DOWNHOLE CORROSION ENCOUNTERED IN THE CO_2 FLOOD AT THE SACROC UNIT

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ABSTRACT

In 1972 a carbon dioxide/water injection project began in the SACROC Unit, Kelly-Snyder Field in Scurry County, Texas. The injection of CO_2 and the highly corrosive produced water has created some very unique problems with downhole equipment. New materials of construction, new design parameters, and new treatment methods have been developed to deal with these problems. The paper describes the corrosion problems encountered with submersible pumps, sucker-rod pumps, tubing, sucker-rods, and other downhole equipment, and it describes the solutions found for these problems. Chemical treatments, coatings, and monitoring programs are discussed. Finally, the effect of CO_2 injection on downhole corrosion is evaluated.

INTRODUCTION

A fresh water injection project was begun down the centerline of the Unit in 1954. In order to improve ultimate recovery over this highly successful flood, a CO_2/water or WAG (water-alternating-gas) injection program was conceived and implemented. This WAG system consists of approximately 350 injectors arranged in inverted nine-spot injection patterns (Figure 1). Both water and carbon dioxide are injected into each injector down a common tubing string. A calculated volume of water is injected followed by a calculated volume of CO_2, then more water, and so on according to parameters developed by reservoir engineering.

Carbon dioxide injection was begun in January of 1972. Water injection was started in some patterns and injection volumes increased in the center-line area earlier in order to bring up reservoir pressure. At the start of the project, there were few wells in the Unit on artificial lift. Most wells were flowing, and there was little water production, as shown in Figure 2. As the project progressed, water production began to rise and in 1974 began a rapid increase. Concurrent with this increase in water production came an increase in the number of wells on artificial lift. In January, 1974, 37 percent of active producing wells were on artificial lift; by June, 1976, 94 percent of active producers were being pumped with 384 submersible pumps, 267 rod pumps, 4 gas lift, and 41 flowing wells.

With this increase in water production and numbers of pumping wells came an associated increase in the numbers of failures attributable to corrosion. Rod parts and tubing leaks increased in

