As borehole complexity increases, operators struggle to comply with stringent waste-discharge guidelines while meeting drilling-performance demands. Today, advances in drilling fluids and cuttings-management techniques are allowing operators to use the most efficient drilling-fluid systems while effectively removing drilling waste from the environment.

An unfortunate side effect of the quest for hydrocarbons is an accumulation of debris that was removed to access those resources. Modern drilling operations generate several waste streams varying from contaminated runoff water to material packaging; however, the majority of the waste is associated with the excavated material, or cuttings, from the borehole. Until the 1980s, little thought was given to the disposal of cuttings and excess drilling fluids. Typically, these materials were discharged overboard in offshore operations or buried when drilling in land-based locations. In the 1980s and 1990s, global environmental awareness increased and the oil and gas industry, along with its regulators, began to understand and appreciate the potential environmental impact of drilling waste.

During this same period, advances in directional-drilling technology ushered in a new age in wellbore construction. Although previous generations of drillers often found it difficult to drill vertical wellbores, by the 1990s, the trend in well trajectories had changed from vertical to horizontal. Rapid technological improvements soon brought horizontal drilling to the forefront. Operators realized significant improvement in well economics by drilling multiple directional wells from a single platform or by drilling complex multilateral wells from one borehole. These advances reduced surface footprints, improved well construction economics, consumed fewer materials, and increased production from each well.

The combination of increasing environmental awareness, new discharge regulations and challenging drilling situations led the oil and gas industry to develop new drilling-fluid and waste-management technologies to support these advanced wellbore designs, while at the same time promoting environmental stewardship. In this article, we explore technologies developed to remove drilling wastes from the environment by placing them in hydraulically generated fractures deep beneath the Earth's surface. We also describe new technologies that are helping to reduce waste by recovering costly nonaqueous drilling fluids.

Oil Muds—More Common Than Ever Before

Oil-base muds (OBMs) came into general use in the oil field in 1942. Early oil-external fluids were composed primarily of asphalt and diesel fuel. These muds helped drillers stabilize water-sensitive shales, provided lubricity for coring operations and minimized reservoir damage.

As the directional-drilling era took hold in the late 1980s, OBM s demonstrated a superior ability to reduce friction between drillpipe and formation. Rotary torque and drag were significantly reduced from levels commonly observed when using water-base muds, allowing drillers to reach farther and drill trajectories with greater tortuosity.
The inhibitive quality of OBMs also helped drillers reduce the risk of borehole failure associated with long horizontal boreholes. An OBM owes its inhibitive quality to its oil-wetting nature—water contact with formation clays is eliminated in an oil-wet environment. As such, formations drilled with oil-base drilling fluids tend to experience less chemical dispersion than those drilled with water-base muds. Just as important, this inhibitive quality minimizes the dissolution of cuttings as they are being pumped from the bit to the surface. Providing that hole cleaning capacity is adequate, in oil mud, or nonaqueous environments, cuttings typically arrive at the surface in much the same condition as they left the bit. Surface solids-control equipment is more efficient with larger cuttings, and the dilution volume required to reduce fine solids content in the drilling fluid is minimized. Ultimately, the total project waste volume is significantly reduced.

From the 1990s to the present, the drilling industry has witnessed a revolution in OBM and oily-waste management. Less toxic and more environmentally acceptable synthetic-base muds (SBMs) have replaced diesel and mineral-oil muds in many areas. Operators now have the benefits of nonaqueous drilling fluids coupled with technologies that help to manage cuttings and excess oil- and synthetic-base muds. Modern SBMs offer the nonaqueous qualities of traditional OBMs but with less toxicity and higher degrees of biodegradability. In some areas, depending on environmental regulations, cuttings coated with SBMs are buried, discharged to the sea or made environmentally benign through bioremediation processes. However, not all areas are suitable for this type of waste management, and more advanced processes are required to protect the environment while drilling (left).

Putting Oily Waste in Its Place

On any drilling project, operators must achieve a balance between minimizing environmental impact, maintaining borehole stability and maximizing drilling efficiency. Since 2001, the use of nonaqueous drilling fluids, both oil- and synthetic-base, has increased on average by 2% per year, a trend that is likely to continue (next page, top). Some formations are more easily drilled using nonaqueous drilling fluids, hereafter referred to as oil-base fluids, owing primarily to the inherent inhibitive and lubricative qualities of these fluids.

When oil-base drilling fluids are used in the drilling process, rock cuttings carried by the drilling fluid through the borehole become coated with a residual layer of the oil. Even when drilling with water-base mud, cuttings from oil-rich shales and sands are transported to the surface for proper disposal. In many areas, stricter environmental legislation and increases in the cost of cuttings-cleaning techniques have eliminated the option of discharging oil-wet or oil-containing cuttings and related drilling waste to the sea.

