# HOT OILING TREATING DEPTH INVESTIGATION

Carter D. Copeland, Owl Energy Services, Ltd.
Efren Jimenez, Intern, Texas Tech University

## ABSTRACT

Field tests were performed to better understand the effectiveness of hot oiling to remove paraffin in downhole tubulars. In particular, the tests were designed to investigate the depth to which paraffin might be melted. The temperature decay following the end of the treatment, pump capacities, and heat loss assumptions were used to estimate the treated depths. The results indicated that annular hot oil treatments might be effective for paraffin wax that is very near the surface but the effective treating depth is very limited. In addition to the field testing, industry surveys of the perceived depth of effective treatment were collected. The results of the field tests compared with the industry survey suggest a dramatic problem of perception compared with reality. This disconnect may result in millions of dollars of expenditures that are ineffective or only partially effective. The field tests for a variety of tubular configurations indicated effective treating depths of less than 200 feet, compared with median perceived depth of 1,000 to 3,000 feet.

The study also brought to light the seriousness of heat transfer losses from the hot oil burner to the wellhead before the process begins to start down the hole. In effect, the truck itself and injection line to the well act like giant radiators that rob heat from the treating process.

The results of the study suggest that alternatives to annular hot oiling need to be seriously evaluated if the artificial lift failure history indicates paraffin deeper than 200 to 300 feet. Furthermore, annular hot oiling during colder periods should be avoided altogether or otherwise very carefully designed and supervised.

## PARAFFIN DEPOSITION

Depending on the nature of the crude oil, the paraffin component can deposit on rods and tubing as the fluid nears the surface and the temperature drops below the cloud point of the crude oil. Once deposited, the paraffin can only be liquefied at temperatures above the melting temperature which is considerably above the cloud point. Paraffin near the surface tends to be harder and thicker and softens with depth. This difference in the character of the paraffin is partly the result of lower temperatures near the surface and partly the result of lighter components of the oil being flashed off with the decreasing pressure and temperature. The lighter components in crude oil tend to increase the solubility of the paraffin in crude oil. The ranges of melting points for paraffin vary dramatically but are rarely above 180 to 185 degrees Fahrenheit (°F). Rod inspection companies reported they use 180°F baths to soak the rods before inspection and very seldom have problems with hydrocarbon buildups surviving this temperature.

The best method to determine the melting point temperature of the toughest paraffin in the well near the surface is to secure a sample when the artificial lift equipment is repaired. Concurrent with this sampling, the depth of paraffin deposition can be directly witnessed. In the Permian Basin, the thicker and harder paraffins are generally less than 1,500 feet from the surface but significant paraffin deposits from some crude oils have been found as deep as 6,000 feet. Below this depth, there is generally enough heat to keep the paraffin from being a problem. The depth of paraffin deposition in other geologic provinces will vary with natural temperature gradients for area.

## DIRECT COSTS OF PARAFFIN

Buildup of paraffin can result in significant costs, both direct and indirect. These costs can be broken down into both surface costs and downhole costs. The indirect costs can be orders of magnitude more costly than the actual hot treatment.

In surface facilities, untreated paraffin buildup can result in complete plugging of facilities and flowlines. These blockages are not always easy to locate and often times require replacement of the equipment. The paraffin also can accelerate the buildup of fines that accumulate in the separation equipment and stock tanks.

In downhole equipment, paraffin buildup in the rod by tubing annulus over time can lead to dramatic costs. The bind or friction on the rods will create an increase in rod loading that can cause the rods to part. The friction over long intervals can cause loss of displacement at the pump. Electrical demand and consumption will increase with the friction loading.

If rods in a well with paraffin buildup part, the direct costs can be dramatic. Paraffin packed around the top of the rod can prevent the overshot from engaging. Paraffin packed around the rods can increase the loading enough that the pump cannot be unset, resulting in a costly stripping or fishing jobs.

## INDIRECT COSTS OF FAILED HOT OILING

In addition to the direct costs related to paraffin, the indirect costs related to treating for paraffin can be severe. From a reservoir engineering standpoint, there is a risk of formation damage and loss of productivity if any paraffin is pumped into the formation that hardens or carries fine from the wellbore. Second, if the hot oil truck or the stock tanks have BS&W, trash can be deposited on the tubing anchor. Together with the chemical treating program, hot oiling is considered a major cause of stuck tubing anchors and the resulting fishing costs. Similarly, any dirty fluids that make it by the anchor may result in pump problems (i.e. sticking, excessive wear, etc). Paraffin can cause increases in electrical demand and consumption from the bind that is placed on rods. Perhaps the greatest cost is related to safety and the risk of human life. A hot oil truck is generally accepted as one of the most dangerous pieces of equipment in the oil field. Fires related to boiler failures or volatile crude gas ignitions are not uncommon. **Even after weighting these costs for their frequency, the indirect costs of paraffin far outweigh the cost of hot oiling.**

