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Abstract

A prior study performed for the Department of Energy yielded the fact that the largest problem contributing to abnormal production decline in stripper gas wells was due to fluid accumulation in the wellbore. Furthermore, the study identified that mechanical failures accounted for 23% of the problems contributing to abnormal production decline. Mechanical failures are generally corrosion related to the surface or downhole equipment. This study proposes to develop methodologies including decision trees and a procedure guide to identify the most effective technologies for corrosion mitigation for stripper wells. The application of systematic methodologies and techniques will increase the efficiency of problem assessment and implementation of corrective measures to minimize the effects of corrosion on stripper wells. Effective corrosion mitigation and treatment methods for stripper wells will benefit every producer by increasing production and ultimate recoveries since it is one of the most common problems leading to production decline.

Field research will be conducted on several hundred wells in Ohio available to James Engineering, Inc. to identify critical factors affecting rates of corrosion and the methods currently employed to mitigate the effects of corrosion. Specifically, wells previously identified as experiencing mechanical failure will be reviewed in addition to those where no corrosion has been observed. Previous methods of corrosion mitigation and repair will be investigated. As a result of the field research, a decision tree and procedure guide will be prepared to help operators mitigate the effects of corrosion on stripper well production performance. The field research will attempt to determine when a particular type of corrosion treatment method is effective.

The culmination of this study developed a procedure guide detailing potential areas of corrosion, their causes, and cost effective corrosion mitigation and repair procedures. A summary of the results of the study was presented at the joint meeting of the AAPG and SPE at the Eastern Regional Meeting in Pittsburgh, Pennsylvania on September 9, 2003.

Table of Contents

List of Graphical Materials

Table 1	None

Introduction

A prior study performed for the Department of Energy yielded the surprising fact that the largest problem contributing to abnormal production decline in stripper gas wells was due to fluid accumulation in the wellbore. Furthermore, mechanical failures were identified as accounting for 23% of the problems contributing to abnormal production decline. Mechanical failures are generally corrosion related to surface or downhole equipment. This study proposes to develop methodologies including decision trees and a procedure guide to identify the most effective technologies for corrosion mitigation for stripper wells. The application of systematic methodologies and techniques will increase the efficiency of problem assessment and implementation of corrective measures to minimize the effects of corrosion on stripper wells. Effective corrosion mitigation and treatment methods for stripper wells will benefit every producer by increasing production and ultimate recoveries since it is one of the most common problems leading to production decline.

Field research was conducted on hundreds of wells in Ohio available to James Engineering, Inc. to identify critical factors affecting rates of corrosion and the methods currently employed. Specifically, wells that were identified in the previous study as experiencing mechanical failure were reviewed in addition to wells where little or no corrosion had been observed. Previous methods of corrosion mitigation and repair were also investigated. As a result of the field research, a procedure guide and decision trees were prepared to help operators mitigate the effects of corrosion on the production performance of stripper wells. The field research assisted in determining when a particular type of corrosion treatment method was effective.

The culmination of this study resulted in the development of an application guide detailing potential areas of corrosion and cost effective corrosion mitigation procedures. This final technical report reviews summarizes the procedure guide and the Society of Petroleum Engineers paper prepared and presented at the Eastern Regional Meeting on September 9th in Pittsburgh, Pennsylvania. Both the procedure guide and the SPE paper are presented in their entirety in the Appendix of this report.

Executive Summary

A prior study performed for the Department of Energy yielded the surprising fact that the largest problem contributing to abnormal production decline in stripper gas wells was due to wellbore fluid accumulation. Furthermore, mechanical failures were identified as accounting for 23% of the problems contributing to abnormal production decline. Mechanical failures were in generally corrosion related in the surface or downhole equipment. This study proposes to develop methodologies including decision trees and a procedure guide to identify the most effective technologies for corrosion mitigation for stripper wells. The application of systematic methodologies and techniques will increase the efficiency of problem assessment and implementation of corrective measures to minimize the effects of corrosion on stripper wells. Effective corrosion mitigation and treatment methods for stripper wells will benefit every producer by increasing production and ultimate recoveries since it is one of the most common problems leading to production decline.

Field research was conducted on hundreds of wells in Ohio available to James Engineering, Inc. identifying critical factors affecting rates of corrosion and the methods currently employed. Specifically, wells that were identified in the previous study as experiencing mechanical failure were reviewed in addition to wells where little or no corrosion has been observed. Previous methods of corrosion mitigation and repairs were investigated. As a result of the field research, an application guide and decision trees were prepared to help operators mitigate the effects of corrosion on the production performance of stripper wells. The field research assisted in determining when a particular type of corrosion treatment method was effective.

This final technical report summarizes the procedure guide and the Society of Petroleum Engineers paper prepared and presented at the Eastern Regional Meeting on September 9th in Pittsburgh, Pennsylvania. The procedure guide initially provides a section with sufficient detailed information for the corrosion novice to gain a basic understanding of the mechanism of corrosion. The second section provides simplified step-by-step instruction for those operators who just want to get started. Additional information includes a quick corrosion summary list, a decision tree for total corrosion mitigation plan development, and corrosion field review data collection sheets. A quick summary is provided on corrosion related to production casing, tubing, wellheads, separators, production tanks, gas gathering systems, and production lines. Each of the specific corrosion areas presents a brief general discussion, identifies common corrosion areas, corrosion identification methods, corrosion repair methods, corrosion mitigation methods, and the decision trees and procedures available. The guide also includes a corrosion definitions section, recommended websites for corrosion information, vendor links for information on corrosion related items, recommended sources of information, and a paint information section. The procedure guide and the SPE paper are presented in their entirety in the Appendix of this report.

Experimental Apparatus and Operating Data

No experimental methods, materials, or equipment were used in this phase of the research.

Results and Discussion

The specific steps to develop the methodology of this study and completed as proposed included:

- Literature Search of Appropriate Application of Corrosion Mitigation Methodologies for Stripper Wells
- Develop Data Collection Forms for Field Review
- Perform Field Review of Critical Areas Affected by Corrosion
    - Production Storage Tanks
    - Wellheads
    - Pipelines
    - Downhole Tubulars
- Summarize Results of Field Review of Areas Affected by Corrosion
- Develop Decision Tree to Select Appropriate Corrosion Mitigation Technology
- Test Decision Tree
- Prepare Application Guide Detailing Cost Effective Corrosion Mitigation Technologies
- Prepare Technical Paper and Transfer the Technology

The detailed results of each step to develop the methodology can be found in the quarterly reports, the procedure guide, or the SPE paper. In lieu of presenting each of the detail associated with the individual steps, the summaries, procedure guide, and SPE paper are present instead in this final report. Therefore, this final technical report briefly summarizes the procedure guide and the Society of Petroleum Engineers paper prepared and presented at the Eastern Regional Meeting on September 9th in Pittsburgh, Pennsylvania. The procedure guide and the SPE paper are presented in their entirety in the Appendix of this report.

I. Procedure Guide

The ultimate goal of the study was the development of the procedure guide. Per the original proposal, "An application guide will be prepared to assist operators in determining appropriate corrosion mitigation treatment by evaluating the current treatment methodologies of specific wells to minimize corrosion."

Data Reduction and Methodology

A procedure guide was developed that incorporates the results of the study into logical, step-by-step procedures for mitigating corrosion by the specific components associated with stripper wells. The components, which were divided by section in the procedure guide, include production casing, tubing, wellheads, separators and production units, production tanks, and gathering lines and production lines. Each component section provides a general discussion, then identifies common corrosion areas, corrosion identification methods, corrosion repair methods, corrosion mitigation methods, and the decision trees and procedures applicable to the particular component.

The procedure guide first provides an introduction to corrosion that includes: Corrosion Defined, Components of Corrosion, Types of Corrosion, Primary Agents of Corrosion, The Importance of Ohm's Law, Soil Resistivity Defined, Soil Resistivity Measurement, Potential Measurements, Corrosion Identification Methods, Corrosion Identification Instrumentation, Cathodic Protection Design Factors, Common Methods of Corrosion Control, Corrosion Economics, and Corrosion Training.

However, some operators may want to simply just get started, the procedure guide allows operators to skip the introduction to corrosion, although recommended reading, to begin the their fight against corrosion in the section entitled ***"Where to Begin".*** This section begins with a brief introduction then provides a Quick Corrosion Summary List to quickly highlight where corrosion occurs and provide some corrosion mitigation methods. The guide then provides a "Decision Tree Form For Total Corrosion Mitigation Plan Development" to allow operators to develop their own corrosion mitigation program. Data collection forms are provided as Corrosion Field Review Data Collection Sheets for operators to use in evaluating then incorporating each well, facility, or pipeline into a corrosion mitigation plan. As previously discussed, individual sections are provided for each main stripper well component affected by corrosion.

Other procedure guide highlights include Decision Trees and Repair procedures for tubing and casing leaks due to corrosion, Decision Tree For Production Storage Tanks Corrosion Mitigation and a Plastic Tank Summary. Other highlights of the guide include Gathering System Identification and Review Steps, a Decision Tree Form For Pipeline or Production Line Leak, Pipeline Rehabilitation by Sliplining with Polyethylene Pipe, Plastic Pipe Pressure Rating Guidelines, a form for Pipeline Inspection or Leak Report, a method for Estimating Anode Requirements for Bare pipe or Hot Spot Protection, a few Pipeline Coating Repair Procedures. Further, the Appendix in the guide includes Abbreviations and Definitions, Recommended Web Sites for Corrosion Information, Vendor Links for Information on Corrosion Related Products, Recommended Sources of Information, and Paint Information and Guidelines.

Overall, the procedure guide provides an understanding of corrosion and a review – prioritization methodology. Review - prioritization considerations include identifying: high value wells and gathering systems, corrosion mitigation methods, corrosion correction methods, associated costs, previous corrosion areas, desired facility life, environmentally sensitive areas, significant potential for harm wells, i.e. H_2S wells, and/or wells located in well-populated areas. While the overall subject of corrosion is complex, in most cases the process of corrosion mitigation can be simplified for stripper well operators to the proper application of planning, painting, and plastic.

II. SPE Paper - Society of Petroleum Engineer's Eastern Regional Meeting Presentation

Data Reduction and Methodology

A technical paper based upon the results of the study was presented at the Society of Petroleum Engineer's Eastern Regional Meeting in Pittsburgh, Pennsylvania September 9, 2003. The paper summarizes the overall study and the individual steps leading to the development of the procedure guide. The paper as it was presented is provided in the appendix.

III. Conclusion and Future Work

Corrosion affects every stripper well to some degree and if left unchecked results in the repair or replacement of casing, rods, tubing, separators, production tanks, and pipelines. Additional effects include lost or deferred production, lower equipment salvage values, environmental damage and associated penalties, and decreased safety.

The costs associated with corrosion, while substantial can be managed best when considered as a cost of doing business. Proper planning utilizing the decision trees and procedures presented in the procedure guide should significantly reduce the amount of time and expense that would otherwise be required for addressing corrosion related issues.

Stripper well operators face multiple challenges, cannot afford to utilize the same corrosion control methods as major transmission and natural gas storage companies, but still require economic, efficient, easy to use techniques for corrosion mitigation.

Stripper well operators should develop in-house expertise through education, and training through the West Virginia University Appalachian Underground Corrosion Short Course. It is important that stripper well operators employ consistent methodologies that includes an equipment database, cost estimates, economic prioritization, an annual budget, scheduled maintenance, documentation, and monitoring when planning to effectively mitigate the effects of corrosion.

While the process of corrosion is complex and often misunderstood, it is largely controllable. Primary cementing of production casing over H_2S or coal bearing zones or chemical inhibition should eliminate most downhole casing problems. Regular maintenance through surface preparation, painting, and leak correction would eliminate many wellhead and tank related problems. Proper tank setting and bottom coating would significantly reduce most tank bottom corrosion related incidents. Utilizing plastic tanks for salt-water storage would eliminate most of the problems associated with steel tanks. Finally, coated pipe, cathodic protection, hot spot protection, and the use of plastic for pipeline replacement would significantly reduce many pipeline corrosion problems.

Ultimately, rather than randomly addressing corrosion, a thoughtful review and appraisal of current corrosion related problems then incorporated into a formal plan to mitigate corrosion should make a positive economic impact on the overall cost of operations for most stripper well operators. Simply stated, the proper application of planning, painting, and plastic can achieve great results in stripper well operations.

This concludes "The Study to Evaluate the Effect of Cost of Corrosion on Stripper Well Operations."

References:

Not Applicable.

Bibliography:

Not applicable

List of Acronyms and Abbreviations:

Not applicable.

Appendices
Procedure Guide
SPE Paper

Practical Guide to Identify, Repair, and Prevent Corrosion in Stripper Well Operations

Stripper Well Consortium

SWC Award Number: 2283-JE-DOE-1025

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Table of Contents **Page**

A. Introduction

This procedure guide was prepared as a result of research completed through a joint venture between James Engineering, Inc. and the United States Department of Energy's Stripper Well Consortium program. The goal of the research was to develop a procedure guide detailing cost effective corrosion mitigation methods for stripper wells. The final technical report of this research and SPE paper number 84835 should be reviewed for a complete description of the methodologies, results, and conclusions utilized in developing this procedure guide.

A previous study completed by James Engineering, Inc. showed that 270 of 376 wells evaluated, or over 70%, exhibited some form of abnormal production decline within the past five years. Nearly 50% of the abnormal production declines was due to liquid loading, or fluid accumulation in the wellbore while over 20% of the declines were due to corrosion. The effects of corrosion resulted in both decreased reserves and revenue. However, the nature of corrosion represents a significant opportunity for improvement since the cause appears correctable through the proper application of corrosion mitigation techniques.

The petroleum industry spends millions of dollars every year developing new oil and natural gas reserves and yet additional millions are spent maintaining existing production facilities from the effects of corrosion. The National Association for Corrosion Engineers estimates that the total annual corrosion expenditures for all United States industries combined is $300,000,000,000 while the onshore oil and gas industry alone has annual expenditures exceeding $300,000,000 combating corrosion. Further, it has been estimated that the effects of corrosion are so extensive that the replacement of corrosion damaged materials accounts for approximately 20% of the annual iron produced in the United States.

The oil and natural gas industry has historically observed the effects of corrosion throughout all phases of production operations and considerable strides have been made to understand not only the process of corrosion but also develop methods to mitigate its effects. However, due to the limited income associated with stripper oil and gas wells, many operators often cannot afford to implement the level of corrosion control methods utilized by major natural gas transmission and storage companies. Therefore, this procedure guide was prepared to provide practical methods of corrosion control for the stripper oil and gas well utilizing cost effective methods to not only identify but also mitigate the effects of corrosion.

