An integrated system used in the West Seno project proved to be a solution to sand clean-out problems. The key to success was to create an underbalanced condition that enabled sand particles to be lifted and kept suspended in the circulating fluid.

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One of the most challenging coiled tubing (CT) operations is the inside cleaning of large-diameter casing at a low bottomhole pressure. In the West Seno field, offshore Indonesia, this type of work is basic with regards to recovering production, which is mostly from sanded-up and depleted horizontal wells. Deep wells and limited capacity of the tension leg platform (TLP) prohibit the use of large-sized CT, and this fact adds to the job’s complexity. However, with the integration of several methods, such as the special rotating jetting system, real-time fiber-optic downhole (DH) telemetry system, gas-lift injection technique and a new clean-out, shear-thinning, oil-based gel fluid that has superior suspension ability, work that was almost impossible before is now viable.

Discussed below are two sand clean-out jobs in West Seno field—one of which was successful and the other a failure. Both wells involved extremely challenging clean-out jobs in low bottomhole pressure (BHP), large-diameter casing and long horizontal sections below 3½-in. tubing. The astonishingly high sand retention and carrying capability of the oil-based gel fluid is also discussed as one of the key success factors in this sand clean-out method.

INTRODUCTION

West Seno field, the first deepwater development in Indonesia, is in the strait of Makassar (Fig. 1) in water depths ranging from 2,400 to 3,200 ft. The operation used a Tension Leg Platform (TLP), a Floating Production Unit (FPU) and two export pipelines tied back to the existing onshore processing facility at Santan. The field has been in production since Aug. 17, 2003. Since then, several major workovers and through-tubing intervention jobs have been performed to extend the field’s life.

CT intervention played an important role in helping recover production from West Seno field. It became the method of choice to perform routine jobs, such as to clean out hydrates, paraffin and sand, which had become a common problem since the field’s inception. West Seno sand particles were ranging from very fine, at around 20 microns, to sometimes as big as 300 microns, with an average of 60 microns. However, in this first CT sand clean-out project ever performed at West Seno, the operator realized that the huge sand particle range was not the only challenge. The real challenge came from a combination of several factors:

- Completion configuration—most wells were standard completions with 3½-in. tubing inside 95/8-in. production casing.
- Extremely low BHP—all wells were depleted.
- Deep wells—most wells were more than 10,000 ft, MD.
- Highly deviated—some wells had a long horizontal section.
- Limited space and capacity of the TLP—it was a small wellhead version with no production facility on it.

All of these challenges required the operator to determine a different approach to mitigate job risk and to increase the possibility of success. This new approach was the integration of some of the most advanced technology in CT and engineered chemicals. Included was the use of a special rotating jetting system, a real-time fiber-optic DH telemetry system, modeling software, gas lift injection and the new shear-thinning oil-based gel fluid.

This integrated sand clean-out system was applied to two extremely challenging wells in West Seno. One well was completed successfully, the other was a failure. Several lessons learned and best practices adopted are shared here to promote an understanding of the limitations of this integrated sand clean-out system, and how it may be used efficiently.

WELL DESCRIPTION

The two wells discussed are both on the West Seno TLP, and both have dry tree wellheads.

Fig. 1. Location of West Seno field in Indonesia.
Well 1 was drilled horizontally in 2004 and completed with a stand-alone screen and a 3½-in. standard completion. Earlier in its life, the well had been cleaned out twice, due to sand and hydrate problems. A clean-out job was conducted using CT in September 2007, because the well was unable to flow, due to hydrate plugging at the mudline. The plug was cleaned out, and the well flowed for several months before sanding became an issue.

Oil production decreased 75% in January 2008, due to excessive sand production (7%). It was suspected that sand had eroded and created a hole in the screen. The current production tubing was set high, leaving a section of 9½-in. casing between the end of the tubing and top of the screens, creating a low fluid velocity area, which caused difficulty in transporting sand to surface. Unproduced sand particles accumulated in the low-velocity section of the casing, therefore choking production. The well flowed at a low rate until September 2008, when it was completely sanded up and ceased production.

