



SPE 112442

Continuous Pumping, Multistage, Hydraulic Fracturing in Kitina Field, Offshore Congo, West Africa

Alberto Casero, SPE, and Giamberardino Pace, SPE, Eni E&P; Brad Malone, SPE, and Francois Cantaloube, SPE, Schlumberger; Loris Tealdi, SPE, and Henri Malonga, SPE, Eni Congo; and Rocky Seale, SPE, Packers Plus Energy Services

Copyright 2008, Society of Petroleum Engineers

This paper was prepared for presentation at the 2008 SPE International Symposium and Exhibition on Formation Damage Control held in Lafayette, Louisiana, U.S.A., 13–15 February 2008.

This paper was selected for presentation by an SPE program committee following review of information contained in an abstract submitted by the author(s). Contents of the paper have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Electronic reproduction, distribution, or storage of any part of this paper without the written consent of the Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of SPE copyright.

Abstract

Many West Africa offshore fields are maturing and operators are completing secondary targets in their wells to maintain the economic operation of their valuable assets. Large quantities of reserves can be found in low permeability, consolidated, formations and new techniques are being investigated to improve the economic return of completing these formations.

The Kitina Field, offshore from Pointe Noire, Congo, is one such field. Deeper sands have been produced to economic depletion and the operator is looking for alternative production intervals.

The targeted reservoir is the 3A Sand at approximately 2200 meters TVD. The reservoir is a very heterogeneous lithology with varying quantities of siltstone, sandstone and calcite. The intervals of better porosity show a decrease in clay content, but the good “sands” can be either dominated by quartz or calcite with substantial variations with each meter of height.

Three candidate wells were selected for placing multiple propped fractures using a technique that has been used for six years in North America. This technique utilizes a series of mechanical packers and frac ports that are sequentially shifted “on the fly” allowing continuous placement of more than one hydraulic propped fracture without shutting down the pumping equipment.

During April to June of 2007, eight hydraulic propped fractures were placed in three re-completed, cased-hole wells in the Kitina Field with very encouraging production increases. During the first 90 days of post fracturing production, a production increase of 200% was achieved.

This paper will discuss the steps that were taken to place these propped fractures from an ocean going tender barge using skid equipment and recommendations for the future applications of this stimulation technique.

Introduction

The Kitina Marine offshore field was discovered in 1991 and put on production in November 1997. Originally, the field development considered the three deeper intervals:

- 2A – Limestone,
- 1A – Sand with carbonate cementing,
- 1B – Limestone.

The three reservoirs were developed via a peripheral water injection scheme and a crestal gas injection displacement process. After a quite significant initial rate (around 50,000 BOPD), the field declined quite rapidly. The recovery factors vary between 15% of the 1B reservoir to around 25-30% of the 1A and 2A reservoirs.

The platform has gas lift installed on some of the completions and others produce in natural flow. Production of the platform was 7,000 BOPD prior to the fracture stimulation.

The 3A Sandstone reservoir was initially completed in natural depletion between the end of 2005 and august 2006 via the recompletion of three deeper wells into this shallower and low permeability reservoir (gas lifted wells). The formation permeability to oil is in the range of 2-7 mD. Due to the low permeabilities, during the first year of production, the reservoir 3A oil production potential has been of around 800 BOPD. Their steady-state production was:

- KTM W6 ST – 160 BOPD
- KTM 107 – 130 BOPD
- KTM 111 – 300 BOPD

Level 3A in Kitina field had progressively declining production heading to a marginal-economic scenario. A study was carried out by Eni Congo and Eni E&P with the final objective of re-establishing the reservoir 3A production to a viable economic level (more than 1500 BOPD) without drilling new wells or performing heavy workover operations. Because of the low rates of the three wells producing from the 3A Sand, this target could have been achieved only with a massive hydraulic fracturing operation on all the wells. Therefore the three wells were selected to be treated. Secondly, this was considered an attractive situation for testing new technologies and techniques to build a learning curve applicable in other similar situations opening a wide scenario for further applications in other low permeability reservoir of the Congo Basin. For this reason, different technologies were evaluated and eventually the Continuous Pumping Multi-Stage System (CPMSS) technique was selected.

The CPMSS allows pumping multiple hydraulic fracturing treatments without the need of intermediate operation such as bridge plugs or proppant plugs (run in hole, set, retrieve, and mill or clean) and perforate each interval with multiple TCP or wire-line operations. The CPMSS hardware is a permanent bottomhole assembly that is run and set into the hole after all the interval requiring fracturing treatment has been perforated. This peculiarity allows the placement in the formation of multiple treatments with a continuous pumping operation; the limiting factor is represented by the amount of proppant that can be stored in the silos (or equivalent storage system) and the amount of fluid available.

In conclusion it is possible to pump all the treatments planned in each well in just a few hours which is a substantial time savings. This has the potential to become a remarkable advantage in offshore operation with the rig on location.

Offshore Fracturing Challenges

The petroleum industry has made a well documented effort to improve the production of laminated pay intervals with the use of fracturing^{2,8,9}. The large volume of data provides significant support for hydraulic propped fracturing to improve the well deliverability from laminated pay intervals by improving the poor vertical communication due to negligible vertical permeability.

The industry has also discussed, in much detail, the benefits of placing multiple fractures into a wellbore. These papers are usually discussing this application in horizontal wells where a single reservoir is drilled and stimulated multiple times from the same wellbore^{3,6,10}.

Hydraulic propped fracturing of consolidated formations is not new to West Africa reservoirs. During the early 1980's, hydraulic fracture stimulations had been performed in Gabon from a dedicated stimulation vessel. Both gelled water and gelled oils were used to place sieved sand and man-made proppants into laminated sandstone intervals in a large field of similar characteristics of the Kitina Field in Congo⁴.

In 1991, three prop fractures were performed with good economic success in the Takula Field of Cabinda, Angola¹. A detailed paper was written to discuss the philosophy and methodology of fracturing low permeability, thick, heterogeneous, offshore intervals in the N'Dola Field of Cabinda in the 1998 time frame. The authors describe their methods for placing multiple fractures into a well lithology that is similar to many fields in West Africa from Gabon to Angola.

The work in Cabinda has evolved into placing two or three hydraulic propped fractures into these slanted wellbores in the interest of connecting as much of the laminated pay as possible to the wellbore. A very large single fracture was not effective at growing through all the intervals of interest and then producing through bi-linear flow into a narrow contact area with the wellbore due the limited perforation interval required for fracture execution in deviated cased hole wells.

In late 2006 and early 2007 it was decided by the operator and partners of the Kitina Field of Congo to investigate propped fracturing several selected candidates from their existing wells. These candidate wells were cased and perforated. Some of the wells that were considered as candidates had continuous perforations over the entire interval and others had individual sand bodies perforated with breaks between perforations.

A selected technique would have to isolate each interval and stimulate individual sands. One technique of interest that is being used in North America for vertical to horizontal wells also had the benefit of being a continuous pumping placement system^{7,12}. This type of tool application had been successfully used for the first time offshore during late 2006/early 2007 in neighboring Gabon, West Africa and it was decided to use this technique on a few selected candidates in the Kitina Field.