The advantages of OBMs came at a price. As mentioned previously, the 1980s and 1990s were a time of environmental awakening for the oil and gas industry. Regulators began to discourage discharge of mud and cuttings, while many countries prohibited the discharge of oil-wet cuttings and waste-oil mud altogether.


An example of stricter environmental discharge regulation occurred in the North Sea in late 1990. Two years prior to regulatory changes, the Norwegian State Pollution Control Agency announced a tightening of regulations for offshore disposal of drilled cuttings. Effective January 1, 1993, the allowable oil on cuttings disposed by discharge to the sea was reduced from 6 to 1 percent by volume. Technology available at the time could not reduce oil on cuttings to such a low level.3

BP, then Amoco Production Company, began preparing for this regulatory change in the Valhall field by first evaluating the options. Engineers considered transporting oil-wet cuttings to shore for processing, drilling with water-base rather than OBM, processing the cuttings offshore and disposing of cuttings by subsurface injection.

Initial studies indicated that cuttings reinjection (CRI) would have the least impact on the environment while providing an economical solution to cuttings and oily-waste disposal. In a typical CRI operation, cuttings are mixed with seawater, processed by grinding or other mechanical action to form a stable viscous slurry, pumped down a dedicated disposal well or through the annulus between casing strings on an active well, and forced under pressure into formations (below). This process creates a hydraulic fracture in the formation that effectively contains the slurry. At the end of the injection program, the well or annulus is typically sealed with cement.

Before investing in this new technology, Amoco initiated an extensive testing program to assure that periodic injections would be possible and to gather pressure-response data during and after injection for modeling and model calibration.

Cuttings were prepared for injection by first mixing with water in a 50-bbl [8-m³] tank, then recirculating the slurry through a centrifugal pump modified with carbide-tipped impellers to grind the cuttings at a rate of 5 to 10 bbl/min [0.8 to 1.6 m³/min]. Cuttings were added to a seawater-base slurry to achieve a density of

^ Increasing use of nonaqueous fluid. Statistics provided by M-I SWACO indicate an increased use of nonaqueous fluids since 2001. These fluids include both conventional and synthetic muds.
10 lbm/gal US [1,198 kg/m³]. Mixing continued until the slurry was homogeneous and the slurry had a Marsh funnel viscosity of 45 to 60 s/qt [approximately 45 to 60 s/L]. This process was repeated until a total of 1,000 bbl [159 m³] had been prepared. The total volume was then injected into a formation at a depth of almost 8,000 ft [2,438 m] TVD.

Data gathered during multiple injections into a shale-capped sandstone formation showed stable pressure behavior with each injection sequence, indicating that the periodic injections had created multiple or branched fractures in the same region of the reservoir rather than one continuous fracture. The data also indicated that periodic fracturing injections changed the in-situ closure stress of the formation. Engineers theorized that the cuttings introduced into the formation created a local volume. Because the cuttings remain localized in what became known as the disposal domain, changes in closure stress could be expected to be permanent and repeatable. Stress changes resulting from thermo-poroelastic stress effects were also noted. These concepts will be discussed in more detail later.

Data gathered during these tests supported the theory that misfit strains caused by the periodic placement of cuttings in fractures introduced into an elastic field, such as reservoir rock, can be calculated using basic elastic-theory equations. This helped Amoco engineers develop models to better understand and predict fracture and disposal-domain behavior related to cuttings-injection processes.

During the multiyear evaluation program, engineers injected fluids ranging from water and sand in early tests to actual cuttings in later tests. By the end of the evaluation project, more than 340,000 bbl [54,000 m³] of injection slurry containing more than 76,000 bbl [12,000 m³] of cuttings were pumped into injection wells.

In these early tests, Amoco demonstrated that the injection of cuttings can be a cost-effective means of oily-waste disposal when compared with onshore disposal.

At the time, engineers estimated a US$550,000 cost-savings per Valhall well using cuttings-injection processes compared with land-based or other cuttings-disposal techniques.

Disposal cost is not always the driver behind the use of CRI technology. In remote or environmentally sensitive areas, drilling-waste management can be challenging. Treatment facilities are often either unavailable or logistically inaccessible and costly. In these situations, the injection of cuttings and other associated waste streams into underground formations may offer the only environmentally acceptable

^ Containing injected fluids. Poorly designed reinjection projects risk waste materials leaking back to the surface through natural fractures, along fault planes or following a poorly cemented path up the borehole (left). Depending on the specific gravity of the injected waste, some material may rise to the surface. With proper engineering and a suitable caprock formation, waste is contained within the injection zone (right).

