# COST EFFECTIVE TREATMENT PROGRAMS

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## ABSTRACT

This paper focuses on approaches to eliminate problems occurring in the production system instead of treating each of the symptoms. Evaluations start with downhole treatment and its effect on eliminating or creating problems at the battery. Problems at the battery are next considered since they contribute to problems at the injection well. The impact of proper downhole corrosion treatment on water and oil quality, corrosion, the load to surface treating equipment will be considered. Adverse effects of using too much chemical as well as multiple chemicals will be illustrated. An oxygen exclusion principle is presented. Ultimately cost benefits arising from lower oil in water carryover, less filterable solids, fewer workovers of injection wells, will be highlighted with examples from the field.

## INTRODUCTION

The determination of cost effectiveness is best undertaken after the most advantageous approach to solving the problem is selected.[1] Consider the problem of pressure buildup in a waterflood injection well. The fill from the well is analyzed and found to contain corrosion products, scale, paraffin, oil, and microorganisms. Focusing the approach on the injection well could result in the addition of corrosion inhibitor, paraffin inhibitor, biocide, scale inhibitor, with the possible incorporation of a flotation system and a filter. Alternatively the approach can focus on treating the problem at the battery. The approach that is highlighted here involves focusing the initial effort on defining and solving the problems occurring at the producing well. Field histories of such programs carried out in the Permian Basin will be used to illustrate that this approach results in decreasing the work load of the battery. The next phase involves focusing on solving problems that originate at the battery such that their resolution results in reducing the load to the injection well.

## THE OXYGEN ENTRY PRINCIPLE

The primary approach to cost effectiveness involves taking all precautions to insure that oxygen does not enter into the production system.[2] The damage caused by oxygen entry cannot be cured by chemical treatment. Corrosion inhibitors used in the oil patch are not effective in the presence of oxygen. Oxygen scavengers are for the most part not effective in the presence of $H_2S$ where even tests for the presence of oxygen are questionable.

Representative corrosion rates in one of our operations in Hobbs where the $H_2S$ concentration in the produced water is of the order of 100 ppm (Table 1) shows both the increase in the corrosion rate due to the presence of oxygen as well as the inability of the inhibitor to protect with air present. The inordinate increase in the corrosion rate caused by the presence of a few ppm of oxygen when $CO_2$ is present is discussed in a paper by Bradley.[3]

The mere presence of an oil column above the produced water does not prevent the entry of oxygen into the water. The benefit of eliminating oxygen from our wellbores was clearly seen on several of our leases in the Howard Glasscock Field in our Midland Division. Historically, to minimize back pressure on the reservoir, the casing heads on these low GOR producing wells were vented to the atmosphere. This allowed oxygen entry and contributed to the following problems:

- inhibitor ineffectiveness
- voluminous corrosion products
- high iron sulfide production
- high oil carryover in water
- high suspended solids concentration
- casing leaks.

The installation of low pressure (2-3 psi) back pressure valves to eliminate oxygen entry along with corrosion inhibitor qualification had the following results:

- an 83% decline in corrosion failures
- elimination of downhole biocide treatment
- significant reduction in oil carryover in water
- filterable solids markedly decreased
- iron sulfide production lowered
- fewer battery upsets.

This illustrates the importance of the oxygen exclusion principle, namely that the primary step in establishing a cost effective treatment program is oxygen entry exclusion. The role of subsequently qualifying the inhibitor will be discussed shortly.

Another source of oxygen into a producing well is the flush water used in corrosion inhibitor batch treatment. On the West Fuhrman Mascho Unit in the Midland Division, corrosion failures were suddenly increasing at an alarming rate. It was discovered that because of a misunderstanding, the chemical truck treater had changed from using produced water to an oxygen saturated fresh water for the chemical flush. Corrosion failures decreased rapidly when the treater switched back to using produced water.

Plugging in the water injection system at the Katz Field in the Midland Division was due to aerobic bacterial growth. The problem was traced to high bacterial counts in the water supply well. The problem was eliminated by coating around the tree of the water supply well with a tar like material. In effect, air entry to the system was excluded.

## THE EXACERBATION PRINCIPLE

The essence of this principle is that the presence of corrosion products worsens and/or sometimes causes

- scale formation
- oil carryover in water
- paraffin formation
- reverse emulsions
- sessility.

It is thus prudent, after satisfying the oxygen exclusion principle, to initiate a downhole corrosion treatment program. The extent to which problems had been exacerbated or worsened by the presence of corrosion products can then be evaluated.

## DOWNHOLE CORROSION TREATMENT

The principles and methodology for Conoco downhole treatment programs for rod pumped wells has been described in detail[4]. A qualified inhibitor is one that has passed both the emulsion tendency test and the film persistency test. The former insures that the inhibitor is compatible with the produced fluids, while the latter gives a measure of the degree to which the inhibitor can protect metallic parts between treatments. The results of some of these programs are highlighted by the following.