Physical limitations of fracturing offshore

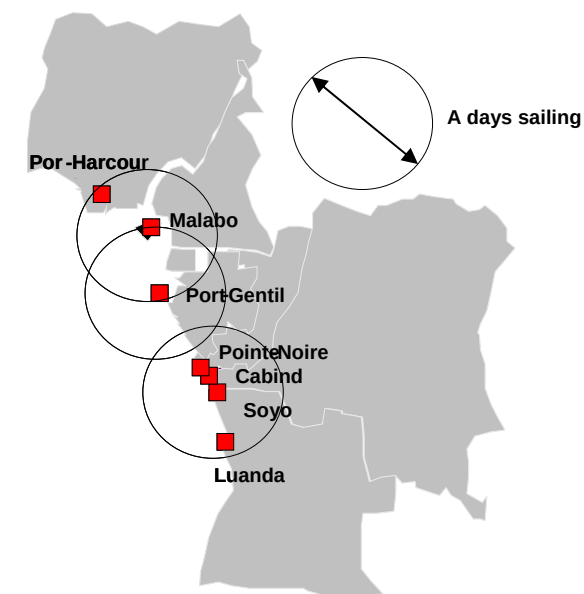
There are many limitations to fracturing offshore that may not be an issue on land. The following is a partial list:

- Space limitations
- Weight/area restrictions
- Flow back of hydrocarbons and solids
- Sea conditions
- Location / remoteness / access
- Available marine and stimulation equipment resources
- Mobilization expense for all rig and stimulation equipment
- Crane availability of the dock and the rig/platform
- High expense to re-mobilize to correct sanding issues

A dedicated stimulation vessel with an experienced crew always looks very attractive and it would be expected to be the most efficient approach, but in times of high utilization of oilfield service equipment, these vessels are in very high demand and there is a risk that they may not be available when the completion calls for them. The very large area of West Africa stretches the capabilities of the existing vessels that are in the theater of operations to reach a rig in a timely fashion. A vessel sailing from Nigeria will take 2.5-3 days to reach this rig work in Congo (See Figure 1). Each country is its own sovereign nation as well, so time must be allotted for customs clearance upon arrival and for departure from each country visited.

The required frac equipment to perform this work would take up too much space on most, if not all rigs and platforms of the industry, hence that is eliminated as an option. Placing skid equipment on the deck of a service vessel was evaluated and it is a relatively common practice⁵ that is occurring in many marine operation areas. Just as stimulation vessels are in high demand, so are service vessels. A large fracturing treatment would require a large service vessel of 600 m² deck space or larger. Sub systems of the vessel are used for air transfer of proppant. Below deck pumps and tanks are used for mix water and mixed gel storage. Therefore, the selection of the vessel and the access for cleaning these tanks and lines would be critical.

Figure 1 – Sailing time West Africa



Another option that was considered and chosen to pursue was to place the skids on the deck area of the large platform tender rig support barge, the Barracuda. (**Figure 2**). The rig-up is comfortably placed on ~1200 m² of open deck space. All the equipment on the single level of the deck was adequate to perform the stimulation treatments except the additional use of 1500 bbls (240 m³) of the tender pit systems located directly below the blender system that held additional quantities of pre-blended gel.

The selection of the Barracuda (See Schematic 1 below) as the work platform and the use of skids then will put certain criteria in motion of the abilities and the limitations that control the execution of the fracture stimulation. A fracture design and sequence of operations must then be built around the given set of equipment, capabilities and available crew.

The major reasons for selecting the skids on the floating barge were:

- Captive pumping package that would be available as soon as the rig was ready for stimulation.
- Up front costs of the skid equipment is lower than using a dedicated stimulation vessel.
- The anchored and moored barge reduces risk of a weather interruption when pumping is initiated.
- Unavailability of either a dedicated stimulation or service vessel.
- Rig support barge was required to re-complete the well.

Figure 2 – Frac Equipment on Barracuda Tender Barge



This rig-up on the Barracuda gave us the capability of having access to 2,500 bbls (400 m³) of gelled fluid, 150,000 pounds of proppant in two gravity silos feeding the blender and another 100,000 pounds pneumatically delivered (depending on timely transfer) to the gravity silo. 5,600 HHP of four fracturing skid pump were rigged up and available for these treatments planned to be pumped at 20-30 barrels per minute. A freshwater based, batch mixed fluid was utilized with this volume of fluid storage.

Fracturing Application to Kitina Field

There has been a search ongoing for decades to improve the efficiency of fracturing horizontal wells ever since it has been identified that horizontal well production can be improved by fracture stimulation^{11,13}. One of the last approaches that have been developed was to use a system that becomes a permanent completion liner. This system is a series of external, mechanical element packers that can be screwed to the deployed liner in strategic places for isolation. Between each of the packers is a sliding sleeve referred to as a frac port. The use of the packers allows the wellbore to be segmented into selected areas for stimulation. Packers of a specified size can be used in either cased hole to straddle perforations or in open hole wellbores to segment that type of completion.

The method of selectively opening the frac port is to drop progressively larger diameter ceramic balls that land on a beveled seat below each of the ports. The seating ball allows sufficient pressure to be applied to create a down force that will

shift the sleeve to the open position while isolating the previously placed fractures of the ports at deeper depths.

There are several theoretical benefits of using this continuous pumping, multi-stage system. Many of these have been realized on land operations and our attempt was to carry these benefits to a marine well. Some of them are:

- With adequate bulk capacity, all stimulation can be done in hours instead of weeks
- Quicker fluid recovery due to the short time for the injection process
- Reducing rig costs may encourage additional fracturing treatments for enhanced stimulation of the well
- The sliding sleeves will allow interval isolation at a later date

The technique has been previously applied for the first time on a marine well in Gabon, six months previously. The four wells were that fractured in Gabon, were three open-hole completions and one cased-hole completion.

Fracturing Execution of Offshore Kitina Fractures

Kitina Marine W6 ST

The first candidate well was KTM W6 ST. This well has 7" 29 ppf L-80 cemented liner run from 1,600 – 3,110m. The well was a re-completion from a lower interval. The intervals of interest for fracturing were in the 3A Sandstone. These perforations had been placed on gas-lift production in August of 2006 until the time of the workover to fracture the perforations in April 2007.

This well was perforated in three intervals from;

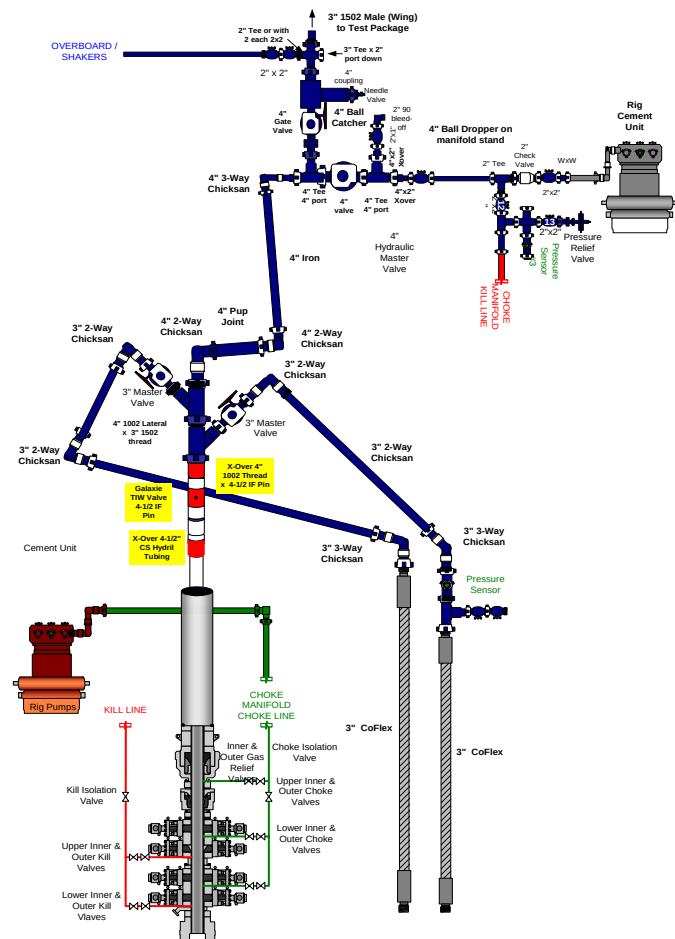
- 2,785m – 2,810m, (2,099m – 2,111m TVD), 4.5" Guns, Big hole charges, 12 jspf, deviation 62.1°
- 2,820m – 2,865m (2,115.3m – 2,135.3m TVD), 4.5" Guns, Big hole charges, 12 jspf, deviation 63.2°
- 2,870m – 2,910m (2,145.4m – 2,157.6m TVD), 4.5" Guns, Big hole charges, 12 jspf, deviation 64.5°

New perforations were added in 2 meter groups to each of the well perforation sets in the interested of reducing the risk of a screen-out caused by tortuosity, prior to running the packer assembly into the well.

