PARAFFIN INTERVENTION CASE HISTORIES, PRACTICES, PROCEDURES, AND ECONOMICS

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Abstract: Treating for paraffin in rod pumped wells is a critical operating cost driver that needs continuing attention. While there are various prevention chemicals, operators still need periodic removal interventions. This paper will summarize prior investigations regarding the removal of paraffin and provide case histories that illustrate the issues. In addition, this paper will discuss the economic considerations related to common paraffin removal processes. The economic considerations will include the direct costs as well as the indirect, hidden costs. In general, paraffin removal in rod pumped wells by annular hot oiling has severe depth limitations that require periodic, supplemental treatments. The economic benefits and trade-offs are largely dependent on the depth of paraffin deposition, the type of paraffin, and the wellbore configuration.

Background: Paraffins are waxy components of crude oil that solidify on production equipment over time. The buildups typically are where the wellbore temperatures are the lowest in the production system. In the summer, the coolest place may be near the surface. Depending on the air temperatures at night, the lowest temperatures may be in the exposed wellhead and flowlines. Once deposited, lighter hydrocarbons continue to evolve from the deposit based on the composition, temperature, and pressure. This continuing separation leads to heavier, harder, and thicker paraffin.

The buildup of waxy paraffin can lead to various operational costs. Plugged flowlines, plugged tubing, rod parts from friction loading, and increased electrical consumption are all examples of direct costs of paraffin buildup. However, the indirect costs may be even more dramatic. These indirect costs are related to the impacts on the mechanical systems and the impact on the reservoir performance. Mechanically, conventional annular hot oiling actually deposits paraffin in the casing by tubing annulus and fines in the hot oiling contribute to stuck anchors and stuck pumps. The lack of adequate removal is a major cause of stripping jobs. In wells where the melting temperature of the paraffin is greater than the formation temperature, repeated hot oiling can be major source of formation damage.

Dealing with paraffin is generally broken down into two processes. The first process includes a range of prevention chemical treatments to keep the paraffin from transforming into a solid or keeping the paraffin dispersed. The second process is removal of paraffin after it is separated from the lighter ends and is attached to the tubing. The most common removal techniques are annular hot oiling and solvents. Prevention and removal processes have serious limitations that limit their effectiveness.

Paraffin Prevention: The prevention chemical processes include pour point suppressants, crystal modifiers, and paraffin dispersants. The complex chemistry of these process generally require the presence of the lighter hydrocarbons to work. There are a variety of problems with these processes that limit their ability to be fully effective. Perhaps the biggest problem is the scheduling of the treatment with the production. Since the chemicals need to be in the hydrocarbon phase continuously, batch treating is obviously the greatest problem. Batch treating yields results only on the batch of fluid being treated. Continuous treating schedules improve the likelihood of chemical being present in the production. However, problems with adequate flush volumes, coordination with pumping schedules and the erratic production of wells all lead to treatment inadequacies.

Compatibility with other treating fluids is a more subtle, but perhaps a more serious problem with paraffin prevention techniques. In the vast majority of wells, corrosion inhibition is the highest priority of chemical treating. Paraffin prevention is a secondary effort that is often times not checked for compatibility with the corrosion treatment. Many chemical companies use aromatic solvents as a carrier fluid for their paraffin prevention chemical. While using aromatic solvent carrier fluids can provide a modest amount of removal capability in addition to the prevention characteristics, the solvent can undermine the effectiveness of the higher priority corrosion inhibitor program. Corrosion inhibitors are filming chemicals and do not work by being present in the fluid. Among the most effective means of stripping the films is to attack them with aromatic solvents. Combination treating programs require a level of due diligence that is often times not managed well. In one case, for example, a chemical company thought that pumping a spacer between the corrosion treatment and a paraffin program would help. However, when confronted with the question of the impact of downhole stripping, they had no solution. After confronting another chemical company with the compatibility issue, they reformulated their paraffin prevention chemical to avoid the use of aromatic solvent carrier fluid.

Whether the problems are human error, fluid compatibility, or delivery process inadequacies, paraffin prevention programs almost always require supplemental, periodic removal programs.

