MANAGEMENT OF HESS SUCKER ROD LIFT FAILURES IN THE BAKKEN

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INTRODUCTION

The Bakken and Three Forks formation is one of North America's largest shale plays, covering much of North Dakota and some areas of Montana and Saskatchewan. Hess operates in over 600,000 net acres in the core of the basin located in North Dakota (as shown in Figure 1) with over 1,000 active wells in the Bakken and Three Forks. In addition, Hess has an active drilling program and large inventory of economic well locations based on current spacing assumptions.

Hess produces from 17 individual fields in the Bakken shale play. Each field is separated by geographical location, and varying pressure-volume-temperature (PVT) properties as shown in Figure 2 and Figure 3. All new wells follow a standardized drilling and completions program. A typical Hess well is drilled to 10,000 feet of vertical depth with a 10,000 foot lateral and completed with more than 30 individual fracture stages. Before artificial lift installation, wells will flow naturally for varying periods based largely on reservoir quality, gas liquid ratio (GLR), and water cut. When the natural flow ends, the well has a sucker rod lift system installed to artificially lift the well.

The Middle Bakken and Three Forks crude composition and production chemistry vary across the basin. The varying water cut, transient production profiles, scaling and salting tendencies, PVT characteristics, and slugging or flumping (flowing while pumping) nature of these wells create operational challenges for sucker rod lift systems. While operating in the basin, Hess has experienced failure rates approaching 0.9 failures/well/year but has improved, currently operating at a failure rate approaching 0.5 failures/well/year. The large inventory of wells and the rapid development pace present economic, production, and resource challenges when considering the failure rates that have been experience over recent years. Further improvement to the failure rate will improve the overall economic viability of this unconventional base.

This paper describes Hess' implementation of a process to decrease two primary forms of artificial lift failures in the Bakken: scale and tubing failures. These means of failure have resulted in over 250 failures (23% of the total failures) since 2012. The following case studies examine each of these failures in turn:

1) Evidence of scale in early wells led Hess to pilot a variety of deployment techniques before finding success in the current scale mitigation technique: scale squeezes. Calcium carbonate scale is most common in fields identified as Area A and Area B. Scale failures occur at the downhole pump and most often result in a stuck pump or bottom hole assembly (BHA). Remediation often results in a workover that does not address or prevent the root cause of failure on subsequent installs. Scale inhibitors have been used to great effect; this paper will present the deployment techniques and applications used to date and address both technical and economic challenges and drivers leading to the ultimate success of this program.

2) Tubing and rod wear impact a large number of wells in an acquired field identified as Area C. These failures are more prevalent in wells with deviated vertical sections, a high water cut with high specific gravities (greater than 1.22), and a high gas-oil-ratio (GOR) that decreases pump fillage and increases gas interference and rod buckling. To reduce holes in tubing caused by deep rod buckling in these types of wells, the use of polylined tubing is now being standardized. Although other forms of remediation methods exist, this paper will address the specific application of polylined tubing and the key drivers that led to the technical and economic success of its use.

Hess has addressed failure rate in the Bakken using a number of pilots that focus on the root cause of failure and have yielded great improvements. These processes are being implemented field-wide to alleviate and eliminate single root causes of failure in existing wells, and their application to infill wells will eliminate hundreds of future failures due to related issues. A disciplined approach has been adopted that leverages lean methodologies such as a

Plan, Do, Check, Adjust (PDCA) cycle and standard work, as a basis for continuous improvement. This paper will demonstrate how this innovative approach can greatly impact the pull on resources and operational costs, thereby improving overall well economics and ultimate recovery of the resource.

CASE STUDIES – SCALE

Scale represents a major cause of failure in both Bakken and Three Forks wells. Scale and the resultant failures can be mitigated in a number of ways. Hess has piloted many different scale mitigation deployment techniques in previous years. We have found a solution in scale squeezes, which reliably protect the integrity of downhole equipment, thus minimizing scale as a failure mechanism and maximizing the economic recovery of wells.

The majority of scale found in Bakken wells is calcium carbonate or iron sulfide. Failures due to scale typically result from a downhole pump failure, ranging from plugged intakes, stuck pumps, and traveling and standing valve failure. No scale failures have been observed in naturally flowing wells. Scale mitigation efforts began by truck treating wells with a scale inhibitor. An attempt to standardize a plan for scale mitigation began in 2010 with the addition of a scale inhibitor to fracture stimulations. Scale inhibitor was added to the proppant in fracture jobs in the fields most prone to scale failures in the Bakken: Area A and Area B. Chemical residuals were expected to remain above the minimum effective concentration (MEC) for a full year after treatment. The treatment during fracture stimulation was found to average $75,000/well/treatment and decreased the failure rate from 10-12%, depending on the area, as shown in Figure 4. This proved to be an expensive mitigation method, and we began to develop and test other means of protection. Early tests of scale squeezes were successful. Due to the lack of failures during the natural flowing period, the squeezes were performed directly before artificial lift installation. Although using scale inhibitor during the fracture treatment trials was considered a technical success, it was no longer economically justifiable when compared to the success of the cheaper scale squeezes executed before artificial lift installation.

