BATCH TREATMENT OF SUCKER ROD PUMPED WELLS

Sheldon Evans & Carolyn R. Doran, Conoco Inc.

ABSTRACT

The results of a pilot inhibition program carried out on eight wells on the MCA Unit, Maljamar, New Mexico, form the basis for a batch treatment program that has been translated to over 400 producing wells in the Hobbs area. The recommended treatment program will be discussed with respect to selection of inhibitor, batch treatment methodology, frequency of treatment, and inhibitor dosage. Results showing the effectiveness of this program with regard to corrosion mitigation, increased production, and improvement of the quality of the produced oil and water will be presented.

INTRODUCTION

The MCA Unit is comprised of approximately 250 producing wells. It currently produces 4,000 BOPD from the Maljamar Grayburg-San Andreas formation at 4,000 feet. A waterflood was initiated in 1963 and currently 18,000 BWPD are being injected. There are two separate water injection systems on the MCA Unit; one utilizes produced water, while the other uses fresh water. The produced fluids are sour.

Vertilog studies were carried out on several wells in early 1980 as part of a program to lower the frequency of casing leaks. These studies showed that most of the penetration was occurring from the inside of the casing, clearly a problem that external cathodic protection could not solve. Corrosion on the inside of the casing was found to be most severe with "problem" wells, that is, wells that were pulled more than 2 times a year. Each time a well is pulled the solution present in the annulus is composed mainly of produced water; this corrosive environment resulted in internal casing corrosion. Approximately 50 percent of the total rig time on the MCA Unit was associated with 30 problem wells; 75 percent of such wells were on the produced water injection side of the field. The primary cause of equipment failure was related to downhole corrosion. It was concluded that the batch treatment inhibition program used at this time was not sufficiently effective in preventing corrosion of all exposed metal parts between the pump intake and the flow line (e.g., pump, sucker rods, inside of casing, and inside and outside of tubing). An investigation was therefore begun to find a more effective batch treatment program. Downhole corrosion mitigation represents a link in the production chain. Its effectiveness is markedly enhanced when it is combined with efficient beam pumping techniques. It was particularly fortuitous that an extensive program to maximize efficiency in the beam pumping system in the MCA Unit had just been completed.[1]

PILOT PROGRAM

A corrosion program was undertaken with 8 problem wells on the produced waterflood side of the field. Two companies were invited to participate in the program; one used inhibitor A while the other used inhibitors B and C (Table 1). Inhibitor C had been used to treat all wells on this side of the field. The following characterized each of the 8 wells in the pilot program:

1) new pump
2) inspected sucker rods
3) treatment at specified time each week
4) treatment witnessed by corrosion technician
5) inhibitor concentration - 25 ppm based on weekly fluid production
6) 5 barrels of produced water were used for flush
7) fluid levels were monitored
8) prevent wells from pounding fluid

The possible oil production shown in Table 1 is based on representative well test data. The difference in oil production (Table 1, last column) was calculated by compensation of the well test data for downtime. All of the failures recorded were due to corrosion. It was concluded that inhibitor A was effective. The increase in possible oil production for wells treated with inhibitor A resulted from keeping these wells pumped off over a long producing period. All of the pump capacities are greater than the well capacities in the MCA Unit. Low fluid levels characterized the 4 wells that were treated with inhibitor A. Pump submergence was frequently greater than 500 feet for wells 53 and 262. Rapid corrosion of pump parts reduced pump efficiency; this could not be completely adjusted with time clocking. Film persistency tests[2] carried out with the inhibitors (Table 2) clearly indicate the superiority of inhibitor A in protecting exposed metal parts from the corrosive environment.

TRANSLATION OF PILOT TO FIELD

In May, 1981, a new inhibitor program, based on the results of the pilot studies, was applied to the MCA Unit. The cumulative number of monthly failures due to corrosion, from January, 1979, through November, 1982, is shown in Figure 1. The new program has resulted in a decrease from 178 to 50 pulling jobs per year. The two most critical steps to a good downhole corrosion mitigation program are inhibitor selection and batch treatment methodology.