Information utilized in the preparation of the guide was based upon experience, repair procedure review, field review of existing wells, well file review, significant literature searches on corrosion mitigation, and interviews with well tenders interviews, producers, oilfield supply representatives, and corrosion product representatives.

The following discussion and terminology provides a basis for the methodologies developed for stripper well operators to address corrosion by first defining corrosion, then reviewing the components of corrosion, the electrochemical nature of corrosion, the various types of corrosion, discuss soil resistivity and its effects on corrosion, corrosion identification methods, corrosion control methods, and finally review the decision trees and associated procedures developed to assist stripper well operators. While an understanding of the mechanism and forms of corrosion can lead to an understanding of the proper means for controlling corrosion, for those who desire to just get started turn to the section entitled "Where to Begin" on page 18. Note that this guide is not intended to be a comprehensive text on the complex subject of corrosion.

B. Corrosion Defined - Corrosion is typically defined as "*the deterioration of a material, usually a metal, due to a reaction with its environment.*" The energy absorbed and stored during conversion from raw ore to finished metal product through refining and fabricating is later released by corrosion as metals seek a less energized state. The required conversion energy varies for each metal - relatively high for magnesium and relatively low for silver. It has been well documented that the greater the conversion energy required, the greater the potential for corrosion. Table 1 shows the conversion energy required for some commonly used metals.

The "corrosion potential" of various metals has been measured in volts then placed in a table called the "galvanic series" by order of their tendency to corrode from the most corrosive (most active or anodic), to the least corrosive (most noble or cathodic), see Table 2.

Table 1. Positions of some metals in descending order of energy required to convert their ores to metals. The greater the required conversion energy, the greater the corrosion potential

	Chemical
Most Energy Required	Potassium
	Magnesium
	Beryllium
	Aluminum
	Zinc
	Chromium
	Iron
	Nickel
	Tin
	Copper
	Silver
	Platinum
Least Energy Required	Gold

The energy difference between metals and their ores can be expressed in electrical terms which are related to heats of formation of the compounds.

Table 2. Practical galvanic series of metals, ranked from most to least corrosive

	Metal	Volts
Progressively More Anodic and More Corrosive	Pure Magnesium	–1.75
	Magnesium Alloy Mix	–1.60
	Zinc	–1.10
	Aluminum Alloy (5% Zinc)	–1.05
	Pure Aluminum	–0.80
	Mild Steel (clean and shiny)	–0.5 to 0.8
	Mild Steel Rusted	–0.2 to 0.5
	Cast Iron	–0.5
	Lead	–0.5
	Mild Steel in Concrete	–0.2
	Copper, Brass, Bronze	–0.2
	High Silicon Cast Iron	–0.2
Progressively More Cathodic and Least Corrosive	Mill Scale on Steel	–0.2

C. Components of Corrosion – or, What does it take for corrosion to occur? Rust, while commonplace to the naked eye, is the result of very complex electrochemical reactions. The electrochemical reactions are related to the flow of electricity and to the chemical interactions between the metal and the surrounding soil. Further, the amount of electricity generated is directly related to the amount of metal being removed. The chemical reactions are a function of the soil type and it's moisture characteristics.

In order for corrosion to occur, there must be four components; an anode, a cathode, a metal path connecting the anode and cathode, and an electrolyte that surrounds the anode and cathode. When all four of the components are combined a "corrosion cell" is created causing electrical current to flow and metal to be consumed. Conversely, corrosion will cease if any one of the four components are removed.

To further define the four components, the anode is the metal electrode in contact with the electrolyte where corrosion occurs, electrons lost, metal dissolved, and current leaves the metal and enters the electrolyte. The cathode is the metal electrode in contact with the electrolyte where no corrosion occurs, electrons gained, rust deposits occur, and current is picked up. The metal path connecting the anode and the cathode is where the electrons flow. The electrolyte is a solution or conducting medium such as soil containing water, oxygen, or dissolved chemicals where metal ions and current flow. Figure 1 below shows a common battery corrosion cell where electrons flow from the negative electrode (*anode*) through the wire and light bulb (*metal path*) to the positive electrode (*cathode*), and ions flow from the positive electrode through the sulfuric acid (*electrolyte*) to the negative electrode.

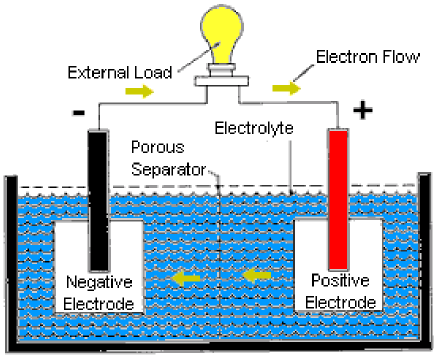
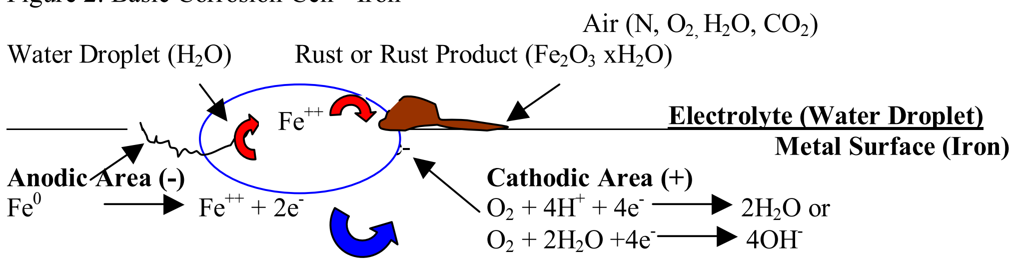


Figure 1 - Components of a Battery Cell (Discharge Circuit)

While figure 1 identifies the anode and cathode as two separate entities, they are often a part of the same piece of metal. Refining and fabricating create individual steel grains variances within the same piece of metal that make them anodic or cathodic to one another. The variances are further enhanced by varying environmental, soil conditions, and pipeline coating inconsistencies. Therefore the electrodes may be a fraction of an inch apart or they may be miles apart.

Figure 2 shows the chemical reactions for a corrosion cell in a single piece of steel. Metal loss begins to occur at an anodic area as atoms of iron, Fe^0, go into solution as Fe^{++} ions in the electrolyte (water droplet), or $Fe^0 \rightarrow Fe^{++} + 2e^-$. Corrosion slows as Fe^{++} ions accumulate near the anode surface until precipitated as rust product (Fe_2O_3 x H_2O) due to the presence of oxygen thus allowing the corrosion process to continue. The electrons, e^-, released from the atoms of iron flow through the metal path creating electricity until their charge is neutralized through chemical reduction with hydrogen or oxygen; or $O_2 + 4H^+ + 4e^- \rightarrow 2\ H2O$ or $O_2 + 2H_2O + 4e^- \rightarrow 4OH$.

Figure 2: Basic Corrosion Cell - Iron



Note: the essential difference between ordinary steel and pure iron is the amount of carbon in the steel: low carbon 0.3%, medium 0.3 – 0.6%, high 0.6 – 1.0%, and ultra high 1.25 – 2.0%.

In summary, corrosion is the release of the refining and fabricating energy required to convert iron ore (iron oxide) into steel leaving the steel in a higher energy state with a natural tendency to return to its lower energy state of native iron ore as iron oxide or rust

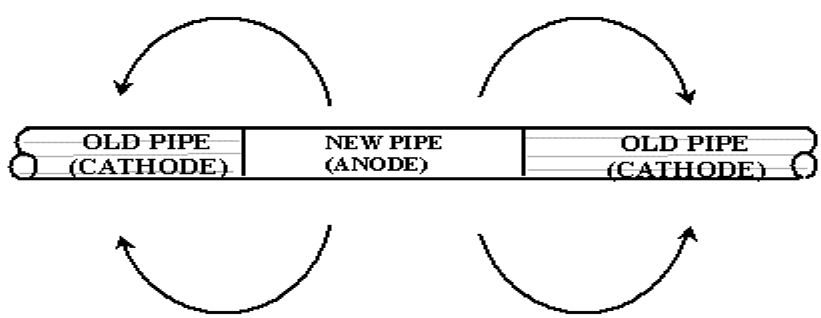
D. Types of Corrosion - Because corrosion categories vary according to specific industries, for the purposes of our study, corrosion was divided into two fundamental types: general and localized. General corrosion is characterized by a uniform layer of corrosion or metal loss, with no pitting, and is generally a very slow process. Localized corrosion can be aggressive and was further categorized as galvanic, pitting, crevice, inter-granular, stray current, microbiologically induced, de-alloying, erosion, and stress.

Galvanic corrosion occurs due to the potential difference between two materials. Pitting corrosion is evidenced by trough shaped cavities over a small area with rust covering most pits. Crevice corrosion occurs due to changes in the local chemistry in shielded areas under gaskets, washers, insulation material, fastener heads, surface deposits, disbonded coatings, lap joints, and clamps. Intergranular corrosion is localized attack along or immediately adjacent to the grain boundaries to grain boundaries while the bulk of the grains remain largely unaffected. Stray current corrosion is very aggressive and occurs when an unprotected line crosses a line protected by impressed current. Microbiologically induced corrosion (MIC) is initiated by the presence of microorganisms, bacteria (aerobic or anaerobic), or fungi and results in pitting and crevice corrosion. Oil transport lines and waterflood operations often have to address MIC. Erosion corrosion is generally associated with turbulent flow of fast moving fluids is also associated with the rubbing action of sucker rods against tubing walls. De-alloying and stress corrosion (associated with materials in deeper wells) are generally not factors in stripper well operations.

Differential corrosion cells are created by the following: differential aeration of compacted compared to un-compacted soil, mill scale corrosion of where pipe steel is anodic to mill scale, new pipe anodic to old pipe, dissimilar soils or soil conditions, and the relative size of the anodic to the cathodic area.

A new steel section with no rust on it becomes anodic to the rest of the existing rust coated pipeline and corrosion on the new steel is accelerated, see figure below.

Example of New Pipe to Old Pipe Galvanic Corrosion
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



E. Primary Agents of Corrosion - Moisture content, oxygen, carbon dioxide, hydrogen sulfide, chlorides, temperature, pH, environment, and physical effects are the primary agents of oilfield corrosion. The rate of corrosion increases as the concentration of any of these factors increases, with the exception of ph. Corroding agents often work together resulting in a “synergistic effect” to further increase corrosion rates.

First, without moisture, corrosion would not occur. Corrosion is minimized in arid environments like the desert due to decreased moisture content, but is greatly enhanced in humid, moist, or wet environments. Eliminating and/or reducing moisture contact is essential to minimizing corrosion and is accomplished through enclosures, coverings, coatings, and the elimination of leaks. Small leaks over time are very detrimental and should be quickly repaired.

Oxygen is one of the most common corrosion agents affecting all equipment due to its ready availability and its tendency to form metal oxides. Buried structures are also impacted by variations in oxygen content due to soil differences such as clay vs. sandy, hard rock vs. silty, or compacted vs. uncompacted. Relatively oxygen poor compacted soil (anodic area) at the bottom of the pipe causes current to flow to the relatively oxygen rich less compacted soil (cathodic area) at the top of the pipe. Painting, coating, and cathodic protection are generally effective measures against oxygen-enhanced corrosion.

Carbon dioxide and hydrogen sulfide gases are most often associated with specific reservoirs or geographic areas and their presence can be anticipated and planned for. Material selection, primary cementing, chemical inhibitors, painting, or scrubbers are effective at combating H_2S and CO_2. H_2S reacts readily with iron in the presence of water and results in the precipitation of iron sulfide, a black porous substance cathodic to iron.
The increased chlorides associated with oilfield brines accelerate corrosion rates due to increased conductivity. Storage tank bottoms are especially susceptible to corrosion due to varying water levels from rain and snow when combined with oxygen and released brine, therefore, it is important to minimize any brine leakage inside the tank dike.

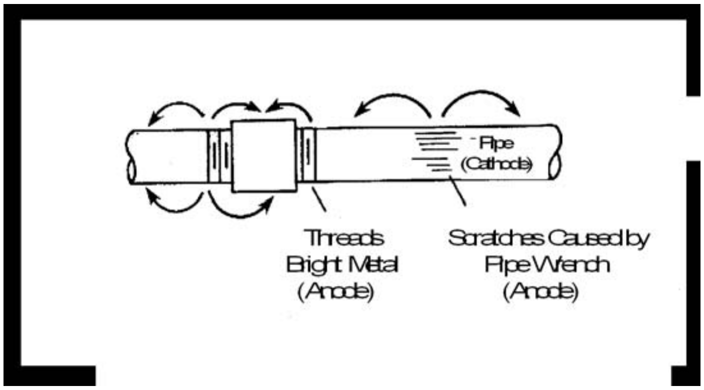
Increased temperature increases the surface rates of corrosion while decreased temperature slows corrosion dramatically after all soil moisture is frozen. Therefore, corrosion cells are much more active in the summer than in the winter especially where temperatures drop below freezing.

PH is calculated as a negative logarithm of the concentration of hydrogen ions, where a ph of 7 or greater is basic or alkaline, 7 neutral, and less than 7 acidic. Relatively, below 4.5 is extremely acidic while greater than 9.0 is very strongly alkaline. Each increment of ph represents a ten-fold increases in ph since pH is measured logarithmically, for example from 5 to 6. Acidic conditions are conducive to corrosion, therefore, environmental conditions affect ph, especially in those areas where acid rain is a problem.

Physical problems that increase the potential for corrosion include mill scale, tool marks, gouges, nicks, and bite marks from pipe wrenches on steel surfaces that expose bright metal. The “bright metal” surfaces become anodic to the adjacent cathodic metal, for example field cut threads, which should be coated with spray paint. Cold working metal (field bending) and welding introduce residual stresses that make the material susceptible to stress corrosion cracking. See example of field cut threads and pipe wrench marks below.

Well tenders and roustabouts trained in corrosion identification can assist operators in mitigating corrosion through early recognition in determining proper corrosion mitigation methods.

Examples of anodic areas caused by bright metal thread and wrench mark scratches
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



F. The Importance of Ohm's Law: I = E / R
Ohm's Law defines the relationship between corrosion, current, voltage, and resistance where the current (I) in amperes equals the voltage differential between anode and cathode (E), divided by the resistance of the entire circuit (R). ***The amount of current generated is directly proportional to the rate of metal loss or corrosion at the anode, i.e., the greater the current flow in the corrosion circuit, the greater the metal loss.*** One ampere of direct current discharging into a typical soil can remove approximately twenty pounds of steel in one year, or 20 pounds per ampere-year. While metal consumption rates are expressed in pounds per ampere per year, most currents measured are only thousandths of an ampere, or milli-amperes.

