# Deep Gas-Distillate Well + 28% Carbon Dioxide = Potential Trouble

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INTRODUCTION

It is the purpose of this paper to study in detail the problems involved in operating an extremely corrosive high pressure gas well and the methods which have been employed to successfully resolve these problems.

COMPLETION HISTORY

The subject well was completed in the Ellenberger formation at a depth of 13,477 ft on June 12, 1955. The well is located in the Puckett Field of West Texas. Production casing was 5-1/2 in. set at 12,560 ft. Tubing was run to 12,460 ft with a packer set at 12,440 ft. The tubing was 2-7/8 in. nine per cent nickel using C. S. Hydril couplings.

PRODUCTION HISTORY

Producing rates have varied from 26 mmcf to 10 mmcf. Current production rates have averaged 10 to 12 mmcf per day. Distillate production has averaged 15 BPD and water production 12 BPD.

SUMMARY OF WORKOVERS AND REPAIRS

(1) A tubing caliper survey was conducted on April 25, 1957. This survey indicated that the nine per cent nickel tubing was in good shape with only minor pitting. The survey did indicate that the top joint was partially collapsed but this damage was not attributed to corrosion. The survey also indicated some evidence of several loose couplings.

(2) The tubing was pulled on May 20, 1957, and a Tuboscope end inspection was performed. This inspection revealed two damaged threads, one damaged seal, and one external crack.

(3) The heater and meter runs were replaced because of inadequate size. Corrosion was not the cause of replacement.

(4) A hardness check was performed on the tubing and 433 joints were below Rockwell C-30 and four were above Rockwell C-30. The nine per cent nickel tubing was rerun on May 22, 1957, and the well was back on stream on May 26, 1957.

(5) On August 9, 1957, a leak in the tubing was discovered. The tubing leak was not repaired at this time and a decision was reached to continue producing with pressure on the casing.

(6) During November, 1957, the body of the safety valve blew off when the wing valve was closed. Fortunately no one was injured. The valve was installed in May, 1957, and was equipped with stainless steel flanges. Examination of the valve revealed that the failure was due to corrosion and erosion. Additional inspections at this time revealed considerable corrosion in the choke body, in the 2 in. flowline, the wellhead control valves, and in the coils of the indirect heater.

(7) In February 1958, the nine per cent nickel tubing was pulled and a subsequent survey, on the surface, indicated the following classification:

Grade one (0 to 12-1/2 per cent reduction) - 34 joints
Grade two (12-1/2 to 25 per cent reduction) - 68 joints

These 102 joints were considered to be representative and the remainder of the string was not inspected.

(8) A new string of N-80 was inspected, plastic coated, and pressure tested. This string was run on February 20, 1958. A leak developed in this tubing in less than 30 days (Fig. 1). The area around the leak is not indicative of the condition of the coating in general as it was buffed prior to photographing. The tubing was not pulled and production was continued with pressure on the casing.

(9) During November, 1959 the plastic coated N-80 parted at 2900 ft with a jagged break (Fig. 2). The tubing was pulled and severe corrosion damage was evidenced on all pin ends (Figs. 3, 4, 5, 6, 7). Blistering and pitting was evidenced in the upsets and the couplings (Figs. 8, 9). It is believed that the tool used in the hydrostatic testing of the tubing damaged the coating at the point of the break shown in Figure 2. In addition, it was found that a leak had developed in the casing at 8,238 ft.

(10) The casing leak was squeezed off in December, 1959. New 2-7/8 in. N-80 tubing with Hardy Griffith Teflon seals was run. This tubing was bare.

Fig. 1

Fig. 2

Fig. 4

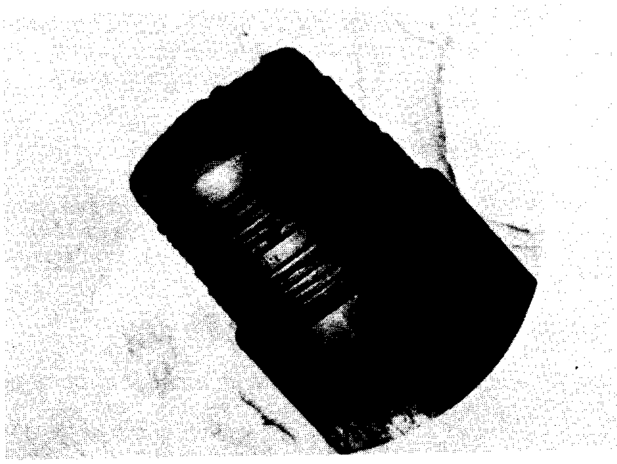

Fig. 5

Fig. 3

Fig. 6

Fig. 7

Fig. 8

Fig. 9

INHIBITOR TREATMENT

A decision was reached to use an organic corrosion inhibitor to attempt to control the corrosive attack. The first problem was the selection of an inhibitor. Different inhibitors were evaluated in the laboratory, and evaluation included the use of wheel tests to determine per cent protection and film persistency. Published reports indicate that many variables exist in this type of testing and that very exact controls must be maintained if the results are to be representative (1). Additional tests were made to insure that the selected inhibitor was compatable with the well fluids.

