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A Novel Approach to Access Trapped Reserves below Highly Depleted Reservoirs

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Abstract

In mature fields, hydrocarbons may become "trapped" below the main production zones. These overlying formations may be produced to a very low pressure, while the smaller trapped reserves may remain at virgin pressures or be slightly depleted. Drilling the depleted reservoirs requires a low mud weight to prevent losses and avoid either lower reservoir influx or shale collapse. Due to the often marginal size of the trapped reserves, reducing well costs is critical to project economics. One obvious solution is to deepen an existing producing well and commingle the production from the reservoirs, thus reducing cost when compared to a new dedicated well. Three novel technologies have been identified that, when combined, would allow wells to be deepened at low cost and without severe losses. These include through-tubing drilling, aphron-based drilling fluid, and real time ECD modelling.

This paper describes a project where these technologies were applied. Owing to the high-risk nature of the project and the need to protect existing production from the chosen well, in-depth planning and staged implementation of the new technologies were undertaken. A comprehensive risk management procedure was developed and careful testing and data gathering undertaken. The well was successfully executed within planned time. The authors will outline the theoretical and practical aspects of the technology selection criteria, risk management aspects, and how all these were combined to deliver a successful well.

Introduction

The near vertical (20º inclination) North Sea gas well was producing 200,000 m^3/day from the upper reservoir zone. The upper reservoir zone, which has been producing for more than 20 years, was depleted from original field virgin pressure of 366 bar to 50 bar. The target lay beneath this depleted reservoir with a thick (40m) claystone layer inbetween that contains intermittent sand lenses.

Throughout most of this field the lower reservoir is below the gas water contact. Thus, the majority of the field only drains the upper reservoir zone. The only well that previously produced from the lower reservoir had watered out. Consequently, in order to avoid the water leg, the plan was to target the remaining reserves in an up-dip location. Therefore, only a relatively small amount of reserves are in the lower reservoir, especially when compared with reserves in the upper block. However, it was perceived that if the well could be deepened inexpensively, it would be an attractive project.

The target reservoir had been drained by one production well until it had watered out after eight years of production. It was not clear exactly how much had been produced from this lower reservoir zone, but the pressure was believed to be ca. 250 bar. Additionally, it was believed that the sand lenses in the claystone layer, due to their discreet nature, might be at virgin pressure (366 bar). The top of the claystone layer was anticipated to sit 17m below the 4½ -in. shoe (see Figure 1).

Challenges

This section discusses the challenges that were encountered in the design and execution of deepening the well. These challenges are divided into two categories, namely technical and non-technical challenges.

Technical challenges

Described below are the technical challenges that were realized during the planning phase of deepening the targeted well.

- Shale Stability

One of the main technical challenges was to maintain shale stability while deepening. Hence, since the shale potentially contains virgin pressured sand lenses, an on-balance situation had to be maintained in the shale during the entire deepening process. However, this requirement increased the chance of fracturing the upper reservoir, because depletion had reduced its formation strength significantly. This fracturing can lead to severe losses, which in itself can cause an underbalance (and thus unstable) situation in the underlying shale. Additionally since the well had been sidetracked 15 years previously, it had not been possible to kill it successfully. Therefore, preventing severe losses in the upper reservoir was identified as a major challenge.

Accordingly, during the operation the mud gradient would have to be maintained above the on-balance limit without fracturing the depleted upper reservoir. The static on-balance limit was estimated at 1.14bar/10m. This was based on the potential occurrence of virgin pressured sand bodies within the shale layer. Adding the friction in the annulus while circulating meant the equivalent circulating density (ECD) while drilling that corresponded to this static limit was 1.35s.g. (1.33 bar/10m). Figure 2 shows the ECD limit where the calculated reduction in formation strength of the depleted reservoir is given as a function of reservoir pressure. This assumes the depleted reservoir is normally stressed and behaves in a linear poro-elastic manner. For this reduced formation strength a range is given which corresponds to a range of depletion constants that are used in the formation strength calculations. For sedimentary basins depletion constants have been reported between 0.4 and 1.

