Corrosion Monitoring in Oil and Gas Production

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ABSTRACT

Corrosion monitoring is the foundation of a corrosion control program. The information derived is necessary to determine need, extent, and performance of corrosion control measures.

This paper discusses corrosion monitoring in oil and gas production. Basic philosophy is presented. Many different types of monitoring methods are addressed. The advantages, disadvantages, and application of each are presented. Emphasis is placed on methods addressing corrosion by produced fluids. Only common field methods are discussed. Techniques for monitoring cathodic protection systems are not covered.

INTRODUCTION

Corrosion monitoring is the most important aspect of any corrosion control program. It is, in effect, score keeping. In each operating case, we decide how to address corrosion. The action may vary from no action to an involved integrated program using several control methods. We must keep score in each instance to determine if our actions are prudent. If we do not monitor, we are effectively blind and may not make correct decisions.

Before discussing corrosion monitoring, it is important to understand some basic principles about corrosion. Corrosion is an electrochemical reaction resulting in deterioration of a component by its environment. In oilfield applications, the necessary electrolyte is water. It must be present for corrosion to occur.

The variables influencing corrosion are complex and depend on the material exposed. For this paper, we will address variables that influence weight-loss corrosion of metals, usually carbon and low alloy steel. Weight-loss corrosion, in this case, is defined as the dissolution of metal ions into the electrolyte. This results in localized pitting or general mass loss.

Assuming water is present, the reaction rate of corrosion is dependent on temperature, pressure, carbon dioxide (CO_2), hydrogen sulfide (H_2S), pH, and oxygen (O_2). Other aspects of water composition such as chlorides, bicarbonate, and bacteria are important due to their influence on pH, oxidation, or conductivity. A more complete discussion of corrosion in oilfield environments can be found in the literature.[1]

The following paper discusses the purpose and objective of corrosion monitoring. The need for production and equipment records is emphasized. Environmental and corrosion monitoring techniques are outlined as well as inspection methods. Finally, the application of monitoring is addressed for various production situations.

PURPOSE & OBJECTIVE

The purpose of corrosion monitoring is to gather information necessary to make decisions concerning corrosion control. Without monitoring, we can not attack the corrosion problem efficiently. There are four basic reasons to monitor corrosion:

1. To determine the need for corrosion control measures.
2. To evaluate the effectiveness of a corrosion control program.
3. To optimize a corrosion control program.
4. To detect changes in conditions and aid in troubleshooting problems.

The objective of corrosion monitoring is to get data that provides an adequate confidence level at the most economical cost. The scope of the monitoring program will depend heavily on the needs and economics of the system. This scope will vary not only from project to project, but change with time for a single project.

It is advantageous to use multiple monitoring methods. The benefits of getting a second opinion can not be stressed enough. Monitoring methods vary in the type of data derived, quickness of response, and cost incurred. By using a blend of multiple methods, we can design a monitoring program to provide a firm basis for making decisions while maximizing the information to dollar ratio.

One key factor to successful monitoring is proper location and orientation of the monitoring device. Since there are many environments in a system, multiple monitoring locations may be required. Many conditions can change through a system such as temperature, pressure, fluids separation, or flow rates. These changes can affect corrosion rates by altering such items as water content, velocity, CO_2 solubility, H_2S content, O_2 entry, deposit formation, and microbial activity. In every case, orient the monitoring device to expose it to the corroding medium. Examples will be discussed later.

PRODUCTION & EQUIPMENT RECORDS

Maintaining records is an important part of a corrosion monitoring program. They provide needed information on past performance and present conditions. Computer systems are invaluable in this effort.[2,3,4] Today's computer technology offers personal computers linked by networks with access to large mainframe computers. Without this help, data analysis can be laborious. Even without computers, we must keep accurate records on producing conditions, corrosion control, and equipment performance. They are a vital part of the monitoring program.

Producing Conditions

Records of producing conditions can aid in detecting changes in the system and, for example, differences between wells. Producing parameters monitored should be those with direct impact on corrosion rates. A few examples are flow rate, water cut, temperature, pressure, gas/water composition, and production method. Since water is primary to corrosion, its amount and velocity has dramatic impact on corrosion rates. Changes in these conditions often require a shift in the corrosion control program.

Periodic gas analyses are needed to determine the level of components that affect corrosion in a system such as CO_2, H_2S, and oxygen. Changes in these could indicate upset conditions in a plant, or intrusion of a foreign production zone. Early detection of these problems is necessary to reduce costly damage from corrosion.

Similarly, differences in water analysis can provide key information in anticipating, or showing cause for, a change in corrosion rates. Variations in ion concentration (Cl^-, HCO_3^-, SO_4^{2-}, etc.) can indicate intrusion of foreign water, changes in the source, or changes in the formation/condensed water ratio. A periodic check of ion concentrations can not only indicate a change in corrosion rates, but may pinpoint the cause.

Other helpful water characteristics include pH, oxygen content, and bacteria presence. Maintaining records of these parameters is important because often it is not the value, but the change in value that is critical. The presence of bacteria, for example, does not show their activity. However, an increase in population count might.

The production method of a well will affect corrosion rates and monitoring choices. Conversion of a naturally flowing well to gas lift will increase the dissolved gases in the produced fluid. This can increase the corrosion rates substantially depending on the amount of CO_2, H_2S, and oxygen in the lift gas. Therefore, we must maintain records of production method and indicate when it changes.

Equipment Performance

Information on installed equipment is equally important. Whether a part provides good service or fails, we can draw the right conclusions only when material type and conditions are known. Equipment performance, or failure, records are therefore an integral part of a corrosion control program. They provide the definitive proof of program performance and apply to virtually any system. When done properly, an equipment performance record system can equate to large savings in operating costs.[2]

An equipment performance monitoring program should have the following characteristics:

1. Commitment from management and field personnel.

2. A clear, concise form for recording the following information:

    A. Specific name of system, well, etc.

    B. Service type.

    C. Location within the system.

    D. Failed component (maker, model #, etc).

    E. Cause of failure, if known.

    F. Repair method and cost.

3. A method for data assimilation and reporting.

The key to a successful equipment performance program is to provide a useful report back to those who supplied the data. If field personnel use the report, they will provide accurate, timely data for input. This combination of accuracy and usefulness will lead to continued support from field and management personnel.

One major step in achieving accurate records is proper design of the data form. The form must include all the information given above, but be short, and easy to use. The easier it is to use, the more it will get used. It should also be designed for easy transfer to a computer.

Getting the data is certainly a big part of the battle. Equally important, however, is the use of the data. Various types of reports may be generated to allow quick assimilation of trends. These may be as simple as a failure listing for a single well, or as complex as an annual company-wide statistical evaluation. This is best accomplished through a computer database system that can extract information as tables, charts, or graphs. This will allow easy assessment of the data, and in turn, help make necessary changes in the corrosion control program.

Equipment performance records provide definitive data on the effectiveness of a corrosion control program. The program is easy and inexpensive to carry out. However, the time lag can be great and waiting for failures can become very costly. For this reason, failure records are usually supplemented by other monitoring methods with quicker response. These will be discussed later.

Corrosion Control Program

We must maintain records on the events and procedures of the corrosion control program. This information is used with other monitoring data to assess program effectiveness. Without it, we cannot determine the next step towards optimization. The data should include:

1. When the program was implemented, or changed.

2. What the actual program conditions and procedures were.

3. If the program is effective.

For example, chemical treating programs may not be carried out as recommended. Maintaining proper treating frequency, or amounts, can be difficult even if the intent is genuine. However, the critical aspect is knowing the actual treating conditions. Only then can you make proper decisions based on other monitoring data.

ENVIRONMENTAL MONITORING TECHNIQUES

The following presents various methods for assessing the corrosive environment and monitoring changes.

Water Analysis

As discussed before, variations in the ion concentration of the water can indicate changes in the corrosiveness of the system. One way of tracking this is through periodic analysis of water samples. There are standardized methods which compare ion concentration graphically in a pattern, making trends more noticeable.[5] These standard analytical services are available at laboratories all over the world.

Sampling techniques are critical in getting representative water samples. For example, sampling ports should be flushed out to get a representative sample of a flowing stream. However, if you are concerned about corrosion in dead areas, the stagnant water in the sampling port is precisely what you need. Be sure the sample is representative and not contaminated by other factors.

In some cases, on-site analysis of certain ions is desirable. Unless kept anaerobically under pressure, reactions can occur in samples to change the equilibrium of some ions. Bicarbonate (HCO_3^-),for instance, converts to carbonate (CO_3^{2-}) when dissolved CO_2 leaves the solution. Iron can oxidize to Fe_2O_3 unless the sample is preserved with acid. These changes can be critical. On-site analysis is sometimes needed to avoid misleading results.

On-site analysis of various ions in water can be accomplished by using colorimetric kits, or digital titration. The colorimetric kits produce a color showing presence and concentration. The results can be measured by using visual standards, or a calibrated spectrophotometer. Digital titrators are small, hand held reagent dispensers. Various reagent cartridges are available depending on the ion in question. The digital titrator measures the amount of reagent needed to reach a visual end point.

The colorimetric tests can be performed on-site, quickly, and inexpensively. In most cases the spectrophotometer will provide more consistent results over visual comparison. Digital titration is convenient and more reproducible. In some cases, these field methods may not be sufficiently accurate. Laboratory methods may be needed. However, you may need to preserve the field sample to get meaningful results.[5]

Measurement of pH

Laboratory pH values for field water samples are not equal to the pH in the system. Since pH is a function of ions and dissolved gases, it can change drastically with time.[6] Oxidation of iron followed by precipitation of ferric hydroxide can act to raise the pH. Loss of dissolved CO_2 will also increase the pH. Therefore, pH must be measured on-site to be meaningful.

Field measurement of pH can be performed by indicating pH papers, or a pH electrode with meter. The papers are inexpensive and easy to use. They are available in various ranges. The pH meters are more accurate, but can be subject to fouling. The pH meters can be costly, however many new models suitable for field use are available at a reasonable cost. The accuracy needed depends on the system and its problems. In the oilfield, an accuracy of 0.5 pH units is usually adequate.

