THE AMERICAN OIL & GAS REPORTER®
FEBRUARY 2016
The "Better Business" Publication Serving the Exploration / Drilling / Production Industry

Technology Solves Sanding Problems

By John H. "Jay" Thompson,
Jeff Dwiggins
and Scott Muster

OKLAHOMA CITY–The industry's concept of sand control has been redefined by unconventional reservoir development. A decade ago, sand management was associated with conventional, high-permeability reservoirs, where "getting the beach out" was required to sustain hydrocarbon production in sand-producing intervals, particularly sandstones and other unconsolidated formations.

With the advent of multistage completions of horizontal wells in unconventional resource plays, the production of frac sand and other proppants has become a more widespread challenge. For the majority of oil and gas fields, sand from the reservoir is an inevitable byproduct of hydrocarbon production. In unconventional wells, however, it is a consistent challenge.

Virtually all wells completed in unconventional formations experience some level of proppant flowback, since all wells in these plays require hydraulic fracturing to produce economic rates of liquids and gas. Proppant flowback begins immediately with fluid flowback at the time of pressure release, but can occur to different degrees throughout a well's productive life cycle. Depending on the particular operator's completion method, sand flowback issues can range from moderate to severe, and may present myriad problems.

The immediate concern is damage to artificial lift systems and other downhole equipment, in particular electrical submersible pumps, as well as plungers, valves and tubular components. Sand-related problems can be very expensive to remediate, resulting not only in increased operational costs, but also potentially leading to equipment failures that necessitate unscheduled repairs and interrupting hydrocarbon flow to the sales line (increasing costs while decreasing revenues).

Given the prevailing low commodity price environment and the need to optimize the economics of each asset, a single equipment failure can impact a well's bottom-line performance materially. Costs vary based on the type and size of equipment installed and the well's location, but the capital expenses associated with a well intervention to repair or replace a damaged ESP system can exceed $150,000 for horizontal wells. The value of lost and/or deferred production from downtime also must be factored into the equation, along with the possibility of decreased reservoir performance that may never be restored.

In some wells, downhole pumps have to be replaced as often as three or four times a year because of wellbore sanding, creating an operating cost structure that challenges profitability, especially at lower wellhead prices. In pad developments with multiple wells, recurring sand problems that require frequent interventions can negatively impact the economics of individual pads as well as entire field development areas.

Looking at well construction trends in shale and tight reservoirs, proppant flowback and sand control issues certainly do not appear to be diminishing anytime soon. In fact, given the correlation between higher volumes of sand pumped during hydraulic fracture treatments and better production performance in horizontal wells in many plays, proppant volumes pumped per well have effectively doubled since late 2013, according to data from Primary Vision Inc.

Increased proppant concentrations per stage mean that wells completed with 500-750 pounds of proppant for each lateral foot a few years ago now are being completed with 1,000-1,500 pounds/foot (routinely exceeding 7 million pounds total for each lateral completed in the Bakken, Eagle Ford and other plays). While helping operators maximize production and recovery rates, it also obviously places twice as much frac sand in the formation.

Sand-Related ESP Failures

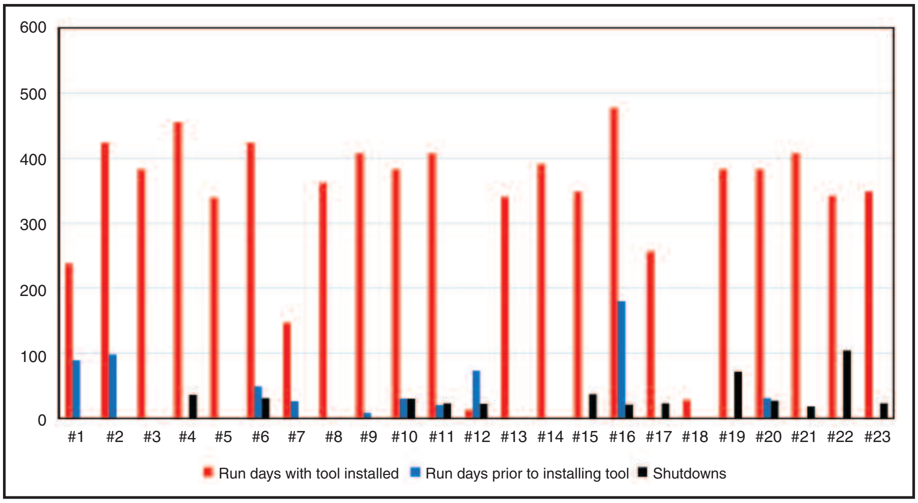
Sucker rod pumping is the most widely used artificial lift method in U.S. onshore operations, but oil and gas companies invest more capital in electric submersible pump equipment than any other lift method. In fact, ESPs account for more than 45 percent of the total annual spending on artificial lift installations. They are deployed routinely in shale plays to accommodate high productivities, and frequently are used in combination with other forms of artificial lift at different stages of a well's productive life.

For example, a horizontal well may be equipped with an ESP to accommodate the high-rate initial production phase, but then converted to rod pump or some other form of lift once IPs have dropped. But even in these situations, proppant flowback typically occurs most frequently in the earliest stage of production, when an ESP is required to accommodate the peak initial flow volumes.

Consequently, ESPs in horizontal shale wells commonly suffer from severe erosion and radial wear caused by frac sand and other residual solids. The biggest chal-

FIGURE 1

ESP Run Days Before and After Installing Sand Control Tool (Mississippian Lime Wells)



lenges for ESPs are sand and gas slugging, which lead to excessive temperatures in the motor, cable and pump section. Prominent failure modes are related to erosion, sand accumulation, plugging or contamination, and loss of radial stability.