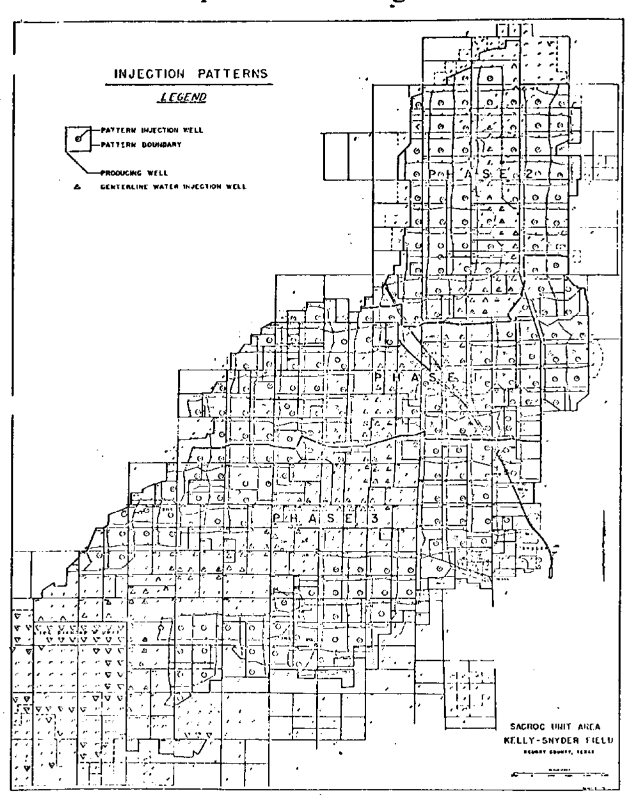

FIGURE 1

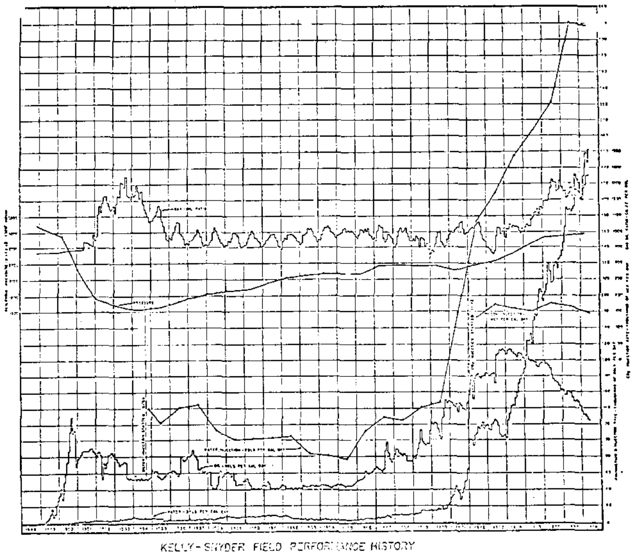

FIGURE 2

frequency in rod-pumped wells, as did pump and motor problems in subpump wells. Aggravating this situation was an earlier-than-expected breakthrough of carbon dioxide. In some wells, CO_2 broke through in as little as four to six months. Carbon dioxide cuts rose rapidly and remained at high levels in some wells. With the breakthrough of water from a pattern injector, a marked increase in scaling problems was noted in some wells. Each of these problems was dealt with and continues to be dealt with using a combination of chemical and mechanical means which are described below.

Sucker Rod Pumping Wells

Prior to 1972 there were few rod pumps operating within the Unit. In January, 1973, there were 130 active rod pumps at SACROC. As shown in Figure 3, the number of pumps rose substantially in 1974 and 1975 from 125 in January, 1974, to 268 in December, 1975. This increase in pumps, coupled with the rapid rise in water production started in 1974, resulted in a rise in failures, as seen in Figure 4. Some of this rise, especially in 1975, is attributable to the increase in pump numbers — more pumps, more failures. Additionally, the operations personnel had to adjust their scheduling to accommodate this increased number of pumps which required more attention than did the flowing wells. A larger portion of the failures is attributable to mechanical problems — stroke length and speed, defects in rods, and similar factors. The remainder of the rise in rod-pump failures is attributable to corrosion effects.

Corrosion failures were manifested as both rod and tubing failures. There have been essentially no failures of the pumps themselves due to the use of monel for manufacturing barrels, plungers, and all wetted pump parts. These pumps have given excellent service with long run lives and little work required to refinish them. The rod and tubing failures occurred throughout the Unit. There is no correlation between failure frequency in a well and the geographical location of the well within the Unit. Similarly, there is only a minimal correlation between failure frequency and other factors such as water cut and water composition. In developing a treatment, each well must be considered individually.

In response to the increase in failures seen in Figure 4 for 1975, the number of treated pumps was increased from approximately 100 pumps in April

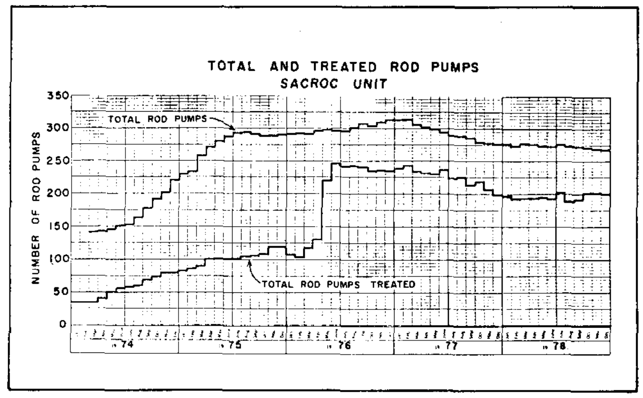

FIGURE 3

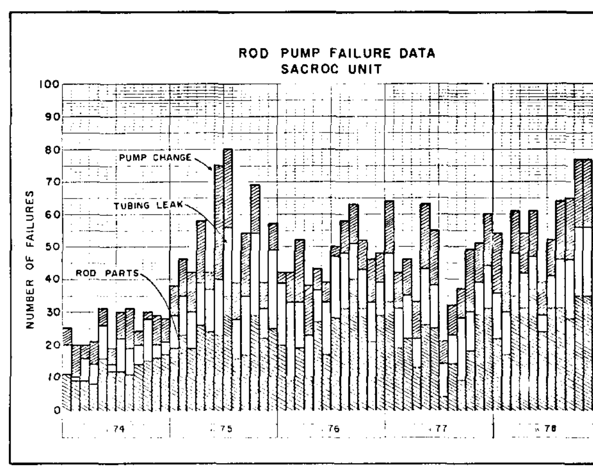

FIGURE 4

1976 to over 200 pumps in June 1976 (Figure 3). As Figure 4 shows, this increase in the number of treated pumps helped create a decrease in total failures. A calculated index used to help evaluate treatment effectiveness is the jobs per well per year. This term is calculated by dividing the total number of failures during the year by the average number of active pumps for the year.