Acid Gas Analysis

Produced gas analyses are routinely performed in the laboratory by chromatography. A periodic analysis can indicate system changes that affect corrosion, such as CO_2 content. Analysis for H_2S, however, must be conducted on-site. Metal sample containers will absorb H_2S to varying degrees, resulting in lower values than actually in the field. Thus, a report of zero H_2S in a lab sample has no significance.

Techniques for measuring H_2S in the field include "length-of-stain" detector tubes[7,8,9], cadmium sulfate method[10,11], and the Tutwiler method.[12] The "length-of-stain" tubes are inexpensive and easy to use. However, the accuracy is operator dependent. The cadmium sulfate method is recommended for H_2S concentrations less than 5 grains/100 scf (approx. 80 ppm). For greater concentrations, the Tutwiler method is preferred.

Often, the exact value of H_2S is not as important as knowing if it is present. However, a precise value is required when determining the need for sulfide stress cracking (SSC) resistant materials. Based on accepted criteria, a system with an H_2S partial pressure of 0.05 psi or greater requires SSC resistant materials.[13]

Measurement of dissolved H_2S in the produced water is also of importance. Detecting changes can pinpoint location of sulfate reducing bacteria activity. It is helpful to be aware of dissolved H_2S because it can interfere when conducting other analyses. Field test kits are commercially available that are easy to use and produce semi-quantitative results.

Oxygen Detection & Measurement

Oxygen presence is of significant importance in any system.[14] It can enter through loose packing, ineffective seals, or open tanks. Dissolved oxygen in the water at levels greater than 0.025 ppm (25 ppb), can increase corrosion rates dramatically. Trace amount of oxygen in gas can create corrosion and safety concerns.

Dissolved oxygen content can be measured using a membrane probe oxygen meter or, more precisely, a Membrane-covered Polarographic Oxygen Detector (MPOD).[15] A membrane probe is placed in the flow stream. Oxygen transports through the membrane due to the difference in partial pressure. The meter measures the current produced by the reduction of oxygen and correlates it to concentration. There are many meters of this type on the market, some of which are capable of monitoring at levels and conditions pertinent to the oilfield. An MPOD can be used for continuous in-line monitoring in clean water systems. However, they require routine calibration and maintenance.

Colorimetric kits can also be used to measure dissolved oxygen in water. As with other colorimetric methods, results are dependent on field technique. Care should be taken to ensure no interfering ions are present. Errors in testing technique usually result in high readings. Therefore, colorimetrics is often a handy go/no-go test.

A galvanic probe is one tool for detecting oxygen presence in water. The probe consists of two isolated, dissimilar metal electrodes; usually steel and brass. A sketch is shown in Figure 1. In a water system, current will flow between the electrodes due to the potential difference between the dissimilar metals. In time the electrodes will polarize, resulting in a decreased current. However, oxygen is a strong depolarizer. Current flow will remain high if oxygen is present, or increase anytime it enters. The current output of the galvanic probe is not a quantitative measure of oxygen content. However, it is extremely useful in detecting cyclical entry of oxygen in a system.

Both the MPOD and galvanic probe are used for oxygen detection in water systems. They can work in oil/water systems as long as the sampling location avoids oil contact. Although oil can be detrimental to both methods, the MPOD is more susceptible to fouling than the galvanic probe.

Oxygen in gas lift and injection gas is also of importance to monitor. Oxygen present in these gases can accelerate corrosion in the gas system as well as the production. Oxygen in gas can be measured with a trace oxygen analyzer. Measuring trace oxygen at several locations can help pinpoint the cause of oxygen entry.

Deposits Analysis

Analysis of deposits found in a system can give needed information in addressing corrosion problems. Samples can be taken directly from piping or vessels, or from coupons exposed to the system. For example, you can catch samples of solids when running a pig through a pipeline. Knowing the compositions of these deposits can help determine the type of corrosion problem and detect changes in the system.

Sample collection and handling are important for proper interpretation of results. Select a representative sample and place it in a sealed container. The container must be labeled with the date, full details of the sample condition and its location in the system. Providing complete, accurate information is critical. Corrosion products can change after they are removed from the system. For example, when iron sulfide comes in contact with air, it oxidizes to iron oxide. A sample that was black (iron sulfide) when collected, may be brown (ferric iron oxide) by the time it reaches the laboratory. So, color of the sample when it was collected becomes important information. Sampling techniques designed to minimize oxygen contact are useful in avoiding these changes.

To determine composition, samples should always be analyzed in the laboratory. However, you can gain some immediate information with simple field tests. For example, place a small piece of the deposit in a cup and drop in a small amount of 15% hydrochloric acid (muriatic pool acid). Record observations and include in sample description. If the sample reacts (fizzes) and gives off H_2S (rotten egg odor), iron sulfide is present. If it reacts and no H_2S is emitted, it is probably a carbonate. This information is very helpful to the laboratory in their analysis.

Microbial Activity

Bacteria can increase corrosion problems by their presence, or byproducts.[16,17] The presence of bacteria colonies covering areas of the metal surface, can accelerate corrosion by creating concentration cells. They can also create a local environment of low pH. When they are active, bacteria can change the environment and therefore influence corrosion.

The most common troublesome bacteria in oilfield environments are sulfate reducing bacteria (SRB). SRB are anaerobic, that is they grow in the absence of oxygen. They can lay dormant in aerated solutions and become active after the oxygen is gone. They can also flourish in small oxygen starved areas of an otherwise aerated system, like under deposits. SRB converts sulfates in the system to H_2S, making the environment more corrosive.

There are many test methods to determine the presence and activity of SRB.[5,18,19] The most common of these is a culturing method using API RP-38 broth medium.[20] The referenced API RP-38 describes a serial dilution method used to determine relative presence of SRB in water. The method gives a range of presence in colonies/ml, dependent on the number of broth bottles with a positive result.

Another method cultures SRB in a small amount of sand and nutrient.[21] This procedure reduces environment disturbance by using a higher sample water to media ratio. An activity index is determined by watching the growth rate over a period of days.

Culturing from water samples will show presence of bacteria in the moving flow stream, i.e. planktonic bacteria. However, it is usually the sessile bacteria, deposited on the system parts, responsible for corrosion. Coupons or probes of various designs are used to study sessile bacteria activity.[19,22,23] Their basic principle is to provide a surface where sessile bacteria can grow. For example, flush mounted coupons can assess biocide effectiveness when running a pipeline pig. An analysis of the surface can reveal information on the type and activity of SRB.

Each type of bacteria monitoring has distinct advantages and disadvantages. Culturing water samples is easy, but only captures the planktonic bacteria. In addition, false positive readings (within 2 hours) are possible in water containing dissolved H_2S. Probes can provide information on the sessile population. In either case, special strains of SRB may require a specific nutrient for detection. Above all, cleanliness is the key. Anything contacting the system must be sterile. Procedures are critical.

Presence of SRB does not constitute a problem. The important parameter is activity. Is the population growing, or is it stable? If SRB activity is found, look for a related problem. The presence of SRB is significant only if it causes a problem.

Residual Chemicals

Measurement of residual oilfield chemicals can be helpful in trouble shooting a treating program. Sulfite residuals in the water can be used to help determine treatment dosages where sulfites or sulfur dioxide is used as an oxygen scavenger. Chlorine residuals can be used to optimize chlorine treatment of fresh water for bacteria control. Field colorimetric kits are available for either of these applications. On-line monitors are also available for residual chlorine measurement.

Detection of residual amounts of corrosion inhibitor is somewhat more difficult. There are some field and laboratory procedures used. Reliability is highly dependent on inhibitor chemistry and field fluids. In many cases, laboratory techniques are the only choice. An increase in total amine can indicate an inhibitor is moving through the system. However, results are only qualitative.

A copper ion displacement test (CID) can help detect the presence of a filming inhibitor in a system.[24] Here, a coupon is dipped in, or exposed to the inhibited fluids and then immersed in a copper solution. Copper will deposit on those areas not filmed by the inhibitor. Examination can lead to an qualitative measure of inhibitor presence.

CORROSION MONITORING TECHNIQUES

Corrosion Coupons

Monitoring corrosion with coupons is the most common technique used. A corrosion coupon is a small, specially prepared piece of metal placed in a system and allowed to corrode. Coupons are carefully cleaned and weighed before and after exposure. Visual examination reveals characteristics of the corrosion attack. Pitting rates are measured and general corrosion rates calculated from weight loss data.[3]

Besides environment, there are other factors that affect coupon results. They are:

1. Coupon material.

2. Coupon preparation and cleaning procedure.

3. Coupon location and orientation.

4. Time of exposure.

The coupon material should have corroding characteristics similar to the material in the system. Surface preparation and cleaning procedures should be consistent and documented. Standard procedures are available in the literature.[3,25,26]

Short exposure times yield quick results, but can be misleading. In some cases initial rates may be high, but decrease with time. On the other hand, pitting corrosion can take time to develop. Expose coupons for at least one month, unless high uncontrolled corrosion rates are expected.

Corrosion coupons are often positioned at several locations throughout a system. As pointed out earlier, corrosion is usually not uniform across a system because of changes in temperature, pressure, flow rates, etc. Coupons are an excellent way to assess these changes. Comparing coupon data can give magnitude and location of potential problems.

The orientation of the coupon with respect to flow must also be considered. Position coupons to contact the electrolyte as uniformly as possible. In cases of stratified flow, locate the coupon on the bottom side of the pipe, or in vertical runs, to allow contact with the water phase. When using flat coupons, orient them so flow impinges on the coupon edge. This will expose the coupon surface more uniformly by minimizing shielding. Examples of coupon fittings and orientation are shown in Figure 2.

Handling of coupons during installation and retrieval will affect corrosion rates. A drop of sweat or sweaty hand prints can increase the rate of corrosion at the point of contact. A greasy thumb print can provide some protection to an area of the coupon. Disposable gloves are useful in avoiding contamination during handling. Storing coupons in inhibited envelopes will prevent corrosion before installation and after exposure. Good handling practices are critical to get consistent results.