G. Soil Resistivity Defined
Soil resistivity, the reciprocal of conductivity, is the accepted industry standard as the primary indicator of soil corrosivity, and is measured in ohm centimeters, or ohm-cm. The lower the resistivity, the easier current flows through the soil. Soils with resistivities below 1000 ohm-m can cause severe pipeline deterioration. Soil resistivity is defined by the equation: ρ, the resistivity of the soil in ohm centimeters, equals 2 times Π (3.1416) times A, the soil cross sectional area, times R, the resistance of the soil sample in ohms.

Soil is comprised of solids, a combination of stones, gravel, silt, and clay, and voids filled with liquids and gases (electrolytes). Soil resistivity, a function of the soil solids and the voids, is specifically related to the soil type or composition, moisture content, acidity, salt content, oxygen, bacteria, and temperature. Soils with measured resistivities greater than 50,000 ohm-cm are mildly corrosive; 30,000 to 50,000 ohm-cm are moderately corrosive, and less than 30,000 ohm-cm are very corrosive. Table 2 summarizes soil resistivity as a function of the soil type.

Moisture helps chemicals in the soil surrounding pipelines to carry electrical current. The higher the moisture content, the lower the soil's resistivity. Moisture content of ~16% is required for oxidation and reduction to occur. For example, sandy loam with 2.5 moisture content has a resistivity of ~1,500 ohm-m, while at 15% moisture content the resistivity drops to 105 ohm-m. Soils with high organic content have low resistivities, higher moisture levels, and higher electrolyte levels. Sandy soils drain faster, have lower moisture content, lower electrolyte level, and higher resistivity. Solid rock contains virtually no moisture or electrolytes and has very high resistivity levels.

Table 2 Soil Resistivity as a Function of Soil Type		
Soil Type	**Ohm – Cm**	**Corrosion Level**
Poorly graded gravels	100,000 – 250,000	Negligible
Well graded gravels	60,000 – 100,000	Mildly Corrosive
Clayey gravel	20,000 – 40,000	Moderate
Silty sands	10,000 – 50,000	Severe to Moderate
Clayey sands	5,000 – 20,000	Severe to Moderate
Fine sandy or silty soils	8,000 – 30,000	Severe to Moderate
Silty or clayey fine sands	3,000 – 8,000	Severe
Gravelly clays	2,500 – 6,000	Severe
Inorganic clays	1,000 – 5,500	Severe
Sand	90 – 8,000	Severe
Marshy ground, Loam	2 – 150	Very Severe

Similar to chlorides (brines) in water, chlorides in soil accelerate corrosion, through increased conductivity thereby significantly reducing resistivity. For example, sandy loam with 15.2% moisture content at 0% salt is 107 ohm-m, while at 20% salt is only 1 ohm-m; both readings represent severe corrosion potential. Again, small leaks over time are very detrimental.

Resistivity increases substantially when moisture content falls below 10% or temperatures fall below freezing. For example, sandy loam with 15% moisture at 60° Farenheight has a 72 ohm-m resistivity, while at 14° F has a 3,300 ohm-m reading.

H. Soil Resistivity Measurement - Soil resistivity measurements provide a direct indication of the corrosive properties of soil. Measurements of soil resistivity variations along a given pipeline route help predict potential areas of corrosion. For example, pipeline sections in low resistivity soils become anodic and corrode relative to those sections in higher resistivity soils. The most common field soil resistivity measurement methods include the Wenner four-pin method (the most accurate), the three-pin method (variation in-depth method), and the copper-copper sulfate reference electrode, or CSE method. Laboratory testing of samples obtained through drilling or excavation operations may be performed to assess soil resistivities.

The Wenner four-pin method (ASTM G-57) and the three-pin method measure the average resistivity of large volumes of soil based on the spacing of the measuring pins. The resultant resistivity is the average resistivity of the soil (electrolyte) to a depth equal to the spacing between adjacent electrodes (soil pins). The maximum depth (pin spacing) of this standard test set has been designed for 20 feet, which is recommended for standard survey. Four pins are driven into the ground in a straight line with each being spaced a distance x from the next. The distance between pins is equal to the depth measured. AC current is then passed between the two outer pins while voltage between the two inner pins is measured. Voltage is measured with the AC on and off, and the difference of the voltages, ΔV, determined. The resistance between the inner pins is $R = \Delta V$ times I, where I is the applied AC current. Measurements should be made perpendicular to a pipeline and no closer than ten feet to the pipe. Readings are typically taken every 100 - 400 feet over the length of pipeline by a two to three man crew.

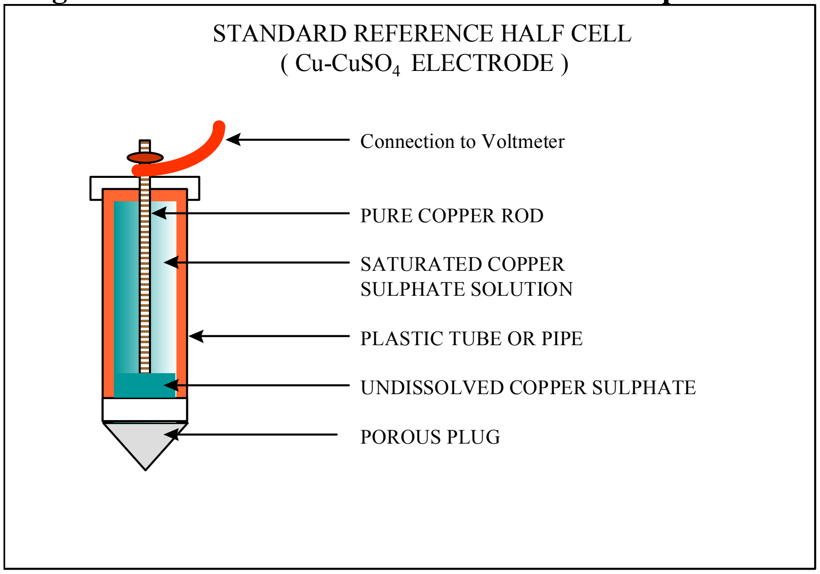
I. Potential Measurements

Potential measurements, pipe to soil or soil to soil, are used to identify extent of metal corrosion, cathodic protection, stray currents, and hot spots. Measurements are accomplished using test stations, copper–copper sulfate electrodes, and voltmeters. Typical sign convention is that reactive metals are negative and noble metals are positive. *More negative readings along a pipeline indicate a hot spot or an increase in corrosion potential.*

The copper–copper sulfate electrode or CSE method measures a small volume of soil in the area surrounding the tip of the rod. The positive terminal of the voltmeter is connected to the CSE reference electrode and the negative terminal to the pipeline, tank, or other structure. Pipe to soil potentials are generally negative under corrosive conditions when measured with a CSE. Digital meters, rather than analog, are recommended due to their ease of use and resistance to damage if polarity is reversed. See example of copper-to-copper sulfate electrode below

The main use of metal to soil measurements is to determine whether a pipeline has sufficient cathodic protection (positive lead to pipe, negative lead to CSE, digital meter set to DC). A pipeline with –850 millivolts along most points is considered to be cathodically protected when measured with a CSE. Rust build-up over time on older non-protected lines make it less likely to corrode and metal to soil measurements taken over time would become less negative. A newly laid, coated pipeline may have a pipe-to-soil potential of -500 to -700 millivolts while an old bare pipeline may be –100 to –300 millivolts.

Example of copper-copper sulfate electrode, CSE
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems

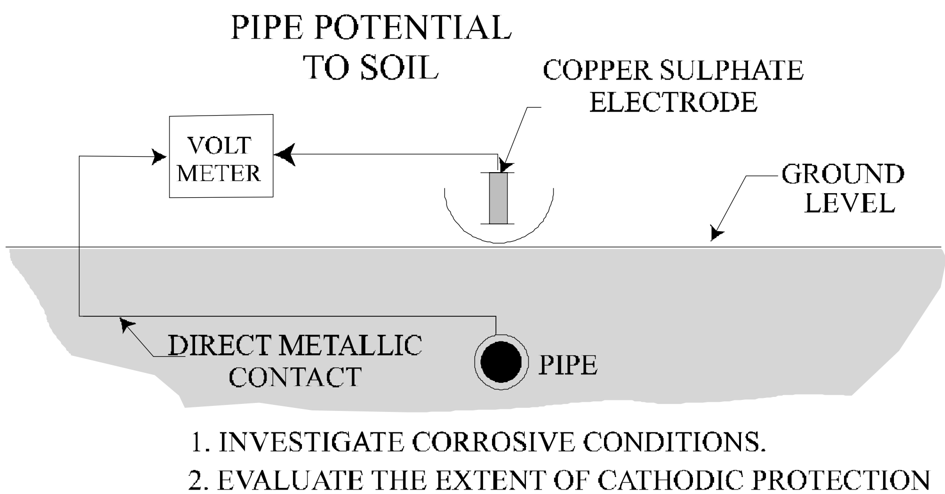


Permanent test stations provide a means for determining soil and pipe conditions instead of utilizing portable “stations”. It is recommended that stripper well operators consider installing permanent test stations to monitor pipeline corrosion even when no cp or coatings are utilized. Stations should be installed at a maximum intervals of one every half-mile. This type of survey utilizes the pipe as the 'reference' against which the ground potentials are measured. The voltage will decrease if a coating fault exists as the portable meter half-cell is moved towards the fault. See example of potential test below.

Resistivity readings can be shifted up to one volt by scrap batteries, buried tools, welding rods, farm implements and parts, abandoned 'foreign' services, abandoned concrete bases, disused welding tips, and natural unidentified features.

Stripper well operators usually find contracted services that conduct soil resistivity measurements cost prohibitive. The general condition of most gathering system right of ways, un-mowed and unmarked, increase the time required for soil resistivity surveys who are unfamiliar with operator systems. An estimated cost for a contracted three-man soil survey crew for one mile is approximately $1,000 per day. However, in-house personnel with nominal training and investment for equipment can complete soil resistivities.

Example of pipe potential to soil test using copper-copper sulfate electrode CSE
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



J. Corrosion Identification Methods - Corrosion identification methods include visual inspection, physical observation, pressure and production monitoring, electronic inspection, soil analysis, fluid analysis, chemical analysis, corrosometer electrical resistance (E/R) measurement, hydrogen probes, and metal coupon analysis.

Visual inspections are limited to external surfaces but are beneficial to stripper well operations due to the low cost and general effectiveness. Visual inspections identify potential problems with wellheads, exposed sections of casing and tubing, separators, production units, meters, storage tanks, and surface lines. Well tenders or production managers should complete visual inspections for prioritizing maintenance, repairs, or replacements.

Physical observation identifies mechanical failure due to corrosion resulting in the loss of pressure and product from wellheads, tanks, or pipelines. Well tenders, landowners, and production variance reports assist in identifying mechanical failures. Physical observation identifies corrosion resulting in the loss of pressure and product in wellheads, tanks, or pipelines. Well tenders, landowners, and production variance reports assist in identifying mechanical failures. Physical signs of a natural gas leak include an odor, a hissing sound, dirt or water being blown into the air, bubbling in wet areas, patches of dead vegetation, fire burning above the ground, dry spots in moist fields, areas of abnormally hard or dry soil, or a white vapor cloud close to the ground. Oil spills are generally identified as seepages or as rainbow sheens.

Well tenders often identify mechanical failures through monitoring operating pressures and production volumes. Decreases in normal operating pressures may indicate a casing or pipeline failure while decreases in gas production or increases in fluid production often indicate a casing failure. Loss of fluid from a tank noted during tank gauging or normal gas production without normal fluid production may indicate a leak at the bottom of a tank.

Electronic inspection allows for the review of the internal surfaces of production casing and pipelines. Electronic methods include radiographic examinations (x-ray), ultrasonic devices, electromagnetic inspection, caliper surveys, and measuring electric current in casing. Large production companies, gas transmission companies, or natural storage companies utilize electronic logging to regularly monitor casing and pipelines. Regular monitoring identifies pitting or general corrosion so that corrective action can be taken prior to catastrophic mechanical failure. These will typically indicate the specific location of any potential area and then classify it as either a class 1, 2, or 3. Stripper well operators generally rely on more cost effective methods of prevention or repair, rather than incur the expense of periodic electronic inspection.

Electronic identification equipment used by stripper well operators includes portable gas detectors, pipeline locators, gps units, and portable gas analyzers. Electronic gas detectors identify gas leaks even when an odor is not perceived. Pipeline locators identify the location of steel pipelines and the tracer lines installed with plastic pipelines. Global positioning satellite or gps units are very affordable and user friendly for use in identifying pipeline routes, and well and leak locations. Data from gps units can be easily downloaded to relatively inexpensive topographic mapping software such as Terrain Navigator for printing seamless maps. Portable gas detectors assist in determining the presence of H_2S or CO_2. An H_2S concentration of 250 ppm or more and ph of 6.5 or less indicates a corrosive environment, while for CO_2, a 7-psi partial pressure with a ph of 7 or less and a count of 100 ppm or greater indicates a corrosive environment. Cathodic protection cannot prevent hydrogen embrittlement.

Soil resistivity analysis, previously discussed, identifies the conductivity of the soil to determine the potential corrosivity. This testing can be accomplished in-house with some training by stripper well operators and is generally too expensive to contract out to experienced companies.