The packer assembly (**Schematic 2**) is run to depth to allow the packers to straddle the three perforated intervals. This assembly is run on 4-1/2" 12.75 ppf tubing as a production liner assembly. The setting tool is then pulled from the well and a

fracturing seal assembly is then run into the well and landed in the sealbore of the liner hanger packer. The tubing annulus was then isolated with the Blow Out Preventors (BOP) at the surface. During the fracturing treatment, annulus pressure was maintained by a rig pump and the pressure is monitored by both the rig crew and the fracturing control monitoring system. A 4" master valve was placed on the frac work string as tubing isolation as well as valves in the treating equipment lines of the frac spread (Schematic 3).

Schematic 3 – Wellhead Configuration



When the production liner assembly is run and set, all the sleeves and access to the perforations are closed. The initial fracture port is opened with pressure differential. All remaining intervals are manipulated using a ball which also acts as isolation for any fractured intervals located below the targeted interval. After the initial frac port is opened hydraulically, each sequential port is opened with a ball sized specifically to a seat made for that particular ball size.

Injection Test

The initial steps of this fracturing operation were to pump several pre-frac injections for diagnostic purposes. The annulus pressure was increased to 1,000 psi and then the tubing pressure was increased until the hydraulic fracturing port was opened, exposing the lower most perforated interval. This fracture port opened at 4,500 psi surface pressure as designed.

A Step Down injection test was then performed to evaluate the near wellbore perforation and tortuosity restrictions that may exist. Linear gel was pumped at rates from 25 bpm down to 12 bpm and then the shut-in pressure was monitored for 60 minutes.

The formation breakdown pressure was observed at approximately 2000 psi on the surface. The total measured friction observed at 20bpm was 500 psi. 100 psi was allocated to the perforations and 265 psi was attributed to tortuosity.

Calibration Test

The next test performed was a 325 bbl injection of a 35 pound gel loading delayed borate crosslinked gel. This was pumped at 20 and 25 bpm. The pressure decline post shut-in was observed for 60 minutes.

Frac Design

Based on the pre-job Step Down Test and the Calibration Test the fracturing parameters were adjusted in the Pseudo three dimensional fracture models. A summary of each of the wells is listed in **Table 1**.

Propped fracturing execution of frac ports 1 and 2 followed later by frac port 3

The KTM W6 ST was the first well to be fracture stimulated on the Kitina platform on April 13, 2007. The stimulation liner assembly was run into the hole on 4-1/2" tubing and set across three perforated intervals. During the treatment of the bottom and middle zones were fractured stimulated without shutting down the pumps.

100,756 lb of 20/40 Intermediate strength, light-weight, ceramic proppant (ISP) was placed in the lower-most interval and 106,154 lb of 20/40 ISP was placed into the middle perforated interval. A frac ball was launched immediately upon starting the flush of the first fracture. This allowed the lower fracture to be isolated and opened the fracture port of the second interval. **Figure 3** shows the responding data of these two fractures being placed.

You will notice that two proppant slugs were pumped in the pad fluid of fracture number 1. A proppant slug was late in being delivered on fracture number 2. The pumping rate is consistent at 20 bpm until the rate is reduced to have a controlled launch of the frac ball on the surface and then again when the ball is calculated to land at the fracture port. The placement time of two discrete propped fractures was 123 minutes.

As explained earlier, the volume of the equipment on this rig-up required that the proppant silos and the gel had to be re-loaded after the initial two fractures. It had been planned to shut-down after the initial two fractures and then continue pumping after these preparations had been done. Unfortunately the top frac port was opened, but had received sand fill, causing the annular area to be filled with proppant, making it impossible to place the third fracture through the port. Perforations were shot through the stimulation liner and the third fracture (see **Figure 4**) was placed via these new perforations. A new step was added prior to shutting down on these multi-phase fractures, the port must be opened and the fracture initiated by pumping a non-proppant laden fluid into the open port prior to shutting down. This assures that the fracture port is open and ready to accept the next proppant stage.

Kitina Marine 111

The second candidate well was KTM 111 and this well had three intervals that were to be fractured. This well has tapered production casing of 10.75" 55.5 ppf L-80 and 9-5/8" 53.5 ppf L-80 string set at 2,496m and was perforated in one continuous interval:

2,240m – 2,320m, (2,120m – 2,151m TVD), 7" Guns, Deep Penetrators charges, 8 jspf, deviation 24°

The fracturing packers were placed in the perforations to break up the well bore into three intervals. No additional perforations were added in this completion that was shot with 8 jspf of Ultra Deep Penetrating perforations.

The fracturing assembly was run on 4-1/2" 12.75 ppf tubing as a production liner assembly. The setting tool was then pulled out from the well and a fracturing seal assembly was then run into the well and landed in the 10 feet long seal bore of the liner hanger packer. The tubing annulus was then isolated with the Blow Out Preventers (BOP) at the surface. The fracturing procedure is similar to KTM W6 with the annulus pressure maintained by the rig pump and monitored with both the rig and the frac control unit.

The Packers and frac ports on this well can be found on completion (See **Schematic 4**).

Propped fracturing execution of frac ports 1 and 2 followed by frac port 3

The procedure was similar on this well with a mini fall-off test followed by a step rate, a step down and calibration injection pumped prior to the first prop fracture. The volumes were slightly adjusted based on the initial data from the diagnostics testing.

The fractures of the lower and middle intervals were pumped on May 17th 2007. 94,105 lb of 20/40 ISP was placed in the lower-most interval and 91,528 lb of 20/40 ISP was placed into the middle perforated interval. A frac ball was launched immediately upon starting the flush of the first fracture. This allowed the lower fracture to be isolated and opened the fracture port of the second interval. **Figure 5** shows the responding data plots of these two fractures being placed. The second fracture was followed by a second, larger, frac ball that opened the port of the third frac and isolated both the intervals that were fractured below. This interval was overflushed with brine by 100 barrels to be sure the fracture port was open and clear to allow fracturing of that interval after the proppant and gelled fluids were prepared. This overflush acted also as an additional injection test on the upper level.

The third fracture treatment was placed three days later with 178,802 pounds of 20-40 ISP placed into the fracture (See **Figure 6**). The treating and pressure plots of all three fractures are shown with post frac pressure matching performed to arrive at the post fracture interpretations of the fracture properties.

The data as interpreted from the data pumping segment of the treatment is listed on **Table 2**.

Kitina Marine 107

The third candidate well was KTM 107 and this well also had three intervals but the lowermost perforations were close to an Oil Water Contact so it was decided that the lowermost perforations would have a packer above the lower perforations, the port opened, but the interval would not be fractured.

This KTM 107 well was completed with a 7" 29 ppf, C-75 liner from 2,425m-3,032m. The 9-5/8" 53.5 ppf, L-80 casing extended down to 2,580m.

This well was perforated in one continuous interval:

2,454.5m – 2,565m, (2,143m – 2,151m TVD), 4-1/2" Guns, Ultra Deep Penetrators charges, 5 jspf, deviation 51.4°. Thus the fracture would have to be placed through both the 7" and the 9-5/8" casing strings that were cemented in place.