Figure 2 also contains two points that are derived from experience in similar reservoir settings. Point 1 (♦) is based on the drilling performance when the well was originally drilled (1.05s.g. equivalent circulating mud density) into the upper reservoir, which at the time had 98bar reservoir pressure. No initiation of a fracture was identified; indicating the formation strength at that time (98bar reservoir pressure) was at least 1.03bar/10m. The depletion constant, derived from this minimum formation strength at 98bar, was used to predict the formation strength at 50bar reservoir pressure. Point 2 (+) is based on water injectivity tests in wells in similar reservoir settings.

The figure also shows that for the current reservoir pressure (50bar) the range of formation strengths is below the limit required for shale stability. In other words, no operating window seemed to be available for maintaining shale stability without fracturing the depleted reservoir above. However, several uncertainties exist in calculating this range. First, the formation strength at virgin pressure is not precisely known. This formation strength is based on the lower bound of leak-off pressures in wells that penetrate the same reservoir setting, i.e. the virgin formation strength could be higher. Further, the graph does not take into account that the near-wellbore area can be stronger than the formation itself, because of the prevailing hoop stresses. In this respect it must be noted that drilling fluids can restore the near-wellbore stresses in instances where these have been eliminated by perforations. Therefore, the formation strength, derived from the water injectivity tests, must be seen as a lower bound since there the hoop stresses have not been (partially) restored.

In summary, the mud weight window for deepening the well was believed to be both very tight and unclear. Therefore, before deepening, an investigation into whether a sufficiently large operating window was available had to be performed. For a successful deepening the well, this window was set at 1.35-1.45s.g.

- Impairment of Targeted Lower Reservoir

To prevent severe losses the depleted upper reservoir needs to be shut off. However, the challenge here is to prevent any impairment of the targeted lower reservoir. Preventing severe losses, and the subsequent impairment of the targeted reservoir, is considered a challenge since the expected pressure in the targeted reservoir (250bar) is significantly lower than virgin pressure (366 bar).

- Regain Access

As mentioned, this was a currently producing well with production of ca. 200,000m^3/day. It was desirable to be able to regain this production at any time. This could occur during the deepening process in case the deepening turned out to be unsuccessful or afterwards once the reservoirs had come to pressure equilibrium, when the risk of cross-flow is eliminated. There were other producing wells in the block of the upper reservoir, but a simulation showed that it would not be possible to produce all the reserves from this well. Therefore, the plan must allow for future access to the upper reservoir and any plan would need to take into consideration the potential risk of losing production from that zone.

Non-technical Challenges

The well planning team also faced a number of other challenges not directly related to the technical problems listed above. When the project team for the well began its work, the project was considered an easy well just to deepen. When the well had originally been identified, the intention was to drill it relatively inexpensively through-tubing with coil tubing. However, during the design phase, more and more challenges were identified. Managing the perception of these challenges proved a key factor in the project. The first step was to recognize this was not a simple project and would require more time for planning than was originally anticipated. Secondly, once the team identified these risks, it was recognized that significant time and effort would be required to convince stakeholders that the risks were manageable and that the project remained feasible.

Once it was anticipated that the deepening of the well was feasible, a tight window of opportunity between the drilling of another well on the same platform (allowing for synergies in reduced mob/de-mob costs) and a major platform shutdown was identified. Additionally, execution of the deepening could only start once operations on the previous well had ceased. Furthermore, it was not known exactly when the shutdown would begin, as it was dependent on the arrival of a large construction vessel.

Finally, as marginal reserves were expected from the targeted reservoir, a limited budget would be available. In addition, since the well was producing, it not only had to pay for itself but also had to cover lost production from the upper reservoir zone. Besides mitigating the identified risks, the methods for developing the targeted reserves, therefore; also had to be cost-effective as it was impossible to justify a new well or even a sidetrack.

Planning Phase

This section first discusses all concepts considered for developing the reserves in the targeted lower reservoir. Afterwards, the final drilling concept, which was based on through-tubing drilling on jointed pipe, is discussed in more detail.

