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MULTI-DISCIPLINARY TEAMWORK DELIVERS OUTSTANDING KRECHBA HORIZONTAL WELL PERFORMANCE

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ABSTRACT

Krechba is one of seven fields in the In Salah Gas Development in District 3 of Algeria. Early in the FEED stage for Krechba up to 25 vertical wells were envisaged to develop the thin Carboniferous reservoir. To reduce development costs, feasibility studies were performed on the option of drilling 6-8 horizontal wells, which included 2-3 CO_2 injection wells. This option was later adopted in the Development Plan. The horizontal wells were planned with 1000m horizontal legs, but in the execution phase this target was increased to 1500m to increase well deliverability and injectivity.

Due to the variable sand quality, sophisticated LWD tools were used to geosteer the horizontal section through zones of the best porosity, maximizing the productivity of the wells. Real-time reservoir modelling and visualization software was used at the rig site and in the Subsurface team in Sunbury (London), to aid decision making while drilling the horizontal section and to effectively communicate changes in the plan.

Because of the existence of high tectonic stresses in the area, a wellbore stability study was performed before the start of drilling. However, severe instability problems were encountered in the first well, requiring a major re-design of the programme. Despite this, the well successfully reached a horizontal length of 1300m. These design changes were agreed at a peer review meeting, which brought together expertise from within Sonatrach and BP to analyse and review the development team's experiences and plans. Subsequent wells using the new design demonstrated a remarkable improvement in drilling performance and a significant learning curve.

This achievement was due in no small part to the efforts of the Drilling and Petroleum Engineering, and Subsurface teams to maintain a close working relationship, despite being geographically widely separated between Sunbury, Hassi Messaoud, and Teguentour.

Keywords: Horizontal Drilling, Wellbore Stability, Geosteering, Real-time Software

INTRODUCTION

The In Salah Gas project consists of 7 fields within District 3. The project is a phased development with the first three fields (Krechba, Teguentour and Reg) to be brought on line during 2004. The other 4 fields (Garet El Befinat, Hassi Moumene, In Salah and Gour Mahmoud) will be developed later.

The development team is split between Hassi Messaoud and Teguentour in Algeria and Sunbury in the UK. The approximate distance between the bases in Algeria and Sunbury is 2400km and approx 500 km between the bases in Algeria.

KRECHBA FIELD

The Krechba field is located in the Northern part of the development area. There are three main reservoirs (see Fig. 1). The Carboniferous C10.2 sands are being developed for first gas in 2004. In addition to production, the C10.2 reservoir has been identified as suitable for CO2 injection below the Gas Water Contact.

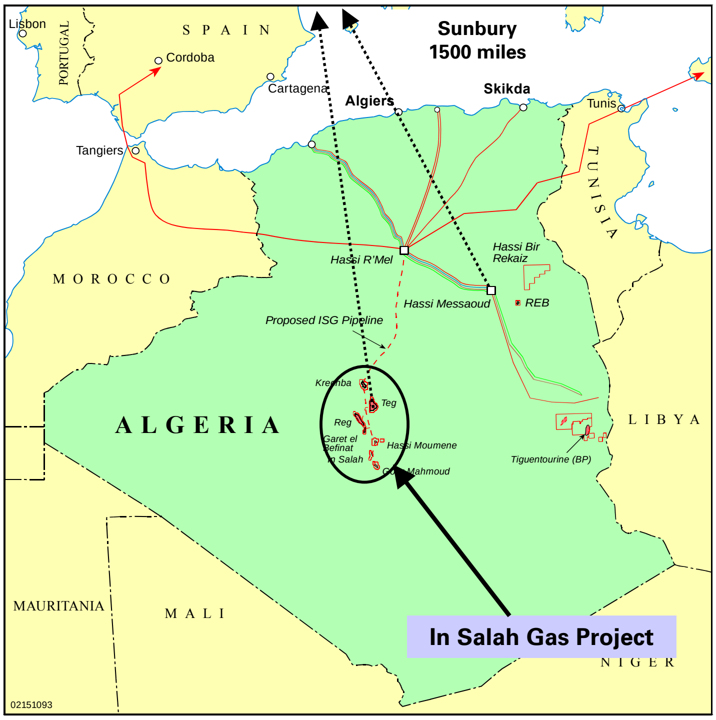

Fig. 1: In Salah Gas project location

The In Salah Gas Project needs to strip out CO2 from produced gas in order that Sales Gas meets contractual specifications at the point of entry into Sonatrach's Northern Natural Gas Network in Hassi R'Mel.

