DESIGN CRITERIA AND OPERATIONAL CONSIDERATIONS TO REMEDY CASING LEAKS

Bharat G. Mody, Halliburton Services
Pat Saunders, Halliburton Services

INTRODUCTION

In the early 1950's, casing failures and leakage were recognized as a very serious problem in west Texas and western Kansas[1] (Figure 1). The cost of casing repair, lost production and well damage due to the casing leaks was estimated to be in excess of $10 million per year[2]. At that time the exact cause of casing failure and leakage was not known and could not be established.

One possible explanation was thought to be corrosion of the cement and pipe by formation waters which contained soluble sulfates[1]. Later it was also recognized that casing leakage could occur because of inefficient mud-cement displacement during cementing. If pockets of mud are left in the vicinity of the casing because mud and cement were incompatible, different amounts of oxygen can be available to the casing. As a result of this "differential oxygen availability", a galvanic cell can form to remove metal from the casing by electrolytic action. A current of only one ampere leaving the pipe carries with it 20 lb (9.1 kg) of metal per year[3]. This removal of metal from the casing could be directly responsible for casing failure or leakage because it decreases the casing's tensile strength and collapse resistance (Figure 2).

The presence of H_2S in the formation fluid or a mud is also known to be responsible for casing failure due to its highly corrosive nature.

After understanding the importance of sulfate resistance, the concept of differential oxygen availability and the effect of H_2S on the casing strings, it will be necessary to answer a few questions.

1. Where does the corrosive water originate?

2. Is it in a static or dynamic state?

3. Is it a highly pressured zone or a low pressure zone?

Once these questions are answered, the proper selection of downhole tools can be made to repair corrosion damage.

Packers, bridge plugs and retainers play a major role in a successful squeeze operation. For example, successful squeezes can be obtained only to be undone by high reverse pressures. Therefore, the cement retainer is used to keep hydrostatic and reverse pressure off the squeezed zone. Packers and bridge plugs may be used to conduct testing and squeeze operations with only one trip in the hole.

There are various cements, additives and processes specifically designed for the squeeze operation and readily available from the service companies.

This paper will stress the importance of understanding the various types of corrosion which occur in a well; to do this it is necessary to understand why and under what conditions they occur. Then, the proper cementing composition and procedure can be selected to help prevent the problem from reoccurring.

MECHANISM OF SULFATE ATTACK AND ITS CONTROL

Cement is mainly composed of chemical compounds like tricalcium silicate (C_3S), β-dicalcium silicate (C_2S), tricalcium aluminate (C_3A) and tetracalcium aluminoferrite (C_4AF). When cement hydrates in the presence of water, it liberates lime [$Ca(OH)_2$] and hydration products of C_3S and C_2S as follows:

1. $3\ CaO \cdot SiO_2 + H_2O \rightarrow 3\ CaO \cdot 2\ SiO_2 \cdot Aq. + Ca(OH)_2$

2. $2\ CaO \cdot SiO_2 + H_2O \rightarrow 3\ CaO \cdot 2\ SiO_2 \cdot Aq. + Ca(OH)_2$.

In the formation waters, Na_2SO_4 and $MgSO_4$ are the two most common, naturally occuring sulfates. The Na_2SO_4 does not attack the hydrated silicates of the cement appreciably because hydrated silicates are less soluble than NaOH and $CaSO_4 \cdot 2\ H_2O$ (gypsum) produced by the reaction[1]. The $MgSO_4$ present in the formation water reacts with $Ca(OH)_2$ and forms a precipitate of almost insoluble $Mg(OH)_2$ and $CaSO_4 \cdot 2\ H_2O$.

3. $MgSO_4 + Ca(OH)_2 \rightarrow Mg(OH)_2 + CaSO_4 \cdot 2\ H_2O$.

These insoluble compounds, $Mg(OH)_2$ and $CaSO_4 \cdot 2\ H_2O$, accumulate in the set cement in place of $Ca(OH)_2$. But, since they require more space than the $Ca(OH)_2$, they start forcing apart the set cement particles, causing a decrease in compressive strength of the cement.