## THE ANNULAR HOT OILING PROCESS

The compelling need to avoid many of these problems has made periodic paraffin removal an ongoing maintenance issue. The most widely used treatment for the removal of paraffin in pumping wells is annular hot oiling. A special truck with a propane supply, a boiler and a pump is used to heat crude oil (sometimes water). The crude oil is typically loaded from the load line on the front of a stock tank. The 50-70 barrel load of oil is heated with the boiler to about 250°F. For safety reasons, the hot oiler is typically located 50-100 feet from the well. A 2 inch hose is run from the hot oiler to the wellhead and the hose is connected to the wellhead. After heating the oil, the fluid is pumped through an injection line attached to the casing. Typical volumes pumped down the casing range from 45-70 barrels pumped at 1-1.5 barrels per minute. The typical volume pumped down the well depends on how much of the hot oiler’s load was previously used to hot oil down the flowline and whether time was authorized to reload the hot oil truck. The fluid pumped through the casing valve and down the tubing by casing annulus heats the tubing. The heat in the tubing is transferred to the fluids inside the tubing that include the paraffin buildup. Depending on the time the paraffin is exposed to sufficient heat, the paraffin either fully liquefies, partially liquefies or remains a solid. For the paraffin that only partially melts, there may be globules of solid paraffin detached from the tubing paraffin on the rods that is not melted at all. All three scenarios are likely present in all hot oiling jobs. The process is also dependent on the pumping action of the well. The liquefied paraffin hopefully is pumped out of the well before the paraffin solidifies. If the pump fails to remove the liquefied paraffin, the higher weight paraffin can run or ooze down the tubing. As the fluid pumped into the annulus continues to fall and loses it heat to both the tubing and the casing. Most wells are pumped off and the fluid pumped down the well falls to the bottom where the well’s pump returns it to the surface. The casing is commonly on a vacuum at the end of the job. Throughout the hot oil treatment, the pumping unit is typically left on hand (i.e. 100 percent run time) for the entire day. Failure to return the pumping unit to automatic pumping is another indirect cost of hot oiling. If the well pumps off and pounds fluid, the pump, rods and tubing can be damaged.

There is a general belief that hot oiling directly down flowline is effective at least near the wellhead. There is also a general belief that at least the paraffin near the surface in the tubing is removed. Many operators believe there are enough benefits from removing paraffin in the flowlines and removing paraffin at the very top of the well that regular hot oiling is performed. The effective treating depth needs and many quality control issues are often times ignored (i.e. pump efficiency, well pumping fluid and not unloading gas, etc.)

## PERCEIVED TREATING DEPTH SURVEY

To assess the engrained perceptions of hot oiling, attendees of the 2011 Artificial Lift Forum held in Midland Texas in 2011 were asked how deep they believed annular hot oil oiling effectively removed paraffin. The results of this survey are shown in Table 1. Approximately 80 percent of the people believed that paraffin was effectively treated to at least 500 feet. Approximately 67 percent of the people believed that paraffin was effectively treated to at least 1,000 feet. These results were consistent with other surveys.

## HISTORICAL MODELING

In the 1990's, Sandia National Laboratories (Sandia) developed an educational tool that was widely accepted for modeling downhole temperature profiles. The model was reasonably confirmed with field tests and the spreadsheet version of program was generally acclaimed. However, the success of mathematical modeling was confused with success of actually removing paraffin. To quote the author, "The goal in developing the Hot Oiling Spreadsheet was to provide a public-domain, user-friendly program for evaluating the effectiveness of hot oiling jobs. The success in meeting such a goal is determined by how much the program is used by the customer, the oil patch." Unfortunately, mathematical modeling is only one factor in determining the effectiveness of hot oiling.

The program and the examples in the paper generally confirmed that hot oiling would only be successful in melting paraffin that was deposited relatively shallow in the tubing. For example, one version of the model used by a vendor highlighted in the Sandia report showed that a large hot oil job at unusually high temperatures would not melt the paraffin deeper than 500 feet. Another job modeled by Sandia in their report used a larger than normal volume pumping into the well at 180°F. The results indicated the job would not melt **any** waxes in the tubing that had melting points greater than 140°F. The last test cited in the paper circulated hot oil with an inlet temperature of 180°F with a downhole temperature probe. The temperature at 300 feet' did not get above 120°F after almost two and half hours of pumping. The vast majority of the paraffin waxes in the oil field have melting temperatures above 120°F!