Disposal of CO2 into the atmosphere is not an option, given Joint Venture's goals to reduce greenhouse gas emissions. Storage within an aquifer within the project area is therefore the only viable option available to the project. The Krechba field C10.2 aquifer has been identified as the most suitable within the area. The C10.2 sand is a thin, continuous structure with a low relief approximately 20-25 metres thick at about 1800m depth. To develop this reservoir with vertical wells would have required approximately 25 penetrations, which was quickly eliminated as uneconomic.

The field Development Plan, based on 2D seismic, therefore featured horizontal wells with 1000m legs in the reservoir. Due to uncertainty on the reservoir top and the thin section, it was anticipated that only 60% of the horizontal length would be in the reservoir itself. Based on this assumption, the Development Plan required four producing wells and three CO2 injectors.

KRECHBA-501 – FIRST CO2 INJECTOR WELL

Fig. 2 shows the original trajectory (yellow) for KB-501, that was based was based on 2D mapping (net pore thickness). When the 3D porosity cube was loaded into the EarthVision software it became apparent that the original planned trajectory would not intersect the higher porosity lobes, which would have reduced the available injectivity in the well.

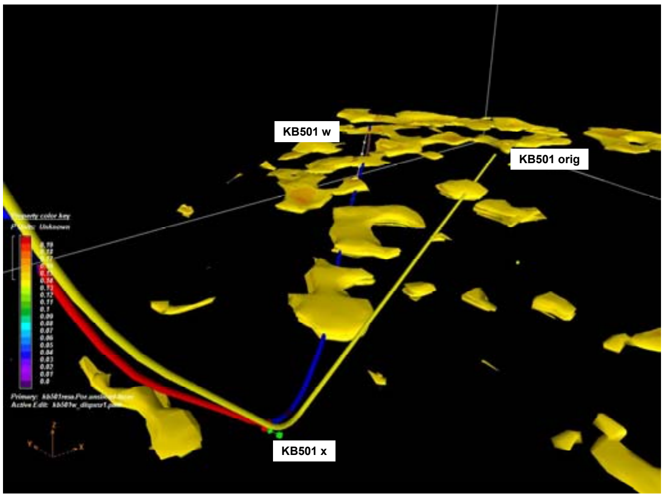

Fig. 2: KB-501 Original (yellow) and revised (blue) directional paths

The well was therefore redesigned, red in the overburden and blue in the reservoir section, to intersect these lobes and the well length increased from 1000 to 1300m. In addition the pilot hole (KB-501x) can be seen in green. The new trajectory was a 3D design with changes in the azimuth in both the overburden and reservoir sections.

The wellbore stability study performed in BP's Technology Group in Sunbury indicated that, due to the regional tectonic stresses, the preferred orientation for drilling directional wells was in the North-West South-East plane. All of the horizontal wells were therefore planned in this direction and the surface locations were built in advance of the start of drilling, based on the bottom hole targets in the Plan of Development. From offset wells, the most problematic formation was anticipated to be the Visean mudstone. The well was designed so that the 13-3/8" casing would be set in the upper part of the Visean, below the deepest incidence of lost circulation from the offset wells in which it had been a major problem. The mud weight would then be increased to approximately 1.1 – 1.2 sg to control these mudstones until the next casing point, which would be set just above the reservoir in the C10.3 sandstone. The mud weight selected for the Visean interval was based on offset vertical wells, and the wellbore stability study, which predicted that a 1.2 sg mud weight would be sufficient to counteract the tectonic stresses at the planned deviation. Fig. 3 shows the typical field lithology.