The isolation packers were placed in the perforated intervals at 2,515m to isolate the bottom perforations. Another packer was placed at 2,471m, which separated the upper perforations into two intervals. The production liner top packer was at 2,434m, only 9 meters below the 7" liner top.

The fracturing assembly was similar on all the wells. The base pipe of the fracturing liner is a 4-1/2", 12.75 ppf tubing placed between all the packers and the fracturing ports. The setting tool was used to place the assembly on bottom and then pulled from the well. A fracturing seal assembly was then run into the well and landed in the sealbore of the liner hanger packer. The tubing annulus was then isolated by closing the Blow Out Preventers (BOP) at the surface.

The Packers and frac ports on this well can be found on completion **Schematic 5**.

This procedure was different since the lower interval was to be opened for production, but not fractured. The lower most port was opened with hydraulic pressure and then an isolation ball was dropped and slowly pumped down to land in the seat and open the middle frac port. This was successfully accomplished and then a mini-frac was performed on the middle perforations of this well.

The data as interpreted from the data pumping segment of the treatment is listed on **Table 3**.

Propped fracturing execution of Frac Port 2

The fracture of the middle intervals occurred on June 9, 2007 and was performed as expected and placed the designed 99,000 pounds of ISP into the middle interval. The last minute of the displacement did not go as planned. See **Figure 7**.

As stated earlier, in an operation such as using skids that do not have adequate volumes to pump multi-stage fracture treatments, a ball must be landed and the fracture port opened and overflushed to allow time for the re-stocking of proppant and gel. In this case when the ball landed, the fracture port opened, but the top fracture port sanded off within seconds of the ball landing on the port.

This could be caused by two mechanisms that were both possible in this well.

1. Proppant behind the fracturing ball would be the first placed into the new perforations before adequate pad would open a fracture.
2. There was communication behind the casing, placing proppant into the "open" 7" x 4-1/2" annulus which would also block the perforations.

An evaluation of the procedure for dropping the frac ball was done and it was determined that the ball was dropped into the treating line when it was planned. Further investigation determined that it is a somewhat known, but obscure and not documented occurrence the frac balls are subject to gravity, even when being pumped at high rates down fracture tubing. If a calculation of the force of gravity is performed on the ball, it is found that it could be possible for the 1.25 Specific Gravity ball to advance 4-6 bbls in the 1.03 SG fracturing fluid. Instead of the ball being behind several barrels of clean frac fluid, it is theorized that the ball would instead have 2-3 barrels of slurry behind the ball. When the ball lands and opens the frac port, a slurry of 8 ppa proppant in the first fluid to enter the annulus and cause a screen-out of the perforations.

This phenomena has not been a serious issue in North America as the spacing of the fracturing ports is normally 150 meters or more and more flush can be placed in front of the ball before it is launched without over-flushing the previous propped fracture. The annulus area we were dealing with was also very small. It would take very little proppant to cause an issue in an annulus with only 2.2 bbls of annular area in this cased hole.

The other possible explanation for the screen-out was also possible as it was determined the quality of the cement bond in the very top of the 7" liner top was somewhat suspect. It was possible that there was communication around the single packer that was set in the perforations.

An indication that significant proppant had been placed into the annulus, more than would have been behind the ball, was that attempts to clean this top frac port kept producing proppant upon each attempt to clean the interval.

Eventually it was decided to move forward with the completion and the 4-1/2" production liner was perforated with a short interval of large diameter charges.

The top interval received a mini-fracture to be certain that we could place the proppant, now through perforations in three strings of casing. The 20/40 mesh intermediate strength proppant had to pass through the 4-1/2", 7" and the 9-5/8" casing.

Eight days after the initial propped fracture, a mini-frac with a step down was pumped. It was determined that the well was behaving normally and a pumping schedule was created. 133,000 pounds of proppant was placed at 20 bpm. See **Figure 8**.

Production Results and Post Frac analysis

The production of the reservoir 3A prior to the fracturing campaign was of around 600 BOPD. The following production increases were realized with the improved fractured production (**Table 4**):

WELL NAME – num. frac – reservoir – permeability	Q oil PRE-FRAC [BOPD]	Q oil initial POST FRAC [BOPD]	Q oil steady- state POST FRAC [BOPD]	DELTA steady state [BOPD]
KTM-W6 (3 fracs) Kitina 3A (10 md)	160	2100 (x 10)	600 (X3)	+ 400 BOPD
KTM-111 (3 fracs) Kitina 3A (10 md)	300	900 (x 3)	650 (X2)	+ 350 BOPD
KTM-107 (2 fracs) Kitina 3A (10 md)	130	1000 (x 7)	700 (X4)	+ 550 BOPD

Table 4 – Pre and post frac production results

An overall steady-state increase (after 90 days) for these three wells from 600 to 1950 BOPD for a Fold of Increase (FOI) of 3.3 (+230%) (**Figure 9**). A further production decline is expected. However, stabilization to a long term FOI of 2-2.5 is foreseen.

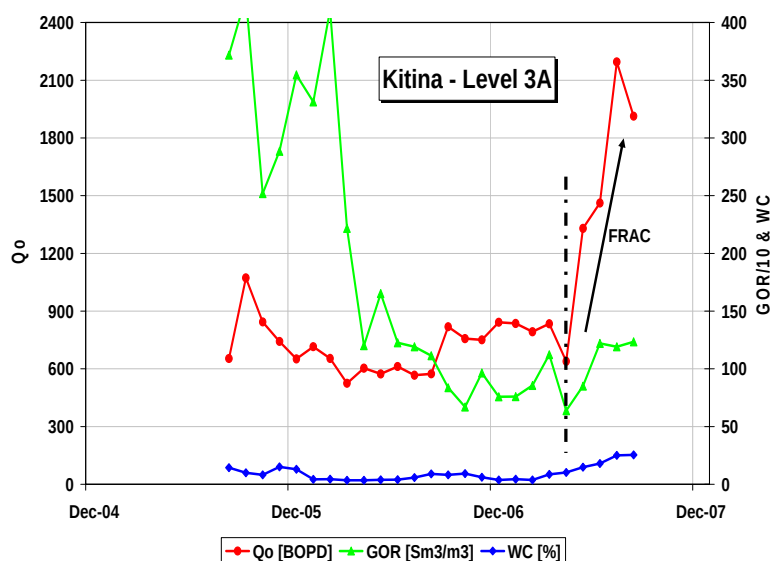


Figure 9: Reservoir 3A – pre and post frac production performance

Conclusions

Despite the difficulties encountered on two of the three wells treated, the continuous pumping multi-stage system proved to be an excellent technology to simplify multi-fracturing operation. It is also to be clear that to a certain extent some of the “failures” we had on the first and the third well are not definitively related to the system that is un-reliable, but to the specific conditions of Kitina application.

In Kitina’s wells the CPMSS was applied in an operative scenario that was not the optimum. In other words, the system was used to the limit of its capabilities (very short frac port distance) and not exactly in the “continuous pumping” way in which it was designed for. These two specific conditions had not been chosen, but imposed by the fact that the wells were already drilled, perforated under a different completion strategy. The well completion strategy to use CPMSS and the availability of a proper stimulation vessel would be able to deliver the even better optimization of the multi-frac completion.

Nevertheless, even the delays encountered on the two wells did not prevent the ability to achieve the original goal of pumping all the fracture treatments planned as designed. This turned out to be an alternate advantage of CPMSS: flexibility and the possibility to have easy alternative solutions to modify the completion at the rig site in case of situations such as the ones faced on Kitina.

Kitina KTM111, the second well treated, is the near perfect example showing the capabilities of this system with two treatments and an injection test continuously pumped. This was followed by a third frac that was only delayed due to rough weather for cutting proppant at sea.

Post treatment production performance showed a Folds of Increase after 90 days from the treatment ranging between 2 and 4 for each well and met the expectations set at the beginning of this endeavor. In such time-frame, the reservoir 3A of Kitina passed from a potential of around 600 BOPD to around 1900 BOPD.