4. Marsh funnel viscosity is the time in seconds for one quart of fluid to flow through a Marsh funnel. This is not a true viscosity, but serves as a qualitative measure of how thick a sample of fluid is. The funnel viscosity is useful only for relative comparisons.
method of disposal. For example, in extreme northern and southern climates, where harsh winter weather can virtually eliminate onshore treatment options and year-round drilling operations, CRI may offer the only practical solution for cuttings and drilling-waste disposal.

The Risks of Reinjection
As with all E&P operations, CRI has risks. Most often, injection programs proceed without serious mishap. However, particularly in the early days of this technology, there were instances where the path to the disposal formation, down either casing or an annulus, became blocked, effectively shutting down CRI operations. On rare occasions, injection slurries have migrated through natural fractures, hydraulically induced fractures or poorly cemented sections of the well, then back to the seabed. This event results in a release of injection slurry to the seafloor (previous page).

Failures such as these not only are costly in environmental terms, but also pose serious economic risks such as operational downtime, injection-well remediation, or in the worst-case scenario, a need to drill a new injection well. CRI operations can be jeopardized by many factors such as mechanical failures at the surface or undercapacity of the disposal system, causing costly delays to the drilling project. To minimize these risks, engineers use advanced pneumatic collection, transportation and storage systems like those developed by M-I SWACO to decouple drilling and CRI operations (above left).

During times of CRI equipment failure or when cuttings are generated faster than they can be processed, these pneumatic systems can rapidly move waste and oily cuttings discharged by solids-removal equipment to storage tanks for later processing. The pneumatic system can transfer the cuttings over distances greater than 100 m [328 ft] and vertically between decks of a platform, so storage tanks can be sited at a distance from the drilling package. This avoids the crowding problems associated with additional equipment on the drilling platform.

Downhole risks are less obvious and often more complicated. Plugging of the tubing, annulus or perforations can threaten the success of a CRI operation. Solids in suspension naturally settle during stagnant periods between injection phases. The rate of settling is a function of time, particle size and the low shear-rate viscosity of the fluid. Larger particles, typically greater than 300 microns, are screened out at surface to help reduce settling potential.

As injection is initiated, solids in the bed are compacted and form a solid plug, preventing
further injection. Clearing blockages, reperforating the tubing at a shallower depth or moving to another injection well are costly steps that threaten the efficiency of the drilling operation.

Cognizant of these reinjection risks, Sakhalin Energy Investment Company (SEIC) nonetheless chose CRI technology for drilling-waste management in the harsh offshore Sakhalin Island drilling environment. CRI was selected as the most effective drilling-waste management approach offshore Sakhalin Island for several reasons. First, the discharge of drilling wastes is no longer allowed and second, shore-based drilling-waste management facilities are not available. Further, the area is ice-free only about six months of the year; even if onshore options existed, shipping to shore would limit the drilling operational window. By contrast, drilling-waste management using CRI would allow year-round drilling operations.

Although CRI presented the only practical solution for drilling-waste disposal, a previous annular injection well had become plugged, requiring a new well to be drilled for cuttings injection. In addition to the loss of this first well, the operator faced significant risks related to the lack of historical operational data and experience, and the potential for solids dropout and subsequent injector plugging in the newly drilled directional well.

The new injection well served two purposes; it would be the primary injection well during drilling operations, and would later be used as a field-development well. As such, it was significantly deviated and had a much larger diameter than the typical disposal well. Both the wellbore diameter and its deviation increased the risk of cuttings settling on the low side of the injection tubing, a situation that could potentially plug the disposal well.

Risk management was a crucial factor for success, so monitoring and quality-assurance efforts focused on slurry design and optimization, pumping procedure design and optimization, solids-transport modeling and assurance of appropriate shut-in intervals between batches.

Engineers selected the primary through-perforations injection point at 2,062 to 2,072 m [6,765 to 6,798 ft] MD with a backup injection point at 1,756 to 1,766 m [5,761 to 5,794 ft] MD. The injection tubing was 5 1⁄2-in. tubing from 1,756 to 1,766 m [5,761 to 5,794 ft] MD with a backup injection point at 2,062 to 2,072 m [6,765 to 6,798 ft] MD with a backup injection perforations injection point at 2,062 to 2,072 m [6,765 to 6,798 ft] MD.

The injection-tubing volume of approximately 150 bbl [24 m³] took three slurry batches to displace. Limitations in slurrification tank capacity limited the amount of slurry volume that could be mixed at one time to around 80 bbl [15 m³]. Since the tubing volume could not be displaced with one batch of slurry, cuttings in suspension could remain in the injection string for some time. Engineers were concerned that the long residence time and the deviated nature of the wellbore might cause the cuttings-laden slurry to settle and form beds of waste material along the low side of the injection tubing. These cuttings beds might slide down and plug the well during the shut-in intervals between batches. Because of the high risk of plugging, quality-control requirements for slurry rheology were critical.

