Case study: HPHT infill well drilled successfully in highly depleted reservoir on UKCS field

By L. Fambon, G. Joffroy, TOTAL E&P UK

DRILLING INFILL WELLS on HPHT fields after a significant depletion has occurred represents a difficult challenge. It requires drilling from a cap rock remaining at or close to virgin pressure into a reservoir in which pore and fracture pressures have largely decreased due to production. No mud-weight window exists anymore at the transition between cap rock and reservoir.

The difficulty is further increased by uncertainties in the pressure profile along the well path, the rock mechanics and their change generated by the high and rapid depletion, and also by depth uncertainty on the top reservoir.

For this reason, most HPHT fields are developed by drilling all wells before a pre-defined limit of depletion level is reached where the mud-weight window closes. This limit is usually low.

However, HPHT producer wells face depletion-related threats to their integrity: sand production and/or deformation of the production liner under rock movement. When these threats become effective, the well and its associated production will be lost. Replacement wells will need to be drilled. Additional wells are also needed to increase reserves by creating new off-take points.

This article describes the preparation work performed before drilling an HPHT infill well (Franklin Infill A - FIA) in the highly depleted Franklin reservoir in the UKCS, the management of uncertainties during the drilling and some of the lessons learned from this first experience. Among them is the important influence of the reservoir depletion on the mechanics of the formations above reservoir.

The success of this first HPHT infill well after significant depletion proves the feasibility of drilling such wells. It opens the door to new opportunities in HPHT developments.

BACKGROUND

Franklin, located in the Central North Sea, is one of the highest profile HPHT fields in the world. The reservoir lies at 5,300 m below sea level in 92 m water depth. Its original pressure was 1,100 bar, and the downhole temperature

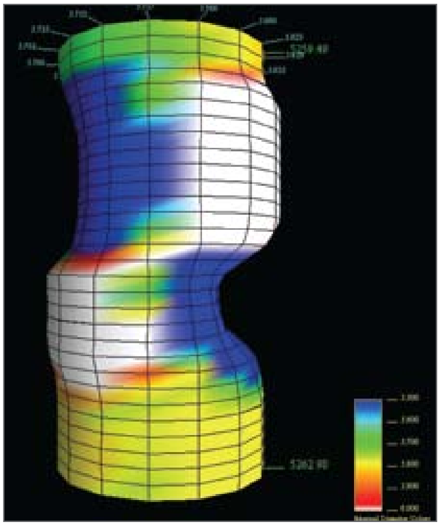


Figure 1: On HPHT fields, wells are exposed to multiple threats due to the large amount of depletion, such as liner deformation.

reaches 200°C. The fluid produced is gas condensate, with 3-4% CO_2 and 30-40 ppm H_2S. Depletion on this field is initially very quick. The order of magnitude is a decrease of 100 bar per six months.

Initial studies had concluded that infill drilling was not possible after depletion had reached 100 bar. Based on these studies, the field development plan stipulated that all planned development wells (F1 to F6) be drilled prior to the start of production. This was performed in the late 1990s, and production started in 2001. Subsequently, one well (G9) was drilled on the nearby Elgin field just at the 100-bar depletion limit and did not encounter noticeable difficulty.

On HPHT fields such as Elgin/Franklin, wells are exposed to multiple threats due to the large amount of depletion. One such threat is sand production, which can lead to erosion of materials such as the downhole safety valve, Christmas tree and surface piping. At the moment, no reliable downhole sand control method can be run in HPHT wells. The wells have to be choked down and can ultimately be lost, which leads to a significant loss of production.

The other threat is liner deformation due either to subsidence, which leads to buckling of the liner, or to tectonic movements along faults or other bedding plane (Figure 1). The liner can ultimately be fully sheared off. Both threats have been experienced on UKCS HPHT fields by different operators.

The identification of these threats pushed the operator to design a well architecture to overcome the 100-bar depletion limit and to drill into a significantly depleted reservoir, in order to be able to replace a well if and when it has failed. A feasibility study was launched in 2004, which concluded that drilling such a well was feasible and identified two possible architectures. Based on these results, the development phase was launched.

The Geoscience Department subsequently identified a candidate for such an infill well, which would increase the reserves of the field. This provided an opportunity to try the proposed solutions and validate the feasibility study conclusions.

THE CHALLENGE

For wells drilled before depletion occurs, a mud-weight window exists between the pore pressure and the fracturation pressure. When depletion occurs, the fracturation pressure in the reservoir decreases along with the pore pressure. At the interface between the cap rock, which stayed at virgin pressure, and the depleted reservoir, no mud-weight window exists anymore (Figure 2).

a) Defining the pore pressure profile

As can be seen in Figure 3, FIA was located in a graben separated from the existing crestal wells by a fault, and from the F5 down dip well by another fault.

The Fulmar reservoir consists of three main units:

- The C sands at the top have relatively poor characteristics: degraded permeability and presence of vertical baffles.
- The B sands in the middle have the best properties and are the main contributors to production.
- The A sands at the bottom are tighter but can include good layers at the top

Under the main Fulmar reservoir are the Pentland sands with poor characteristics. They are barely depleted and remain close to virgin pressure.