The future objective are to apply the CPMSS in an open-hole sub-horizontal well designed and drilled for this application in another Congolese offshore field.

In general, CPMSS is considered an excellent completion strategy for horizontal wells, not only for tight gas or shale gas reservoir, but also for low permeability oil reservoirs.

Acknowledgements

The authors would like to thank the following for permission to present this data: Oil Ministry of Republic of Congo, Eni E&P, ENI Congo, Chevron Congo, S.N.P.C., Schlumberger and Packers Plus Energy Services.

We'd also like to thank Asibor Ehizokhale, Noe Hurtado and Reda Tarabet for their on site and post job analysis of the pressure data.

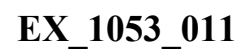
We would also like to express our gratitude to the excellent cooperation and support from the personnel of the Pride Barracuda.

References

1. Bagzis, J.M., et al: "Optimized Hydraulic Fracturing Improves Oil Production in the N'Dola Field, Offshore Angola," SPE 49108 presented at the 1998 Annual Technical Conference and Exhibition held in New Orleans, LA, USA, 27-30, September 1998.
2. Barba, R.E. and Shook, R.A.: "Post Frac Evaluation of Multiple Fracture Treatments Using the "Completion Efficiency Concept," SPE 90483 presented at the 2004 Annual Technical Conference and Exhibition held in Houston, TX, USA, 26-29, February 2004.
3. Butter, M., East, L, and Kuvshinov, I.: "Post Frac Evaluation of Multiple Fracture Treatments Using the "Completion Efficiency Concept," SPE 102633 presented at the 2006 SPE Russian Oil and Gas Technical Conference and Exhibition held in Moscow, Russia, 3-6, October 2006.
4. Internal Documents.
5. Jain, S. et al, "Case Study from 12 Successful Years of High Temperature Fracturing in Bach Ho Field Offshore Vietnam," SPE 106712 presented at the 2007 SPE Production and Operations Symposium held in Oklahoma City, OK, USA, 31 March 3 April, 2007.
6. Lietard, O., Ayoub, J., Pearson A.,: "Hydraulic Fracturing of Horizontal Wells: An Update of Design and Execution Guidelines," SPE 37122 presented at the 2nd International Three-Day Conference and Exhibition on Horizontal Well Technology held in Calgary, Alberta, Canada, 18-20, November 1998.
7. Lohoefer, D., Athans, J. and Seale, R.: "New Barnett Shale Horizontal Completion Lowers Cost and Improves Efficiency," SPE 103046 presented at the 2006 Annual Technical Conference and Exhibition held in San Antonio, TX, USA, 24-27, September 2006.
8. Neumann, L.F., et al: "Case Study of Multiple Hydraulic Fracture Completion in a Subsea Horizontal Well, Campos Basin," SPE 98277 presented at the 2006 SPE International Symposium and Exhibition on Formation Damage Control held in Lafayette, LA, USA, 15-17, February 2006.
9. Rodrigues, V.F., et al: "First Applications of a Multiple Fracturing in Noncemented Horizontal Offshore Wells," SPE 94583 presented at the SPE Latin American and Caribbean Petroleum Engineering Conference held in Rio de Janeiro, Brazil, 20-23, June 2005.
10. Rodrigues, V.F., et al: "Horizontal Well Completion and Stimulation Techniques – A Review With Emphasis on Low-Permeability Carbonates," SPE 108075 presented at the SPE Latin American and Caribbean Petroleum Engineering Conference held in Buenos Aires, Argentina, 15-18, April 2007.

11. Seale, R., Athans, J. and Themig, D.: "An Effective Horizontal Well Completion and Stimulation System," SPE 101230 presented at the 2006 Abu Dhabi International Petroleum Exhibition and Conference held in Abu Dhabi, UAE, 5-8, November 2006.
12. Seale, R., Donaldson, J. and Athans, J.: "Multistage Fracturing System: Improving Operational Efficiency and Production," SPE 104557 presented at the 2006 Eastern Regional Meeting held in Canton, OH, USA, 11-13, October 2006.
13. Seale, R., Themig D. and Athans, J.: "Effective Stimulation of Horizontal Wells - A New Completion Method," SPE 106357 presented at the 2006 SPE Technical Symposium of Saudi Arabia Section held in Dhahran, Saudi Arabia, 21-23, May 2006.

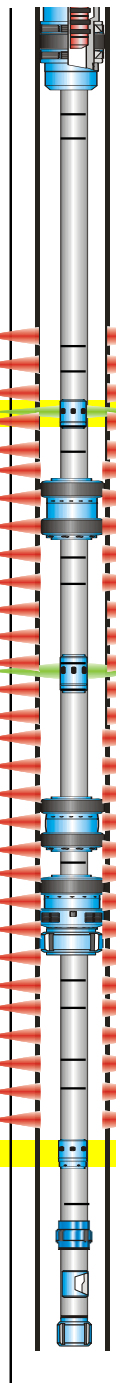
IWS EXHIBIT 1053



Schematic 2 - KTM W6 ST Final Packer Schematic

2764.94 RKB		←	7" Permanent Packer	5.75"	5.25"	
CE @ 2768.38 RKB 60°Deg		←	4-1/2" L-80 CS Hydril Tubing	4.50"	3.95"	
		←	7" 29 ppf C-75 Production Casing			
Perfs @ 2785.0 RKB 2810.0 RKB						
Fracport @ 2801.23RKB		←	3.25" Ball	5.75"	3.00"	
		←	4-1/2" L-80 CS Hydril Tubing	4.50"	3.95"	
CE @ 2815.73 RKB		←	7" x 4-1/2" Cased Hole Hydraulic Packer	5.75"	3.75"	
Perfs @ 2820.0 RKB 2865.0 RKB	←	4-1/2" L-80 CS Hydril Tubing	4.50"	3.95"		
FracPort @ 2861.30 RKB	←	3.00" Ball	5.75"	2.75"		
CE @ 2865.48 RKB	←	7" x 4-1/2" Cased Hole Hydraulic Packer	5.75"	3.75"		
CE @ 2867.62 RKB	←	7" x 4-1/2" Cased Hole Packer	5.75"	3.75"		
	←	4-1/2" L-80 CS Hydril Tubing	4.50"	3.95"		
Perfs @ 2870.0 RKB 2910.0 RKB						
FracPort @ 2909..85 RKB	←	4-1/2" Hydraulic FracPort	5.75"	3.95"		
Cir.Sub.@ 2913.30 RKB	←	4-1/2" Toe Circulating Sub	5.50"	N/A		
	←	4-1/2" Single Valve Float Collar	5.00"	N/A		
Tub.Bot.@ 2916.82 RKB	←	4-1/2" Bullet Re-Entry Guide	5.50"	3.95"		
		PBTD =2982.0 MD TVD =2181.0 MD 67 Deg.				

Schematic 4 - KTM 111 Final Packer Schematic

Top @ 2213.66 RKB CE @ 2217.09 RKB 23 Deg		9.625" x 5.25" Permanent Packer	7.75"	5.25"
		4-1/2" L-80 CS Hydril Tubing	4.50"	3.95"
3.0" FracPort @ 2249.13 RKB		4-1/2" Re-Closeable FracPort 3.00" Seat For 3.25" Ball	5.75"	3.00"
CE @ 2254.27 RKB		9-5/8" x 4.5" Cased Hole Hydraulic Packer	7.75"	3.75"
		4-1/2" L-80 CS Hydril Tubing	4.50"	3.95"
2.75" FracPort @ 2276.72 RKB		4-1/2" Re-Closeable FracPort 2.75" Seat For 3.00" Ball	5.75"	2.75"
CE @ 2300.15 RKB		9-5/8" x 4.5" Cased Hole Hydraulic Packer	7.75"	3.75"
CE @ 2304.34 RKB		9-5/8" x 4-1/2" Cased Hole Packer	7.75"	3.75"
Hyd. FracPort @ 2320.00 RKB		4-1/2" Hydraulic FracPort	5.75"	3.95"
Cir. Sub. @ 2321.7 RKB		4-1/2" Toe Circulating Sub	5.50"	N/A
		4-1/2" Single Valve Float Collar	5.00"	N/A
Tub. Bot. @ 2323.5 RKB		4.5" Bullet Re-Entry Guide	5.50"	3.95"
PBSD = 2153.0MD TVD = 2325.0 MD 23 Deg.				

