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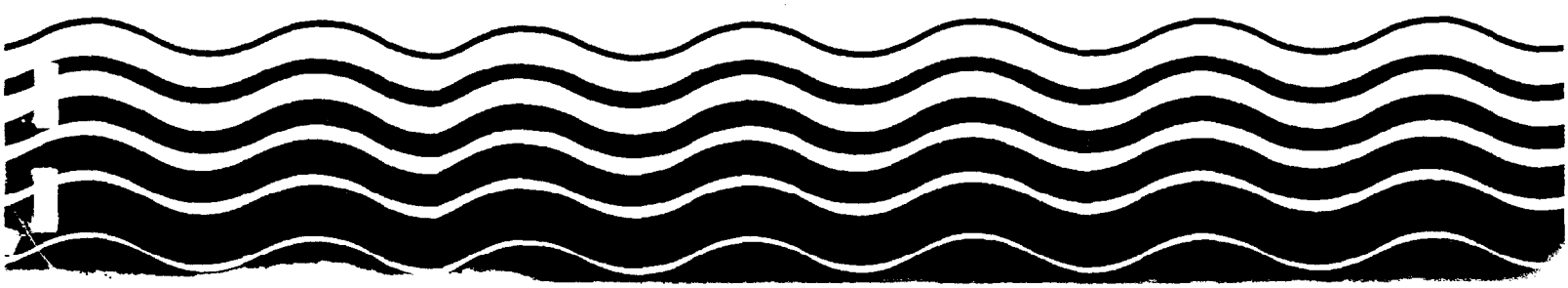
Corrosion, Its Detection and Control in Injection Wells



TECHNICAL ASSISTANCE DOCUMENT: CORROSION, ITS DETECTION AND CONTROL IN INJECTION WELLS

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INTRODUCTION

In order to protect underground sources of drinking water (USDWs), injection wells must not allow fluids to escape into unauthorized zones. Any escape of liquids may cause contamination of USDWs directly, or by forcing lower quality fluids to move. If a well protects USDWs by not allowing substances to escape or migrate, it is said to have mechanical integrity. One part of mechanical integrity is to assure that the well does not develop leaks; and, one possible cause of a leak in a well is corrosion.

Most injection wells are constructed with metallic materials for structural reasons. Non-metallic materials may be used in specific areas where metals are not adequate. Corrosion of the metallic materials and degradation of the non-metallic materials are the chief causes of premature failure in injection wells.

Although there are several forms of corrosion, they may be grouped into two main forms, general and localized. General corrosion is the uniform or near uniform thinning of metal. If the rate of general corrosion is tolerable, an adequate lifespan can be built into the disposal well materials by adding a corrosion allowance to the design thickness. If the general corrosion rate is too high, the material should not be used. Localized corrosion consists of several forms of attack that lead to failure of the equipment before the corrosion allowance is used up. Failure may arise from the development of a leak, from mechanical failure caused by localized thinning, or from crack propagation. Examples of localized thinning and crack propagation are pitting and crevice corrosion.

The degradation of non-metallic materials may exhibit a variety of forms, all of which lead to loss of structural properties and possible failures.

The purpose of this document is to summarize information on the occurrence, detection and control of corrosion. It is not intended to establish any regulatory requirements for injection wells. Section I provides a description of the types of corrosion; section II explains inorganic incrustation, whereas III gives some representative examples on the effect of corrosion on injection wells. Section IV, of this manual, discusses well corrosion with respect to typical waste fluids and section V describes the various corrosion control techniques. Corrosion of the well components by the underground environment is explained throughout this manual (as applicable). The reader is directed to Barnes and Clarke (1969) for more detail on corrosion of well components by natural ground water. Appendix C. has check lists that can be used by the regulatory inspector and the well operator to detemine the effectiveness of corrosion control measures.

I. TYPES OF CORROSION

Corrosion is a term which is widely used in describing the degradation of construction materials used in all phases of injection practices. A majority of corrosion reactions directly alter the well components. For example, rust results from the direct alteration of a metallic casing. However, incrustation reactions affect well performance by clogging well screen openings and by decreasing pore space in the injection formation. Failure of a well through incrustation occurs indirectly. For this reason, incrustation will be discussed in a section of its own. Of special interest are the effects of hazardous wastes on injection wells, which result because well injection is the most widely used technique for disposal of these wastes. The appendices contain information on the corrosive effects of hazardous waste.

An Electrochemical Background to Corrosion.

Corrosion, strictly speaking, is the electrochemical dissolution of metal in an electrolyte. Examples of electrolytes are acids, alkalies, salt solutions, and the soil. An electrolyte contains positive and negative ions. When the metal corrodes, it gives up electrons and the metal ions enter the electrolyte solution.

At the corroding metal surface, two types of reactions are occurring simultaneously:

- The anodic reaction, in which metal atoms are dissolved to form positively charged ions and electrons.

- The cathodic reaction, in which specific ions in the electrolyte accept the electrons. See Figure 1.

Thus, there is a passage of positive charge from the metal to the electrolyte at the anode, balanced by a passage of negative charge from the electrolyte to the metal at the cathode. When corrosion occurs, a current flows from the anode to the cathode. Since the anode and cathode currents are equal and opposite, no electric shock is experienced from a corroding system.

If the corrosion is general, the anodic and cathodic sites are switching continuously, resulting in relatively uniform metal loss. When corrosion is localized, such as crevice or pitting corrosion, the anodic and cathodic sites are located on different parts of the same metal surface. With galvanic corrosion, the anode and cathode are two different metal surfaces.

The anodic reaction does not change, i.e., metal atoms giving up electrons to form ions. However, the cathodic reaction will vary, depending on the type of electrolyte. The examples of steel in aerated salt solution and in aerated and deaerated sulfuric acid will be used to illustrate three different cathodic reactions.

In all cases, the anodic reaction is the same. At anode sites, the steel corrodes to form ions and electrons:

$$Fe\ (metal) \longrightarrow Fe^{2+} + 2e^{-}(in\ electrolyte) \tag{1}$$

For aerated salt solution, the balancing cathodic reaction is:

$$\frac{1}{2}O_2 + H_2O + 2e^{-} \longrightarrow 2OH^{-} \tag{2}$$

For aerated hydrochloric acid, it is:

$$O_2 + 4H^{+} + 4e^{-} \longrightarrow 2H_2O \tag{3}$$

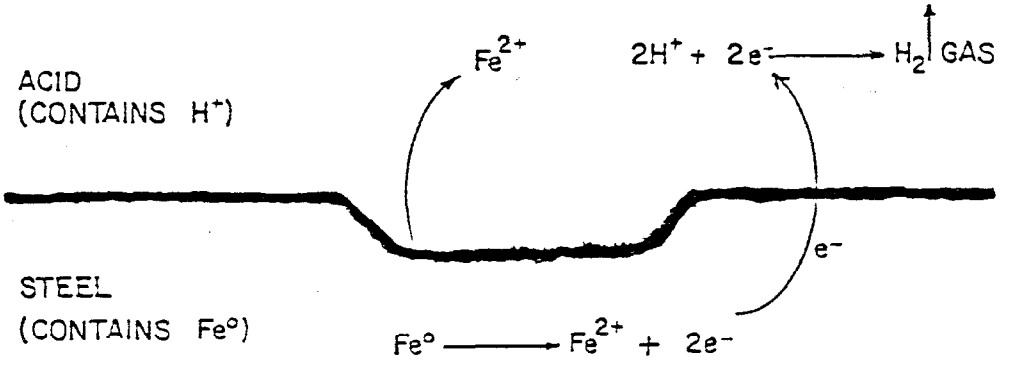


Figure 1. CORROSION REACTION

Carbon Steel in a Reducing Acid

And for deaerated hydrochloric acid, it is:

$$2H^+ + 2e^- \longrightarrow H_2 \ (gas\ evolved) \tag{4}$$

The rate of corrosion (the anodic reaction) is often controlled by the type of cathodic reaction. Disposal well environments exhibit a wide variety of possible cathodic reactions which must be evaluated. The anodic and cathodic reaction products will often combine to form solid corrosion products, such as rust. Unless mechanically removed or naturally swept away, the formation of solid corrosion products often inhibits further attack and reduces the corrosion rate. Figure 2 shows the thermodynamic states of iron and its compounds depending on the oxidation-reduction potential (Eh) and hydrogen ion concentration (pH) conditions.

Factors Which Influence Corrosiveness of Injection Well Environments.

The corrosion potential of an injection well will depend on the materials of construction, the nature of the hydrologic and geologic environments and the operating conditions. For example, concentrated sulfuric acid is not corrosive towards carbon steel at ambient temperature because it is strongly oxidizing, which causes passivation (to cause the formation of a protective film). However, if the temperature is raised or the velocity of flow is increased, concentrated sulfuric acid becomes extremely corrosive towards carbon steel for two reasons. First, increased temperatures cause the protective film to dissolve; and second, increased velocities cause the protective film to be mechanically removed.

Alloys which easily passivate, such as stainless steels and titanium, act in an opposite manner to carbon steel and have better corrosion resistance under aerated or flowing conditions. They are more likely to be attacked when oxygen concentration is low, such as in joints or cracks.

The presence of aggressive species will alter corrosion behavior. The chloride ions, for example, may easily penetrate the passive film on stainless steel and cause a deep localized form of attack known as pitting.

The pH, which is a measure of acidity or alkalinity, is a useful indicator of corrosiveness for certain alloy systems. With carbon steel, a pH of less than 4 indicates the presence of hydrogen ion (free acid), which is usually corrosive. If aggressive species are present and the environment does not promote scale formation, carbon steel may be susceptible to corrosion at pH 5.5. Even at pH 12-14 (high alkalinity), corrosion of certain metals such as zinc or aluminum may occur.

Increasing the temperature usually increases the corrosion rate; the amount depends on what factors control the cathodic reaction.

If the cathodic reaction is controlled by the availability of oxygen molecules at the metal surface, which occurs through diffusion, the increase in corrosion rate with temperature is relatively slow. If the cathodic reaction is controlled by ionic reduction, such as hydrogen ions to hydrogen gas the increase in corrosion rate with temperature is relatively rapid. [Increasing temperature also increases the opportunity for forms of localized corrosion such as pitting or stress corrosion cracking.]

The synergistic effect of corrosive mixtures must also be considered. Combinations of chemicals, which by themselves are relatively non corrosive, may be extremely aggressive towards specific alloys. For example, injection streams containing dilute nitric acid or dilute flowing sodium chloride are usually not corrosive towards stainless steel. However, if the two streams are combined, severe pitting of the stainless steel may result.

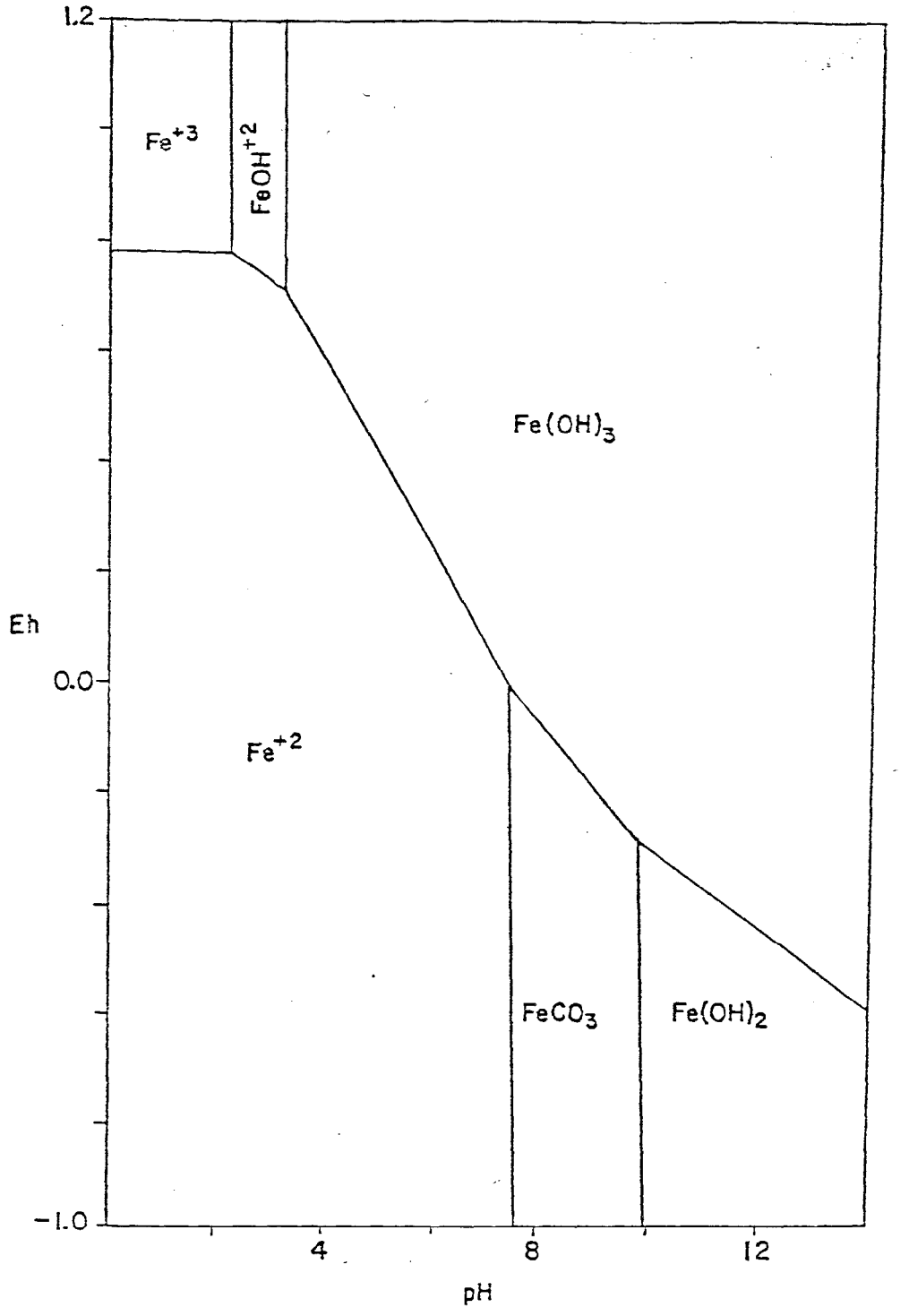


Figure 2. Oxidation-Reduction Potential (Eh) and pH Diagram Showing Stability of Iron Species and Phases at STP

To summarize, a variety of factors will affect the corrosiveness of an injection well environment. These include the characteristics of the alloy, the presence of aggressive species, the pH, the temperature, oxygen concentration, and velocity or turbulence of flowing streams. It is also important to know whether chemicals present in the injection stream increase or decrease corrosion.