Multiple complete water analyses (CWAs) were performed in fields with scaling tendencies to investigate trends and identify which wells required scale treatment. A trend was observed in Area A for bicarbonate levels above 200 mg/L, while no trend was found in Area B, as shown in Figure 5. Calcium and bicarbonates are both required for calcium carbonate to precipitate. Bakken produced water has an excess of calcium; thus bicarbonates are the limiting ions that define the capacity for scale to form. A higher concentration of bicarbonates inside the water increases the capacity of scale to precipitate. Lower water cut rates in Area B resulted in average costs of squeezes much lower than those in Area A. The decision was made in the first quarter of 2014 to squeeze all wells in Area A with bicarbonate levels above 200 mg/L (approximately 75% of wells in Area A), and to squeeze all wells in Area B during artificial lift installation. Water samples are taken from the treated wells to measure phosphate residuals on a monthly basis after the squeeze. When the residuals drop below the MEC levels, a re-squeeze is performed. The cost of a squeeze is less than half the cost of treatment with a scale inhibitor during the fracture, and it has proven just as effective. Moreover, scale inhibitor additions to fracture fluid treat the well when scale failures are not expected. Unfortunately, scale squeezes can be very costly in areas with high water production. To maintain economic viability, scale squeeze designs are limited to a maximum of 50 barrels of water per day (BWPD), which includes the majority of the field-wide production levels. If the rates of individual wells exceed this threshold, the residuals are monitored closely to determine re-squeeze dates appropriate for rapidly changing production rates, and to test the limits of the chemical to obtain maximum effectiveness in future designs.

An additional benefit of scale squeezes is the removal of trucking requirements. North Dakota experiences many days of extreme weather and thawing periods, forcing restrictions of trucks allowed on non-paved (lease) roads. Truck-treated wells go untreated during these periods, whereas squeezed wells are protected for a much longer time and have no trucking requirements during the protected period. Scale squeezing is a much safer treatment method, requiring much less manpower, and is now the preferred and standard method of treating Hess wells for scale in North Dakota. Although this method has become the standard, challenges still exist moving forward. An increasing well count increases the number of squeezes and re-squeezes. The anticipated well count increases the re-squeezes to over 500 squeezes per year required in the near future if other treatment methods are not identified. This number of squeezes will burden vendors because it is more than ten times the current rate of squeezes, and will require an increase in vendor manpower and infrastructure. We have found the best way to combat this burden is trusted partnerships with vendors. At the end of 2014, a presentation was made to all chemical and pump truck companies to inform them of future projections. This allows service companies to plan for future personnel requirements. Although a scale mitigation standard has been set, pilot projects to further optimize treatment methods are ongoing.

We are currently testing alternative methods of treatments, including continuous liquid chemical treatment and chemical pills below the pump, as well as optimizing batch treatment technology.

CASE STUDIES – POLYLINED TUBING

A Bakken field identified as Area C was found to have many failures resulting from holes in tubing. These failures are attributable to a variety of factors. Area C was an acquired field. When it was acquired, it had a high amount of dog leg severity (DLS) in the vertical section, which increases the side loading on the rod string during sucker rod lift, increasing the risk for failure due to parted rods/couplings and holes in tubing. Area C wells also have a much higher GOR and higher water cut than many other Bakken fields. All of these attributes make rod pumping more difficult. This leads to ineffectively drawn down wells with constant gas interference and numerous wells with tubing holes caused by constant rod buckling. A high failure rate in Area C was not significantly decreased by guiding rods alone.

A pilot project in the area investigated using polylined tubing to reduce failures due to rod and tubing wear. The purpose of lined tubing is to reduce friction between the rods and tubing, resulting in reduced wear and decreased failures. Pilot wells were chosen based on their mean time between failures (MTBF) and consisted of wells in which the majority of wear or the holes in the tubing were in the bottom portion of the tubing string, mitigating rig time and complications associated with multiple crossovers. These choices lessened the time and resources spent on the pilot project. Due to the high cost of polylined tubing compared to the standard L-80 tubing, much thought was put into the length of polylined tubing used in each well. The implementation of polylined tubing has an additional benefit because guides are not recommended to run inside the polylined tubing, decreasing the total cost of the sucker rods. In areas where rod-on-tubing wear is imminent, the total wear volume of the tubing is also increased in hopes of extending the run life.