The author recognized the significant limitations of his work and suggested there were situations that would require more rigorous modeling. The model appears to have been developed only for boundary conditions that were limited to wells that were cemented to the surface. The insulating qualities of the cement have a dramatic impact on the effective depth of treatment by trapping the heat in the well and mitigating heat transfer/losses to other heat sinks. This simplifying assumption made the modeling more effective but severely limited the application.

There are a vast number of wells where the insulating effect of the cement is replaced with massive heat sinks of water or mud behind casing with a low top of cement. In a well with 7 inch casing there is about 6-1/2 tons of steel in the in first 500 feet being cooled by at 15-20 barrels of water. In addition to the radial thermal conductivity, convection effects further limit heat inside the casing from going deeper. Lastly, if the uncemented casing is adjacent to porous intervals or other casing with cement, the heat sink qualities of the total system become even larger, particularly when compared with the typical hot oil job size.

Although the Sandia modeling did not address the multitude of possible boundary conditions with large heat sinks, the implications of the additional heat losses are clear. If the heat losses away from the casing increase, there is less heat available to melt paraffin deeper in the well. From a practical viewpoint, if the model for the insulated configuration case indicated only limited penetration, the modeling for uninsulated casing with massive heat sinks behind the casing would likely have concluded the depth of effective heat penetration is dramatically shallow. The Sandia work was a potentially helpful educational tool. Industry could have used the work to guide a better understanding of paraffin removal. However, as evidenced by the survey of perceptions of effective treating depth 15 years later, the impact of the work was very limited. A better understanding of these basic principles could have saved millions of dollars from being spent on mostly ineffective annular hot oiling treatments.

## DIRECT FIELD EVALUATION OF TREATING DEPTH

Although the conclusions of this field study could have been inferred by better analysis of the Sandia work, this investigation technique provides a well specific approach to understanding the effective treating depth of hot oil treatments. This investigation also discovered a number of issues with annular hot oiling that were not previously appreciated.

## TEMPERATURE DECAY DISCUSSION

To assess the depth of an annular hot oil treatment, the decay of the temperature following a job was critical to estimating the effective treating depth. The key assumption in this investigation is that heat losses outward from the tubing following an annular hot oil treatment are minimal. Unlike the Sandia boundary condition issues where the treatment is in direct contact with casing, the boundary condition for the tubing after the treatment is much simpler. After a typical treatment, the well is on a vacuum and the annulus is filled with gas. Gas has dramatically less thermal conductivity than either steel or liquids. Without liquid in the annulus, the thermal contact between the tubing and casing is limited to the tubing collar line contact with the casing. Over a joint of tubing, the steel to steel contact area that is not exposed to gas is less than .001 percent of the total circumference of the tubing. In effect, the low specific heat gas becomes a thermal insulator. The resulting profile of the temperature in the tubing "captures" a snapshot of most of the factors involved in the hot oiling (i.e. pumping volumes, rates, casing heat sinks, etc). In effect, the produced fluid temperature profile represents an imprint of the net thermal energy that was added by the hot oil to the fluid in the tubing where the paraffin actually exists.

## DEPTH ANALYSIS

To determine the effective depth of the treatment, the amount of production was based on the capacity of the pumping unit and the amount of time after the end of the treatment that the temperature remained above the melting point of 150°F. This approach could reasonably be applied to any well with good pump action and adjusted for the actual melting point of the paraffin in any well or field. The capacity of the pump was predicted from an S-ROD wave equation software analysis at 80 percent efficiency. Once the amount of pumping time for the decay period was determined, the production was estimated. With the rod and tubing configuration known, the depth of the fluid was calculated.

## PRELIMINARY HEAT LOSS ASSESSMENT

A variety of casing configurations were chosen. None of the wells selected had cemented to the surface (i.e. large heat sink losses near the surface). Table 2 is a summary of the well configurations that were tested. These configurations were selected to reflect the different heat loss scenarios where there are large anticipated heat losses near the surface.

Well A represented the largest heat sink near the surface of the three wells. This well had the largest mass of steel per foot to transmit the heat losses, the greatest cross sectional area of casing per foot and the greatest ratio of circumferences. Altogether, this well was expected to have the greatest "radiator" effect, thereby causing the greatest heat losses per foot. This well was expected to have the shallowest effective heating of the tubing.