Oxygen Corrosion (modified after EPA, 1982).

Oxygen dissolved in water causes rapid corrosion of certain metals (Allen and Roberts, 1978). This effect is particularly pronounced with carbon steel. The effect of dissolved oxygen is realized at the anodic area of the metal where the insoluble metallic hydroxide (rust) is precipitated. The oxygen corrosion reaction for iron in the absence of other influencing constituents proceeds as follows (Ostroff, 1965):

$$Fe + 2H^{+} \longrightarrow Fe^{+2} + H_2 \tag{5}$$

$$H_2 + \frac{1}{2}O_2 \longrightarrow H_2O \tag{6}$$

$$2Fe^{+2} + \frac{1}{2}O_2 + H_2O \longrightarrow 2Fe^{+3} + 2OH^{-} \tag{7}$$

The extent of corrosion is limited by the rate at which oxygen is delivered to the anodic area. In a closed injection system (not in contact with air), the reaction will continue only until the dissolved oxygen in the injection fluid is consumed (Warner and Lehr, 1977). In open systems, where air can enter the injection fluid, corrosion continues as the oxygen supply is replenished. In general, with increasing dissolved oxygen levels in the injection fluid the corrosion rate progresses until a point is reached where the flow of oxygen becomes limited by the barrier of metallic hydroxide developed on the anodic surface.

Oxygen corrosion is enhanced by the presence of dissolved chloride and sulfate ions. Generally, corrosiveness increases with increasing salt concentration until a maximum is reached after which corrosiveness decreases. The initial increase is due to the electrolyte conductivity increase, and the subsequent decrease results from the decreased solubility of oxygen in the electrolyte (Uhlig, 1962).

Carbonate ions inhibit oxygen corrosion; it acts to counter the acceleration effect of chloride and sufate ions in water containing dissolved oxygen. The degree of inhibition is dependent on the relative concentrations of the chloride and sulfate salts and carbonate alkalinity. When calcium is associated with the carbonates, there is further capacity for protective action (AWWA, 1971).

Again, the rate of corrosion because of dissolved oxygen generally increases with increasing temperature. Higher temperatures allow more oxygen to diffuse to the steel surface. However, when the temperature becomes higher than $90°C$, oxygen solubility decreases, and the corrosion rate can be expected to decrease even in open systems. In closed systems, the oxygen cannot escape and the corrosion rate continues to increase with increasing temperature until all oxygen has been depleted (Ostroff, 1965).

The velocity of the injection fluid can also affect the rate of corrosion. As the velocity increases, the transport of oxygen to the metal surface becomes faster and consequently the corrosion rate increases. Also, increases in the velocity of the injection fluid can cause mechanical scouring of corrosion products, thus removing the protective film. Localized velocity increases can occur at elbows or at other protuberances. Injection-fluid pH also affects the rate of corrosion of solutions containing oxygen. For carbon steel, the corrosiveness of a fluid generally increases as pH decreases. In the pH range of 4 to 9.5, the steel surface is coated by protective corrosion reaction products, and corrosion progresses at a slower rate as oxygen diffuses through this layer. Below a pH of 4, the corrosion products dissolve, and consequently, more rapid corrosion ensues (Ostroff, 1965).

Oxygen corrosion causes pits in the metal surface. The pit develops at a localized anodic point and continues by virtue of a large cathodic area surrounding the anode (AWWA, 1971). Pits may be either sharp and deep, or shallow and broad. Additionally, a corrosion product may form over these pitted areas. A common form of oxygen corrosion in wells is the formation of nodules of altered material called tubercules. These are caused by the aggregation of iron bacteria, mixed carbonates and hydrated metal oxides.

A special type of oxygen corrosion is caused by differential aeration cells, a result of differences in oxygen concentration between two parts of a system. Differences in dissolved oxygen concentrations cause differences in the solution potential of the same metal. For these cases corrosion occurs at the area of the metal where oxygen concentrations are low. An adjacent area of relatively higher oxygen concentration serves as the cathode in the reaction.

Corrosion products, chemical precipitates, or other debris on a metal surface hinder oxygen diffusion by covering the metal in local areas. These circumstances can result in high localized oxygen concentrations with corrosion taking place under the deposit.

The growth of microorganisms in injection wells can also result in the formation of localized oxygen concentration on parts of the metal surface (Ostroff, 1965). Corrosion can therefore occur around areas of tubing or casing covered by slimes or masses of bacterial growth (See Microbiologically Influenced Corrosion).

Carbon-Dioxide Corrosion (modified from EPA, 1982).

Carbon dioxide dissolved in water can contribute to the corrosion of steel, but at equal concentrations it is much less corrosive than oxygen (Ostroff, 1965). Carbon-dioxide corrosion of well components is of particular concern in enhanced-oil-recovery (EOR) operations involving carbon dioxide miscible injection systems. In these operations, carbon dioxide is injected before, after, or alternately with water.

When dissolved in water, carbon dioxide forms carbonic acid:

$$CO_2 + H_2O \longrightarrow H_2CO_3 \ (Carbonic\ Acid) \tag{8}$$

This carbonic acid causes a reduction in the pH of the water which makes it quite corrosive to steel (API, 1958):

$$Fe + H_2CO_3 \longrightarrow H_2 + FeCO_3 \quad (Iron\ Carbonate\ Corrosion\ Product) \tag{9}$$

The acidity of the solution, and therefore, the corrosion rate, is influenced by the partial pressure of carbon dioxide. The partial pressure of a gas refers to the fraction it contributes to the overall pressure of all the gases in the mixture. At higher pressures, more carbon dioxide will dissolve in water creating a stronger acid. If the partial pressure values are above 30 psi, or in metric units 2.1×10^5 Newtons per square meter ($\frac{N}{m^2}$) – the well stream is probably corrosive; seven to 30 psi (4.8×10^4 *to* 2.1×10^5 $\frac{N}{m^2}$) may be corrosive, and 0 to 7 psi (0 *to* 4.8×10^4 $\frac{N}{m^2}$) is noncorrosive (API, 1958). In most injection well environments, carbon dioxide is miscible with the fluid since pressures rarely fall below 1,200 psi (8.3×10^6 $\frac{N}{m^2}$) [critical pressure of carbon dioxide is 1180 psi] (Allen and Roberts, 1978).

The rate and amount of corrosion caused by dissolved carbon dioxide are also dependent on the oxygen content, the salts dissolved in the water, the temperatures, and the fluid velocities. Water containing both dissolved oxygen and carbon dioxide is more corrosive to steel than water which contains only an equal concentration of one of these gases (Ostroff, 1965). In waters containing magnesium and calcium bicarbonates, an increase in temperature can cause the evolution

of carbon dioxide that results in increased corrosion. At the same time, carbonates of these salts can precipitate out on the metal surface, resulting in the formation of a protective coating, which may reduce corrosion rates. As with other types of corrosion, higher than normal fluid velocities can cause erosion of corrosion products (that normally retard the corrosion reaction), allowing corrosion to continue unabated.

Carbon-dioxide corrosion may appear as a uniformly thinned metal surface or as rounded non-uniform pits. Surfaces constantly bathed in dissolved carbon dioxide solutions will tend to exhibit uniform thinning, whereas pitting is caused by carbon dioxide dissolved in droplets of water condensed on the injection-tubing wall (API, 1958).

Hydrogen-Sulfide Corrosion (modified after EPA, 1982).

Hydrogen sulfide gas dissolved in water, even in small amounts, can create a very corrosive environment (Allen and Roberts, 1978). Dissolved hydrogen sulfide forms a weak acid and in the absence of oxygen will attack iron and non-acid resistant alloys (Warner and Lehr, 1977); moreover, it becomes severely corrosive to acid-resistant alloys when oxygen is present. Hydrogen sulfide is often present in oil field production brines that are subsequently disposed by well injection. This practice has resulted in instances of severe corrosion in injection tubing, especially when the brines become contaminated with oxygen during surface handling (API, 1958). The general mechanism of this type of corrosion as it affects iron and steel is stated as follows (API, 1958):

$$Fe^{o} + xH_2S = FeS_x\ (Iron\ Sulfides) + xH_2 \tag{10}$$

Other metals react in the same manner to produce metallic sulfides. The corrosion rate in water containing hydrogen sulfide is also influenced by the presence of dissolved salts and dissolved carbon dioxide (Ostroff, 1965); when these substances are present, hydrogen sulfide corrosion rates increase.

Hydrogen-sulfide corrosion of steel or iron results in the deposition of black scale (iron sulfide) on the metal surface. The scale tends to cause a local acceleration of corrosion because steel is anodic to the iron sulfide (Allen and Roberts, 1978). This reaction results in deep pits in the metal. Cracking, in high strength steels, is due to embrittlement caused by atomic hydrogen formed in the corrosion process which interferes with the ability of the steel to yield under stress. In low strength steels, atomic hydrogen diffuses into the steel where it combines to form molecular hydrogen. These trapped molecules cause the steel to blister which may lead to premature failure.

Microbiologically Influenced Corrosion.

Microbiologically influenced corrosion is an insidious form of localized corrosion in natural waters, which occurs in crevices formed under deposits that harbor microorganisms. Failure occurs by wall penetration. Since many injection streams will kill or inhibit microorganism growth, microbiologically influenced corrosion problems are unlikely to be internal to the injection string.

Microorganisms are generally not corrosive until they settle on the metal surface. Microbiologically produced hydrogen sulfide is an exception to this rule, since it can cause corrosion remote from the deposit. Settlement of microorganisms can be aided by tubercule or slime-forming bacteria and also by surface irregularities or roughness on the metal. Once settled, the microorganisms (and also tubercule or slime-forming bacteria) may accelerate corrosion in several ways, as shown below:

- the metabolism and growth of the microorganism colony may modify or accelerate the cathodic reaction, which in turn accelerates the anodic reaction of metal loss

- the deposit itself creates an oxygen concentration cell, which increases the likelihood of crevice corrosion

- the deposit tends to concentrate ions such as chloride or manganese from the environment, which increases the likelihood of localized corrosion

Microorganisms are usually corrosive if they are allowed to settle. Two examples of such microorganisms are the anaerobic sulfate-reducing types and the aerobic iron-oxidizing types, which are extremely corrosive towards carbon steel and stainless steel, respectively.

Biocides are useful in killing planktonic (floating) microorganisms in contaminated waters. However, the effectiveness of biocides in killing sessile (attached) microorganisms is unproven. The tubercule or slime that harbors the microorganism forms a protective layer that inhibits the effectiveness of the biocide.

Galvanic Corrosion (modified after EPA, 1982 and E.E. Johnson, Inc., 1975).

Galvanic corrosion occurs where two different metals or alloys come in contact under specific conditions. Almost all metals have different solution potentials, so that when the two metals come in contact, this difference in potential results in current flow through the electrolyte. This is an important consideration for brine disposal wells since saltwater is an excellent electrolyte. The severity of galvanic corrosion depends upon the difference in potential between the two metals, and the relative size of the cathode and anode areas. The galvanic series for metals and alloys in sea water are shown in Table 1. Overall, this table is applicable to high TDS fluids but not necessarily to acidic fluids. This table is a useful guide to indicate whether corrosion can occur between two metals; however, other factors are equally important, so that separation in the series is not the prime indicator of whether corrosion is eminent. The more active metals are found at the top of the series. When two metals are electrically coupled, the more active metal is susceptible to corrosion and the less active will be protected.

