IADC Drilling Conference, 27 February–1 March 2000, Amsterdam, the Netherlands.

Addis, M.A., Gunningham, M.C., Brassart, Ph., Webers, J., Subhi, H. & Hother, J.A. 2008. Sand quantification: the impact on sandface completion selection and design, facilities design and risk evaluation. Paper SPE 116713, presented at the 2008 SPE Annual Technical Conference and Exhibition, 21–24 September 2008, Denver, CO, USA.

Alberty, M.W. & McLean, M.R. 2001. Fracture gradients in depleted reservoirs – Drilling wells in late reservoir life. Paper SPE 67740, presented at the SPE/IADC Drilling Conference, 27 February–1 March 2000, Amsterdam, the Netherlands.

Anderson, E.M. 1905. The dynamics of faulting. Transactions of the Edinburgh Geological Society, 8, 387–402, https://doi.org/10.1144/transted.8.3.387

Anderson, E.M. 1951. The Dynamics of Faulting and Dyke Formation with Applications to Britain. Oliver and Boyd, Edinburgh.

Antheunis, D., Vriezen, P.B., Schipper, B.A. & van der Vlis, A.C. 1976. Perforation collapse: failure of perforated friable sandstones. Paper SPE 5750, presented at the SPE European Spring Meeting, 8–9 April, Amsterdam, Netherlands.

Bailey, A.H.E., King, R.C., Holford, S.P. & Hand, M. 2016. Incompatible stress regimes from geological and geomechanical datasets: can they be reconciled? An example from the Carnarvon Basin, Western Australia. Tectonophysics, 683, 405–416.

Bell, J.S. & Gough, D.I. 1979. Northeast–southwest compressive stress in Alberta – evidence from oil wells. Earth and Planetary Science Letters, 45, 475–482.
BIDDLE, K.T. & RUDOLPH, K.W. 1988. Early Tertiary structural inversion in the Stord Basin, Norwegian North Sea. *Journal of the Geological Society, London*, **145**, 603–611. https://doi.org/10.1144/gsjgs.145.4.0603

Biot, M.A. 1941. General theory of three dimensional consolidation. *Journal of Applied Physics*, **12**, 155–164.

Bishop, A.W. 1974. The strength of crustal materials. *Engineering Geology*, **8**, 139–153.

Boe, G.M., Wong, S.-W., Davidson, C.J. & Woodland, D.C. 1994. Borehole stability in shales. *SP Drilling & Completion*, **9**, 87–94.

Boylan, A. & Williams, C. 1998. Brent Breakout Study. Z&S Geology Report ZSL-97-462.

Bradley, W.B. 1979a. Failure of inclined boreholes. *Journal of Energy Resource Technology*, **101**, 232–239.

Bradley, W.B. 1979b. Mathematical stress cloud – stress cloud can predict borehole failure. *Oil & Gas Journal*, **77**, 92–102.

Bruce, S. 1990. A mechanical stability log. Paper SPE19942, presented at the SPE/IADC Drilling Conference, 27 February–2 March 1990, Houston, TX, USA.

Buchanan, J.G. & Buchanan, P.G. 1995. *Basin Inversion*. Geological Society, London, Special Publications, **88**, http://sp.lyellcollection.org/content/88/1

Charlez, P.A. 1991. Rock Mechanics: Theoretical Fundamentals. 1st edn. Editions Technip, Paris.

Charlez, P.A. 1997. Rock Mechanics: Petroleum applications. 2nd edn. Editions Technip, Paris.

Coates, P.A. 1980. Log derived mechanical properties and rock stress. Paper presented at the SPWLA-1980-U. SPWLA 21st Annual Logging Symposium, 8–11 July 1980, Lafayette, LA, USA.

Cooper, M.A. & Williams, G.D. 1989. *Inversion Tectonics*. Geological Society, London, Special Publications, **44**, http://sp.lyellcollection.org/content/44/1

Crook, A.J.L., Willson, S.M., Yu, J.G. & Owen, D.R.J. 2006. Predictive modelling of structure evolution in sandbox experiments. *Journal of Structural Geology*, **28**, 729–744.

Davison, J.M., Leaper, R. et al. 2004. Extending the drilling operating window in Brent: solutions for infill drilling in depleting reservoirs. Paper SPE 87174, presented at the IADC/SPE Drilling Conference, 2–4 March 2004, Dallas, TX, USA.