A pressure test showed tubing leaks and communication with the annulus. A workover to change tubing and sting production tubing into the screen packer was performed. The job was finished in early February 2009, when the production tubing was successfully changed, eliminating the tubing leak. However, production tubing was not able to connect to the screen, due to an inability to unseat the old production packer. Thus, the low velocity area remained, and production was still choked. The last slickline bailer run confirmed that the sand was accumulated at the low side of the casing section, below the end of the 3½-in. tubing, Fig. 2. The well was proposed for a CT sand clean-out job to regain production.

Well 2 was a sidetrack, drilled and completed in 2003. Like Well 1, it was horizontal and was completed with a stand-alone screen and a 3½-in. standard completion. The well had no problems until recently. In 2010, well production slowly decreased by 80%, due to excessive sand production. This well had a similar completion configuration to Well 1, in which the completion string was not stung into the lower completion packer, and thus left a low velocity area, Fig. 3. After a slickline bailer run, it was confirmed that what happened in Well 1 had also occurred in Well 2. The well was proposed for a CT sand clean-out to recover remaining reserves.

INTEGRATED SAND CLEAN-OUT SYSTEM

Since this was the first sand clean-out project in West Seno field, the operator realized that a successful sand clean-out job depended upon an understanding of the basics, which are:

- How to make the fluid hydrostatic pressure in the tubing or casing lower than the BHP, so as to lift the sand particles.
- How to keep the sand particles suspended in the circulating fluid and transport them completely from the tubing or casing.

The operator and its CT service provider developed a solution called the integrated sand clean-out system. This system uses some of the most advanced CT technologies, including:

- Special jetting rotating system—a spinning jet nozzle that helps break or stir up the sand.
- Real-time fiber-optic DH telemetry system—coiled-tubing with fiber optic built into the pipe that enabled the operator to see the BHP and BHT in real time at the surface.
- Modeling software to model the clean-out operation—the solids loading and percent solids coming out were modeled.
• Gas lift injection to lower hydrostatic pressure in the CT-tubing annulus—the clean-out operation would not be performed using reverse circulation, but, instead, using the “long way.” This was the only way to clean the sand from inside the casing.

• New clean-out shear-thinning oil-based gel fluid—with its high sand retention and carrying capability, this fluid enabled the sand to remain suspended, even as it went through a low-velocity section in the casing.

Special jetting/rotating system. This tool has nozzles on two sides, rotating in a speed-controlled head to maximize jet velocity and wellbore coverage. This jetting action will penetrate the sand fill and create a pilot hole for the tool’s penetration. During job design, special software is used to maximize the most effective pump rate, rate of penetration (ROP) and size of drift ring and nozzle head.

The nozzle head was designed to have a built-in chamber with viscous fluid in it. This fluid would help slow down the head’s rotation, assuring that the jet would impact the tubing or casing wall at a 90° angle, or close to it. This 90° angle was the key for effective impact. If the head was spun at an uncontrolled high speed, the jet might impact the tubing or casing wall at a much steeper angle and reduce the jetting impact.

To help increase the impact force, nozzles were designed to be able to reduce fluid dispersion. With this capability, jetting will be further concentrated in one spot, helping to reduce the need for higher pump pressure to obtain similar results. This impact force was extremely important to make sure that the fluid could break the packed sand in the wellbore.

Real-time fiber optic DH telemetry. With fiber optics built into the CT, this system offered a tremendous benefit of being able to monitor the casing collar locator (CCL), BHP and BHT in real time. This capability played a significant role in reducing the risk of cleaning out the sand using CT. The bottomhole pressure work window could now be defined and monitored in real time to maintain desired overbalance, at-balance or under-balance conditions. The information reduced the risk of pipe sticking, prevented unwanted treating fluids entering the formation, and reduced operational time and material usage.