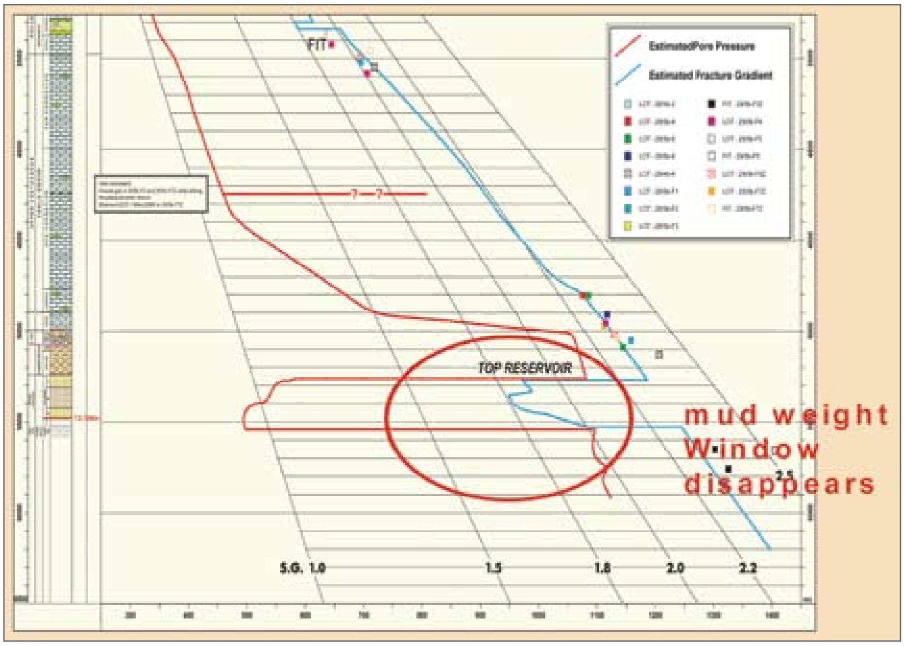


Figure 2: The mud-weight window disappears along with depletion.

All field data were reviewed to define the pore pressure profile along the well path as it was crossing the different units.

The monitoring of the average pressure of existing Franklin producers had shown a depletion of more than 600 bar of the main reservoir. Material balance analysis, interpretation of faults pattern and review of 4D seismic data provided a relatively good understanding of the reservoir behavior. The pressure of the Fulmar B sands was confidently estimated at 500 bar at FIA location at the planned reservoir penetration date. It was regularly revisited to take into account continuous production and drilling planning. An uncertainty range of +/- 30 bar was attached to this value, based on uncertainties on field internal fault continuity an transmissivity.

The pressure of the tighter C sands was more difficult to predict. Open hole pressure measurements taken on the Elgin G9 well drilled seven months after production start-up had shown a 60-bar difference with the B sands.

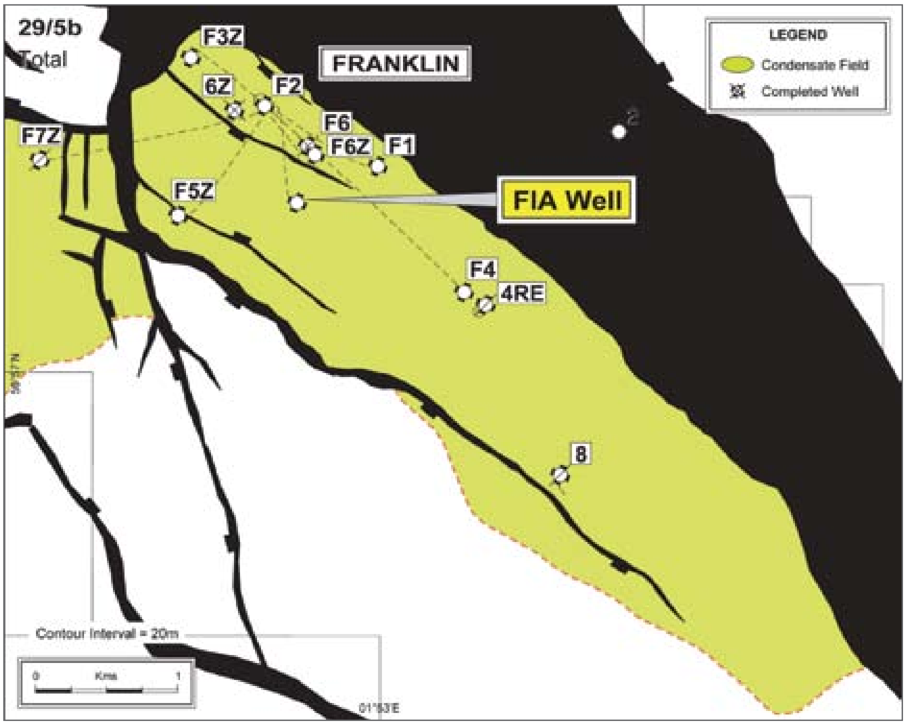


Figure 3: The FIA well was located in a graben.

The only other information available was obtained from production logging runs performed on crestal producers. Their analysis showed that C sands were produced on these wells. The degree of dynamic communication through the fault between crestal wells and FIA panel at the level of the C sands was nevertheless difficult to ascertain. Material balance could not help there as the contribution of the C sands was minimal compared to the B sands.

The production logging runs indicated also a differential depletion between B and C sands, but its amount could not be reliably estimated.

The highest uncertainty lies in the pressure transition profile between the cap rock, believed to have remained at virgin pressure, and the reservoir section. Is it at the very top of the reservoir, or is the bottom of the cap rock affected by depletion through microfractures? How thick is the reverse pressure transition zone (RPTZ), and how steep is the pressure gradient in this zone? Rock mechanics study suggested that it could be less than one meter thick.

Considering all uncertainties, different scenarios were envisaged, and a pressure profile along the well path was drawn for each of them. A probability of encountering higher pressure at top reservoir was evaluated for each scenario. The result is shown in Figure 4.

b) Rock mechanic properties

Rock mechanic experts were brought in to estimate the two main rock properties necessary to design the well: fracture gradient of the reservoirs and borehole stability of the cap rock. One has to differentiate between the fracture initiation gradient (FIG) and the fracture propagation gradient (FPG). The fracture propagation gradient is close to the minimum horizontal stress and can be modeled.

In the case of Elgin/Franklin, a full-scale rock mechanic model, coupled with the geological and dynamic reservoir model, had already been built and was used for this purpose. It estimated the FPG at 1.65 sg equivalent mud weight (EMW).