$$\text{jobs per well per year} = \frac{\text{total failures}}{\text{avg. no. pumps}}$$

This index is calculated using both total jobs, which include pump resizes and similar work, and total failures in the numerator. The values of this term are illustrated in Table 1. The effect of the rise in total failures can be seen in the rise in jobs per well per year for 1975. The increase in the number of treated pumps is in part responsible for the decreases in jobs per well per year in following years. Improved control over mechanical conditions of the pumps also contributed to the reduction.

TABLE 1—SUCKER ROD PUMPS JOB FREQUENCY.

YEAR	JOBS/WELL/YEAR* TOTAL JOBS	FAILURES
1974	1.93	1.44
1975	2.46	1.79
1976	2.06	1.67
1977	1.89	1.35
1978	2.58	1.93

*CALCULATED AS TOTAL FAILURES IN YEAR/AVG # PUMPS FOR YEAR

There is a wide range in the type of corrosive attack observed at SACROC. General etching is quite common, as is pitting attack. Less common is intergranular corrosion. Pitting corrosion is a more serious cause of failures in rod pumps than the other types of attack. This fact is due to the pits causing stress-concentration points in the rods which in turn initiate fatigue cracks. Also, of course, pits will penetrate the tubing wall much more rapidly than will a similar amount of general corrosion. Factors affecting the type of attack seen are such things as CO_2 cut, H_2S concentration, water cut, and the tendency of the well to form scales, notably calcium carbonate and iron sulfide. There is no direct correlation between these factors and corrosion rates or types; however, one needs to be aware of them when considering treatments.

Chemical treatments for rod pump wells at SACROC are conventional batch dosages of scale and corrosion inhibitors down the casing-tubing annulus with produced water flush. These batch treatments are performed on a weekly basis by several different chemical service companies. The corrosion inhibitors used are generally of the filming amine type. Scale inhibitors in use are generally of the phosphate ester or phosphonate type. When the need to treat was first determined, a great deal of field testing was carried out to find the most suitable compounds for treating and to determine optimum dosages. As a result of this testing a rule-of-thumb was developed for determining treatment rates, which states that one gallon per week of corrosion inhibitor should be used for every 100 barrels per day of produced fluids; the amount of scale inhibitor should be half that of corrosion inhibitor. The initial chemicals selected were generally oil-soluble, water-dispersible compounds. However, as fluid levels rose with increasing water production, copper-ion displacement tests indicated that the inhibitor was not circulating down the annulus and back up the tubing. In order to improve treatment effectiveness, the chemicals used were changed to water-soluble, oil-dispersible compounds. This change was successful in getting the filming inhibitors back up the tubing, thus reducing the number of corrosion-induced failures. In 1975 a pump optimization program was implemented to lower fluid levels and hence maximize production. With this lowering of fluid levels, treatments were returned to the use of oil-soluble, water-dispersible compounds. In some wells with high water cuts or high fluid levels, however, the use of water-soluble chemicals has proven more effective.

In a small number of wells, chemical treatments seemed totally ineffective. Even with increased dosages of corrosion inhibitor, the number of rod parts due to pitting in these wells remained at high levels with total rod string replacement after one month in some cases. In these extreme problem wells, success has been achieved using spray metal coated rods. These rods are conventional steel rods which are coated with a thin layer of type 316 stainless steel using a plasma-like process. This layer of 316 is then covered with a baked-on epoxy coating to add durability. This combination of corrosion resistance by the 316 stainless and mechanical toughness of the epoxy overcoat has significantly reduced the numbers of failures in the wells in which the coated rods have been tried.