INHIBITOR SELECTION

The recommended guidelines for inhibitor selection are shown in Table 3. The objective of a batch treatment is to coat all exposed metal parts that come in contact with the inhibitor with a protective film. This film must protect (be persistent) the metal from the corrosive environment until the next batch treatment. The produced fluids contain little or no inhibitor during most of the period between treatments. The following conditions are recommended for persistency tests:

1. All steps (filming, rinsing, corrosion) must be undertaken with the oil-water ratio of each of the produced fluids.
2. Saturate test fluids with only one corrodent occurring in operation (e.g., CO_2 or H_2S).
3. Temperature: 150°F (if bottom hole temperature is greater than 150°F, state bottom hole temperature).
4. Blank tests for a given fluid sample must be made in triplicate and the average used for comparison.
5. Evaluate inhibitors at the 5,000, 10,000, and 20,000 ppm concentration levels. For a given fluid and inhibitor, tests should be made in duplicate at each concentration level.
6. Submit inhibitors with blind numbering (e.g., A, B, C, etc.).

Inhibitor A met all of the qualifications stated in Table 2 and was used to treat all of the wells on the produced waterflood side of the field, starting in May,

1981. At this time a satisfactory inhibitor from another company was used to treat the fresh waterflood side of the field.

Emulsion tendency tests[3] were carried out to determine whether or not a stable emulsion would form when a given inhibitor was added to the produced fluids. The inhibitor originally used on the fresh waterflood side of the field met the requirements for persistency (Table 3), but did not pass the emulsion tendency test. Tests carried out when this inhibitor was used revealed that production and oil carryover were cyclically dependent on the time of treatment. Production decreased the day after treatment; the oil in water carryover was often of the order of 700 ppm the day after treatment.

Dynamometer cards revealed that the travelling valve was sluggish in closing until a day or so after treatment. Similar tests carried out with the inhibitor that qualified for the new inhibition program revealed no dependency of production to the time of treating; the average oil in water carryover was 40 ppm.

BATCH TREATMENT METHODOLOGY

The recommended guidelines for batch treatment are shown in Table 4. The preflush serves to wet the upper portions of the casing and tubing. As a result, when the predispersed inhibitor is added and flushed, it travels faster down to the fluid level, and coats exposed metal parts more uniformly.

For a long time the industry has accepted 1/2 barrel of flush per thousand feet of depth. In recent tests on pumped off wells[4], using polarization probes, it was demonstrated that with the same volume of inhibitor, increasing the volume of flush markedly increased the inhibitor effectiveness. The nature of the protective film is a function of contact time and inhibitor concentration. Too low a flush results in a short contact time with a high concentration of inhibitor. The extra flush results in a contact time of several hours between exposed metal parts and an inhibitor concentration in excess of 1,000 ppm.

In the old treatment program (before May, 1981) all wells were treated weekly. The treatment frequencies shown in Table 4 were adhered to for the new program. Fluid production per well ranges from just a few barrels per day to several hundred barrels per day. The new program is characterized by decreases both in inhibitor usage and the number of truck stops (Table 5). Comparison of both programs, at today's prices, reveals that the new program is less costly by approximately $6,100 per month. This takes into account an additional cost of $1 per gallon for the new inhibitor.

There are a few wells in the MCA Unit that produce more than 350 BFPD. These are treated twice a week with but one truck treatment. Half of the required inhibitor dosage is applied in accordance with Table 4. After the flush (step 3) additional predispersed inhibitor is pumped down the annulus. This inhibitor dosage remains on the walls of the casing and tubing. Three days later the well is circulated such that 4 barrels of fluid are displaced into the annulus.

INHIBITOR DOSAGE

Calculation of inhibitor dosage based on weekly fluid production is an accepted procedure. After a batch treatment the concentration of inhibitor in the annulus can vary between 5,000 and 50,000 ppm, depending on the volume of inhibitor added, the volume of fluid in the annulus, and the volume of flush. An example is shown in Table 6.