The FIG is much more difficult than the FPG to predict; therefore, it was used only as an indication and considered as an unreliable, but existing, margin. On this well, it was predicted to be around 1.87 sg EMW.

Both gradients are a function of formation pressure. As such, their profile in the RPTZ suffers from the same uncertainty as the reservoir pressure profiles.

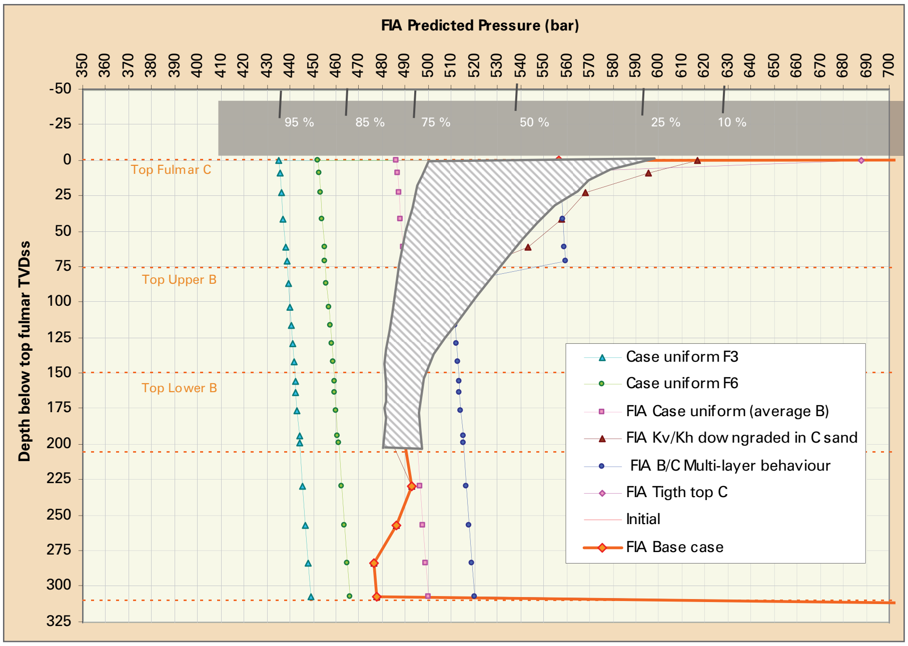
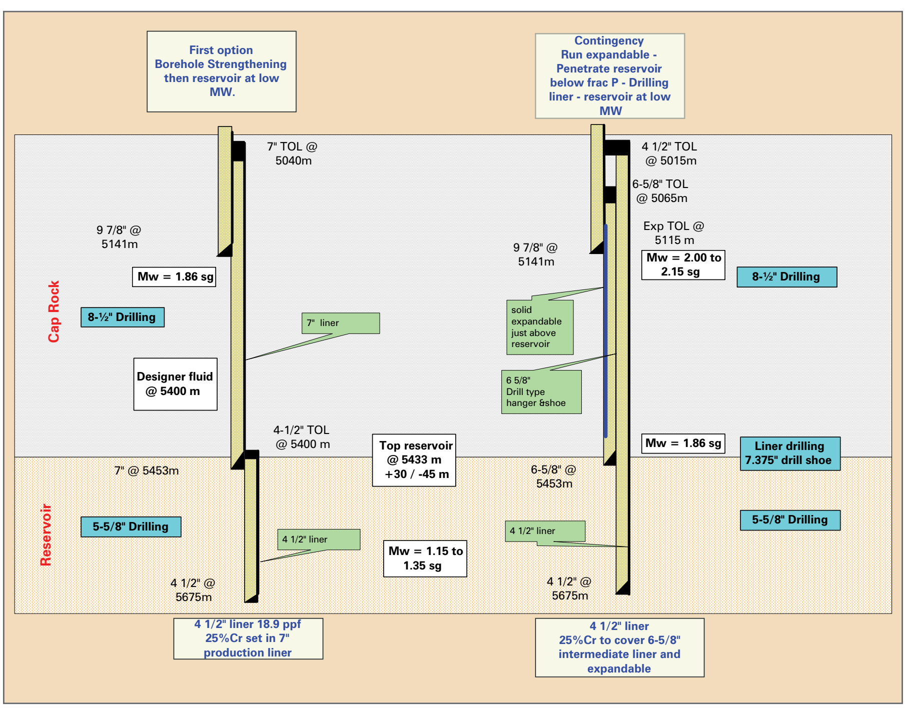


Figure 4 (above): A pre-drilling prediction was made for the penetration into the reservoir, with different scenarios being considered due to pressure prediction uncertainties.

Figure 5 (below): The two architectures defined at the feasibility study. On the left is architecture 1 retained as primary. On the right is architecture 2 retained as contingent.



The other information requested from rock mechanics was the borehole stability of the cap rock. This allows definition of the minimum mud weight one can use to cross the RPTZ without suffering unmanageable borehole instability of the open hole above. The amount of information on the cap rock is even more limited than on the reservoir. The uncertainty on the defined value is consequently higher.

c) Top reservoir depth uncertainty

Depending on the architecture selected, the top reservoir depth prediction was critical to maximize the success of the RPTZ drilling. Extensive geophysical techniques were used to minimize the uncertainty attached to this test prediction. These included, among others, thorough examination of the seismic data and uncertainty studies on depth conversion. The prediction was given to +30m / -45 m.

d) High-pressure layers in cap rock

On Elgin/Franklin, thin limestone layers (centimetric to decimetric) are often found in the cap rock. They are gas-bearing, although they don't constitute reservoirs, being too small and of very poor properties. Their pore pressure should not be affected by the reservoir depletion. When they are submitted to a fluid column pressure lower than their pore pressure, they slowly but continuously bleed small amounts of high-pressure gas into the wellbore. They can be drilled underbalanced but sometimes require high mud weight to enable trips. They are encountered more often on Elgin than on Franklin. A geology study concluded that the probability was low to find any in the bottom section of the cap rock.

e) High-pressure layers within reservoir

The likelihood of high-pressure layers in the reservoir was considered low. If any, they would have been very tight layers.