Eaton, B.A. 1969. Fracture gradient prediction and its application in oilfield operations. Paper SPE 2163. *Journal of Petroleum Technology*, October, 1353–1360.

Engelder, T. & Fischer, M.P. 1994. Influence of poroelastic behavior on the magnitude of minimum horizontal stress, \(S_h\), in overpressured parts of sedimentary basins. *Geology*, **22**, 949–952.

Engelder, T., Lash, G.G. & Uzcategui, R.S. 2009. Joint sets that enhance production from Middle and Upper Devonian gas shales of the Appalachian Basin. *American Association of Petroleum Geologists Bulletin*, **93**, 857–889.

Fjaer, E., Holt, R.M., Horsrud, P., Raen, A.M. & Risnes, R. 2008. *Petroleum Related Rock Mechanics*. 2nd edn. Developments in Petroleum Science, **53**, Elsevier, Amsterdam.

Geertasma, J. 1957. The effect of fluid pressure decline on volumetric changes of porous rocks. *Transactions AIME*, **210**, 331.

Germay, C. & Lhomme, T. 2016. Upscaling of Rock (Mechanical) Properties Measured on Core Plugs. Epslog Technical Note, internal report.

Gunningham, M.C., Addis, M.A. & Hother, J.A. 2008. Applying sand management process on the Lunskoye high gas-rate platform using quantitative risk assessment. Paper SPE 112099, presented at the 2008 SPE Intelligent Energy Conference and Exhibition, 25–27 February 2008, Amsterdam, the Netherlands.

Hancock, P.L. & Bevan, T.G. 1987. Brittle modes of foreland extension. In: Coward, M.P., Dewey, J.F. & Hancock, P.L. (eds) *Continental Extensional Tectonics*. Geological Society, London, Special Publications, **28**, 127–137, https://doi.org/10.1144/GSL.SP.1987.028.01.10

Hancock, P.L. & Engelder, T. 1989. Neotectonic joints. *Geological Society of America Bulletin*, **101**, 1197–1208.

Hatchell, P.J., Van den Beukel, A. et al. 2003. Whole Earth 4D: reservoir monitoring geomechanics. Paper SEG-2003-1330, presented at the SEG Annual Meeting, 26–31 October, Dallas, Texas.

Henning, A., Yassir, N., Addis, M.A. & Warrington, A. 2002. Pore pressure estimation in an active thrust region and its impact on exploration and drilling. In: Huffman, A.R. & Bowers, G.L. (eds) *Pressure Regimes in Sedimentary Basins and their Prediction*. AAPG Memoirs, **76**, 89–105.

Hillis, R.R. 2003. Pore pressure/stress coupling and its implications for rock failure. In: Van Rensberg, P., Hillis, R.R., Maltman, A.J. & Morley, C.K. (eds) Geological Society, London, Special Publications, **216**, 359–368, https://doi.org/10.1144/GSL.SP.2003.216.01.23

Hottman, C.E., Smith, J.H. & Purcell, W.R. 1979. Relationship among Earth stresses, pore pressure, and drilling problems offshore Gulf of Alaska. *Journal of Petroleum Technology*, **31**, 1477–1484.

Hubbert, M.K. & Willis, D.G. 1957. Mechanics of hydraulic fracturing. *Petroleum Transactions, AIME*, **210**, 153–168.

Hubbert, M.K. & Rubey, W.W. 1959. Role of fluid pressure in mechanics of overthrust faulting: I. Mechanics of fluid-filled porous solids and its application to overthrust faulting. *Geological Society of America Bulletin*, **70**, 115–166.

Kattenhorn, S.A., Aydin, A. & Pollard, D.D. 2000. Joints at high angles to normal fault strike: an explanation using 3-D numerical models of fault-perturbed stress fields. *Journal of Structural Geology*, **22**, 1–23.

Kenter, C.J., Van den Beukel, A.C. et al. 2004. Geomechanics and 4d: evaluation of reservoir characteristics from timeshifts in the overburden. Paper ARMA-04-627, presented at the Gulf Rocks 2004, the 6th North America Rock Mechanics Symposium (NARMS), 5–9 June, Houston, Texas.

Khaksar, A., Taylor, P.G., Fang, Z., Kayes, T.J., Salazar, A. & Rahman, K. 2009. Rock strength from core and logs, where we stand and ways to go. Paper SPE 121972, presented at the EUROPEC/EAGE...
Conference and Exhibition, 8–11 June 2009, Amsterdam, the Netherlands.