After cleaning, coupons are weighed to determine loss due to exposure. This weight loss is used to calculate a general corrosion rate, commonly reported in mils per year (mpy). This rate assumes the corrosion occurs uniformly. To put this in perspective, coupons should be examined to characterize the corrosion attack. Standard terms can be used to describe and qualify the attack.[3] Defining the terms with photographs will give consistency. When pitting corrosion is present, measure pit depths and report a pitting rate equivalent in mpy. This rate will be higher and usually more indicative of actual corrosion rates. This is particularly true in the oilfield because pitting is the prominent attack form.

Analyzing and reporting coupon results can be greatly enhanced by establishing a computer system.[4] An example coupon report is given in Figure 3. This computer database stores all pertinent data concerning the coupon exposure. Figure 4 shows a plot of coupon data for a gas well. Here the rates show a decrease at the start of a chemical treating program.

Coupon results present a corrosion rate of the coupon itself. Whether this rate is equal to system parts, depends on conditions. In any event, coupon data will provide relative information on changes in a system with respect to time and location. The quality of this relative data is dependent on the consistency of the 4 factors listed above. To compare data from exposure to exposure, location to location, coupons must be from the same supplier. The supplier must use consistent coupon materials, preparation techniques, and cleaning procedures.

Coupons do not give immediate data. The analysis can produce a time lag. However, coupons do provide information on the type of corrosion attack. They are easy to use, inexpensive, and applicable to any system.

Iron Content

For steel materials, corrosion is simply iron dissolving into the water phase. Therefore, we can get a relative indication of corrosion activity by monitoring the iron content of the water (often referred to as iron count).

There are two critical issues in sampling water for iron counts. First, the location must represent the system. If the concern is downhole corrosion, samples must be collected as close to the wellhead as possible to reflect activity downhole. This is diagramed in Figure 5. Second, the sample must be clean. Avoid corrosion products and other solids in the sample.

An example water sampling device for a gas well is shown in Figure 6. The connection to the system is made on the bottom side of a flow stream. Water will collect and displace liquid hydrocarbons even at small water production rates. The 1" ball valve allows easy removal of the sample cylinder. A small sampling valve is positioned horizontally at the top of the cylinder to allow pressure release. Its horizonal orientation will prevent solids plugging. An additional sampling valve is located at the cylinder base. Stainless steel components are used to avoid contamination.

An iron analysis of the sample can be performed on-site using a colorimetrics test kit, as described before. The test must be performed at once because the iron will oxidize and fall out of solution in a short time. Preserving the sample with 1 ml 15% HCl per 200 ml of water, will hold the iron in solution for months. The preserved sample can be tested by colorimetrics or sent to a laboratory for analysis. For oil wells, you must measure iron in the oil also. This must be done in the laboratory.

The iron data generated must be related to fluid production to produce consistent information. A constant iron content in declining fluid production correlates to an increasing corrosion rate, not a constant one. Iron content must be converted to iron production. Figure 7 gives a nomograph for calculating iron rate in lb./day based on fluid rate (water), bbl./day, and iron content, ppm.

An example plot of iron production data is shown in Figure 8. In this case, iron production monitoring showed the benefit of one chemical treatment method over another. Iron readings moved downward and stabilized somewhat, after small volume batch inhibitor treatments began.

Iron counts are an inexpensive, easy way to monitor corrosion activity. It does not provide actual corrosion rates, but does provide relative information. There is no time lag in obtaining data; however, you must compare recorded readings to see results.

Iron counts may not yield meaningful results in sour systems. The reactivity of H_2S and iron can produce sporadic data depending on the equilibrium of iron sulfide. Naturally occurring iron in the producing formation can also affect results, depending on amount and solubility. Also, iron counts are difficult to correlate at high water rates. Large changes in the corrosion rate produce small changes in iron that make trends difficult to see.

Electrical Resistance Probes

The electrical resistance (E/R) probe is an instrumented coupon designed to measure the change in electrical resistance as it corrodes. Since resistance increases with decreasing mass, the rate of change can be correlated to a corrosion rate.[27,28,29] A diagram of an E/R probe is shown in Figure 9. An example plot of E/R probe data is given in Figure 10. Note that the slope determines the corrosion rate.

Because E/R probes are measured on-site, they can provide information faster than conventional coupons. Frequent measurements can pinpoint rapid changes. As with conventional coupons, probe handling and location are very important. E/R probes can be applied to any system and lend themselves to automated monitoring.[4,30,31] They can be installed to send data directly to a computer from a remote location. The computer can read the probes as frequently as necessary and directly calculate a corrosion rate.

Linear Polarization Probes

Linear polarization rate (LPR) techniques measure the current necessary for slight polarization of a test probe. This current is correlated to an instantaneous corrosion rate of the probe.[32,33] The probes are available in several different sizes and configurations.[27,34] Figure 11 shows a diagram of one type.

The strong advantage of the LPR probe is in providing real-time corrosion rates. It can detect changes in a system immediately. It is particularly useful in comparing corrosion inhibitor effectiveness.

Because it uses potential measurements, the LPR must be in a continuous electrolyte to work. This makes it ideal in water or high water production, but not applicable to most 3-phase systems. The probe is relatively easy to use, but data must be interpreted by experienced personnel. The probe must be installed and allowed to equilibrate before readings are meaningful. Presence of conductive scales, such as some forms of iron sulfide, can mask response of the LPR probe.

Above all, remember the corrosion rate given is that of the probe, not of the pipe wall. Use the generated data in a relative sense. Even though they are instantaneous, single readings are meaningless. Gathering data trends over time is necessary to get results.

Potentiodynamic Polarization Probes

The potentiodynamic polarization instrument is a device for varying the potential of an electrode continuously at a preset rate. A plot is made of potential versus log of the current density required. Information such as corrosion rate, pitting tendency, and passive behavior can be derived from these curves.[33,35] An example of a polarization curve is shown in Figure 12.

The use of potentiodynamic testing in the field has been limited to short term evaluations. It is not a routine monitoring method. However, it is used extensively in the laboratory to test corrosion inhibitors. It has also been used to study the passive/active behavior of high alloy materials. The main use of potentiodynamic testing in the field has been limited to inhibitor evaluations.[35,36]

Potentiodynamic polarization probes, as with the LPR, provide a real-time corrosion rate. However, in this case, the full Tafel slope is developed resulting in a more accurate rate. In addition, reverse scans can be used to predict pitting tendencies.[35] In field studies, it is not uncommon to use both methods since the electrode probe is the same.

Like the LPR, A continuous electrolyte is needed to conduct potentiodynamic scans. Readings are valid for the probe electrode, not the pipe wall. Relative data carries more importance. In addition, the procedure is more complicated than the LPR and the results require more interpretation. The operator must be experienced in these techniques to get useful data.

Hydrogen Probes

Hydrogen probes measure corrosion activity by capturing hydrogen generated from the corrosion reaction. There are two basic types of hydrogen probes used in the oilfield.[37] The pressure hydrogen probe (PHP) and the electrochemical hydrogen probe (EHP).

Nascent hydrogen (H^0) forms at the cathode sites wherever corrosion is taking place. Since it is the smallest atom, H^0 has the ability to migrate through steel.[38] The PHP provides a cavity to trap the migrating H^0. It passes through the steel and into the cavity where it combines to form hydrogen gas (H_2). Since the hydrogen gas is not mobile, the pressure of the cavity increases. Changes in the cavity pressure is correlated to corrosion activity. The size of the cavity is restricted to improve response. Figure 13 shows a diagram of a finger, or intrusive, type probe.

The EHP operates on the same principle except the cavity is filled with an electrolyte. It uses an auxiliary electrode to oxidize the migrating hydrogen atoms. The electric current required to sustain the oxidation is proportional to the hydrogen entry rate and thus, corrosion activity. The EHP is commonly a patch type probe that is strapped on the outside of the pipe to detect hydrogen permeating through.

The EHP provides a more quantitative indication of hydrogen activity than the PHP, but is somewhat more expensive. The finger type probes respond to corrosion occurring on the probe itself. The patch type responds to corrosion on the pipe wall. However, the seal to the pipe wall can be difficult to achieve and maintain.

Hydrogen probes can give quick information. Data from the PHP is not real-time, trends must be reviewed. However, the EHP can provide real-time data. In the oilfield, hydrogen probes work best in sour systems. This is because the presence of H_2S increases the amount of nascent hydrogen available by retarding the H^0 H_2 reaction.

Hydrogen probes provide relative data on corrosion activity. They do not give actual corrosion rates, but will detect a change. Figure 14 shows an example plot of data from a PHP. Note the significance lies in the incremental pressure increase, not the cumulative reading.

Hydrogen probes are a specialty techniques and not widely used in the oilfield. However, they have produced some meaningful data in published cases.[37]

INSPECTION

Since inspection is a procedure to determine the condition of equipment or piping, it is often overlooked as a corrosion monitoring technique. However, inspection methods can be used to detect corrosion damage and evaluate the need for corrosion control. Most important, they provide the necessary proof for rating the success of a corrosion control program. The following briefly discusses several inspection techniques used in field operations.

Visual

Visual examination is the most common inspection technique. It is inexpensive, simple, and often forgotten. Careful examination of vessels, piping, and equipment can give helpful information on corrosion damage, surface flaws, and contamination. It can also help assess the need for further inspection and determine the best method.

Ideally, periodic visual inspections should be scheduled. However, conduct them anytime the opportunity arises. A visual inspection is low cost and very informative whenever vessels are opened, pipe is cut, or tubing is pulled.

Make a record of the visual exam with observations and findings. Include the following:

1. Extent of metal loss.
2. Appearance of attack.
3. Location of attack.
4. Orientation of attack.
5. Are deposits present? Sample deposits.
6. Condition of coating, if present? Sample, if disbonded.
7. Is the surface oil or water wet?
8. Measure pit depths with gauge.
9. Take pictures.