Modeling software was used to model and simulate the sand clean-out operation to reduce risk and improve the possibility of success. For example, in West Seno, the TLP’s space and capacity governed many things, including the size of CT that could be used. The highest load rating of the TLP top deck was only 600 lb/ft², thus the use of CT bigger than 1.5 in was not feasible. Larger CT might aid the clean-out operation, but with the depth of most West Seno wells, the weight of the spooler would exceed maximum TLP top deck rating.

Because of that, software was run to determine whether the 1.5-in. CT could do the job. Tubing forces were modeled to see if the CT could still be run in-hole (RIH) to target depth and pulled out of hole (POOH), and also whether the flow-rate through 1.5-in. CT was still sufficient to bring solids to surface. This software played an extremely important role, since it could combine all of the parameters of the new integrated system and simulate whether a job could be performed.

Gas lift. In the effort to reduce hydrostatic pressure in the wellbore, thus helping to lift sand to surface, the operator came up with an idea to use gas lift injection during the clean-out. A mixture of gas and clean-out fluid in the CT-tubing annulus was expected to reduce hydrostatic pressure, creating an underbalanced situation.

In West Seno, the clean-out return fluid flowed directly to the production facility, making it an open loop system. From an operational safety standpoint, this open loop system was considered safe since the return fluid, which consisted of a mixture of shear-thinning oil-based gel fluid, sand particles and injected gas from the wellbore, was never circulated out to the mud pit and gasuster. They were all pumped directly to the production facility on the West Seno FPU. Injected gas was separated and burned using the FPU’s flare boom. The remaining fluid went to, and was temporarily stored in the FPU’s wet oil tank.

However, since this fluid would eventually be pumped together with the hydrocarbon sales product, a breaker was required to break the shear-thinning oil-based gel fluid. An unbroken gel fluid could create an off-spec sales product, when it was pumped together with the sales hydrocarbon in the export pipelines. The breaker injection was installed at the CT blowout preventer (BOP) riser. This location was considered to be the most efficient. Previously, the breaker had been pumped through the methanol injection control line, so as to put the breaker injection point as deep as possible at around 4,500 ft, MD, which would provide more time for the breaker to contact the gel fluid and help speed up the gel breaking process. However, due to mudline temperatures that were close to sub-zero, the breaker froze and plugged the methanol injection line.

Multi-phase flowmeter (MPFM). Attached on the return line to monitor fluid and gas return rate, the MPFM became a critical factor in the integrated system, because it provided a confirmation of the amount of return fluid and return injected gas to surface. Knowing these data enabled the operator to determine whether the clean-out operation was in a balanced or an underbalanced condition. Efficiency of the gas injection could also be seen from this MPFM by comparing the amount of gas injected and gas coming to surface.

Clean-out shear-thinning oil-based gel fluid. This new fluid system is an oil-based gel designed to be used for sand clean-out in water-sensitive formations. It has an exceptionally high solid suspension characteristic compared to conventional gelled oil. Since it is a diesel-based solution, it has a lower density than other water-based gel fluids, resulting in a lower hydrostatic fluid column suitable for clean-out application in low BHP conditions. The viscosity ranged from 80 to 100 cp. The fluid also showed excellent viscosity stability in various shear rate (170/s to 1,000/s) and temperature (40°F – 300°F). Several additional benefits of this fluid include:

- It can be batch-mixed or pumped on the fly.
- Lower additive concentrations compared to other gelled oil systems.
- Adequate and consistent sand suspension without using any foaming agent.
- The fluid can be energized without other additional additives.
- Single-fluid formulation for the entire clean-up stage results in operational simplicity.
- Less sensitive to the type of diesel compared to other gelled fluids.
- Less sensitive to the ratio of the gelling agent to activator concentration, making it more robust compared to the traditional gelled oil systems.
**WELL 1 SAND CLEAN OUT**

**Job design.** This well had ceased producing and was shut-in. Slickline work had been performed to find that the top of sand (TOS) was at 9,870 ft. Formation pressure was estimated at 2,000 psi or the equivalent mud weight (EMW) of 5.02 ppg. Reservoir temperature was at 148°F. The well was horizontal with a 90° deviation beginning at 12,700 ft MD.