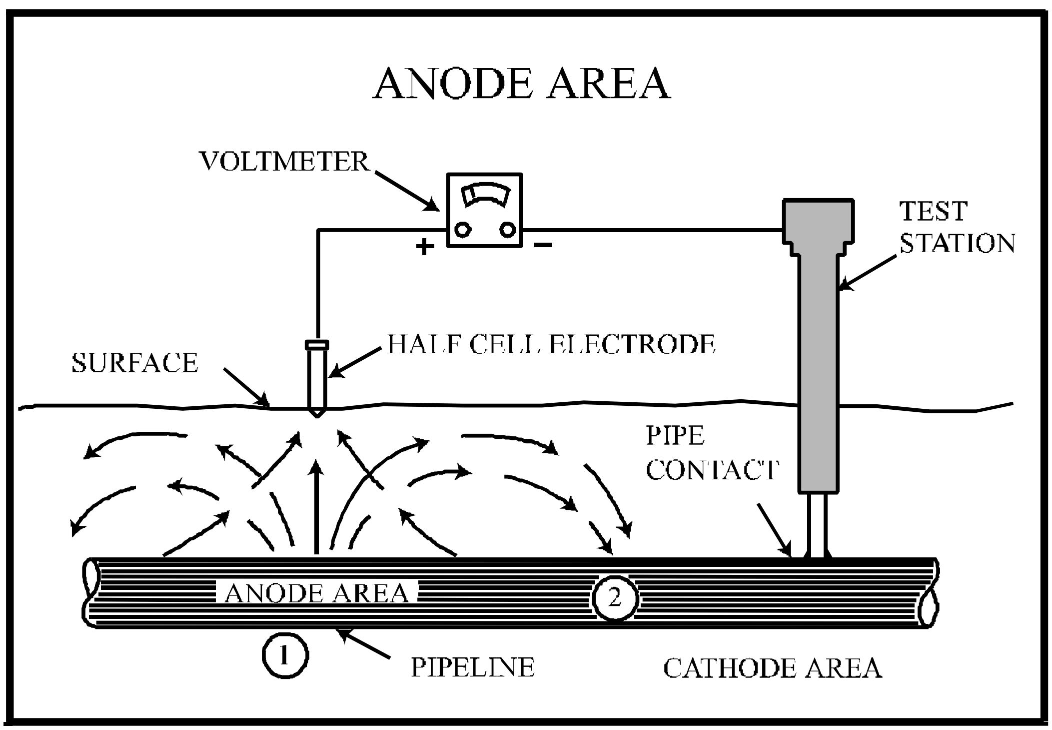
Pipe-to-soil and soil-to-soil potential measurements can be taken with copper-to-copper sulfate electrodes to identify corrosive environments. Roustabouts and technicians can be trained to utilize the equipment associated with these measurements.

Chemical analysis, performed by trained oilfield chemical company personnel, identifies potentially corrosive elements in a production stream. Specifically, chemical analysis is used to identify the presence and concentrations of iron, sodium, potassium, calcium, magnesium, chlorides, sulfates, carbonates, resistivity, hydrogen sulfide, pH, and total dissolved solids. The increased concentration of these factors generally increases the corrosive environment with the exception of ph. Continuous monitoring of fluids is required for water floods due to the interaction of injected water and reservoir fluids.

Ph measurements can be measured in the field or sent to the laboratory for analysis. Ph is the negative logarithm of the hydrogen ion calculated in powers of 10, that is, a solution with a ph of 1.0 is 10 times greater than one with a ph of 2.0. Significant corrosion is unlikely in alkaline water or soils with ph values of 7 or higher while any ph of 6 or less provides an environment for significant corrosion and probable pitting.

Corrosion coupons identify internal pipeline corrosion and quantify the metal loss in millimeters per year, mils per year, or MPY. Pre-weighed coupons are put in line, left for one month to one year, removed, and then analyzed. Coupons are photographed, cleaned, visually inspected, dried, re-weighed, and re-photographed. The corrosion rate is then estimated based upon the weight of coupon material lost. Champion Technologies recommend that a coupon test of less than 5 MPY and no pitting indicates corrosion is unlikely, less than 5 MPY with pitting indicates isolated corrosion, while greater than 5 MPY indicates active corrosion. Further, the most frequent causes of pipeline internal corrosion are improper welding, too high or low of velocity, inadequate pigging leading to scale or paraffin buildup, liquid buildup, bacteria growth, or use of the wrong inhibitor.

Example of typical test station
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



Common corrosion areas identified in the study that stripper well operators should concentrate on includes un-cemented H2S bearing zones, top joints of either tubing or casing near the packing, all leaking connections, unlined metal salt water storage tanks, heater tube areas, bottom of oil and brine storage tanks, and bare pipelines in moist areas. Further, it is important for operators to be able to differentiate between corrosion that looks bad and corrosion that requires immediate attention. Company employees can receive corrosion training through the Appalachian Underground Corrosion School held in May of every year in Morgantown, West Virginia.

Documenting all analyses, visual identifications, observations, and leak repairs will assist in the mitigation of future mechanical failures. The records provide vital information regarding past performance and current conditions.

K. Corrosion Identification Instrumentation - The instrumentation utilized in the identification and analysis of pipeline corrosion include voltmeters, multi-meters, soil resistivity test instruments, wall thickness gages, pit gages, current interrupters, pulse generators, pulse analyzers, pipe locators, cable locators, ammeter clamps, insulator checkers, test rectifiers, holiday detectors, reference electrodes, coupons, portable power supplies, wire reels, portable shunts, soil resistivity pins, magnetic flux leakage, ultrasonic, x-ray, and soil resistivity boxes. Companies that typically utilize most of the previously mentioned instruments are those engaged in the corrosion business, large oil and gas operators, or transportation or storage companies with corrosion departments. Most major oil field supply companies have a complete line of corrosion related products, but may not have the technical expertise to provide advise on specific operator requirements.

One company, Corrosion Control Products Company, (800) 421-2623, offers twenty different product groups with 220 corrosion related products. General product areas include Cable Locators, Metal Detectors, Leak Detectors, Level Indicators, Non-Destructive Dry Film Thickness Gauges, Destructive Paint Inspection & Thickness Gauges, Certified Coating Thickness Calibration Standards, Wet Film Thickness Gauges, Ultrasonic Thickness Gauges, Holiday Detectors, Coating Surface & Contamination Testers – 8, Temperature & Humidity Measurement – 7, Surface Moisture Meters, Coating Adhesion Testers, Miscellaneous Coating Equipment & Accessories, Pipeline Coatings, Protective Coatings, Heat Shrinkable Products, Flange insulation Kits, Insulation Unions and Fittings (300 and 3000 psi), Casing Seals and Insulators, Rock Shields , Pipeline Pigs, and Corrosion Control Accessories.

L. Cathodic Protection (cp) Design Factors: Stripper well operators should carefully consider the following design factors: risk, length of line, operating pressure of system (plastic versus steel), life of project (coated steel versus non coated), resistivities of soil, availability of electric power, existence of other DC power sources, measurement of existing pipe to soil potentials using standard half cell, current demands, resistance to earth of the anodes, quantity and location of anode or anode systems, electrical supply requirements, test and monitoring facilities. Other considerations include landowner issues, public authorities, ground bed easements, cables, transformer rectifier sites, and electricity supplies.

Experience indicates that stripper oil and gas operators can generally achieve good success utilizing either plastic pipe, or a combination of coated pipe and sacrificial anode system for protecting most small diameter (2" – 4"), low-pressure (5 – 250 psi) gas gathering systems. Larger diameter (>4"), high pressure systems (>250 psi) should be reviewed for the relative benefits of utilizing impressed current over the sacrificial anode system. Existing systems without coating or cp will benefit by the application of hot spot protection during repairs or replacements.

Stripper well operators need to determine what is an acceptable risk when reviewing corrosion mitigation strategies, with risk defined as the likelihood of failure times the consequences of failure. The determination of relative risk based upon the safety, environmental, and financial liabilities associated with each facility will assist stripper well operators in prioritizing corrosion mitigation procedures.

M. Common Methods of Corrosion Control

The goal of corrosion control should be to facilitate operation of the wells, maintain mechanical integrity, and protect the overall investment. A corrosion control program should not be one that simply manages failures and leaks, but one that incorporates cathodic protection, protective coatings, material selection - corrosion resistant materials, insulating joints, chemical inhibitors, and environment control. Note that any corrosion control method implemented on an existing structure will not “repair” current damage, but will arrest further damage to the structure.

Note: Chapter three on corrosion control from the US Department of Transportation Guidance Manual for Operators of Small Natural Gas Systems contains a simplified description of the corrosion control requirements contained in the pipeline safety regulations. This section does a great job identifying and explaining the various corrosion control methods generally applicable to stripper well operators for natural gas gathering systems and should also be reviewed. The manual is generally free upon request.

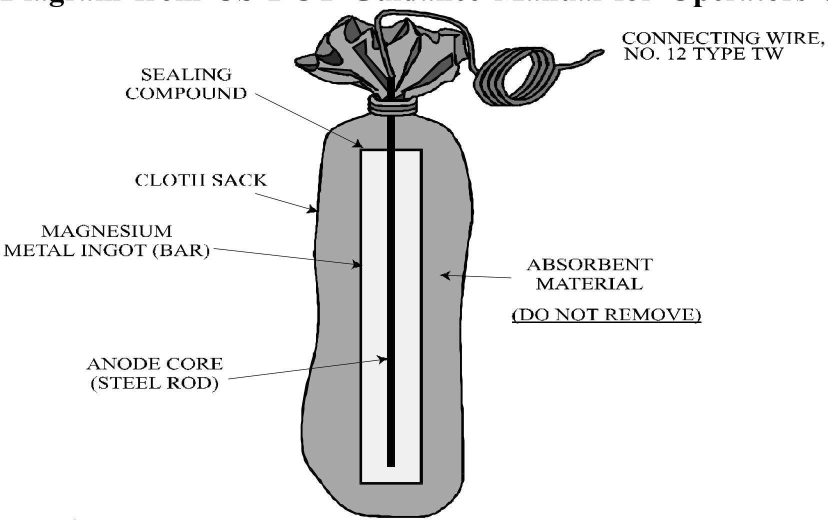
Corrosion protection is achieved when the corrosion current equals zero either by the application of a perfect, no holiday coating which is not possible, or by making the difference between the anode and cathode voltage equal to zero through the application of cathodic protection.

Cathodic Protection, cp, was first utilized in 1824 when Sir Davy attached zinc plates to the copper sheathing on British naval vessel hulls to retard the corrosion. The cp process uses direct current from an external source to oppose the discharge of current from anodic areas by making pipelines or storage tanks the cathode in the electrochemical cell. Without cp, current flows from pipeline anodic areas into the surrounding soil causing the pipeline to corrode. Cathodic protection does not eliminate corrosion but directs it at a less costly, expendable, replaceable, material. Cathodic protection for protecting pipeline systems is generally achieved by utilizing sacrificial anodes and rectifier ground bed or impressed current systems.

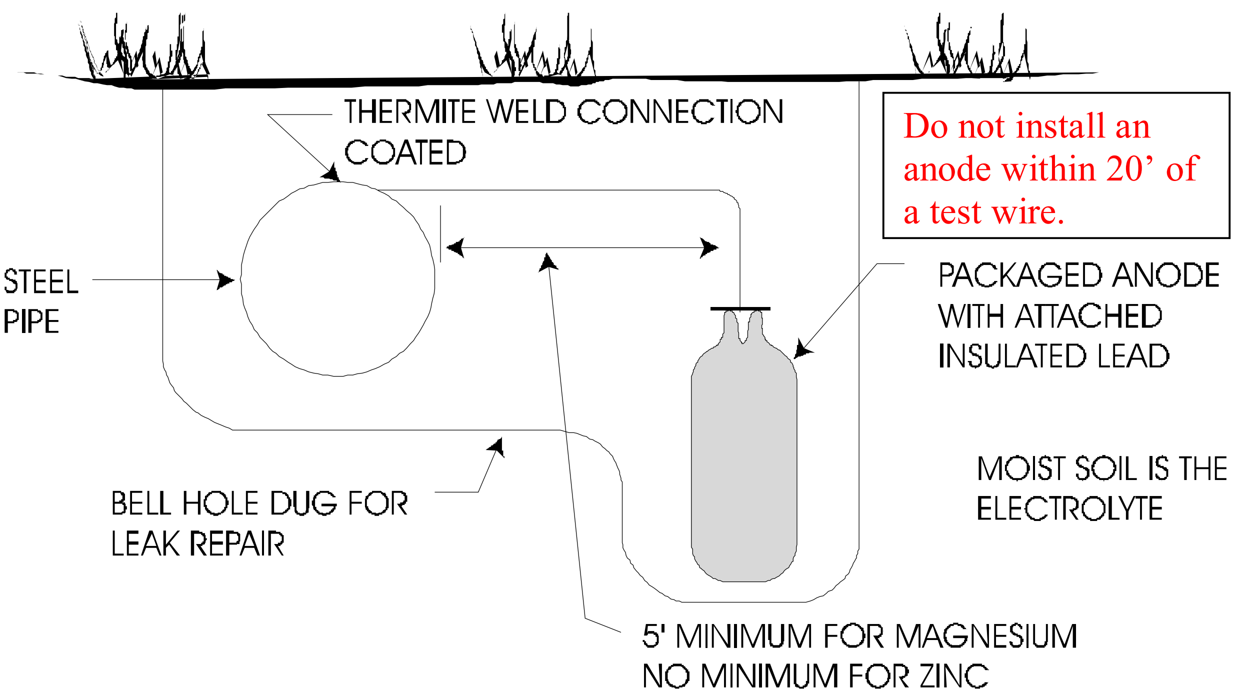
Sacrificial anode systems accomplish protection by coupling a magnesium or zinc anode to the pipeline for current to flow from the anode to pipeline, progressively destroying “sacrificing” the anode and protecting the pipeline. A galvanic or sacrificial anode is able to provide protective current to a steel structure because of its relative position in the galvanic series as compared to steel. Magnesium and zinc anodes are commonly used for low resistivity environments with typical anode sizes of 17 or 34 pounds. The advantages of sacrificial anodes include no external power requirement, low voltage output, no voltage variance, ease of installation, location adaptability, no maintenance, and no inspection requirements. Sacrificial anodes are not applicable to long lengths of new bare steel lines. Similarly, platinum rods are commonly used inside heater treaters, separators, filters, and salt-water disposal tanks. See examples of magnesium anode and installation below.

Rectifier ground bed systems include an AC power supply, a rectifier unit, a ground bed of anodes, connecting cables, and the pipeline: see example below. The rectifier utilizes a transformer to step down high AC line voltage to low AC voltage, then utilizes a rectifying element to converts the low AC voltage to DC which is transferred by a single cable to a high silicon iron or graphite anode ground bed located 150 to 450 feet from the pipeline. Rectifier ground bed system advantages include variable DC voltage application, protection of bare steel lines, and automation for varying moisture conditions. Disadvantages include possible foreign structures interference, unintentional current interruption, required regular maintenance, and higher operating costs. A note of caution: electricians unfamiliar with DC power have a 50-50 chance of hooking up an impressed current system backwards.