Marsh funnel viscosity is a key indicator of CRI slurry quality. For this well, engineers were concerned that the normal injection-slurry viscosity range of 60 to 90 s/qt [60 to 90 s/L] might not be adequate. Since gel strength and low shear-rate viscosity (LSRV) contribute to rheology characteristics that affect static suspension, further tests were performed on the slurry using a Fann Model 35 viscometer and LSRV analysis using a Brookfield low-shear-rate viscometer. Solids-settling tests, at a room
temperature of 17°C [63°F] and at the estimated downhole temperature of 60°C [140°F] were also performed. Based on these data, an initial Marsh funnel minimum viscosity requirement was set at 120 s/qt [approximately 120 s/L]. Engineers later reduced the requirement to 90 s/qt after experience was gained with the injection system.

Critical to a successful operation was determining how long slurry could be left in the injection tubing without solids dropping out and potentially plugging the disposal well. Engineers used gel-strength and LSRV data and a numerical model to predict cuttings transport, settling velocity and the maximum allowable residence time. Simulation software was also used to ensure optimization of operational procedures and of the slurry rheology and solids-suspension characteristics—both for periodic injection and for shut-in stability between batches.

The simulator divided the injection-well configuration into small segments. Then, fundamental physical relationships helped numerically determine local solids concentrations, cuttings-settling rate, bed formation, bed sliding and erosion, and solids accumulation at the bottom of the well.

Engineers assumed that 80-bbl slurry batches would be pumped at a rate of 4 bbl/min [0.64 m³/min] and that the shut-in time between batches would be four hours. The numerical simulations demonstrated that injection at a rate of 4 bbl/min would erode any solids bed that might have formed in the 4½-in. tubing. Simulations also showed that after four hours of shut-in between batches, the upper solids bed (above the 5½-in. tubing) would slide from 1,756 to 1,935 m [5,761 to 6,348 ft] along the tubing. Since this is still approximately 125 m [410 ft] above the top of the perforations, a shut-in interval of four hours was allowed.

CRI proved to be the most effective drilling-waste management option for SEIC’s drilling operations offshore Sakhalin Island. Optimization and risk-management procedures were successful in reducing the uncertainties associated with this critical cuttings-injection well. The drilling window was extended to year-round operations, and logistical constraints associated with ship-to-shore disposal were resolved. By achieving a zero-discharge operation, this project demonstrated that cuttings re-injection is an economically sound, environmentally friendly, long-term solution for cuttings disposal in remote and environmentally sensitive areas.

### Advances in CRI Modeling

Once surface procedures and plugging risk have been properly assessed and managed, engineers turn their attention to fracture propagation. The planning phase of most CRI projects uses numerical models to predict the propagation behavior of the fracture relative to the injected volume (previous page). For production engineers, modeling fractures is a key process to optimize hydrocarbon recovery in low-permeability reservoirs. Today, CRI engineers use similar processes to design waste-injection programs, reducing risk to the operator and assuring a smooth, efficient drilling process.

In CRI operations, safe containment of the injected waste must be ensured. The extent and propagation properties of the fracture network created during fracturing operations must be predicted with confidence; this is often accomplished with three-dimensional hydraulic fracturing simulators. Typically, large volumes of waste are injected, creating large fracture networks. Waste-containment mechanisms must be evaluated during feasibility studies to identify possible disposal zones and fracture-containment zones (below).

Three fracture-containment mechanisms are particularly important in selecting a disposal formation. Formations with fracture gradients larger than those in the target injection zone can often prevent the fracture from propagating beyond the design bounds. Overlying formations with increased fracture gradients, such as salt formations, are also ideal containment or sealing formations. A fracture may also be contained by a high-permeability formation even though its fracture gradient is lower. As carrier fluid leaks off into the high-permeability formation, solid particles are left behind, preventing the fracture from growing in the high-permeability zone.

Lastly, a fracture may be contained by a harder or stiffer formation with a higher elastic modulus. Once the fracture approaches or enters the harder or stronger formation, the width of the fracture in and near the stiffer formation is reduced; thus, the frictional pressure is increased, preventing or slowing fracture growth into the formation. Since these fracture containment formations are not difficult to recognize, appropriate injection and containment zones can easily be identified.