Laboratory analysis of deposits will identify any corrosion products present. Knowing this will aid in troubleshooting the problem. Failed coating samples should be sent to a coatings lab for analysis. If the coating failed, we must determine why.

There are some tools you can use to enhance a visual inspection, such as optical borescopes. Borescopes can literally be an extension of your eye. Rigid borescopes are quite effective in straight tubes and looking into a hole. Although more expensive, flexible borescopes provide greater versatility in hard to reach locations.[39]

Mechanical Calipers

Mechanical calipers use spring loaded feelers to inspect the presence and depth of corrosion in pipe.[40,41] They typically consist of multiple feelers to cover an adequate sampling of the surface. Response from the feelers is sent electrically to a strip chart, or mechanically scribed on a cylinder. Calipers are most commonly used to inspect downhole tubing and casing.

The calipers with an electric response must be run on electric wireline. The mechanical scribing calipers are less expensive because they can be run on slick-line. In either version, the presence of scale can mask results. Scale and corrosion products can fill pits and hide them from the feelers. Take steps to remove the scale before inspection, or results could be optimistic.

Calipers only provide a sampling of the corrosion damage, but the data is real. The sampling is made statistically better by increasing the number of feelers. Getting data from each feeler is extremely helpful because it provides a cross sectional assessment of the pipe condition, as shown in Figure 15.

A history of caliper data will give actual penetration rates of the tubing. Keep in mind, the data is in the past tense. It does not provide the current corrosion rate, but only what has occurred in the past. The best frequency for inspections will depend on corrosion rates. In general, the caliper is a long term evaluation tool. Ideal frequencies are often 6 months to 1 year or more.

Most of the focus here is on downhole inspection. Other uses of calipers include heat exchanger tubes and horizonal pipelines.

Electromagnetic Inspection

Direct current (D.C.) electromagnetic inspection methods induce a magnetic field to detect corrosion pits. The magnetic field is monitored for disruptions, i.e. flux leakage, created by corrosion pits. The measured flux leakage is calibrated, amplified, filtered, and converted into a strip chart recording showing pitting severity. This is a common method for inspecting tubing, casing, and pipe.[42] An example of a downhole inspection tool is diagramed in Figure 16.

There are two basic configurations of D.C. electromagnetic tools. One inspects tubular goods on the surface, after they are removed from service. In this type, the inspection equipment is on the outside of the pipe. The other type inspects from the inside of piping, casing, or tubing while it is in place, i.e. in situ. In either case, D.C. electromagnetic tools often have difficulty detecting large areas of gradual wall loss in pipe. For this reason, a secondary device is often used to more accurately detect broad uniform wall loss.

An alternating current (A.C.) electromagnetic device is typically used to measure wall thickness in conjunction with the in situ D. C. inspection tools. This device passes a low frequency electromagnetic signal through a test section. A phase shift between the transmitted and received signal is measured. This phase shift is proportional to the average wall thickness between the transmitter and receiver coils. Since the measurement is an average, it can be relatively insensitive to small isolated pits. However, it will find large areas of uniform wall loss.

The surface inspection units typically use a gamma-ray radiation device for more accurate wall thickness measurement. Here, a gamma-ray radiation source is aimed at the pipe wall. A wall thickness is correlated based on either the unabsorbed or the back-scattered radiation collected. Both methods give a relatively accurate thickness measurement.

In situ electromagnetic tools provide better coverage of the pipe wall compared to mechanical calipers. Most can inspect 100% of the pipe area. The disadvantage of electromagnetic tools stems from the amplifying and filtering of the data. This massaging of the signal can affect inspection results. Some equipment may be more accurate than others in certain cases.

Surface inspection of downhole tubing can yield more accurate results than in situ tools by allowing time to verify the readings. The inspector can use other means, such as ultrasonics and visual, to evaluate indications from the electromagnetic unit. Since results are inspector dependent, a higher quality inspection can be obtained when the inspector has more time. If you plan to pull the tubing regardless, a surface inspection is the best answer. When using surface inspection units, the tubing joints should be numbered to correlate attack location within the string.

Another approach uses a surface inspection unit attached to the wellhead to inspect tubing as it is pulled through. This reportedly saves cost by reducing work-over rig time. However, the operator is forced to make quick decisions based on strip chart readings, negating the benefits of a surface inspection. Inspecting the tubing after it is laid down requires more time, but it allows the operator to investigate more thoroughly.

Horizonal pipelines are inspected in situ using an electromagnetic inspection tool, or pig.[43,44] The inspection pig is motorized or pumped through the pipeline and records data as it travels. Other equipment, such as video cameras, can be added to the tool to enhance inspection. Presence of solids could effect inspection results and pig travel. Use cleaning pigs before an inspection to remove solids.

<u>Radiographic Inspection</u>

Radiographic inspection (x-ray) is a technique using differential absorption of a radiation source to measure corrosion. A source emits radiation through a test area. Variations in thickness will cause different amounts of the radiation to be absorbed. The unabsorbed radiation is collected and correlated to a wall thickness. The two basic types of radiographic inspection are manual and real-time radiography.[39]

Manual radiography collects the unabsorbed radiation on sensitive film. In real-time radiography, the image is sent directly to a viewing screen or television monitor and can be taped for future review. Both methods can be used on virtually any accessible area of pipe. Real-time radiography allows coverage of a large area in a short time. However, the resolution can vary. Testing parameters can be optimized using manual radiography. Corrosion damage can then be more accurately measured through densitometry. The economics of choosing a method, or combination, depends largely on the amount and size of the pipe inspected.[45]

Many people are familiar with radiography for weld inspection in the oilfield. Its benefits as a corrosion detection and monitoring technique are now being more realized. Radiography allows inspection of selected key areas in a system without shut down. In a flow line, for example, selected areas might include elbows, restrictions, or other places where higher corrosion rates are expected. It is usually not economical to inspect 100% of a system with radiography. So, selection of the test site is critical. Also, it requires experienced personnel to conduct the inspection and analyze results.

Ultrasonic Inspection

Ultrasonic inspection induces high frequency sound waves in the test piece to detect position and depth of flaws. In corrosion monitoring, ultrasonics is used to assess corrosion damage by measuring wall thickness of a vessel, tubing, casing, or pipeline. The high frequency sound beam travels through the metal test piece and is reflected at the opposite side. The reflected beam is analyzed to determine the location and extent of corrosion damage.

There are various types of ultrasonic inspection equipment. The simplest form is the ultrasonic thickness (UT) meter. The UT meter merely analyzes the data from the first reflection and displays it as the thickness. The UT meter is very easy to use. However, the information can be misleading because it uses only one reflection at a time. Systems that analyze multiple reflections can provide additional data leading to more accurate results. In these systems, the inspector scans the surface of the pipe or vessel wall with the ultrasonic transducer. The reflections produced from the scan are displayed on an oscilloscope and/or logged into a computer for analysis. There are three types of scanning techniques:[39]

A-scan - A single point reading.

B-scan - A series of measurements along a line. For example, a line around a pipe circumference, or a line up the side of a vessel across the fluid level.

C-scan - Multiple readings in a close spaced grid pattern over an area of interest.

Automated crawling equipment can reduce the time consuming job of scanning. In C-scans, a computer can analyze the information and enhance it to produce a three dimensional map of the corroded surface.[46] Although this method is expensive, it can be economical for high risk situations.

Ultrasonics is a highly sensitive inspection technique that yields good accuracy. It has strong penetrating power allowing inspection of thick sections. It can inspect large piping or vessels where radiography is impractical. As with other inspection methods, ultrasonics requires no shut-in time providing the test area is accessible. Also the equipment can be quite portable if computers or automated scanning is not needed.

Ultrasonics is very good for detecting areas of gross metal loss, such as large pits and grooves. It can often miss isolated pitting. Ultrasonics testing requires an experienced technician. Although some meters are simple to use, readings can be misleading without some expertise in ultrasonics. Also, rough or irregular shapes can be difficult to inspect, and scanning large areas can be time consuming.

It is often helpful to use ultrasonics along with radiography. Radiography can be used to spot problem areas and the ultrasonics can make precise measurements of the damage. Coupling of these two methods results in a more economical inspection procedure.

APPLYING MONITORING METHODS

Always consider corrosion monitoring needs during project design. Installation of monitoring fittings, etc., is easier and less expensive during the initial stages of a project. An important consideration in planning a corrosion monitoring program is economics. You must assess the failure risk/cost and project life before designing a program.

Any comprehensive monitoring program should include:

1. Monitoring the producing conditions.

2. Monitoring the corrosion control program

3. Monitoring equipment performance.

In addition, employ economic inspection methods as practical. Perform visual inspection whenever vessels are opened or pipe is cut. Record observations and keep them on file. Schedule an inspection program for vessels and surface piping, using radiography and ultrasonics. Frequencies will vary. Government requirements are involved in many areas. Review these requirements and include them as part of the comprehensive monitoring plan.

The following provides examples of applying corrosion monitoring methods to various specific oilfield systems.

Gas Production

A gas production system typically consists of gas wells, gathering lines, and gas treating facilities. In gas systems, the most common monitoring method is coupons. Coupons provide overall corrosion and pitting rates, as well as information on the type of attack. E/R probes are used to supplement coupons where there is a need for more immediate data. Inspection methods are also used more in gas systems, due to higher operating pressures and failure risks.

Important locations to monitor a gas system include each wellhead, downstream end of the gathering lines, and between each vessel or separator. That is, monitor at each temperature level, pressure level, and wherever liquids are removed. Make provisions to be sure that the coupons, or E/R probes, contact the produced water in each case. This may mean installing them in vertical flow sections, or on the bottom side of a horizonal line.

In monitoring downhole corrosion, iron counts and mechanical calipers are used in addition to coupons. Results from wellhead coupons, or E/R probes, will give relative information, but may not equal downhole corrosion rates. Iron counts provide immediate information correlating to corrosion activity downhole. An inspection program using mechanical calipers will add definitive data on tubing condition.