This polylined tubing pilot project involved many learning opportunities throughout its implementation. The first lesson learned involved the crossovers used. Initially, the crossovers used from the standard L-80 tubing to the polylined tubing proved to be an immediate failure point. All crossovers above the polylined tubing were exchanged for polylined crossovers. It was later discovered that the original crossovers had a manufacturing defect that affected all of our installs. The defect led to a leak path regardless of the guides, couplings, or rod selection run throughout that section. The new polylined crossovers seal against the polylined tubing like a gasket, preventing any leaks from occurring. Another lesson involved rod coupling selection for the polylined tubing section. Type T Couplings were initially run through the polylined section, which is a much softer coating than spray metal. These couplings wore down quickly and then eroded through the polylined tubing. Failures in these wells were expensive, requiring the replacement of the worn couplings and multiple joints of damaged polylined tubing. The overall solution was to use polylined crossovers above the polylined tubing, no guided rod strings in the lined tubing section, and spray metal couplings in the lined section. This criterion is under review to determine whether it should be implemented in other areas.

An alternate objective of the polylined tubing pilot project was to determine the optimal length of lined tubing. Minimizing the amount of polylined tubing used minimizes the additional cost; however, determining the minimal length for each well has proven difficult. In some of the problematic wells, previous failures in the lower portion of the string have moved up the hole above the polylined tubing section. This indicates the success of the lined tubing: in the Bakken wells, there have been no failures in the section of polylined tubing. Holes resulting from wear occur further up hole, as previously mentioned, or the well failures are caused by other failure mechanisms such as pump issues. Additional testing is underway to determine the optimal length of lined tubing in each well. Improvements due to polylined tubing installation are evident, but results have shown that it is necessary to improve upon all aspects of the artificial lift system to substantially improve upon the failure rate in this area. Other pilot projects currently being considered in areas of high tubing wear explore rod guide placement on tubing strings.

CASE STUDIES – SUMMARY

Failures due to scale have decreased dramatically in Area A and Area B. Scale failures decreased from 19% of the total number of failures to 6% in Area A and from 38% to 17% in Area B. These rates are expected to continue to decrease as a larger percentage of wells are squeezed, with the hope of eventually eliminating scale failures altogether. Current scale failure results for Area A and Area B are shown in Figure 6. Area C is much smaller in terms of both size and well count than Area A or Area B, and the polylined tubing pilot is in a much earlier phase than the scale mitigation efforts previously mentioned, so a complete evaluation would be premature. There are currently 23 wells using polylined tubing technology; some of the wells in the pilot have just reached their average MTBF run time before the polylined tubing install. Because the wells have not yet failed, it is impossible to report on the success of the method meant to reduce failures. The results shown for Area C in Figure 7 are, therefore, a worst-case scenario for MTBF results analysis. Using only current data, there has been an average increase of three months in MTBF for each well using polylined tubing technology. It is also important to note that there have never been any tubing or rod failures in polylined tubing sections.

MORE WITH LESS – EBS

As the total number of Bakken wells continues to increase, the well count is quickly outgrowing the staff. Facing a substantial increase in well count, Hess has developed a method for effectively and efficiently operating in these conditions. Exception based surveillance (EBS) is a tool that was developed to standardize repetitive tasks and obtain maximum value from field personnel. EBS clarifies roles and responsibilities, and benefits personnel by minimizing employee exposure to safety hazards.

One method of exception based surveillance is lease operating by exception (LOBE). LOBE is used to increase the total number of wells that a lease operator can effectively manage, while also increasing the operator's productivity. LOBE refines the earlier method of visiting each well site daily to record numbers and monitor maintenance needs. Each route is remotely monitored and will be visited to perform routine and preventative maintenance based on a schedule. Only when a well flags for certain variables falling outside of the guidelines will a well receive a visit outside of its schedule. A multitude of performance triggers are located in the field. When certain performance triggers are flagged, a standardized process is initiated based on the trigger. This same idea is being implemented across engineering and technician disciplines with flags such as pump fillage, run time, and production variance being developed, each with their own standard process. As EBS implementation progresses, more triggers will be identified and defined. As a trigger is located, a swim lane workflow is developed to approach and mitigate each issue with clearly identified responsibilities for different roles. The workflow ensures that each group works efficiently and each issue is resolved in a reasonable time.

Exception based surveillance is a broad project still in the early stages of implementation and development. Ensuring that an area is ready for EBS implementation is a burden that requires assessment of well readiness, communication, and whether standard work practices apply to the field's current values. As more fields are added to the EBS project, it will become easier to locate hotspots, areas for improvement, and potential production additions.