Although most of the corrosion failures in the Unit in rod pump wells are attributable to the corrosive agents in the produced water, some investigations have been conducted into the effects of other factors, notably micro-organisms and oxygen. While not a widespread problem, there are wells in SACROC that have indications of moderate concentrations of anaerobic bacteria, including sulfate reducers. While these bacteria may not actively participate in the corrosion processes, they may provide stagnant areas necessary for concentration cell attack. Because of the sporadic nature of the appearance of bacteria there has been no concerted attempt to control them. In the few instances where biocidal inhibitors have been tried, there has been no observable effect on failure rates or iron counts. Oxygen has not been a problem contributing to corrosion in producing wells at SACROC. However, there has been evidence of some plugging in producers caused by precipitation of iron sulfide. This post-precipitation was determined to have been caused by the fresh water, carrying oxygen, used for flush fluid. This condition was alleviated by changing the flush fluid to filtered produced water.

The effectiveness of the rod pump chemical treatments has been monitored using conventional methods. The chemical service companies are requested to submit bi-weekly iron counts, determined using a field spectophotometric method. These values are tabulated in graphic form for each well. Also included on these graphs are all failures and other well work that is done. The tabulations of well work and failures are additionally maintained for those untreated wells. Well-head coupons were tried at one time to attempt to get an indication of downhole corrosion rates. However, these coupons were not successful due to the mixed nature of the produced fluids; the coupon would become oil-wetted, in effect inhibited, and not give a true bare-metal corrosion rate. Film persistency meters were also tried with similar results. The devices would become oil-wet, which rendered them ineffective. Thus the best measure of treatment effectiveness lies in analyzing failure frequencies. Although this method requires a long time period for data accumulation, when it is coupled with iron counts it can provide an operator with a fairly reliable means of evaluating his treatment program.

The treatment programs at SACROC are generally effective in alleviating failures due to corrosion. The primary cause of corrosion at the Unit is the produced water. Isolated cases of carbon dioxide corrosion have been observed, but this corrosion mechanism is not generally seen in the field. Rising hydrogen-sulfide concentrations also have contributed in some cases to the overall corrosion problem. A study of 38 rod pump wells in the southern half of the field (the last area to be processed with CO_2) in which failure data and iron counts before and after CO_2 breakthrough are correlated with CO_2 cuts indicates that CO_2 had little effect on downhole corrosion. There was no observable increase in either iron counts or failure rates for these wells after CO_2 broke through. In summary, then, the primary agent responsible for corrosion in SACROC rod pumps is the produced water. This produced water has several factors affecting its corrosiveness. Among these factors are high chloride content, high magnesium content, and relatively high sulfate levels. The corrosion caused by this water can be controlled in most instances by selection of an appropriate inhibitor based on previous experience or testing. In those instances where chemical treatment is ineffective, mechanical protection methods may be employed to reduce failure frequency.

SUBMERSIBLE PUMP WELLS

When carbon-dioxide injection was begun in 1972, there were approximately sixty submersible pumps operating at SACROC. During 1972 and 1973, this number remained quite stable. As can be seen in Figure 5, the number of subpumps increased gradually in 1974 and then rose more rapidly in 1975 and 1976. In January, 1975, there were 120 active subpumps in the Unit. By June, 1976, the count had risen to 385 active pumps. As with rod pumps, this increase in pump numbers, coupled with the rapid increase in water production, resulted in a rise in the number of total failures, noted in Figure 6. To compensate for increases in pump numbers which naturally cause a rise in the numbers of total failures, a normalized curve is presented in Figure 6. This curve represents the specific failure rate or failures per month per pump. As seen in Figure 6, this value has remained essentially constant even with increases in pump numbers. Another measure of pump performance, the jobs (or failures) per well per year, is illustrated in Table 2. This term is calculated for subpumps in the same manner as it is calculated for rod pumps. As seen in Table 2, there has been no great increase in the jobs per well per year and this factor has decreased for 1978.

TABLE 2 SUBMERSIBLE PUMPS JOB FREQUENCY.