![Modeling fracture confinement. Advanced fracture simulators help engineers visualize the extent and orientation of induced fractures. Injection zones are most often capped at the top, and sometimes on the bottom, by shales or evaporite formations; this helps in containing the vertical growth of the fracture network.](image)

Understanding the storage mechanisms in cuttings-injection operations is another key process for predicting the disposal capacity of an injection well. Experts in the field tend to agree that multiple fractures are created from intermittent cuttings-slurry injections. In a recent laboratory evaluation, a series of color-coded slurries was injected into several 1-m³ blocks of different types of rocks. Afterwards, the blocks were split and the fractures were analyzed. Results showed that slurry injection created subparallel fractures. Field-pilot drill-cuttings injections with real-time seismic and tiltmeter monitoring and subsequent coring into the predicted fracture networks also proved that CRI processes created multiple fractures. A consistent finding of these programs is that repeated slurry injections create multiple or branched fractures; these fractures characteristically occupy an evolving region, or disposal domain.

The reason that new fractures are created from repeated slurry injections is that shut-in periods between injections allow the disposal fractures to close onto the cuttings and dissipate any pressure buildup in the disposal formation. The presence of the injected cuttings causes a redistribution of the local stresses, resulting in the creation of new fractures with subsequent injections. The new branch fracture will not be aligned with the azimuths of previous existing fractures; instead, a network of fractures is created from periodic slurry injections. On CRI projects, the drilling-waste management plan is generally in place before drilling commences, so modeling of uncertainties and risks is particularly important for CRI design and engineering. Risks can be reduced by using numerical simulators to model uncertainties. For example, on a well in South America, little information was available on formation properties such as permeability and Young's modulus. At the time of the disposal-well design, the drilling program had not yet been finalized. Therefore, the cuttings generation and required slurry-injection volume and rates were undefined. Because of these uncertainties, the extent of the fractures created from CRI operations was predicted as a range rather than a single value.

Since each uncertainty has a different distribution and impact on CRI operations, a probabilistic approach helped engineers generate a risk-based result. For example, risk-analysis results based on fracture simulations and ranges of uncertainties helped develop probabilistic predictions of fracture extent from the wellbore. Simulations indicated that there was a 90% chance that the fracture extent from the wellbore would be larger than 230 ft [70 m] and smaller than 270 ft [82 m], while the 50% probability value of the fracture extent would be 250 ft [76 m]. Based on this result, engineers determined that a well spacing of 300 ft [91 m] would be adequate to avoid drilling a live well into a disposal fracture.

This risk-based approach can be applied to modeling of other important CRI parameters such as disposal capacity. Simulations indicated that repeated slurry injections create multiple or branched fractures; these fractures characteristically occupy an evolving region, or disposal domain.

12. G-function analysis is a technique to describe fracture pressure-decline behavior. It is a nondimensional function of postshut-in time normalized by the pumping time. Variance in fracture shape can be identified by changes in pressure decline after shut-in that is identified by this specialized time function. For more on the G-function: Gurajani SN and Nolte KG: “Fracture Evaluation Using Pressure Diagnostics,” in Economides MJ and Nolte KG: Reservoir Stimulation, 3rd Edition. Chichester, England: John Wiley & Sons Ltd (2000): 34–46.
that there was a 90% chance that at least 31,000 bbl [4,929 m³] of cuttings could be safely injected into this well. Assuming 20% cuttings by volume in the slurry, this means that the disposal capacity of this well is at least 155,000 bbl [23,849 m³] of slurry. Since the injection zone was a permeable sandstone formation from which fluid could readily leak off, the impact of fluid volume on disposal capacity was ignored.

Analysis of the operational data also helps validate modeling results and provides early warning of potential downhole problems. On a well in the Sakhalin area, a dedicated CRI well was drilled, and 5%-in. injection tubing was installed. The injection zone was a low-permeability shale formation with interbedded sandstone layers, both above and below the perforated interval. Hydraulic fracturing simulations demonstrated that fractures created from slurry injection would grow upward from the shale formation and into multiple zones.

As operations began, step-rate pump-in and falloff tests were performed. Analysis of slurry properties and injection-pressure data showed the signature of fracture-height growth during the injections (right). More detailed analyses on the pressure-decline data after slurry injections also showed fracture-height recession over multiple zones during the shut-in periods. Pressure and pressure-derivative plots versus a specialized time function, often referred to as the G-function, indicated the signatures of fracture-height recession over multiple zones.12 These results were consistent with preinjection fracture-modeling results.

Integration of the geologic evaluation, numerical modeling and pressure signature yielded a full picture of fracture development downhole. Analysis of the pressure data in this case allowed engineers to avoid rapid injection-pressure increases and the potential for loss of injectivity by adjusting the injection-rate and slurry-viscosity specifications as part of the ongoing quality-control process.

**Pressure Monitoring During CRI Operations**

Pressure monitoring forms the foundation for understanding how an injection well is performing. Pressure trends over time provide a key indicator of operations performance. If the pressure rises slowly over time, this might suggest a normal filling of the injection zone. However, a rapid pressure rise suggests near-wellbore plugging that requires immediate attention. Conversely, a rapid drop in pressure might indicate a leak in the system, either at the surface or downhole. Finally, pressure data are a key input parameter for hydraulic fracture models, which are used both for initial system design and model validation throughout the life of the injection operation.