The resistance of cement to $MgSO_4$ can be increased by lowering the lime content of portland cement to give a product which is high in β-C_2S compared to C_3S. However, in practice, resistance to $MgSO_4$ by this means is limited because C_3S is needed for development of early compressive strength in the cement.

It is also possible that the lime liberated by the hydration of C_3S and C_2S could be leached out in formation water, allowing the formation water to penetrate into the set cement. When the formation water containing Na_2SO_4 comes in contact with C_3A in the set cement it reacts even more rapidly than with $MgSO_4$. The Na_2SO_4 reacts with C_3A according to the following three definite chemical reactions[4]:

4. $Na_2SO_4 + Ca(OH)_2 \rightarrow 2\ Na(OH) + CaSO_4 \cdot 2\ H_2O$.

5. $Na_2SO_4 + 3\ CaO \cdot Al_2O_3 \cdot Aq. \rightarrow 3\ CaO \cdot Al_2O_3 \cdot 3\ CaSO_4 \cdot Aq. + Na_2O \cdot Al_2O_3 + NaOH$

6. $Na_2O \cdot Al_2O_3 + H_2O \rightarrow 2\ Na(OH) + 2\ Al(OH)_3$

As a result of these reactions, calcium sulfoaluminate, sodium hydroxide, aluminum hydroxide and gypsum are formed. The calcium sulfoaluminate formed at room temperature contains 31 molecules of water. This is a large molecule and most of the expansion and disintegration of cement is considered to be caused by the deposition of this material (Figure 3).

The calcium sulfoaluminate may also be formed by the reaction of the gypsum, produced by reaction 4, with the $C_3A \cdot Aq.$ as follows:

7. $CaSO_4 + 3\ CaO \cdot Al_2O_3 \cdot Aq. \rightarrow 3\ CaO \cdot Al_2O_3 \cdot 3\ CaSO_4 \cdot Aq.$

The formation of calcium sulfoaluminate by this reaction can be controlled to a certain extent by the use of pozzolan in the portland cement[5]. Pozzolan reacts with the lime to form cementatious material, thereby limiting the production of $CaSO_4$ by reaction 4. Also because pozzolan reacts with lime, a very limited quantity of lime is available to be leached by the formation water. Thus the penetration of formation water into the set cement decreases and thereby prevents formation water containing sulfate ions from coming in contact with C_3A in the set cement. Result: sulfate resistance of the cement is increased (Figure 3).

Sulfate resistance can also be greatly increased by substituting C_4AF for calculated quantities of C_3A in the cement composition. This is done by replacing part of the Al_2O_3 with Fe_2O_3 in the raw feed from which the cement is manufactured.

The sulfate attack on the cement is greatest between 80° to 120°F, lower between 120° to 160°F and becomes negligible at or above 180°F[4]. This is mainly because of the inability of calcium sulfoaluminate to hold a large quantity (31 molecules) of water at a higher temperature.

The rate of attack on set cement slurry by solution of Na_2SO_4 and $MgSO_4$ is governed to some extent by the concentration of these salts in water. A limiting concentration does exist for both Na_2SO_4 and $MgSO_4$, beyond which a further increase in concentrations does not accelerate the rate of attack. The maximum limiting concentrations are[3]:

Na_2SO_4	1.0% by weight or SO_4^{--}	6800 ppm
$MgSO_4$	0.5% by weight or Mg^{++}	1000 ppm

CASING FAILURE DUE TO DIFFERENTIAL OXYGEN AVAILABILITY

The complexity of drilling fluids increases with the depth of drilling. Nowadays it is difficult to find mud and cementing compositions compatible to each other. In general though, we can say that when mud and cement come in contact with each other a highly viscous interface is formed which is difficult to displace, and the chance of cement channeling through the mud increases considerably[6]. Because of the different oxygen content of both mud and cement, the onset of highly localized corrosion increases.