If the area of the active metal is significantly smaller than the area of the noble metal, substantial corrosion of the active metal may occur. In some cases the noble metal may be enbrittled by the formation of hydrogen at the cathodic end.

On the other hand, if the area of the active metal is very large compared with the area of the less active metal, corrosion will not be so severe.

Most of the galvanic corrosion is confined to the interface between the two metals. The conductivity of the solution determines how the corrosion is spread over the active metal. Figure 3 shows how conductivity affects the extent of galvanic corrosion. In some cases, similar metals may develop a potential difference because of their different metallurgical histories. Figure 4 shows one such case.

Non-metallic Degradation.

Non-metallic construction materials include cementitious materials such as ceramics and plastics. The discussion will be confined to plastics. Plastics are of two types: thermoplastics and thermosets. Both types may be reinforced or filled with materials such as glass or graphite to enhance their strength, lubricity, etc.

When non-metallic materials are exposed to a hostile environment, they may degrade. The degradation of non-metallic materials can take several forms, which include blistering, crazing, swelling, softening, and delamination. In most cases, the result of degradation is the loss of mechanical properties leading to well failure. Table 2 gives a qualitative evaluation of the chemical effects of certain organic solvents and mineral acids on specific plastics.

TABLE 1

GALVANIC SERIES FOR METALS IN SEA WATER
(Jellinek, 1958)

Active or Anodic End

Magnesium
Zinc
Alclad 3S
Aluminum 3S
Aluminum 61S
Aluminum 63S
Aluminum 52
Carbon Steel
Alloy Steel
Cast Iron
Stainless Steels (active)
- Type 410
- Type 430
- Type 304
- Type 316

Ni-Resist
Muntz Metal
Yellow Brass
Admiralty Brass
Aluminum Brass
Red Brass
Copper
Aluminum Bronze
Compostition G Bronze
90/10 Copper-Nickel
70 + 30 Copper-Nickel-Low Iron
Nickel
Iconel
Silver
Stainless Steels (passive)
- Type 410
- Type 430
- Type 304
- Type 316

Monel
Hastelloy C.
Titanium

Noble or Cathodic End

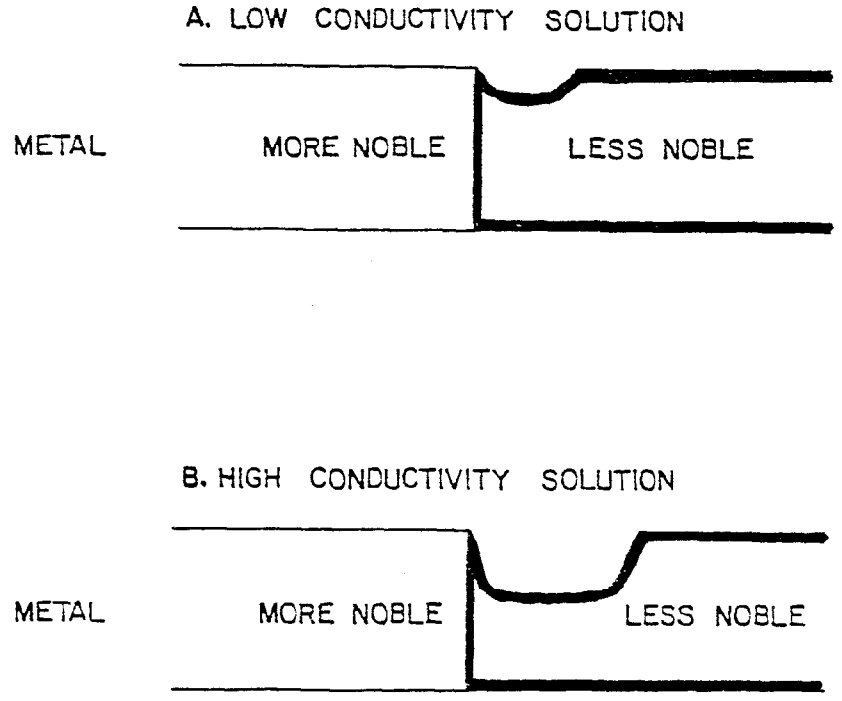


Figure 3. The Effect of Solution Conductivity on Galvanic Corrosion
a) Low Solution Conductivity
b) High Solution Conductivity

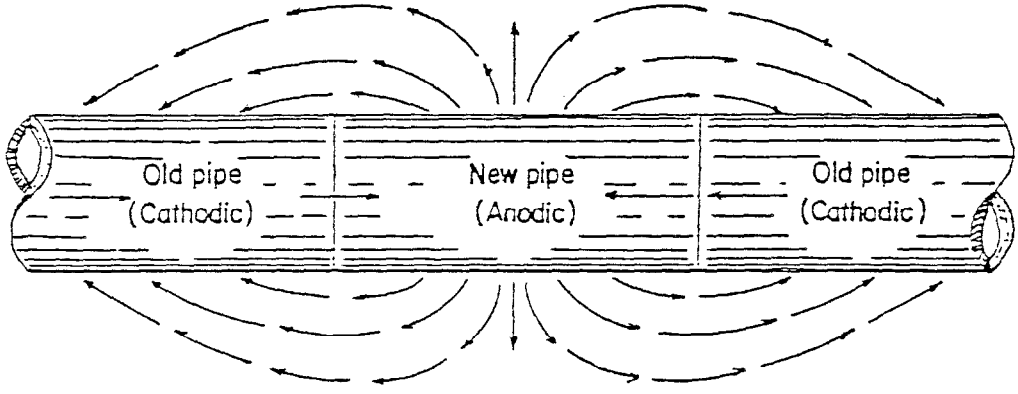


Figure 4. New Pipe Replacing a Section in an Older Pipeline Often is Anodic and Corrodes Faster than the Old Pipe which is Partly Protected by Previously Formed Coatings of Rust

TABLE 2

CHEMICAL RESISTANCE OF SOME COMMERCIAL PLASTICS

Chemical Class	Cellulose Acetate Butyrate	Nylon	Polycarbonates	Cellulose Acetate
Resin Type	Thermoplastic	Thermoplastic	Thermoplastic	Thermoplastic
Subclass or Modification	Hard	6/6	Unfilled	Soft
Chemical Resistance				
Mineral acids, weak	Good	Very Good	Excellent	Fair to Good
Mineral acids, strong	Fair to Good	Poor	Fair	Poor
Oxidizing acids, concentrated	----	Poor	----	Very Poor
Alkalines, weak	Good	No effect	Poor	Poor
Alkalies, strong	Poor	No effect	Poor	Very Poor
Alcohols	Poor	Good	Poor	Poor
Ketones	Poor	Good	Poor	Poor
Esters	Poor	Good	Poor	Poor
Hydrocarbons, aliphatic	Fair to Good	Very Good	Poor	Fair to Poor
Hydrocarbons, aromatic	Poor	Fair to good	Poor	Poor to fair
Oils, vegetable, animal, mineral	Good	Good	Poor	Fair to good

Chemical Class	Polyethylene	Polyethylene	Polyethylene	Methylmethacrylate
Resin Type	Thermoplastic	Thermoplastic	Thermoplastic	Thermoplastic
Subclass or Modification	Low Density	Medium Density	High Density	Unmodified
Chemical Resistance				
Mineral acids, weak	Good	Excellent	Excellent	Good
Mineral acids, strong	Good	Excellent	Excellent	Fair to Poor
Oxidizing acids, concentrated	Good to Poor	Good to Poor	Good to Poor	Attacked
Alkalies, weak	Good	Excellent	Excellent	Good
Alkalines, strong	Good	Excellent	Excellent	Poor
Alcohols	Excellent to Poor	Excellent to Poor	Excellent to Poor	----
Ketones	Excellent to Poor	Excellent to Poor	Excellent to Poor	Dissolves
Esters	Excellent to Poor	Excellent to Poor	Excellent to Poor	Dissolves
Hydrocarbons, aliphatic	Fair	Fair	Fair	Good
Hydrocarbons, aromatic	Fair	Good	Fair	Softens
Oils, vegetable, animal, mineral	Good	Excellent	Good	Good

TABLE 2
(continued)

Chemical Class	Cellulose Acetate Butyrate	Cellulose Acetate		
Resin Type	Thermoplastic	Thermoplastic	Thermoplastic	Thermoplastic
Subclass or Modification	Hard	Soft	Unmodified	Copolymer
Chemical Resistance				
Mineral acids, weak	Fair to Good	Good	Excellent	Excellent
Mineral acids, strong	Poor	Fair to Good	Excellent	Excellent
Oxidizing acids, concentrated	Very Poor	----	Good to Poor	Excellent
Alkalines, weak	Poor	Good	Excellent to Good	Excellent
Alkalies, strong	Very Poor	Poor	Excellent to Good	Good
Alcohols	Poor	Poor	Excellent to Good	Good below 80°C
Ketones	Poor	Poor	Excellent to Good	Good below 80°C
Esters	Poor	Poor	Excellent to Good	Good below 80°C
Hydrocarbons, aliphatic	Fair to Good	Fair to Good	Good to Fair	Good below 80°C
Hydrocarbons, aromatic	Poor to Fair	Poor	Good to Fair	Good below 80°C
Oils, vegetable, animal, mineral	Fair to good	Good	Good	----

Chemical Class	Polysterene	Polystyrene acrylonitrile	Polyethylene chloroethylene	Polytrifluoro-ethylene
Resin Type	Thermoplastic	Thermoplastic	Thermoplastic	Thermoplastic
Subclass or Modification	Unmodified	Unmodified	Unmodified	Unmodified
Chemical Resistance				
Mineral acids, weak	Excellent	Excellent	Excellent	Excellent
Mineral acids, strong	Excellent	Good to Excellent	Excellent	Excellent
Oxidizing acids, concentrated	Poor	Poor	Excellent	Excellent
Alkalies, weak	Excellent	Excellent	Excellent	Excellent
Alkalines, strong	Excellent	Good to Excellent	Excellent	Excellent
Alcohols	Excellent	Good to Excellent	Excellent	Excellent
Ketones	Dissolves	Dissolves	Excellent	Excellent
Esters	Poor	Dissolves	Excellent	Excellent
Hydrocarbons, aliphatic	Poor	Good	Excellent	Excellent
Hydrocarbons aromatic	Dissolves	Fair to Good	Excellent	Excellent
Oils, vegetable, animal, mineral	Fair to Poor	Good to Excellent	Good	Excellent

Chemical Class	Cellulose Acetate Butyrate	Cellulose Acetate
Resin Type	Thermoplastic	Thermoplastic
Subclass or Modification	Unmodified, Rigid	Plasticized (nonrigid)
Chemical Resistance		
Mineral acids, weak	Excellent	Fair to Good
Mineral acids, strong	Good to Excellent	Fair to Good
Oxidizing acids, concentrated	Fair to Good	Poor to Fair
Alkalines, weak	Excellent	Fair to Good
Alkalies, strong	Good	Fair to Good
Alcohols	Excellent	Fair
Ketones	Poor	Poor
Esters	Poor	Poor
Hydrocarbons, aliphatic	Excellent	Poor
Hydrocarbons, aromatic	Poor	Poor
Oils, vegetables, animal, mineral	Excellent	Poor

(After: The Chemical Rubber Company, 1978)

One method of checking the applicability of non-metallic materials is to remove samples at regular intervals during exposure and to measure the loss of mechanical properties, such as flexural strength. If the loss levels off to an acceptable value, the material is usually considered suitable.

II. INORGANIC INCRUSTATION
(SCALE-FORMING TENDENCY)

Inorganic scaling corrosion can occur as a result of incompatibility between injection fluids and the naturally occurring fluids in an injection zone. Persons and Hart (1980) have discussed calcium carbonate scaling in Class V, heat pump wells. This discussion can also be applied to other types of injection wells. Calcium carbonate scaling occurs as a result of lowering carbon dioxide (CO_2) solubility in solutions containing dissolved calcium carbonate ($CaCO_3$); this is because CO_2 is in equilibrium with $CaCO_3$ and a change in pressure or temperature results in a shift in the equilibrium. In readjusting to the new equilibrium, $CaCO_3$ may be precipitated when the temperature is raised and/or when the pressure is reduced. Figure 5 shows the relationship between CO_2 solubility and pressure and temperature in water. Other inorganic compounds show similar behavior to calcium carbonate. Warner and Lehr (1977) discussed methods of predicting the solubilities of some chemical constituents of injected wastewater through calculation of a stability index. A discussion of the work of Warner and Lehr (1977), relative to chemical stability, is presented below.

Chemical Stability.

The following text has been extracted and modified from Warner and Lehr (1977).

Stability of the chemical compounds in the injected wastewater is desirable. An unstable compound may precipitate during or after injection and cause plugging. The influence of pressure, temperature and pH change in initiating instability have been individually pointed out, but have not been quantified. Also, these factors can act simultaneously and/or synergistically – making interpretation difficult.

