Final Report
KKG Group
Paraffin Removal

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Abstract

The Rocky Mountain Oilfield Testing Center (RMOTC) has recently completed a test of a paraffin removal system developed by the KKG group utilizing the technology of two Russian scientists, Gennady Katzyn and Boris Koggi. The system consisting of chemical “sticks” that generate heat in-situ to melt the paraffin deposits in oilfield tubing. The melted paraffin is then brought to the surface utilizing the naturally flowing energy of the well.
Introduction

The Rocky Mountain Oilfield Testing Center (RMOTC) has recently completed a test of a paraffin melting chemical stick developed by two Russian scientists. The scientists and an American partner visited RMOTC in September, 2001 to perform two field tests of their device. The Teapot Dome oil field, also known as the Naval Petroleum Reserve No. 3 (NPR-3), is located thirty-five (35) miles north of Casper, Wyoming (See Figure 1). During the testing process, RMOTC provided a cased wellbore, workover rig, circulating equipment and tubing to conduct the tests. The tubing was partially or fully plugged with paraffin from a recent workover on a shale well.

Background

Historical Problems

The problems with the deposition of paraffins and asphaltenes in oilfield tubulars is well known in the oil and gas industry. Paraffin (wax) can be deposited as the oil is produced from the formation due to a combination of factors including temperature and compositional changes occurring in the tubing and wellbore. The deposition of the paraffinic wax layer can significantly affect production.

If the paraffin is deposited in the formation or near wellbore, it can be very difficult or impossible to remove. The next area of concerns is the perforations or inside the casing where the paraffin is more accessible but depending upon depth of the well can also be very difficult and costly to remove. Paraffin deposited inside tubing either in flowing or rod-pumped wells is probably the most accessible for removal but also can impose obstacles depending upon depth, well configuration, bottomhole pumps etc.

Figure 1. Location of NPR-3
The problems with paraffin at RMOTC (Naval Petroleum Reserve #3) have been extensive. (See Ref. 1). The formations at RMOTC lie at depth of 250 ft from surface to approximately 5500 feet. The majority of the oil produced is a high gravity (32 API or higher), light green crude. The deepest formation (Tensleep) produces an asphaltic, black crude which has been historically used for hot oiling. Even some of the highest gravity crude, (~40 API) has shown a strong paraffin deposition tendency with several RMOTC tests focused on the prevention and removal of paraffin.

**Removal of Paraffin**

The removal of paraffin in the oilfield has been by three methods or combinations of the methods. Mechanical removal is possible with surface equipment and to a lesser extent downhole deposition. Chemical removal uses a variety of solvents, dispersants, crystal modifiers etc to solubilize the paraffin and pump it from the system. Thermal methods rely on the addition of heat to melt the paraffins and remove them from the wellbore. Combinations of the above methods, such as heated solvents, are also possible.

**Problems Associated with Conventional Treatments**

The problems inherent in removing paraffin have been discussed in the literature (Mansure - Ref. 2). Specific problems related to conventional thermal methods such as hot watering and hot oiling will be discussed relative to the RMOTC test of the KKG group thermal chemical stick.

Mansure describes some of the difficulties with conventional hot oiling and hot watering processes. One of the main drawbacks is that hot oiling can actually induce formation damage into the well. During a normal operation, stock tank oil is heated to a fairly high temperature (~250 F) and injected into the annulus of the wellbore between the tubing and casing. As the fluid drops in the casing annulus, the temperature drops rapidly due to the large surface areas and temperatures gradients involved. Straub (See Ref. 3) presents a field example where a conventional hot oil treatment failed to raise the bottomhole temperature and had actually depressed the temperature from 125 F to 115 F. These temperatures effects can actually cause deposition of paraffin downhole due to either paraffin in the stock tank oil or dropping the bottomhole temperature. In effect, the hot oil treatment intended to remove paraffin can actually cause paraffin to be deposited.

The chemical system developed by the KKG group can avoid many of the heat loss problems associated with conventional hot oiling. Since the heat from the chemical reaction is generated in-situ, heat losses to the earth are minimized. As the chemical reacts with the water present in the tubing, generated heat is
developed next to the paraffin wall deposit where it can be most effective. Other in-situ heat generating systems have been used in the industry before, oftentimes, with very good results (1,4). One such system developed by Shell Oil company was used at the Naval Petroleum Reserve #3 in 1984. Collesi (4) also describes using the same Shell system for surface equipment cleanup utilizing in-situ heat. As given by Collesi, the Shell system includes the use of two salt solutions, sodium nitrate (NaNO2) and ammonium nitrate (NH4NO3) or ammonium chloride. The reaction is as follows:

\[ \text{NaNO}_2 + \text{NH}_4\text{NO}_3 = \text{N}_2 + 2\text{H}_2\text{O} + \text{Heat} \ldots \]

The amount of heat generated is 132,500 BTU’s of heat per barrel of solution (4). In addition to heat, nitrogen gas is also generated which can aid in fluid recovery.

