# Corrosion and Corrosion Control of Oil and Gas Producing Equipment

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## INTRODUCTION

The useful life of oil field equipment is often measurably reduced by corrosion. There is a corresponding increase in both capital and operating costs which ultimately will shorten the economic life of the producing property.

In the last 15 to 20 years there have been continuing advances in corrosion control technology. Such advances have resulted from a better understanding of the causes and occurrences of corrosion and steady improvements in mitigation materials and techniques. Successful corrosion control must begin with defining the problem and its cause, followed by the selection of a technically sound and economic means of mitigation. The latter can reach maximum effectiveness only when it is incorporated into a program which, after initial protection is established, provides for the routine maintenance of corrosion control measures, the required supervision and technical support and periodic evaluation.

The purpose of this paper is to explore the types and causes of corrosion in oil field producing equipment, means for its control and how to obtain maximum effectiveness from corrosion control programs.

## CORROSION—CAUSES AND CONTRIBUTING FACTORS

Technically, corrosion can be simply defined as the destruction of a metal by chemical or electro-chemical reaction with its environment. The oxidation of steel to form iron oxide or rust is, of course, the most common and well known type of corrosion. Corrosion of a metal by chemical or electro-chemical reaction is often accompanied by certain mechanical forces which accelerate metal destruction.

Stress forces are frequently combined with corrosion to produce so-called "stress corrosion" failures. In certain metals and under certain conditions the above results in cracking, generally at grain boundaries in the molecular structure, and is referred to as "stress-corrosion cracking."

Corrosion reduces resistance to fatigue and, consequently, "corrosion-fatigue" failures are commonly observed.

High velocities and/or solids produce erosive effects on metals and when this occurs in a corrosive environment failure results from "corrosion-erosion."

Metal-on-metal wear in a corrosive environment results in "corrosion-wear" failures.

Hydrogen formed in a corrosion reaction can penetrate the metal and set up extremely high internal forces, resulting in failure from "corrosion and hydrogen embrittlement." As stated above, these combination failures result from actual corrosive attack, accelerated by a second environment effect.

Oxygen attack was cited above as a typical cause of corrosion. There are, of course, others.

Carbon dioxide and hydrogen sulfide are commonly found as constituents in produced gas. They are referred to as acid gases because in solution in water they form weak acids. These acids, as do other inorganic acids, react with steel to corrode it.

Liquid hydrocarbons often contain organic acids, which react with steel in a manner similar to inorganic acids. Whereas acid gases in a producing stream depend on the presence of water in the same stream to produce a corrosive acid, organic acids cause corrosion in wells producing only a trace to no amounts of water.

Galvanic or electrochemical corrosion is frequently observed in oil field producing operations. Galvanic corrosion occurs when two dissimilar metals, coupled together, are submerged in a common electrolyte, or when similar metals, coupled together, are submerged in a common, but non-uniform, electrolyte. In either of the latter two cases a difference in electrical potential will exist between the coupled metals; and, as fluids flow from points of high pressure to points of low pressure, an electrical current will flow from the metal with the higher potential to that with the lower potential through the electrolyte. The metal from which the current leaves, corrodes as the current flow is accompanied by a loss of the structural metal to form metallic ions in solution in the electrolyte. It should be noted that frequently some level of corrosion exists on each metal simply as a result of exposure to the electrolyte which is then accelerated on one of the metals by galvanic attack. The point from which the current flows and metal loss occurs, is called the anode and the point to which the current flows is called the cathode.

Even though electro-chemical corrosion is commonly associated with the galvanic action between dissimilar metals, anodes and cathodes are present in all corrosive action. This is true because so-called chemical corrosion, as almost any chemical action, is accompanied by the transfer or displacement of electrons to produce current flow and thus specific anodic and cathodic areas. In this sense, all corrosion processes can be regarded as electro-chemical.

Corrosion rates in a given system are often influenced by certain other naturally occurring conditions in conjunction with those causes specifically stated above. Often, several of these contributing factors may function in the same system and may either accelerate or decelerate corrosion rates. These factors may be divided into three groups — those associated with the metal, the surface of the metal, and the environment. The more common of these factors are cited and briefly discussed below.