Well B did not have the as much cross sectional area of casing to dissipate heat as Well A but Well B had the greater mass of water directly behind the production casing and the greatest withdrawals of fluid (i.e. BTUs) from the tubing. The counter flow of the production acts like a heat exchanger and works against heat transfer down the hole. Well C was expected to have the deepest heat penetration of the three wells for a number of reasons. First, for the same injection rate, the smaller injection area would create greater velocity of the BTUs going down hole. Second, although there is an uncemented intermediate string and larger heat sink, the smaller diameter has less cross sectional area to conduct the losses. Lastly, Well C has a dramatically lower volume lift system. The thermal energy in the form of heated production is far less. Despite these advantages, the heated depth is not expected to be materially deeper because of the same large mass of steel and water/mud behind the casing plus the contact with porosity intervals outside the intermediate casing make this heat sink close to a constant temperature, highly conductive boundary condition.

Table 3 includes a summary of the configuration in terms of where the heat loss is occurring at the surface of the tubulars. The loss of heat in all three of the wells with no cement to the surface is far greater than simply the ratio of the circumferences for a number of reasons. In addition to the heat sink and boundary conditions previously discussed with the Sandia work the ability of the tubing to absorb heat is much more limited than the casing. When the upper end of the tubing near the surface is heated throughout, there are still losses going out from the casing. Collectively, the losses are far greater than the ratio of the circumferences would suggest. One important unknown is the fluid level in the annulus. Although these wells were believed to have fluid to the surface, any air at the very top of the well would act as an insulator. Collectively, however, considering all of the factors involved as well as the Sandia work, the effective treating depth would be expected to be less than 200-300 feet in each of the cases.

## PROCEDURE

The general procedure was to take a series of temperature measurements during a typical job to assess a range of the heat loss questions. The jobs were called out with no specifications. Readings were taken by an intern as a training project at various points and times throughout the job and following the pumping with a Fluke IR 62 thermometer gun. The first measurement point was at the boiler output to confirm the starting point of the job after the oil was heated. The next reading was at the end of the truck to assess the heat losses across the truck. The casing inlet temperature was measured to assess the flowline losses and the beginning surface temperature of the job into the well. Lastly, the temperature on the flowline near the wellhead was taken throughout the test to measure the profile of the temperature of the fluids in the well.

## RESULTS

A "typical" job involved loading the hot oiler with about 70 barrels of lease crude and preheating the oil. Approximately 10-20 barrels of fluid were pumped down the flowline to make sure the line was clear of paraffin. The remaining heated oil was then connected to the casing side outlet valve and the well was hot oiled. The operator confirmed that a single load was the most "typical" procedure used by most operators with an initial portion being used to treat the flowline and the remainder going down the well. Most field supervisors do not want the added cost on their budgets to reload the hot oiler to start with a full load going down the well. Table 4 summarizes the key measurements up to the casing side outlet valve and Table 5 summarizes the depth of penetration calculations.

## CONCLUSION AND IMPLICATIONS

There are a number of conclusions and practical implications of this field investigation, including:

### Effective Field Investigation Technique

This methodology is a cost effective technique that can be economically performed by any operator in virtually any wellbore configuration. Unlike theoretical modeling, this approach captures the interaction of a multitude of real time variables including treating volumes, treating rates, tubular configurations, producing rates, ambient conditions, etc. If the paraffin problem is very shallow and annular hot oiling is effective, this technique can be used to evaluate changes in any of the variables to improve their field procedures.

Surface losses: Losses in the annular hot oiling process prior to the fluid entering the well are a major concern. The average loss in the temperature gain from the boiler across the truck and flowline to the well was 37 percent. In effect, the truck and flowline acted like giant radiators that dissipated heat to the ground and air. These jobs were performed during hot summer time conditions. These losses will be magnified in wet, cold or wintertime conditions. The practical implication of these losses is that "typical" annular hot oiling should virtually never be done in cold weather without serious engineering of the entire job procedure and a clear understanding of the objectives. There is almost no doubt that many cold weather jobs were completely ineffective because of the low starting temperature at the inlet to the well.

Limited Effective Treating Depth: This work confirms and builds on the Sandia work on paraffin in the 1990's. The conclusion that could have been drawn from the modeling work was that effective treating depth is very limited in wells that are insulated with cement. If the wells are not insulated with cement to the surface, the depth of effective paraffin removal is even shallower. Depending on the melting point of the paraffin being treating, the effective depth may be no more than 200-300 feet for a wide range of tubular configurations

Operational Problems Explained: The lack of effective treating depth helps explain some of the operational problems and costs that many operators experience. For example, many operators have had artificial lift failures soon after hot oiling that required rod to be fished. Many of these jobs encounter paraffin that prevents the rods from being fished. Similarly, ineffective annular hot oiling can explain why electrical demand and consumption is not reduced more often by hot oiling. Lastly, ineffective annular hot oiling can still leave well vulnerable to rod parts related to friction loads below the depth of effective treatment. In general, operators should anticipate very limited removal of paraffin by annular hot oiling only near the surface.