Example of typical magnesium anode
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



Example of typical sacrificial magnesium anode connection to pipeline
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



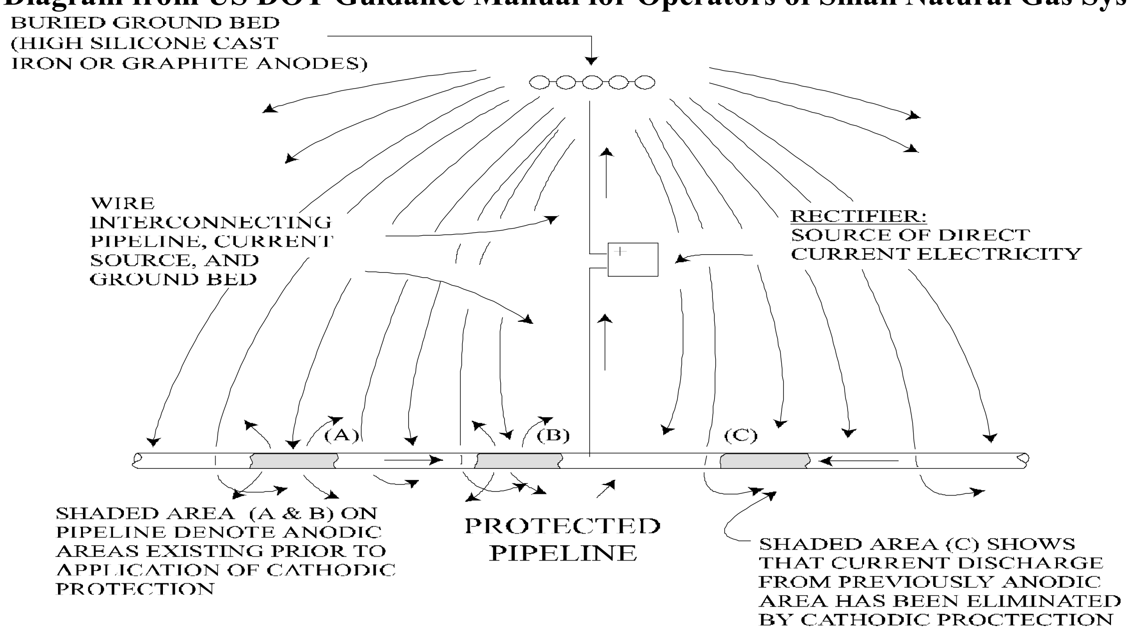
It is usually not economical to protect an entire “bare pipe” pipeline of considerable length. New bare buried pipelines can be assumed to require 1 milliamp per square foot of surface, (~50 amps for 1 mile of 30”, ~ 3 amps for 1 mile of 2 3/8”). However, "hot spot" protection, generally economically justified, can be utilized to protect only the very corrosive soil sections. Hot spot protection extends the useful life of the entire pipeline by the application of cp to only the severely corroding areas. Installation of the anodes should be made at a distance of at least 10 ft perpendicular to the pipeline when replacing line sections or applying repair clamps. Most oilfield supply companies carry anodes and Cadweld guns for connecting anodes to the pipeline. See attachment example below.

The industry and governmental standard for cp effectiveness is – a negative (cathodic) potential of at least 850 mV or 0.850 V with cp applied when measured with respect to a saturated copper-copper sulfate reference electrode. This 850 mV measurement consists of the 550 mV natural difference between non-corroding steel and the CSE plus 300 mV caused by the inflow of current. Naturally occurring corrosion cells have voltages less than 300 mV. The – 850 mV is the most widely used, can be taken with current applied, take less time to measure, requires only minimum equipment, personnel, and vehicles, and there is no need to compare to previous readings.

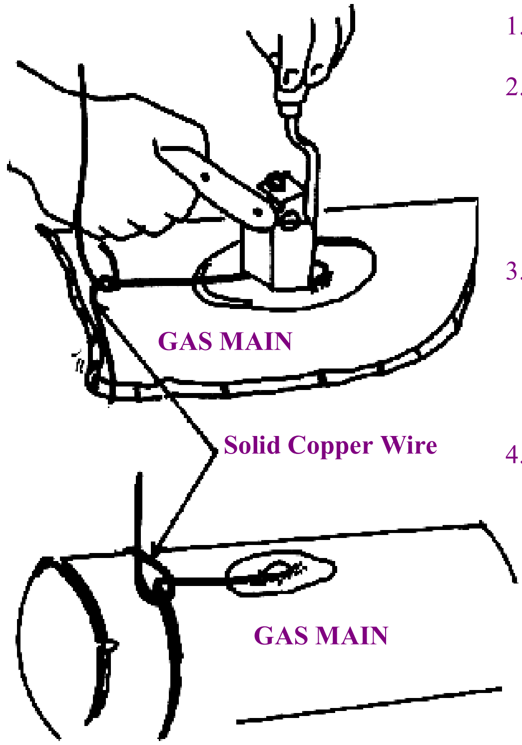
Over time, the corrosion process often results in the formation of insoluble corrosion products that provide a level of protection called passivity. Therefore, the rust buildup often acts as a partial barrier to further corrosion. The study revealed that production storage tanks set in clay do not appear to suffer from the effects of corrosion. Furthermore, metal brine tanks with one or barrels of crude added do not experience the accelerated corrosion experienced by other tanks without crude, due to the coating action provided by the crude.

Cathodic protection requirements are established through soil resistivity measurements taken before and after pipeline and cp system installation. Stripper well operators typically do not utilize soil testing but some other method based on experience or rule of thumb to determine cp requirements.

Example of typical rectifier ground bed system
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



Example of Procedure for installing a magnesium anode by Thermo-weld Process
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



1. Loop wire as shown to avoid strain on bond.
2. Insert conductor in mold-do not push end of conductor past center of tap hole. Drop metal disc over tap hole. Remove all starting power from cartridge by tapping the inverted cartridge on lip of mold.
3. Close cover, hold mold steady. Ignite starting power with flint gun as shown. When powder fires, remove gun immediately. Hold mold steady for 10 seconds. Remove slag from weld.
4. See the manufacturer's recommendation before proceeding.

After welding, all exposed pipe should be well coated and wrapped.

Pipeline Protective Coatings: Pipelines are corrosion protected through coatings to ensure reliable service over a long time. Coating qualities include effective electrical insulator, effective moisture barrier, applicability, ability to resist holidays, good adhesion to pipe surface, ability to withstand normal handling, storage, and installation, resistance to disbanding, ease of repair, and environmentally nontoxic. Pipelines coatings include coal tar enamels, mill applied tape systems, crosshead extruded polyolefin with asphalt/butyl adhesive, dual side extruded polyolefin with butyl adhesive, fusion bonded, and multi layer epoxy/extruded polyolefin systems. Pipeline coatings are most effective when installed in combination with cp due to the defects associated with all coatings. A cp system will only need to protect the minute areas of steel exposed rather than the whole surface of an uncoated structure.

The current requirements for pipeline corrosion protection are reduced through coatings to 5% to 10% of the cost of protecting bare steel pipe. Therefore, coatings on a cathodically protected pipe reduce the surface area of exposed metal on the pipeline, increase the overall resistance, and thereby reduce the current required for the protection of underground pipelines. The cp current then flows principally to holidays or voids in the coating where a calcareous deposit forms further reducing the current required for cp.

Coatings include both organic and inorganic. Organic coatings include enamels, hot applied mastics, cold liquid coatings, hot applied waxes, cold applied waxes, prefabricated films and tapes, and extruded plastic coatings. Inorganic coatings such as enamel or epoxy paints offer a temporary yet generally sufficient solution to corrosion problems. Metallic coatings, such as nickel plating are generally not appropriate for oilfield application except in rare instances.

Internal coatings are achieved on steel storage tanks by the oil that lines it, while wells that produce oil by pumping are often protected inadvertently though the coating of oil or paraffin generally observed due to stuffing box leaks.

Coatings - Surface Equipment Painting: Coatings for cp for most surface equipment generally includes the application of primer and paint. Stripper oil and gas operators typically utilize various primer and paint systems to combat corrosion on most metal surface equipment surfaces like wellheads, separators, dehy's, and fluid storage tanks. Coatings should be formally inspected annually, while well tenders should casually inspect the facility with every visit. Any coating defects should be addressed as soon as possible to minimize the effects of corrosion or noted for the annual maintenance program. Once a surface facility has been properly coated, repainting should not be necessary for at least five to ten years except in extreme conditions.

Painting is the oldest and most widespread means of combating corrosion, but cannot be considered as a cure-all. Enamel paints should be selected to suit the particular corrosion conditions affecting the structure to be protected. The most important aspects of painting are surface preparation, product selection, and proper mixing.

The first and most important step in painting is surface preparation. Painting industry standards call for solvent cleaning, hand tool cleaning, power tool cleaning, white metal cleaning, commercial blast cleaning, brush off blast cleaning, pickling, near white metal blast, power tool to clean metal, water jet cleaning, or industrial blast**.** ***However, stripper well operators should ensure that surface are clean, free of oil and grease, all loose mill scale, rust, paint removed by scraper or wire brush, and that the surface is dry.*** High-pressure portable steam cleaners have also been found to be appropriate for use in the field for hard to clean areas.

The second step is product selection. Stripper well operators often use exterior enamel paints supplied by local oilfield equipment suppliers. Typical oilfield paints include Rustoleum, Tnemec Alkalyd Enamel, and Vangaurd Tank and Rig Paint (Miller Supply).

The third step in painting is proper mixing of the paint. The manufacturer's instructions should be carefully followed since inadequately mixed or improperly thinned paint will result in greatly reduced protection. Paints of good quality give satisfactory results because the manufacturer has properly proportioned the pigment and vehicle.

Summer student help is often used by stripper well operators to achieve adequate, affordable, corrosion protection through painting by brush or roller. Two days are generally required to complete painting for most facilities with a two-man crew; day one for surface preparation, day two for paint application. A third day may be required for wells with pumping units or tank batteries with more than two tanks.

Corrosion Resistant Materials: Corrosion resistant materials can be non-metallic or corrosion resistant alloys. Materials utilized for stripper well applications include plastic, stainless steel, and fiberglass, while plastic is the predominant product of choice for both fluid storage tanks and pipeline material.

The primary use of plastic is in pipelines either as original material, complete replacement, or as a liner inside of existing pipelines. General limiting factors in applying plastic are its maximum pressure rating, temperature rating, susceptibility to damage during installation, or damage by offset construction.

Sliplining, or plastic pipe insertion renewal, is a cost effective method of providing mechanical integrity to a gas gathering system affected by corrosion. A brief summary of the Plastics Pipe Institute Pipeline Rehabilitation by Sliplining with Polyethylene Pipe is presented in the Gathering-Production Line Section.

Plastic tanks are utilized for the storage of produced brine, but not recommended for the storage of any produced hydrocarbons. Plastic tanks are often painted to further minimize degradation by ultraviolet rays. Plastic tank guidelines are provided in the Production Tank Section.

Plastic is also utilized for lining tubing or coating packers in corrosive downhole environments or for saltwater disposal applications. Stainless steel needle valves are used extensively throughout the industry for pressure gauges. Fiberglass use has diminished due to the limited number of manufacturers and the superior attributes of plastic.

Dielectric Isolation
Insulating joints are used to break the metallic path, thereby interrupting current flow, and are typically inserted as insulating flanges or unions between protected and unprotected pipelines. This type of corrosion control is utilized to limit cp, reduce the effects of stray currents, and to separate dissimilar metals. Insulating joints are typically a requirement by most gas transmission companies between transmission lines and a stripper well operator's gas gathering system. Above ground facilities may act as cathodic current gathering areas for the outsides of well casings and can be protected utilizing isolation unions.

Chemical Inhibitors
Inhibitors slow or prevent corrosion related chemical reactions and are typically added in small concentration as oxygen scavengers, passivators, and biocides. Inhibitors are generally grouped by mechanism as passivating, vapor phase, cathodic, anodic, film forming, neutralizing, organic, precipitating, volatile, and reactive. Inhibitors can be oil soluble, oil soluble brine dispersible, water-soluble, oxygen scavengers, or surfactant based. Application areas include tubing, gathering systems, water disposal lines, oil or water storage tanks, and gas sweetening or dehydration units. Treatments are by batch every two weeks to three months, or by continuous injection. Chemical treatments are generally applied for internal corrosion control, but can be effective on external corrosion control of wells with H_2S on the 4 ½ x 8 5/8" annulus.[i]

N. Corrosion Economics
Every investment made by stripper well operators should be considered carefully. The cost of applying corrosion mitigation methods to existing facilities should be weighed against the structure replacement cost, risk of spills, product loss, associated fines, safety of personnel, and potential litigation.

O. Corrosion Training
It is recommended that operators provide training in corrosion identification and mitigation. Stripper well operators can develop in-house expertise for their employees through the West Virginia University Appalachian Underground Corrosion Short Course held in May each year at the West Virginia University in Morgantown, West Virginia. Three days of training costs approximately $500 for registration, materials, and room and board. NACE corrosion technician certification can be achieved over a period of three successive years. Additional information on the course can be found at www.aucsc.com. Additional materials are available from www.corrosionsource.com, www.corrosion-doctors.org, or www.hghouston.com/services_5.html.

Section II - Where to begin

Once an operator has a general understanding of corrosion, its effects, and possible mitigation methods, the next question is generally "how do I get started?" Since stripper well operators cannot usually afford to implement an immediate corrosion mitigation program on all production operation areas, it is necessary to establish a review – prioritization procedure. Prioritization considerations include identifying: high value wells or gathering systems, corrosion mitigation methods, corrosion correction methods, associated costs, previous corrosion areas, desired facility life, environmentally sensitive areas, significant potential for harm wells, i.e. H2S wells, and wells located in well-populated areas.

A quick overview of all stripper well common corrosion areas is provided as page 21, see Stripper Well Corrosion Mitigation Summary by Corrosion Area. The second page provides an outline to develop an in-house corrosion mitigation program. The third page is a form to utilize in performing annual field reviews. The remaining pages address each major stripper well corrosion area with the major sections are bolded with associated decision trees, procedures, and forms listed accordingly. An index is provided on page 18 listing the individual sections for ease of use. Each major section summary provides a general discussion, identifies the associated common corrosion areas, corrosion identification methods, corrosion repair or replacement methods, corrosion mitigation methods, decision trees, and procedures.

The appendix provides a dictionary of corrosion related terms, a list of "Recommended Web Sites for Corrosion Information", a list of Links for Vendor Information for Various Corrosion Related Products, Recommended Sources of Information,

The remainder of this procedure guide provides information directly related to the identification and treatment of corrosion in the most common areas of stripper well operations including production casing, tubing, wellheads, separators, production storage tanks, and pipelines. While the overall subject of corrosion is complex, for stripper well operators the process can oftentimes be simplified to the proper application of planning, painting, and plastic.

The development of a corrosion mitigation program will ultimately result in the prioritized repair and maintenance of equipment vital to the continued operation of most stripper wells. Properly maintained equipment results in higher profitability, higher resale value, reduced problem solving time, reduced environmental risks, and reduced safety risks.

A second index is provided for procedure guide ease of use on the following page.