THE TWO ARCHITECTURES

In order to tackle this drilling challenge, the 2004 feasibility study identified two different architectures. They are shown in Figure 5.

The first one involves the use of a specially designed mud loaded preventively with specific loss circulation materials (LCM). The technique is known as "borehole strengthening." Once reservoir has been penetrated, the RPTZ is cased off by a 7-in. liner. The liner is a standard E/F production liner 42.7 ppf, 25% Cr with premium connections.

The second one involves the use of an expandable liner to cover most of the cap rock. The RTPZ is then drilled with a lower mud weight below the FPG. The remaining opened cap rock would be short enough so that borehole instabilities can be managed. The RPTZ is then covered with a cemented 6 ⅝-in. flush connection drilling liner. Once the reservoir has been drilled, the 6 ⅝-in. liner is covered by a 4 ½-in. production liner 18.9 ppf, 25% Cr with premium connections.

Once RPTZ is covered, the mud weight can be decreased to a value just enough to safely drill the reservoir.

As the main difficulty was lying across the RPTZ crossing, the top architecture of the well was taken as a standard Elgin/Franklin architecture as designed for virgin pressure. Production casing set at the top of the cap rock (above PTZ) is 10 ¾-in. and 9 ⅞-in. casing. This allowed focus on the RPTZ crossing and gave a comfort factor, because this top architecture is designed to hold well full of gas at virgin reservoir pressure, regardless of circumstances.

Before being implemented, both architectures needed further development work, thorough testing, qualification and engineering calculations. The main ones are detailed in the next section.

SPECIAL DEVELOPMENTS

Specially designed mud

The borehole-strengthening technique was already used in the industry. The principle is to create a fracture by using a mud weight higher than the FIP and plug it on creation, to prevent its further development. The plug is formed by LCM continuously present in the mud. The created fracture increases the rock stress locally, enhancing the hole's ability to support high mud weight. The process is easier when filtration exists behind the plug in the fracture, because the pressure inside the fracture decreases and allows it to close back on the plug. It is therefore more commonly used with water-based mud, which exhibit higher filtration values. The high temperatures experienced on Elgin/Franklin dictate the use of oil-based mud. As filtration of oil-based mud is very tight, the filtration from the fracture faces into the formation is virtually nil. The consequence is that the plug at the fracture mouth needs to be tightly sealing as soon as it is created.

The other difficulty is to define the width of the fracture to seal. Rock mechanics calculations show that there is a direct relationship between geometry of the fracture, width and length, and the amount of overpressure. The higher the pressure, the wider the fracture, at a given length. For a given overpressure, the equation has two unknowns, so one has to fix a parameter. In our case, it was estimated that the mud could be designed to form an efficient plug of 1-mm width, while keeping reasonable rheological properties despite a high solid content.

The mud was therefore designed and tested to be able to seal a 1-mm gap. The LCM additives consist of sized grounded marble and sized graphitic material. The graphitic material comprises some very coarse sections. Laboratory testing took place to adjust LCM additives relative concentrations, to achieve a quick and efficient plugging of 1-mm slots. As well as these in house tests, tests were performed in a third-party laboratory. Figure 6 shows efficiency of plugging at various concentrations.

Expandable liner

Expandable liners are becoming more widely used in the industry. They are usually used to seal off weak zones to allow for increasing the mud weight to penetrate deeper zones at higher pressure. This makes them work under a burst mode. In our case, the expandable liner had to work in a collapse mode. Expanded pipe has low collapse capacity, and this is one of the limitations of the technique. The standard off-the-shelf expandable for this application was 7 5/8-in. x 9 5/8-in.- 29.7 ppf, with a claimed collapse capacity of 218 bar. To increase the collapse capacity to the required value, a development programme was undertaken with the selected provider.

A heavier expandable pipe of 38 ppf (0.5-in. wall thickness) was selected, and the associated connection was designed. An expansion test of the system was carried out in the provider facility during summer 2005, including expansion of an elastomer-bonded section inside a joint of base pipe. This test proved that such thick pipe and connections could be successfully expanded. The expanded pipe was then cut into sections and pressure-tested to burst, collapse and tension conditions. The minimum collapse pressure was 366 bar. So the operator confidently considered the system capable of sustaining 345 bar collapse pressure.

Although expandable liner has been run previously in high-temperature wells, the operator thought it prudent to test the expansion system with high mud weight and high temperatures. This was done in a shallow well in a special facility in Dallas, Texas. The system was left soaking with 2.15 sg oil-based mud at 176°C for 18 hr before initiating expansion and expanding 18 m of pipe. Examination of the seals and parts of the system afterwards showed no significant degradation. The system was declared qualified for the application.

It was decided to not cement the expandable liner on deployment in the well. The volumes of cement involved were too small to guarantee good-quality cement at 5,000 m depth. Any problem encountered during the expansion process would have left the cement setting and prevented the expansion process to take place. Instead, some joints of the liner were bonded with elastomer. Some were planned to be installed in the open hole to seal against the formation. Another one was planned to be installed in front of the previous casing to act as a top seal and hanger mean.

IMPLEMENTATION STRATEGY

Primary and back-up architecture

Out of the two architectures, it was decided to implement architecture 1 as the primary. The main reasons were:

- In case of failure of the borehole-strengthening method, it allowed plugging of the hole with a cement plug and side track from the 9 7/8-in. shoe, starting with a fresh hole to implement the contingent architecture.
- Also, in case of failure of the borehole-strengthening method when reaching the reservoir, the depth of the top reservoir would then be accurately known, and the placement of the expandable liner would be optimized.
- It was quicker.

Architecture 2 was kept as contingent and preparatory work was done to make it ready for deployment.