Paraffin Removal: Once paraffin is separated from the lighter hydrocarbon components, solidified, and attached the steel, the two predominant paraffin removal processes are thermal melting (i.e. hot oil/water) and chemical dissolution (i.e. solvents). Before each process is discussed, there are principles that need to be better understood about the properties of the paraffin. In general, the hardest and thickest paraffin in a well is near the surface. The temperatures and pressures are less near the surface than further down the hole. As the pressure increases, more of the lighter ends are kept in the paraffin. Deeper paraffin tends to be softer and more "greasy". Unlike prevention techniques that focus on cloud point temperatures, removal techniques focus on the melting temperature of the paraffin. In particular the most critical factor that should guide the understanding of removal alternatives is the melting point of the paraffin near the surface. Because of the nature of each crude oil and the amount of separation during paraffin formation, the melting temperature can be surprisingly high. In fact, the melting temperature can be far higher than the formation temperature. If the melting point of the paraffin is above the formation temperature, there is a risk of both formation damage and tubular plugging. If this melting temperature is below the formation temperature, the paraffin problem is primarily a tubular treating problem. In general, the higher the melting point of the paraffin near the surface, the deeper paraffin exists in a well. The risk of paraffin formation damage and the depth of paraffin deposition are the most important considerations for removal techniques.

The Hot Oiling Process: The most common treatment for the remediation of solidified paraffin is melting the paraffin with a hot oil or hot water treatment. During this process, a hot oiler truck heats a load of oil or water with a portable boiler and injects the fluid directly into the flowline at the surface melt and displace the paraffin in the flowline to the battery. Additional heated fluid is then pumped down the tubing by casing annulus while the well is pumping. This heat passes through the tubing, melts the paraffin, and the liquefied paraffin is then pumped out of the well. The process is so effective at removing paraffin near the point of injection that the effectiveness away from the point of injections is overlooked or taken for granted.

Field personnel have passionate debates and biases about using hot oil or hot water that are generally not substantiated without defining the practices in the field. The specific heat of water is approximately 1.0 BTU/lb F while oil is approximately 0.5 BTU/lb F. Those proponents of hot water rightfully claim that more heat can be added to the well at a given temperature even though the temperatures are limited to near the boiling point of water. Proponents of hot oiling like to claim that oil can be heated to much higher temperatures and only the temperatures above the melting point of paraffin matter. (Note: Boiler safety and issues with vapors generally limit typical practices to 250F at the boiler. Furthermore, many operators believe the oil can be "burned or overcooked" at temperatures above 250F.) Oil proponents also emphasize the increased solubility in the system as the cooled oil is pumped back and the avoidance of bacteria and oxygen in the system.

In practice, however, the technique of the typically unsupervised hot oil operator can have the biggest impact on which selection works. The cost of boiler fuel, the daily schedule, and even the day of the week have a bearing on the effectiveness of the job.

Regardless of the fluid that is used, the hot oil/water process has significant safety and operational and formation risks.

From a safety perspective, a hot oil truck is considered one of the most dangerous pieces of equipment in the oil field because of boiler failures that result in fires or explosions. This single piece of equipment accounts for a disproportionate share of fatalities.

Operationally, the risk of solids in the fluid can stick tubing anchors or foul downhole pumps. Some operators, pump oil from the lower, backside valves on their oil tanks to clean their tanks. Some operators pull oil from over the top. Some operators pull from the load line. Operators that use produced water introduce the risk of solids in the water. Collectively, these varying sources of solids increase the risks to downhole equipment.

From a formation damage perspective, the problems are more subtle and cumulative. Hot oiling can deposit paraffin on the walls of the casing that is stripped off during future jobs. The resulting paraffin that is carried downhole has less light ends and has a generally higher melting point. If solid paraffin from the surface is displaced into the formation, the risk of formation damage increases.

Depth of Effective Treatment: As noted earlier, the success and sense of gratification of the process near the point of injection surface has created a lack of awareness or lack of concern as to the depth that hot oil/water treatments succeed in removing paraffin. Copeland, et.el surveyed oil field professionals in 2012 and found the vast majority of those surveyed generally believed that paraffin was melted to at least 1500' or deeper.

Sandia National laboratories studied the heat transfer processes in 1996 and successfully developed a model of the temperatures during the hot oil process. The basic heat transfer study was confirmed with field tests. This study suggested that typical hot oiling could not melt paraffin below 500-800'.

Unfortunately, the heat transfer modeling in the Sandia investigations was limited to wells that are not necessarily common to many areas of the country. In particular, the study used wells where the production casing was cemented to the surface. Cement acts as an insulator that greatly simplifies the assumptions of losses during the process. For the large number of wells where the production casing is not cemented to the surface, the water, drilling mud, or formation porosity outside the casing act as tremendous heat sinks that "steal" heat from the process of heating up the tubing. These thief zones, greatly reduce the ability to heat up the tubing deeper in the well.

The other significant limitations of the Sandia heat transfer study were the surface configurations. The study does not define the surface layouts but there is reason to believe the boiler was very near the wellhead so that the modeling of the heat losses across the truck and the flowline could be simplified. There is no reference in the study to the heat losses across the hot oil truck, the flowline materials/distances to the well or even the ambient conditions during the research. Like the uncemented casing limitation, these losses at the surface also act as a heat sink/thief to the overall process.