A means of anticipating instability in a system affected by more than one variable is through use of a saturation or stability index. Several such indices have been developed including those by Langelier (1936), Ryznar (1944), Larson and Buswell (1942), and Stiff and Davis (1952). The first three indices are applicable to waters of low ionic strengths, while the Stiff and Davis index is intended for use with concentrated solutions, such as highly saline ground waters. As an example of the use of such indices, the Stiff and Davis (1952) stability index for calcium carbonate is:

$$SI = pH - K - pCa - pAlk \tag{11}$$

In equation 11, K is an empirical constant used to compensate for various ionic strengths and temperatures. The values of $K, pCa, and\ pAlk$ are taken from graphs (Figures 6 and 7). A positive index indicates scale formation and a negative index indicates corrosiveness by the injection fluids.

The following example of the use of the stability index was taken from Ostroff (1965), and modified.

From the water analysis in the first column of Table 3, the concentration C of each ion in moles per 1,000 grams of water (molality) was calculated using the relationship:

$$C = \frac{epm}{Z(1{,}000\ SpGr - \frac{TDS}{1{,}000})} \tag{12}$$

$$where\ epm = concentration\ of\ the\ ion,\ equivalents\ per\ million$$

$$Z = valence\ of\ the\ ion$$

$$SpGr = specific\ gravity\ of\ the\ brine = 1.06$$

$$TDS = total\ dissolved\ solids, ppm = 152{,}474\ \frac{mg}{l}$$

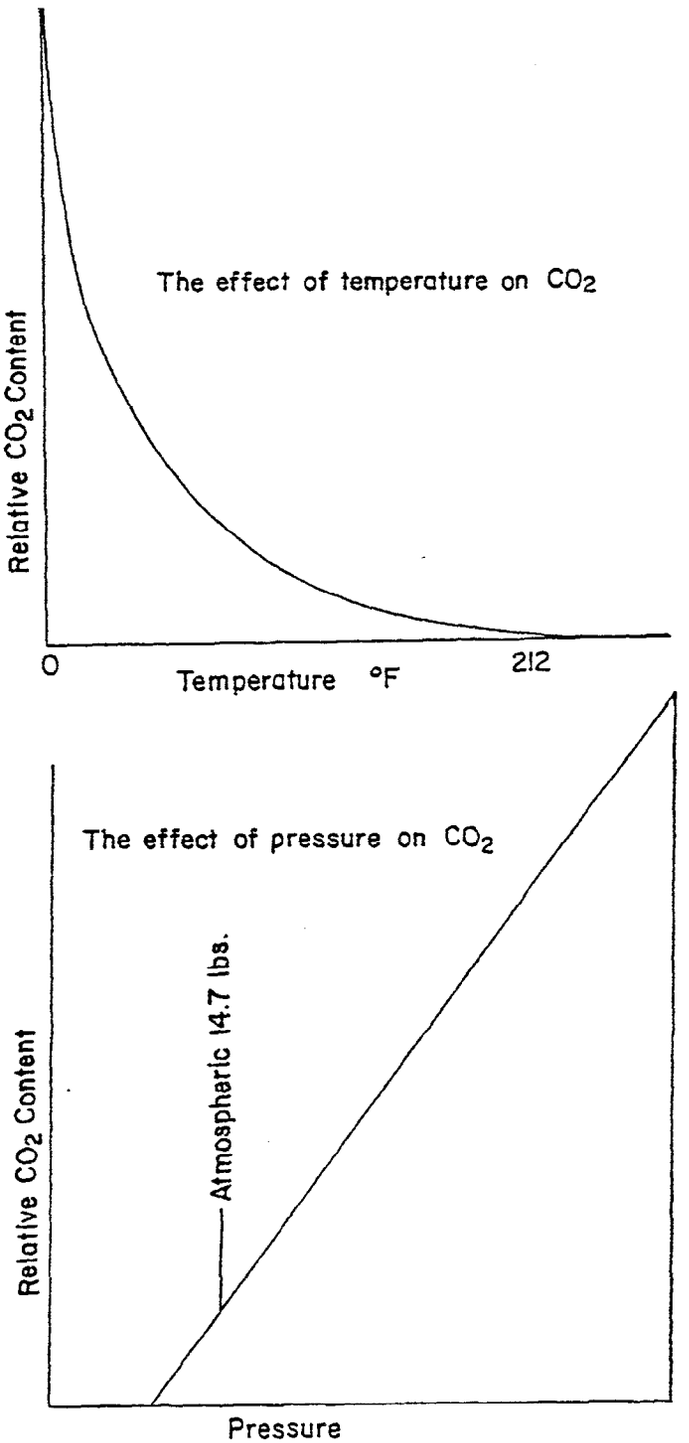


Figure 5. The Effects of Pressure and Temperature on Carbon Dioxide Solubility (Modified after Persons and Hart, 1980)

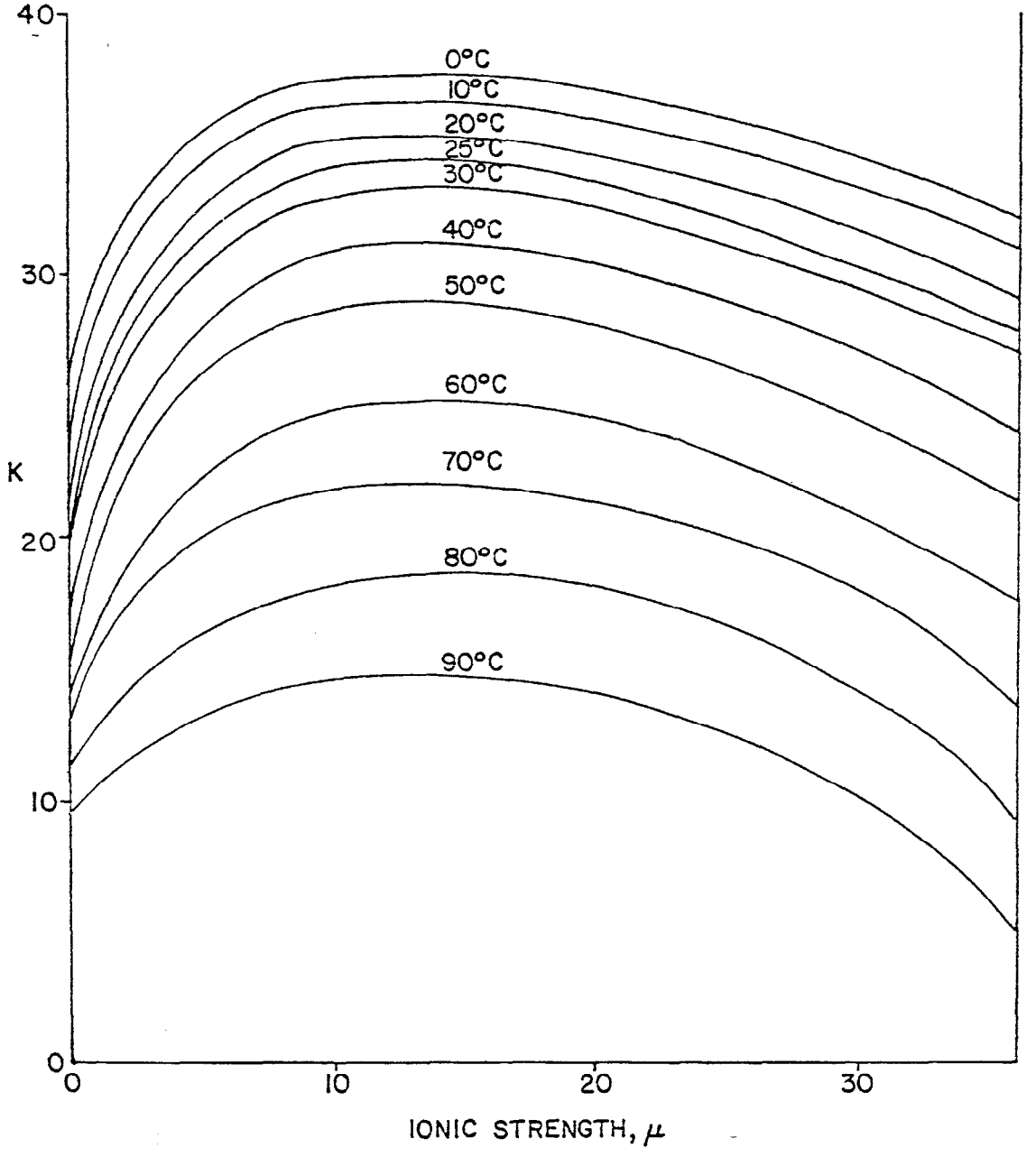
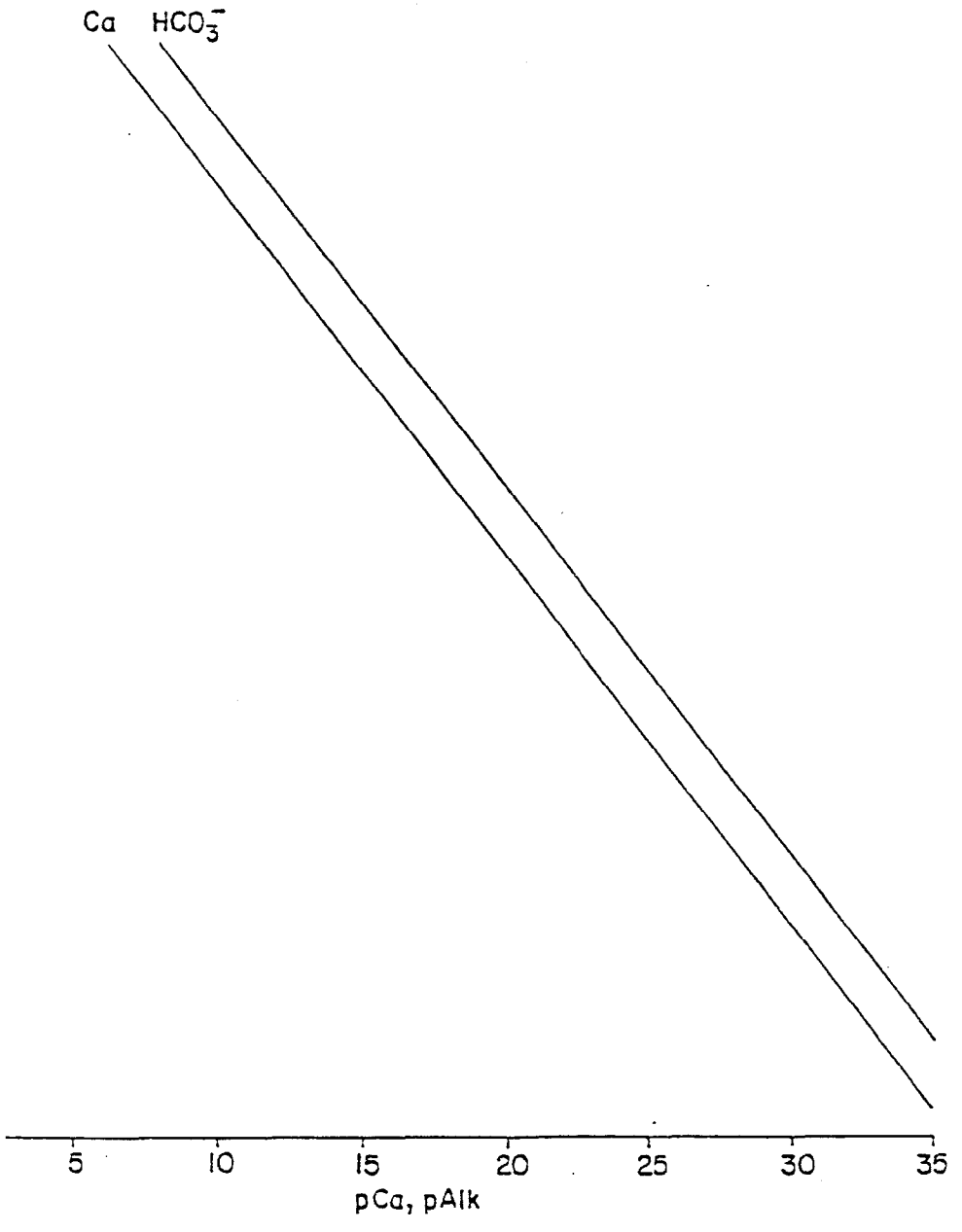


Figure 6. Values of K at Various Ionic Strengths (from Warner and Lehr, 1977; after Stiff and Davis, 1952)



:e 7. Graph for Converting Concentrations of Calcium and Alkalinity (in ppm) to pCa and pAlk. pCa = -log [Ca], pAlk = -log[Alk], Alk = $[OH^-] + [MCO_3^-] + 2[CO_3^{2-}] - [H^-]$ (Ibid.Figure 5)

TABLE 3

WATER ANALYSIS USED IN SAMPLE CALCULATION OF CALCIUM CARBONATE SATURATION USING STIFF AND DAVIS INDEX
(Ostroff, 1965)

Component	mg/l	epm	Molality (C)
Carbonate $(CO_3)^{-2}$	---	---	---
Bicarbonate $(HCO_3)^{-}$	46	0.8	0.001
Sulfate $(SO_4)^{-2}$	7,530	157	0.086
Chloride Cl^{-}	88,300	2,487	2.740
Iron Fe^{+2}	14	0.5	0.000
Calcium Ca^{+2}	8,570	428	0.236
Magnesium Mg^{+2}	2,819	232	0.128
Sodium Na^{+}	45,195	1,965	2.165
TOTAL	152,474		

This gives the results shown in the third column of Table 3. Using these molalities, the ionic strength u is calculated.

$$u = \frac{1}{2}[C_1(Z_1)^2 + C_2(Z_2)^2 \cdots C_n(Z_n)^2] \tag{13}$$
$$= \frac{1}{2}[(0.001)(1) + (0.086)(4) + (2.740)(1) + (0.236)(4) + (0.128)(4) + (2.165)(1)]$$
$$= 3.35$$

Then, from Figure 6, at $u = 3.35$ and $T = 77°F(25°C)$ (average temperature of the fluid), the value of K is found to be 2.96.