Two situations were identified when the contingent architecture would be deployed prior to entering the reservoir:

- If high-pressure gas-bearing limestone layers were encountered in the cap rock. This would require a high mud weight to be controlled safely during a trip, and therefore the probability of success of the borehole-strengthening method would be lowered to an unacceptable value.
- If the defined mud weight was found too low to manage borehole instability in the cap rock, necessitating again an increase in the mud weight and compromise the borehole-strengthening technique success.

Mud weight definition

The mud weight necessary to implement the primary architecture had to be a compromise: Using a low mud weight maximizes the chances for a successful borehole strengthening, but it increases the chances of borehole instabilities in the cap rock. Although instabilities can be managed to a certain level, there is a threshold from which they cannot be managed without raising the mud weight. Using high mud weight reverses the problems.

Given the uncertainties on the rock mechanic properties in the cap rock and in the reservoir, a probabilistic approach was taken to define a theoretical optimum mud weight. For each mud weight, a probability of success of the borehole-strengthening technique was defined, as well as a probability of managing the borehole instability. The two curves were plotted on the same graph (Figure 7). The mud weight value at which they cross is the optimum mud weight. In our case, a 1.86 sg mud was deemed optimum, yet the minimum mud weight the cap rock had been drilled so far was 2.15 sg.

Drilled in 6 5/8-in. liner

The liner drilling technique was becoming available at the time development work was ongoing. This technique presented two main advantages. First, there is no need to trip out of hole to run the liner, leaving the cap rock in an underbalance condition for a long time. On these wells, it is typically four days between when the bit is picked off bottom and when the liner arrives at bottom, applying HPHT procedures.

Second, it allows using a higher mud weight during drilling. If heavy losses were experienced when entering the reservoir, and the hydrostatic applied on the cap rock dropped, the formation may collapse. With a drilled-in liner, it would collapse around the liner, leaving the hole cased off. Isolation behind the liner might be already achieved by the collapsed formation. In case further isolation is needed, an integral liner top packer would seal off the top of the liner, and the shoe could be tacked by a cement squeeze.

Losses response plan

The main risk associated with the primary architecture was encountering total losses when penetrating the reservoir with a high overbalance. The common practice to deal with losses is to pump LCM pills with increasing concentration of LCM material, and if that's not successful, keep the hole filled with mud and then revert to a lighter fluid, firstly base oil then water, when available volume of mud has been used.

This was not applicable in this case: the mud is already largely charged with LCM material; therefore chances of success with LCM pills would be low. Additionally, the potential for collapsing of cap rock around the BHA (bottomhole assembly), as well as the potential for small gas layers to flow into the borehole, under a decrease of the hydrostatic column, were to be considered.

The expected rate of losses also had to be taken into consideration: Geomechanical calculations indicated that, given the amount of expected overbalance, any fracture opening would propagate so quickly that very little time would be allowed to prepare a pill.

Keeping the well full with lighter fluid, typically water, once all available mud had been pumped into the well, would have resulted with a mixture of incompatible fluids in the wellbore. This would have created more difficulties in regaining control of the well.

In our well, the chance of important gas ingress following losses was considered low. In the reservoir itself, the fracture propagation pressure was higher than the pore pressure. Above it, the only source of gas ingress was the potential small carbonate layers. They would bleed gas into the wellbore rather than generate a genuine kick. Therefore, the usual requirement of keeping the well full at any price was challenged very strongly.

If losses happened, the first thing we wanted to achieve was to pull back the BHA into the previous shoe, set approximately 300 m above, in order to remove it from the cap rock formation most susceptible to collapsing under loss of hydrostatic. The level in the well would be allowed to drop. The potential small gas ingress from the limestone layers in the wellbore would be kept at bottom by pumping mud at a low rate of 100 l/min.

As soon as the BHA is safely pulled to shoe, the level in the well would be assessed by the use of an echo meter. This would allow the definition of the mud weight required to control losses. The well would then be displaced to the required mud weight, and a cement plug set at bottom to abandon the bottom of the hole and revert to the contingent architecture. This was the ideal case.

However, so much uncertainty was lying in the expected pressures and well behaviour that all cases had to be considered carefully and a way of regaining full control of the well found for each permutation.

The benefits of the plan were explained to the offshore crew, who then agreed to the proposed losses response plan. The fact that the top well architecture was able to sustain a well full of gas increased their confidence in applying it.

As will be developed in the following sections, this losses response plan did not need to be applied. However, it had to be revisited several times to incorporate the new information acquired while drilling and to adapt it to each drilling situation.