Owing to challenges that were more complex than previously believed, it was necessary to re-evaluate all the possible options to drill the well. This even included those that had been discounted when the original plan of through-tubing coil tubing drilling was proposed. Certain concepts, such as underbalanced drilling, were ruled out immediately, as the risk of shale collapse was too high.

Several concepts were identified as being possible:

- Drilling through the tubing – with coil
- Drilling through the tubing with jointed pipe
- Pulling the tubing, drill jointed pipe
- Mill 4 ½-in. liner, drill remaining upper reservoir, run expandable liner over the upper reservoir, deepen the remainder of the reservoir.

As discussed in the previous section, some of the challenges were to devise a cost-effective approach and to remain within the available time window. In order to compare each option on an equal level, it was necessary to look at the required time each concept would take and the associated risk economically. The wells were compared, not just against drilling capital expenditure but also the chance of success for each well, the risk of losing the upper reservoir production including the associated loss of income, and the length of time the upper reservoir would have to be closed-in. It became clear that drilling the well through tubing would be the most cost effective method.

There were also a number of additional factors that made the through-tubing drilling concept preferable. It had not been possible previously to kill the well; therefore this would be the first significant stage. The well kill would be performed with coiled tubing. Therefore, by not pulling the tubing, the exposure would be limited as production from the upper zone could be re-instated, thereby limiting the costs required to reach that point, should the kill be unsuccessful. Jointed pipe was selected for drilling through tubing. Compared to drilling on coiled tubing, jointed pipe can be rotated, reducing the risk of differential sticking and providing the ability to deal with over pulls. In addition, it provides a greater chance to recover from a shale collapse and its higher strength generally makes it more robust.

It was recognized that through-tubing jointed pipe drilling would incur further challenges that would add considerably to the complexity of the project. One of these additional challenges was preventing damage to the completion during drilling. The minimum restriction in the completion was 3.813" in. at the nipple, below the packer. The completion would have to be pulled if damaged, significantly increasing costs. To help protect the completion a special wearbushing was designed for the tubing hanger, complemented with a lower RPM at surface that allowed drilling to take place essentially with the motor but without the risk of differential sticking. In addition, after the deepening, a pressure test of the completion was planned to ensure that no or at least insignificant damage had occurred. A contingency completion was included in the costs and well plan to ensure it could be replaced immediately if damaged so as not cause any delay to production. This was especially critical, as installation would require a rig, magnifying the expense dramatically.

Since the through-tubing drilling concept was seen as a fairly new technology, it also carried more risks up front. Hence, it was recognized that a 'tool' would be required to convince stakeholders that the identified risks were controllable. Further, it was recognized that this "tool" would make it easier to make decisions during operations. This was agreed early in the planning phase that this system would be in-place to take the emotional response out of decision-making. Figure 3 shows a section of the traffic light system, which was devised to serve this purpose.

As the well was to be drilled through tubing, 2 7/8-in. slim drill pipe was identified as best suited to deepen the well through the 5in. completion. In order to maximise the hole size, it was decided to employ a 4 1/8-in. bi-centred bit with a 2 7/8-in. mud motor. Drilling with the bi-centred bit would help increase the clearance when running the 2 7/8-in. liner, while also helping lower the ECD. A 2 7/8-in. MWD-GR was identified as one that could be run in the hole. While the suitable equipment to do the job was identified, availability was a question mark. Thus, securing the necessary equipment would prove to be vital, especially as the timing of the job was critical.

Another major challenge was difficulty in controlling the bottomhole pressure and consequently the ECD of the drilling fluid. This was very important, as the mud weight window available for deepening the well was small. This was due to deepening with 2 7/8-in. drill pipe inside 5in. tubing (15lb/ft) resulted in a very small clearance that caused relatively high friction while circulating. Maintaining control over the bottomhole pressure was accomplished with a monitoring tool that could estimate in real-time and any stage during the process the pressure loss caused by friction, and thus the bottomhole pressure (Figure 4). This computer system is hooked up to the mud logging unit, from which it receives the data required for real-time hydraulic calculations. These are then transmitted back to a display at the drillers position, thus giving the rig floor a real-time feedback of how their actions were influencing the surge pressure and ECDs down-hole.