The next step is to enter the concentrations from Table 3 of Ca^{2+} (8,570 ppm) and HCO_3^- (46 ppm) as the ordinate of Figure 7. Reading the abscissa, the pCa is 0.67 and the pAlk is 3.12 (pH is given as 6.1).

Substituting in Equation 11, the stability index is calculated as follows:

$$SI = pH - K - pCa - pAlk = 6.1 - 2.96 - 0.67 - 3.12 = -0.65 \tag{14}$$

This indicates that the fluid is corrosive and undersaturated with respect to calcium carbonate, meaning that no scale formation is expected.

Ostroff (1965) discusses the stability of magnesium carbonate, magnesium hydroxide, calcium sulfate, barium sulfate, iron, and also silica. Barnes (1969) suggests a thermodynamic approach to predicting the stability of inorganic compounds in solution. Dissolved organic compounds may or may not be unstable. Selm and Hulse (1960) list polymerization of organic chemicals as a source of precipitates which can cause plugging. In addition to the predictive methods of analyzing for chemical stability, empirical methods may also be used. The fluid in question should be subjected to the pressure and temperature conditions encountered in the subsurface, and then observed to evaluate its tendency to form precipitates over an extended period of time.

III. FAILURE DUE TO CORROSION - REPRESENTATIVE EXAMPLES

Brine Disposal.

Early in the history of brine disposal wells, it became apparent that steel casing would readily corrode in the presence of strong electrolyte solutions. One of the methods adopted to prevent corrosion in brine disposal wells was to use wood stave pipe. Although the wood pipe was resistant to internal corrosion, in many cases, the steel bindings would corrode due to constituents in formation fluids (Holloway and McSpadden, 1961). Asbestos-cement pipe was used at one time because of its resistance to electrolytic corrosion. However, Holloway and McSpadden (1961) caution that this type of pipe is subject to massive scaling problems.

Case 1. In the state of North Dakota, there was a corrosion problem in brine disposal wells — and, also one in injection wells that used produced water. The produced water contained sodium chloride concentrations that ranged from 100,000 ppm to over 200,000 ppm which were very corrosive to the steel tubing. The brine would eventually corrode through the tubing; where this occurred the tubing, sometimes, had to be replaced in only several months. Rarely, was the tubing effective for a period of two years.

The development of a new tubing has aided operators in all but eliminating the problem. The operators, presently, use fiberglass tubing or internally coated steel tubing. The latter tubing is used when high temperatures and pressures are encountered.

Case 2. In a Great Lake's state, an oil field contained very corrosive brine (the injection wells are of carbon steel). The oil company which operated the field experienced 76 well failures over the course of one year. Of these, 19 failures occurred in wells that had already experienced one failure; and, three failures happened in wells which had already experienced two failures during the year. In most cases, the problem was a tubing leak that developed because the brine was so corrosive. The company tried mixing an additive to the injection fluid, but failures still took place with the same frequency. The company continues to replace tubing joints as necessary.

However, one possible solution to the problem could be to replace the materials used in the tubing for fiberglass, or if this is not structurally feasible — then a ferric type tubing with a protective synthetic coating could be employed. Another possible solution, though expensive, would be pretreatment of the waste.

Hazardous Waste Disposal.

Different types of wastes are injected in commercial facilities. Because of this, the potential for operational problems is higher than for on-site or non-commercial facilities which usually inject wastes within a certain type range.

Probably due to the problems associated with the diversity of wastes injected and to the inadequate training of operators at one commercial injection site, up to 45 million gallons of hazardous wastes were released into an unauthorized zone. The wells in question had fluid seals in lieu of mechanical packers in the casing tubing annulus. These systems are complex to operate as the injection pressure, pressure in the annulus, temperature, specific gravity, injection occurrences and other parameters determine where the fluid seal (interface) is located. The operator had to add significant amounts of fluid to the annulus to maintain the desired operating conditions. The fluid was probably flowing out of the casing through holes created by the corrosive action of the waste. Along with the annulus fluid, large volumes of hazardous waste were also released through the holes caused by corrosion.

A logical scenario can be reconstructed from the plant record as follows:

- Inadequate monitoring caused the interface of the annulus and injection fluid to rise to a location in the annulus which was succeptible to corrosion.

- One or a series of long episodes of subjecting the unprotected casing to the effects of the corrosive waste caused perforations which allowed the fluid to escape.

- Lack of corrosion monitoring and indiscriminate injection of many types of wastes made it difficult for the operator to know that there was a problem.

- The operator started adding small volumes of annulus fluid to keep the well within the range of operational parameters. As time passed, the holes in the casing became larger. However, due to indequate instrumentation, the gradual change in annulus fluid requirements, and inadequate operator training — the changes went unnoticed and/or the warnings were not heeded.

- The fluids interface stabilized as the operator found a pressure at which annulus fluid addition was minimized. Unfortunately, the interface was located at a place which was vulnerable to further corrosion.

- Mechanical integrity tests were carried out and damage was discovered.

It is obvious that human error played a large role in this mishap. However, a corrosion monitoring system would have provided advance warning as to the effects of the injection fluids. Periodic evaluation keyed by the corrosion monitoring system, would also have minimized the magnitude of the release.

Inorganic Incrustation in an Injection Well.

Keech (1982) reported an occurrence of inorganic iron and calcium carbonate incrustation on a well screen in a ground-water heat pump return well which was so intense that backed up water in the well flowed 70 feet above static water level. After cleaning the well, it was kept under constant pressure so that the water in the well was constantly moving. This apparently prevented scale precipitation on the screen from stagnant water.

Dilute Organic Acid and Stainless Steel (Moniz, 1986).

Type 304L stainless steel injection tubing had been in service for two years handling a dilute organic waste, containing 1% nitric acid. The downhole temperature was $140^{o}F$. The annular space between the injection string and the tubing contained 10% inhibited sodium chloride brine.

The injection tubing developed leaks at the couplings (type 304L stainless steel). Disassembly of the injection tubing revealed that the joint surfaces exhibited various degrees of localized corrosion or pitting in the threads. In severe cases, the localized corrosion had caused wall penetration.

The pitting was caused by chloride ions from the brine and the nitric acid from the waste mixing that formed a highly corrosive environment for the stainless steel. Pitting was augmented by temperature and the geometry of the joint, which favored the development of crevice conditions and prevented the corrosion from being washed out. Pipe dope in the threads did not provide an adequate seal to prevent the mixing of the two chemicals. A remedy was to replace the annular space sodium chloride brine with sodium nitrite, which does not cause similar corrosion problems when mixed with the waste stream.

IV. DETECTION AND MEASUREMENT OF CORROSION
(MODIFIED AFTER EPA, 1982)

Tubing and casing materials should be compatible with the injection operation, as well as the fluid to be injected, and the environment in which the well is constructed. To determine proper construction materials, it may be desirable to first test the corrosiveness of the injection fluid in the laboratory. Despite the consideration given to corrosion control during well design, there often is a need to recognize corrosive environments during well construction and to detect and measure corrosion in an operating injection well.

Before initiating a corrosion-prevention program, it is necessary to determine if corrosion will occur, the cause of corrosion, and the rate and severity of corrosion. To determine the effectiveness of a corrosion-prevention program, the rate and effects of corrosion should be measured before and after application of prevention measures. The following are descriptions of five commonly used methods of detecting and measuring corrosion:

Weight-loss Coupons and Corrosion Loops.

The most common of all corrosion rate measurement tests involves exposing pieces of metal similar to those in the injection system to the corrosive environment. Small, preweighed and measured coupons made of different metals are exposed to well fluids for a defined period of time, removed, cleaned, and weighed to determine the corrosion rate (Allen and Roberts, 1978). Downhole coupon installation can be made by using standard wireline equipment. Corrosion rates are usually measured in mils per year (mpy) penetration or metal loss. A low corrosion rate may not be acceptable if localized corrosion (such as pitting) is occurring, whereas, a high rate with a general area type of metal loss may be, in certain cases a relatively insignificant problem.

The visual appearance of the coupon after exposure may indicate the type and cause of corrosion (Ostroff, 1965). For example, a black sulfide coating shows the presence of hydrogen sulfide in the system. Ferric oxide indicates oxygen is present, and carbon dioxide corrosion can be detected by ferrous carbonate deposits. An example of how a coupon test can be used to evaluate corrosion rates of various metals in a saltwater injection well where hydrogen sulfide containing brines are being disposed is provided in Table 4. It should be noted that the list of alloy compositions is not comprehensive and the condition rates are specific to the conditions of the exposure described. With the exception of a few metals and alloys of changeless performance, any indicated usage should be correlated in detail with all related corrosion data.

Weight loss coupon tests are only comparative. The difference in the size and thermomechanical history of a coupon compared with actual items of equipment means that the corrosion rate measured on a coupon rarely matches what is obtained in equipment. Nevertheless, coupons provide the most useful guide to corrosion, particularly localized corrosion effects. [When suitably fabricated and exposed, coupons predict general corrosion, crevice corrosion, pitting, stress corrosion cracking, embrittlement, galvanic corrosion and metallurgical structure related corrosion.]

At one time, coupons were widely used and considered to be the best method for estimating internal corrosion, especially in oil field production and injection well operations. The principal disadvantages of the coupon test method are the time required to obtain results and the limited area tested, i.e., only at the point of installation (Allen and Roberts, 1978).

Another method of determining the corrosion potential of injection fluids is the use of a "corrosion loop". A corrosion loop is a section of casing which is valved so that some of the injection stream is passed through a small pipe running parallel to the injection pipe at the surface of the well. The composition of the pipe is the same as the well casing. The only differences are

TABLE 4

ILLUSTRATION OF CORROSION RATES OBTAINED FROM
WEIGHT LOSS COUPON TESTING IN
"SOUR" (HYDROGEN SULFIDE CONTAINING) SALTWATER
(Gulf Oil Corporation, 1948)

Metal or Alloy	Corrosion Rate* (Mils per year)
Nickel	1.0
K Monel	1.1
Nickel Plated Steel	2.8
Antimonial Admiralty	3.2
Type 316 18-8 (Mo)	5.5
Aluminum 6061-T6	6.9
Type 304 18-8	10.2
Type 347 18-8 (Cb)	10.8
70-30 Copper Nickel (70% Cu, 30% Ni)	14.0
Carbon Steel J-55	15.6
Carbon Steel N-80	16.0
Alclad	16.2
Croloy 2-1/4	17.8
Galvanized Steel	23.3
Croloy 5	23.4
9% Nickel	25.4
Copper Steel (0.26 Cu)	25.8
Yoloy (2 Ni, 1 Cu)	25.9
5% Nickel	27.3
12 Chrome Cast	28.7
3% Nickel	29.0
0.40 Carbon Cast	29.7
Croloy 9	30.1
Carbon Steel H-40	32.6
Croloy 12	33.5
Corten (0.48 Ni, 1.04 Cr, 0.41 Cu)	35.6
Ampco Grade 8 (88 Cu, 10 Al, 1 Fe)	36.0
Cr-Mo-Si Steel (2.09 Cr, 0.56 Mo, 1.17 Si)	38.1
Everdur 1010	62.2
Copper Plated Steel	64.6
Red Brass Alloy 24 (85 Cu, 15 Zn)	67.1
Copper	107.8

---

* Corrosion rates of insulated coupons 4.5 by 1.5 inches in SWD line, Darst Creek Field, Texas, 60 days exposure. Corrosion rates are average of 4 coupons. Saltwater tests: pH-7; H_2S-200 mg/l; total solids-26,000 mg/l; temperature-120°F; velocity-2 ft/sec.

that the corrosion loop pipe has a smaller diameter than the well casing and the temperature is lower. The corrosion loop is essentially a small scale version of the well. The corrosion loop can be removed from the system upon closing the appropriate valves. The pipe can then be analyzed for corrosion. If corrosion is observed in the small scale casing, corrosion is probably occurring in the well casing.