Investigations by Copeland, et.el in 2012 studied practical temperature profiling techniques across the entire hot oiling process. These investigations were done in wells where the casing was not cemented to the surface and the where the hot oiler was a more conventional, safe distance from the well. One of the most striking findings was the heat loss at the surface across the equipment and throughout the treating line to the well. Combined with the downhole heat sinks, this investigation confirmed that the depth of effective hot oiling was far less than generally believed by industry.

Together, these investigations indicated that practical hot oiling effectiveness in wells where the casing was not cemented to the surface would be in the range of 300-600' if the job was pumped in the summer when surface losses were mitigated. Practical wintertime hot oiling would be further limited. During cold weather, wells with large casing configurations and high melting temperature paraffins could easily be treated to only 50-100'.

While there is little doubt the hot oil/water process removes paraffin near the surface and works from the top of the well downward, the degree of misperception regarding the depth of removal is a human factor that contributes to the indirect costs of paraffin removal. There is almost no question that many rod failures and many stripping jobs were the direct result of inadequate paraffin removal.

The Solvent Process: The solvent process does not use heat and injects a batch of solvent down the casing. At the bottom of the well, the solvent mixes with the wellbore fluids and is returned to the surface by the downhole pump. The ability of the mixture to dissolve paraffin is enhanced by the addition of the solvent. As the mixture contacts the paraffin and is agitated by rod action, the paraffin is dissolved and produced out of the well. The solvent is a hydrocarbon that is then sold with the crude oil. This process does not have the heat transfer limitations of hot oiling and has the ability treat the entire production string.

The process, however, has a number of drawbacks. Compared with hot oiling that works from the top of the well and progresses downward, there is no instant gratification or success at the surface. The process requires contact time and works from the bottom of the well and progresses upward. Second, the cost of the solvents can be high sizing the job has considerable uncertainty. Third, the cost of the process requires modifications to general accounting procedures. Ideally, accounting systems should credit back a portion of the sale of the crude oil to the field superintendent's budget to reflect the value of the solvent was sold with the production. Netting this revenue from the production also avoids paying royalties on the solvents that were not part of the mineral estate. Collectively, these factors favor more frequent use of hot oiling. However, direct comparisons of job costs are most meaningless because solvents have the potential to treat the entire well while hot oiling is severely depth limited. The value of the deeper treatment is critical to the comparison.

For operators that use solvent techniques, the type of solvent needs to be evaluated. Higher cost aromatics generally have the greatest capacity to dissolve paraffin and react the quickest. However, on a delivered basis, there are many situations where other solvents, like diesel or gasoline are more cost effective.

There are also several operational problems with solvents. Some operators let the wells circulate for a 24-48 hours. Returns back down the well increase the risk of solids similar to hot oiling jobs. The volumes and contact time are also a problem for solvent methods. Solvent jobs can only be evaluated by breaking a union at the surface and visually checking for the presence of paraffin. Lastly, larger solvent jobs in wells that have been repeatedly hot oiled may free up significant solids on the wall of the casing that can stick an anchor or foul a pump. Unfortunately, solvent treating cannot typically be done on a continuous basis because of the adverse effects on the corrosion inhibitor program.

Despite the drawbacks, solvent treating can avoid the risk of a solid paraffin collars/plugs deep in the well. The operational costs of these plugs can be quite severe.

Hybrid solvent treating: The best paraffin removal process should capture the broad range of industry experience. Filtering at the surface should be a part of either process to avoid inadvertent solids from fouling downhole equipment. The significant heat transfer/depth limitations of hot oiling should be recognized by periodically supplementing the efforts with solvent treatments to address the deeper problems. In some areas where solvent treating should be the primary removal method, hot oiling might be effective in advance of the solvent job by removing the heaviest, hardest paraffin in the upper section of the well, thereby reducing the amount of solvent that would be required.

Field Case Study-Hot Oiling: Heat transfer studies by Sandia National Laboratories and industry studies of surface temperatures, no matter how compelling, are best supported by actual evidence during field operations. Anecdotally, many operators have been frustrated with encountering paraffin related problems during repairs on wells that were recently hot oiled. Perhaps the most frustrating experience is the inability to fish a parted rod because of paraffin and having to strip the tubing out of the well. Depending the severity of the paraffin problem, a simple rod part may result in $20,000-30,000 repair. One of the most severe repairs is an unfishable shallow rod part where the rating of the tubing can be exceeded with the weight of the tubing, the weight of the parted rods, the weight of the fluid load, and the required anchor unsetting force. Unfortunately, failure analyses and cost analyses due not typically investigate the systematic hot oiling process as a root cause of the higher costs.