As indicated previously, maintaining shale stability while deepening was one of the major technical challenges. Severe losses or even fracturing of the upper and severely depleted reservoir had to be prevented while retaining the ability to possibly regain production from the upper reservoir. Moreover, all of this had to be accomplished without impairing the depleted target reservoir. In order to deal with all these challenges, an aphron-based drilling fluid system was introduced[2]. The water based system builds up a filter cake that can withstand a large overbalance. Air bubbles employing a hydrophobic surface form the filter cake. This allows them to experience capillary pressure resistance as they move into the depleted reservoir, which in this case is water-wet. Due to the pressure differential, the bubbles expand in the formation where the surfactants mixed into the fluid system force them to aggregate rather than coalesce. The cumulative capillary resistance of these aggregated bubbles is relatively large[1] so a reasonably good seal is created between the formation and the wellbore.

A useful characteristic of the aphron-based system is that the seal will be removed once the well is brought into an underbalanced situation. In that case the bubbles will be produced back. This characteristic gave the flexibility to stop the deepening process at any time and to regain production from the upper depleted reservoir. In addition, with the aphron drilling fluid system the bubbles are broken down over time, meaning that any potential impairment of the target reservoir would be removed, also over time.

The first phase in deploying the system was to seal off the existing perforations in the upper reservoir. At first sealing off the perforations by spotting cement across them was considered. However, owing to the relatively small distance between the production liner hanger and the top reservoir, this idea was abandoned as the risk was too high to cement in the completion should too much cement be spotted. Therefore, for sealing off the perforations, it was planned to spot an aphron-based pill containing lost circulation material (LCM) as a bridging agent. Afterwards, the well would be filled with the aphron-based drilling fluid system. To confirm that a sufficient seal had been applied and that the required mud weight window was available, a subsequent pressure test was planned up to an equivalent mud weight of 1.35s.g. The result of this pressure test was included in the traffic light system as a go/no-go milestone.

After a successful pressure test, the next stage was to deepen the well to TD (3 1/2in. hole) using the aphron-base system. Once drilling reached the top of the claystone, it was critical that there be enough time before the shutdown to complete operations. The risk of shale collapse meant leaving the claystone layer partially drilled or uncased was not an option. At TD, the well was planned to be completed with a pre-drilled 2 7/8in. liner to guarantee shale stability during the well life.

Owing to the complexity of the basic program, additional, operations were to be kept to a minimum. With the risk of shale collapse, no logging program would be undertaken so as not to keep the hole open any longer than necessary or to differentially stick the tools given the large overbalance. Alternatively, an MWD-GR would be run in the BHA. This approach was justified, as good log information was available from the nearby well, which had previously penetrated the lower reservoir. Secondly, it was decided not to cement and perforate the reservoir. It was felt that cementing in such small liner size would be a risky and a difficult to control process and if the well had managed to reach TD it should not be jeopardized by a cementing job, where success could not be guaranteed and may result in the loss of the both reservoirs. Hence, the well was designed to stay vertically and laterally away from the water.

In summary, three key technology enablers had been identified: through tubing drilling, aphron-based drilling fluid, and real time ECD modelling. These, in combination with adhering to the stoplight policy, would hopefully, allow the well to be deepened safely, at low cost and without severe losses.

Implementation of the Plan

Once the plan for deepening the well had been devised, an implementation program was put in place that was designed to increase confidence in the techniques to be employed. This program consisted of engagement sessions with all relevant parties to raise their understanding of the problems and how they fitted into the solution. For these site visits, data gathering exercises and hands-on exercises were held. This process also helped increase confidence and buy-in into the project, both internally and externally.

One of the data gathering exercises consisted of a field-visit to Venezuela where the aphron-based drilling fluid system had been used before in approximately 95 wells. This Field visit revealed that the system, which was used to prevent losses and reservoir impairment, was very successful. Furthermore, from an operational standpoint, the system was easy to mix and to maintain and appeared to be very adaptable. More data on the aphron-base system were obtained from lab tests, which showed that the risk of emulsion forming between the mud and reservoir fluids (water, condensate) was relatively small.