FAILURE ANALYSIS

In order to improve, it is important to measure current performance. Hess uses a Safety, Quality, Delivery, Cost (SQDC) approach when comparing success, achievements and increased performance. Failure rate is a key metric for measuring the quality of our producing wells in North Dakota. The most efficient wells effectively drawdown the reservoir to output optimum production while lengthening the average run time between each failure. These two variables are connected and, usually, inversely related values. In order to properly measure the current status and to improve upon it, Hess has developed a failure analysis dashboard. Each failure is analyzed to determine the exact location and root cause. This dashboard accounts for multiple variables such as depth of failure, wear seen, solids found (and their type), pump condition (as well as notes from teardown reports), and many other variables to help in properly determining the root cause of failure. This dashboard allows us to easily locate areas with high risks or high rates of failure to mitigate the possibility of future problems with the same root cause.

Recent discussions between top Bakken operators have revealed failure rates ranging from higher than 2 failures/well/year to as low as 0.4 failures/well/year. With a current failure rate approaching 0.5 failures/well/year, Hess is in the early stages of true field optimization but making improvements to decrease failure rates. While existing failure rates are maintained with current rig fleet operations, the total well count will put a strain on resources if the current failure rate is not significantly decreased. One goal of the Bakken team is to understand the current failure mechanisms and decrease the failure rate while the total well count is more easily managed. When successful pilots are expanded into infill wells and fields with high well counts, it will be easier to maintain the fields with longer run times and optimized production rates.