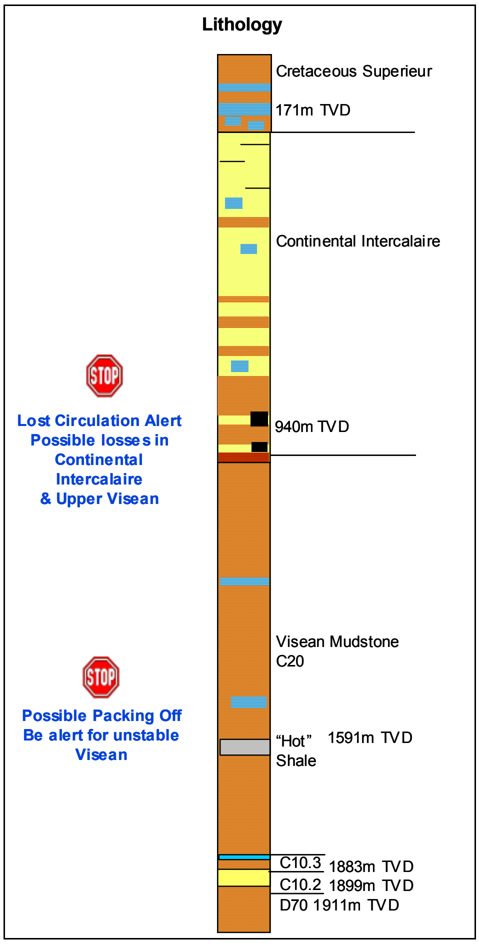

Fig. 3: Krechba field lithology column and drilling hazards

During drilling of the KB501 well 12¼" section, hole problems soon indicated that there was wellbore instability, which was not being controlled with the mud weight in use. In particular as the hole angle increased close to 60° poor hole cleaning and cuttings beds caused severe tight hole.

These problems were compounded by frequent mud pump failures. Several packoffs and twist-offs were experienced in the lower part of the Visean, requiring the 12¼" hole to be sidetracked three times. The mud weight was eventually raised to the maximum that the 13-3/8" LOT would allow, i.e. 1.3 sg, without losses. However, it was necessary to set 9-5/8" casing early because, based on the experience prior to sidetracking, this was still not expected to be sufficient to control the lower Visean.

Following a detailed review of all the drilling data and hole problems from the first three attempts to drill the 12¼" section the ISG Wells Team decided that a mud weight of 1.45 sg would be required for this mudstone. Since this was above the LOT value at the 13-3/8" shoe, it was necessary to set 9-5/8" casing and drill 8-½" hole through the lower Visean troublesome interval. This interval had been observed in offset vertical wells as an exceptionally washed-out section and was referred to as the C20.2 'unstable zone', with direct correlation possible from the gamma ray logs. This enabled the rig site geologist to pick the 9-5/8" casing point just above this zone from the MWD

On the third attempt the 12-¼" section was successfully drilled to 1872m MD just above the 'unstable zone' and 9-5/8" casing was run and cemented at 1869 m MD. On drilling out the 9-5/8" shoe a LOT was performed to 1.66 sg, which allowed the mud weight to be raised to 1.45 sg. The 8½" interval was then drilled with no hole problems through the so-called 'unstable zone' to 2027m MD, and a 7" drilling liner was run and cemented. The setting depth of this liner was also changed from the plan, since the mud weight was now much higher than originally expected, in order to avoid losses in the C10.3 sandstone. The liner was therefore set just into the top of the C10.3 instead of in the middle.

The key lessons learned from KB501 were therefore:

- The mud weight required for the upper and lower Visean sections are different. In the upper section 1.3 sg is sufficient. The C20.2 lower Visean requires a higher mud weight than the leak-off at the 13-3/8" shoe will support.
- Because of this, a casing point is required above the Visean 'unstable zone'.
- Drilling practices in the Visean are extremely important. The directional BHA's on KB501 were designed to build angle mainly in oriented mode, which aggravated hole cleaning problems due to the lack of pipe rotation. For subsequent wells BHA's were designed to build angle at the required rate in rotary mode.
- The directional profile was modified slightly to have more of the build to horizontal in the 6" hole to enable the 12-¼" and 8-½" intervals to be drilled mostly in rotary mode. Experience on KB501 showed that higher build rates were possible in the 6" hole than had previously been anticipated.
- The use of low viscosity followed by high weight (1.6 sg), high viscosity pills at each connection in the 12-¼" hole, is crucial to maintaining good hole cleaning. Large quantities of fine cuttings and cavings were seen in returns from the original hole when these sweeps were pumped.
- Wiper trips do not improve poor hole conditions in the tectonically stressed Visean in fact, when performed excessively, appear to aggravate them. The best solution to poor hole conditions is to prevent them occurring in the first place by use of the correct mud weight and good drilling practices.