Early in a project, rock properties are not always clearly understood, and the exact lithological sequence is not always known, so engineers make assumptions for a wide variety of model-input parameters. This initial feasibility study determines the range and potential storage capacity of a hydraulically induced subsurface fracture complex, the lateral and vertical growth of the fractures, and the anticipated pressure changes during CRI operations (bottom). These simulations provide guidance for injection-well design, the number of injection wells required, the pressure regime for the tubing design, and surface-equipment specifications.

![Monitoring injection cycles. CRI engineers monitor injection-cycle pressure data to identify trends such as fracture-height growth. The slight increase in fracture initiation pressure (red) may indicate fracture-height growth, although further analysis is required for confirmation.](image)

![Typical injection pressure and pressure falloff signatures during a single injection episode in CRI operations. Shown here is a typical injection-pressure recording over an entire injection cycle that includes a pumping or injection period and a shut-in period. After pumping stops, the fracture will close and pressure will decline, eventually reaching that of the formation. Variances or abnormalities in these curves help engineers identify problems in the injection system.](image)
Once the injection well has been drilled and logged, the rock properties and lithology sequence are input into the model, improving its accuracy. Then, after the first injection sequence, injection pressures at specific pumping rates, slurry densities and viscosity data provide further information for model validation and adjustment. This cycle of monitoring, model update and validation is repeated at intervals during the slurry-injection project, so the model is continually refined, and the projected ranges for slurry-injection capacity, fracture growth and pressure development are narrowed.

Technicians at the wellsite closely monitor injection-pressure data to ensure that the pressure response is developing as predicted. Deviations from the modeled pressure trends during the slurry-injection project, so the model is continually refined, and the projected ranges for slurry-injection capacity, fracture growth and pressure development are narrowed.

Engineers use the monitoring system data to ensure that operational parameters are within the ranges specified and simulated in the prewell planning phase. During injection operations, a monitoring and diagnostic software package ensures that the injection well is performing as expected and alerts CRI operators to any developing risks (above). A cuttings-transport simulator is also available to forecast slurry stability and help maintain injectivity. If the real-time monitoring system signals potential risks, M-I SWACO CRI assurance engineers at the wellsite then use FracCADE fracturing design and evaluation software or other diagnostic tools to provide a more detailed pressure analysis.

In the North Sea, one operator used CRI techniques to inject cuttings below the 13%-in. casing shoe of the main wellbore. The injection formation was located in a geologically complex environment close to a major fault. This location significantly increased the risk level associated with CRI operations and disposal fracture containment.

To minimize these risks, a group of M-I SWACO geomechanics experts specializing in injection monitoring and pressure-trend analysis identified subsurface risks and geological hazards during injection operations and fracture-geometry evolution. The team monitored and evaluated all injection parameters on a daily basis and performed in-depth analysis of injection pressure.

Pressure analysis during one injection sequence resulted in abnormal postshut-in-pressure decline, represented by a straight-line pressure-decline pattern. This unusual pattern had not been observed during earlier injections. Analysis of the event showed no significant variations in injection parameters or slurry rheology.

The main objectives of pressure-decline analysis are to identify the reasons for unusual pressure patterns, to predict the impact on fracture behavior and the CRI system, and to evaluate any associated risks. Data from other CRI projects had demonstrated that a straight-line pressure-decline pattern may have several causes, one being the development of abnormal restrictions at the injection point.

The engineering team analyzed pressure derivatives with respect to nondimensional G-function data after a specific shut-in time to detect changes that occurred during the pressure-decline process. Analysis of the derivatives indicated linear behavior during the pressure decline. Based on the initial information from the straight-line pressure-decline interpretation and indirect factors such as behavior of pressure derivatives, the most likely cause of this unusual pressure-decline behavior was a restriction in the injection point.

To confirm the diagnosis, a cement bond log (CBL) was run to verify the condition and level of cement at the injection point and to determine whether a restriction had developed at that injection point. CBL data confirmed that the level of cement in the 9%-in. annular section was higher than designed and had bridged part of the openhole section, introducing a restriction at the injection point.

From the pressure-analysis results and a review of the CBL data, engineers were able to define the problem and implement mitigation procedures to minimize the restriction impact.
and the risks to further injection operations. Changing the volume of the displacement stage and reduced residence time for cuttings in the static well annulus allowed operations to continue despite the annular restriction. More than 46,000 bbl [7,300 m³] of injection slurry were safely injected into the CRI well.