When the casing is cemented with poor mud displacement, pockets of mud are left behind, some in contact with the casing. If mud is highly alkaline (high pH) and contains more dissolved oxygen, then oxygen is more readily available for chemical reaction. These areas where the mud is in contact with the casing become cathodes and the areas without mud (lower pH) become anodes. The iron at the anode goes into solution as ferrous ions, liberating two electrons which are conducted through the casing to the cathode. There they are accepted by the dissolved oxygen to form two hydroxyl ions.. These hydroxyl ions react with ferrous ions at the anode to precipitate ferrous hydroxide. Hence, corrosion occurs at the anode. A schematic of this process if shown in Figure 4 and chemically it can be written as follows[2]:

Anodic Reaction $Fe \rightarrow Fe^{++} + 2\,e^-$

$Fe^{++} + 2(OH)^- \rightarrow Fe(OH)_2 \downarrow$ (Rust)

Cathodic Reaction $1/2\ O_2 + H_2O + 2\,e^- \rightarrow 2\ (OH)^-$

The elimination of oxygen from the fluids by physical means, or by the addition of active reducing agents (oxygen scavengers) such as ferrous chloride, ferrous hydroxide, powdered iron, stannous chlorides and hydrazine to the drilling fluid will decrease oxygen content. This will minimize the differential oxygen availability.

To improve the mud-cement displacement, service companies have developed various spacer fluids which are compatable with drilling fluids as well as cement slurries. The use of spacers and flushes ahead of cement slurry during cementing improves the chances of getting a uniform cement sheath around the casing. The use of oxygen scavengers ahead of cement slurries and spacers should be recommended when highly alkaline mud containing dissolved oxygen is in the well prior to cementing.

MECHANISM OF H_2S ATTACK AND ITS CONTROL

The problem of hydrogen sulfide corrosion primarily occurs in the Permian Basin of west Texas, New Mexico and throughout Arbuckle production in Kansas.

Hydrogen sulfide (H_2S) enters the well from the formation or by the reaction between metal sulfides and acid. In the formation, H_2S can be present as a component of natural gas and as a dissolved gas in the crude oil or formation water. The sulfides can also be generated by "spoilage" of a mud, when anaerobic bacteria feeds on organic agents and changes sulfates (SO_4^{--}) into sulfides (S^{--})[7]. These sulfides can accumulate in the soluble form. In high temperature wells, thermal degradation of sulfur bearing organic compounds can generate sulfides which also can accumulate in the liquid phase.

The hydrogen sulfide is very corrosive in the presence of moisture. Carbon dioxide or oxygen intensify the corrosiveness. Generally speaking, the sulfide corrosion starts slowly and its rate increases with time. The mechanism of this type of corrosion can be simply expressed as:

$$H_2S + Fe \xrightarrow[\text{moisture}]{\text{In presence of}} FeS + 2\ H$$

Some metals other than iron also react in essentially the same manner to produce metallic sulfides. The iron sulfide produced by the above reaction adhears to the pipe or casing surfaces as a scale (Figures 5 and 6). The presence of this scale may accelerate the corrosion because it is cathodic to the steel surface. It causes deep pitting (Figures 5 and 6).

Hydrogen, produced by above reaction, can also enter into the steel to embrittle it. Or, it can form molecular hydrogen which contributes to blistering and cracking of tubular goods[8] (Figure 6). Although it is not necessary to have oxygen or carbon dioxide for H_2S corrosion, the presence of these gases increases the severity of corrosion. As a rule of thumb, either oxygen or carbon dioxide is always present where corrosion is a severe problem[8].

The presence of bacteria can accelerate the rate of corrosion, but there must be a suitable environment for their growth to cause considerable damage. Most of the time casing in contact with the formation water provides an essential environment. Bacterial growth can be controlled by adjusting pH, and isolating formation water from the casing will minimize corrosion. If hydrogen sulfide is detected or suspected during drilling, it is essential to use H_2S scavengers in drilling fluid and completion fluids to protect the casing.