Following setting the 7" liner, a 6" pilot hole was drilled, cored and logged to TD below the C10.2 reservoir. The pilot hole was then plugged back and sidetracked to horizontal. Because the 7" liner had been set shallower than originally planned it was not necessary to use a whipstock, and the sidetrack was successfully achieved in 6" open hole in the C10.3 sandstone. The horizontal section was drilled with water-based mud weighted with calcium carbonate, with lubricants used to reduce torque. TD was reached at 3400m MD, of which 1300m was horizontal. A 4-½" pre-perforated liner was run and the well was treated with an organic acid to dissolve any mud filter cake and calcium carbonate solids. The liner included a non-return valve to isolate the horizontal section from the completion brine during the displacement from drilling mud. The 5" completion was then run, and the well was tested by injecting brine into the formation. The well was completed and tested in 153 days from spud, compared to the AFE of 93 days.

Before spud of the second well, a Peer Review meeting was held in Sunbury with representatives from the ISG Wells and Subsurface teams, Sonatrach, and BP's Technology Group. The purpose of the meeting was to review the well data from KB501, and also to see how the plans for the first production well KB11, had been modified to incorporate lessons learned from KB501. The Peer Review team examined the ISG Wells Team proposals and recommended that as far as possible, the well design modifications that had been successful in allowing KB501 to reach TD should be duplicated in KB11 and future wells. This involved a change of production hole size from 8½" to 6", but the Subsurface team confirmed that this would not significantly impact the productivity of the wells.

The other change to the KB11 well design was that, based on the 1300m achieved in KB501, the horizontal section for KB11 was extended to 1500m to maximize productivity. However, based on the 3D porosity modelling, extending the original plan by 500m would have taken the well parallel to a fault and into an area of very low porosity. This would have caused two potential problems:

1. Drilling parallel to a fault could be a hazard, there is a rubble zone associated with a fault plane and the lower the intersection angle between the wellbore trajectory and fault plane the longer the

2. bit spends in this zone, this increases the chance of a pack off, stuck pipe and losing the bottom hole assembly.
2. The lower porosity zone would have an impact on production. The low porosity zone had permeability in the fractions of a milliDarcy and thus the incremental rate contribution from the extension would be very low.

The well needed to be redesigned to avoid these challenges. In conjunction with the drilling team, a 3D trajectory was designed with a turn to the left keeping the well in higher porosity rock along the entire 1500m length. (See Fig. 4).

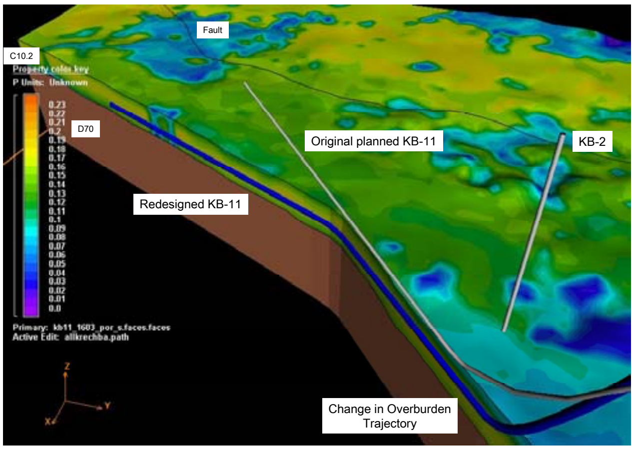

Fig. 4 – KB-11 original and revised directional plan

KRECHBA-11 – FIRST PRODUCTION WELL

KB-11 was spudded on 4 Feb 2003. The revised plan, with the 9-5/8" set above the C20.2 Visean 'unstable zone' was followed and was extremely successful in avoiding the hole problems seen in KB501. The AFE time for KB11 was 106.5 days, and the actual from spud to release was 79 days. Non-productive time was only 7% compared to 42.5% on KB501. Clearly, the design changes and incorporation of the lessons learned from KB501 were very successful in improving performance. A comparison of the time vs. depth curves is shown in Fig. 5.

With the problems in the overburden largely solved, it was necessary to concentrate on the reservoir section to ensure that the primary objective of the well, to produce at least 85mm scf/d of gas, would be met. The thin reservoir section and the variable porosity dictated that the well path should be geosteered by real-time LWD tools in order to maximize the productivity of the well.