In another North Sea case, an operator was using annular injection processes between the 13%-in. and 9%-in. casings in a production well to dispose of oil-base cuttings generated by primary drilling operations. After five months of normal injection procedures, a pressure spike of 600 psi [4,137 kPa] was noted during annular injection. Sudden injection-pressure increases may be related to a number of factors, including well obstruction or well plugging, fracture plugging, particle settlement and operational errors such as closed valves. Some problems are relatively easy to identify through adequate analysis of pressure signatures, but others are more elusive.

Onsite engineers and technicians checked the well for potential leaks and confirmed the integrity of the CRI system. During evaluation, routine CRI operations continued with the knowledge that the injection pressures were spiking higher than normal. While carefully monitoring the annular pressures during injection, technicians noted that annular pressure spikes seemed to coincide with high levels of production caused by artificial lift. Since there were no other practical alternatives for cuttings management, it was critical to understand the reasons for the consistent increase in surface pressure during the postshut-in period after CRI injection and its relationship to production activity. Following a careful and extensive evaluation, engineers found that the CRI pressure spikes were related to fracture-gradient increase resulting from thermal expansion of the formation during production.

Analysis of CRI pressure behavior showed that a considerable pressure difference occurred when the well was flowing and when it was static. Engineers discovered that the 600-psi variation observed between the two situations coincided with a theoretical fracture-gradient increase associated with a 23°C [41°F] change in rock temperature. The effect of the rise in temperature resulting from production operations was greatest near the wellbore, increasing formation stress by about 600 psi. The CRI injection pressure had to overcome this effect to open the fracture, causing a sudden increase in the injection pressure.

Daily monitoring of injection parameters and regular in-depth pressure analysis can significantly reduce risk and increase the level of injection quality assurance. Monitoring also helps to ensure environmentally safe and seamless CRI operations in spite of the significant uncertainties of data availability and quality. Regular in-depth pressure analysis allows engineers to monitor the progression of injection fractures, validate and update geomechanical models and extend the life of the injection well.

Reducing Oil Waste

The amount of waste-oil mud pumped down injection wells along with cuttings is considerable. Although OBMs generally have a much longer life than water-base muds, their life is not indefinite. During the course of drilling, solids-removal equipment extracts cuttings and fine solids from muds as they return to the surface. However, even with highly efficient equipment, not all of the solids can be removed. The small amount left in the mud is continuously subjected to the grinding action of pumps and other mechanical equipment. Over time, the particles become smaller and smaller, eventually reaching sizes less than one micron and exponentially increasing their surface area (above).

As the ultrafine solids content in the mud increases, the fluid’s performance and general stability decreases; eventually the mud is considered “worn out” and is disposed of. Since much of the economic value of an oil mud lies in the oil itself, generations of drillers and service companies have searched for methods to recover base oil from these worn-out muds.

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The amount of waste-oil mud pumped down injection wells along with cuttings is considerable. Although OBMs generally have a much longer life than water-base muds, their life is not indefinite. During the course of drilling, solids-removal equipment extracts cuttings and fine solids from muds as they return to the surface. However, even with highly efficient equipment, not all of the solids can be removed. The small amount left in the mud is continuously subjected to the grinding action of pumps and other mechanical equipment. Over time, the particles become smaller and smaller, eventually reaching sizes less than one micron and exponentially increasing their surface area (above).

As the ultrafine solids content in the mud increases, the fluid’s performance and general stability decreases; eventually the mud is considered “worn out” and is disposed of. Since much of the economic value of an oil mud lies in the oil itself, generations of drillers and service companies have searched for methods to recover base oil from these worn-out muds.

The M-I SWACO RECLAIM technology is a chemically enhanced solids-removal process, capable of eliminating the majority of the fine solids from nonaqueous fluids. The fine solids, or low-gravity solids (LGS), that accumulate in a mud system during the drilling process hinder efficient drilling in several ways: pipe-sticking potential is increased, rotary-torque levels may rise, the penetration rate may decrease, and the mud may experience other problems related to its increased viscosity.

Solids-control equipment typically removes LGS particles greater than 5 to 7 microns, while smaller particles remain in the mud system. As the concentration of these fine solids continues to build, the only conventional recourse is to dilute the mud system to reduce the LGS concentration or to build new mud. Dilution and building of more mud increase waste, disposal volumes and the overall cost of the drilling project.

The RECLAIM system is designed to remove the bulk of fine colloidal particles and may also be used to increase the oil-to-water ratio (OWR) of the drilling fluid. The technology comprises flocculants, surfactants and a RECLAIM unit skid containing all the components required to effectively flocculate fine solids in a nonaqueous fluid (below).