The process benefited significantly from utilizing a test well; an old well that had been adapted for the training of personnel and the testing/introduction of new and novel technologies. The primary aim of the test well exercise was to familiarize pertinent personnel with the aphron drilling fluid and test well control procedures. Therefore, many of the relevant parties were present for the testing program, including drilling supervisors, mud engineers, asset staff and senior well engineers, among others. The exercise showed that when the mud is circulated through a choke, the pressure drop across the choke creates many additional bubbles. Consequently a super-aphronized mud is created[1]. As seen in the test well, this super-aphronized fluid system can create some well control problems. Thus, procedures were developed to prevent the creation of a super-aphronized drilling fluid.

The real time ECD monitoring tool was tested also at the test well. The outcome of the real-time modeling was compared with gauges that were run in hole as part of the bottomhole assembly. As a result, the software model had to be adjusted slightly to accommodate the air content of the aphron based drilling fluid.

Another improvement introduced during the implementation phase was the introduction of a belly board in the derrick of the rig. Several safety alerts from around the world were discovered during tripping and racking exercises of this highly flexible pipe. The bellyboard would allow an intermediate racking point in addition to the monkey board.

During this implementation phase, the project team took the well through a rigorous approval process, comprising technical challenges of the initial concept followed by the more detailed design. Associated with each of these challenge sessions was a review, which not only addressed all technical issues associated with the well (subsurface, concurrent operations, hook-up) but also all organizational, commercial and other non-technical issues. The traffic light system proved to be a very useful tool in demonstrating how each of the potential risks would be dealt with during drilling to provide confidence that unnecessary risks would not be taken. Obviously, management buy-in was crucial, and the decision process that was guided by the traffic light system made it clear to all parties involved how to proceed with the well.

The final stage in this process was to bring the key players together for a “drill the well on paper” exercise. The main objective of this session was to run through all stages of the operations, demonstrating where the lessons learned had already been implemented as a result of the processes outlined above. Additionally, this was the time to highlight any outstanding issues needing to be addressed and, due to the set-up, allowed the assignment of the appropriate action parties. The last objective of that session was the re-iteration of the traffic light policy. The timing of when the decision points were to occur was crucial. As was discussed the project was to be executed in a very narrow time window. The key points in the schedule were:

1) Formation strength test results – if the upper zone could not withstand an ECD level of 1.35s.g. then it would not be safe to proceed.
2) Top Claystone layer – once drilling reached the top of the claystone there must be enough time before the shutdown to complete operations. Leaving the claystone layer partially drilled or uncased was not an option due to shale collapse risk.

Execution

After well over a year of preparation and planning, the operational aspects of the well went incredibly smooth. After the drilling the new development well on the platform, the rig was skidded over the existing well for deepening. Once the SSSV had been removed, coil tubing was used to spot a pill consisting of the aphron-based drilling fluid and $CaCO_3$ across the perforations in the upper reservoir. The completion tubing was subsequently displaced with the aphron-based fluid to surface and a pressure test equivalent to 1.35 s.g. was undertaken against the formation without any visible losses being observed. The limit of 1.35 s.g. was then set as the ECD limit for the drillers to aspire to with the aid of the real-time hydraulics modelling software. Next the Christmas tree was removed and a standard BOP was installed. A barracuda mill and motor assembly were then run in hole on 2 7/8" drillpipe through the 5" completion tubing to mill away the existing 4 ½" production liner shoe. A PDC bit was not deemed acceptable to do this due to the high steel content of the float shoe. The 3 ¾" PDC bit was run in hole and the well was deepened through the upper reservoir and shale package into the lower reservoir, a total of 102mAH. During drilling no losses or differential sticking was encountered and a steady ROP of 2-3m/hr was achieved. The 4 1/8" bi-centred bit could not be used; the wear pad on the motor was larger than the pilot bit diameter and therefore significantly reduced the pass through diameter of the bi-centred bit. The open hole section was completed by a 2 7/8" liner with a predrilled section across the lower reservoir. The Christmas tree was then replaced and the well was displaced to N_2 using coil tubing.