Section II Getting Started Forms

Stripper Well Corrosion Mitigation Summary by Corrosion Area

I. Production Casing

- Cover potentially corrosive zones during primary cementing
- Treat annular areas with chemical H_2S inhibitor where appropriate
- Paint top joint and maintain coating
- Minimize standing water in packing area
- Repair surface leaks according to methodology provided
- Repair downhole leaks according to methodology provided

II. Tubing

- Paint top joint and maintain coating – after each pulling
- Coat bright metal wrench marks with spray paint as temporary coating
- Replace top joints according to methodology provided
- Consider plastic lined tubing or fiberglass for saltwater disposal
- Minimize storing used tubing for extended periods of time
- Store tubing on elevated racks and lubricate threads

III. Wellheads

- Paint and maintain coating
- Eliminate leaks; replace, tighten, or tape threaded connections
- Paint exposed sections of field cut threads –spray paint if necessary
- Minimize soil and fluid accumulation around wellhead
- Work valves and lubricate fittings regularly to ensure continued operation
- Valve wellhead outlets to minimize interior oxygen exposure

IV. Separators, Production Units, Gas Dehydrators, and Meters

- Paint and maintain coating
- Eliminate leaks; replace, tighten, or tape threaded connections
- Keep control covers in place and closed / Maintain controls
- Repair vessel coating scratches promptly with spray paint
- Purge interior with carbon dioxide and seal outlets for long term storage

V. Production Tanks

- Paint and maintain exterior coating - Coat bottom with mastic or coal tar
- Set tanks to minimize scraping bottom coating vs. pushing with dozer
- Set tanks on pea gravel rather than sharp edged limestone
- Eliminate connection leaks - identify leaking tank bottoms through tank gauges
- Put two barrels of crude oil in steel brine storage tanks
- Replace steel brine storage tanks with plastic tanks

VI. Gas Gathering Systems

- Install plastic lines within pressure limitations
- Consider hot spot anodic protection for bare steel corrosive areas
- Slipline with plastic on corroded sections rather than removal and new installation
- Use variance reports and check meters to identify mechanical failures
- Set up main lines for pigging to reduce fluid and deposit build-up
- Get training at Appalachian Underground Corrosion Short Course

Form 1 - Decision Tree For Field Wide Corrosion Mitigation Plan Development

Phase I: Identify the Problem

1. Complete field review with well tender utilizing Form 2
2. Prepare well equipment inventory on spreadsheet
3. Prepare wellbore schematics for problem wells
4. Prepare map identifying wells, gathering system, and pipelines (type, size, and age)
5. Estimate average production per well, mcfdeq
6. Prepare gas sales variance report
7. Prepare leak, repair, or replacement summaries

Phase II: Measure the Problem

1. Sort wells by gathering system then by descending mcfdeq
2. Determine system priority by mcfdeq, variance, and environmental concerns
3. Review maps, schematics, and leak summaries
4. Utilize appropriate equipment decision tree form
5. Estimate costs for maintenance, repair, or replacement
6. Prepare economics by well and gas system

Phase III: Solve the Problem

1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon
3. Estimate annual budget for expenditures
4. Prepare repair schedule
5. Prepare maintenance schedule
6. Prepare replacement schedule

Phase IV: Monitor the Changes

1. Prepare monthly gas sales variance reports
2. Conduct weekly well tender meetings
3. Complete annual review of all facilities
4. Complete annual pipeline inspection
5. Document maintenance and repairs
6. Review pipeline repairs to identify trouble areas

Form 2 - Annual Corrosion Field Review Data Collection Sheet

I. General Information

Area of Inspection: Lease________________Pipeline____________Other______________

Inspection Completed by: __________________

Date of Inspection: _____-_____-________

II. Identification and Correction

Area	Extent**	Recommended Correction/Protection Method
Downhole – casing	______	____
Downhole - tubing	______	____
Wellhead - casing	______	____
Side Nipples/Valves	______	____
Top Joint - tubing	______	____
Pipeline	______	____
Valve, Master	______	____
Valve, Needle	______	____
Valve,____________	______	____
Valve,____________	______	____
Tank (210 bbl)	______	____
Tank (100 bbl)	______	____
Tank (50 bbl)	______	____
Fitting	______	____
Fitting	______	____
Fitting	______	____
Production Unit	______	____
Separator	______	____
Riser	______	____
Vent/Marker	______	____
Ladder	______	____
Lubricator, TPL	______	____
Plunger	______	____
Rods/Pump/Tbg	______	____
_________________	______	____

****Corrosion Extent – Minimal (Min), Moderate (Mod), Severe (Sev)**

III. Methods of Correction: Clean, Protect, Repair, Replacement

Clean	1. Scrape____	2. Wire Brush____	3. Sand____	4. Sand Blast____
Protect	1. Paint____	2.Prime____	3. Top Coat____	4. Insulate____
5. Flange____				
Repair	1. Clamp____	2. Plug hole____	3. Packer____	4.Tank bottom____
Replacement	Pipeline	1. Replace section____	2.Slipline____	
	Tank	1. Replace steel tank with used steel or plastic tank_______		

IV.Comment:____

____

____

____

Section III - Production Casing Corrosion Summary

General Discussion: Production casing generally experiences corrosion where exposed to environmental conditions, oxygen, H_2S, CO_2, and moisture. The loss of mechanical integrity in the top of joint of casing, typically near the packing area, causes multiple problems including loss of product and ceased production operations. Potential surface problems are identifiable by well tenders, but downhole problems are often gradual and not observed until mechanical failure occurs. Cased-hole logs can identify general casing conditions and potential trouble areas but are generally cost prohibitive for stripper well operators. Operators are best served by planning sufficient primary cement over potential trouble areas, maintaining chemical inhibitor programs, coating surface equipment, and providing training for well tenders in casing leak identification.

Common Corrosion Areas:

- Exterior at surface - At the surface near the packing area
- Exterior downhole - Just above top of cement
- Exterior downhole - Across from hydrogen sulfide bearing zones
- Exterior downhole - Across from coal bearing intervals

Corrosion Identification Methods:

- Visual surface inspection by well tender
- Loss of annular pressure or influx of additional fluid
- Discolored produced fluid – muddy, unusual odor such as rotten eggs (H_2S)
- Possible increased pressure on secondary string (intermediate or surface casing).
- Cased-hole logging Baker Hughes logging capabilities include
- Vertilog: 360° identification of internal and external corrosion
- Vertiline: Magnetic flux leakage for internal and external inspection of pipelines.
- Digital Magnelog – Identify multiple pipe string wall thickness changes

Corrosion Repair Methods

- Surface leak see Casing Repair Procedure 1
- Set Tubing and packer to isolate leak. See Casing Repair Procedure 2
- Mechanical casing patches – Expensive and results in loss of internal diameter
- Squeeze cementing of affected area - Costly and sometimes unsuccessful

Corrosion Mitigation Methods

- Provide cement sheath around pipe through corrosive interval with primary cementing.
- Chemical inhibition of annular fluids generally by batch treatment
- Casing metallurgy modifications to address H2S
- Cathodic protection: usually effective for wells less than 10,000'; estimated cost $5,000

Decision Trees

- Top Joint Casing Leak
- Downhole Production Casing Leak

Procedures

- Top Joint Casing Repair Procedure
- Downhole Casing Repair Procedure – tubing and packer

Form 3 - Decision Tree For Top Joint Production Casing Leak

Phase I: Identify the Problem (Indications of Failure)

1. Well tender observance of potential mechanical failure due to corrosion
2. Observance of physical sign of failure: gas leaking from casing at packing
3. Loss of pressure on tubing and tubing casing annulus
4. Loss of production; unable to remove fluids

Phase II: Measure the Problem

1. Estimate production loss
2. Review repair history
3. Estimate remaining reserves
4. Estimate cost of repair or replacement: See Casing Repair Procedure 1

Phase III: Solve the Problem

1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon
3. Prioritize work based upon economic benefit

Phase IV: Monitor the Changes

1. Monitor post workover production
2. Compare results to predicted production and expenditure
3. Maintain mechanical integrity by periodic painting

Production Casing Surface Corrosion Repair Procedure

- Produce well to line pressure prior to moving in rig, then vent to tank
- Precut and bevel equivalent weight/foot 4 ½” casing (6” to 1’of casing and collar)
- Move in and rig up service unit. Set out appropriate safety equipment
- Conduct safety meeting, identify location hazards, review well information and objectives, modify plan to maximize safety and repair results
- Check pressure on 8 5/8” x 4 ½” annulus, safely vent to atmosphere away from well head
- Remove top ring of wellhead (8 5/8” x 4 ½”)
- Trip out of hole with all or part of tubing. May want to check total depth of well
- Make up landing joint (8’ to 10’) of tubing and compression packer
- Place precut 4 ½” nipple over setting joint of tubing with packer
- Set 4 ½” compression packer at approximately 2’ below top of 8 5/8” x 4 ½” ring
- Load annulus above packer between tubing and 4 ½” casing to ensure packer setting
- Vent 4 ½” casing gas below packer through tubing to atmosphere to production tank
- Remove top split ring, rubber packing, and bottom split ring in 8 5/8” x 4 ½” head
- Reinstall rubber packing and put small amount of water on top to ensure good seal
- Mark 4 ½” casing to cut below corroded area
- Use cutting torch to cut, split, and removal damaged area - be prepared for possible fire
- Prepare new cut for welding by first grinding then beveling
- Weld precut 4 ½” nipple with collar to prepared cut
- Modify split rings as necessary to reinsert around 4 ½” casing due to additional weld
- Reinsert bottom split ring, packing rubber, and top ring
- Put on top ring and tighten
- Release and pull packer
- Trip in hole with tubing to appropriate depth*
- Swab as necessary to kick off well. Return well to production and maintain

Estimated costs to repair corrosion-impacted wellhead

Service rig and crew	__ hours @ __ per hour	$________
Dozer	__ hours @ __ per hour	$________
Packer (Baker R4)		$________
Supervision		$________
Reclamation		$________
Total		$

**May want to consider checking TD, sand pumping, and swabbing while rig is on location

Form 4 - Decision Tree For Corrosion Mitigation – Downhole Production Casing

Phase I: Identify the Problem (Indicators of Mechanical Failure)

1. Decreased gas production by chart observation or integration volumes
2. Well loaded up with fluid: verify with echometer
3. Overall increased produced fluids: tank measurement
4. Increased pumping time required to maintain production
5. Hydrogen sulfide odor: Check concentration with caution
6. Discolored produced fluids
7. Pressure loss on tubing and/or tubing-casing annulus
8. Change in chemical analysis of produced fluids

Phase II: Measure the Problem

1. Compare well condition to previous or offset well experience
2. Estimate top of cement
3. Confirm or determine appropriate fluid removal method*
4. Estimate cost of tubing-packer installation for remedial action
5. Estimate remaining reserves / production potential by pressure and decline curve analysis

Phase III: Solve the Problem

1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon
3. See downhole casing repair procedure
4. Prioritize work based upon economic benefit

Phase IV: Monitor the Changes

1. Monitor post workover production
2. Compare results to predicted
3. Continue corrosion inhibitor program in casing and casing-tubing annulus fluids

*Installation of packer and tubing may necessitate change of production method, installation of a second string of tubing, or pumping unit and slim hole rods.

Downhole Casing Repair Procedure: Utilizing tubing and packer to isolate hole in casing

- Produce well to line pressure prior to moving in rig, then vent to tank
- Move in and rig up service unit and required equipment
- Conduct safety meeting, identify location hazards, review well information and objectives, modify plan to maximize safety and repair results
- Check pressure on casing tubing annulus, then vent to tank
- Trip out of hole with tubing and check total depth of well
- Trip in hole with seating nipple and tubing
- Set packer approximately 100' above estimated top of cement with sufficient tail joint(s) according to preferred placement to perforated interval(s)
- Swab to ensure proper packer placement (check annular pressures)
- Run additional tubing and rods if necessary
- Swab as necessary to kick off well
- Return well to production and maintain

Form to estimated cost to repair corrosion-impacted wellhead

Service rig and crew	__ hours @ $__ per hour	$ _______
Dozer	__ hours @ $__ per hour	$ _______
Packer		$ _______
Supervision		$ _______
Reclamation		$ _______
Tubing (second string for optimized tbg plunger)		$ _______
Rods		$ _______
Pump		$ _______
Pumping Unit		$ _______
Roustabout	__ hours @ $__ per hour	$ _______
Total		**$ ________**

Section IV - Tubing Corrosion Summary

General Discussion

Tubing corrosion is often found at the exterior of the top joint in the packing area, on the interior and exterior of used tubing left on the surface for extended periods of time, and downhole in corrosive environments associated with enhanced oil recovery or H_2S. Stripper wells operators often utilize used strings of tubing and rods due to the economic benefits of used equipment.

Common Corrosion Areas

- Exterior at the surface in the packing area
- Interior in the string in salt water disposal wells or enhanced recovery wells
- Interior in pumping wells where rods wear the same tubing areas continuously

Corrosion Identification Methods

- Well tender observance of potential mechanical failure due to corrosion
- Decrease in overall production (oil, gas, and water)
- Decrease in casing pressure
- During regular servicing
- Pressure test with tubing plunger set in seating nipple (wet string)

Corrosion Repair or Replacement Methods

- General treatment is to replace affected joint(s) upon visual inspection

Corrosion Mitigation Methods

- Chemical Inhibition by batch, plastic tube, or continuous injection with pump
- Plastic lined tubing
- Fiberglass tubing
- Minimize used tubing storage time on racks due to exposure to oxygen
- Store tubing on racks as well for extended storage and grease threads

Decision Trees

- Top Joint Tubing Leak

Procedures

- Not applicable

Form 5 - Decision Tree For Top Joint Tubing Leak

Phase I: Identify the Problem (Indications of Failure)

1. Well tender observance of potential mechanical failure due to corrosion
2. Observance of physical sign of failure
3. Loss of pressure
4. Loss of production

Phase II: Measure the Problem

1. Estimate production loss
2. Review repair history
3. Review wellbore schematic
4. Review remaining reserves
5. Estimate cost of repair or replacement

Phase III: Solve the Problem

1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon
3. Prioritize work based upon economic benefit

Phase IV: Monitor the Changes

1. Monitor post workover production
2. Compare results to predicted production and expenditure
3. Continue maintenance program of periodic painting to minimize future failures

Section V – Wellhead Corrosion Summary

General Discussion

Wellheads suffer from corrosion due to harsh operating environments experienced during drilling, completion, and operations. Wellheads should be cleaned and painted after surface facility installation is complete. Soil should be cleared from the wellhead to elevation grade minimizing fluid accumulation, exposing all valves or outlets. Outlets should be equipped with valves to minimize oxygen exposure. Only the surface exposed portions of the tubing and casing strings generally require maintenance due the diminished pressure requirements over time. Even small connection leaks are detrimental and should be repaired quickly. Field cut threads and wrench marks will become anodic and therefore should be painted. Valves should be operated regularly to ensure continued ease of operation.