Kirsch, E.G. 1898. Die Theorie der Elastizität und die Bedürfnisse der Festigkeitslehre. Zeitschrift des Vereines deutscher Ingenieure, 42, 797–807.

Last, N.C. & McLean, M.R. 1996. Assessing the impact of trajectory on wells drilled in an overthrust region. Journal of Petroleum Technology, SPE 30465, 620–626.

Last, N.C., Plumb, R.A., Harkness, R.M., Charlez, P., Alsen, J. & McLean, M.R. 1995. An integrated approach to evaluating and managing wellbore instability in the Cusiana Field, Colombia, South America. Paper SPE 30464, presented at the SPE Annual Technical Conference and Exhibition, 22–25 October 1995, Dallas, TX, USA.

Last, N.C., Harkness, R.M. & Plumb, R.A. 1998. From theory to practice: evaluation of the stress distribution for wellbore stability analysis in an overthrust regime by computational modelling and field calibration. Paper SPE/ISRM 47209, presented at the SPE/ISRM Eurock ’98 Conference, 8–10 July 1998, Trondheim, Norway.

Mandl, G. 2000. Faulting in Brittle Rocks: An Introduction to the Mechanics of Tectonic Faults. Springer, Berlin.

Molenaar, M.M., Hatchell, P.J., van den Beukel, A.C., Jenvey, N.J., Stammeijer, J.G.F., van der Velde, J.J. & de Haas, W.O. 2004. Applying geomechanics and 4D: ‘4D in situ Stress’ as a complementory tool for optimizing field management. Paper ARMA/NARMS 04-639, presented at Gulf Rocks 2004, the 6th North America Rock Mechanics Symposium (NARMS): Rock Mechanics Across Borders and Disciplines, 5–9 June 2004, Houston, TX, USA.

Moos, D. 2014. The future of geomechanics – where we are, how we got here, and where we’re going. Paper presented at the SPE Workshop, Applying Geomechanics in the E&P Industry: Best Practices and Recent Technological Developments. 29–30 April 2014, Guadalajara, Mexico.

Morita, N., Black, A.D. & Guh, G.-F. 1990. Theory of lost circulation pressure. Paper SPE 20409, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, LA, 43–58.

Noufal, A., Geramy, C., Lhomme, T., Hegazy, G. & Richard, T. 2015. Enhanced core analysis workflow for the geomechanical characterisation of reservoirs in a giant offshore oilfield, Abu Dhabi. Paper SPE 175412, presented at ADIPEC, Abu Dhabi International Petroleum Exhibition and Conference, 5–9 November 2015, Abu Dhabi, UAE.

Olorio, J.G. & Lopez, C.F. 2009. Geomechanical factors affecting the hydraulic fracturing performance in a geomechanically complex, tectonically active area in Colombia. Paper SPE 122315, presented at the SPE Latin American and Caribbean Petroleum Engineering Conference, 31 May–3rd June 2009, Cartagena, Colombia.

Osorio, J.G., Penuela, G. & Otlora, O. 2008. Correlation between microseismicity and reservoir dynamics in a tectonically active area of Colombia. Paper SPE 115715, presented at the SPE Annual Technical Conference and Exhibition, 21–24 September 2008, Denver, CO, USA.

Peric, D. & Crook, A.J.L. 2004. Computational strategies for predictive geology with reference to salt tectonics. Computer Methods in Applied Mechanics and Engineering, 193, 5195–5222.

Plumb, R.A. 1994. Influence of composition and texture on the failure properties of clastic rocks. Paper SPE 28022, presented at Rock Mechanics in Petroleum Engineering, 29–31 August 1994, Delft, the Netherlands.

Raaen, A.M., Hovem, K.A., Johansen, H. & Fjaer, E. 1996. FORMEL: a step forward in strength logging. Paper SPE 36533, presented at the SPE Annual Technical Conference and Exhibition, 6–9 October 1996, Denver, CO, USA.

Ross, L., King, K. et al. 2006. Seismically based integrated reservoir modelling, Lunsksoye Field, offshore Sakhalin, Russian Federation. Paper SPE 102650, presented at the Russian Oil and Gas Technical Conference and Exhibition, 3–6 October 2006, Moscow, Russia.

Salz, L.B. 1977. Relationship between fracture propagation pressure and pore pressure. Paper SPE 6870, presented at the 52nd SPE Annual Technical Conference, 9–12 October 1977, Denver, CO, USA.