Using the above information, the cleanout was simulated using the software. The 1.5-in. tapered CT was to be used, because the TLP deck rating only allowed a weight of 16,100 ft of 1.5-in. tapered CT reel to be laid on the TLP’s drilling deck. Because of this, the tubing forces simulation was modeled, to make sure that the CT could reach the target depth with safe pulling and set down capacity.

Because of the risk and the complexity of the job, plus the fact that this would be the first sand clean-out job using the integrated system, the operator decided to approach this work in a conservative manner. This meant that all parameters used during the design and planning of the operation were chosen primarily to mitigate risk:

- **Solids loading is less than 10%.** Ten percent was chosen as a general rule-of-thumb for solids percentage inside the circulating fluid. It was believed that having less than 10% of solids in the circulating fluid would guarantee that it would be carried and lifted by the circulating fluids, eliminating any possibility of solids settling inside the tubing.
- **Bed fraction is less than 30%.** Bed fraction is a comparison of the sand bedding section inside casing with the casing’s cross-sectional area. It is the amount of sand that is allowed to bury the coil tubing when the CT is cleaning the sand from the inside casing. Thirty percent was chosen as a general rule-of-thumb, because it was considered that more than 30% bedding section increased the risk of sticking the CT. More than 30% was also an indicator that more sweeps were needed before going for more fill bite.
- **Transport ratio is at 0.1.** If 0 means that no solids were transported and 1 means all solids were transported (solids & carrier fluid are moving at the same rate). 0.1 is the lowest ratio at which solids can be transported. Less than 0.1 means the solid is floating stationary inside casing and is not transported. Using 0.1 is a very conservative approach to make sure that the job was designed effectively.
- **Limit CT pressure to 7,000 psi.** This is based on the engineer’s discretion, but 7,000 psi was chosen to make sure that CT life is not compromised.

By implementing these four parameters into the CT clean-out simulation software, a pumping schedule was generated, Fig. 4. The final pumping schedule would be the result of fine-tuning bite size, bite length, bite speed, number of sweeps, gas injection rate and pumping rate with the circulating fluid used; in this case diesel and shear thinning oil-based gel fluid. To consider a successful clean-out job, more than 95% of solids would need to come to surface according to the simulation.

**Well 1 job execution.** The CT was run using a fiber-optic DH telemetry system, combined with a special jetting rotating system. Tool length was 15 ft, and max outside diameter (OD) was 2.125 in. at the CT connector. The objective was to clean-out inside the 9¾-in. casing section’s 8.681-in. inside diameter (ID). Fluids used were diesel and the new shear-thinning oil-based gel fluid. The fluid system was set up with all return diverted through the tree wing valve and to the FPU wet oil tank facility. Breaker injection was located at the CT riser to break the return oil-based gel fluid. An MPFM was also installed at the

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**Fig. 3.** Schematic of Well 2 completion.
return line as part of the mandatory requirement for this type of sand clean-out to have continuous return fluid quantity and quality monitoring. The MPFM cable was hooked up to the CT cabin, so that the MPFM reading could be seen together with other readings given by the DH telemetry system. Gas lift was also turned on to reduce BHP during clean-out. A rate of 2.7 MMcfgd was injected, with casing pressure maintained at 1,500 psi.

After passing 9,826 ft, diesel was pumped ahead of the oil-based gel fluid to stabilize the hydrostatic column and to get the feel of responsiveness when manipulating the surface choke to later adjust BHP. Once BHP obtained from fiber-optics stabilized at 2,000 psi (similar to the estimated formation pressure given by the reservoir engineer, at a pumping rate of 1.2 bbl and 2.7 MMcfgd), then the oil-based gel fluid began pumping from the surface. The breaker pumping was also initiated, using a pneumatic diaphragm pump at 3–5 lpm.