Schematic 5 - KTM 107 Final Packer Schematic

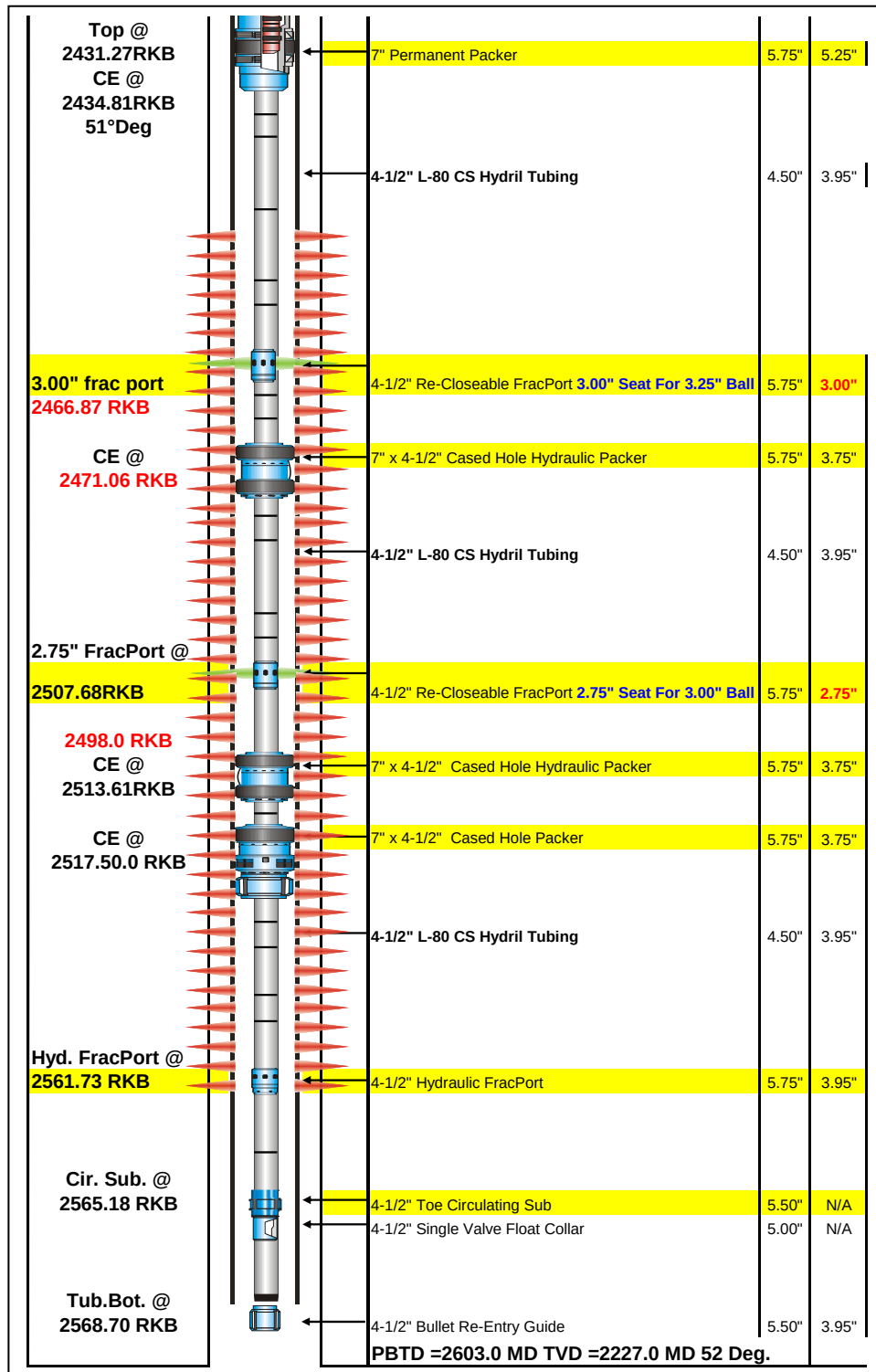


Table 1 - KTM W6 ST Fracturing Data

	Lower Interval Pre-Job	Lower Interval Post-Job Pressure Match	Middle Interval Pre- Job	Middle Interval Post- Job Pressure Match	Upper Interval Pre-Job	Upper Interval Post-Job Pressure Match
Pad Volume Clean Fluid, %	50	52	50	47	43	44
Interval Gross Height, m	17.3	17.3	20.3	20.3	17.3	17.3
Interval Net Height, m	17.3	17.3	20.3	20.3	17.3	17.3
Interval Leak-Off Height, m	17.3	17.3	20.3	20.3	17.3	17.3
Closure Gradient, psi/ft	0.696	0.675	0.696	0.675	0.673	0.673
Closure Pressure, psi	4750	4750	4750	4750	4645	4750
Young's Modulus, psi	3.4e+06	3.4e+06	3.4e+06	3.4e+06	3.49e+06	3.49e+06
Toughness, psi/sq in	1000	1000	1000	1000	700	700
Ct Leakoff Co- efficient, ft/min E0.5	2.9e-3	3.0e-3	2.9e-3	3.0e-3	7.9e-2	3.2e-3
Fluid Efficiency, %	26	37	26	23	28	22
Pump Rate, bpm	20	20	20	20	20	20
Propped Fracture Wing Length, ft	57	44.8	62	64.5	62.8	61.6
Avg Propped Width, in	0.15	0.18	0.13	0.136	0.2	0.136
Eff. Conductivity	4780	3106	5464	2514	8648	5908
Effective Fcd	+30	+30	5.3	2.4	8.4	5.8
Proppant Volume, pounds	100,500	100,756	100,500	106,154	180,000	161,000
Total Gel Pumped (Pad+Carrier) bbls	1079	986	1084	1104	1624	1222

Figure 3 - KTM W6 ST Fracturing Execution of the Lower and Middle Prop Fractured Intervals