Figure 1 – Hess Operated DSUs in North Dakota

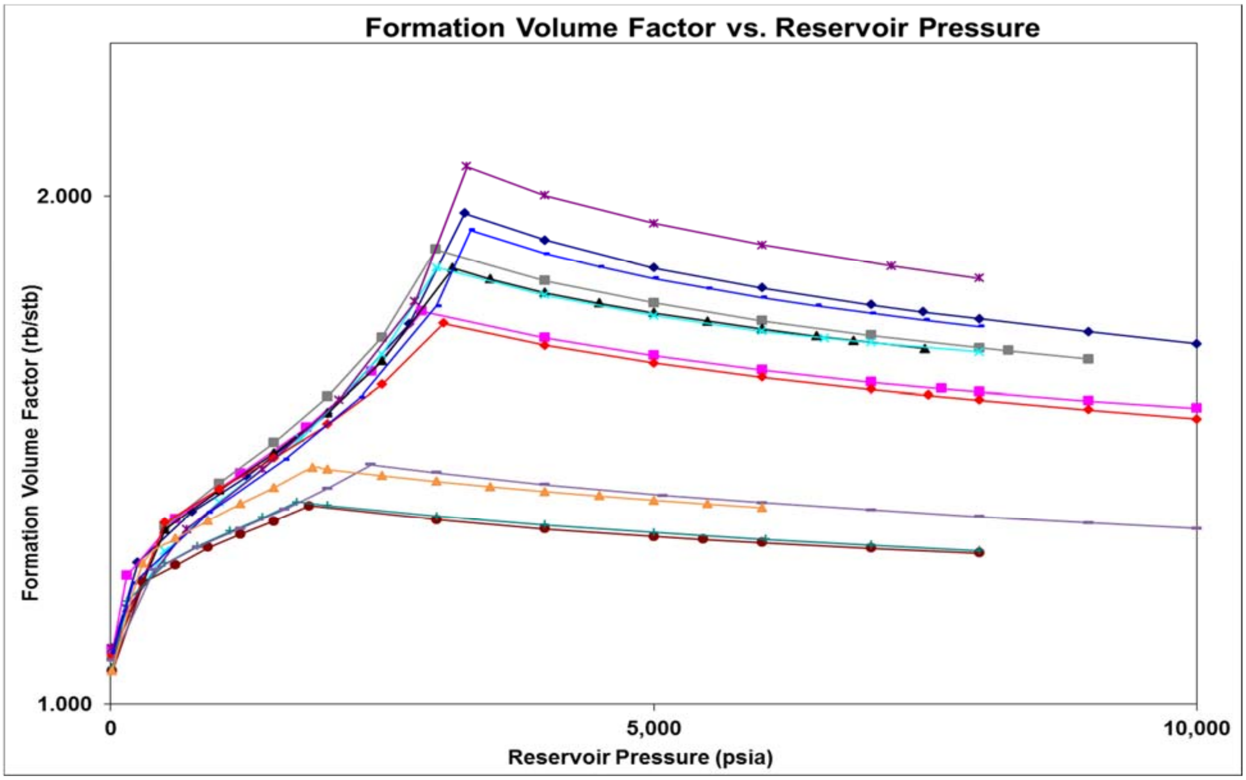


Figure 2 – Formation Volume Factor vs. Reservoir Pressure