ACTUAL DRILLING

Herring anomaly

Top sections were drilled as planned. The 13 3/8-in. casing was called 100 m

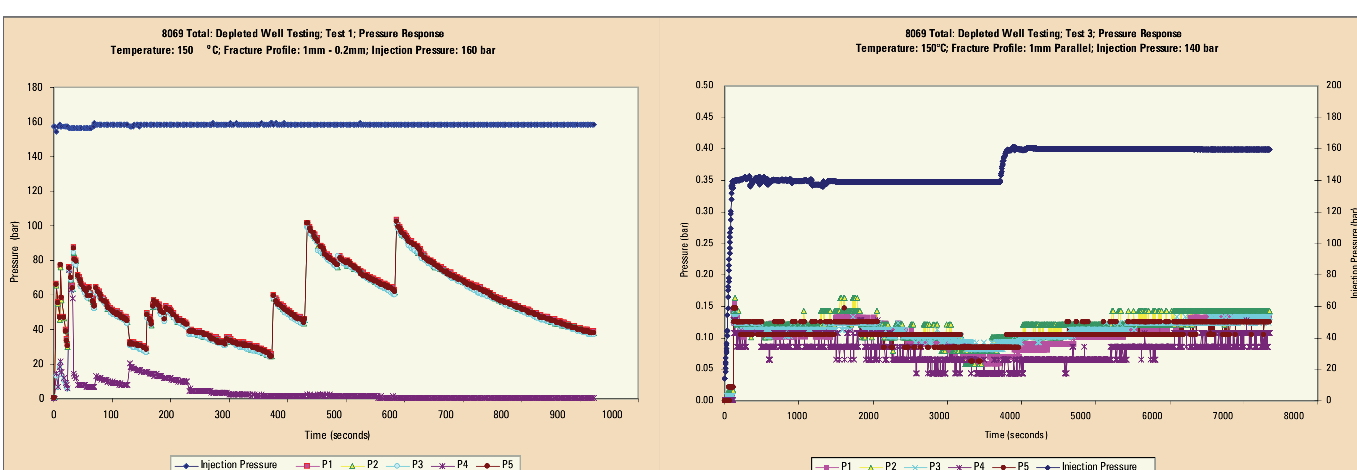


Figure 6: Different mud formulations used for sealing a 1-mm gap. On the left, a plug forms but breaks out. On the right, the plug forms and does not transmit any pressure past it.

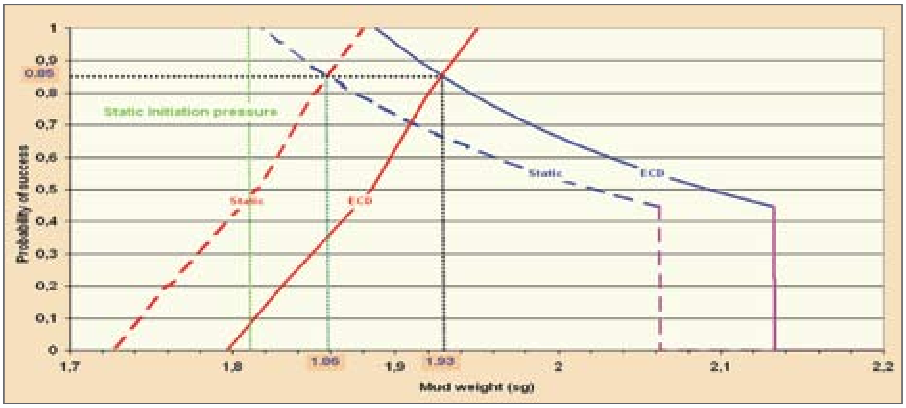


Figure 7: Probability of success of the borehole-strengthening technique in the reservoir and of the borehole instability management in the cap rock function of the mud weight. The optimum mud weight is at the crossing point of the two curves.

short at 3,585 m. This resulted in a LOT (leak off test) value of 1.84 sg EMW instead of a planned 2.10 sg EMW. These types of lower values had already been experienced on Elgin/Franklin without creating problems, so drilling continued as planned into the 12 ¼-in. phase with the planned 1.60 sg mud weight.

As drilling was progressing in the Herring formation, 150 m before planned phase TD and 450 m above top reservoir, the gas level suddenly increased. The drilling was stopped, and the flow checks performed indicated a constant flow of 500 l/hr. When shutting the BOP, the casing pressure was rising only very slowly, and no stabilization of the pressure could be achieved in a reasonable time. The encountered layer was highly pressurized, but with very low permeability. Further, numerous flow checks were performed in an attempt to depressurize it, but proved unsuccessful as the flow remained constant.

An incremental rise in mud weight to 1.8 sg slightly decreased it. Analysis of the flow trend function of the mud weight indicated a 2.05 sg EMW formation pressure. As the BHA included a MWD tool and a mud motor, spotting cement through the BHA was considered too risky. After 20 days of investigations, the bottomhole hydrostatic was eventually raised to 1.98 sg EMW by filling the open hole with heavy mud at 2.4 sg while the mud inside the casing remained at 1.75 sg. The ingress flow, although not stopped, decreased enough to pull back the BHA to surface and run a stinger to set a cement plug at bottom and regain full control of the well.

It was the first time out of 21 wells drilled in the Elgin/Franklin area that this formation was found with such a high-pressure, flowing gas. It had usually been drilled with a 1.6 sg mud. Gas levels at this depth usually increased tenfold from 0.3% to 3%, before returning to a background level of 0.3%.

At this date, there is no firm conclusion on the presence of this flowing layer there, but a strong suspicion exists that it is linked to the depletion of the reservoir.

Eventually, after considering all possibilities to continue the drilling of this well, the hole was side-tracked above the abandonment cement plugs. The new hole was stopped 50 m above the anomaly depth, and the production casing was run and successfully cemented at 4,939 m.

The main consequence of this event was that this Herring high-pressure layer was now to be crossed in the 8 ½-in. section. Its required mud weight, confirmed when crossing it again to be 2.05 sg minimum, was considered too high to implement the borehole-strengthening technique. Therefore, the primary architecture was ruled out from the start of the 8 ½-in. section. A decision was made to implement the contingent architecture.

Tight mud weight window in the 8 ½-in. x 8 ¾-in. drilling section

As the expanded outside diameter of the liner, including the connections protection sleeve, was 8.55-in., the hole had to be opened from 8 ½ in. to 8 ¾ in. This was achieved by inserting a hole opener with PDC cutting structure within the drilling BHA.

After confirming that the minimum mud weight to control the Herring anomaly was 2.05 sg, the mud weight was further increased to 2.15 sg. This was the original mud weight used in previous wells and was supposed to ensure a gauged hole in the cap rock, to allow proper sealing of the elastomer around the expandable liner. No specially designed additives were added at that time as there was no intention to penetrate the reservoir with this type of mud weight.

When reaching the Plenus Marl formation at 5,111 m, some losses occurred at an equivalent mud weight of 2.16 sg. To take into account equivalent circulating density (ECD), the mud weight had to be decreased to 2.08 sg. On previous wells, this formation was drilled in the 12 ¼-in. phase with lower mud weights.

The originally planned depth of the production casing was reached, and drilling continued into the cap rock. Further down, in the Valhall formation at 5,241 m, some high gas were seen again, indicating the presence of a charged limestone layer, but drilling could continue without raising the mud weight.