There is no magic number, e.g., 25 ppm, for batch treatment. It has been shown that by selecting the proper inhibitor, good protection can be provided with concentrations, based on total weekly fluid production, less than 25 ppm[4]. As we do not have the luxury of monitoring the needs of each well, we recommend 25 ppm for all wells. The concentration actually obtained for a given well varies, depending on the metering capability during batch treatment. For example, in most fields, one can expect delivery to the nearest whole gallon. At Conoco's Dickinson Heath Sand Unit in North Dakota, inhibitor is delivered to the nearest quart. There, with pump set depths of the order of 10,000 feet, several low producing wells are successfully treated with as little as 5 quarts of inhibitor.

PULLING OF WELLS

It is important to note that the new program was started directly with the guidelines shown in Table 4. No attempt was made to clean any surfaces, nor was any downhole equipment changed. It is recommended that at the next scheduled truck treater visit after a well is pulled, double the original inhibitor dosage be used, and that the well be circulated such that at least one tubing volume is circulated.

CONCLUSIONS

The combination of efficient beam pumping and a well designed batch treatment program has resulted in longer downhole equipment life along with lower monthly treating costs. Along with increased oil production, there was an improvement in the quality of both the produced oil and the produced water. Effectively the load on the surface treating equipment had been lowered because the suspended solids and the oil carryover have been significantly reduced.

REFERENCES

1. DeFoe, P. R., "Efficient Beam Pumping Gives Results," Proceedings of the Southwestern Petroleum Short Course, Texas Tech University, Lubbock, Texas, (April 1981) pp. 303-313.

2. NACE T-ID-2 Task Group Report, "Cooperative Evaluation of Inhibitor Film Persistency Test," Materials Protection, 5 69 (1966).

3. NACE TPC #5, "Corrosion Control in Petroleum Production," (1979), p. 51.

4. Shehorn, L. S., "Corrosion Monitoring on Rod-Pumped Wells Using Linear Polarization Probes," SPE Paper 9363, Presented at the SPE-AIME Annual Fall Meeting, Dallas, Texas, September 21-24, 1980.

ACKNOWLEDGMENT

The technical suggestions and support of P. R. DeFoe, Sr., Production Superintendent, Hobbs Division, are gratefully acknowledged. The authors wish to express appreciation to Conoco Inc. for providing the opportunity and permission to present this material.

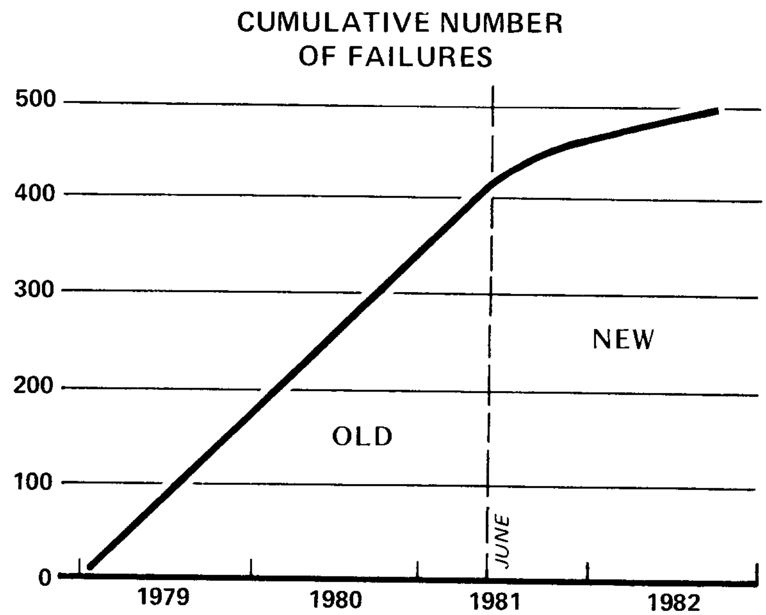

FIGURE 1 — CORROSION HISTORY OF MAC UNIT

TABLE 1
MCA PILOT CORROSION STUDY

Year Before Program					Year After Program				
Well No.	Inhibitor	No. of Failures	Total Down Time, Days	Possible Oil, BPD	Inhibitor	No. of Failures	Total Down Time, Days	Possible Oil, BPD	Difference BPY
21	C	6	70	34	A	0	0	38	+3,833
256	C	2	10	6	A	0	0	20	+5,110
283	C	4	82	23	A	0	0	23	+1,825
287	C	11	114	33	A	0	0	45	+8,030
53	C	6	49	23	B	8	82	10	-4,161
66	C	5	49	17	B	0	0	16	+ 365
262	C	0	0	10	B	4	30	12	+ 365
265	C	2	10	20	C	2	12	20	- 219