FIRST IDENTIFY THE CORROSION PROBLEM - THEN SOLVE IT

In order to design a successful squeeze treatment to repair casing leakage, it is necessary to first determine the mechanism causing corrosion.

The most commonly occurring corrosion is caused by formation waters containing soluble sulphates[5].

Resistance to sulfate attack can be increased during primary and squeeze cementing by decreasing the amount of tricalcium aluminate in the cement.

Bond logs that show a poor cement to pipe bond are forecasts of future problem areas because cement is partially bonding to the casing. Hence, as explained previously, pockets of mud containing higher amounts of oxygen than cement in the same proximity containing lesser amounts of oxygen can create a condition of differential oxygen availability.

To prevent the removal of considerable amounts of metal from the pipe, it is necessary to correct the problem as soon as possible. To prevent the problem from occuring in the first place mud flushes and spacers should be used in the primary cementing operation for the efficient removal of mud and to help cement bond better to the pipe. Anticipating this corrosion mechanism and proper consideration for its prevention in the primary cement design will save time and dollars later.

Once corrosion occurs and the mechanism causing it is identified, it is time to consider the existing downhole conditions. Temperature surveys and injection profiles will indicate where corrosive water originates. The corrosive water zone can then be isolated to help prevent the corrosion process from reoccurring. If the water is in a static condition, it is a simple matter of isolating the performations across the zone of interest by using plugs or packers in the casing. Then, conventional squeeze operations can be performed to isolate the casing from the corrosive water. If a cross-flow exists it is difficult to obtain a successful squeeze because of dilution of the cement. Modification of "conventional" squeeze operations will ease this difficulty, however, which will be explained later.

In the past, many squeeze jobs were unsuccessful because the formation was fractured in an attempt to squeeze. Once this fracture was created larger volumes of cement were required and repeated efforts were needed to successfully squeeze the leak[9]. Fracture gradients and hydrostatic pressures must be considered and every effort made to prevent the initiation of a fracture[10].

Job Design

Before a squeeze cementing operation is begun, several questions must be answered[11]:

1. What types of squeeze packers should be used?
2. What should the maximum squeeze pressure be?
3. What types of cementing composition or process would be best suited for the job?

Type of Squeeze Packer

Two basic types of squeeze packers are the drillable and the retrievable.

The drillable type is sold and left in the well as a permanent plug, or drilled out after the job. The retrievable type is rented on a job basis and is removed following each job.

Drillable packers are supplied with backpressure valves and are best suited for those situations where the cement tends to flow back after the job. The backpressure valve will hold the cement in place while the tubing is reverse circulated and pulled up the hole. The modern drillable packers are designed to be drilled out easily.

Retrievable squeeze packers are designed to be run in the well, used for a variety of operations, then retrieved. They have a number of applications and some advantages over drillable packers:

1. They can be set and released many times to allow greater flexibility in their use, such as locating and squeezing one or more leaks in the casing with only one trip.

2. They are less expensive to run.

3. If the cement is to be drilled out, less rig time is required.

A consideration in use of a retrievable packer is that the squeeze cement, if not sufficiently dehydrated, may be disturbed by a reversing or swabbing effect created by pulling the tool, and the slurry will flow back into the well. If this happens, pressure can not be released and the tubing can not be reverse circulated.

In conclusion, well conditions and squeeze pressure requirements usually determine the choice of a retrievable or a drillable squeeze packer.

Materials

Various materials and processes designed for the different squeeze cementing requirements are available to the industry. The cement used in both injection and producing wells should be resistant to water or any other fluids it may come in contact with. Pozzolanic cements have long been recognized as resistant to many corrosion fluids[12].

As previously explained, pozzolan reacts with the water soluble lime liberated by the hydrating cement. So, when pozzolan cement sets, there is less lime available to be leached by the formation water, and a permanent low permeability is maintained. This limits the possible entry and subsequent damage by corrosive waters, thereby protecting both the cement and the pipe.