The total pressure in a given system controls the partial pressures of acid gases, as it does other component gases. Pressure is thus related to the severity of corrosion; and, generally, higher pressures can be correlated with increased corrosion rates when an acid gas is present.

Temperature, as it affects solubilities and chemical reaction rates, will influence corrosion rates. An increased temperature will generally result in an increased corrosion rate.

Velocity, turbulence and solids are all factors in that they may independently or collectively erode away protective films, resulting in increased corrosion rates. Solids can furthermore precipitate on a metal surface to cause pitting-type corrosion and accelerate corrosive attack.

Bacteria do not corrode steel directly, but produce products which cause corrosion. Sulfate-reducing bacteria are found very commonly in water systems. They produce hydrogen-sulfide, the same acid gas previously discussed, to cause corrosion.

Water-oil ratios are important because corrosion rates vary with changes in water-oil ratios.

Deposits on the metal surface may definitely influence corrosion rates. Some of the more common are water scales (such as calcium carbonate), corrosion products, paraffin, mil scale and even crude oil films. In some cases, such deposits may act as a barrier between a corrosive environment and the metal surface and thus retard corrosion. In other cases corrosion progresses, and often at an accelerated rate, beneath such deposits.

The type of steel, that is, its metallurgical structure, will influence corrosion rates. As yield strengths increase, corrosion susceptibility increases. This is true with increases in yield strength in common carbon steel as well as with increases in yield strengths through the various API grades.

Deformation of metal goods as a result of poor handling as well as surface damage caused by tongs and wrenches develops areas of highly localized stress. At such points of localized stress, accelerated corrosion is likely to occur.

## CORROSION DETECTION AND MONITORING METHODS

The detection of corrosion, defining the cause and contributing factors, determining the apparent rate of attack and ascertaining the results of mitigation measures are all essential to an effective program of corrosion control. Several methods, as well as instruments and measuring devices, now available, are very useful in obtaining such needed information.

If possible, whenever a piece of equipment is out of service, it should be visually inspected as a means of detection or to ascertain the results of mitigation measures. Before protective measures are established such an inspection should reveal the cause of corrosion and possible contributing factors. When contributing factors, such as those previously discussed, are known to exist when the equipment is in service, particular attention should be given to the inspection of those surfaces or areas which might experience higher corrosion rates as a result of such "in service" conditions. Direct measurement of pit depth and general loss in wall thickness can also be accomplished during a visual inspection. Small strips of metal, cut in various shapes and sizes from different materials of specific interest, are used as test coupons to determine corrosion rates. These coupons are mounted on a rigid holder suitable for installation at some access point in the system. They are available for both down-hole and surface applications. Coupons detect corrosion only at the point of exposure and do not necessarily reflect the corrosion rate of the entire system. Furthermore, surface conditions within the system may result in a somewhat different corrosion rate than that indicated by the coupons. Coupon data should then always be carefully used, in that it reflects apparent and not necessarily actual corrosion rates. Coupons should be left in the system for a sufficient length of time to lessen the effect of usually high initial rates on the average or stabilized corrosion rate. Coupon weight loss, determined by weighing the coupon before and after exposure, is converted into mils per year of apparent metal loss in the system.

Electrical probes of various types are also used to determine mils per year of apparent weight loss in a system. These probes, with accompanying instruments, make it possible to read directly the apparent corrosion rate without removing the probe from service. The useful life of the probe, which may be as long as several years, depends on the nature and severity of the corrosion in the system. Even though probes have an obvious advantage over coupons in permitting a direct measurement of corrosion rates without regular retrieval, coupons offer the advantage of allowing visual inspection of the corroded specimen. The above discussion of limitations in the use of coupons and coupon data also applied to electrical probes.

Analyses of oil, water and gas phases in a system frequently help to determine the cause of corrosion and whether or not other contributing factors are present which may be influencing corrosion rates.