Common Corrosion Areas

- Un-cemented intervals bearing H_2S
- Un-cemented coal bearing intervals
- Packing area - top joint tubing or casing corrosion
- Outlet threads without valves

Corrosion Identification Methods

- Visual weekly inspection by well tender
- Annual formal inspection of facility
- Loss of wellhead pressure
- Visual of gas leaking at surface
- Loss of overall production
- Increase in fluid production
- Unusual odor at wellhead – H_2S Leak

Corrosion Repair Methods

- **See production casing surface repair procedure**

Corrosion Mitigation Methods

- Paint after removing all loose paint, oil, and grease.
- Remove soil from around the wellhead down to surface casing – provide proper drainage
- Put plugs and valves in all open threads with proper lubrication
- Operate all valves on a regular basis
- Lubricate fittings on a regular basis
- Tighten leaking fittings
- Use dielectric insulation flanges

Decision Trees

- Not Applicable

Procedures

- See top joint tubing and casing repair procedures

Section VI - Separators, Production Units, Gas Dehydrators, and Meters:

General Discussion
While interior corrosion is difficult to identify, exterior corrosion troubles generally occur where connections leak over time or around heater tubes. Production unit controls should be kept covered for maximum life. Covers or sealing gasket replacement should be considered for gas orifice and positive displacement meters.

Common Corrosion Sources
- Vessel exteriors
- Interior
- Leaking connections
- Fire tube area

Corrosion Identification Methods
- Visual inspection of exterior corrosion
- Interior corrosion difficult to identify, possibly caused by H2S, or Carbon Dioxide
- Weekly well tender visual inspection
- Annual formal facility inspection

Corrosion Repair Methods
- Replace frozen valves
- Operator will need to decide when to field repair or shop repair extensive corrosion

Corrosion Mitigation Methods
- Primer and paint on shop coat initially, then maintain coating
- Promptly paint all scratches (spray paint ok)
- Maintain production unit control covers
- Employ sealing compound on all connections and make up tight
- Plug outlets and purge vessels pulled from service with nitrogen or carbon dioxide
- Review anode status of production units so equipped

Decision Trees
- Not Applicable

Procedures
- Not Applicable

Section VII - Production Tank Corrosion

General Discussion

Production storage tanks are generally constructed of steel, plastic, or fiberglass. Steel tanks provide excellent storage for crude oil and brine especially when combined with a well-maintained exterior coating. Leaking tanks cause multiple problems including ceased production, loss of product, use of resources, and associated environmental penalties. Plastic and fiberglass tanks degrade and become fragile with time, while buried cement vaults can crack and leak.

Common Corrosion Areas

- Exterior bottom of tank – environmental conditions and coating
- Interior of the top load line – water and oxygen
- Interior of steel brine storage tanks due to oxygen aggravated by chlorides
- Exterior heater tube areas
- Exterior near saltwater leaks, drains and general exterior
- Exterior where operator identification or product warning labels have parted from tank
- Exterior tank tops from splash due to separator or well unloading

Corrosion Identification Methods

- Visual through oil, water or excessive corrosion
- Tank gauges variances identified by well tender
- Production report variances identified by production manager
- Determine soil resistivity
- Complete annual inspections of facilities

Corrosion Repair Methods

- Remove from service and transfer to storage yard where multiple tanks can be repaired
- Purge tank with nitrogen or carbon dioxide prior to cutting or welding
- Seal tank heater tubes by welding shut, when they begin leaking
- Suitable fire and safety equipment at the location
- Repair tanks by welding on patch, or replacing entire bottom of tank

Corrosion Mitigation Methods

- Paint with top coat and maintain coating:
- Coat bottom and 1 foot of the sides with coal tar epoxy (mastic) prior to putting in service
- Use pea gravel or sand rather than sharp edged limestone for base material
- Set tanks slightly above grade in dike without dozer to avoid damaging coating
- Limit standing water in dikes and eliminate brine discharge on dike interior
- Put 1 to 2 barrels of crude oil in steel tanks for brine only wells
- Eliminate vegetation (moisture) from around bottom edge of tank
- Utilize plastic tanks for brine storage
- Consider Cadwelding (4) 17# magnesium anodes at NESW positions

Decision Trees

- See Production Storage Tank Decision Tree

Procedures

- See Production Storage Tank and Plastic Tank Considerations

Form 6 - Decision Tree For Corrosion Mitigation – Production Storage Tanks

Phase I: Identify the Problem (Indicators of Mechanical Failure)
1. Significant exterior corrosion
2. Brine or crude oil at the exterior of the tank
3. Decreasing tank volume based on tank gages
4. Static tank volume with normal gas production

Phase II: Measure the Problem
1. Estimate product loss
2. Review repair history
3. Estimate associated remaining reserves
4. Estimate cost of repair or replacement: See Tank Repair and Replacement Options*

Phase III: Solve the Problem
1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon:
3. Prioritize work based upon economic benefit

Phase IV: Monitor the Changes
1. Monitor post remediation production
2. Compare results to predicted production and expenditure
3. Eliminate any connection leaks
4. Maintain mechanical integrity by periodic painting (enamel or epoxy based paints)
5. Complete annual inspection of surface facilities

***Tank Repair or Replacement Options**
1. Repair tank on location
2. Remove tank and repair off site, return to service
3. Replace steel tank with (smaller) plastic tank
4. Remove and do not replace, if no longer necessary

Production Storage Tank Considerations
Plastic
1. Size tank appropriate to production
2. Tanks can be set on clay, sand, or gravel
3. Utilize manufacturers suggested method for hook up
4. Paint tank to minimize Ultra Violet degradation
5. Utilize tanks for brine storage only as recommended
6. Mechanical integrity may diminish through aggressive direct blow downs to tank.

Steel
1. Size tank appropriate to production
2. Coat bottom of tank and 1' of sides with coal tar or mastic
3. Paint remaining surface with top coat after setting tank ASAP
4. Add 1 to 2 barrels of crude oil to insulate interior of tank of brine only wells
5. Tank labels encourage corrosion once the top has become dis-bonded allowing moisture to collect. Replace as necessary, especially when repainting.

(Steel Tank Dimensions) 100 barrels - 8'6" diameter x 10', 210 barrels– 10' diameter x 15'

Plastic Tank Summary

Norwesco, Snyder, and Poly Processing Company manufacture oilfield brine storage tanks. Plastic tanks should be painted to reduce Ultra Violet (UV) ray degradation. Crude oil should not be stored in plastic tanks since it will degrade and soften the tank. The limited warranted is three-year service life while many tanks under normal use exhibit ten to fifteen year lives. The maximum continuous temperature is 100° F and the maximum pressure is atmospheric. Most tanks are translucent although they are available in solid green or black. All tanks are of one-piece construction from linear or cross-linked High Density Polyethylene (HDPE) plastic.

Safety Checklist (after Poly Processing Company)

- Confirm storage product compatibility with type of PE tank and fittings
- Maintain atmospheric pressure through adequate tank ventilation
- Protect tank from over pressurization by tanker trucks and fill line purging
- Prevent excessive heat near or inside tank. Maximum continuous temp 100° F
- Have and use Material Safety Data Sheets (MSDS) for product being stored
- Regard tanks as confined spaces and follow proper entry procedures
- Secure ladders properly at top and bottom with only one person on a ladder at a time
- Avoid standing on the slippery and flexible tank domes (no weight load rating)
- Never move tanks while holding liquid
- Never allow personnel under tank when it is being lifted

Installation Checklist (after Poly Processing Company)

- Remove and check the uninstalled parts typically shipped inside the tank
- Locate the tank wisely to facilitate servicing and minimize expenditures
- Protect personnel from chemical danger in the event of a leak
- Protect the tank from traffic damage and excessive heat (100° F maximum)
- Tanks are designed for aboveground use only
- Use adequate secondary containment according to governmental requirements.
- Use Teflon tape, paste, or both at all threaded connections. Do not over tighten.
- Use flexible, hose type connections to preserve warranty. Flexible hoses allow for tank expansion and contraction, and reduce pump and piping vibration stress on the tank.
- Support hoses, piping, and valves using structural support independent of the tank sidewall and dome.
- Fully support the entire bottom of the tank on a clean smooth concrete foundation or in a PPC approved metalwork. Failure to provide proper foundation and support constitutes a misuse of the tank and will void your warranty.
- Fill the usable capacity of the tank with water and hydro test for 24 hours after installation, prior to product being introduced to ensure tank and fitting integrity.
- Install appropriate and required warning labels.
- Tanks should be inspected on a routine scheduled basis and findings reported

Section VIII - Natural Gas Gathering Lines and Oil Production Lines

General discussion

Corrosion in natural gas gathering lines and production lines results in the loss of saleable product, spill cleanup time, environmental liabilities, and the cost of repair or replacement. Unfortunately, many stripper well lines are not coated or cathodically protected, and gathering system information is not well documented. Gathering system components and modifications should be documented and mapped.

Common Corrosion Areas:

- Externally, where pipelines exit or enter the ground
- External where soil types or conditions are conducive to corrosion
- Internally, where fluid remains stagnant, for example, in low-lying areas.

Corrosion Identification Methods:

- Well tenders, landowners, and domestic gas users.
- Production variance reports (Comparison of master meter to total of individual meters)
- Use of line pressure monitoring and check meters
- Physical signs: odor, hissing, bubbling, dead vegetation, fire, and moist field dry spots
- Oil spills are generally identified as seepages or as rainbow sheens
- Use of gas detectors and scheduled pipeline inspections
- Installing pipe to soil potential test stations even if no cp is installed
- Utilize corrosion coupons from chemical companies for internal corrosion
- Close interval resistivity surveys for trouble areas
- Document historic pipeline problems

Corrosion Repair Methods

- Clamps: Inexpensive but possible additional damage due to oxygenated soil
- Section replacement for bare steel: beware galvanic corrosion due to new pipe-old pipe
- Plastic replacement: inexpensive, low-pressure limitation
- Sliplining existing steel lines with plastic
- Fiberglass: Expensive
- Fiberspar: Glass fiber reinforced epoxy laminated pipe rated for 200 to 750 psi, can be spooled up to four miles; typically not for stripper well operators

Corrosion Mitigation Methods

- Map the system
- Document all repairs and replacements
- Hot spot protection for old bare steel lines in aggressive soil conditions

Decision Trees

- Pipeline or Production Line Leak Decision Tree

Procedures

- Gas Gathering System Identification and Review Steps
- Sliplining Procedure
- Plastic Pipe Pressure Rating Guide

Gas Gathering System Identification and Review Steps

- Identify entire system of wells and pipeline on section township map
- Identify the following
    - Size and lengths
    - Construction material(s) (plastic, steel, coated, protected)
    - Installation dates
    - Cathodic Protection or coatings
    - Valves
    - Meters
    - Compressors
    - Drips
    - Domestic Gas Users
- Document work or replacement history
- Prepare topographic and line drawing – very important!
- Collaborate with superintendents, well tenders, roustabouts, and installers
- Field review system starting with most important systems first, greatest mcfd
- Walk system sections with global positioning system, (Garmin GPS 12), line locator, flagging tape, and leak detector: noting all gps readings in notebook.
- Utilize gps to identify valves, road crossings, leaks, and potential trouble areas
- Download GPS data to Terrain Navigator software or equivalent
- Update maps based upon field review
- Field review annually and update maps
- Continue to document all pipeline work

Instrumentation

- Gas sniffers
- Global Positioning Systems (GPS)
- Two terminal resistivity determination
- Four terminal resistivity determination, Wenner method
- AC Soil rod, typically copper sulfate
- Pipeline locator

Brief History of High Density Polyethylene Pipe:
High-density polyethylene pipe, or HDPE, has become a significant part of the in the fight against corrosion. According to the American Gas Association, in 1965 there was only 9,200 miles of plastic pipe being used, 10% of the total pipe utilized for pipelines, while five years later the number grew to 45,800 miles. By 1982, there was 215,000 miles, with greater than 500,000 miles in 1996, over 90% of the total pipe utilized for pipelines. According to the Plastic Pipe Institute (PPI), HDPE has lower life cycle costs including corrosion resistance, leak tight, lower instances of repair, and maintains optimum flow rates.

Personnel and contractors who install or repair, HDPE, should be familiar with the proper methods for installation and fusing. Black HDPE pipe contain at least 2% carbon black and will resist damage from sunlight. Other colored products are compounded with antioxidants, thermal stabilizers, and UV stabilizers, but these UV stabilizers will eventually deplete, therefore, non-black should not remain in unprotected outdoor service for more than 2 years. Plastic pipe has limitations but many can be overcome with proper markers (surface and underground), proper application, and pressure relief valves.

Form 7 - Decision Tree Form for Pipeline or Production Line Leak

Predicting pipeline failure is difficult for most stripper well operators since most methods of evaluating pipeline integrity are cost prohibitive. Operators should utilize detailed map preparation, scheduled line monitoring, production variance reports, and installing plastic lines whenever possible. The pressure limitations associated with plastic are generally sufficient for most low-pressure stripper well repairs or replacement. Plastic pipe is appropriate for new well installation with proper pressure control or pressure relief devices.

Phase I: Identify the Problem (Indicators of Mechanical Failure)

1. Decrease in fluid production (production line leak). Tank gauge.
2. Decrease in gas production: chart review
3. Decrease in line pressure
4. Significant variance of individual meter(s) to master meter (>5%)
5. Observance of physical sign (see Physical Signs of Gas Leak)
6. Review map, known, and documented histories of previous pipeline trouble areas
7. Utilize gas detection equipment

Phase II: Measure the Problem

1. Estimate production loss
2. Review pipeline repair history
3. Review map of gathering system
4. Review options for repair*
5. Estimate cost of repair or replacement

Phase III: Solve the Problem

1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon
3. Prioritize work based upon economic benefit

Phase IV: Monitor the Changes

1. Monitor post workover production
2. Compare results to predicted
3. Note pipeline changes to map
4. Analyze pipeline systems for upgrade potential to minimize future failures

***Pipeline Repair Options**

- Clamp
- Small section replacement with plastic
- Small section replacement with steel (coated on uncoated)**
- Large section replacement with plastic
- Slip lining existing steel line with reduced id plastic (See slip lining procedure)

**Consider using anodes for hot spot protection on leak areas
**Consider installation of pipe to soil test stations when repairing existing steel pipelines

Pipeline Rehabilitation by Sliplining with Polyethylene Pipe (after Killebrew, Inc. and Institute Forms Technologies)

Sliplining is an economical method of restoring structural integrity to corroded pipes, and is suitable for water mains, sewers, gas mains, industrial plants, and storm water lines. Sliplining involves installing a new, factory-manufactured pipe inside an existing deteriorated pipe. With sliplining, it is possible to repair long lengths of pipe and negotiate slow bends with this process. High-density polyethylene thermoplastic pipe (HDPE) is commonly used for pipes up to 48 inch in diameter and fiberglass reinforced polyester pipe (FRP) for larger pipes. Sliplining requires the old pipe to be in sufficient condition to withstand having a new pipe inserted without collapsing or moving. The gas industry has been inserting polyethylene (PE) pipe into deteriorating gas mains for many years.

