- Statoil is calculating minimum horizontal stress more accurately and making HPHT wells more stable.
- Wells drilled through formations cooled by nearby water injectors cause thermal stress changes that contribute to mud circulation losses.
- TTD&C for sub-sea wells could save $6–10m per operation.

Relieving the pressure

Statoil is conducting wide-ranging research into improving oil recovery and well stability. Thor Bensvik of Statoil explains how this can improve productivity and profits.

Improving productivity and maximising oil recovery in depleted, high pressure/high temperature (HPHT) reservoirs and wells operated from the seafloor or that are past their production peak are serious challenges faced by the oil industry. New well-completion methods are required to optimise production from marginal fields, while simpler intervention processes are needed for sub-sea reservoirs.

Well positioned

Statoil has an excellent reputation for positioning wells, especially high-angle and horizontal wells in the deepest parts of a reservoir and those that do not follow simple paths (3D wells). However, it is not easy to hit the target because the reconstructions of subsurface geology and reservoir complexity (earth models) are imprecise.

Statoil has launched the Dart project, named for its objective of hitting the target, and developed products to achieve real-time, optimised and quality-controlled positioning of production wells. These products have been used in Statoil's facility for real-time operations support, the hydrotreated naphthenic oil onshore support centre at Stjørdal in Norway, which is a step towards the 'intelligent field' concept. Linking offshore installations with onshore support teams enhances value and leads to better collaboration.

Pressure and stress

In addition, Statoil's rock mechanics specialists are fine-tuning their predictions of borehole stability. The method, which has been successfully applied to exploration wells, involves calculating minimum horizontal stress. This is important in planning complex wells, especially horizontal or high-angle sections, as it reduces the loss of drilling fluids through fractures and ensures that the rate of hydrocarbon production does not damage a weak reservoir.

Calculating the horizontal stress required to close a fracture normally involves two steps. After drilling to a predetermined depth, the borehole is protected by a metal casing. A well integrity (extended leak-off) test is then conducted on the unprotected section of the borehole, just below the casing.

Once this has been done, the first step is to increase the drilling fluid pressure until the borehole wall starts to fracture. Pumping continues until the fracture extends into the undisturbed formation beyond the wall, at which point pumping is stopped to allow the fracture to close. The second step involves using a pressure-versus-time graph to estimate the minimum horizontal stress required to close the fracture, which marks a safety threshold.

Statoil has added a third step, resulting in a more accurate measurement. The pressure is released by allowing the fluids to flow back up to the surface, ensuring that the fracture is closed. This means that the next borehole interval can be drilled safely. This is repeated at each casing shoe as the borehole deepens.

HPHT borehole stability

Since most HPHT fields have vertical or sub-vertical wells, research into horizontal stress in HPHT boreholes is scarce. However, Statoil has several HPHT fields with horizontal wells, such as the gascondensate Kristin field. Drilling development wells is complicated by the limited range of mud weights and the rapid reduction in reservoir pressure during production, which means more wells cannot be drilled when the reservoir has been significantly depleted.

Statoil has been studying the rock mechanics of HPHT shale intervals to improve well planning and design. For instance, a better understanding of the mud-weight window could explain how a well is affected by its inclination relative to the sediment bedding and laminae, which can act as planes of weakness. The Norwegian Geotechnical Institute has provided geological, petrophysical and rock mechanical characterisation studies of shale cores cut from the reservoir to develop numerical models of the shale's stability.

The petroleum research division at the Norwegian Institute of Technology verified the models using hollow cylinder tests representing boreholes. After altering the angle of the cylinders relative to the bedding, it was shown that shale strength, and therefore borehole stability, is reduced when wells are drilled parallel or sub-parallel to it.

Another concern is the underbalanced drilling of shale intervals after reservoir depletion when the shale pore pressure is higher than that of the drilling mud. It was found that the low permeability of the shales (0.1nD perpendicular to the laminations) means metre-thick intervals retain high pore pressures, even when sandwiched between heavily depleted and lower pressure reservoir sandstones. The tests showed that an underbalance of 37MPa is possible before shale failure or collapse in a borehole perpendicular to the bedding. This bodes well for underbalanced shale drilling where the mechanical properties and stresses of the shale intervals are known.

Drilling cooled formations

Rock mechanics specialists have shown that wells drilled too close to water injectors in mature oil fields can lead to severe mud losses. It is standard practice to inject cold seawater into oil reservoirs to maintain pressure and push oil towards production wells. However, injection cools the surrounding rocks, altering the natural stresses and causing a vertical fracture determined by the stress field.

Such thermally induced fractures may extend for hundreds of metres depending on time, water injection rate, thickness of the reservoir formation and ratio of the water's heat capacity to the sedimentary rock. The estimated size of a cooled zone is based on a cylindrical model; however, the fracture actually makes it ellipsoidal.

Being the first company to analyse this phenomenon, Statoil's drilling engineers are in a better position to locate new wells beyond the influence of cooling zones. In Statoil's Statfjord and Veslefrikk fields, several wells drilled near water injectors suffered such severe mud losses that they had to be plugged and sidetracked.

Although research is still ongoing, rock mechanics experts have shown that mud circulation losses are related to thermal stress changes because the wells have been drilled through formations cooled by nearby water injectors. This also induces fractures through which the mud losses occur. A fracture starts at the wellbore and adopts a similar orientation to that induced by the injector.

Improving sub-sea recovery

Through tubing drilling and completion (TTD&C) is a cost-effective technology for increasing tail production. It also shows promise for improving oil recovery from sub-sea fields. TTD&C technology allows offshoot wells (sidetracks) to be drilled out sideways by cutting through the production liner and sometimes through production casing. As the sidetracks are performed below the production packer with the drill pipe conducted through the tubing, neither the tubing nor the Christmas tree has to be removed. Such wells are useful for accessing pockets of isolated oil and gas in mature fields.

It is also possible to minimise borehole lengths and avoid problems in overlying formations by sidetracking in reservoir intervals. Using a small, conventional drill pipe, Statoil has reduced the cost per operation to around $4m, including completion and perforation, saving $1.5–3m compared with conventional sidetracking.

Recent technical advances also show that open (uncased) holes might be extended to 2,000m using present methods and that multilaterals can be economically installed, making simultaneous production from a parent well and its sidetrack possible. The next challenge is to extend the technology to improve oil recovery from Statoil's sub-sea developments. A project is now underway to facilitate implementation at the Norne field with the Gullfaks satellites and the Snorre, Statfjord and Heidrun licences possibly following suit. With an estimated saving per operation of around $6–10m, the benefit of TTD&C for sub-sea wells promises to be even greater than those for platform-based drilling.

These areas of research all promise increased yields and reductions in production costs. The aim is to find ever more efficient methods for all aspects of the drilling process so that as the reservoirs become emptier they can still be safely and successfully drilled.

AUTHOR

Thor Bensvik is the drilling and well operations manager for the Snøhvit project at Statoil. The first phase of the Snøhvit project covers the Snøhvit and Albatross fields, which lie about 140km north west of Hammerfest in northern Norway.

The wells will come on stream when the Hammerfest LNG plant at Melkøya is completed in 2007. Statoil is the operator for the development and operation of the Snøhvit project.