YEAR	JOBS/WELL/YEAR* TOTAL JOBS	FAILURES
1974	0.66	0.59
1975	0.95	0.79
1976	1.14	1.02
1977	1.41	1.16
1978	1.38	0.82

*CALCULATED AS TOTAL FAILURES IN YEAR/AVG # PUMPS FOR YEAR

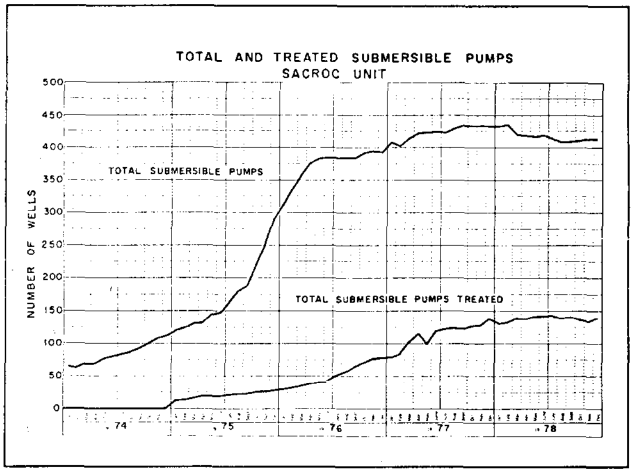

FIGURE 5

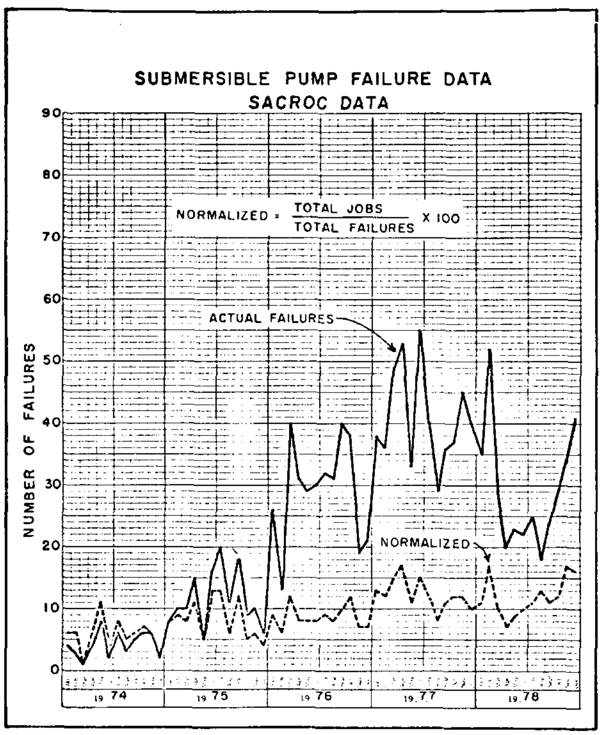

FIGURE 6

The initial corrosion failures observed with submersible pumps occurred in the tubing string. When a flowing well was converted to subpump, in most cases the tubing originally in the hole was run with the pump. Because this tubing was bare and generally quite old, the increased water production associated with the pump caused rapid failure in many instances. To combat this problem, plastic-coated tubing was run with subpumps. The coating was a thin film modified epoxy-phenolic compound used to coat injection tubing. Although there are still tubing leaks, they are not as numerous as before and are generally associated with improper handling of the plastic-coated tubing.

The majority of submersible-pump corrosion failures are caused by attack on the pump and motor housings. The attack was more frequently in the form of pits rather than general etching and was aggravated by iron sulfide deposits and other scaling problems. The most severe attack occurred on the motor housing, apparently due to metallurgy and temperature, and because this attack was below the pump intake it could not be effectively combatted using corrosion inhibitors. Hence other means of preventing the attack were investigated. The first of these methods involved coating the pump and motor housing with a fiberglass-reinforced polyester material. Although some success was achieved using this method, there were distinct disadvantages. Due to the thickness and composition of the coating, heat dissipation from the motor was reduced, resulting in shorter motor life. A second problem with this coating was its minimal resistance to mechanical damage. Given the deviated wellbores at SACROC a great deal of the coating could be scraped off on the way down. Additionally this coating had to be field applied, resulting in non-uniform coverage and subsequent susceptibility to attack.