Coupons can be installed and retrieved downhole in special mandrels using wireline. However, if you have to run wireline, it may be more economical to run an inspection tool instead and evaluate the tubing itself.

The extent and frequency of wellhead monitoring will depend on the failure risk and the data needed. Typically, coupons are applied widely throughout a field. Exposure times may range from 1-3 months. Iron counts and E/R probes are sometimes used on selected wells and moved to other wells as interest changes. The frequency of these techniques is about 2-3 readings per week.

Frequency of caliper inspections is a function of corrosion rate and caliper resolution. Caliper results showing no change become uneconomical after a while and the frequency should be extended. When monitoring several wells, develop a schedule to inspect a few wells each year. For example, select a group of six wells to monitor and split these into two groups of three. Run three caliper inspections per year, but alternate between the two groups. This program gives a larger data sampling and yearly data while maintaining the cost at three calipers per year.

In gathering lines, locate coupons (or E/R probes) where you expect the highest corrosion rates. One example is a location farthest from an inhibitor injection point. Coupon fittings allowing access under pressure are helpful. An inspection program using radiography and ultrasonics should be also planned to assess actual condition. Inspection frequency will depend on operating pressure and failure cost exposure.

Coupons are also the most common corrosion monitoring method in gas treating facilities, such as glycol dehydration and amine sweetening. Common monitoring locations include rich (glycol or amine) lines, lean (glycol or amine) lines, gas inlet, and gas outlet. Here, pressure access coupon fittings are necessary to avoid system shut down. High pressure, high velocity locations are selected for periodic inspection. Again, radiographic/ultrasonic inspection frequency will depend on conditions. However, visual inspections of any location should be conducted anytime the facility is down.

Periodic laboratory analysis should be conducted on lean and rich samples of the glycol, or amine to check quality. Chemical degradation or absence of inhibitor can affect corrosion rates throughout the facility. Some on-site measurements, such as glycol pH, can be helpful when performed properly. However, there is no substitute for a routine lab check.

Water Injection Systems

Water injection systems can consist of water supply wells, supply gathering lines, handling facility, distribution (injection) lines, and injection wells. The basic corrosion monitoring philosophy for water flood injection also holds true for water disposal. However, water disposal systems are usually small. The economics points towards corrosion control methods, such as fiberglass piping, where routine monitoring is not needed.

In general, coupons are used throughout a water handling system to detect changes in operating conditions. Coupons should be changed concurrently to allow data comparison from one location to another.

In the water source system, locate coupons at each supply well and in each leg of the gathering system. This will allow early detection of a problem and locate its source. Coupons should also be installed in the water handling facility at the inlet and outlet of each tank, vessel, or pump. Results may help pinpoint oxygen entry through a pump suction leak, failure of a gas blanket system, or bacteria contamination of a tank. Finding the location of a problem is more than half the battle of solving it.

Coupons in the injection system should be strategically located based on the system layout. Include all remote and high risk wells. Also, include at least one well close to the handling facility and one far away. Try to cover each water leg, including the main trunk line. In any event, always locate a coupon at the farthest point downstream in the system.

Suspended solids analysis from injectivity tests can detect a problem by showing presence of oxides or sulfides, for example. Moving farther upstream can pinpoint origin of the problem. Keep records of these analyses.

Corrosion problems in water injection systems are commonly caused by oxygen entry or bacteria activity. Once a problem is detected, determine the cause and source by using a specific monitoring technique. For example, use an O_2 meter (or test kit) to measure dissolved oxygen on both sides of a pump or tank. A differential reading will indicate air entry, or problem with the gas blanket system. A persistent problem could be continually monitored using a galvanic probe. This is extremely helpful in detecting cyclic oxygen entry. Evaluate bacteria problems in a similar manner using culturing techniques described previously.

Oil Production

Oil production systems consist of oil wells, gathering lines, separation equipment, and storage tanks. With some exceptions, the main method for monitoring corrosion in oil systems is by failure records. In addition, visual inspections are also made throughout the system and recorded. Electromagnetic inspection of production tubing is typically done, after the tubing is pulled. This inspection data can help quantify the failure damage and confirm cause. Production records are also used to detect changes in fluid rate or water cut. This can allow you to change a treating program, for example, before failures occur.

Other routine monitoring methods are usually not needed because of low failure costs. Oil systems usually operate at low operating pressures resulting in a leak failure mode. There are exceptions. Wells/systems that present a high failure risk will require additional routine monitoring. Examples include some offshore fields, and the Alaskan North Slope. In these cases, routine monitoring with coupons, E/R probes, and scheduled inspections may be justified.

Special short term programs using coupons, E/R probes, or even LPR probes have been used to assess conditions in a new field. A brief program could also be used to conduct a field inhibitor evaluation. However, the program has a limited scope and short duration in these cases.

The efficient use of failure data is exemplified in the case of rod pumped wells. Because of the cyclic stress, sucker rod failures will occur rapidly when well conditions get more severe. They will frequently show a change long before coupon data. Sucker rod failures are also indicative of tubing conditions since they see the same environment. The sucker rod is, in effect, a coupon providing excellent data.

Another aspect worth mentioning concerns gas lifted oil wells. Corrosion can be affected by changes in the CO_2 or H_2S content of the lift gas. Be conscious of changes in the lift gas source and send a sample in for lab analysis periodically.

Lift gas could also become contaminated with oxygen. Leaking flanges, for instance, upstream of a compressor could cause air contamination in the lift gas. Be aware of signs implying oxygen corrosion, such as corrosion near an oxygen source, or evidence of iron oxide. If suspected, measure dissolved oxygen in the produced water using a meter or field kit. Oxygen in the lift gas can be measured with a trace oxygen analyzer. For either case, begin at the evidence and move upstream to pinpoint the source.

SUMMARY

Corrosion monitoring is the most important part of a corrosion control program. It provides the necessary information to determine need, extent, and performance of corrosion control measures. We have discussed many different monitoring methods and their application. In designing a corrosion monitoring program, there are several important points to remember:

1. Always consider corrosion monitoring needs during the initial stages of any project or field.

2. There are many different types of monitoring methods. Each has different advantages and disadvantages.

3. Design an economical corrosion monitoring program by first assessing failure risk and cost exposure associated with the system.

4. When possible, use multiple monitoring methods. The different methods will complement each other, and permit better interpretation of data.

5. Maintaining accurate records in a usable form is essential to the life and benefit of a monitoring program.

6. Periodically review the monitoring program and alter to fit the changing system.

In essence, corrosion monitoring is score keeping. The data is critical. If you do not keep score, how do you know if you are winning?

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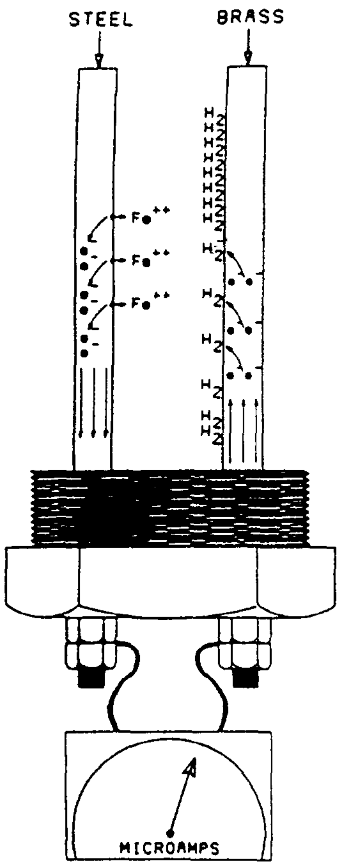
GALVANIC PROBE



ANODE (steel): $Fe \longrightarrow Fe^{++} + 2e^-$

CATHODE (brass): $2H^+ + 2e^- \longrightarrow H_2$

DEPOLARIZATION: $O_2 + 2H_2 \longrightarrow 2H_2O$

Figure 1 - Sketch of a Galvanic Probe used for measuring oxygen presence--
-- the polarization/depolarization mechanism is shown.