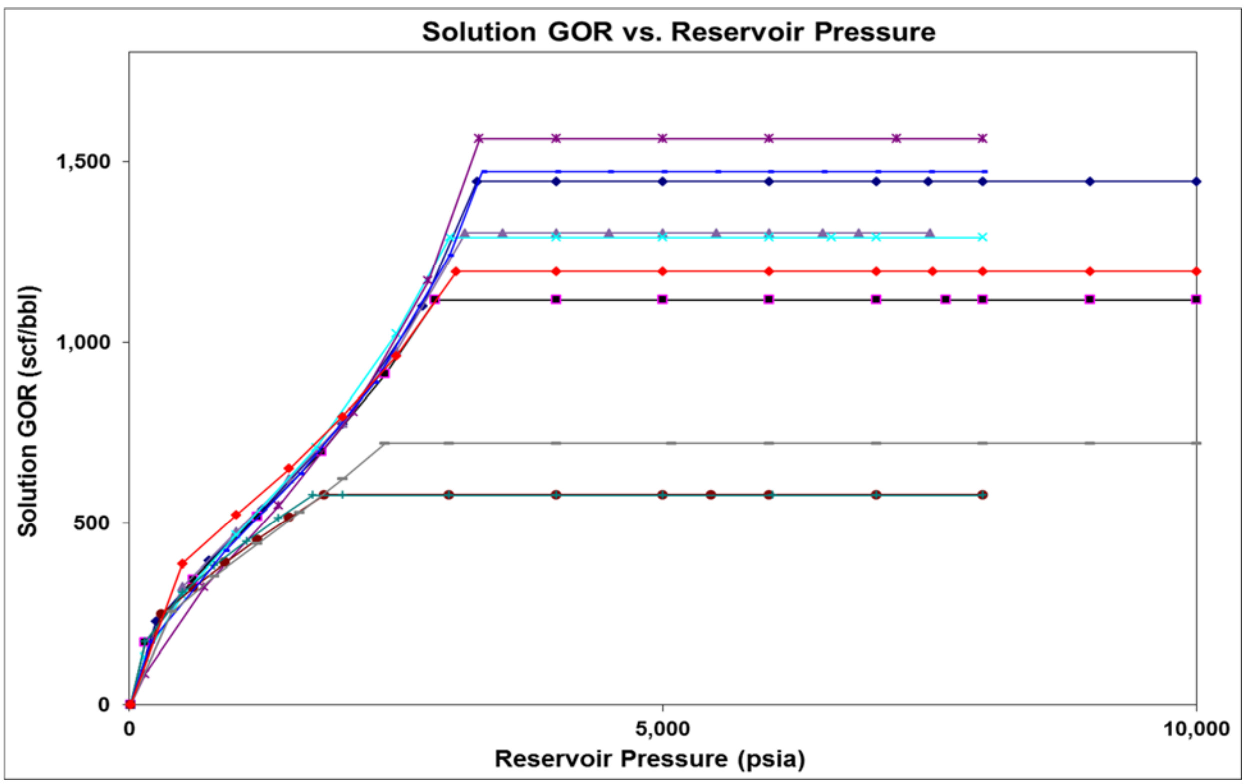


Figure 3 – Solution GOR vs. Reservoir Pressure

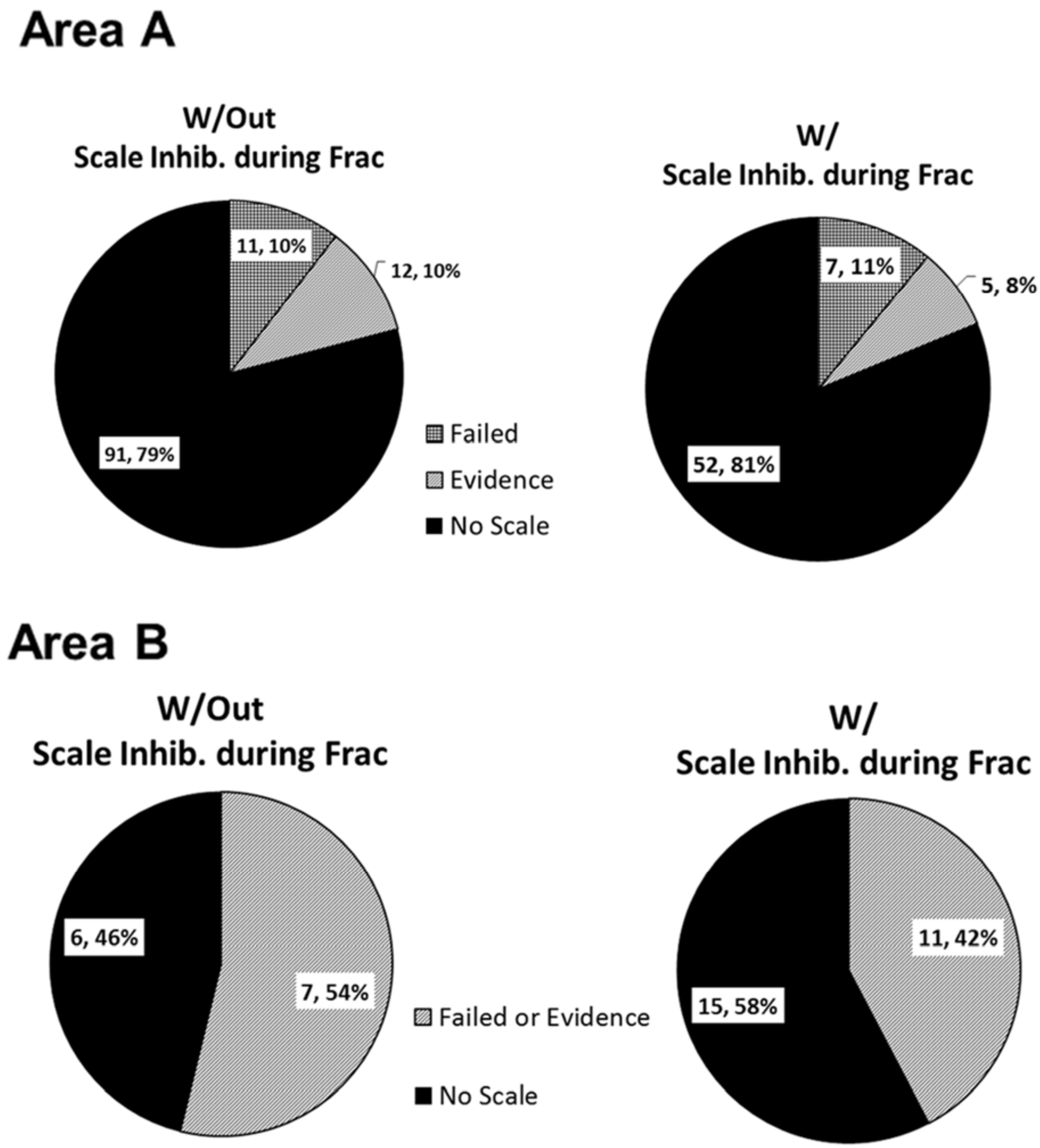