An iron count was taken on December 15, 1959, with 65 ppm being present. By January 4, 1960, the iron count had increased to 181 ppm. These figures are considered to be below an actual baseline count as an abnormal volume of water was still being produced as a result of the workover.

(1) By using one drum of inhibitor mixed with 8 bbl of distillate the first inhibitor treatment was accomplished on January 6, 1960. The mixture was flushed with 94 bbl of distillate and 66 bbls overflush. Iron counts on January 11, 1960, were down to 41 ppm.

(2) On March 7, 1960, iron counts had climbed to 74 ppm and the well was retreated on March 9, 1960. This treatment consisted of one drum of inhibitor mixed with eight bbl of distillate and flushed with 94 bbl of distillate and 56 bbl overflush. Iron counts on March 11, 1960, were 35 ppm.

(3) Iron counts had increased to 118 ppm by May 9, 1960, and the well was retreated on May 13, 1960. This treatment consisted of one drum inhibitor mixed with 336 gal # 2 diesel and flushed with 94 bbls of distillate and 56 bbl overflush. May 17, 1960, iron counts were 28 ppm.

(4) On June 17, 1960, only 30 days after treatment, the iron counts were 255 ppm. This high iron count occurred immediately after a tubing caliper survey. A decision was reached to defer further caliper surveying as an evaluation tool. Tubing condition was good. Again on June 22, 1960, the well was treated by using three drums of inhibitor and 24 hr shut-in or soak time. Iron counts were up to 95 ppm by June 27, 1960.

(5) The iron counts had climbed to 185 ppm by August 5, 1960, and a decision was reached to change inhibitors.

On August 9, 1960, treatment was accomplished by using 3 drums of inhibitor mixed with 27 bbl of # 2 diesel with a 200 bbl distillate flush and 106 bbl of overflush. The well was shut in for 24 hr. Iron counts on August 12, 1960, were 55 ppm.

(6) October 10, 1960, found the iron count up to 105 ppm and the well was retreated on October 11, 1960. The treatment consisted of 3 drums inhibitor mixed with 27 bbl # 2 diesel, flushed with 180 bbl distillate overflushed with 86 bbl of distillate. Well was shut in 24 hr. Iron counts on October 14, were 32 ppm.

(7) After approximately 3 months (January 16th) the iron counts were only 55 ppm. However, the well was retreated on January 24, 1961, with 3 drums inhibitor mixed with 26 bbl # 2 diesel flushed 180 bbl of distillate overflush 86 bbl distillate. Iron counts were 72 ppm on January 30, 1961. No explanation is offered for higher iron count.

(8) Iron counts had climbed to 145 ppm on April 12, 1961 and the well was retreated on April 19, 1961. The treatment consisted of 3 drums of inhibitor mixed with 26 bbl of # 2 diesel and flushed with 180 bbl of distillate and shut-in overnight. Iron counts were 75 ppm on April 24, 1961.

(9) June 15, 1961, iron counts were 65 ppm. Because of the elapsed time, the well was retreated on June 27 with 255 gal (4-2/3 drums) inhibitor with 26 bbl of # 2 diesel and flushed with 180 bbl diesel. The final 100 bbl of flush contained another 20 gal of inhibitor. July 10, 1961, iron counts were 80 ppm.

(10) Iron counts were 170 ppm on October 4, 1961, and the well was retreated October 9, 1961. This treatment consisted of 145 gal of inhibitor mixed with 1,000 gal # 2 diesel and flushed with 165 bbl of distillate. The final 70 bbl of flush contained 20 gal of inhibitor. The well was shut-in overnight. Iron counts on October 11, 1961, were 49 ppm.

(11) January 8, 1962, found the iron counts up to 165 ppm and the well was retreated January 30. This treatment consisted of 110 gal of inhibitor mixed with 125 bbl of distillate. The well was shut-in for 48 hr after treatment.

## METHOD OF TREATMENT

(1) Care was taken to insure that the inhibitor and carrying agent were mixed in clean tanks that were free of water.

(2) The inhibitor and carrying agent were thoroughly mixed prior to injection.

(3) Injection rates were held below one barrel per minute.

(4) Wells were shut in after treatment for 12 to 48 hours.

## IRON COUNTS

Determinations were conducted in the field and in the laboratory. Samples were gathered by using a plastic lined pot fitted with stainless steel valves. The pot was thoroughly blown down prior to catching each sample.

## SUMMARY OF COSTS OVER 50 MONTHS

November 1957 to December 1959 (25 months)

Repairs and Replacements

| | |
|---|---|
| 1. Wing valve blown off | 692.00 |
| 2. Replaced high alloy tubing with plastic coated N-80 | 46,991.00 |
| 3. Squeezed hole in casing and ran new string (bare N-80) | 87,000.00 |
| Total | $134,683.00 |

January 1960 to February 1962 (25 months)

Repairs and Replacements . . . . . . . . . . . . . . None

Cost of inhibition program was approximately $500.00 per treatment or a total of $5,500.00 during the 25 month period.

## CONCLUSIONS

Through proper selection, application and evaluation, organic corrosion inhibitors can be used successfully and economically in the control of corrosion in high pressure, high carbon dioxide gas wells. This particular program has resulted in a cost reduction of $129,183.00 during the past 25 months.

## BIBLIOGRAPHY

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