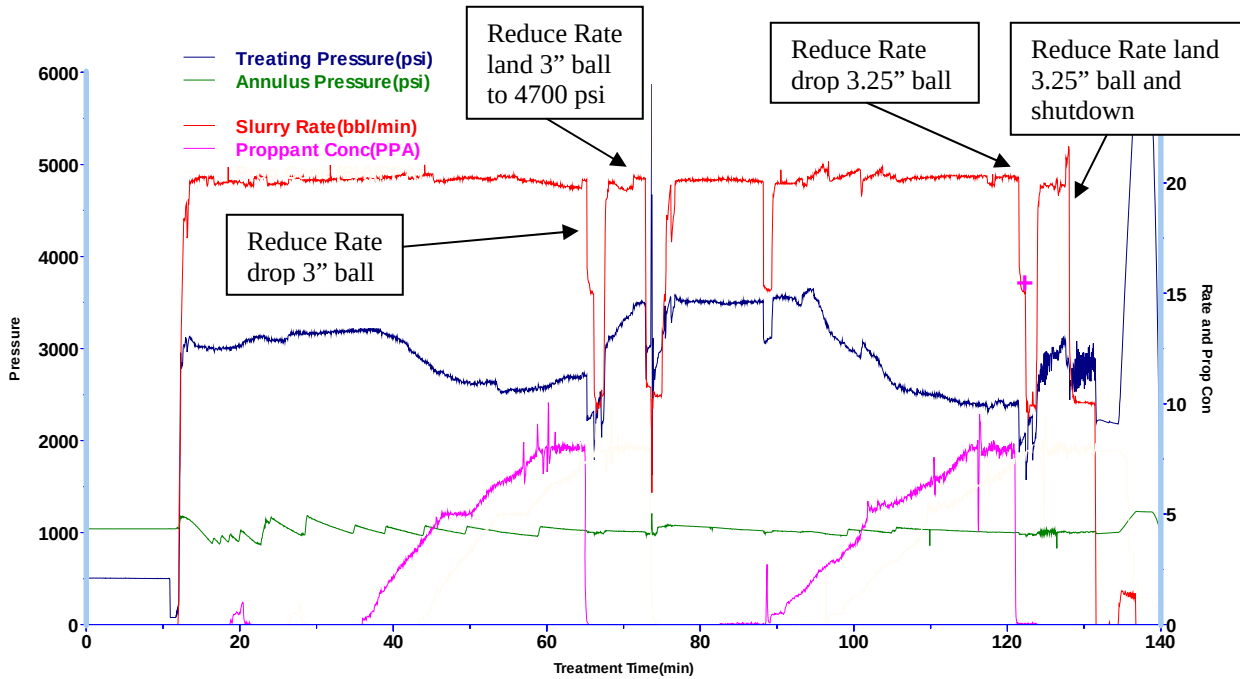


Figure 4 - KTM W6 ST Fracturing Execution of the Upper Interval

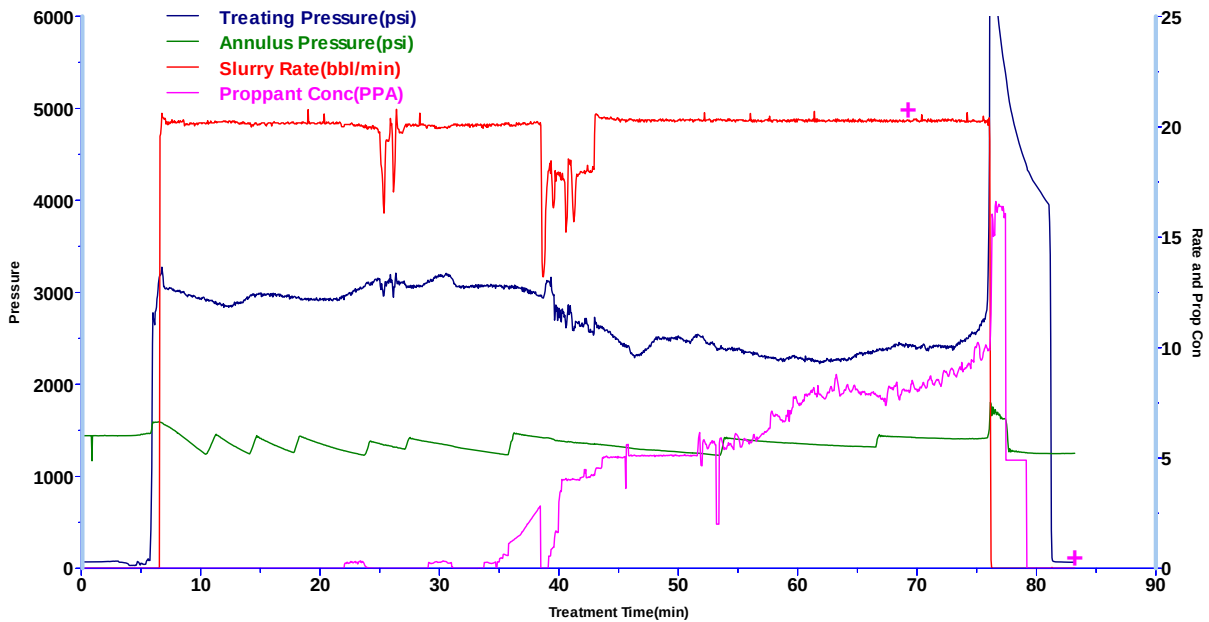


Table 2 - KTM 111 Fracturing Data

	Lower Interval Pre-Job	Lower Interval Post-Job Pressure Match	Middle Interval Pre- Job	Middle Interval Post- Job Pressure Match	Upper Interval Pre-Job	Upper Interval Post-Job Pressure Match
Pad Volume Clean Fluid, %	52	55.5	49	50.5	48	47
Interval Gross Height, m	16	16	46	46	5	5
Interval Net Height, m	16	16	46	46	5	5
Interval Leak- Off Height, m	16	16	46	46	5	4
Closure Gradient, psi/ft	0.507	0.505	0.507	0.505	0.507	0.505
Closure Pressure, psi	3567	3567	3543	3540	3477	3463
Young's Modulus, psi	3.42e+06	3.42e+06	3.42e+06	3.42e+06	3.42e+06	3.42e+06
Toughness, psi/sq in	1200	1200	1200	1200	1200	1200
Ct Leakoff Co- efficient, ft/min E0.5	2.0e-3	3.6e-3	2.0e-3	3.6e-3	2.0e-3	2.1e-3
Fluid Efficiency, %	45.3	39	40.7	35.8	50.8	40.0
Pump Rate, bpm	20	20	20	20	20	20
Propped Fracture Wing Length, ft	319	312	341	144.3	340	389.6
Avg Propped Width, in	0.234	0.227	0.233	0.344	0.347	0.341
Eff. Conductivity	4307	4663	4897	5638	8007	9310
Effective Fcd	1.8	2.0	1.9	5.2	3.1	3.2
Proppant Volume, pounds	108,000	94,105	108,000	91,528	152,800	178,802
Slurry Volume bbls	1194	657	1194	655	1619	841

Figure 5 - KTM 111 Fracturing Execution of the Lower and Middle Prop Fractured Intervals