TABLE 2 — REPRESENTATIVE FILM PERSISTENCY TESTS

	Percent Protection		
	Inhibitor		
Filming Concentration, ppm	A	B	C
5,000	94	31	23
10,000	95	18	56
20,000	95	70	84

TABLE 3 — SELECTION OF INHIBITOR

SUBMIT AT LEAST TWO PROBLEM WELL FLUID SAMPLES TO ONE (OR MORE) CHEMICAL TREATING COMPANY, REQUESTING THAT THEY CARRY OUT PERSISTENCY TESTS AT THE 5,000, 10,000, AND 20,000 PPM CONCENTRATION LEVELS WITH EACH FLUID SAMPLE.

SUBMIT THE BEST CANDIDATE INHIBITOR FROM EACH COMPANY WITH THE PROBLEM WELL FLUID SAMPLES TO AN INDEPENDENT LABORATORY FOR PERSISTENCY TESTS.

SELECT THE INHIBITOR(S) THAT SHOW MORE THAN 80 PERCENT PROTECTION IN INDEPENDENT LABORATORY PERSISTENCY TESTS AT THE 5,000, 10,000, AND 20,000 PPM LEVELS.

CARRY OUT EMULSION TENDENCY TESTS WITH EACH FLUID SAMPLE WITH A ONE PERCENT INHIBITOR CONCENTRATION. THE EMULSION MUST EXHIBIT 90 PERCENT BREAKOUT WITHIN FIVE MINUTES.

TABLE 4 — BATCH TREATMENT METHODOLOGY

THE SEQUENTIAL PROCEDURE FOR BATCH TREATMENT IS:

1. PUMP ONE BARREL OF PRODUCED WATER DOWN THE ANNULUS (PRE-FLUSH).

2. PUMP THE REQUIRED INHIBITOR VOLUME DISPERSED IN PRODUCED WATER DOWN THE ANNULUS.

3. PUMP PRODUCED WATER CORRESPONDING TO ONE BARREL PER THOUSAND FEET OF DEPTH (SURFACE TO PUMP) DOWN THE ANNULUS.

THE TREATMENT FREQUENCY, BASED ON BFPD, IS:

UP TO 50 BFPD	MONTHLY
50 TO 150 BFPD	EVERY TWO WEEKS
150 TO 350 BFPD	WEEKLY
350 TO 800 BFPD	TWICE WEEKLY

TABLE 5 — COMPARISON OF OLD AND NEW PROGRAMS

	Monthly Number Of Truck Stops	Gallons of Inhibitors Per Month
Old Program	648	1,814
New Program	469	906

TABLE 6
CONCENTRATION OF INHIBITOR IN ANNULUS
AFTER A BATCH TREATMENT

SAMPLE CALCULATION

5 1/2" casing, 5.012" ID
2 7/8" OD tubing, 2.441" ID
Pump set depth, 3500 feet
Fluid level, 3300 feet
Pump submergence, 200 feet
2 gallons of inhibitor
5 barrels of flush

Volume of fluid in annulus:

$$200 \text{ ft.} \times .01644 \frac{\text{BBls}}{\text{Ft.}} \times \frac{42 \text{ Gal.}}{\text{BBl}} = 138 \text{ Gal.}$$

Volume of flush:

$$5 \text{ BBls.} \times \frac{42 \text{ Gal.}}{\text{BBl.}} = 210 \text{ Gal.}$$

Total Volume = 348 Gal.

$$\text{ppm} = \frac{\text{Gal. of inhibitor}}{1{,}000{,}000 \text{ Gal. of fluid}}$$

$$\frac{2 \text{ Gal.}}{348 \text{ Gal.}} = \frac{x}{1{,}000{,}000}$$

X = 5,750 ppm