Figure 4 – Scale in Area A and Area B

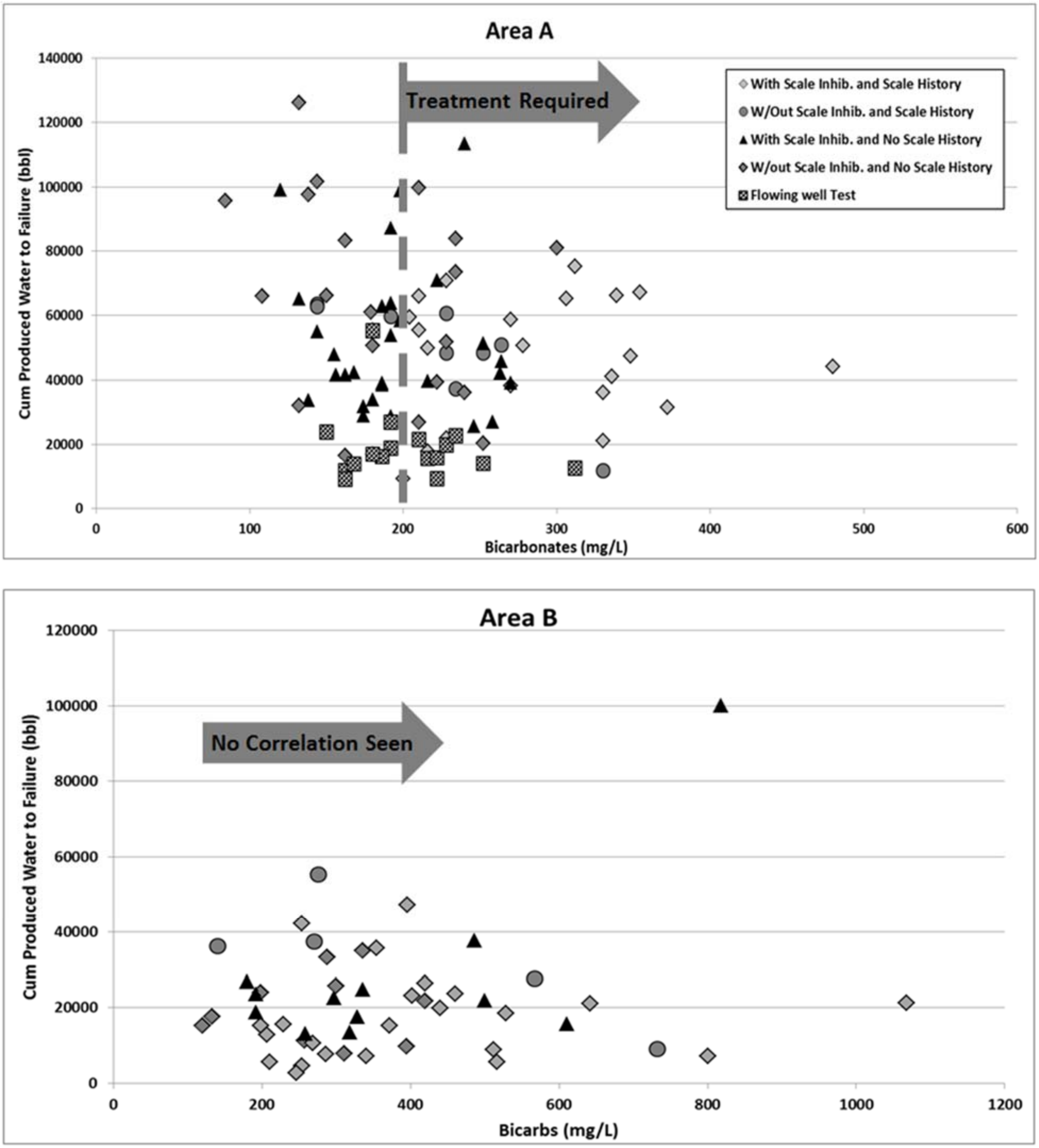
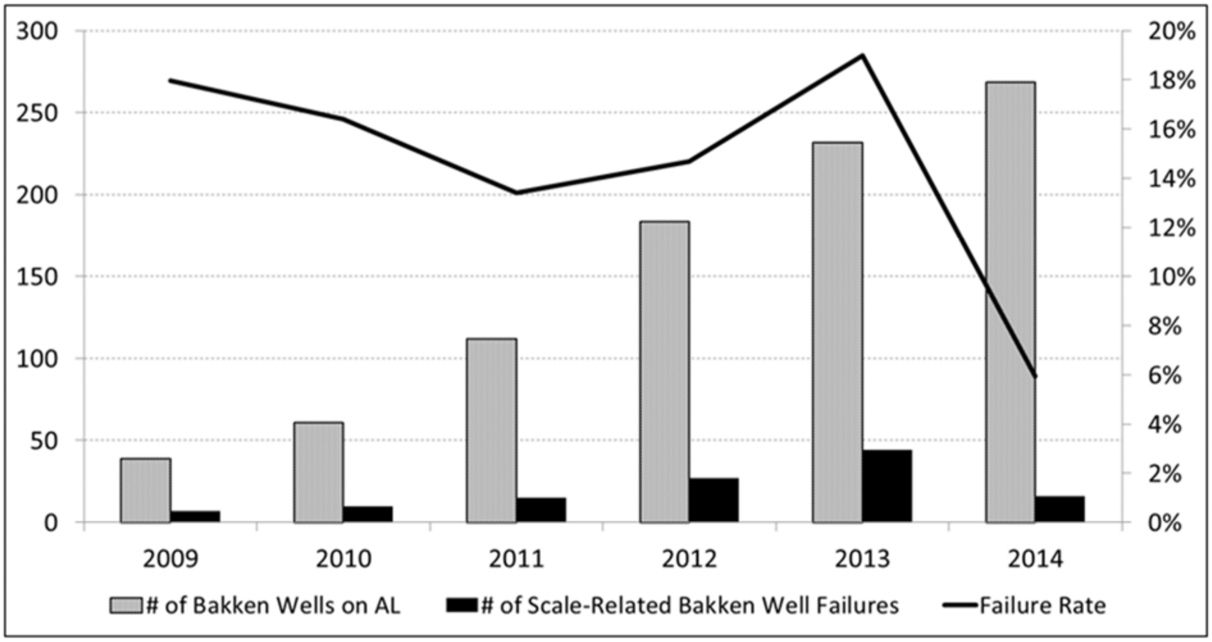