A repair job for a well in Washington County, Texas in 2015 investigated the paraffin removal process. The well was being pulled to repair a hole in the tubing 21 days after the well was hot oiled. The ambient temperature during the hot oil treatment was approximately 90F. Typically, the operator unset the pump and hot oiled directly down the tubing to clean the rods for inspection while pulling the pump. The reservoir temperature was high enough that the risk of formation damage was minimal. The well had 5-1/2" casing with a top of cement at 8900'. The 9-5/8" surface casing was set at 2840'. Based on the industry studies, the paraffin should have only been removed to depth of 300-600'. For this job, the well was not hot oiled down the tubing. The rods were pulled and were free of significant paraffin to a depth of 550'. At that depth, heavy paraffin was encountered. If the well had failed with a rod part below this depth instead of deeper tubing failure, successfully fishing a rod part would have been unlikely. Significant paraffin was encountered down to 1075'. Since the last failure, the well was hot oiled on a regular schedule 30 times. The well produces approximately 7 BOPD of 47 API Gravity crude oil. The melting point of the surface paraffin was 140F. The depth of the well at which 140F is encountered is approximately 3700', indicating that paraffin depositon is limited to a tubular issue. The bottom hole temperature is estimated to be 250F and is well above the melting point of the paraffin.

This well work generally confirms the prior investigations that found effective annular hot oiling treating depths were limited to 300-600'. Hot oiling only removes the upper section of paraffin in the well. Paraffin below this upper section continues to build according to the crude properties, the temperature profiles in the well, and the wellbore configuration.

This well work also strongly suggests the need to improve the paraffin removal process by periodically using solvents to remove the paraffin deposited deeper in the well. The apparent "success" of the hot oiling program would have been completely nullified if the artificial lift repair job had turned into a stripping job.

Field Case Study-Solvent Treating: A certain property in Pecos County, Texas produces from a reservoir with a bottom hole temperature of approximately 125F. The composition of the hardened paraffin near the surface had a melting temperature of approximately 175F. This high melting point suggested that paraffin could be deposited all the way back into the formation. Repair jobs found paraffin inside the tubing to the bottom of the hole. The previous operator sold the property partly because of the operating costs related to paraffin. Several of the wells were down with paraffin related plugging at the time of the sale. After identifying the depth of paraffin deposition, hot oiling was largely discontinued in favor of solvents. Diesel was found to be more cost effective on a delivered basis. Now that artificial lift paraffin problems have been diminished, the operator is now focused on methods to remove paraffin that is likely to have been deposited in the formation. Delivering effective heat and delivering solvents with effective physical contact/contact time will be an ongoing challenge.

This property illustrates the need for operators to understand their paraffin problems deeper than the point of injection of hot oiling and the potential impact on the economic value that can be diminished by failing to address paraffin issues. The loss to the previous operator by prematurely selling the asset before addressing the paraffin problem was well over $500,000.

Paraffin Removal Economics: These field cases illustrate the complexity of evaluating the economic trade-offs of paraffin removal techniques. Far too much budgetary emphasis has historically been placed on job costs that do not reflect the expectations/benefits of the treating results.

The first study illustrates the need for greater statistical analysis of failures. Hot oiling was repeatedly successful to a depth sufficient to avoid shallow failures. As the temperature and pressure increase with depth, the solid paraffin is typically softer and takes longer to build up to the point of failure. In this case, another failure mechanism was reached before the "collar" of paraffin would have eventually caused a rod part. However, had the rods parted before the tubing failed, the costs could have been dramatically higher.

The second field study illustrates the severe economic impacts of paraffin mismanagement. The type of paraffin, the depth of deposition, and the inability to transmit heat to sufficient depths made hot oiling impractical. This property should have always been treated with solvent based processes. Per job hot oiling job costs were an irrelevant measure given the failure to remediate the problem.

The general framework for choosing the removal technique begins with the properties of the crude oil. Crude oil with high paraffin content, high paraffin melting temperatures, relatively low reservoir temperatures, and low production rates should almost always include periodic solvent treating. The depth of the well at which the cloud or pour point is reached is a very good initial indicator of the depth of paraffin deposition. More frequent use of hot oiling will be favored with lower melting point paraffin. Ultimately, reservoir performance and artificial lift repair experience is the most definitive data. If rig experience encounters hard, thick paraffin significantly below 500’, solvents should be increasingly emphasized.

Summary: Treating for paraffin is a complex analysis of both prevention and removal processes. While chemical prevention processes can very cost effective, there are number of inherent inefficiencies that require periodic removal interventions. Typical hot oiling/hot watering has serious depth limitations that have been confirmed with heat transfer modeling, surface temperature studies and actual artificial lift repairs. The direct and indirect costs of not evaluating the paraffin mitigation programs are significant, particularly if the formation performance is affected.

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