Another mechanical means of protecting the pump and motor housing which was tried on a limited basis was a nickel coating. Very poor results were achieved with this coating due primarily to its low resistance to mechanical damage. Thus wherever a holiday was created in the coating, the steel of the housing would be exposed to the well fluid and corrode preferentially to the nickel and at a much greater rate than had there been no coating at all. The best coating solution found thus far to combat the housing corrosion problem is a modification of the spray metal process used for sucker rods. The coating process itself is the same as that used for the rods; the difference is in the diameter of the object being coated and in the material used to coat. Type 316 stainless steel and monel have been used to coat the subpumps, both with baked-on epoxy overcoats. A great deal of success has been seen using this method, which is largely responsible for the decrease in jobs per well per year seen in 1978.

Even the spray metal process is just a coating, however, and as such is still subject to damage when the pump is run in hole. Because of this flaw inherent in a coating approach to prevent the attack of the motor and pump housings, work is being done currently to investigate the possibility of manufacturing the housings from a 300-series stainless steel. The 300-series stainless steels have shown superior resistance to corrosive attack in other applications at SACROC.

Submersible pump failures at SACROC can be classified in three general categories. These categories each are characterized by a separate cause of failure. The first of these categories can be classified as failures caused by mechanical problems with the pump. The second category consists of failures caused by corrosive attack on the motor, pump, tubing and cable. This category has been discussed previously with the exception of cable problems, which will be discussed later. The third category consists of those failures caused by scale built-up within the body of the pump. Carbon-dioxide injection caused a rise in bicarbonate concentrations and a similar rise in measured scaling tendencies. Scaling problems were generally noted when first water breakthrough occurred at a well. Scale problems were initially alleviated through the use of a continuous injection of scale inhibitor down the casing-tubing annulus, using a sidestream of produced fluid as flush. However, due to the corrosive effect of the scale inhibitor and produced water on cable armor and exposed tubing and casing, this treatment was changed to the application of a 60/40 percent or 80/20 percent mixture of scale inhibitor and corrosion inhibitor. This treatment has proven successful in preventing scale problems in those wells which have shown a high scaling tendency. Figure 5 illustrates the progression in the numbers of pumps treated in this manner since 1975. Prior to 1975, there were no submersible pumps treated for scaling problems. These scale treatments also have helped in reducing scaling problems in surface producing facilities.

It should be noted that the corrosion and scale problems discussed above are, like the problems discussed in association with rod pumps, scattered throughout the Unit. There are no correlations between physical location, depth, water cut, carbon dioxide cut, or other factors with the exception that frequently when a subpump first experienced a scale problem it would also be experiencing its first water breakthrough. This lack of correlations resulted in the necessity of treating each installation as an individual without being able to use a "cookbook" approach.

Cable problems in submersible pump wells are minimal. Some problems with corrosion of the armor have been noted, but the use of galvanizing on the armor and the change to a corrosion- and scale-inhibitor chemical where used have kept these problems under control. Due to the pressures generally kept on the casing-tubing annulus, approximately 150-200 psig, swelling or bloating of the cable insulation through the armor is frequently observed. This bloating is the result of gas under pressure permeating the insulation; the rapid reduction of pressure upon pulling the cable out of the hole does not allow the gas to back-permeate and hence the insulation bloats due to the expanding gas. This occurrence is dealt with by sending most of the cable pulled to a yard where it is allowed to de-gas and then is high-potted to test for insulation failures. A reel of tested cable is then run back in the hole. This procedure has proven effective in minimizing down-time due to cable failures.

Failure data is the primary tool used in evaluating the effectiveness of corrosion-abatement programs for subpumps. To monitor scale treatment effectiveness, phosphate residuals are measured bi-weekly. As with rod pumps, attempts to determine corrosion rates using such methods as coupons were not successful. Since the majority of corrosion problems in subpump wells cannot be chemically treated, there are no methods such as iron count determinations that provide useful information regarding downhole corrosion.