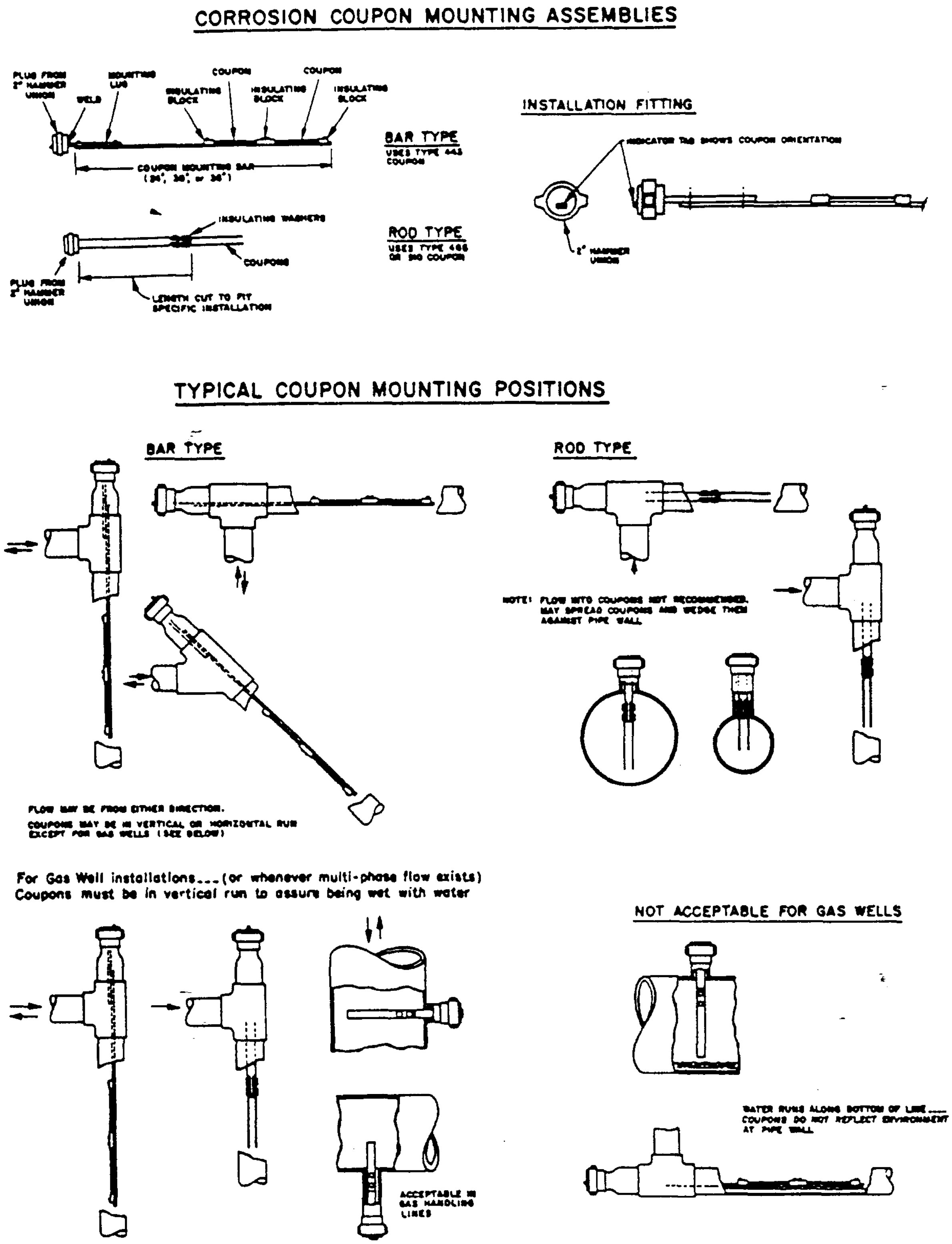


Figure 2 - Examples of various coupon fittings and orientations

CORROSION COUPON EXPOSURE ..ESULTS FOR: APRL 28, 1986

LEASE OR UNIT: 5121230

WELL OR PLANT: 2

89012345678

COUPON LOCATION: FLOW LINE
TYPE SYSTEM: GAS WELL

POSITION: HORIZONTAL, HORIZONTAL FLOW   TYPE: BAR

COUPON #	EXPOSURE DATES	DAYS	DAILY PRODUCTION	WEIGHT LOSS:GMS	OVERALL CORROSION RATE:MPY	BODY PITS DPTH IN	BODY PITS RATE MPY	END PITS DPTH MILS	END PITS RATE MPY	REMARKS
UW-32	8-28-85	58	0.BO	0.0058	0.1	.0	0	.0	0	CPN BDY ATTACK: SPOTTY ETCH ,
UW-33	10-25-85		10.BW	0.0050	0.1					HLDR BLK: NONE , EDGE: NONE
			297.MCF							WELL TREATED WITH INHIBITOR STICKS TWICE MONTHLY
UW-40	10-25-85	54	0.BO	0.0069	0.1	.0	0	.0	0	CPN BDY ATTACK: SPOTTY ETCH ,
UW-41	12-18-85		10.BW	0.0055	0.1					HLDR BLK: NONE , EDGE: NONE
			250.MCF							WELL NOT TREATED SINCE 10-25-85
THE POSITION OF THE COUPON STATION HAS BEEN CHANGED TO HORIZONTAL, VERTICAL FLOW .THE TYPE COUPON TO ROD										
TM-08	12-18-85	63	0.BO	0.0074	0.1	.0	0	.0	0	CPN BDY ATTACK: SPOTTY ETCH ,
TM-09	2-20-86		10.BW	0.0294	0.3					HLDR BLK: NONE , EDGE: NONE
			297.MCF							COUPON LOCATION MOVED, WELL NOT TREATED

COMMENTS ON LATEST DATA FROM ARCO MERCURIO MARTINEZ

LOW OVERALL CORROSION RATES AT ALL LOCATIONS.

NO COUPON-BODY PITTING AT ANY LOCATION.

NO COUPON-END PITTING AT ANY LOCATION.

Figure 3 - Example of coupon report showing necessary information

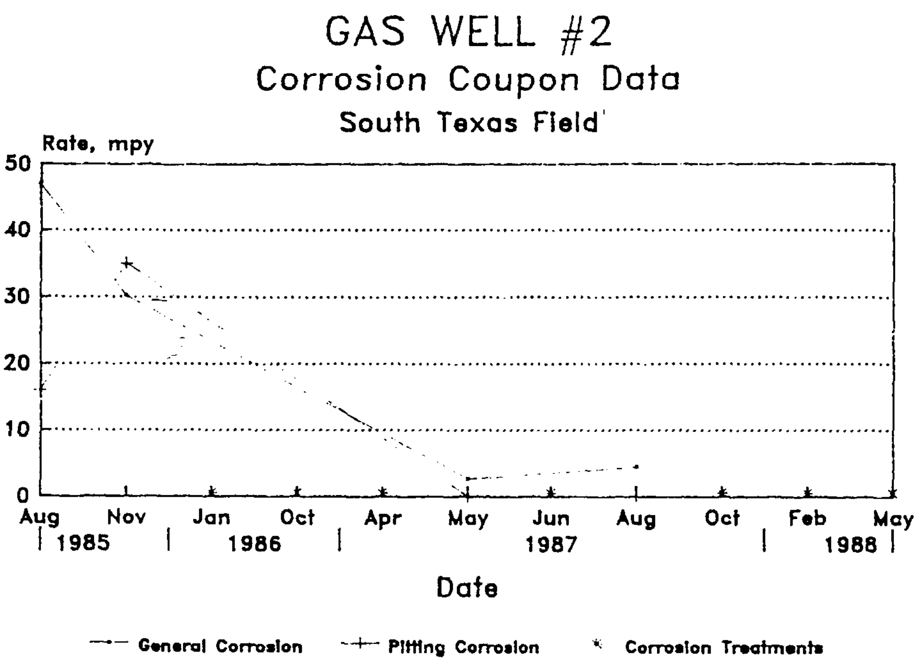


Figure 4 - Plot of coupon data showing overall corrosion rate and apparent pitting rate versus time

IRON COUNT SAMPLING POINT

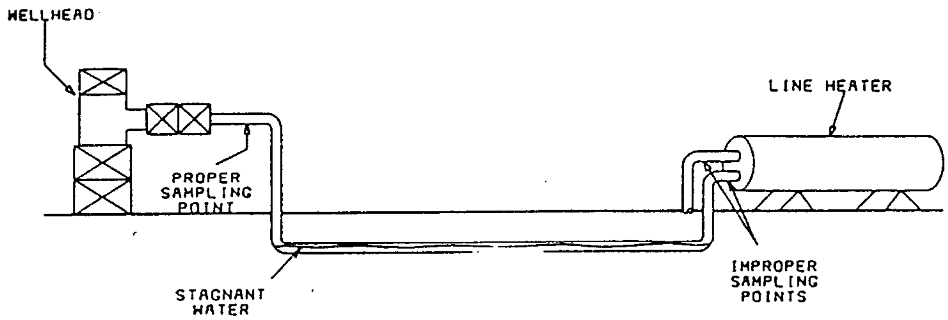


Figure 5 - Diagram showing proper location for iron count water sampling when monitoring downhole conditions at the wellhead

WATER SAMPLING SYSTEM
FOR IRON MONITORING

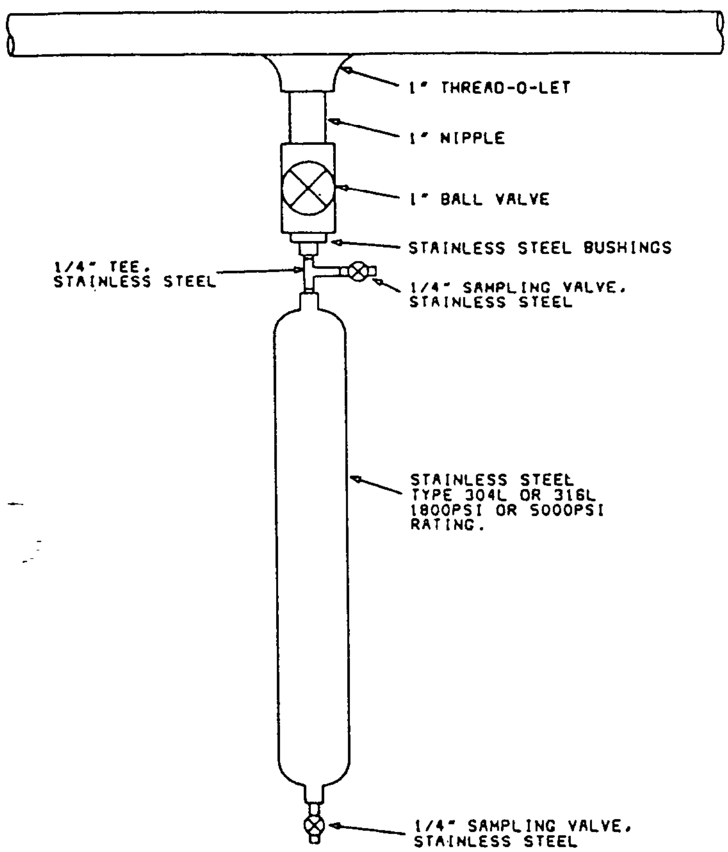


Figure 6 - Schematic of water sampling device designed for safe sampling in a gas system