During the clean-out process, there were several parameters that needed continuous monitoring:

- CT weight
- Circulating pressure
- Corrected depth of CT inside the well
- Wellhead pressure
- CT-tubing annulus BHP reading from fiber-optics DH telemetry system
- Inside-CT BHP reading from fiber-optics DH telemetry system
- BHT reading from fiber-optics DH telemetry system
- MPFM reading, showing hydrocarbon, gas and water flowrates.

By following the pumping schedule, the clean-out went smoothly. Average circulating pressure was 3,800 psi while pumping the oil-based gel fluid at 1.2 bbl, and maintaining gas lift injection rate at its maximum, 2.7 MMcfgd. The fiber-optics DH telemetry system also showed the differential pressure during jetting circulation to be 1,800 to 1,900 psi, which was good, considering the most effective differential pressure was at 1,500 to 3,000 psi. The BHP was maintained at balanced conditions, at 2,000 psi. Sometimes, sand slugs were recovered at the surface sampling point.

Average lost return rate was observed at 0.1 to 0.3 bblm. This was consistent with what had been agreed during the planning of this job, Fig. 5. In the job procedure, it was emphasized that the minimum return rate that could be tolerated at the surface when pumping at a maximum rate of 1.2 bpm was 0.8 bblm. The reason for this conservative approach was simply because the operator did not want to take any risk by having a return rate less than 0.8 bblm. According to the risk assessment performed during the job planning, a return rate less than 0.8 bblm might create sand bedding that could eventually bury the CT and stick it in the hole. Therefore, this lost return rate of around 0.1 to 0.3 bblm was still considered safe within the limit.

At 10,711 ft, MD, there was an issue when the circulating pressure suddenly dropped. A decision to pull the CT was made to determine what had happened. After reaching the surface, the jetting rotating system nozzles were found to be washed out. After changing the nozzles, CT was run back in the hole, and sand clean-out continued. During the investigation, it was learned that the jet nozzles were washed out, because they spun on the low side of the casing, rubbing the casing wall until they finally washed out. The solution was to add a drift ring to create some stand-off at the nozzle, so that it didn’t rub the casing wall when it spun.

The clean-out successfully reached the desired depth of 11,280 ft, MD. This depth was selected, assuming that the objective was to clean-out what was thought to be sand bridging in the casing section in-between the tubing end and top of the gravel pack (GP) packer only. However, since the job progressed well, a decision was made to try to clean-out further, to see if the CT could at least clean-out the sand to a certain distance inside the screen. The clean-out job was continued into the screen section that started at 11,312 ft, MD. However, at 11,350 ft, MD, the CT saw a tag indication. To ensure that there was no possibility of sticking the CT, it was swept to the end of tubing while pumping was continued. Once clean returns (no sand) were observed, diesel was then pumped bottoms-up to

![Fig. 4. Pumping schedule design for Well 1.](image)

![Fig. 5. Cleanout job log from Well 1.](image)
displace all oil-based gel fluid. It was then decided to end the job. Total CT pumping was 54 hours.

**WELL 2 SAND CLEAN OUT**

**Job design.** The well had been producing at a very low rate. Slickline work had been performed and found that TOS was at the end of tubing at 7,204 ft. Formation pressure was estimated at 1,100 psi or an EMW of 2.82 ppg; reservoir temperature was 151°F. The well was horizontal, with the end of tubing at 7,204 ft. Formation pressure at the bottomhole was 1,100 psi or an EMW. To mitigate the risk, the operator performed several simulations to determine the operating window. This operating window would indicate the lowest BHP at which this clean-out operation could still be performed. Several conservative parameters were also used during the simulation, such as using the largest sand particle (300 microns) to simulate heavy and big solids, and using high permeability at the sand fill to simulate heavy leak-off. For Well 2, the lowest BHP at which the clean-out operation could still be performed was 900 psi, with a minimum return rate at 0.8 bpm.