Various types of wireline calipers are available for the internal inspection of tubing strings in place. Certain of these calipers are highly selective in the inspection of the internal tubing wall and are excellent means of determining the extent of corrosion and, by successive surveys, corrosion rates. Other calipers are primarily "gauge" tools and are generally used to classify tubular goods.

When visual inspections are not convenient, the remaining wall thickness of surface vessels and lines can be determined using sonic instruments; such inspections can be made while the equipment is in service. X-rays have also been used for such in-service inspections. Successive inspections are used to determine the progress of corrosion or the rate of loss in wall thickness.

An instrument is now available for measuring the average wall thickness of well casing in place. When a loss in original wall thickness is found, an internal casing caliper, similar to the tubing caliper discussed above, must be used to determine whether the loss in wall thickness is external or internal.

Soil resistivity surveys, pipe to soil potential surveys and current flow surveys are all electrical measurements to show potential or existing attack to buried pipelines, the cause or source of such attack and to evaluate the effect of mitigation measures.

## CORROSION CONTROL METHODS

### Inhibitor Treatments

Inhibitors are chemicals that reduce the corrosion rate when added to a corroding system. They function by different principles, or by a combination of these principles. The two most common forms of corrosion inhibitors are "neutralizing" inhibitors and "film-forming" inhibitors.

Neutralizing inhibitors react chemically with the corrodent to reduce metal destruction. An example of this is the use of ammonia to inhibit corrosion in a vapor space such as the annulus of a producing well above the fluid level. Many neutralizing chemicals are inorganic in nature. Usually, specific amounts of such inhibitors are required to complete the necessary chemical reaction. Residual effects of neutralizing inhibitors are minimal.

Film-forming inhibitors are usually organic and are polar being either cationic or anionic. These materials function by their ability to attach to the metal forming a barrier between the corrodent and the metal. Film formation may result from "chemisorption" in which the inhibitor molecule is chemically bonded to the metal lattice or may be physically adsorbed to the metal. Chemisorbed films are considered to be only one molecule in thickness while physically adsorbed films may be of sufficient thickness to be visible to the naked eye.

Film-forming inhibitors are, by far, the most common type of inhibitors used in oil and gas producing operations. These inhibitors, even though all are in a common generic class, vary in physical properties and effectiveness. Solubility and dispersibility in both oil and water varies, as well as foaming, emulsifying and plugging tendencies. Selection of the wrong inhibitor for a given system may even accelerate corrosion rates or otherwise be detrimental to the producing operation. It is, therefore, not only necessary to select an inhibitor which will effectively reduce corrosion rates but one which will also be compatible with the system to be treated.

Thus, the selection of a suitable corrosion inhibitor can be a complex problem. In recent years various laboratory tests have been used to test inhibitors under simulated field conditions and to ascertain inhibitor compatibility with the environment in which they are to be used. These laboratory screening procedures make it possible to select the better materials and to eliminate the obviously poor ones and the needless and expensive field testing which might result. One such test is dynamic and is conducted at elevated temperatures in a corrosive environment composed of oil, water and an acid gas. Film persistency, or the ability of the inhibitor film to protect the metal with no excess inhibitor present in the corrosive environment, is the basis on which inhibitor performance is evaluated. Weighed metal coupons are exposed in sealed test bottles to an oil-water mixture containing a specific inhibitor concentration, for a fixed period of time. This is called the filming phase and is usually repeated at varying inhibitor concentrations from 10,000 PPM to 100,000 PPM (1 per cent to 10 per cent). The filmed coupons are rinsed and then exposed, in test bottles, to an oil, water and acid gas environment for a fixed period of time, usually 24 hours. The test may be extended by changing the exposure or corrosive fluids every 24 hrs for as long as is desired. Such extended tests are usually 72-96 hrs in length. After final exposure, test coupons are then reweighed and the weight-loss reported as per cent protection based on the blank weight loss, i.e., the weight loss of coupons exposed to the same corrosive oil-water environments but without the benefit of inhibitor protection. The weight-loss and/or per cent protection is used as a measure of film persistency and a comparative basis on which to evaluate inhibitor performance. The inhibitor or inhibitors exhibiting the highest per cent protection, or the greatest film persistency, are selected for field use. This so-called "bottle" or wheel test is widely used today in the laboratories of both producers and suppliers. Field results have correlated well with laboratory evaluations, proving the value of such screening techniques. By far, the greatest percentage of all film-forming inhibitors used in oil and gas producing operations are used to inhibit down-hole corrosion. By virtue of the method of treatment and treatment frequency, successful inhibition, in most cases, requires the use of materials with good film persistency. An understanding of how film persistency can be evaluated in the laboratory prior to the actual field use of inhibitors is, therefore, important.