Various thixotropic cements are also available for use in fractured and high permeability zones. Thixotropic cement slurries have the ability to gel when the slurry velocity decreases or pumping of slurry ceases[13]. Higher gel strengths are thus attained earlier which helps prevent the cement slurry from flowing deep into the fractured and high permeability zones. Once the squeeze is established, tubing can be reversed out in a shorter period of time without maintaining backpressure on the squeeze because development of higher gel strength also means the slurry will not flow back into the well. An economical retrievable squeeze packer can be used without much complication.

In some instances, due to cement contamination or a subsurface cross-flow, it becomes necessary to use various sealants along with the cement.

One process involves pumping a spearhead of a special sealant and silica mixture, which combines with the divalent metal ions in the formation water to form a gel plug. Water containing the divalent metal ions could also be pumped ahead of the spearhead to form a gel plug if concentrations of divalent ions are low in the formation water. Accelerated cement is normally pumped behind the sealant. If the sealant and the cement meet, the set of cement is further accelerated by formation of a gel plug between the sealant and the cement. As a end result, the cement forms a permanent wellbore seal, isolating the casing from formation water.

Another common procedure is to spearhead with a monomer solution. The monomer solution contains an activator which converts the monomer into a polymer (gel). The convernsion time is controlled by the concentration of activator. Cement is tailed in as in the preceding process, but pumping is timed so that the last few sacks of cement are being pumped while the sealant is developing initial set.

SUMMARY

Casing leaks cost millions of dollars a year to the oil industry.

Through the years, the mechanisms causing leakage have been determined, namely corrosion due to differential oxygen availability and chemical reactions by the formation water.

Different types of cement and manipulation of basic incredients in a cement, plus cementing techniques such as the use of flushes and spacers, have all helped prevent casing leakage to some extent. Similarly, proper tools, materials and techniques used in squeeze cementing have helped repair casing damage and prevent its reoccurrence.

When proper study is made of where corrosion mechanisms originate and the conditions they originate under in a particular well, efficient treatment can be designed. The correct tool can be selected and appropriate additives and techniques can be employed for a successful squeeze operation. Thus, reoccurrence of casing leaks can be held to a minimum.

ACKNOWLEDGEMENTS

Authors wish to express their appreciation to Halliburton Services to publish this paper. A special thanks is extended to Mr. Homer Waggoner for providing valuable references and Mr. Craig Dennison for helping prepare this paper. Our thanks are also due to those within the organization who offered their suggestions.

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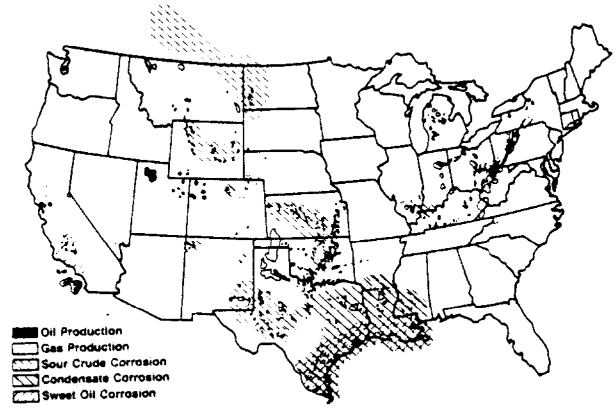
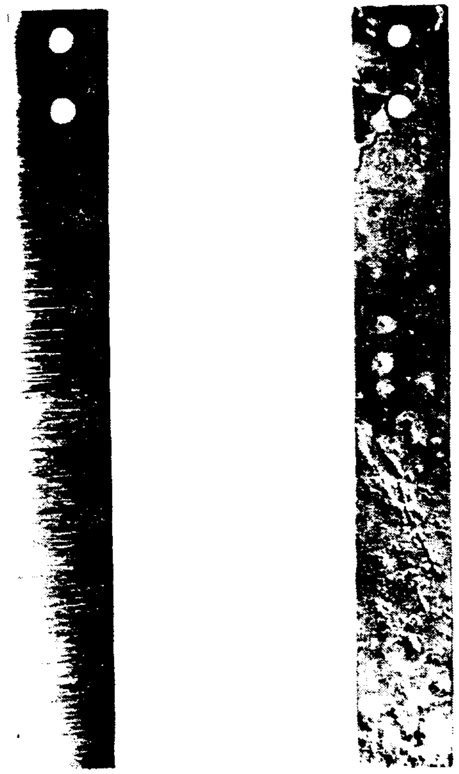