One well known limitation of the loop is that the environmental conditions inside the well are different than in the corrosion loop, and it may be more or less subject to corrosion than the well. For example, the temperature in the corrosion loop is usually lower than inside the injection string since temperature usually increases with depth. This may lead to incorrect predictions for corrosion loop monitoring. Also, the effect of corrosion-accelerating features, such as joints, may not be adequately represented in a corrosion loop.

Electrical-Resistance Probes.

Electrical-resistance corrosion probes are based on an adaption of the Wheatstone bridge, and measure changes in electrical resistance of a metal speciman as it corrodes (Ostroff, 1965). The Wheatstone bridge circuit provides a simple but accurate means of measuring electrical resistance. The basic components of a Wheatstone bridge are a power source and three resistors which are calibrated before the test. The resistance of the system is introduced into the circuit. By measuring an induced current, the unknown resistance can be calculated. Probes are available in a variety of sizes, thicknesses, metals, and alloys.

The probe is attached to a portable galvanometer. Several probes can be monitored at convenient time intervals with one instrument; this is particularly valuable when it is necessary to measure corrosion rates at different points within the system at the same time.

The electrical-resistance probe has found its principal applications in injection systems involving gas streams because the probe does not have to be submerged in water to function. One of the disadvantages is that it is usually limited to the measurement of uniform corrosion. The probe can give misleading results if a deposit forms on it (Allen and Roberts, 1978). It is a sensitive and delicate instrument not easily repaired, and it is difficult to operate by the untrained.

Polarization-Resistance Probes.

A polarization-resistance probe can be used to measure corrosion current and corrosion rate because metal loss is directly proportional to current flowing from the test electrode (Allen and Roberts, 1978). This instantaneous corrosion-rate meter has the capacity to detect very low rates of uniform corrosion, and it can record data for multi-test points on a continuous basis. In addition, some progress has been made in using corrosion-rate meters to predict pitting-type corrosion.

The polarization-resistance probe is particularly useful in studying the changes throughout an injection well system caused by the introduction of corrosion inhibitors, air leaks, or other changes. The test probes must be submerged in liquid and positioning must be done with care in a flowing stream to avoid shadowing one electrode by another (Allen and Roberts, 1978). The electrodes may experience short-circuiting resulting from corrosion products or solids in the injection fluid.

Well-logging methods.

Caliper surveys, electromagnetic pipe analysis survey (PAS) logs, casing potential logs, and ultrasonic/radioactive-measurement logs are techniques commonly used for evaluating active corrosion. Brief descriptions of these methods are provided below.

Caliper surveys are run to inspect the internal surface of tubing or casing. Mechanical feelers contact the inside metal surface and will measure the diameter of the pipe and can detect the metal loss due to pitting and thinning. A baseline caliper log should be run to provide the basis for

comparison. Caution should be exercised when running calipers through coated tubing to prevent pipe coating damage. In addition, caliper feelers may remove protective scales and allow corrosion to occur in the feeler tracks.

Casing-thickness logs can be developed by using an instrument called a Pipe Analysis Survey (PAS) tool, which relies on an electromagnetic field to measure the thickness of metal at any point in the casing. This type of log can be used to calculate external metal loss when the loss of metal on the inside of the casing has been measured with an internal caliper.

The following discussion of PAS tools has been taken from Nielsen and Aller (1984). The PAS tool detects casing defects such as holes, gouges or cracks, by measuring fluctuations in an induced magnetic field with coils mounted in small pads. The PAS is able to discriminate between defects on the inside and outside of the casing wall by means of a high-frequency eddy current test, which detects flaws on only the inner surface, and a magnetic flux leakage test, which inspects the full casing thickness. An evaluation of the various nondestructive mechanical integrity testing techniques indicates that a combination of high-frequency eddy current and magnetic flux leakage tests provide an optimum approach for in-place inspection of well casings to detect small, isolated defects or corroded areas and to determine whether they are located on the internal or external casing wall.

Current flow in the well casing can be measured with a logging tool with two sets of contactor knives. Polarity of the voltage reading between the two contacts indicates at any given point whether current is flowing from the casing. Corrosion is indicated where current is leaving the pipe. A casing potential log is the best approach to find active corrosion on the outside of the casing and to show effectiveness of cathodic protection (Allen and Roberts, 1978).

Finally, ultrasonic or radioactive devices can be used to measure wall thickness and detect thinning of metal. The principle limitations are that small pits may not be detected, and the measurement is made only at one point.

Detection of Microbiologically Influenced Corrosion (Horacek, 1986).

Although it is easy to detect planktonic microorganism populations in water, the detection of sessile microorganisms is an uncertain science. Furthermore, the population size of either type is not necessarily an indication of their potential to induce corrosion. The diagnosis of microbiologically influenced corrosion is extremely difficult, because the evidence of microorganism contamination may have disappeared by the time the failure analysis is performed.

V. CORROSION CONTROL

Corrosion can be minimized by the application of a number of different design considerations and operating techniques which include: use of construction materials resistant to potential corrosion by the designated injection fluid, protective coatings to the tubing and casing, provision in the design of the well to allow for future application of corrosion inhibitors to the casing/tubing annulus if the need arises and pretreatment of the injection stream.

Metals resistant to corrosion are available for virtually all corrosive environments encountered in injection operations. The problem with many of these corrosion-resistant metals is their prohibitive cost. Iron and steel may corrode, but their lower cost, ease of manufacturing, and strength have helped them become the most commonly used metals in injection operations (Allen and Roberts, 1978). Other more resistant metals and alloys provide resistance to corrosion in specific applications, but they cost significantly more than carbon steel.

The choice of metals to resist corrosion in a specific application is affected by the corrosive environment, as well as the physical requirements for the material. In a hydrogen sulfide environment, the effect of hydrogen embrittlement on strength and durability of a metal is the primary concern (Allen and Roberts, 1978). Carbon steels are resistant to sulfide-stress cracking as are other more exotic alloys. Low-alloy steels, heat treated to high strength levels are not recommended because of their greater tendency toward sulfide cracking (API, 1958). For carbon dioxide and oxygen environments, where embrittlement is not a concern, metals should be selected based on control of metal loss. These metals are typically more expensive alloys, such as stainless steel nickel-base alloys or titanium; consequently, economics might dictate that other methods of corrosion control be used. For corrosion resistance to most acids, compatible stainless steel is usually employed for injection tubing strings. Tables of suitable metals and alloys for hydrogen sulfide, carbon dioxide, and oxygen corrosion are provided in Table 5.

Downhole applications of nonmetallic corrosion-resistant materials are limited to certain types of plastics. Other nonmetallic materials, such as asbestos-cement and ceramics, do not possess the temperature resistance or toughness necessary for injection tubing. The most extensively used plastic pipes and tubings are fiberglass pipes reinforced with epoxy resins (reinforced thermostatic plastic, RTP) (Donaldson, 1972). The material is highly resistant to corrosive fluids, and it also affords relatively good resistance to corrosive attack by acids and alkalies (Ostroff, 1965). PVC and other plastic pipe also offer this corrosion-resistant capability, but have lower strength and temperature ratings than reinforced fiberglass materials. A disadvantage of epoxy-reinforced fiberglass and other plastic tubing materials is their relatively poor resistance to attack by organic solvents and dissolved chlorine.

Protective Coatings.

Coatings prevent corrosion by removing or separating the corrosive environment from the metal. Paints, plastics, cement, rubber, and ceramics have been used to provide such barriers (EPA, 1982). In addition, some metal coatings, like zinc on steel, cathodically protect the base metals.

Organic, inorganic, or metallic coatings are selected on the basis of the temperature, pressure, and corrosiveness of the environment. A major problem with protective coatings is that a break in the coating exposes the base metal to corrosion (Ostroff, 1965). These breaks are called "holidays."

Inorganic cement linings are also used extensively for tubing in wells handling brines (API, 1958; EPA, 1982). Cement linings are not recommended for use with highly acidic solutions. Moreover, cement linings are permeable to water and corrosion products tend to form between the

TABLE 5

SUITABILITY OF CASING AND TUBULAR GOODS
TO VARIOUS CORROSION ENVIRONMENTS
(Allen and Roberts, 1978)

ACCEPTABLE FOR HYDROGEN SULFIDE

1. Low and medium alloy carbon steels, <1 percent nickel, not finished
2. J-55. C075, N-80, S00-90
3. 300 series stainless steel Annealed
4. Incoloy 800 (Ni-Cr-Fe)
5. Inconloy 825 (Ni, Fe, Cr, Mo)
6. Iconel 600 (Ni, Cr)
7. Inconel X-750 (Ni-Cr-Al)
8. Mibek 400 (Ni-Cu) Annealed
9. K-monel 500 (Ni-Cu-Mo)
10. Hastelloy C (Ni-Cr-Mo)
11. MP35N (Co-Ni, Cr, Mo)
12. Stellites (Co-Cr-W)
13. Colomonoys (Ni-Cr-B)
14. Cemented carbides (Tungsten Carbide)

UNACCEPTABLE FOR HYDROGEN SULFIDE

1. Low and medium alloy steels, >1 percent nickel or cold finished
2. Free machining steels, >0.08 percent sulfur
3. Stainless steel, cold finished or precipitation hardened
4. K-monel, cold finished

ACCEPTABLE FOR CARBON DIOXIDE

1. Stainless steels, except free machining.
2. Monels (Ni-Cu)
3. Nickel-iron (Ni-resist)
4. Al-bronze (Cu-Al)

ACCEPTABLE FOR OXYGEN

1. Stainless Steel
2. Monels
3. Nickel-iron
4. Al-bronze

lining and the subsurface metal. The buildup of corrosion products can eventually lead to cracking and sloughing of the lining (API, 1958).

For corrosion control in injection well operations, the only metallic coatings of importance are zinc and aluminum on steel. They may be used on buried steel components where oxygen corrosion is moderate, but their best application is for atmospheric exposure of surface equipment (Allen and Roberts, 1978).

Protection of the Packer and Other Bottom-Hole Components.

The packer and other bottom-hole components may be especially vulnerable to corrosion. Injecting of highly acidic solutions, such as pickle liquor, can cause operational and maintenance problems to the operator.

In some cases coated metallic packers and plastic liners may reduce the corrosion of these components. In other cases, operators have chosen to use "fluid seals" instead of packers to minimize maintenance costs. These fluid seals are designed to isolate the tubing-casing annulus by creating an equal-pressure boundary at or near the bottom of the tubing above the injection perforations or by continuously pumping a corrosion inhibitor through the annulus. The liquid used in the annulus is immiscible with the injection fluid in the former situation. In general, operation of these wells is complex due to the temperature and pressure deformation of the tubing that take place during operation and their impact on the annulus fluid pressure and the location of the immiscible boundary.

Another solution is the placing of oil or other non-ionic liquids in the space between the bottom of the tubing and the packer and/or in the whole upper portion of the injection cavity above the perforations. The lower specific gravities of the non-ionic liquids and the geometry of the bottom-hole components retain liquids between the injection fluid and the vulnerable components. Protective liquid losses are replaced by the injection of 20 - 100 gallons of it every two or three months. This solution has been proven very cost effective.

Preinjection Treatment.

Frequently, the removal of corrosive agents from injection fluid by preinjection treatment methods can be the best means of corrosion control. The most common preinjection treatment used involves degasification and/or neutralization.

Degasification

Degasification involves the complete removal of corrosive dissolved gases from water. The most common method of degasifying water in preinjection treatment is to selectively remove dissolved oxygen. Degasification is usually not cost effective for the prevention of corrosion due to acid gases, carbon dioxide and hydrogen sulfide (Allen and Roberts, 1978). Oxygen degasification can be accomplished by the use of chemical scavengers, vacuum deaeration, or counter-flow gas stripping.

Chemical scavengers for oxygen removal are based on a chemical reaction between oxygen and another chemical. A commonly used chemical is sodium sulfite which is particularly useful for removing small amounts of oxygen from large volumes of water.

Dissolved oxygen is removed in the oxidation of sulfite to sulfate:

$$Na_2SO_3 + \frac{1}{2}O_2 \longrightarrow Na_2SO_4 \tag{15}$$

In practice, a concentration of 10 ppm of sodium sulfite is used to remove 1 ppm of dissolved oxygen (Ostroff, 1965). Catalysts, such as cobalt chloride, are used to increase the rate of the

reaction. The presence of hydrogen sulfide in the water reduces the effectiveness of sodium sulfite to scavenge oxygen. Sulfate-reducing bacteria should also be inhibited from growing in water-handling systems in which sulfite is used to scavenge oxygen.

The sulfite ion can also be formed in water by adding sulfur dioxide gas. Sulfur dioxide can be added from bottled liquid containers or on-site gas generators. The bottled liquid is economical for treating small systems with low oxygen concentrations. The use of sulfur dioxide for oxygen removal has the potential disadvantage of producing corrosive acids in solution and also of creating barium or calcium scales that may plug the injection formation.