There are less extensive uses of film-forming inhibitors in which chemical feed is continuous. In such cases, film formation is still essential; however, extended film life is not, since inhibitor is continuously present in the system. Such treatments are, in fact, called "continuous treatments," and are commonly used to inhibit corrosion in gas processing equipment and water handling systems. Even though procedures are not as extensive as those used in the laboratory testing of down-hole inhibitors, certain laboratory tests are conducted to test the performance of inhibitors to be used in continuous treatments and to ascertain their compatibility with the system to be treated.

A successful down-hole treating program, using a film-forming inhibitor has five basic requirements. (1) The proper inhibitor must be used. Inhibitors are often quite selective and, therefore, will give adequate protection in only certain environments and when applied in a specific manner. (2) Inhibitor application must be compatible with the producing methods in use so that any interruption of production operations will be minimized. (3) The initial treatment must consist of a sufficient inhibitor concentration in a suitable diluent to establish a uniform and highly protective film. This may be quite critical in certain cases and will require pre-mixing a known concentration of inhibitor in a specific diluent on the surface and pumping this treating mixture into the well. In other cases simply dumping concentrated inhibitor into the well, using well fluids as the diluent, is sufficient. (4) The treatment must be properly displaced and, when necessary, circulated to reach all surfaces to be treated and provide sufficient contact time for film formation. (5) Subsequently, continuous or intermittent inhibitor treatments are required to sustain the inhibitor film. Of primary importance in these subsequent treatments is the use of the proper amount of inhibitor and adequate displacement and circulation, when the latter is required.

There are several very common down-hole treating methods now in use. The type of well, method of completion, down-hole conditions, and other factors are taken into consideration when selecting a treating method.

Pumping wells have long been treated using the "batch" method. In such treatments the inhibitor, or an inhibitor-diluent mixture, is pumped into the annulus and is displaced or circulated by diverting the well stream, or a portion of it, into the casing. After treatment of the tubing and rods, the inhibitor is produced to the flowline with the well fluids. So-called "treating pots" are frequently connected to the casing outlet to facilitate inhibitor application.

In pumping wells which have high working fluid levels, "slug, circulate and park" treatments have been conveniently used. Initially a "large volume" of inhibitor is dumped into the casing to mix with annulus fluids. The full well stream is then diverted into the casing to "circulate" the annulus fluids (now containing inhibitor) through the tubing. The fluids may be circulated as often as desired. When the desired amount of circulation is completed, the well stream is returned to the flowline. Switching of the well stream is timed so that the inhibitor-laden fluids will be "parked" in the annulus when the flowline valve is opened and the casing valve closed. This then permits repeated use of annulus fluids, still containing appreciable amounts of inhibitor, by simply circulating these fluids, using the above procedures. The well may be thus treated several times before it becomes necessary to dump additional inhibitor into the annulus, deriving more efficiency from the inhibitor volume used. It should be noted that only wells which do not pump off, and preferably have substantial working fluid levels, can be treated in this manner. Furthermore, pumping volumes and circulation times must be rather precisely known and carefully controlled so that, after each treatment, the inhibitor mixture will again be located in the casing and not pumped down the flowline.