Effects of Carbon Dioxide Injection on Downhole Corrosion

As has been noted previously, water injection at SACROC increased approximately 150 percent immediately prior to and following carbon dioxide injection (Figure 2). Subsequent to this increase in injection rates came a rise in water production rates. Because of this rise in water production, the effect of CO_2 injection on corrosion rates downhole is difficult to evaluate. What little produced water had been dealt with previously in the Unit had been highly corrosive, and hence much (if not a greater part) of the corrosive attack seen in SACROC is likely the result of the corrosive produced water. Corroborating this observation is the lack of specific examples of uniquely CO_2-induced corrosion. While isolated instances of CO_2 corrosion have been observed in the Unit, notably on the exterior of tubing strings, there has been no widespread evidence of such attack. Additionally, there is the evidence of the rod pumps in the last area of the field to be processed by CO_2. As mentioned previously, an attempt was made to correlate failure data with CO_2 production for 38 rod-pump wells in this area. These wells were selected randomly from those patterns receiving CO_2. Both treated and untreated wells were examined, and all the failure history available for each well bore prepared graphically along with all available data regarding CO_2 production. With the data prepared in this manner, one would expect to see an increase in slope for the cumulative failures versus time curve at the point where significant CO_2 production began. Such an increase was not noted in any of the 38 wells investigated. Figure 7 shows a typical well investigated in this manner.

The primary effect of carbon dioxide injection at SACROC has been aggravation of the corrosivity of the produced water. Because solutions of CO_2 in water form weak acids, the CO_2 dissolved in the produced water has caused a reduction in pH to the point where values measured at the surface after separation range from 6.0 to 6.7. This corrosivity of the water has caused numerous problems with surface facilities as well as those encountered downhole. The effects of the produced water are severe enough that they also mask other effects such as corrosion due to hydrogen sulfide. Overall, then, the downhole corrosion problem at SACROC is caused primarily by the action of the produced water and is exacerbated by the influence of other factors, carbon dioxide predominant among them.

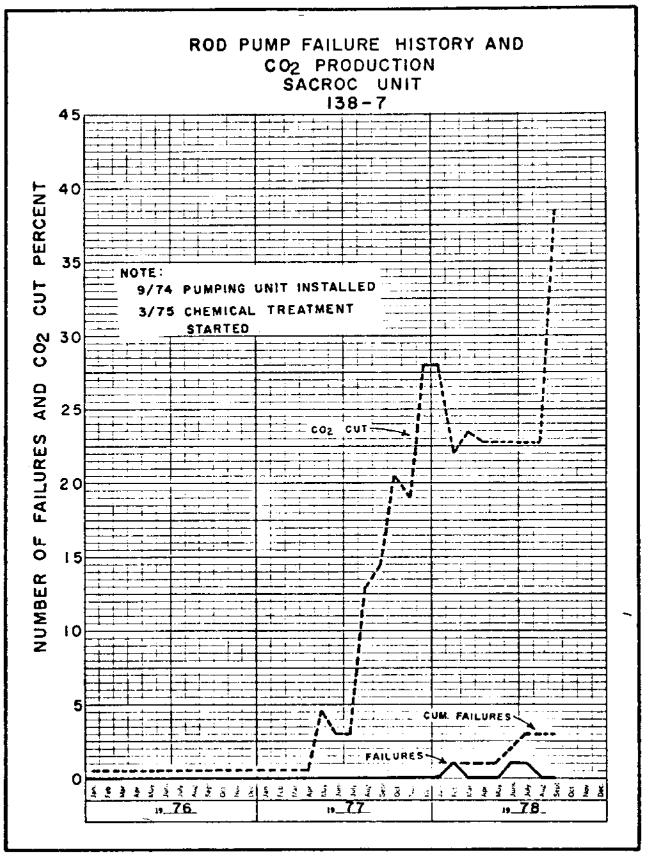

FIGURE 7

CONCLUSIONS

Downhole corrosion problems at SACROC have undoubtedly been aggravated by carbon-dioxide injection. The problems encountered, however, have been successfully combatted using chemical and mechanical techniques. Work continues in finding even more effective chemical treatments and more reliable coatings. The majority of downhole corrosion problems must be dealt with from previous experience and testings. Engineering studies aid in predicting problems and solutions. The actual control of problems encountered must be dealt with by an active corrosion control program using technical personnel working closely with field operating personnel.

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ACKNOWLEDGMENTS

The author expresses his appreciation to the management of Chevron U.S.A. Inc. for permission to publish this paper. Special appreciation is given to all Chevron employees and others associated with the SACROC CO_2 project for their assistance, suggestions, and support in the preparation of this paper.