Sperry-Sun Neutron Density tools were used in the horizontal section to allow real-time measurement of the formation porosity. Because of the length of the BHA the directional measurements were almost 20m behind the bit, so an ABI (At-Bit Inclination) sub was run to ensure the most accurate survey data was available. This was important to allow real-time decisions to be made concerning the well trajectory while drilling.

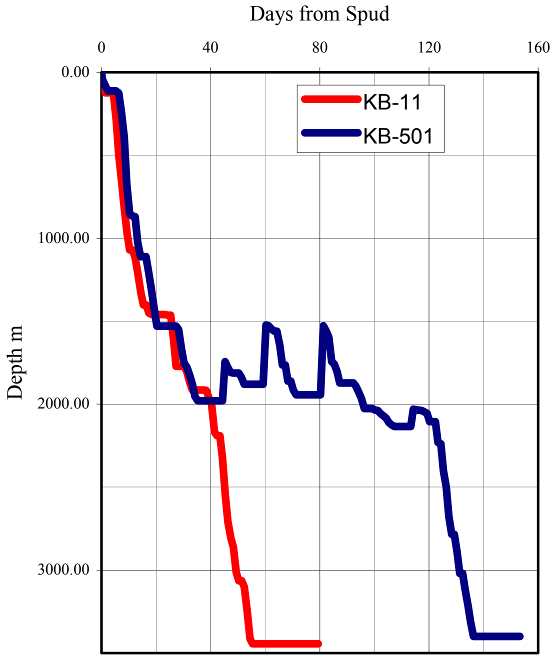

Fig. 5: Comparison of KB-501 and KB11 time vs. depth plots

GEOSTEERING

Geosteering is the ability to react to changes in the prognosed plan often caused by sub-seismic reservoir heterogeneity or drilling challenges. Plans are based on seismic interpretation, structural modelling, analogues and offset well data. When drilling the reservoir section the observed data will often differ from the prognosis and the planned trajectory will have to be changed to take into account these observations in order to optimise production. In addition there could be drilling challenges e.g., the bit drifts to the left or right, these changes to the plan need to be examined, often it might not be necessary to spend rig time returning to the plan.

While drilling the reservoir the trajectory and MWD data were updated and loaded into the model at the rig site after every stand. The forward plan was then discussed between the rig site geologist, directional driller and drilling engineer, and progress against the plan was monitored. Trajectory and MWD data were updated after each survey point, and the forward plan discussed with directional driller. The drilling supervisor was updated with progress and plans two or three times a day. Updates were sent to Sunbury whenever necessary.

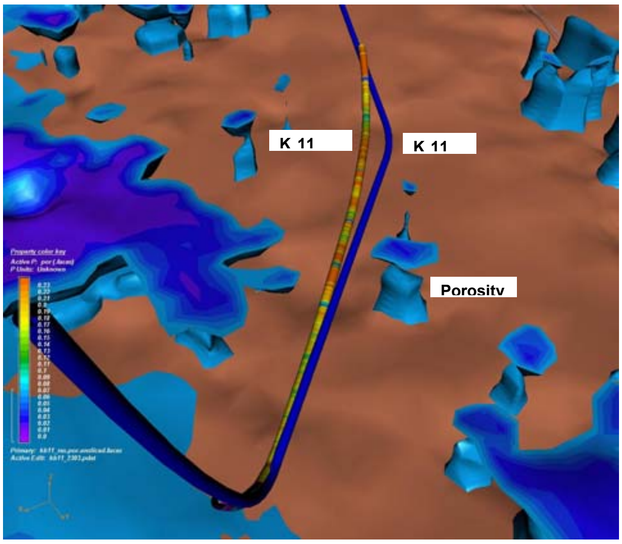

Fig. 6: KB-11 area showing porosity < 7%, planned well in blue and partially drilled well colour coded with real time porosity 766m into reservoir section

Fig. 6 shows the first change to the planned KB-11. The planned trajectory is in blue and drilled trajectory colour coded with porosity. The brown surface shows the base of the reservoir and the 3D bodies show porosity (from seismic) less than 7% (areas of possible drilling hazards).

The challenge was that the bit was drifting to the left and the directional drillers were concerned about the 7° dogleg turn. From the porosity cube there were no hazards to the left of the trajectory, and so it was possible to let the trajectory drift to the left and "cut the corner".