Pumping wells with high working fluid levels have also been treated using the Extended Period Batch Treatment. A large volume of inhibitor is dumped into the casing and allowed to mix with the annulus fluids. If no inhibitor film exists on the rods and tubing the annulus fluids, now containing inhibitor, are circulated to obtain film formation and then are returned to the annulus. No periodic circulation of chemical is required, as the tubing movement during the pumping cycle permits some entry of annulus fluids above the pump to enter the tubing, carrying small amounts of inhibitor, which tend to sustain the inhibitor film on the rods and tubing. The inhibitor supply in the annulus is periodically replenished, usually once per month. This treatment has not been extensively used; however, where tubing movement and other bottom-hole conditions permit annulus fluids above the pump to enter the tubing, the treatment has been successful. It should be recognized that when the "extended period batch treatment" does not effectively control corrosion and the cause is believed to be lack of inhibitor displacement, treatment can be readily converted to the "circulate and park" type described above, to physically effect periodic inhibitor displacement.

The tubing in flowing oil and gas wells is inhibited by periodically pumping an inhibitor diluent mixture down the tubing and then squeezing the mixture into the formation. In some cases simple tubing displacement is preferred over squeezing. In either case, film formation is accomplished as the mixture is pumped down the tubing and as a large percentage of it immediately returns up the tubing when the well is put back into production. When a well is squeezed with inhibitor a large portion of the inhibitor is almost immediately produced back with the well fluids, leaving a certain residue of inhibitor in the formation. This is usually produced back slowly and proves, until it is expended, some continuous, but small, concentration of inhibitor in the produced fluids, to sustain the film on the tubing. Tubing displacements are favored when squeezing inhibitor mixtures may result in formation damage. Squeeze and tubing displacement treatments frequently give protection for six months to one year.

Squeeze and tubing displacement treatments have also been successfully used to treat pumping wells. Such treating is usually done during a pulling job, just after the rods are run and before the pump is seated.

In addition to selecting the most suitable method of inhibitor application, inhibitor valumes and concentrations and frequentcy of treatment also must be chosen. Certain basic rules are generally followed to select values for these variables or some prior experience used. Even though this is sufficient to initiate treatments, optimum values are best determined by monitoring treatment results and, when necessary, making the indicated changes in inhibitor volumes and treatment frequency.

Annular space corrosion in pumping wells is usually controlled by those treatments already discussed. When the annular space is packed off, inhibitor packer fluids are used to control corrosion. The annular space should be completely filled and maintained oxygen free. Multiple completions should have the short string(s) bottomed close to packers to eliminate dead areas which may become corrosive environments.

As previously mentioned, film-forming inhibitors may be fed continuously. Continuous treatments generally employ lower inhibitor concentrations and are fed by chemical injection pumps. Corrosion in water systems and gas processing equipment is commonly inhibited using continuous treatments.

Coupons and the analysis of water for iron content are regularly used to monitor corrosion rates before and after inhibitor treatment to evaluate the success of such treatments, and any interim changes made in treating technique. Coupons are also used to study the film-forming properties of inhibitors under the actual conditions of field application.

## Protective Coatings

Coatings for both internal and external protection of producing equipment are widely used. There is a wide range of products or base materials available to provide a number of different coatings, each of which offers resistance to a specific corrosive environment(s). Successful corrosion protection from coatings depends on (1) selection of the proper coating material, (2) proper preparation of the metal surface to which the coating is to be applied, (3) proper application of the coating to assure a good bond to the steel and complete coverage of the metal to the specified thickness, and (4) proper handling of all coated equipment during transportation and installation to minimize coating damage.

Internal coatings used in down-hole tubing, in flowlines, in water handling equipment and in the water sections of receivers, settling tanks and storage tanks. Phenolics, epoxies, and various modifications of these two plastic resins are being used for thin film (5-7 mils) internal coatings. A plastic resin which is basically a vinyl is now being applied as an internal coating to a thickness of 18-20 mils. The additional coating thickness is, of course, an advantage; however, this vinyl coating has virtually no hydrocarbon resistance and can be used only in all water systems. The above plastic coatings are sprayed on and most are oven cured at a temperature of several hundred degrees. Certain self curing epoxies and coal tar epoxy resins have been successfully used in water handling vessels, receivers, etc. Self curing epoxies are applied to a thickness of 8 mils and coal tar epoxies are applied to a thickness of 16-20 mils. Glass-fiber is often used in the coal tar epoxies to used equipment. The combination of glass fiber and coal tar epoxy, is used to repair damage to internal walls prior to applying a finish coat of coal tar epoxy. Glass fiber and self curing epoxies also are used together in the same manner.