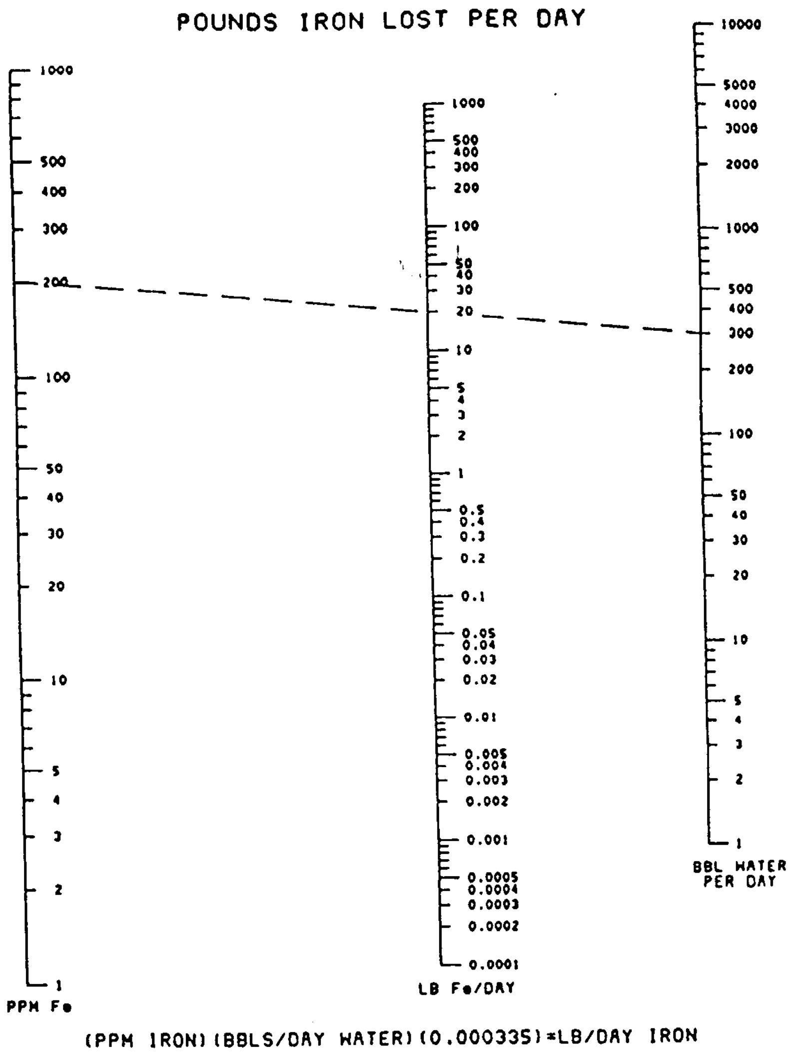


Figure 7 - Nomograph for calculating iron (lbs./day) from iron count (ppm) and water production (bbl./day); formula is given

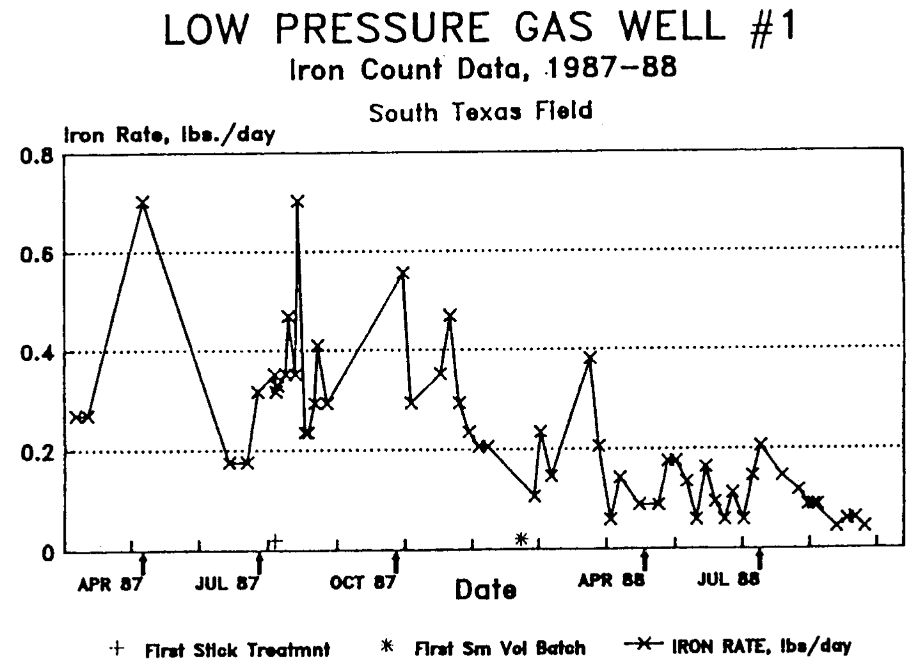


Figure 8 - Example of iron rate plot for a gas well; this case indicates a small volume batch treatment performs better than an inhibitor stick treatment.

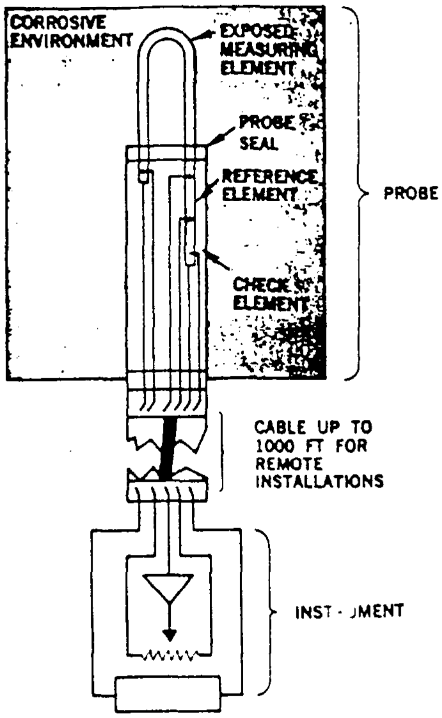


Figure 9 - Schematic of a Corrosometer electrical resistance (E/R) probe (Corrosometer is a registered trademark of Rohrback Cosasco Systems, Inc.; Santa Fe Springs, CA.– picture from Magna Corp. bulletin 866A, 1974)

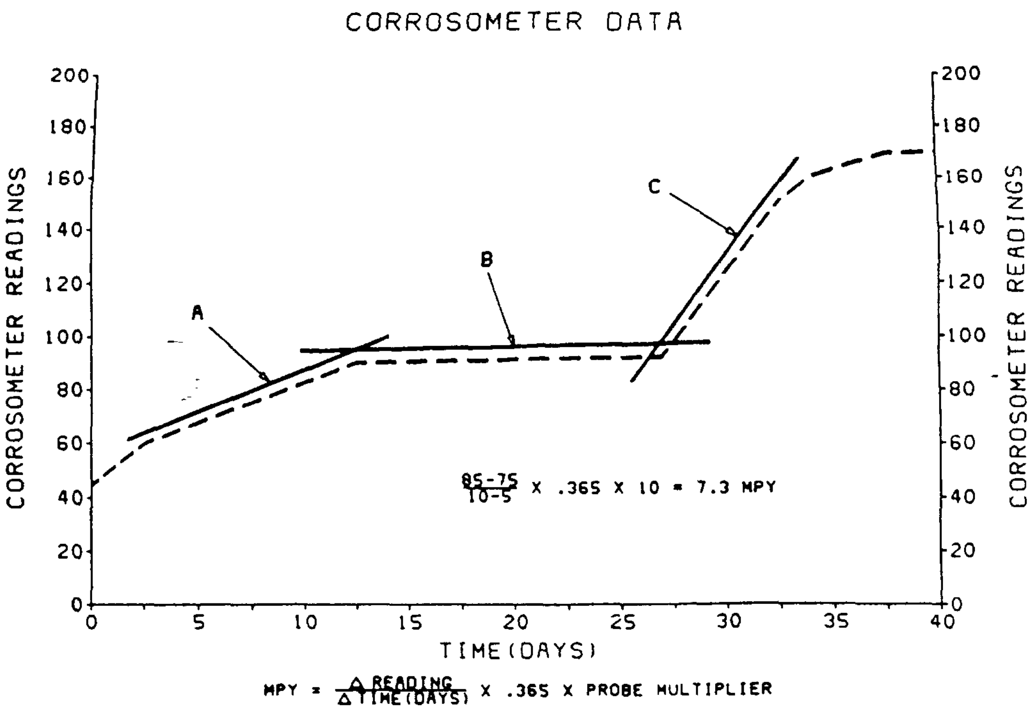


Figure 10 - Example of Corrosometer E/R plot. A, B, and C represent different corrosion rates. (Corrosometer is a registered trademark of Rohrback Cosasco Systems, Inc.; Santa Fe Springs, CA.)

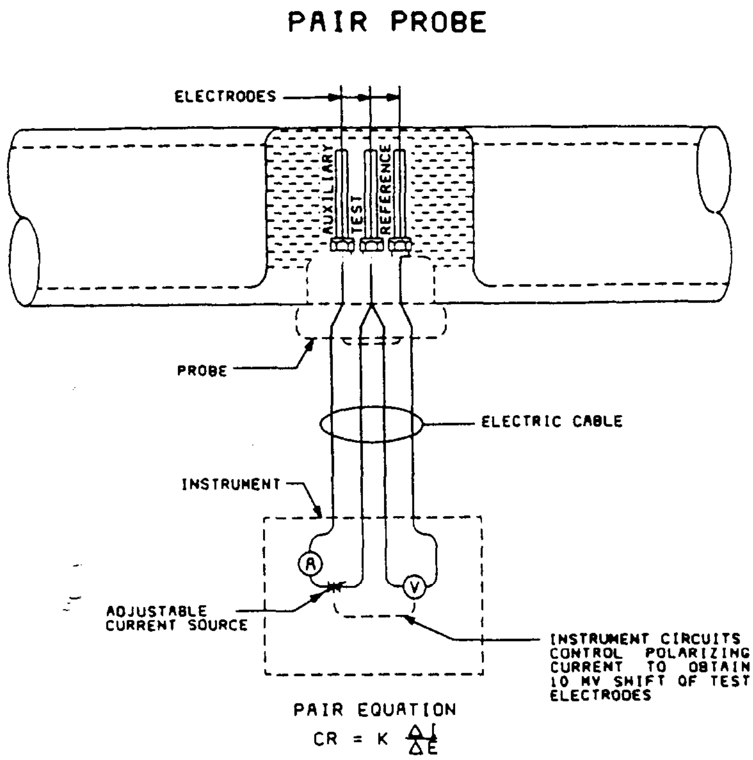


Figure 11 - Diagram of a PAIR linear polarization resistance (LPR) probe (PAIR is a registered trademark of Petrolite Instruments, Houston, TX.)