When reaching phase TD, however, the flow checks indicated that the well was not balanced, and the mud weight had to be raised to 2.10 sg to control the Valhall gas, and 2.12 sg to give a reasonable swab margin for pulling out. The section required therefore a very tight mud-weight window.

Prediction enhancement

In order to place the expandable liner shoe as close as possible to the reservoir without risking penetrating it with such high mud weight, chemo-stratigraphic and bio-stratigraphic correlations were performed. Although it seems a promising technique, the accuracy was reduced by the lower sampling intervals in the reference wells. It did not succeed in improving the placement of the expandable liner and establishing the greater thickness of the reservoir overlaying Heather interval on this well. This phase TD was called at 5,393 m eventually, and proved afterwards to be 58 m above the reservoir.

Running expandable liner

Prior to running the liner, a caliper was run in the open hole to estimate the best placement for the elastomer-bonded pipes. The hole proved to be mostly in gauge. An imaging tool was incorporated in the logging suite to try to establish the reason for the Herring anomaly. Nothing noticeable could be seen at the Herring anomaly, but a fracture could be clearly seen at the Plenus Marl interval where losses were experienced.

The liner was run with four joints with elastomer bonding. One joint was located close to the shoe, two were straddling

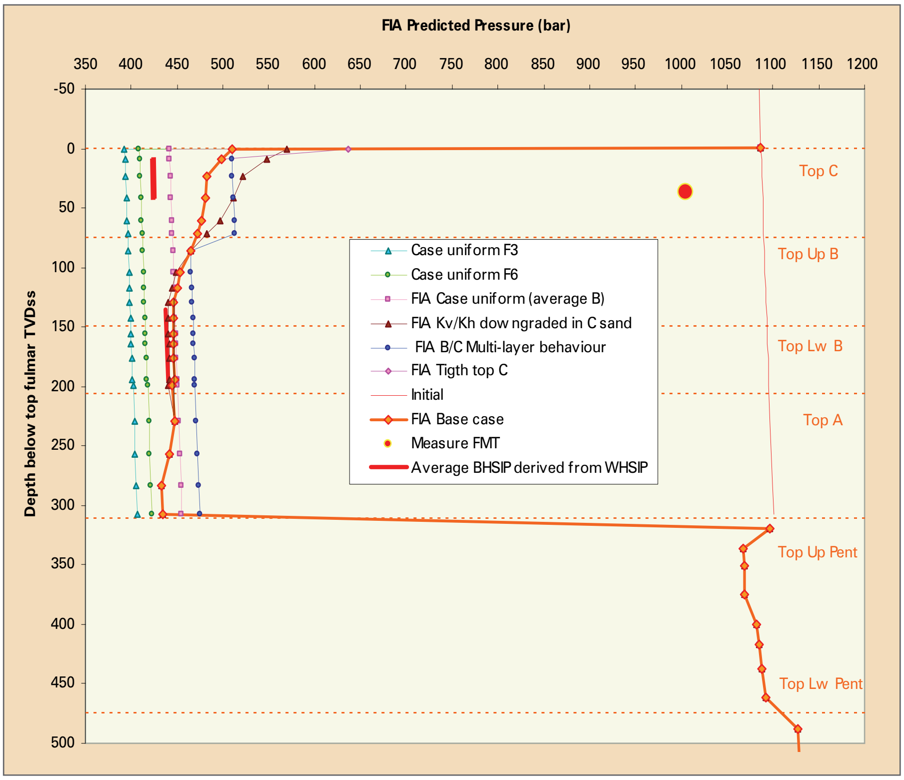


Figure 8: Comparison of actual pressures versus planned pressures within the reservoir. In thick red are the actual pressures. The red dot in the C sands is the pressure measurement taken at 1004 bar just below the shoe of the drilled-in liner.

the Valhall high gas layer, and one was installed at the top to seal against the existing casing. There were lengthy discussions on the thickness of the elastomer. They needed to be thick enough so to ensure sealing against the formation in the open hole, but thin enough to minimize the piston effect when run inside the casing and to ensure that they would not prevent the expansion process.

A consensus was reached with 0.19-in. (4.8-mm) thickness. The specially bonded joints had to be flown from the US to provide the required elastomer thickness.

The liner reached TD without problem. The dart was dropped, but the circulating rate was limited to 300 l/min to minimize ECD on bottom and prevent losses in the Plenus Marls fracture. With this low flow rate, the dart was not displaced properly and stopped half-way down the string. Pumping was stopped after theoretical displacement volume plus some margin. After investigation, including wireline work to locate the dart in the string at 600 m, a decision was made to displace the dart at 600 l/min. This flow rate achieved dart displacement to bottom, but with only 5% mud returns.

The expansion process was initiated at a much higher pressure than expected, close to the burst pressure of the cone launcher element. Once initiated, the expansion process went smoothly, and the liner was installed as planned.

Injectivity test at expandable liner shoe

Prior to continuing to drill, the well was displaced to the planned 1.86 sg mud weight. It was checked that the hanger joint was sealing properly, then the shoe was drilled with a special drill bit. As soon as the shoe was drilled, an influx was recorded from the well. Multiple flow checks and circulations showed a decrease in the flowing trend. At some stage, it was believed that the elastomer around the liner was not properly isolating the Valhall formation.

In provision of a cement squeeze at the shoe, an injectivity test was performed, which gave an injection pressure of 2.17 sg EMW. This value was a surprise, as the formation had always been drilled with a 2.23 sg ECD on the non-depleted wells. Further flow checks and circulations were performed with still a decreasing trend, the last one being perfectly stable. This showed that the seal was effectively achieved. It is believed that the influx – experienced after drilling the shoe – was created by the mud, which had been squeezed when displacing the dart.

Drilling with liner

Once the expandable shoe was cleared, and the stability of the well assessed, the 6 5/8-in. drilled in liner was run. The well was displaced to the specially designed mud loaded with LCM originally designed for the borehole-strengthening technique.