Another internal coating widely used in tubular goods is cement. Cement linings are applied to thickness ranging from approximately 100 mils to several hundred mils, depending on the pipe diameter. Pozzalan cement with various additives is generally used. Bulk cement is put into each joint and cast into place centrifugally by spinning the pipe. Excess cement is removed as the internal lining wall is finished out. End areas are finished out by hand. Cement linings are now primarily used in all water systems, although some are being used in production tubing strings.

External coatings are frequently used on buried pipe lines. Hot applied asphalts and coal tar enamels have been used for many years. Intermediate layers of glass wrap and a final layer of felt are used in conjunction with coal tar to strengthen the coating and increase its resistance to mechanical damage. After surface preparation and priming, the coating is applied to the pipe as it rotates. Glass and felt are wound on the pipe in spiral wraps and imbedded in the coating. In recent years a variety of tapes have become available for external pipe protection. These tapes are made from different corrosion resistant materials. All are spirally wrapped on the pipe, some of which are applied directly on the pipe while others require the use of a primer or mastic. Tapes are generally applied in the field, either by hand or by using wrapping machines; however, some mill or plant applications are made. Even though some tapes have given excellent protection, very few, if any, give the long term protection afforded by hot applied coatings. There are also a number of cold applied external coatings for field application which have been used with varying degrees of success. Obtaining a good bond between steel and cold applied coatings is very difficult and is the biggest disadvantage to these materials. Polyethylene coatings can now be applied to pipe externally. The polyethylene, in sheath form is extruded on the pipe over a mastic. Heat is used to contract the polyethylene sheath and set it on the pipe. Experience todate indicates this means of external protection is comparable to the hot applied coatings.

All coatings, both internal and external, should be applied in accordance with certain specifications and the finished job inspected. All coated equipment should be handled so that damage to the coating will be minimized, preferably eliminated, prior to and during installation. When possible, coatings are often inspected after a certain term of service to evaluate performance.

The internal and external coatings discussed above are the ones more commonly used. There are, of course, others; however, most of these are used very selectively and therefore have only limited application.

## Cathodic Protection

Cathodic protection can be described as the continuous application of direct current, usually at low voltage, to metallic surfaces to displace or neutralize the corrosion process. The entire metal surface thus becomes cathodic, rather than having both anodic and cathodic areas, as are present in the corrosion process. Both impressed and galvanic currents are used in cathodic protection. Impressed currents are obtained from external power sources and may be furnished by a generator battery or rectifier. Galvanic current is obtained from sacrificial anodes when these anodes are directly coupled to the metal surface to be protected. Suitable sacrificial anode materials are magnesium, zinc and aluminum.

Cathodic protection is used to mitigate external corrosion on buried lines and well casings and internal corrosion in water handling equipment. Cathodic protection and coatings compliment one another and are often used together to protect the same surface. The amount of current required for cathodic protection may be reduced by as much as 90 per cent when coatings are used. The actual current requirements result from pin holes in the coating or unrepaired coating damage which occurred in the handling or installation of the equipment. Therefore, there is usually only a very small per cent of a coated metal surface which will require cathodic currents for protection. Any protection lost through deterioration of coatings can be offset by simply increasing cathodic protection currents. All coatings have a certain dielectric strength. For this reason, excessive cathodic protection currents will ultimately burn through a coating and disbond it. This, of course, destroys the coating.