FIGURE 1—CORROSIVE OIL AND GAS AREAS

Typical Corrosion By Salt Water



Polished unexposed

Pitting from salt-water

FIGURE 2

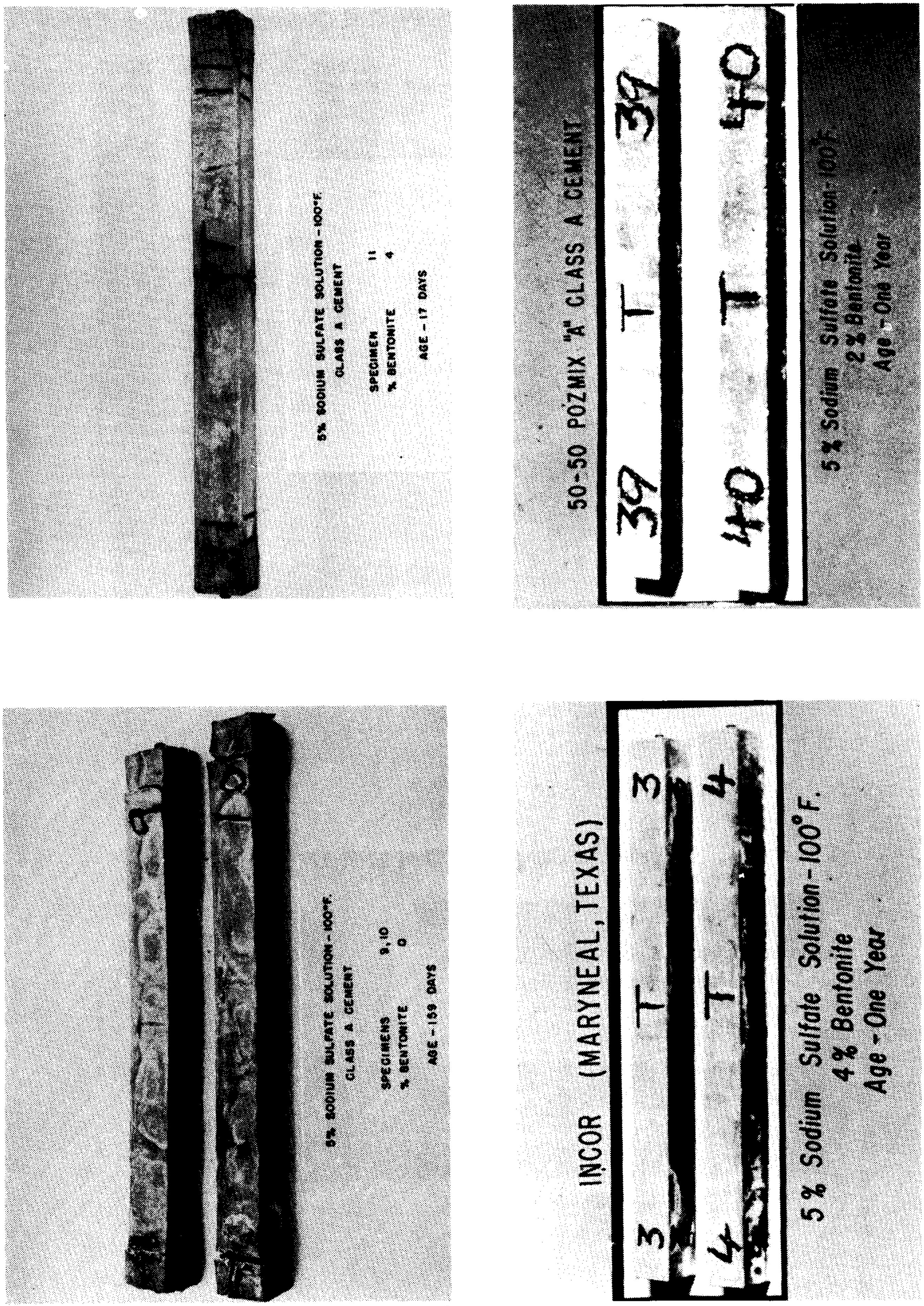

5% SODIUM SULFATE SOLUTION – 100°F.
CLASS A CEMENT
SPECIMEN 11
% BENTONITE 4
AGE – 17 DAYS
50-50 POZMIX "A" CLASS A CEMENT
39
39
40
40
5 % Sodium Sulfate Solution-100°F.
2 % Bentonite
Age – One Year
5% SODIUM SULFATE SOLUTION – 100°F.
CLASS A CEMENT
SPECIMENS 9,10
% BENTONITE 0
AGE – 159 DAYS
INCOR (MARYNEAL, TEXAS)
3
3
4
4
