Corrosion Problems in Packer Fluids

B. F. DAVIS, JR.
Champion Chemicals, Inc.

INTRODUCTION

The primary purpose of a packer fluid is to provide a hydrostatic head above the packer to reduce the force necessary to hold the packer in place when the drilling fluid column in the tubing is removed and well fluids are produced. See Table 1.

TABLE 1

PRESSURES EXERTED BY VARIOUS PACKER FLUIDS

Fluid	Sp.Gr.	psi/1000′
Oil — 60° API	0.745	320
Oil — 20° API	0.943	405
Water — Fresh	1.000	430
Water — Sea	1.025	442
Brine — 10% NaCl	1.070	460
Mud — 9 #/gal.	1.080	464
Brine — 40% $CaCl_2$	1.400	603

In addition to providing a hydrostatic head, the fluid should provide a noncorrosive environment to preserve the casing and tubing. The packer fluid should not contain dissolved solids that could promote scale or allow suspended solids to settle and impair the removal of the packer should it become necessary to pull the tubing.

In order to properly design the most trouble-free packer fluid, first examine the most important factors involved in the corrosion process, then examine the various packer fluids in relationship to the factors affecting corrosion.

CORROSION THEORY

Corrosion is an electrochemical reaction in which there is an anode, an electrolyte, a cathode and an electrical conductor between the cathode and the anode. The electrochemical behavior that must occur in a cell or battery is as follows:

At the anode, a metal ion (cation) dissolves into the electrolyte leaving free electrons (negative charges).

In the electrical connector, the electrons travel to the cathode giving it a negative charge.

At the cathode, the electrons attach themselves to cations in the electrolyte.

In the electrolyte, excess ions transport the electrons through the electrolyte back to the anode.

The factors influencing electrochemical behavior in batteries are also the important factors in the corrosion cell. These factors are:

1. Area of anode and cathode
2. Resistance of electrical connector
3. Resistance of the electrolyte
4. Potential of the cell

Corrosion cells are made up of two half cells and, as in a battery, the cell potential is the algebraic difference between the half cell potentials. For instance, the chemical reactions for two half cells are:

$$E_0 = Fe^0 \longrightarrow Fe^{++} + 2e, \quad E_0 = 2H^+ + 2e \longrightarrow H_2^0$$

Factors that affect the half cell potential are given by the equation:

$$E = E_0 + \frac{RT}{FN} \ln \propto M^{+n}$$

Where E_0 = Potential at standard conditions
R & F = Electrical constants
T = Temperature
N = Valence change of ion
$\propto$ = Activity of metal ion.

With this brief and simplified background, examine some of the corrosion reactions possible in packer fluids. First, consider the relative areas of anode and cathode. (See Fig.

1.) Clean, bare metal is generally anodic to older, passive metal. Clean, bright scratches, such as tool marks, will be anodic to the area surrounding them. Movement of tubing against casing wall will expose bright metal to the packer fluid. Freshly exposed areas will be anodic to older, passive metal. The current that flows in a corrosion cell will flow from small anodes at a high current density whereas on a large cathode the current density may be very low. This will create high rates of metal loss over a small area, causing the surface to be pitted. Scratches or bright metal also tend to reduce overall cell resistance by affording better electrical contact with the electrolyte.

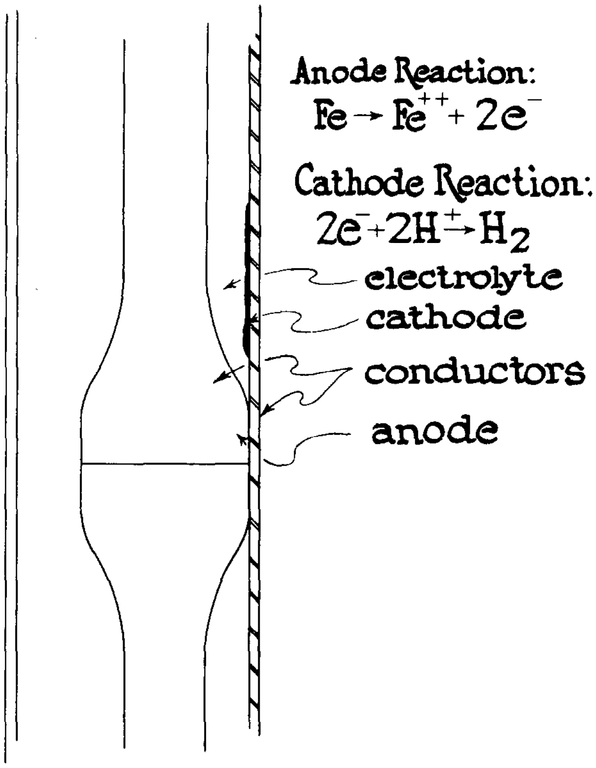

FIGURE 1

This brings up the second factor—the metal conductor. Generally, the pipe is relatively quite thick and its resistance is low. Tightly adhering mill scale, which is also an electrical conductor, will provide a good cathode but is a poorer electrical conductor than is bare, passive metal. Being a conductor, poorly adherent mill scale can act as a cathode to the metal under it if an electrolyte can get between the metal and the mill scale.

Thirdly, the resistance of the electrolyte will vary considerably depending upon the dissolved solids content. A brine containing 50, 000 ppm of sodium chloride will have less resistance than fresh water. Only a few parts per million sodium chloride increase will decrease the resistance by tenfold.