Rectifiers are the most widely used source of impressed currents. Batteries and generators are frequently used in temporary or test installations to determine the amount of current required for cathodic protection. Generators are sometimes used when an external power source is not available. A rectifier receives input AC power, reduces the voltage through a transformer, converts this reduced voltage AC current to DC current for rectifier output. The transformer is constructed with a series of taps to the winding so that various reduced voltages in the desired range are available. Rectifier output is thus controlled by selection of the proper transformer output tap. Conversion of the reduced voltage AC current to DC current is called rectification, hence, the name rectifier. Selenium stacks or silicon diodes are commonly used for current rectification. In simple terms these are electrical check valves which allow current flow in only one direction, to furnish output DC current. Major component parts. fuses, and panel mounted meters and switches are housed in a vented, weatherproof enclosure ready for field installation. The positive output terminal is connected to a series of graphite anodes which are located in the same electrolyte to which the corroding metal is exposed. In the case of buried lines or well casings the anodes are buried in the soil which is the electrolyte supporting the corrosion process. In the case of water-handling vessels the anodes are submerged, by various means, in the water in the vessel. Current thus flows from the anodes through the electrolyte to the exposed metal, to make the latter wholly cathodic. The negative output terminal of the rectifier is connected directly to the metal structure to complete the electrical circuit.

Galvanic current is supplied by sacrificial magnesium, zinc or aluminum anodes when they are directly coupled to steel and share a common electrolyte with the steel. The electrochemical process involved here is one of dissimilar metals in a common electrolyte, previously discussed. However, now instead of having two dissimilar structural metals, damage to either of which will result in equipment failure, one metal is structural and to be protected by a dissimilar and sacrificial metal as current flows from the sacrificial metal to the steel, or structural metal, to make the latter wholly cathodic. The sacrificial metal, or anode, is connected to the steel to complete the electrical circuit. Total current flow is determined by the type size and number of anodes used. Current flow from individual anodes further depend on the nature of the electrolyte, the metal to be protected, its surface conditions and other environmental factors. In some cases, sacrificial anodes are installed which are sized and located to protect the buried structure throughout its remaining years of life without replacement of the anodes. In other cases design and location of anodes require periodic replacement as the anodes are used up or expended.

The design of a cathodic protection system usually requires a preliminary survey to define the problem, locate any areas of highly intensified corrosive attack, the area of steel to be protected, characteristics of the electrolyte (soil or water) such as resistance, and other pertinent environmental conditions. From this information and possibly some actual field tests, the current required to cathodically protect the structure is determined and whether impressed or galvanic current is to be used. If current requirements and other conditions indicate that either impressed or galvanic current can be used, the decision becomes one of economics, in which both initial installation costs and ultimate maintenance and operating costs must be considered.

The current required for cathodic protection is, by the rule-of-thumb method the current required to raise the steel to electrolyte potential to —0.85 volts or to raise the natural steel to electrolyte potential by 0.30 of a volt. To measure this potential a copper-copper sulphate reference electrode is placed in the electrolyte and connected to the positive pole of a potentiometer. The negative pole of the potentiometer is connected to the steel and the reading made. This type of survey is also made at periodic intervals after the installation of cathodic protection systems to determine that protection is being maintained.

Insulated fittings are commonly used to control or contain current flow. These can be either unions or flanges and are of standard construction, except that non-conductive rings or gaskets are used to insulate one-half of the fitting from the other. These fittings are frequently used in conjunction with cathodic protection but are also used simply to control or eliminate the flow of stray currents on buried structures. These currents are from various foreign sources and are often found in the earth. They will enter a structure such as pipeline, travel along it, sometimes for great distances, and then, at some point where the soil resistance is very low, discharge back to the earth. As stated before, when current is discharged from metal, metal loss occurs. Frequently, flowlines will pick up stray currents which will enter the wellhead, travel down the casing and discharge into some low resistance stratum causing external casing damage. For this reason, insulated fittings are often used to insulate the flowline from the wellhead. In addition to blocking current flow at this point, the electrical resistance of the system may be so increased that stray current will not longer enter the flowline at all. If some reduced amount of stray current continues to flow to the line, it will be discharged at another point on the line. This damage is, of course, preferrable to casing damage.

## Corrosion Resistant Materials of Construction

The design engineer and all others concerned with the selection of materials should familiarize themselves with those materials which offer greater corrosion resistance than steel. These materials, in their finished form, may have only limited application due to mechanical strengths, limits of corrosion resistance, excessive cost, or other reasons; however, where applicable, these materials should be used as a means of corrosion control. The corrosive environment can itself seldom be controlled or changed but the materials of construction which go into these environments certainly can.