### Oil in Water Carryover

Downhole corrosion treatment programs at all the fields resulted in markedly reducing the oil carryover in the water. The elimination and/or reduction of solid corrosion products lowers the oil carryover. The following has resulted in increasing the oil in water carryover even when corrosion was not the problem:

a. use of an inhibitor that did not pass the emulsion tendency test
b. using a qualified inhibitor in excessive amounts.

It is recommended that the emulsion tendency test be carried out at least on an annual basis. On several occasions we have changed inhibitors because they no longer passed the emulsion tendency test. This could have been due to some change in the composition of either the inhibitor or the produced fluids. Symptoms of a problem include, a dramatic increase in the oil in water carryover, and an unusual cyclical variation of both production and oil in water carryover with days after treatment. Excellent records have been kept at the MCA Unit in Maljamar, New Mexico, since the inception of the program many years ago. Recently emulsion tendency tests were carried out on the produced fluids from one well with several inhibitors. The blank (no inhibitor) illustrates the quality of both the oil and the water that has been produced during the past few years (Fig. 1).

Inhibitors A and B are being used on the field presently. The oil carryover at the free water knockout is of the order of 30 ppm. Inhibitors C and D were used on the field several years ago. They fail the emulsion tendency test even with the produced fluids of today. Oil-water separation did not occur within the prescribed time, and the water phase was opaque showing the presence of a reverse emulsion. Inhibitor D was used at a time when there was a corrosion problem. The oil in water carryover at that time was of the order of 1,000 ppm. This represented a loss of about 18 barrels of oil a day into the water (6,570 BOPY). After the program was started and it was found that inhibitor C no longer passed the emulsion tendency test, the oil in water carryover rose from about 40 ppm to 500 ppm, with no increase in corrosion related problems. Inhibitor requalification resulted in the use of inhibitors A and B. It is important to point out that at the MCA Unit as well as at several other fields, initiation of the downhole program totally eliminated the usage of reverse emulsion breakers at the battery.

## Scale and Paraffin

The severity of problems caused by scale and paraffin has been markedly reduced at some fields simply by using an effective corrosion inhibitor. At the MCA Unit, before the initiation of the new downhole treatment program, calcium sulfate formation was a serious problem and scale treatment was being carried out. Scaling tendencies do not take into account that the difficult step is often nucleation. Elimination of solid corrosion products at the MCA Unit resulted in eliminating the scaling problem. Corrosion products present nucleation surfaces, surfaces on which both scale and paraffin tend to agglomerate. The severity of the paraffin problem has also decreased.

## Sessility

Analysis of sucker rod failures often revealed that bacterial corrosion (sulfate reducing bacteria, SRB) was a problem. The use of a qualified corrosion inhibitor eliminated this problem. The SRB concentration in the produced fluids (planktonic bacteria) was not changed by this treatment. The corrosion inhibitor was effective in the elimination of corrosion. In effect planktonic bacteria were prevented from attaching to the metal surface and becoming sessile. It is the sessile or attached bacteria that become part of the corrosion chain.

## Iron Sulfide

Iron sulfide in Permian Basin produced fluids can often represent the major load to the battery. Cost effective treatment entails preventing its formation. This is effectively accomplished by downhole treatment with a qualified inhibitor. In Conoco Permian Basin fields, truck treatment, wherein the inhibitor pumped down the annulus coats metallic parts between the pump intake and the surface, has been effective in drastically reducing the presence of iron sulfide. It is concluded that for all of the cases, the bulk of the iron sulfide did not come from the formation, but indeed arose as a result of corrosion of tubing, sucker rods and other downhole production equipment.

Characteristics of leases with iron sulfide production include:

- frequent battery upsets
- use of chemicals to treat bad oil
- surfactant downhole to unstick pumps
- high solids content in produced water
- reverse emulsion
- severe corrosion

In all such Conoco fields, initiation of a proper downhole corrosion treatment program has resulted in:

- surfactant discontinued
- downhole biocide treatment discontinued
- improved water quality
- improved oil quality
- corrosion problem controlled
- decreased downtime
- increased production.

## Inappropriate Chemical Usage

The use of biocide and/or surfactant during the downhole truck batch treatment of rod pumped wells with corrosion inhibitor is not wise. A qualified corrosion inhibitor incorporates a surfactant. In persistency tests we have found that qualified inhibitors were no longer functioning in the presence of most added surfactants. Effectively the film was washed off by the surfactant and so the percent persistency dropped to an unsatisfactory level. In our tests, persistency was negatively effected by the addition of biocide. In most cases added biocide resulted in an emulsion problem. In 1982 we reported the results of a downhole program on the Ford Geraldine Unit[5], wherein downhole biocide and surfactant addition along with the corrosion inhibitor was discontinued, and a new program was begun with a qualified inhibitor. The treatment characteristics are shown in Table 2. The program continues to be in effect with significant savings in corrosion costs, chemical costs, and in an improved water and oil quality. Iron sulfide is no longer a problem.