In total, the operation (excluding rig move), took 21 days with less than 1 % non-productive time recorded. The well was deepened to the required depth and completed and the rig was able to move away from the platform before the required date for the platform shut in. In addition, the aphron-based fluid proved to be a robust and easy system to work with and no losses or differential sticking recorded despite some 470 bar of dynamic differential pressure being placed across the reservoir section. The real-time hydraulics monitoring system proved critical in helping the drill crews manage the ECD's during drilling and tripping. No completion damage was experienced. Finally the traffic light policy was successfully followed & adhered to during the operations and no undue risk was taken.

Key Learning and The Next Step

This well was unique given the many different aspects to it and hence a substantial amount of learning has been gained within the organization, which has been captured and can be implemented in other wells. Each of the key enablers should be able to open opportunities in other fields.

A process is on-going to identify other opportunities, which perhaps were previously thought undrillable or newly identified. Through tubing operations were clearly shown to help minimize the cost of the operations. Costs could be further reduced with the implementation of coil tubing through tubing drilling.

The aphron based drilling fluid would allow reserves to be accessed by drilling through a depleted reservoir. Not only deepening but sidetracking opportunities where higher pressured fault blocks could be targeted without drilling a new well. The potential also exists to use this fluid where protection of the reservoir is an issue, rather than having to go for the expense of undrbalance drilling or where this technique is not suitable.

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2. Ivan, C.D., Quintana, J.L., Blake, L.D.: "Aphron-Base Drilling Fluid: Evolving Technologies for Lost Circulation Control," SPE Paper No. 71377

SI Metric Conversion Factors

ft	X 3.048	E-01 = meters
gal	X 3.785	E-03 = m^3
in	X 2.540	E-02 = meters
lb	X 4.536	E-01 = kg
ppb	X 2.853	E+00= kg/m^3
ppg	X 1.198	E+02= kg/m^3
ppg	X 1.198	E-01 = Specific Gravity (SG)
bar	X 14.5	E+00= psi