The basis for the KKG system is analogous and is given by the inventors as:

\[ 2 \text{Na}(s) + 2\text{H}_2\text{O}(l) \rightarrow 2 \text{NaOH}(aq) + \text{H}_2(g) + \text{heat} \]

The amount of heat generated is 184,800 joules per mole or approximately 3,454 BTU per lb. On a per weight basis, the solid chemical stick is able to generate heat more effectively than a liquid solution.

The generation of hydrogen gas may also aid in recovery but field operations should be aware of the associated hazard. The generation of the gas was witnessed at RMOTC when the fluids were produced back from the annulus.

The production of sodium hydroxide, NaOH, is a small concern due to potential precipitation of gelatinous ferric hydroxide; however, this problem is more significant in formation precipitation than in the tubing. Corrosion effects on the tubing should be minimal due to the probable oil film on the tubing wall and good chemical resistance to caustics by steel.

**Field Test Design**

Preliminary discussions with the Russian inventors, through their American contact, focused on using the chemical sticks in flowing oil wells that were subject to paraffin deposition such as the inventors have attempted in some of the Russian oilfields. Unfortunately, the formations at RMOTC, like many nationwide, are in the final stages of depletion and are usually rod-pumped. The field design therefore was focused on simulating a flowing well used a cased well.

The well chosen for the field test, 27-S-3, was a well which had been recently plugged back to approximately 377 feet from surface. The well was formerly a
shallow Shannon producer that was in the process of being plugged and abandoned( P&A). Figure 1 shows the field layout of the testing site. The casing size was 4-1/2” allowing for 2-3/8” tubing to be used for the test. Figure 2 is a wellbore schematic for the first test. The tubing selected was recently removed from a shale well having extensive paraffin deposition. The tubing was examined by the Russian test engineers and specific joints with varying degrees of paraffin, from partially plugged to fully plugged were selected for the test.

**First Test**

To simulate a flowing well which had been plugged with paraffin, surface equipment was configured to pump down the annulus between the tubing and casing and circulate up the tubing (See Figure 1). A paraffin blockage was simulated by using some of the plugged and partially plugged tubing previously selected. (See figure 3).

To remove the paraffin blockage, the first chemical stick was dropped down the tubing and allowed to generate heat as it reacted with the oil/water mix placed in the tubing as it was run in the wellbore. The plugged joint was placed six joints off bottom, a clean joint was placed below this plugged joint to allow for paraffin movement. Below this clean joints was placed two partially plugged joints – three and four joints off bottom. The bottom three joints were clean. See Figure 2. After two hours, circulation was established from the annulus up through the tubing indicating that the plugged joint had been, at least partially, cleared. Another chemical stick was dropped to ensure the blockage was further removed.

For the next few hours before the tubing was pulled from the well, the well was circulated intermittently with periods of shut down to allow the chemical stick to generate heat and melt the paraffin deposits. During circulation, there appeared some paraffin pieces and sand from the exit flow of fluid. At the end of the day, the tubing was pulled and visually examined. The fully plugged joint was found to be clean with little or no paraffin seen looking down the length of the tubing. Digital photographs were taken (Example -Photograph 1) but due to the length of the tubing, bending, and relatively small diameter of the tubing convey limited results.

The first partially plugged joint (fourth joint from bottom) was found to be clean with only a small residue. The second partially plugged joint (third joint from bottom) was clean with no significant paraffin residue.

The first test was considered to be successful at this point. The removal of the blockages were complete with only nominal residue. The Russian scientists believed that all the remaining residue would have been removed if the test time would have been lengthened perhaps, overnight. The effects of circulating an oil/water mix separate from the in-situ heat generation is not possible to discern;
However, the single act of circulating the fluid would not result in complete removal of the paraffin, in our opinion, at the rates and temperatures utilized (.5 – 1 bpm) at an outside temperature of ~ 60 degrees. The upward flow of oil and water in the tubing would also be present in a flowing well.

The effects of the chemical stick was also demonstrated on surface with a small sample in a container of water with an increase in temperature to approximately 150 F.

**Second Test**

The second test of the chemical removal system was performed on the same well the following day with some slight differences. The test string consisted of a small pup joint with a wire catcher on the bottom. The purpose of the catcher was to prevent the chemical stick from leaving the tubing and dropping into the cased hole below. On top of the catcher, a partially plugged joint was placed and then a fully plugged joint was placed on top of the partial plug.

Three clean joints were placed on top of the assembly. See Figure 3. Appendix B is a listing of the field notes. The second test was delayed until the afternoon until associated personnel for the KKG group could arrive in Casper from Houston. Unfortunately, all flights were grounded because of the terrorist strikes in New York. Photograph 2 shows the two Russian scientists and workover support crew.