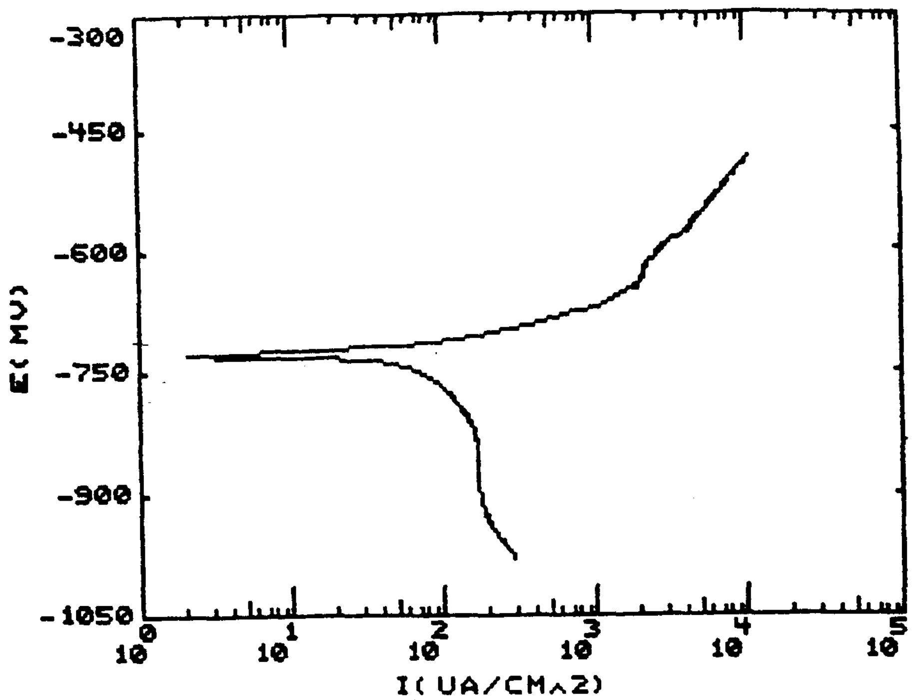
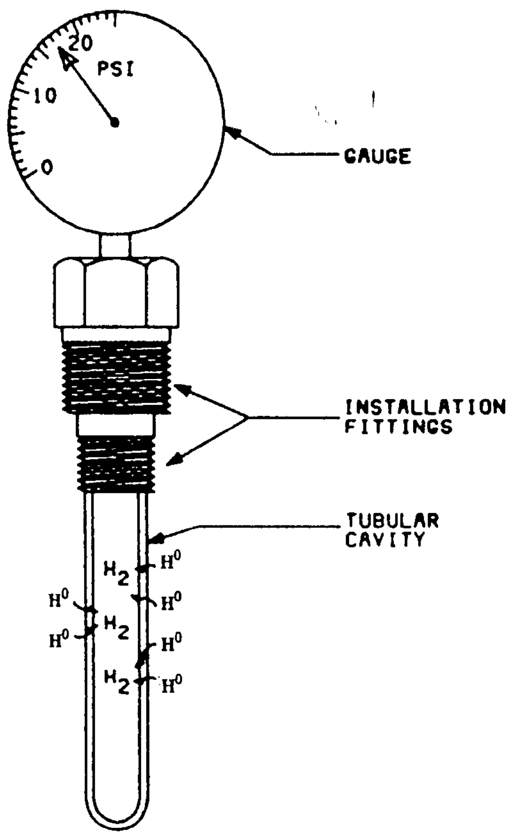


Figure 12 - Plot of potential versus current density for a potentiodynamic scan

HYDROGEN PROBE



INTERNAL OR
TUBULAR PROBE

Figure 13 - Diagram of a finger (intrusive type) pressure hydrogen probe (PHP); the mechanism of H^+ migration and H_2 formation is shown

HYDROGEN PROBE DATA

Example Case

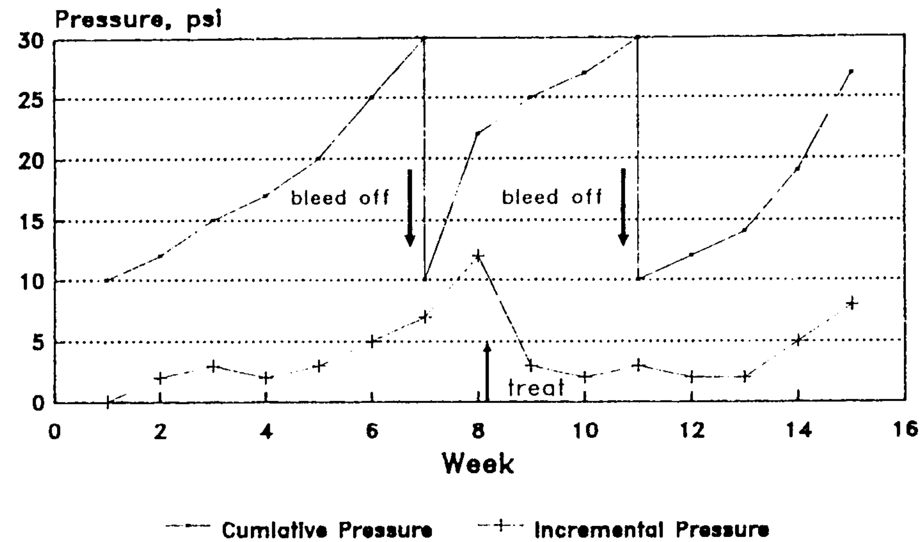


Figure 14 - Plot of hydrogen probe data; note the important aspect is the incremental pressure increase. Decrease in corrosion activity occurs after chemical treatment. Probe must be periodically bled off to keep within range of pressure gauge.

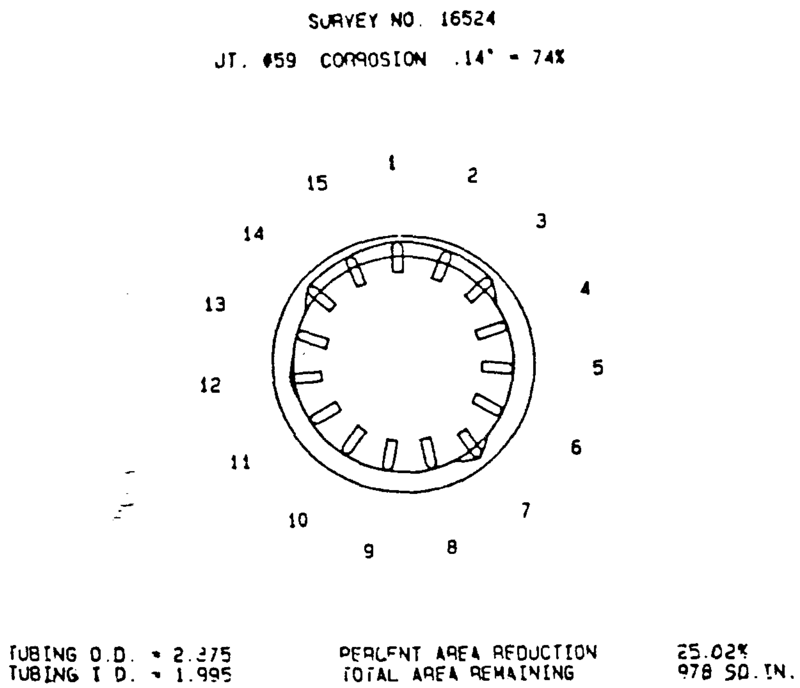


Figure 15 - Cross sectional diagram of corroded production tubing.
Taken from a mechanical caliper inspection report.
(Report by J.C. Kinley Co., Houston, TX.)

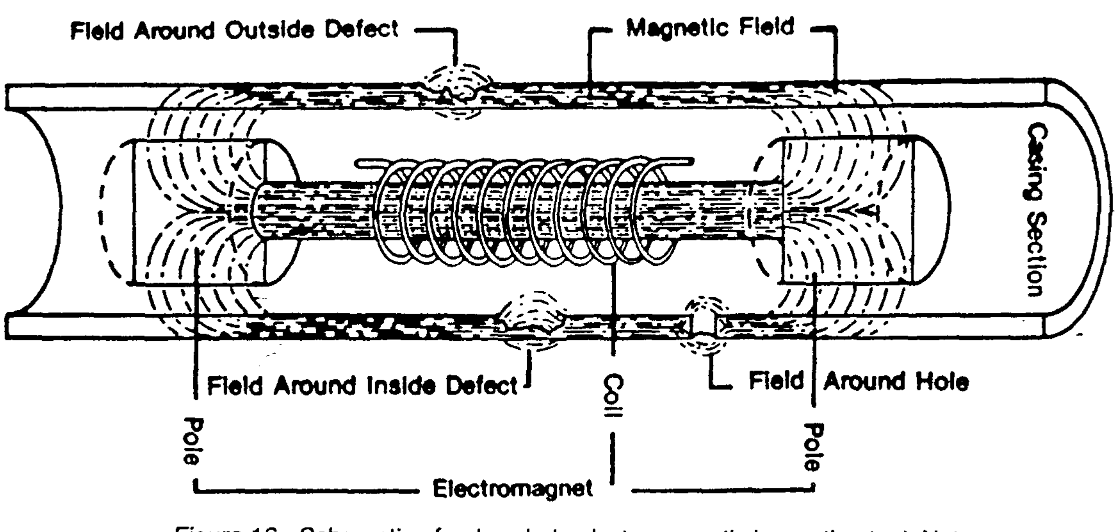


Figure 16 - Schematic of a downhole electromagnetic inspection tool. Note disruption in the field caused by the pitting. (publication no. 9541, rep 01/87, 2.5M; Dresser Industries, now Western Atlas)