Fig. 7 shows KB-11 planned trajectory in blue and drilled trajectory colour coded with porosity, the amended trajectory is in red. The brown surface shows the base of the reservoir and the 3D bodies show porosity (from seismic) less than 7% (areas of possible drilling hazards). Upon examination of the real time porosity data it was decided drill to a higher TVD than planned in the reservoir and not to return to the original path following the turn, but to continue along the revised azimuth.

Geosteering decisions and model updates were made at the rig site and the incremental changes were sent to Sunbury. EarthVision software (EV) was used at both sites to view the progress of the well. It was possible to view the same data at each site and synchronize the views i.e., when the view was changed at one site this change was seen at the other.

The power of these collaborative sessions should not be underestimated. The progress of the well can be readily understood and the forward plan easily communicated. One major advantage of these sessions is seen when further input is required. At the rig site it is possible to access the geologic model and limited seismic, if the observed results are not as prognosed. It is then possible to use the expertise and further seismic in Sunbury to formulate a forward plan, which is then discussed with the operations teams in Teguentour and Hassi-Messaoud. The whole team are then involved in the geosteering decisions.

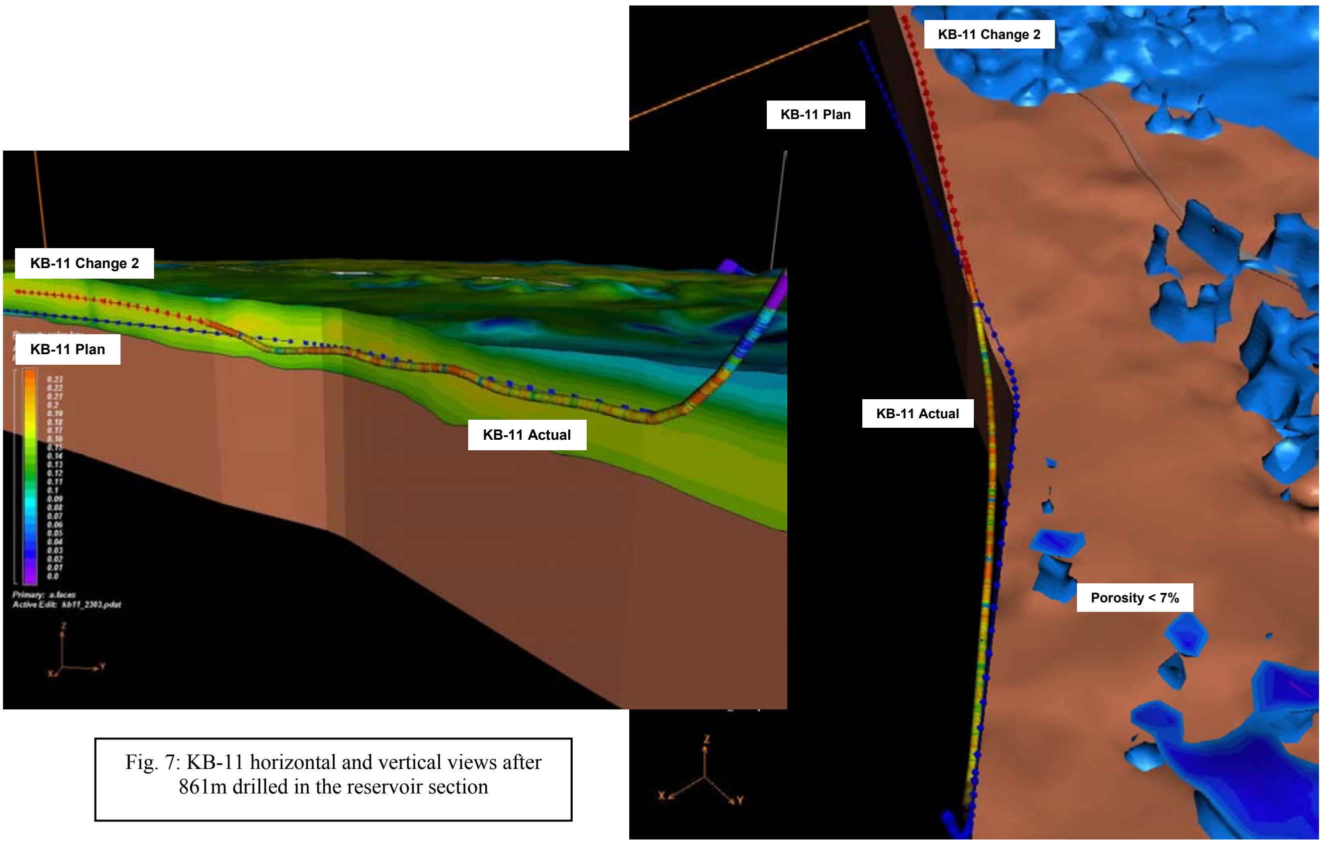

Fig. 7: KB-11 horizontal and vertical views after 861m drilled in the reservoir section