Dunlop and others (1969) recommend the use of ODASA, the oleyl diamine adduct of SO_2, as a 40 percent solution in methanol, as a substitute for sodium sulfite when mixing and freezing difficulties are encountered. A concentration of 25 ppm ODASA is necessary to scavenge 1 ppm of dissolved oxygen.

Oxygen can be removed from water by running it through a vacuum in a packed tower. The low pressure and the small amount of oxygen in vapor contacting the water cause the dissolved oxygen to bubble out of solution (Nielsen and Aller, 1984). The vacuum can be produced by pumps or steam injectors. Several passes through the vacuum deaeration column are necessary to reduce oxygen to less than 0.1 ppm (Nielsen and Aller, 1984). Any free carbon dioxide will also be removed, which may result in scale deposition from the accompanying pH change. If further oxygen reduction is needed, chemical scavengers can be added after vacuum deaeration. Vacuum deaeration is applicable where chemical treatment is uneconomical, or where the addition of scavengers would form barium or calcium scale.

A counter-flow gas stripping column can be used to cause dissolved oxygen to escape from water to a natural gas stream. Either a packed column or a tray-type column can be used, although the tray-type is preferred (Nielsen and Aller, 1984). Efficient removal of oxygen has been reported for a vacuum deaeration system supplemented by hydrocarbon gas stripping (Nielsen and Aller, 1984). Oxygen was reduced from 4.7 ppm to 0.05 ppm which reduced the corrosion of steel by almost 90 percent.

Injection Fluid Neutralization (after EPA, 1982)

Neutralization of an acidic or basic fluid prior to injection can be an effective way to control corrosion. Common chemicals that may be considered for neutralization are listed in Table 6.

A potential problem with adding chemicals to neutralize pH is that insoluble precipitates may form and have to be removed as these solids can cause the physical plugging of the injection zone. Recommended dosage rates for acid and alkali neutralization are shown in Table 7.

Caustic soda, although the most expensive of the alkali sources for acid neutralization, is usually preferred because it reacts instantaneously and creates less sludge. For neutralizing alkalies, sulfuric acid is most often used (Warner and Lehr, 1977.)

Chemical Inhibitors.

The addition of chemical inhibitors may be a cost effective means of preventing or reducing corrosion in wells; however, some may exhibit toxic characteristics and if allowed to escape, could contaminate underground sources of drinking waters (USDWs). For this reason, wells should be tested for chemical integrity before inhibitors are added. Film forming, water dispensable inhibitors, according to Holloway and McSpadden (1961), are generally more effective and less expensive than other types. Generally, inhibitors are used to supplement other corrosion prevention measures. Primary inhibitors are used to chemically combat corrosion, whereas secondary

TABLE 6

COMMON CHEMICALS USED FOR INJECTION FLUID NEUTRALIZATION
(Warner and Lehr, 1977)

Injection Fluid Characteristic	Neutralizing Chemical
Acid	Lime Slurries
	Limestone
	Soda Ash
	Caustic Soda
	Ammonia
	Waste Alkali
Alkaline	Sulfuric Acid
	Hydrochloric Acid
	Carbon Dioxide
	Flue Gas
	Sulfur
	Waste Acid

TABLE 7

ALKALI AND ACID REQUIREMENTS FOR pH NEUTRALIZATION
(Warner and Lehr, 1977)

Alkali	Approximate Dosage (lb/lb of H_2SO_4)
Dolomitic Limestone	0.95
High Calcium Limestone	1.06
Dolomite Lime, Unslaked	0.53
High Calcium Limestone, Unslaked	0.60
Dolomitic Lime, Hydrated	0.65
High Calcium Lime, Hydrated	0.80
Anhydrous Ammonia	0.35
Soda Ash	1.10
Caustic Soda	0.80

Acid	Approximate Dosage (lb/lb $CaCO_3$)
H_2SO_4, 66°Be **	1.0
HCl, 20°Be	2.0
Flue Gas, 15% CO_2	3.0
Sulfur *	0.3

* Would produce a reducing condition which might require additional treatment to produce an oxygen-containing effluent.

** °Be = Degrees on the Baume scale (See Lang's Handbook of Chemistry, 12th Edition).

inhibitors are chemicals that are used as bactericides to kill microorganisms which cause corrosion. A third type of inhibitor is a bactericide which also is a weak corrosion inhibitor.

Corrosion Inhibitors

The conditions of the environment and type of corrosion govern the choice of corrosion inhibitor (Ostroff, 1965). Usually, the choice of inhibitor is based on the experience of the corrosion engineer along with trial and error testing. Some typical corrosion inhibitors are given in Table 8. Generally, organic inhibitors form films on the metal surface, protecting the metal from attack. Some of the inorganic compounds, like the chromates, are anodic inhibitors (Ostroff, 1965). Many of these organic and inorganic inhibitors are considered toxic substances, and therefore, must be used with caution to prevent contamination of potential potable water sources.

The simple addition of corrosion inhibitors alone may not be sufficient to solve all corrosion problems. Corrosion caused by oxygen associated with salts cannot be effectively treated with inhibitors (API, 1958), and for these systems it may be necessary to remove the oxygen as well.

Inhibitors are added to the well tubing as well as to the casing tubing annulus. There are several methods available for adding corrosion inhibitors during well operation. One method involves filling the annulus during well completion with a solution containing either an oil or water-soluble corrosion inhibitor (Donaldson, 1972). Inhibitors can also be slug injected while operations are shut down for a short time, or placed in fluid circulated above the cement in the casing-borehole annulus.

Bactericides (Horacek, 1986)

The nature of injected wastes often precludes the need for bactericides to control bacterial populations. For example, some inorganic wastes contain chemicals such as chlorine, chromate, and compounds of mercury or silver. These have historically been used as bactericides (Ostroff, 1965). While they are no longer approved for such use in the United States, they effectively control bacterial contamination of fluids that contain them as part of the waste stream. Nonaqueous waste streams, it is felt, do not require bactericide treatment.

In some cases, the injected aqueous waste does not contain compounds that are toxic to microorganisms. In such cases, a bactericide may be added to prevent bacterial growth in the injection well. In most cases the bactericides are used against organisms that attach themselves to the well components. It must be understood that there is no correlation between planktonic (free-floating) and sessile (attached) bacterial populations (Costerton, Irvin, and Cheng, 1981). Furthermore, once bacteria attach to the wellbore equipment (i.e., become sessile), there is no method to predict whether they will become corrosive or not (Pope, Duquette, Wagner, and Johannes, 1984); nor is there any proof that the added bactericide will prevent microbic-influenced corrosion from occurring (Ruseska, Robbins, Lashen, and Costerton, 1982). Therefore, bactericides should not be used solely in hopes of preventing bio-corrosion from occurring. Cathodic protection may be the most cost-effective method of preventing microbic-influenced corrosion (Postgate, 1979). Such a system will be most effective if it is designed into the system and installed before the well is used to inject wastewater.

However, bactericides may be useful in preventing bacterial plugging of the injection formation (Updegraff, 1982). A plugged formation leads to increased injection pressure, which could fracture the formation, with possible loss of control of where the injected wastes go.

Bactericides may be added by continuous feed or slug treatments. Service companies that supply bactericides for oil field use should be consulted when selecting a methodology for microbial

TABLE 8

CORROSION INHIBITORS
(Gatos, 1956)

Inhibitor	Approximate Concentrations (percent)	Corrosive Environment	Metallic System
INORGANIC			
Calgon	Small amount	Water systems	Steel
Disodium hydrogen phosphate	Ø.5	Citric Acid	Steel
Potassium dichromate	Ø.55-Ø.2	Tap Water, 68-194°F	Iron-brass
Potassium dihydrogen phosphate & sodium nitrate	Small amount +5	Sea Water - brine	Steel
Potassium permanganate	Ø.1	Ø.3N NaOH solution	Aluminum
Sodium benzoate	Ø.5	Ø.Ø3% NaCl solution	Mild steel
Sodium carbonate	Small amount	Gas condensate wells	Iron
Sodium chromate	Ø.Ø7	$CaCl_2$ brine	Cu, brass
Sodium dichromate + sodium nitrate	Ø.1 + Ø.Ø5	Water	Heat-exchange device
Sodium metaphosphate	Small amount	Ammonia	Mild Steel condensers
Sodium nitrite	Ø.ØØ5	Water	Mild Steel
Sodium orthophosphate	1	Water, pH = 7.25	Iron
Sodium silicate	Ø.Ø1	Oil field brine	Steel pipe

TABLE 8
(continued)

Inhibitor	Approximate Concentrations (percent)	Corrosive Environment	Metallic System
ORGANIC			
Formalin	Small amount	Oil Wells	Oil well equipment
Erthritol	Small amount	K_2SO_4 solutions	Mild steel
Ethylaniline	0.5	HCl solutions	Ferrous metals
Mercaptobenzothiazole	1	HCl solutions	Iron and steel
Oleic acid	Small amount	Polyhydric alcohols	Iron
Phenyl aridine	0.5	H_2SO_4 solutions	Iron
Pyridine + phenylhydrazone	0.5 + 0.5	HCl solutions	Ferrous metals
Quinoline ethiodide	0.1	1M H_2SO_4	Steel
Rosin amine-ethylene oxide	0.2	MCl* solutions	Mild Steel
Tetramethylammonium	0.5	Aqueous solutions or organic solvents	Iron and steel
Thiourea	1	Acids	Iron and steel

* MCl stands for metallic chloride salts; the M represents a metal.

control in an injection well. Appropriate field tests should be done to show that the selected chemical bactericide is effective against the microbes present in the waste. However, once the fluid is injected, it is unwise to assume that the bactericide will continue to be effective; therefore, bacterial eradication must be done prior to injection to insure that bacterial control has been achieved.

It should be noted that most bactericides exhibit varying amounts of toxicity to humans and other animals. Injection of these chemicals should be carefully monitored to protect the integrity of all aquifers penetrated by the injection wellbore. All casing leaks must be corrected and appropriate reports made to all local, State, and Federal agencies involved in groundwater protection.

Cathodic Protection.

Cathodic protection consists of applying an electric current to the surface of the protected metal to overpower the voltage of the corrosion cell and to prevent the resulting discharge of electrical currents from the metal into the ground (Figure 8). The result is that all areas of the metal become cathodic and corrosion stops. All previous anodic areas are suppressed as long as adequate current is applied. In injection well operations, cathodic protection is used primarily for the external protection of well casings. It is typically applied to supplement other corrosion prevention techniques, such as cementing casing through potentially corrosive saltwater zones. Generally, the inside of the casing is protected by corrosion resistant coatings, sprayed onto the surface to be protected (Chemical Week, 1967).

Cathodic protection requires a direct current which may be generated by using an external source of alternating current and a rectifier for converting to direct current. Thermoelectric generators may also be used to produce direct current. Current is discharged into the soil from a group of anodes called a ground bed. Required current for a cathodic protection will vary from 0.5 to 1 amperes for 1,500 feet (457 m) of 6-inch (15.2 cm) casing to as much as 20 amperes for multicased, deep wells. The voltage can usually be adjusted as required from 6 to about 24 volts, depending on the needed current and the resistance of the ground bed (EPA, 1982).

A ground bed can be installed so that electrical resistance between the anode and the surrounding soil are at a minimum (API, 1958). To optimize current distribution on the casing, the ground bed can be placed about 100 feet (30.5 m) from the wellhead and moved as far as possible from other pipe lines. Where possible, placement of the ground bed in areas of low soil resistance is desirable; a low-resistance material is usually packed around the anodes to serve as backfill.

Figure 8 depicts a typical cathodic protection installation for a well casing. A horizontal ground bed is shown. Vertically oriented ground beds, called anode wells, are also used to protect injection wells. These anode wells, which are drilled to about 300 feet (91.4 m), provide better vertical distribution of current, and operate with less power than horizontal ground beds (Allen and Roberts, 1978).

Much of the previous discussions have been taken from the following EPA reports:

U.S. Environmental Protection Agency, 1982:
Injection Well Construction Practices and Technology
(Contract # 68-01-5971)
Prepared by Geraghty and Miller, Inc., and Booz, Allen, and Hamilton, Inc.

Warner, D.L. and Lehr, J.H., 1977:
An Introduction to the Technology of Subsurface Wastewater Injection
EPA-600/2-77-240 Grant Number R-803889.