- The objective for Well 2 was different from that of Well 1, which was to only clean out the sand bridge at the casing section between the end of the tubing and top of the GP packer. Well 2’s objective was to clean out all of the sand from the end of the tubing to the end of the screen. However, since cleaning out to the end of the screen significantly impacted the well’s economics, it was finally decided that the stopping point would be the amount of oil-based gel fluid pumped. In this case, 3,000 bbl would clean the sand down to the middle of the screen section at 9,300 ft.
- Well 2 contained a very long horizontal screen section, from 8,592 ft, MD, to 10,043 ft, MD—a total of 1,451 ft of horizontal screen. This was extremely challenging, since there would be a variety of formation permeabilities along that horizontal section in which one could be a thief zone that might cause extreme fluid loss, and create sand bedding that would eventually stick the CT. During the simulations, five different permeabilities obtained from the log were used.

By implementing the same design parameters used in Well 1, a final pumping schedule was generated, Fig. 6. Since this was a difficult, risky operation, there were several important points that needed to be communicated to the field before the execution:

1. Initial plan called for a penetration rate of 2 to 3 fpm.
   - On the casing side, each bite for 40 ft was followed by a sweep back to initial penetration depth and a long sweep every four bites.
   - On the screen side, each bite for 30 ft was followed by a sweep back to initial penetration depth and a long sweep every three bites.

This plan was to fulfill the “10% solid loading” rule.

2. Since a DH telemetry system was used for DH monitoring, adjustment on bite length and bite number before the long sweep would depend on the following criteria:
   - If DH pressure (DH telemetry system reading) and/or casing pressure increases from the casing pressure baseline value (CPBV) during sweeps, this shows that the sweep is carrying sand. If this occurs, continue with the proposed clean-out schedule/reduce bites number (CT engineer on location determines the number based on simulation).
   - If DH pressure (DH telemetry system reading) and/or casing pressure are stable from CPBV during sweeps, it shows that the sweep is not carrying sand. With this condition, consider increasing bite length/number (CT engineer on location determines the number based on simulation).

3. Do not apply weight-on-bit (WOB) of more than 1,000 lb while jetting with the jetting rotating system, to avoid any damage to the tool.
4. Minimum breaker injection rate was at 1.6 lpm.
5. Make sure to circulate the well bottom-up and clean return before pulling CT to surface.
6. Reciprocate CT when circulating bottoms-up.
7. Do not attempt to penetrate sand fill if returns are not established or lost at anytime. Keep monitoring:
   - Returns at all times from MPFM reading during job execution.
   - BHP pressure from DH telemetry system reading.
8. Take fluid sample from surface sampling point in 10 min intervals or at every abnormal indication seen in DH telemetry reading, WHP reading or from MPFM reading.
9. Keep gas lift rate at the same rate; choke opening should be adjusted when necessary (lost returns).
10. When necessary to adjust choke size, make incremental adjustments, and allow the rates and pressures to stabilize.
11. If DH pressure from the DH telemetry system continues to increase 200 to 400 psi higher than the baseline value, and the WHP decreases, pick up CT until the end of tubing and circulate at the same pump rate until all parameters return to normal.
12. Max loss return rate during sand clean-out was 0.3 bpm. If more than 0.3 bpm, pull out CT immediately to 7,000 ft, MD.
13. Monitor pressure changes on the DH telemetry system during a long sweep. If the pressure remains constant, this indicates there is no bedded section. Considered taking more bites (increase gradually).