Figure 5 – Scale Failure Results in Area A and Area B

Area A



Area B

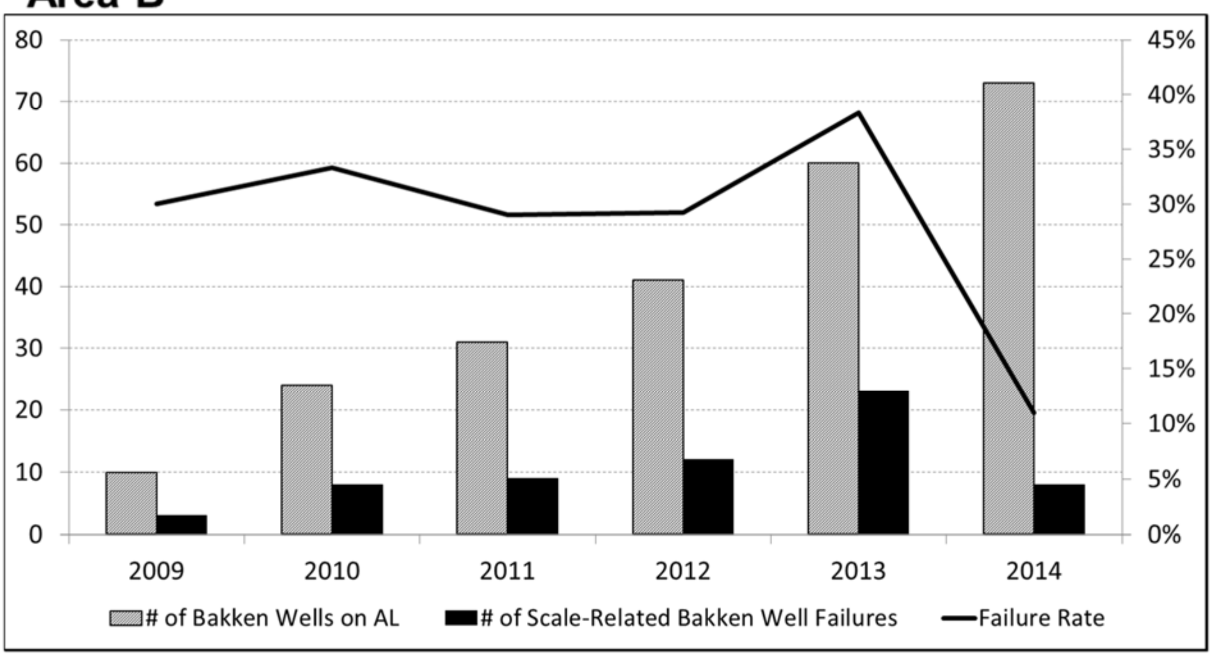


Figure 6 – Failure Rate in Area A and Area B

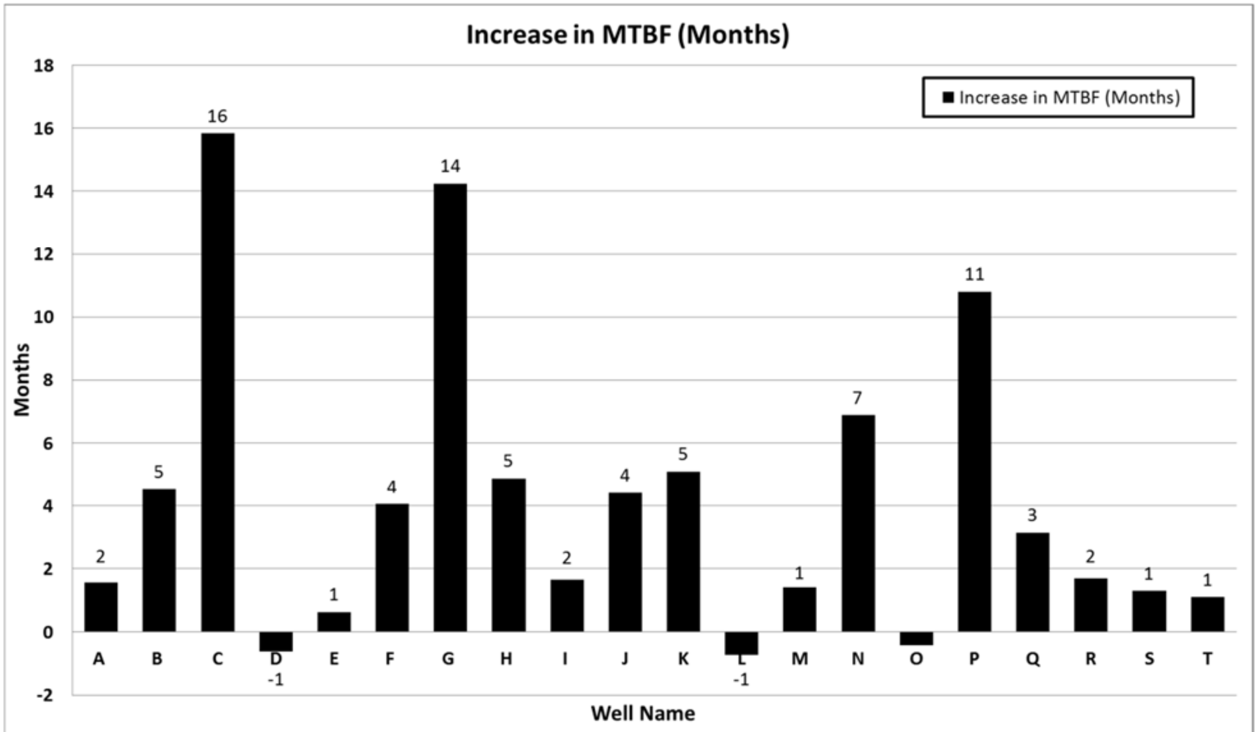


Figure 7 – Polylined Tubing Candidate Increase in MTBF (Months)