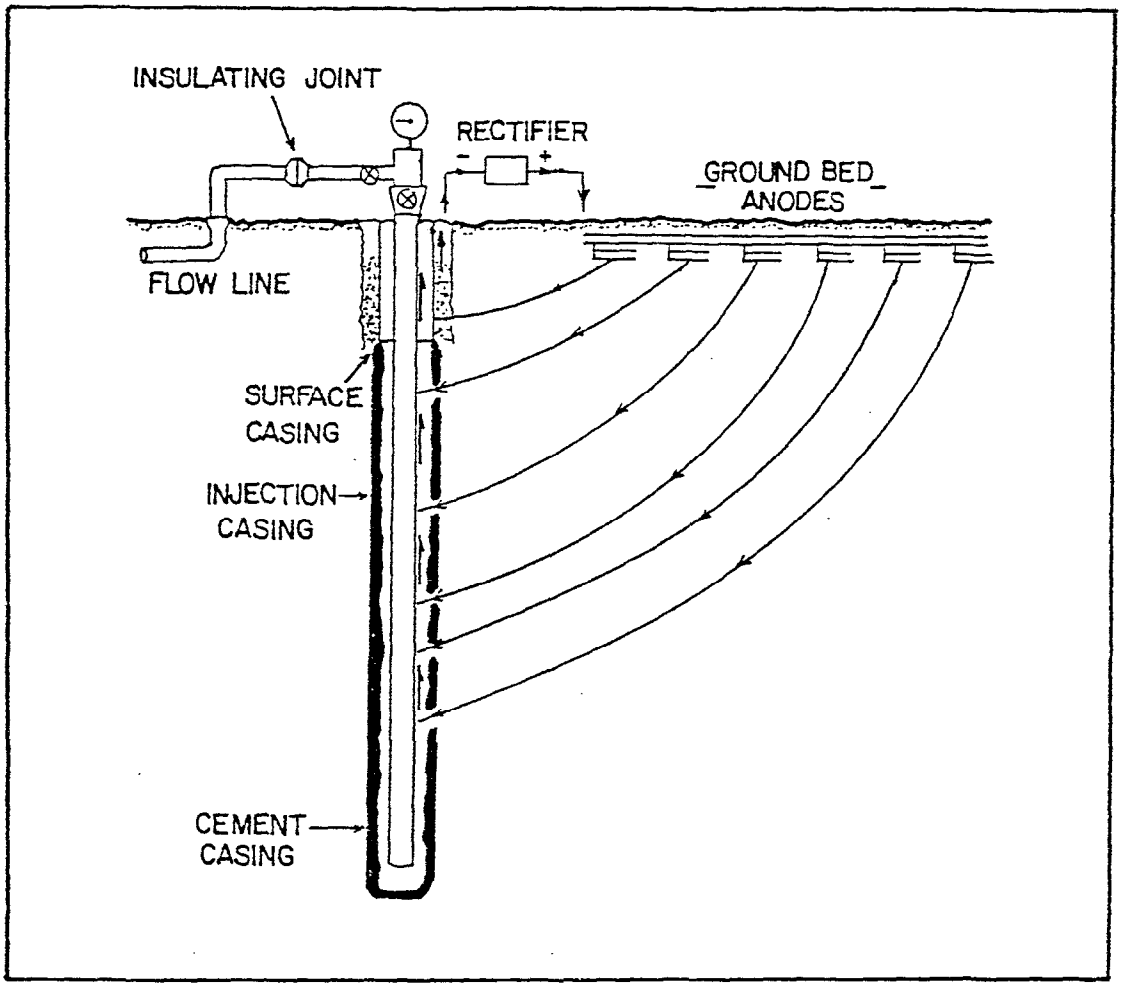


Figure 8. Example of Cathodic Protection Scheme for Well Casing (EPA, 1982)

Corrosion and Hazardous Injection Fluids.

EPA has recently conducted an inventory of Class I hazardous waste wells in the United States (Environmental Protection Agency, 1985). Class I wells are those wells that inject hazardous, industrial and municipal wastes that can affect underground sources of drinking water. The data and/or inventory have provided a data base for determining the composition of the most generally injected waste fluids. Table 9 gives a list of the most commonly injected fluids as well as a description of the type of corrosion that can be caused by those fluids. For most Class I injection wells, pH neutralizers, cathodic, and protective coatings are probably the most effective methods for preventing corrosion.

TABLE 9

CLASS I INJECTION CHEMICALS
(Most commonly injected chemical given first)

INJECTED CHEMICAL	EFFECT ON CORROSION
ACIDS	
Pickle Liquor (HCl, H_2SO_4, $FeCl_3$, $Fe_2(SO_4)_3$)	
$FeCl_3$ (Ferric Chloride)	
HCl (Hydrochloric Acid)	Strong oxidizers and they enhance electro-chemical corrosion.
H_2SO_4 (Sulfuric Acid)	
HF (Hydrofluoric Acid)	
Nonspecified Acids	
BASES AND CAUSTICS	
NH_3 (Ammonia)	Mostly enhance chemical and electro-chemical corrosion.
Nonspecified Alkalines	
Nonspecified Caustics	
$NaOH$ (Sodium Hydroxide)	
DISSOLVED SPECIES	
$NaCl$	Electrolyte - enhances electrochemical corrosion
Sulfates	Can react to form minor amounts of acid - nutrient for bacterial growth
Nitrates	Can react to form minor amounts of acid - nutrient for bacterial growth
Carbonates	Can raise TDS increasing electrolyte content of solution - enhancing electrochemical corrosion
Sulfides	Nutrient for bacterial growth and can react to form acid
Nonspecified Salts	Can raise TDS increasing electrolyte content of solution - enhancing electrochemical corrosion

TABLE 9
(continued)

CHEMICAL	EFFECT ON CORROSION
SPECIES (continued)	
s	Can react to form minor amounts of acid - nutrient for bacterial growth Can raise TDS, increasing electrolyte content of solution - enhancing electrochemical corrosion
)MPOUNDS	
Alcohol	May cause decay of plastic well casing and rubber tubing
;rachloride	
'anides	
ed Herbicides	
ed Pesticides	
ed Organic Wastes	May cause lack of oxygen allowing for growth of anaerobes

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APPENDIX B. Glossary of Corrosion Related Terms

Aerobic: presence of unreacted or free oxygen (O_2).

Anaerobic: an absence of unreacted or free oxygen [oxygen as H_2O or Na_2SO_4 (reacted) is not "free"].

Caliper Survey: the process, by which a tool that is composed of mechanical "feelers", measures the inside diameter of a well casing when it is lowered into a well. The caliper tool is sensitive enough to detect some well diameter changes due to corrosion.

Casing Thickness Log or Pipe Analysis Survey (PAS): uses an electromagnetic field to measure the thickness of metal at any point in the casing. This tool can detect metal loss on the inside or outside of the casing.

Cathodic Protection: reduction or elimination of corrosion by making the metal a cathode by means of an impressed d.c. current or attachment to a sacrificial anode (usually Mg, Al or Zn).

Chemical Stability: the ability of a compound to remain in solution.

Corrosion: the destruction of a substance, usually a metal, or its properties because of a reaction with its (environment) surroundings.

Coupon: a thin metal foil which is used to test the corrosiveness of an injection fluid. The corrosion rate is ascertained by measuring the amount of weight loss by corrosion over a prescribed period of time.

Differential Aeration Cells: differences in oxygen concentration between two points of a system. This results in corrosion due to differences in the solution potential of the same metal at the two points of the aeration cell.

Electrical Resistance Probes: used to measure the changes in resistance of a material as it corrodes. A Wheatstone Bridge circuit is generally employed to measure electrical resistance.

Electrochemical Corrosion: degradation of materials caused by an exchange of electrons in an electrolyte solution.

Galvanic Corrosion: Corrosion that is increased because of the current caused by a galvanic cell (sometimes called "couple action").

APPENDIX B. Glossary
(continued)

Inorganic Incrustation: decrease in injection well performance caused by precipitation of inorganic substances.

Nonmetallic Corrosion: degradation of nonmetallic well components due to chemical action by formation or injection fluids.

Packed Tower: an air-stripper used to remove oxygen from solution.

Planktonic: free swimming or free floating microorganisms.

Sessile: Microorganisms that physically attach to a surface, and they form a continuous film.

Symbiosis: the living together of two dissimilar organisms; the relationship may be mutualistic (co-dependent), commensal (benefits only one), amensal (one suppresses the other), or parasitic (one lives at the expense of the other).

Synergistic: the magnified effect of the combination of two or more phenomena, which is more than the addition of its components.

Thermomechanical history: the mechanical working and heat treatment operations used to make a specific metal product form, such as tubing.

USDWs: Underground Source of Drinking Water: an aquifer or its portion: (1.) (i) which supplies or may supply water for human consumption; or (ii) in which the ground-water contains fewer than 10,000 mg/l "total dissolved solids;" and (2.) which is not an exempted aquifer in accordance with the Federal regulations.

Wheatstone Bridge Circuit: used to measure the resistance of a system.

APPENDIX C. Corrosion Inspection Check List

Name of Inspector:_____Date:_____

Facility:_____Well #:_____

__/__/___ Date of Inspection

__/__/___ Date of Last Inspection

Prepared by:_____

DESCRIPTION OF CORROSION PREVENTION/MONITORING SYSTEM:

[ ] Corrosion Loop

[ ] Weight Loss Coupons

[ ] Electrical Resistance Probes

[ ] Polarization Resistance Probes

[ ] Logs-Type _____

[ ] Cathodic Protection

[ ] Soil Potential Survey

[ ] Well Design (What components aid in the control of corrosion)

_____

[ ] Other (Please describe)

_____

_____

DATE OF LAST CORROSION EVALUATION BY OPERATOR:_____

TYPE

[ ] Visual

[ ] Other (Describe briefly)_____

_____

APPENDIX C. Corrosion Inspection Check List
(continued)

RESULTS OF EVALUATION

[ ] No Significant Corrosion Detected

[ ] Corrosion Taking Place in the:

[ ] Casing; depth _____

[ ] Tubing; depth _____

[ ] Packer

[ ] Other (Indicate component)_____

_____

Injection Fluid Released? YES [ ] NO [ ]

Potential Contamination of USDWs? YES [ ] NO [ ]

CASING MATERIAL

[ ] Steel

[ ] Stainless Steel

[ ] Monel

[ ] Titanium

[ ] Other; Specify _____

TUBING MATERIAL

[ ] Steel

[ ] Stainless Steel

[ ] Fibercast

[ ] Fiberglass

[ ] Other; Specify _____

PACKER TYPE AND MATERIAL

[ ] Tension

[ ] Compression

[ ] Material: Steel [ ] ; Other [ ] , Specify _____

[ ] Special Protection (Please indicate. Note some packers, especially tension packers, have rubber pads or special coatings to prevent contact with injection fluids).

APPENDIX C. Corrosion Inspection Check List
(continued)

INJECTION FLUID CHARACTERISTICS

[ ] Unknown

[ ] pH = ___

[ ] Dissolved Oxygen (concentration) ___ mg/l

[ ] Hydrogen Sulfide, H_2S (concentration) ___ mg/l

[ ] Carbon Dioxide, CO_2 (concentration) ___ mg/l

[ ] Amenable to Biological Degration

[ ] Other Corrosive Characteristics. Describe: _____

_____

[ ] Most Recent Sample Analysis (attached) Indicates No Significant Changes

Were All the Chemical Test Done in Accordance With the Quality Assurance Project Plan for Chemical Analysis for the State?

YES [ ] NO [ ] Unknown [ ]

Date(s):_____

Lab(s):_____

EVALUATION OF THE CASING/TUBING/PACKER MATERIALS TO RESIST CORROSION

(By consulting the tables on page ____of the manual a preliminary evaluation can be made. The inspector may use also different criteria for evaluation; however he/she should indicate the reason for the decision.)

[ ] Adequate

[ ] Inadequate

Criteria Used: _____

_____

_____

_____

APPENDIX C. Corrosion Operator's Check List

Prepared by:_____Date:_____

Facility:_____Well #:_____

__/__/____ Date of Corrosion Evaluation

__/__/____ Date of Last Evaluation of the Wells

I. Is (Are) the Well(s) Designed to Resist Chemical and Physical Attack by the Waste and the Environment?

YES [ ] NO [ ]

Is Waste Treated Prior to Injection: YES [ ] NO [ ]

Briefly Describe Treatment:_____

_____

_____

If You Checked "Yes" in the First Part of this Section Please Indicate Briefly Design Characteristics to Prevent Corrosion (Address: waste type, tubing, packer and casings):

_____

_____

_____

II. Type of Evaluation Done (Please check)

[ ] Corrosion Loop Inspection

[ ] Weight Loss Coupons

[ ] Electrical Resistance Probes

[ ] Polarization Resistance Probes

[ ] Well-Logging Type _____

[ ] Soil Potential Survey

[ ] Well Monitoring Only

APPENDIX C. Corrosion Operator's Check List
(continued)

[ ] Pulled Tubing (Please elaborate)

_____

_____

_____

[ ] Other _____

_____

_____

III. Corrosion Detected (Please check one):
[ ] No (If checked, do not complete the rest of the form)

[ ] Yes (If checked, corrosion taking place in the):

[ ] Tubing; depth _____

[ ] Packer

[ ] Other _____(Indicate component)

[ ] Casing: _____

IV. Action Taken:
[ ] None

[ ] Replaced Component

[ ] Changed Operations (Indicate changes)_____

_____

[ ] Provided Additional Preventive Measures (Indicate briefly)

_____

_____

[ ] In the Process of Providing Additional Preventive Measures

(Indicate briefly) _____

_____

[ ] Further Description of Problem and Action Taken in Attached Page(s).