5 % Sodium Sulfate Solution – 100° F.
4 % Bentonite
Age – One Year

FIGURE 3

Mechanism of Casing Corrosion Due to Differential Oxygen Availability

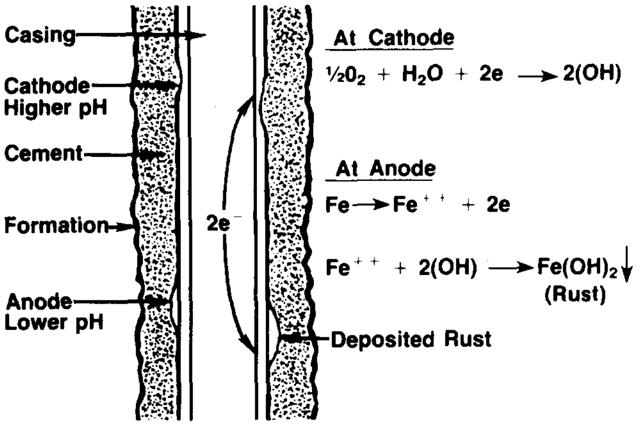
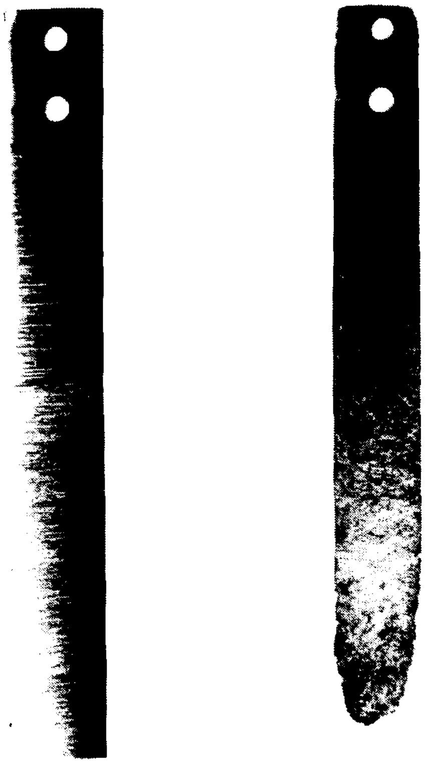


FIGURE 4

Typical Corrosion by Sour Crude

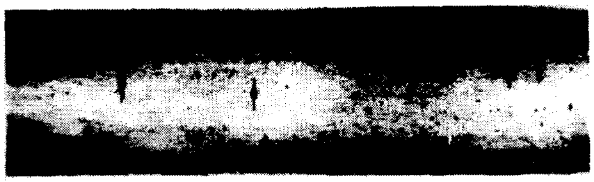


Polished unexposed **Corrosion from sour crude**

FIGURE 5

Types of Corrosion Due to H_2S

Deep Pitting Due to H_2S



Cracks Due to H_2S Originate in Tiny Pits

Blistering Due to H_2S

FIGURE 6