Flocculation of oil-wet solids in suspension is not a trivial task. Surfactants developed by M-I SWACO and their research partners weaken the mud’s emulsion so that proprietary flocculating polymers can agglomerate the fine solids. Once flocculated, the LGS can be removed with conventional centrifuge techniques. The polymer also promotes the demulsification of the brine droplets in the mud. Therefore, a secondary effect of this process is that water is removed along with the solids, concentrating the base-oil and increasing the OWR.

RECLAIM technology may be used on active drilling projects to improve solids-control equipment efficiency, in postwell mud reconditioning of inventory and for the recovery of base oil from worn-out mud systems. In the process, fluids from the active drilling operations or storage location are transferred to the RECLAIM unit feed pump (next page). Before the fluid reaches the pump, a surfactant is injected into the fluid at predetermined concentrations. The surfactant reduces the emulsion stability of the mud allowing the flocculating polymer to adhere to the fine solids.

As the fluid is transferred to the centrifuge, flocculating polymer is added to the fluid stream by an injection pump. The fluid is then routed through a mixing system for blending. Afterwards, high-speed centrifuges separate LGS and water from the base fluid. Reclaimed fluid is returned to the active system or tanks for storage. The waste

\[ ^\text{A self-contained system for reclaiming fluid. The RECLAIM skid-mounted treatment unit contains all the equipment necessary to facilitate the RECLAIM process including polymer and surfactant tanks, water and oil tanks, pumps, mixers, control systems, and feed and return lines.} \]
stream is discarded from the centrifuge for disposal. This waste material contains not only the flocculated solids but also a portion of the water phase. If required, the bulk of the water phase can be removed by adjusting the polymer-treatment level. Excess polymer is also removed, ensuring the generation of a virtually solids-free, reusable, nondegraded base-fluid.

In one case, while drilling in the foothills of the Rocky Mountains northwest of Calgary, an operator was left with 1,258 bbl [200 m³] of 1.20-sg [10-lbm/galUS] low-toxicity mineral oil-base mud after drilling each well, most of which was stored for reuse on the next drilling project.\(^\text{14}\) As mentioned previously, as oil-muds wear out through reuse, performance parameters suffer, particularly the rate of penetration. In this case, the operator needed to improve rate of penetration (ROP) to reduce well costs. One way of improving ROP is to drill with a low-density mud of 0.95 sg [7.91 lbm/galUS] or less. However, the density of the oil-base fluid in use could not be reduced from 1.20 to 0.95 sg by conventional means and would have to be disposed of, increasing the cost of both the drilling fluid and disposal. RECLAIM technology was used on location to reduce the existing mud density from 1.20 to 0.95 sg, eliminating the need to replace and dispose of 1,258 bbl of mud per well.

In another case, mud returned from the field to an M-I SWACO mud plant in the Middle East contained 16 to 20% LGS, had an OWR ranging from 70:30 to 80:20, and an average density of 1.20 sg. The operator’s specification for mud to be returned to the field was a 90:10 OWR with a density of less than 1.08 sg [9.0 lbm/galUS].

At the mud plant, engineers had another problem. Standard treatment to bring the used mud back into condition required high levels of dilution with diesel, which would take a significant amount of time and stress the limits of plant capacity. The dilution process would also produce large volumes of waste fluids that would require disposal.

Using RECLAIM technology, engineers achieved an OWR of 90:10 with no significant change in the volume of fluid being treated. The technology allowed the dilution volume to be significantly reduced from 160 to 30%, which in turn reduced mud-treatment costs. OWRs up to 98:2 were achieved with increased doses of flocculent, and recovered fluid was used for dilution in place of new diesel.

RECLAIM technology effectively eliminated the high dilution required to recondition mud returns from the rig, and significantly reduced disposal costs for excess fluids. Costs to bring the treated-mud properties back to specification were a fraction of those likely to be incurred during dilution or when building new mud.

Managing Waste and Resources

Unearthing terrestrial resources is an age-old process. Regardless of the method used, the generated wastes must be properly managed. Through generations of drillers, the E&P industry has sought the perfect solution for drilling-waste disposal. While current solutions to the problem are not perfect, they are far better than those available just a few decades ago.

Up-to-date practices, including fracturing underground formations, help recover hard-to-access reserves and, at the same time, provide a suitable resting place for millions of tons of drilling waste. By returning rock and debris excavated from the Earth back to their origin, operators have taken a significant step toward environmental stewardship. Similarly, methods such as RECLAIM technology are improving the utilization of available resources, and reducing waste products and the costs of recovering hydrocarbon reserves.

CRI and RECLAIM technologies are among a host of other methods either in use or under development that promise to facilitate movement toward minimizing environmental impact while improving reserve recovery. In the years to come, the continued development and deployment of clean and green technologies will help the oil and gas industry extract the Earth’s resources with minimal environmental impact. —DW

\(^\text{14}\) Fluid density is often given as specific gravity, or sg, representing density in grams per cubic centimeter.