Certain steel alloys, with improved corrosion resistance, are available in tubular goods, fittings, valve trim, pump parts, etc. It should be remembered in using steel alloys that these materials offer only additional corrosion resistance and are not "corrosion proof." This means that they also, in highly corrosive conditions, may require chemical treatment, coating or some other form of corrosion protection. Unless the strength or some other mechanical property of an alloy steel is needed in such cases, carbon steel, at a lower initial cost may, with the same external corrosion protection, give comparable service.

Plastic tubular goods are widely used in place of steel where their mechanical properties permit. There are a number of different basic resins from which plastic tubular goods are extruded. Plastic resins in common use in oilfield tubular goods today are poly-vinyl chloride, polyethylene, acetates, polypropylene and glass-reinforced epoxies. The latter is now reportedly available with internal working pressures of over 1000 psi. Low pressure oil and water gathering systems and water distribution systems present a good application for most plastic tubular goods. Glass-reinforced epoxy tubular goods are being used to construct salt water legs for heater-treaters and, within certain loading limits, as tubing in water source wells where both internal and external tubing corrosion is a problem.

The use of corrosion resistant materials of construction is, and should always be used as, a primary means of corrosion control.

## CORROSION CONTROL PROGRAMS

Corrosion control programs, to be effective, have to provide: (1) the necessary routine surveillance of field operations to detect and define corrosion damage as it occurs, (2) the selection of mitigation measures which are technically and economically sound and which are compatible with operating conditions, (3) adequate instruction of field personnel in initiation and maintenance procedures, i.e., the mechanics of the program, and (4) routine supervision and technical support to insure positive maintenance and periodic evaluation of all programs.

Records permit the continuing review of equipment failures and allow trends, or potential problems, to be spotted before large expenses occur. Coupons, probes, and analyses of produced water will define corrosive environments before major damage occurs.

The program of mitigation must fit the problem and be designed for application under the existing operating conditions. The nature of corrosive attack occurring in two different systems may be identical; but methods of control will differ to comply with operating conditions.

Field personnel must receive adequate instruction in the mechanics of corrosion control programs and methods used to routinely check their effectiveness. Simply assigning corrosion control responsibility is not enough. This must, in all cases, be preceded by adequate instruction. Even though individual programs generally require instruction in specific mechanics, corrosion control short courses and company sponsored training programs provide good basic training in corrosion and corrosion control programs.

Local supervisors and technical personnel should routinely review corrosion control programs to ascertain their effectiveness. This must be supplemented by implementing those changes which will improve the effectivenes of corrosion control programs and take advantage of technological advances.

Effective corrosion control, just as any other phase of an efficient producing operation does not "just happen." The collective effort of supervisors, technical and field personnel, however, can "make it happen."

## ECONOMICS OF CORROSION CONTROL

Corrosion is "waste" as the latter is defined "to expend needlessly, carelessly, or without valuable result; "to squander" or "to be consumed without serving its purpose." Herbert Hoover said, regarding waste, "It is only through the elimination of waste and the increase in our national efficiency that we can hope to lower the cost of living, on the one hand, and raise our standards of living on the other. The elimination of waste is a total asset. It has no liabilities." Similarly, as corrosion control increases operating efficiency, it reduces operating cost while raising operating standards.

The production of oil and gas is simply a means to an end, that is to "make money." There, of course, is a continuing effort by all companies to "make more money" or to improve profits. Profit improvement can be accomplished in both, or either, of two ways: (1) increase revenue, and/or (2) decrease expenses. As far as operating personnel are concerned, some expenses are fixed but a large number are controllable. Expenses which result from corrosion are controllable. They must be recognized as such to understand corrosion control in its true economic perspective.

In determining the economic worth of a corrosion control program the net change in operating expense has to be considered, that is, uncontrolled failure expense versus reduced or controlled failure expense plus the cost of control measures. There may be a choice in the latter which will require a cost comparison between the various alternatives.

To be a contributing factor to an efficient producing operation, corrosion control must, like the overall operation, make money and be flexible enough to permit changes which will improve effectiveness and ultimate profits.

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