KB-11 RESULTS

The KB-11 well reached TD of 3445m after only 57 days from spud, 29 days ahead of AFE, despite drilling 340m incremental horizontal section. A total section of 1500m was drilled with 100% in the reservoir. The production from the well was estimated at 3.4 x 10^6 m3/day (120mm scf/d) compared to the original expectation of 2.4 x 10^6 m3/day (85mm scf/d). The successes of this well were due mainly to several key factors:

- The detailed review of lessons learned from KB501 and application of these to the design of KB11, incorporating advice and expertise from both BP and Sonatrach

- By deviating vertically from the planned horizontal section it was possible to remain in higher porosity rock which drills with a faster rate of penetration.

- By managing the drilling challenges through forward planning, with cooperation between, and input from drilling, subsurface and petroleum engineering, rather than just trying to return to the original plan.

SUBSEQUENT WELLS

The next wells on the field, KB-13, KB-12 and KB-503 all benefited from the same design changes as were successfully used in KB-11. The drilling performances all showed the same substantial improvement over KB-501. Horizontal sections 1500m long were drilled in all the wells except KB-12 which encountered a fault in the reservoir, causing substantial lost circulation that prevented further progress. The improvement in performance can be seen from the chart of drilling days per 3208m (10,000 ft) drilled (see Fig. 8)

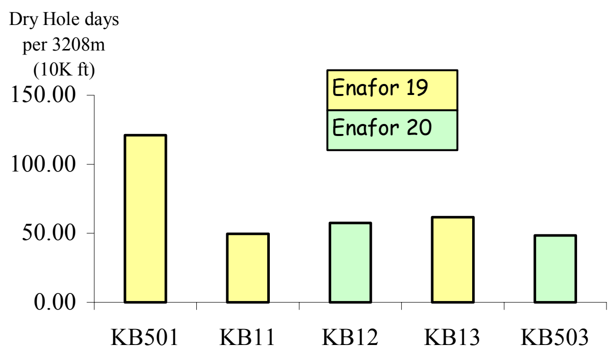

Fig. 8: Krechba drilling progress learning curve

In addition to the marked increase in drilling performance, the results of the production well tests showed that the first gas production commitment of 7.64 x 10^6 m3/day (270 mmscf/day) could be met with three production wells instead of four, and the CO2 injection requirement could be met with two wells instead of three.

The mud weights required to counteract the wellbore stability problems in the Visean mudstone were underestimated in the Krechba pre-planning stage. The wells on which the stability studies were based were vertical, and lost circulation was expected to be a more severe problem than wellbore instability. The experiences on KB-501 showed that significantly higher mud weights were required in the deviated sections than expected.

The casing programme selected at the Krechba pre-planning stage did not allow the required mud weight to be used in the Lower Visean 'unstable zone' C20.2. It was necessary to modify the programme to allow the 9-5/8" casing to be set above this zone.

The multi-disciplinary Peer Review by personnel from both Joint Venture partners was critical in deciding how to best incorporate the lessons learned from KB-501 into the plans for subsequent wells.

Utilization of the new plans on subsequent wells led to significantly improved drilling performance.

Use of real-time software to model the reservoir during the horizontal sections allowed the geologists and directional drillers flexibility to optimise the plans without compromising well objectives.

With 3D geologic visualization it has become easier to share information and ideas, not only within the Subsurface but also the Drilling community. The reasons why certain decisions are made become very clear when viewed using a 3D solid earth model.

ACKNOWLEDGEMENTS

The authors wish to thank all of the Sonatrach and BP personnel that assisted with overcoming the severe problems experienced on KB-501, and provided support and encouragement to the ISG Wells and Subsurface teams in formulating a successful forward plan.