Santarelli, F.J., Tronvoll, J.T., Svennekaiajer, M., Skeie, H., Henriksen, R. & Bratli, R.K. 1998. Reservoir stress path: the depletion and the rebound. Paper SPE 47350, presented at the SPE/ISRM Rock Mechanics in Petroleum Engineering, 8–10 July 1998, Trondheim, Norway.

Santarelli, F.J., Haymoller, O. & Naumann, M. 2008. Geomechanical aspects of 15 years water injection on a field complex: an analysis of the past to plan the future. Paper SPE 112944, presented at the SPE North Africa Technical Conference & Exhibition, 12–14 March 2008, Marrakech, Morocco.

Sibson, R.H. 1977. Fault rocks and fault mechanisms. Journal of the Geological Society, London, 133, 191–213, https://doi.org/10.1144/gsjgs.133.3.0191.

Sibson, R.H. 2003. Brittle-failure controls on maximum sustainable overpressure in different tectonic regimes. American Association of Petroleum Geologists Bulletin, 87, 901–908.

Skelton, J., Hogg, T.W., Cross, R. & Verheggen, L. 1995. Case history of directional drilling in the Cusiana Field in Colombia. Paper IADC/SPE 29380, presented at the IADC/SPE Drilling Conference, 28th February–2nd March, 1995, Amsterdam, the Netherlands.

Skeffington, A.W. 1954. The pore pressure coefficients A and B. Geotechnique, 4, 143–147.

Struik, A.P. & Green, R.T. 1991. The Brent Field, Block 211/29, UK North Sea. In: Abbotts, I.L. (ed.) United Kingdom Oil and Gas Fields – 25 Years Commemorative Volume. Geological Society, London, Memoirs, 14, 63–72, https://doi.org/10.1144/GSL.MEM.1991.014.01.08

Terzaghi, K. 1925. Erdbaumechanik auf Bodenphysikalischer Grundlage. F. Deuticke.

Terzaghi, K. 1943. Theoretical Soil Mechanics. Wiley, Chichester.

Teufel, L.W., Rhett, D.W. & Farrell, H.E. 1991. Effect of reservoir depletion and pore pressure drawdown on in situ stress and deformation in the Ekofisk Field, North Sea. Paper ARMA-91-063, presented at
the 32nd US Symposium on Rock Mechanics (USRMS), 10–12 July 1991, Norman, OK, USA.

Thornton, D.A. & Crook, A.J.L. 2014. Predictive modeling of the evolution of fault structure: 3-D modeling and coupled geomechanical/flow simulation. *Rock Mechanics and Rock Engineering*, 47, 1533–1549.

Tokle, K., Horsrud, P. & Bratli, R.K. 1986. Predicting uniaxial compressive strength from log parameters. Paper SPE 15645, presented at the 61st SPE Annual Technical Conference and Exhibition, 5–8 October 1986, New Orleans, LA, USA.

Willson, S.M., Last, N.C., Zoback, M.D. & Moos, D. 1999. Drilling in South America: a wellbore stability approach for complex geologic conditions. Paper SPE 53940, presented at the Latin American and Caribbean Petroleum Engineering Conference, 21–23 April 1999, Caracas, Venezuela.

Woodland, D.C. & Bell, J.S. 1989. In situ stress magnitudes from mini-frac records in Western Canada. *Journal of Canadian Petroleum Technology*, 28, 22–31.

Wu, B., Addis, M.A. & Last, N.C. 1998. Stress estimation in faulted regions: the effect of residual friction. Paper SPE 47210, presented at Eurock ’98 Conference, 8–10 July 1998, Trondheim, Norway.

Yassir, N.A. 1989. Undrained shear characteristics of clay at high total stresses. Paper ISRM-IS-1989-114, presented at Rocks at Great Depth, ISRM International Symposium, 30 August–2 September, Pau, France.

Yassir, N.A. & Zerwer, A. 1997. Stress regimes in the Gulf coast, offshore Louisiana: data from wellbore breakout analysis. *American Association of Petroleum Geologists Bulletin*, 81, 293–307.

Zerbst, C. & Webers, J. 2011. Completing the first big-bore gas wells in Lunskoye – a case history. *SPE Drilling & Completion*, December, 462–471.

Zoback, M.D. 2008. *Reservoir Geomechanics*. Cambridge University Press, Cambridge.