1. Gullfaks field location and stratigraphy
The Gullfaks field is located 175 km northwest of Bergen in the Tampen area in the northern part of the North Sea. The field is operated by Statoil ASA, and the license partners in PL050 are OMV and Petoro. The oil discovery was made in 1978 by well 34/10-1. Production started in 1986 and production has been from the Jurassic and late Triassic sandstone reservoirs in the Brent Gp, Cook Fm, Statfjord Gp and Lunde Fm.
The traces of hydrocarbons have also been found in the shallower formations on the Gullfaks main structure. However, these were considered insignificant until recently. Figure 1.1 illustrates the Gullfaks stratigraphy depicting the main hydrocarbon-storing formation as well as the overburden formation with the respective oil shows.

2. Shetland discovery
The new discovery was announced in April 2013, several months after re-perforation of the well 34/10-A-8 in the chalk interval at the top of the Shetland Gp. (Zone 1 on the Figure 2.2). By the time of the announcement, the well has produced over 0.5 Mbbl of oil. The true vertical thickness of the pay zone was 4.5 m, while the perforation interval measured 4 meters. Since the reservoir is thin, it was interpreted to have a large lateral extent in order to contain enough volume for sustaining the production observed in A-8. The lateral extent of the upper most Shetland chalk interval is supported by the log data from the wells drilled from the Gullfaks field installations (over 200 wells have been drilled since 1979), and by oil shows that were detected in some of the wells. The log response in the wells across the field and the geological interpretation suggest that the thickness of the reservoir varies from 10 m at the central areas of the structure to 2.5-3 m on the flanks before the chalk-rich interval shales out. Figure 2.1 shows the top Shetland structure and thickness of the reservoir.

The deposition for the Shetland chalk is interpreted to occur while the Gullfaks area was a local underwater high, which allowed the cleaner chalk formed from “pelagic rain” to be preserved on the high, whereas off the high siliciclastic material from the continent has diluted pelagic material forming marls. Figure 2.2 shows depositional concept for the Shetland Gp.
The First

2.1 PVT and geochemistry

In the beginning of 2013 a downhole sampling was performed in the well in order to secure the most accurate PVT- and compositional data. The sample was then analyzed both for PVT and geochemical properties. While the PVT properties of the Shetland oil were similar to certain types of Brent oils found on the Gullfaks field, the geochemical compositional analysis showed a clear difference in isoprenoid content. The Brent oil used as a baseline was sampled in the very same well, A-8, in 1987. Figure 2.1.1 shows the comparison of the isoprenoid content in the Brent and Shetland oils.

During the assessment of the discovery there has been raised a question whether the oil found in the Shetland chalk has migrated upwards during the production time. However, geochemical findings in the oil from Top Shetland suggest that the oil has been in place over the geological time.

3. Production history 2012 – 2014

3.1 A-8 production

Immediately after perforation A-8 was set on stream at a relatively small rate, and later on was open to a liquid rate of 1800 Sm3/d. After a year of production at this rate, the well was choked back to a rate up to 1000 Sm3/d, mainly because of water coning and increasing water cut. Figure 3.1.1 illustrates the production history of the well.

In November 2014 the well was closed for pressure observation and further well interventions. During the well’s lifetime no new wells were put on stream from Shetland reservoir, except one which discovered a slight pressure communication with A-8, but did not produce any significant amount of fluid while A-8 was on stream. After the shut-in of A-8, more wells were put on production from the Shetland reservoir. There are currently 5 active Shetland producers on the GFC platform.

3.2 A-8 PTA model

Having a single well on production in an undisturbed reservoir was a perfect starting point for reservoir modeling process. The measured rates were used along with the pressure reading from a downhole pressure gauge as a reference for model building and history matching. The purpose of the model built based almost solely on the production data was to characterize the permeability distribution in the reservoir as well as assess the total pore volume by studying the pressure decline. The Saphir part of the Ecrin package from Kappa has been used for these tasks.

The model was built before the representative core sample has been obtained, and therefore the parameters like porosity and compressibility were estimated from the analogs. They were initially assumed constant for the entire field. For the sake of simplicity the thickness of the reservoir were assumed to be uniform across the field. Due to the presence of water from the beginning of production, relative permeability modifiers were introduced in the Ecrin model. They were assumed constant and equal to 0.5. The PVT values from the analyzed samples obtained in April 2013 were used for these tasks.