In unconventional reservoir applications, ESP shutdowns happen throughout the life of a well, and sanding is always a concern when restarting the pump. When an ESP cycles off or shuts down, the sand trapped in solution in the production stream begins to fall out and collect on the top of the pump. By the time the ESP cycles back on, sand can accumulate to the point that it clogs the pump chamber.

Restarting a sand-plugged pump can cause catastrophic harm, including the inability to restart because of severe plugging (thereby mandating a workover), significant damage to the upper stages (commonly top 20-30 percent), forcing lower stages into down-thrust, torque twisting and broken pump shafts, and burned motors from starting under high load conditions.

For this reason, fluctuations or disruptions in electric supply are a key issue in ESP applications. Every time the power goes out, sand starts falling back on the pump.

Electricity reliability tends to be a localized problem, and some areas are worse than others. In North Dakota, for instance, ongoing improvements to stabilize the power grid in the Bakken play area have eliminated many lingering problems. However, in areas such as the Mississippian Lime trend in Oklahoma and the Permian Basin, power fluctuations remain the root cause of many production issues, including pump failures caused by sand.

Not surprisingly, sand fallback has been identified as the number one cause of ESP failures in unconventional wells. In propped horizontal shale wells, the fluid column in the tubing string will almost always have significant volumes of suspended sand. Therefore, some sustained level of solids production must be accepted in order for a well to be produced, but establishing a proactive sand management strategy is vital to protecting the ESP, achieving an acceptable run life, and keeping production flowing smoothly.

One solution to controlling an ESP's exposure to proppant flowback is using curable resin-coated sand designed to form a "pack" under temperature and closure pressure conditions to mitigate sand production while maintaining fracture conductivity. The downside to this approach, especially given today's tighter economic margins on well completion and production operations, is the additional cost of premium proppant materials compared with uncoated frac sand.

Many ESP manufacturers have technologies engineered to cope with sand passing through the pump. But when the ESP shuts down from a power failure, pump-off conditions, production shutdowns, etc., previously pumped sand falls back onto the top stages where it wreaks havoc on attempted restart.

Sand Control Tool

An alternative approach available to operators is a low-cost mechanical tool that is located in the tubing string just above the ESP pump discharge to guard against sand-related problems. The relatively simple device captures fallback sand and segregates it away from the pump. It diverts falling-back, solids-laden fluid to an inner chamber, which in turn, allows the fluid to drain off back through the pump, while capturing sand and solids within the chamber.

When the pump is restarted, the captured sands and solids are expelled from the chamber by the flow action of the pumped fluid, and are carried to the surface. The system can be cycled endlessly, eliminating potential damage to the pump at every shutdown while lowering lease operating expenses by protecting downhole equipment and increasing ESP run times.

Because it has no moving parts, it is fail-safe and invisible to the ESP. An important technical feature of the technology is an automatic self-flushing capability that empties the pump after every restart. Since there are no ports to the annulus (the tool does not communicate with the annulus), pumped recirculation is impossible.

SandRidge Energy is deploying the technology in more than 30 ESP well installations in the Mississippian Lime play, and the company is realizing substantial increases in ESP run times in hydraulically fractured wells that historically have suffered from problems caused by significant sand production.

Figure 1 shows performance data on ESP systems installed in 23 SandRidge-operated wells equipped with the tool to safeguard the downhole pumps. All of the wells produce sand, and two of them yield such heavy sand concentrations that two devices have been installed in each well to ensure the ESPs are protected. With well production rates varying between 400 and 6,200 barrels a day across the field, two sizes of ESPs are installed: a 4.0-inch outside diameter system for wells producing at lower daily rates, and a 5.38-inch outside diameter pump for wells with rates greater than 3,500 bbl/d.

ESP run life in the field is on an upward trend, thanks to high efficiencies, good operational procedures, and a focus on ESP reliability solutions. The sand control tool has performed flawlessly, allowing the pumps to record as many as 477 run days (and counting) after the tool was installed, representing an average 1,200 percent improvement in ESP run times.

No pumps have been lost because of sand in the field since the tools were installed, and there have been no workover call-outs to mitigate sand-related well or pump failures. In an extreme case, as many as 104 shutdowns were observed within six months in one of SandRidge's wells. With the tool in place, the ESP was protected at every shutdown and production was able to resume immediately flowing each time the pump was restarted.

By preventing damaged pumps and costly well workovers, the tool provides an affordable safeguard against sand fall-back in wells equipped with ESPs. The net result for SandRidge in the Mississippian Lime is significantly lower lease operating expenses, extended ESP run life, increased overall production, and dramatically reduced downtime and deferred production. ❐

JOHN H. "JAY" THOMPSON *is the artificial lift specialist with SandRidge Energy in Oklahoma City. He has been with SandRidge for three years, but has more than 27 years of experience in the surface and downhole pumping industry. Thompson's interests include the effects of wellbore design and how that affects ESPs, root cause failure analyses, and how the longevity of downhole equipment can be improved.*

JEFF DWIGGINS *is managing director of Artificial Lift Solutions. He has more than 25 years of experience providing support for all types of artificial lift projects in many of the world's major oil-producing areas, including Russia, China, the Middle East, Asia, South America and the United States. Dwiggins started his own consulting firm in 2002, opening his international office in 2005. He holds a B.S. in mechanical engineering from the University of Oklahoma.*

SCOTT MUSTER *is managing principal of MCe Performance, and works as a marketing consultant to Houston-based Multilift Welltec LLC, which manufactures the SandGuard™ tool used to protect the ESPs in SandRidge Energy's Mississippian Lime wells. Muster is an award-winning branding/marketing executive with more than 25 years of experience coaching teams of corporate thought leaders and graphic arts professionals to produce marketing materials and messaging. He is a graduate of the University of Houston.*