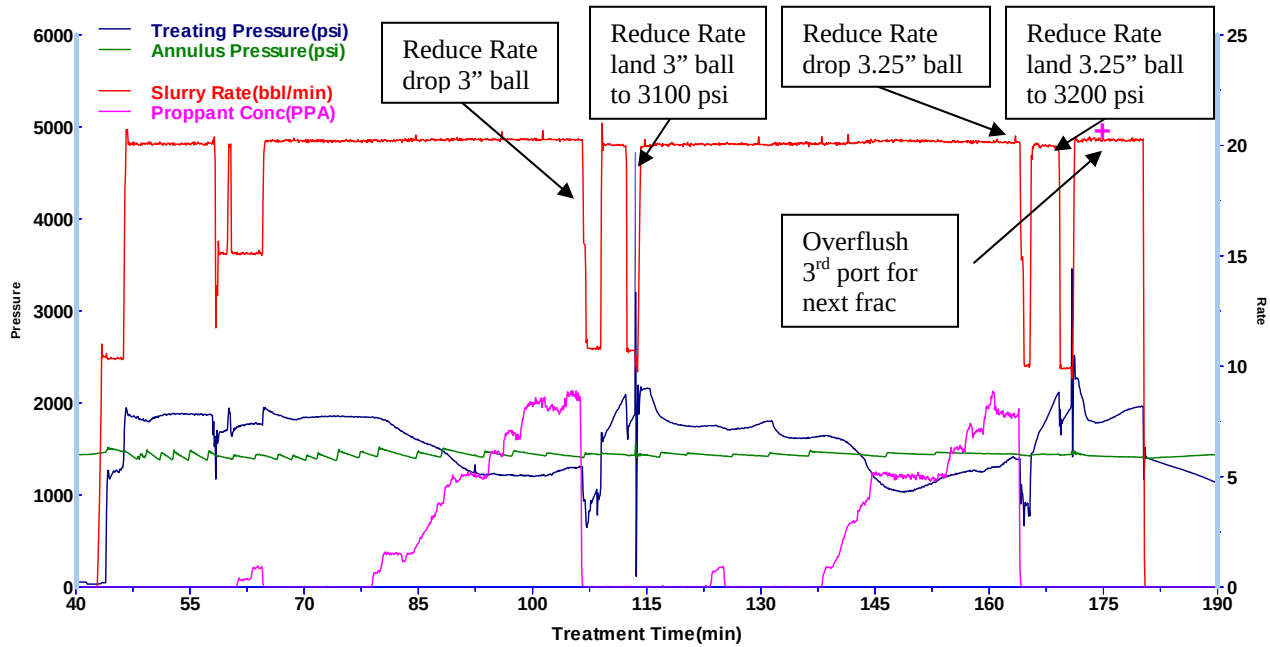


Figure 6 - KTM 111 Fracturing Execution of the Upper Interval

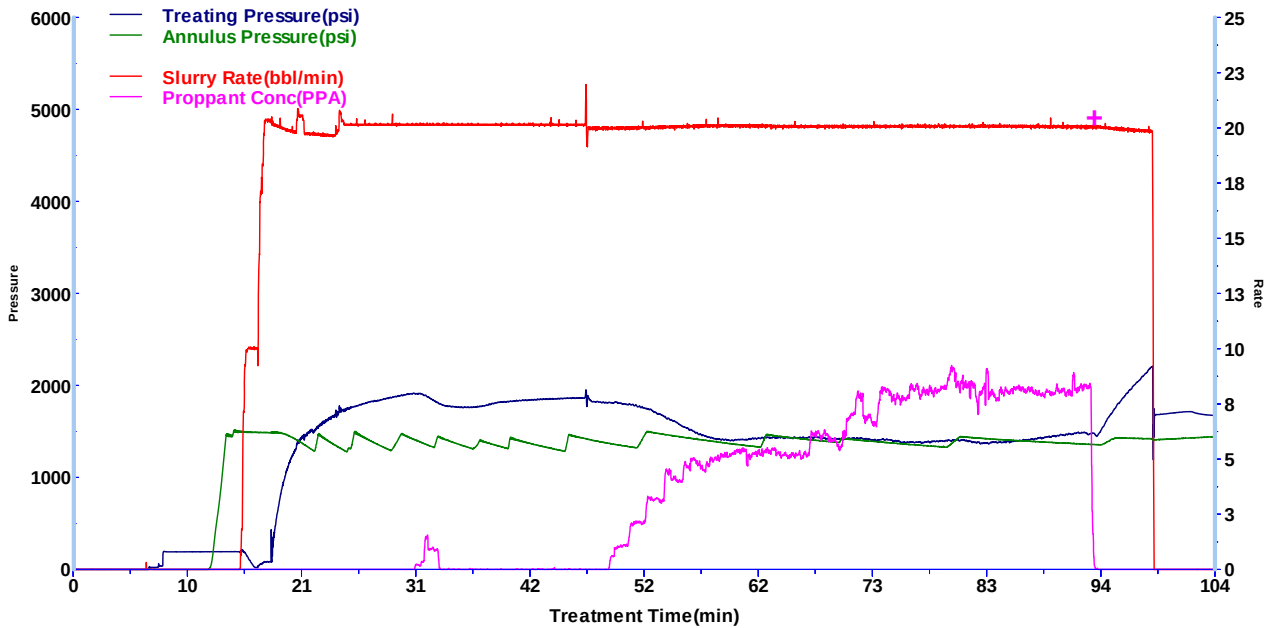


Table 3 - KTM 107 Fracturing Data

	Middle Interval Pre-Job	Middle Interval Post-Job Pressure Match	Upper Interval Pre-Job	Upper Interval Post-Job Pressure Match
Pad Volume Clean Fluid, %	49	50.5	48	47
Interval Gross Height, m	29.4	31	29.4	31
Interval Net Height, m	29.4	31	29.4	31
Interval Leak-Off Height, m	29.4	31	29.4	31
Closure Gradient, psi/ft	0.591	0.668	0.596	0.628
Closure Pressure, psi	4040	4230	4676	4394
Young's Modulus, psi	5.12e+06	5.12e+06	5.12e+06	5.12e+06
Toughness, psi/sq in	1000	1000	1000	1000
Ct Leakoff Co-efficient, ft/min E0.5	2.2e-3	2.8e-3	2.2e-3	2.9e-3
Fluid Efficiency, %	44.6	22.3	46.6	40.4
Pump Rate, bpm	20	20	20	20
Propped Fracture Wing Length, ft	207	247	190	147.8
Avg Propped Width, in	0.136	0.112	0.219	0.139
Eff. Conductivity	3267	2210	3207	1536
Effective Fcd	5.2	2.14	8.9	3.2
Proppant Volume, pounds	98,457	99,005	149,000	133,204
Slurry Volume bbls	788	711	993	813

Figure 7 - KTM 107 Fracturing Execution of the Middle Interval

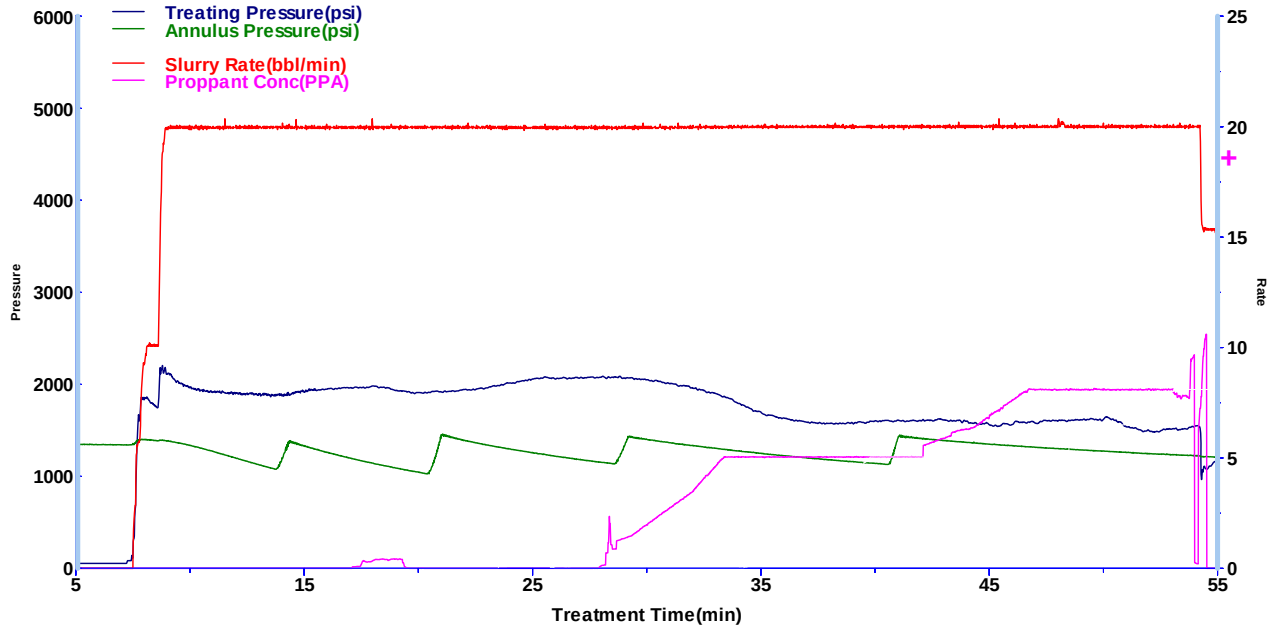


Figure 8 - KTM 107 Fracturing Execution of the Upper Interval