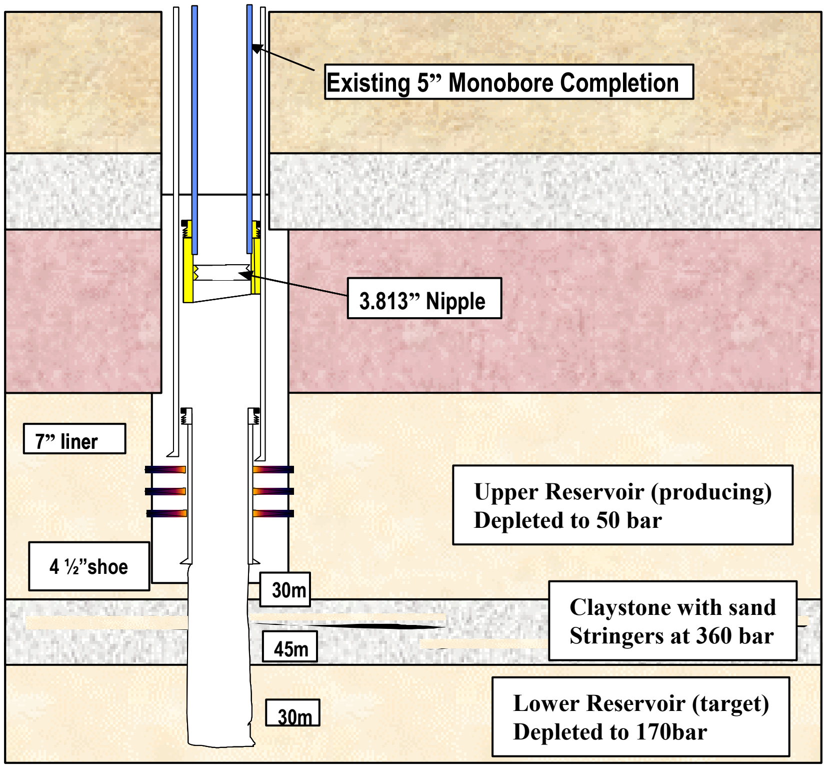

Figure 1. Well Schematic

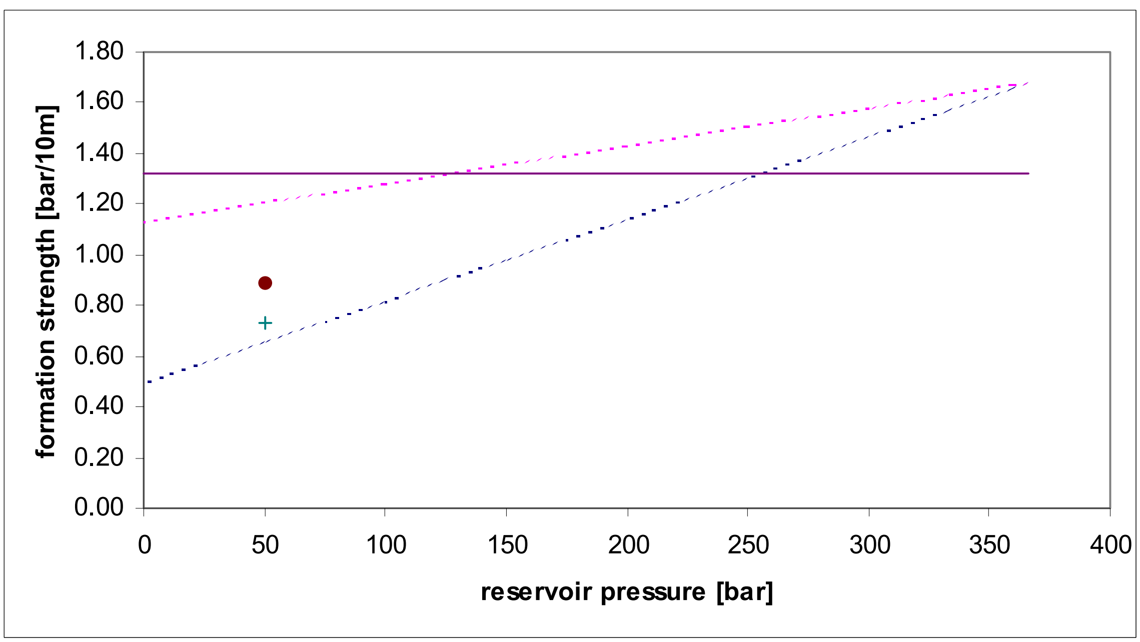

Figure 2. Reservoir Formation Strength vs Reservoir Pressure