The well’s behavior during the early production period (until April 2013) was affected by the flow of oil into a flooded zone at the near-wellbore area, which resulted in increasing BHP during production. The pressure history is shown in Figure 3.3.1. The early build-ups (taken in the period before March 2013) produced inconsistent results. The first build-up showing used as a basis for future interpretation was the one taken in the end of March 2013, the subsequent build-ups showed very good agreement to each other. The build-ups used as a basis for the main interpretation were the two performed in the end of 2013 and 2014. These build-ups are shown in the next figure:

3.4 Final model

In addition to the production and pressure history the faults interpreted from seismic surveys have been taken into consideration. The transmissibility multipliers were assumed to vary in the range 0.1–0.5. The resulting contour was populated with the permeability values from the build-up interpretation in A-8 in the central area, while permeability values on the flanks were obtained via the DFIT tests in the wells perforated in the same reservoir in 2014. The figure below shows the model with the matched permeability values for each segment.

The figure 3.4.2. shows the pressure evolution across the field during the lifetime of A-8.
4. Modelling results vs 4D seismic response
In July 2014 an ocean bottom cable (OBC) seismic survey (one of many over the years performed on Gullfaks) was shot. One of the objectives of the seismic interpretation was to assess possible changes in the Top Shetland reservoir from the start of production. The OBC seismic survey from 2008 was used as the baseline for the 4D interpretation, to be able to investigate possible changes due to Shetland production.

The expected response from depletion of Shetland, giving a rise in effective pressure increase the grain contact giving increased P-wave and S-wave velocity. Amplitude and time shift changes have been studied for both compressional waves (PP) and converted waves (PS). A hardening effect is seen on the compressional waves (PP) and converted waves (PS). The lateral pressure distribution from the A-8 PTA model. A comparison of the reservoir pressure at the time of acquisition of the 2014 survey and the 4D amplitude changes and the time shift between 2008 and 2014 is given in Figure 4.1.

5. Conclusions
The article considers a reservoir model built for a newly discovered carbonate reservoir in the Norwegian sector of the North Sea. The depletion which occurred after 2 years of production is modelled, and the model is history matched. The lateral pressure distribution from the model at the time when the seismic survey was shot is then compared with the 4D seismic interpretation, and the pressure effects interpreted from the seismic response match the pressures predicted by the reservoir model.

Extra-Deep Azimuthal Resistivity for Enhanced Reservoir Navigation in a Complex Reservoir in the Barents Sea
by David Selvåg Larsen, Andreas Hartmann, Pascal Luxey, Sergey Martakov, Jon Skillings - Baker Hughes; Gianbattista Tosi, Luigi Zappalorto - ENI Norge

Goliat is an ENI Norge-operated oil field located in the Arctic Barents Sea, 85 km NW of the city Hammerfest. The Goliat reservoirs have a complex structural setting characterized by a large number of faults and a high structural dip towards the flank of the structure. This challenging combination calls for horizontal production wells for effective drainage.

The Goliat field consists of several proven hydrocarbon reservoir units, but to date only Kobble producers have been drilled. The Kobble Formation is of Middle Triassic age and is divided into two main Upper Kobble represents essentially a prograding deltaic system with mouth bars and lobes. In the Lower Kobble, the system shifts into a more proximal, heterogeneous fluvial setting where sand bodies have limited lateral continuity.

One particular challenge is that the well design requires the 8½-in. reservoir section to be initiated in the overlying Snadd shale. To minimize shale exposure in the landing section aggressive build-up rates are employed, decreasing the length needed in shale. However, a steep approach may lead to deeper penetration in upper Kobble, in unwanted intra-shale drilling. Therefore, the key to successful well placement is the early detection of the reservoir top and the accurate mapping of the reservoir sand architecture remote to the wellbores.

One way to successfully navigate a complex reservoir like Goliat is to use extra-deep azi-muthal resistivity (EDAR) can detect stratigraphic boundaries up 30 m from the wellbore in optimal resistivity environments (Hartmann et al., 2014). The development of advanced multi-component inversion modelling techniques (Sviridov et al., 2014) enhances the interpretations of resistivity data and can accurately provide real-time information regarding reservoir geometry. EDAR service provided the capability to detect the top of the reservoir at about 20 m true vertical depth (TVD) and nearly 100 m MD before entering the reservoir, enhancing accurate wellbores landing. Extra-deep measurements also helped the uncertainty in faults detection, where related throw can be estimated based on the displacement of bounda-
ries. The use of a measurement with increased depth of detection (DOD), combined with advanced multi-component techniques and real-time 3D visualization of data and reservoir model were vital to ensure the successful placement of the well. Real-time mapping of the reservoir geometry was key to optimize reservoir exposure.