The first chemical stick was dropped at approximately 1:50 pm and allowed to react with the oil/water mix in the tubing. Due to lack of surface feedback (gas, noise, etc), a second stick was dropped a half hour later followed by a few gallons of water down the tubing. Circulation was established around 3:15 pm at a slow rate. The third and fourth chemical sticks were dropped approximately one-half hour later. Gas returns became evident during the next hour along with paraffin returns and some aluminum foil. The aluminum foil was from the outer casing of the sticks. Normally, it is anticipated that the foil would react with the sodium hydroxide and be dissolved. Due to limited test time on the second day, some foil went unreacted.

The well was circulated at a fairly high rate during the last half hour before the tubing was pulled for the night. Similar to the first test, it is not possible to differentiate the effects of circulating and the effects of the chemical stick. In a flowing well which has a full paraffin blockage, of course, there would be no flow until the chemical stick could remove enough of the paraffin to initiate fluid communication between the bottomhole pressure and the surface.

The results of the second test were similar to the first. The plugged joint was found to be mostly clear with only some small soft paraffin samples. The partially
plugged joint had only a light deposit remaining. The pup joint and catcher were clear with no signs of aluminum foil or other debris. Again, due to the limited daylight hours and test time, the Russian scientists believed all the residue would have been removed with additional chemical sticks and contact time. In addition, flowing wells should not have to be shut in during the treatment. Fluid movement should aid in removal of the newly dissolved paraffin; however, there is probably a trade-off between heat removal by the flowing fluid and paraffin removal.

**Conclusions**

Based on the above tests and a small sample test at surface, it is believed that the system developed by the KKG group is promising in the in-situ generation of heat and the removal of paraffin blockages.

The chemical sticks appear to be consumed almost completely with only some small aluminum foil remains recovered at surface. Hydrogen gas is evolved in the process which may pose some consideration in select circumstances.

Due to the density of the sticks, they tend to drop quickly through fluid. RMOTC did not witness any displacement of the chemical sticks upwards during the circulation of the well.

Based on field cases and theoretical heat loss considerations, the chemical stick should be beneficial for deep, flowing wells where heat losses limit conventional hot oiling techniques.

The downhole effects of producing sodium hydroxide is not considered serious due to the reaction occurring within the tubing and the chemical resistance of steel. The possible beneficial buffering effects of the formation water is unknown due to the many differing environments and oilfield waters.

**References**


SPE 18889, presented at the SPE Production Operations Symposium, Oklahoma City, Oklahoma, March 13-14, 1989.

Appendix A

Field Notes of Test 1

9/10/2001
Ran tubing. Spaced out. Bottom of tubing six inches off bottom at 377 ft. From bottom the fourth and fifth joints were partially plugged with paraffin. Joint seven was fully plugged based on visual observation. The first chemical stick was dropped at 11:55 am.
12:05 am Tubing pressured to 200psi.
12:07 Bled off.
12:07 – 12:37 Let chemical react.
1:58 Established circulation with circulating unit at 200 psi down tubing/casing annulus.
1:59 Circulating the well at 50 psi.
2:05 Good circulation. Tubing may be clean. Recycle fully open. Good returns with moderate throttle.
2:15 Dropped ½ bomb with slightly larger diameter.
2:20 Started pumping at 50 psi.
2:45 circulate hole with moderate - small volumes.
2:55 Let well sit 30 minutes.
3:30 Pumping moderate volumes. Good returns to tank. Catching shale; sand, and some paraffin.
3:55 Circulate at 180 psi.
4:00 Shut down. Ready to pull tubing.
The joint that was plugged was clean (seventh joint). The fifth joint which was partially plugged had just a small residue. The fourth joint that was partially plugged was clean.
Appendix B

Field Notes Test 2

9/11/01

1:30 – 1:40 pm. Run pipe. Catcher; one joint partial plug; 1 jt plugged; 3 jts clean.
1:50  Dropped first chemical stick.
2:18  0 psi. Shut-In.
2:30  Dropped second stick.
2:35  Dropped two gallons water
2:42  Dropped two gallons water.
3:10 – 3:15. Circulate slow with water.
3:42  Dropped third stick
4:05  Dropped ½ fourth stick
4:13  Circulate well. Gas returns back.
4:19  Circulate water back. Cool.
4:30 – 4:40  Circulate water with pint of paraffin. Some aluminum foil.
5:00 – 5:30  Circulate at high rate. Some LCM present from circulating unit.
5:30  Pull tubing.
Plugged joint mostly clear. Some soft paraffin present. Partially plugged last joint
had just a light deposit. Pup joint (catcher) mainly clear.
Figure 1 Site Layout

Photograph 1.
Treated Tubing
Figure 2. Test 1 Configuration

Figure 3. Test 2 Configuration
Photograph 2. Russian scientists with workover crew