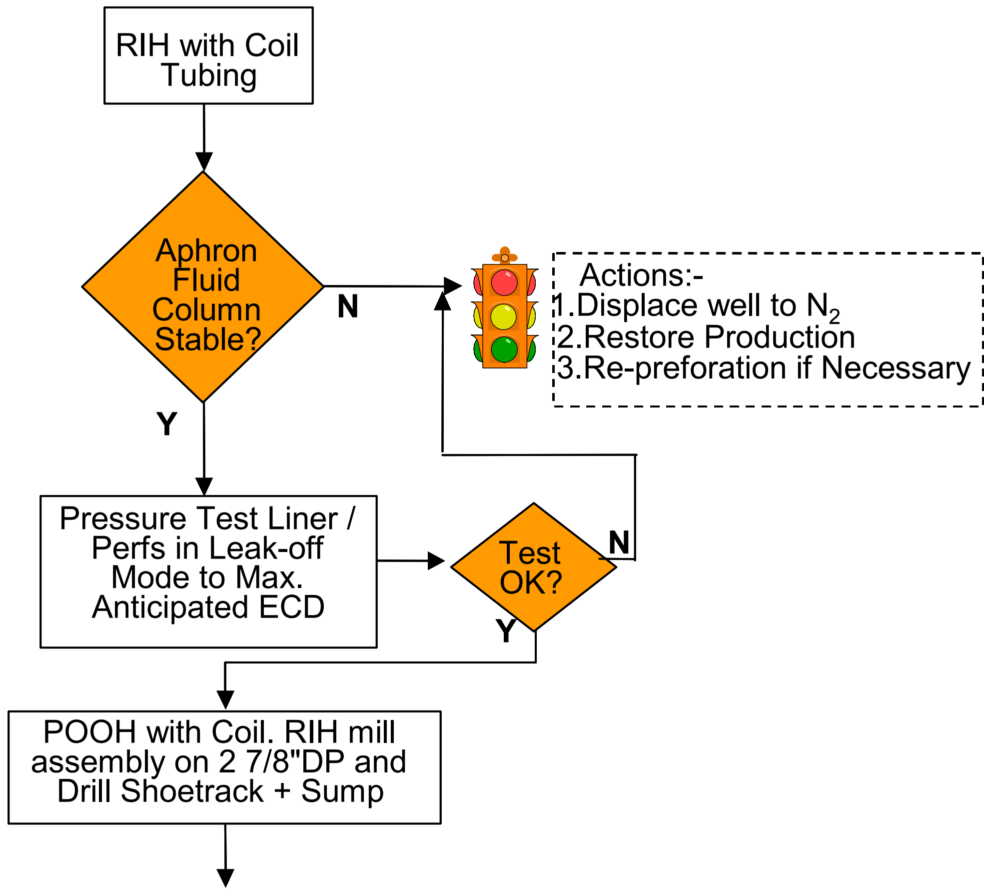

Figure 3. Traffic Light System

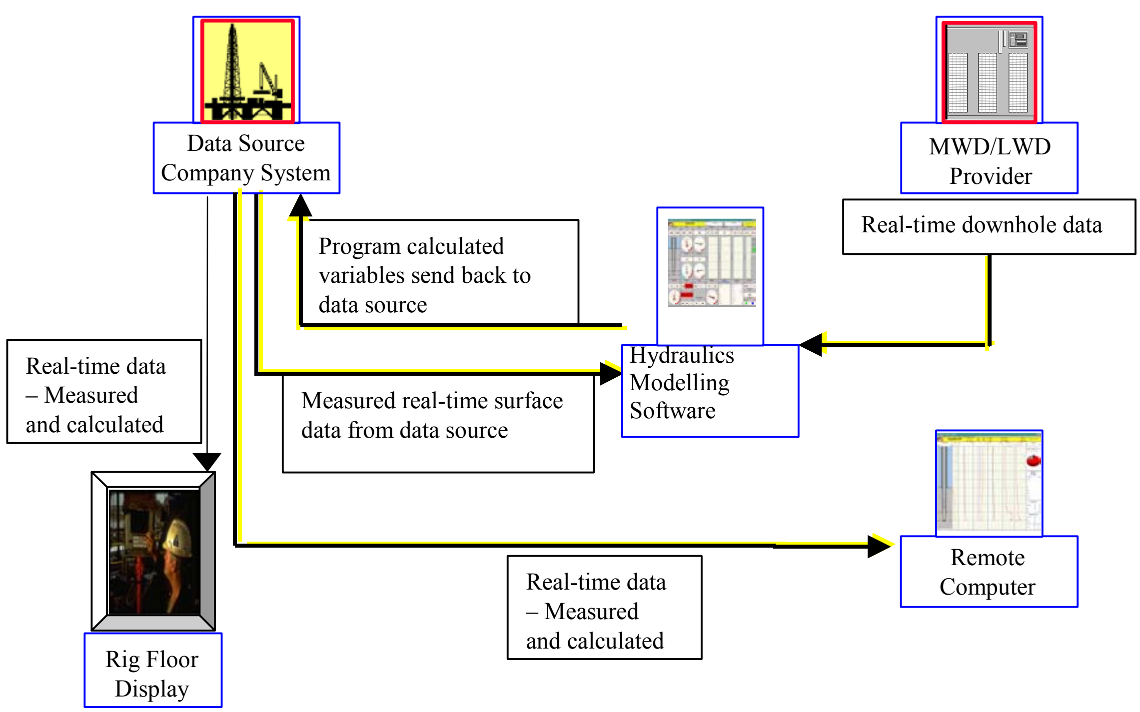

Figure 4. Real time Hydraulics Modeling Software.