Mismatched Perceptions and Training: When the effective treating depth is compared with the perceptions of field personnel and artificial lift professionals, there is a serious need for additional training. When 84 percent of the participants in an artificial lift forum believe hot oiling effectively treats to no shallower than 1,000 feet and modeling and field investigations indicate the likely effective treating depth is no deeper than 200-300 feet, there is fundamental training problem. This lack of training has no doubt led to many of the indirect costs associated with ineffective paraffin treatments. Perhaps more importantly, this perception problem has kept serious alternative treatments for paraffin from being developed to reduce the total cost of operating wells.

## REFERENCES

Mansure, A.J. and Barker, K.M., "Practical Hot Oiling and Hot Watering for Paraffin Control", SPE Operations Symposium, March 1993. (Part of this work was performed by Sandia National Laboratories for the United States Department of Energy under contract DE-AC04-94AL85000)

Mansure, A.J., "Hot Oiling Spreadsheet", Sandia National Laboratories, Sand96-2247 UC-122, 1996 (part of Sandia National Laboratories contract with the Department of Energy under contract DE-AC04-76DP00789)

ACKNOWLEDGMENTS
I would like to thank Mr. Efren Jimenez for his contribution as an intern and the Owl Energy Services Ltd. team of Mr. Bruce Martin, Mr. Brian Williams, and Mr. Corbin Powell. I would also like to dedicate this effort in memoriam to Mr. Art Pena who was an encouraging friend and a continuing contributor and participant to the best practices of artificial lift practices.

Table 1
2011 Permian Basin Artificial Lift Forum Paraffin survey

| How deep do you believe annular hot oiling effectively treats paraffin? | | |
|---|---|---|
| **Depth Range** | **Number** | **% of total** |
| 0-500 | 7 | 10 |
| 500-1000 | 16 | 23 |
| 1000-1500 | 13 | 19 |
| 1500-2000 | 12 | 17 |
| 2000-2500 | 10 | 15 |
| 2500+ | 11 | 16 |

Table 2
Tubular Configurations for Hot Oil Field Investigation

| **Well Name** | **Casing** | **Tubing** | **Rods** | **Cmt Top** | **PBTD** |
|---|---|---|---|---|---|
| Well A | 13 5/8", 9 5/8", 7" | 2 7/8" | 1", 7/8", ¾" | Prod-7000<br>Inter-Surf | 10,480' |
| Well B | 13 3/8", 9 5/8", 5 ½" | 2 7/8" | 1", 7/8", ¾" | Prod-7400<br>Inter-Surf | 8,307' |
| Well C | 13 3/8" , 8 5/8", 4 ½" | 2 3/8" | 7/8", ¾, 7/8" | Prod-6610<br>Inter-2700' | 8,669' |

Table 3
Tubular Heat Transfer Configuration Factors

| **Well Name** | **Tubing OD circumference (in)** | **Casing ID circumference (in)** | **Casing circumference as a percentage of the combined Circumference** | **Fluid Capacity (BFPD)** |
|---|---|---|---|---|
| Well A | 9.0 | 19.8 | 69 | 111 |
| Well B | 9.0 | 15.6 | 63 | 243 |
| Well C | 7.5 | 12.6 | 63 | 22 |

Table 4
Annular Hot Oiling Surface Temperatures

| **Location** | **Average Temperature (F)** | **Average Gain above Ambient (F)** | **Avg loss from Avg Boiler Gain (F)** | **Cum Percentage lost from boiler gain** |
|---|---|---|---|---|
| Boiler | 224 | 128 | 0 | 0 |
| Hot Oiler Tailgate | 194 | 98 | 30 | 23 |
| Casing side outlet Valve | 176 | 80 | 48 | 37 |

Table 5
Hot Oiling Effective Penetration

| Well | Approx Initial Flowline Temp at end of pumping (F) | Approx Decay time to 150 F (Min) | Depth of Treatment (Ft) |
|---|---|---|---|
| Well A | 188 | 4 | 60 |
| Well B | 173 | 3 | 100 |
| Well C | 210 | 65 | 320 |