The fourth factor is the cell potential. The corrosion cells can become very complicated if one attempts to work out all of the little factors; just examine the more important ones. Normally, the corrosion cell is an iron half cell and a hydrogen half cell where iron is the anode creating ferrous ions and the hydrogen half cell creates hydrogen from hydrogen ions in the electrolyte. Therefore, reducing the hydrogen ions will reduce the cell potential. Increasing the resistance of some portion of the cell will reduce the corrosion current regardless of the cell potential. These two methods are most often used to control corrosion in the annulus protected by a packer fluid.

PACKER FLUIDS AND CORROSION PROCESSES

The most common initiator of corrosion in any aqueous-base packer fluid, whether it be low solids mud, ordinary brine or sea water, is oxygen. Oxygen reacts readily with bare metal at the metal-electrolyte interface depleting the electrolyte of oxygen, thus setting up an oxygen concentration cell which increases in cell potential as the oxygen concentration near the surface becomes exhausted. This cell potential then decreases as the total oxygen is used up. This action causes a high concentration of iron ions near the anodic areas. Precipitation of iron hydroxide leads to a decrease in pH or an increase in hydrogen ions and allows corrosion to continue in the form of the normal Fe and hydrogen corrosion cell.

Fortunately this occurrence usually creates a deposit of a thin iron oxide film uniformly over the anodic areas and hydrogen forms over the cathodic areas stifling the corrosion by creating a high resistance barrier in the area of both anodes and cathodes. If no other contaminants change this condition, it may exist static for years.

In view of what has just been discussed, it is apparent that the reactions that initiate corrosion can be stifled by simply scavenging the oxygen out of the packer fluid. It takes only about 10 pounds of catalyzed sulfite, or its equivalent, to scavenge the oxygen in 100 barrels of water or brine or mud. Generally, muds properly treated will have a high pH which also discourages the corrosion reaction by having an abundance of hydroxyl ions.

Changes which can occur in a packer fluid after it is in the well may come from gas leaking by the packer from the producing zone. Gases which are most harmful are carbon dioxide and hydrogen sulfide. Both of these gases dissolve in water to increase hydrogen ions; in the case of hydrogen sulfide this causes the protective oxide film discussed previously to be converted to iron sulfide usually in such a manner that it is no longer protective.

Also, a disaster can be caused by acid from an acid stimulation leaking by a packer into the annulus. This can cause rapid penetration of the tubing or casing. The tubing may become sufficiently thin that it may twist off when attempts are made to unseat the packer or it may part from normal stresses or movement.

Another source for the formation of hydrogen sulfide in a packer fluid may be from sulfate-reducing bacteria. These bacteria are quite common in the air and in surface waters. They thrive in warm, static conditions utilizing sulfates in water and will consume hydrogen which keeps the corrosion cell polarized or from becoming active. These bacteria are anaerobic, meaning that they require no oxygen for life. Their byproducts tend to form scale or tubercles on steel which upsets the status quo condition at electrical neutral areas and, in fact, can cause normally anodic areas to become cathodic to the bacteria-formed deposits. This logically creates high current density at the newly formed anodes and hastens penetration.

Corrosion from bacterial growth can be avoided by treating the packer fluid with a good biocide. The chlorinated phenate biocides generally are used in muds where the pH is 8-9. If it is objectionable to use these materials, because of their halogenated organic nature, aldehydes or quaternaries can be used. The aldehyde-type biocides can be used in muds or brines. Some quaternaries can be used in muds; however their use should be checked to be sure they do not cause coagulation of the mud.

A widely used treatment for sweet brines is a chromate inhibitor which kills bacteria and oxidizes and passivates the entire metal surface. Trace amounts of hydrogen sulfide gas, which may leak by the packer from produced gas, will be oxidized by the chromate inhibitor. The principal drawback to the use of chromates is that if the concentration of chromate is not above 700 ppm, severe pitting can occur.

Organic inhibitors that are brine soluble have been developed for use in sour brines or in brines which may become sour from a packer leak or from bacteria growth. These inhibitors should be used at about one 55-gallon drum per 100 barrels of brine or mud. Sour brine rarely contains any appreciable oxygen and chromates cannot be used; therefore, the organic inhibitors are the best protection against corrosion.

Since, as stated earlier, creation of a resistance barrier in the corrosion cell minimizes metal loss, complete removal of the electrolyte also will stop the action of the corrosion cell. The use of inhibited oil provides the most positive guard against corrosion. The use of oil alone does not remove the electrolyte which is left from residual wetting by the drilling fluid. The inhibitor used in oil should be of such a nature that it causes the mud or water-base fluid to release from the steel and be replaced by an organic film.

RELATED PROBLEMS

Inhibitors can be used in the drilling mud which will leave the casing clean and hydrophobic in nature so that clean crude oil can be used in many instances without serious corrosion damage. Dead fluid areas, such as the space between a packer and perforations above a packer, will become filled with brine or be filled with the completion fluid. This space is susceptible to corrosion from bacteria or normal corrosion. This space is difficult to inhibit; however heavy liquid inhibitors have been developed which can be used effectively in inhibiting corrosion in these dead spaces.

Dead fluid areas also are often found between a packer and a set of gas lift valves. This space will experience the same type of corrosion cell as has been described and should be protected in the same general manner as packer fluids.

CONCLUSIONS

Corrosion controlling materials are available for most any type of packer fluid; however the best protection against corrosion will result from properly designed program before the well is drilled or completed.

Probably the best packer fluid from a corrosion standpoint is inhibited oil, followed by properly treated mud or brine.