**Job execution.** Coiled tubing was run, breaking circulation every 1,000 ft, Fig. 7. Returns were taken with the choke position adjusted to 20/64 in. The downhole telemetry system was used during this operation to ensure real-time bottomhole monitoring, to prevent sand accumulating above the CT string, which could lead to stuck CT. As soon as CT reached the depth of interest (7,154 ft—50 ft above expected top of fill) the pull test was performed, and diesel began pumping at 1.2 bpm, with the choke adjusted to 40/64 in. Paraffin was observed at the sampling point in the return line to production, and fluid returns were intermittent. After observing return fluid on the surface, it was suspected that lost returns had occurred, even though...
gas lift was already turned to its rate of 3 MMscfd. Bottomhole pressure from the DH telemetry system showed 750 psi instead of 1,100 psi or the estimated formation pressure. Based on the simulation, this condition showed that the clean-out job could not be continued, because BHP was lower than 900 psi with no fluid returns to surface. However, several actions could be taken to confirm this before deciding to POOH with CT.

An attempt to reduce the permeability and fluid leak-off of the formation by squeezing with 83 bbl of oil-based gel failed. During the squeeze, BHP increased to 1,100 psi, but decreased again, once the displacing fluid (diesel) reached the screen. Another attempt to establish circulation by opening returns and activating gas lift at 2.5 MMscfd was done, but even with the gas lift at its maximum injection rate, return rate was still intermittent, ranging from 0 to 0.3 bpm. During circulation, chemical breaker was pumped at 1.6 lpm to ensure oil-based gel fluid viscosity was reduced at surface.

A final attempt to establish circulation was done by picking up CT above the gas lift injection point while maintaining circulation at a maximum rate of 1.25 bpm. Bottomhole pressure was increased to 1,050 psi, and BHT increased as well, indicating that gas lift was working and was injecting gas into the tubing. MPFM showed the return rate trend had increased to around 0.1 to 0.6 bpm, but was still unstable. Coiled tubing was run to just below the gas lift injection point, return was lost and BHP was instantly decreased, confirming that all fluids went into the formation. At this point, it was concluded that reservoir pressure was too low, and the job could not be continued.

**BEST PRACTICES/LESSONS LEARNED**

Several points were learned from these two sand clean-outs in West Seno field. These points could be applied to any sand clean-out job using the same integrated system, whether on land or in moderate-to-deepwater environments.

**During design stage:**
- Less than 10% solid loading inside the circulating fluids helps reduce the possibilities of solids settling.
- Less than 30% bed fraction reduces the risk of sticking the CT.
- Use a transport ratio of 0.1. This value was used to model the clean-out at its worst condition or for designing the clean-out at the threshold or minimum rate at which solids started circulating out with the fluid.
- Always perform several clean-out simulations to find the operating window that would be the limit at which the clean-out job should be halted.

**During operation stage:**
- Locate chemical breaker injection point at CT BOP riser. For non-deepwater applications in which there are no concerns with seabed temperature, the injection point could be located as deep as possible—for example, a chemical injection point for scale that is usually located down in the tubing.
- Use a drift ring for long sand clean-outs to prevent the wash-out jet nozzles.
- Use the DH telemetry system to help adjust bite length and numbers before a long sweep.
- Never apply WOB of more than 1,000 lb while jetting to avoid damage to the jetting rotating system tool.
- Breaker injection rate was 1.6 lpm, minimum. Use two pneumatic pumps, with one as a back-up if the other pump leaks. The breaker chemicals were detrimental to pump seals.
- MPFM and BHP readings from the DH telemetry system were the two most critical parameters to determining penetration rate during operations. Taking fluid samples at surface from time to time was a good practice, mostly in abnormal conditions.
- Keep gas lift rate at its maximum injection rate, adjust production choke opening when necessary.
- Maximum lost return rate during sand clean-out was 0.3 bpm.

**WEB EXCLUSIVE:** Please visit www.worldoil.com for acknowledgements, references and author biographies.

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**Fig. 6.** Pumping schedule design for Well 2.

**Fig. 7.** Cleanout job log from Well 2.