The running string was spaced out so that continuous drilling could be achieved on a full 28-m stand, hoping to penetrate the reservoir in this interval. The idea was to keep a high ECD while drilling, therefore keep the open hole high-pressure shale open. A connection would make the downhole pressure decrease to equivalent static density and increase the chances of borehole collapsing.

As seen above, the reservoir was deeper, so a connection had to be performed. The hole remained stable when circulation was stopped to connect the next stand and drilling could resume. The cutting structure of the shoe was damaged on a hard limestone stringer before encountering the reservoir, and drilling stopped.

The decision was made to pull out to change the cutting structure. As some cutters were left in the hole, a clean-out run was undertaken with a bit and a junk basket. Then the drilled in liner was run again.

During all these operations, the hole remained perfectly in gauge without any fill found at bottom. This was a surprise as rock mechanic calculations had accounted for manageable borehole instabilities with this mud weight in the high-pressure cap rock.

The liner drilled the remaining of the cap rock and penetrated the reservoir at 5,451 m. No more than 500 l of losses were noticed when penetrating the reservoir. These very low levels of losses lead to questioning the top reservoir depletion. Drilling was continued until 5,484 m, where the liner hanger was about to hang on top of the expandable liner. The liner was then cemented.

At the end of the cement job, the liner top packer could not be energized. When the running tool was pulled to surface, it was found that the packer energizing dogs had been prevented to expand by jammed LCM material from the designer mud. The debris barrier, plugged by the same material, had collapsed and failed under the increase of pressure downhole. A separate run had to be performed to run a back-up liner top packer.

Reservoir drilling

Once achieved, the successful isolation of the transition between cap rock and reservoir, one could believe that the mud weight could be decreased to drill the remaining of the reservoir with a minimum overbalance.

Mud weight was decreased down to 1.5 sg prior to drilling the shoe with a special PDC bit. High levels of gas were experienced as soon as the shoe was drilled. Mud weight was raised to 1.60 sg, and drilling continued on 40 m, in the believed poor productivity C sands, still with high gas levels. These high gas levels could have come from the cap rock via a leak path through a deficient cement sheet of the liner, or from a higher-than-expected pressure in the drilled reservoir section.

Drilling stopped, and wireline logging was performed, including pressure measurements. The well was displaced back to 1.86 sg designer mud to allow a safe trip out of hole.

A resistivity/gamma ray log was then run. These logs showed the presence of good sands at the top of the reservoir, covered partially by the drilled-in liner. A pressure measurement logging tool indicated a pressure in this layer of 1,004 bar, which was an equivalent mud weight of 1.92 sg. Nevertheless, the Geoscience Department remained convinced that the best reservoir sands still to come were heavily depleted.

The situation was as follows: All techniques planned to isolate the high-pressure formations from the low-pressure ones had been used, and still the open hole was showing high pressure. The only remaining option was to drill to final depth with the designer mud. The losses response plan was updated, and drilling continued at a reduced penetration rate into the remaining C sands, the B sands and 55 m into the A sands. The plan was to stay away from the virgin pressure pentland sands.

TD was reached at 5,678 m with only a seepage losses rate noticed around 200 l/hr for a small period. ECD during this drilling was computed at around 1.93 sg, with peaks up to 2.0 sg EMW. It is difficult to ascertain which of the following happened:

- The borehole was fractured, and the borehole-strengthening technique worked.
- The designer mud increased the fracture initiation pressure by creating a perfect seal between the borehole and the formation.
- The mud column pressure was below the initial fracture initiation pressure.

Wireline logging was performed, which included pressure measurement points. However, the pressure measurement tool could not create enough drawdown relative to the hydrostatic pressure of the mud to give actual formation pressure. The indication gained was only that the pressure was lower than 1.42 sg EMW.

A wiper trip was performed with a formation evaluation tool in the string. There was no blockage of the tool by the LCM within the designer mud.

Final 4 ½-in. liner was then run. It hung up 40 m above TD. It was decided to cement it in place and drill out inside cement afterwards to give access to the lowest planned perforation intervals.

Completion and perforation

For completion, the well was displaced to water and checked for integrity. The completion was installed without noticeable problem. Perforation was started on wireline. Because the formation pressure was not yet ascertained, pressure was applied at surface to make sure the perforation would not take place largely underbalance. There were problems during perforations operations, including misfire, stuck guns and coiled tubing fishing. The last part of the perforation was performed on coiled tubing. The Top C layer perforation was aborted for fear of potential problems generated by the high-pressure difference between this layer and already-perforated low-pressure sands.

Clean-up, bottom pressure

The well was lifted with coiled tubing by pumping nitrogen and cleaned up. The wellhead shut-in pressure by the end of the clean-up indicated a bottomhole shut-in pressure of 440 bar: 0.82 sg EMW. This indicated that the best sands had been drilled with 600 bar (8,700 psi) overbalance. Figure 8 illustrates the comparison between pressure prediction and actual pressure at the time drilling the reservoir was performed.

Moreover, the indications were that the well was delivering its expected potential and that the formation damage created by the designer mud, even under this large overbalance, was either insignificant or largely bypassed by the perforation tunnels. Since then, the well has been delivering 17,000 bbl/day.

CONCLUSIONS

- An infill well was successfully drilled, completed and perforated in an HPHT reservoir after depletion of 660 bar had occurred.
- Two architectures were designed to achieve this goal, providing a fallback solution for any geological or reservoir surprises encountered.
- Despite efforts to reduce geological and reservoir uncertainties, surprises were found – the biggest in the overburden, long before reaching the reservoir. Most are believed to be a consequence of the reservoir depletion.
- High permeability sands up to 100 millidarcy were drilled with 600 bar overbalance without any significant losses.
- The formation damage created by the designer mud, if any, was bypassed by the perforations.

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