In a batch treatment the inhibitor forms a film on the metallic parts that remains persistent until the next treatment. During most of the production cycle between treatments inhibitor is not present in the produced fluids. The extent to which biocide and/or surfactant impede the formation of the persistent film, they contribute to field problems. If the biocide used in a truck treatment is not present during most of the producing cycle, then it cannot be treating most of the produced water.

## CONCLUSIONS

The establishment of a cost effective treatment program takes into account the entire production system. The exclusion of oxygen entry by mechanical means is an essential component. A combination of efficient beam pumping with a well designed downhole treatment program will result in longer equipment life, improved oil and water quality, and in lowering the load on the surface treating equipment. Ultimately, there will be fewer workovers required for both producing and injection wells.

## REFERENCES

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Table 1

REPRESENTATIVE CORROSION RATES
(Produced Fluids, 100 ppm $H_2S$)

| Condition | Corrosion Rate, mpy |
|---|---|
| No air | 32 |
| No air plus inhibitor | 2 |
| Air present | 280 |
| Air present plus inhibitor | 280 |

Table 2

MONTHLY TREATMENT SCHEDULE*

| | Truck Stops | Inhibitor | Biocide | Surfactant |
|---|---|---|---|---|
| | | Gallons Per Month | | |
| January 1982 | 473 | 691 | 157 | 126 |
| March 1982 | 492 | 1153 | 255 | 404 |
| September 1982 | 364 | 383 | 0 | 0 |

*Ford Geraldine Unit, Reference 5.

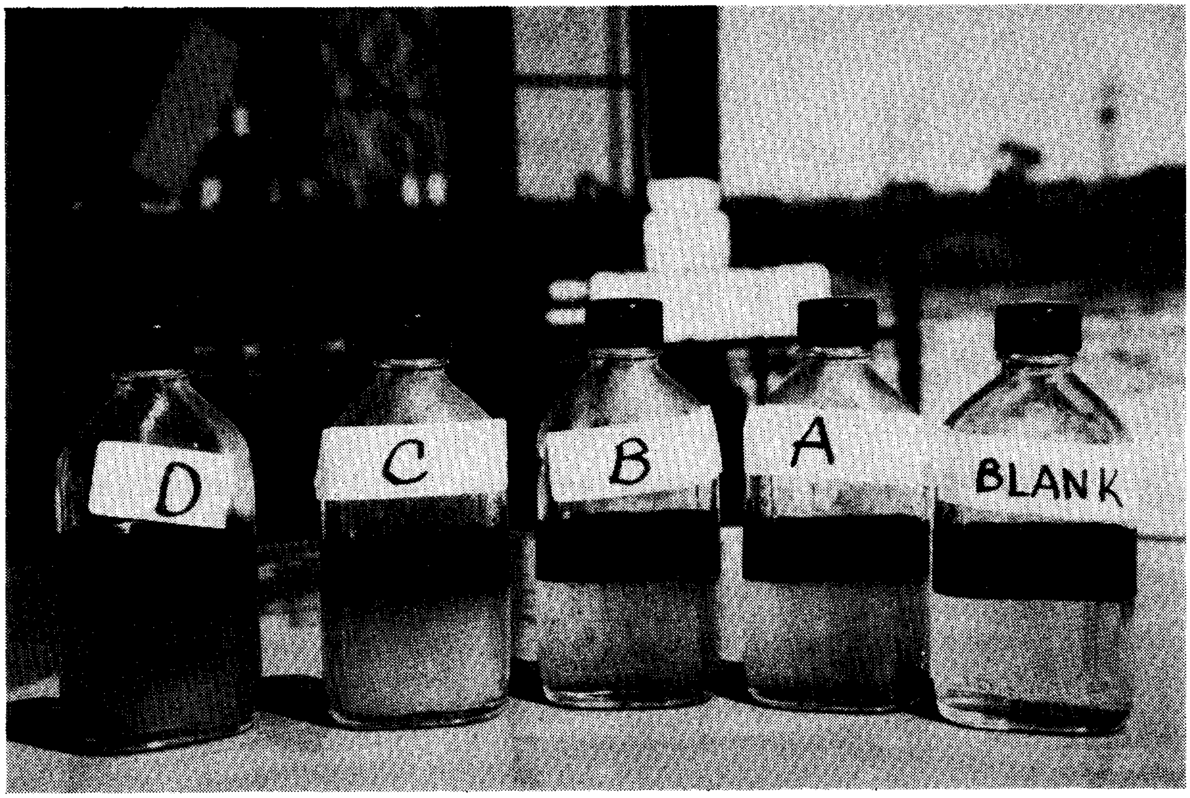


Figure 1 — Emulsion tendency tests, MCA unit