During sliplining installation, excavations are made for an insertion pit and at each lateral or tie in location. The liner, usually fused lengths of P.E. pipe creating one continuous pipe, are then pushed into an existing larger pipe, or a winch cable can be inserted through the existing line and then pull the line through.

Sliplining advantages include:

- Ability to rehabilitate structurally unsound pipe
- Efficient alternative to removal and replacement, and minimizes surface disturbance
- Five hundred foot insertions are not uncommon
- Diameter reduction generally made up by improved flow of continuous plastic line

Sliplining disadvantages include:

- Reduced cross-sectional area
- Difficulty locating new leaks because the gas will not surface near the actual leak.

Design considerations include:

- Select the largest feasible diameter, normally 10% less than original internal diameter
- Determining a liner wall thickness
- Analyzing the flow capacity

Sliplining project steps include:

- Isolate and blow down the existing line
- Excavate and cut out sections at both ends of the pipe section and at any tie-ins
- Attach a tapered nosepiece to the front of the PE pipe to push or pull the pipe
- Insert the PE pipe into the existing pipe and begin pulling (or pushing)
- Proceed carefully due to unexpected bends, valves, or diameter changes.
- Provide insertion point protection to avoid damage as new pipe slides into existing pipe.
- Inspect first section for damage as liner pipe is through to the exit excavation.
- Make connection to existing system, purge system, pressure test, return to production

Most oilfield contractors are familiar with sliplining and should be able to assist stripper well operators with designing a replacement procedure. Pipeline construction companies are also familiar with slipline process but may be cost prohibitive for stripper well operators to use.

Plastic Pipe Pressure Rating Guidelines
This form was adapted from API Specifications LE and has been limited to those pipe sizes and SDR ratings that are generally appropriate for stripper well operators. The original chart is for sizes 1.25 inches through 54 inches and 255 psi, SDR 7.3, through 40 psi, SDR 41.0. Refer to supplier's guidelines for updated pressure ratings. The chart reflects the maximum allowable operating pressure in psig at 73.4 degrees F. Federal regulations limit the maximum allowable pressure for plastic pipe to 100 psig for natural gas.

Pressure design calculations are based on the following formula that relates the stress on the pipe wall to internal pressure. $P = (2xS/(SDR-1)) \times DF \times F$, where S equals the long term hydrostatic strength in psig, P equals the internal pressure in psig, SDR equals the standard dimensional ratio of D/t, D equals the outside diameter, t equals the minimum wall thickness, DF equals the design factor, and F equals the service factor.

Mueller's Formula For Gas Flow has been found to best describe smooth wall pipe flow like PolyPipe $Q = ((2826/G^{0.425}) \times (P_1^2-P_2^2/L)^{0.575} \times d^{2.725}$, where Q equals the gas flow rate in scf per hour, G equals the gas specific gravity, P_1 equals the pipe inlet pressure in psia, P_2 equals the pipe outlet pressure in psia, L equals the length of pipe in feet, and d equals the pipe internal diameter.

Plastic pipe experiences thermal expansion at a approximately 1 inch per 100 feet of pipe per 10° F change. Coiled lengths are available for ½" through 4", while straight lengths are available for ½" through 54".

PE 3408 Industrial Piping System: Pipe Data and Pressure Ratings for Natural Gas										
Pressure Rating		**SDR 7.3- Max 100 psi**			**SDR 9.0– Max 100 psi**			**SDR 11.0- Max 100 psi**		
Pipe Size	**Nominal OD**	**Wall, In.**	**Avg. Id**	**lbs/ foot**	**Wall, In.**	**Avg. Id**	**lbs/ foot**	**Wall, In.**	**Avg. Id**	**lbs/ foot**
0.500	0.840	0.115	-	-	0.093	-	-	0.076	-	-
0.750	1.050	0.114	-	-	0.117	-	-	0.095	-	-
1.000	1.315	0.180	-	-	0.146	-	-	0.119	-	
1.250	1.660	0.227	1.179	0.44	0.184	1.270	0.37	0.151	1.340	0.31
1.500	1.900	0.260	1.349	0.58	0.211	1.453	0.49	0.173	1.533	0.41
2.000	2.375	0.325	1.686	0.91	0.264	1.815	0.76	0.216	1.917	0.64
3.000	3.500	0.479	2.458	1.98	0.389	2.675	1.65	0.318	2.826	1.39
4.000	4.500	0.616	3.194	3.27	0.500	3.440	2.74	0.409	3.633	2.30
5.375	5.375	0.736	3.815	4.66	0.597	4.109	3.90	0.489	4.338	3.27
5.000	5.563	0.762	3.948	5.00	0.618	4.253	4.18	0.506	4.490	3.50
6.000	6.625	0.908	4.700	7.09	0.736	5.065	5.93	0.602	5.349	4.97
7.125	7.125	0.976	5.056	8.20	0.792	5.446	6.87	0.648	5.751	5.75
8.000	8.635	1.182	6.119	12.01	0.958	6.594	10.05	0.784	6.693	8.42
10.00	10.750	1.473	7.627	18.66	1.194	8.219	15.62	0.977	8.679	13.09
12.00	12.750	1.747	9.046	26.25	1.417	9.746	21.97	1.159	10.293	18.42

Form 8 - Pipeline Inspection or Leak Report
(After Oil and Gas Journal Corrosion and It's Control and USDOT Guidance Manual)

1,) Date: __________________ **2.) Reported by:______________________**
3.) Time: ___________AM/ PM **4.) Phone :(_______) - _______ - _______**

5.) Description of Leak: ____
6.) Gas System Name: ____
7.) Nearest Well or Tank: ____

8.) County: __________________Township: _________________ Section: _______________

9.) Directions from Nearest Intersection: ____
____

10.) Cause of Leak: ____
11.) Condition of Right of Way: Good / Fair / Poor
12.) Length of Line Exposed: __________ Feet **13.)** Pipeline Size: ____________ Inches
14.) Type: Steel/Plastic/Fiberglass **15.)** Pipeline Depth: __________ Feet
16.) Estimated Age of Line: _______Years **17.)** Normal Operating Pressure: ___ Psig
18.) Cathodic Protection/Coating_______

19.) Type of joints: Welded_______ Screwed__________ Other____________

20.) Type of Soil at Surface: Clay / Sandy / Loam (Black Dirt) / Cinders / Refuse

21.) Type of Soil at Pipeline Depth: Clay / Sandy / Black Dirt / Other

22.) Moisture Content: Dry / Damp / Wet

23.) Soil Packing: Loose / Medium / Hard

24.) Describe Pipeline Damage: ____
____
____

25.) External condition: Smooth________ Pitted___________ Depth of Pits__________

Corrective Action Taken:
26.) Pipeline Repair Made: Clamp / Joint Replacement / Section Replacement (____ Feet) /

27.) Line Replacement / Slipline with ______Inch Plastic/ Other_______________________

28.) Installation of Hot Spot Anodes? Yes / No / ____________________________________

29.) Comments:
____
____
____

Estimating Anode Requirements for Bare pipe or Hot Spot Protection

The basic principal of protecting hot spot areas is to apply protection where leaks are occurring. The time to install cathodic protection is at time of leak repair when the line is exposed, the labor is there, the equipment is there, and the cost for an anode and anode installation minimal. The application of anodes will generally be beneficial even without an associated soil resistivity or potential, with 17 # magnesium anodes generally appropriate. (From Pipeline Rules of Thumb Handbook). Operators who complete soil resistivity surveys may consider utilizing a hot-spot criteria of potentials more negative than –600 millivolts or soil resistivities less than 10,000 ohms.

A. Bare Pipe Protection Determination

Step 1 Determine Area of Pipe to be Protected

Calculation: Outside Diameter in Inches x Pi (3.1415) / 12 inches per foot

Example 1: Surface area of 2,000 ft of 4” ((4” x 3.14) / 12) x 2000’ = 2,093 sq ft

Example 2: Surface area of 2,000 ft of 2 3/8” ((2 3/8” x 3.14) / 12) x 2000 = 1,242 sq ft

Step 2 Determine Current Requirements - 1 milliamp per square foot – bare pipe

Example 1: 2,000 ft of 4” - 2,093 sq ft x 1 ma per sq ft = 2,093 milliamps

Example 2: 2,000 ft of 2 3/8” - 1242 sq ft x 1 ma per sq ft = 1,242 milliamps

Step 3 Determine Number of 17 lb. anodes required at assumed 100 milliamps per anode*

Example 1: 2,000 ft of 4” - 2,093 milliamps / 100 milliamps per anode = 20.9 anodes

Example 2: 2,000 ft of 2 3/8” – 1,242 milliamps / 100 milliamps per anode = 12.4 **anodes**

Step 4 Determine Anode Spacing

Example 1: 2,000 ft of 4” - 2,000 ft / 20.9 anodes = 96 ft

Example 2: 2,000 ft of 2 3/8” - 2,000 ft / 12.4 anodes = 161 ft

B. Hot spot protection:

To protect 100’ 4” line hot spot with a 100 milliamp output from 17 lb magnesium anode:

Area of each hot spot: ((4” line x 3.14) / 12) x 100 feet = 105 square feet

No. Anodes: 105 square feet x 1 ma per square feet / 100 ma per anode = 1.05 anodes

For 100’ of 2 3/8” line:

Area of each hot spot: ((2 3/8” x 3.14) / 12) x 100 feet = 62.1 square feet

No. Anodes: 62.1 square feet x 1 ma per square feet / 100 ma per anode = 1.00 anodes

A 17# anode will provide varying levels of protection depending on line condition and soil resistivity. The incremental cost for a 34 lb magnesium may be justified for some operators.

*For single anodes against fully protected pipe (not fully protected, higher current output)

C. Magnesium Anode Output Determination: (Remember that 3,000 ohm soil is a corrosive environment, therefore 1000 ohm soil is very corrosive.)

17 lb anode: 180,000 / soil resistivity: Example for 3,000 ohm soil; 180,000 / 3,000 = 60 milliamps (ma) current output from 17 lb. anode (4000 ohm = 45 ma, 2000 ohm = 90 ma, 1000 ohm = 180 ma)

34 lb anode: 195,000 / soil resistivity: Example for 3,000 ohm soil; 195,000 / 3,000 = 65 milliamps (ma) current output from 17 lb. anode (4000 ohm = 49 ma, 2000 ohm = 98 ma, 1000 ohm = 195 ma)

Pipeline Coating Repair Procedures: (After North Coast Energy)

- Repairing a nick or gouge in the coating
- Repairing a previously coated pipeline after a new weld
- Repairing coating after fittings.

Procedure 1: Repairing a Nick or Gouge in the Pipeline Coating Using Tape

- Clean pipe around the length of the damage and two to three inches on either side
- Remove all jagged edges and any distorted or potential disbonded areas
- Coat pipeline circumference with primer being careful to fill any voids, especially at the edges of the coating
- Start taping at one end, overlapping ½ of the width of the tape each wrap, while keeping constant tension (almost stretching) on the tape
- When finished wrapping, smooth down edges by hand to assure a good bond to the pipe
- Ensure that tape and primer are compatible. There are many tape manufacturers with various widths and thickness available. Not all primers and tape are compatible. Some thicker tapes for areas of stray current or have a plastic backing that has to be removed prior to application.

Procedure 2: Repairing a Previously Coated Pipeline After a New Weld Using Tape

- Wait for the weld to cool, then clean scale off the weld
- Trim the old coating back to good smooth coating and then clean pipe of any dirt or debris back to the clean coating
- Apply primer to all new and cleaned areas to be coated, or over 3" of previously taped, good coating
- Start taping over the previously taped, primered area, overlapping ½ of the width of the tape with each wrap, while keeping tension (almost stretching) on the tape
- When finished wrapping, smooth down edges by hand to assure a good bond to the pipe

Procedure 3: Repairing Coating After the Installation of Fittings Using Tape

- Trim all the old coating back to good smooth coating, and then clean the pipe of any dirt or debris back to the clean coating
- Apply primer to all new and cleaned areas to be coated. In addition, apply primer over 3" of previously taped, good coating
- Plan the application of the tape to avoid wrinkles. It is necessary to have the tape smooth on all surfaces for maximum effectiveness.

Section IX - Appendix

Abbreviations and Definitions
Recommended Web Sites for Corrosion Information
Vendor Links for Information on Corrosion Related Products
Recommended Sources of Information
Paint Information and Guidelines

Abbreviations

CP	Cathodic Protection
EMF	Electromotive Force
AST	Aboveground Storage Tank
UST	Underground Storage Tank
MIC	Microbiologically Induced Corrosion
CRA	Corrosion Resistant Alloy
ma	milliamps
ohm-cm	ohm-centimeters

Definitions

Active or Active Metal - A state in which a metal tends to corrode(opposite of passive or noble).
Alkaline - pH greater than 7
Alkyd – Type of resin formed by polyhydric alcohols and polybasic acids
Alloy – Combination of any two elements when at least one is a metal
Ammeter - An electronic instrument for measuring the magnitude of electric current flow.
Anaerobic – Absence of air or un-reacted or free oxygen.
Anode – Positively charged electrode of electrolytic cell where oxidation (corrosion) is the principle reaction.
Atmospheric corrosion - Gradual degradation of a material by contact with substances present in the atmosphere, such as oxygen, carbon dioxide, water vapor, sulfur, and chlorine compounds.
Backfill - Material placed in a drilled hole to fill space around anodes, vent pipe, and buried components of a cp system.
Bare lines – Unprotected steel lines with no coating, sacrificial anodes, or impressed current.
Base - A chemical substance that yields hydroxyl ions (OH-) when dissolved in water.
Bimetallic or Galvanic Corrosion - Corrosion resulting from dissimilar metal contact.
Biological corrosion - Metal deterioration due to metabolic activity of microorganisms, such as Sulfate Reducing Bacteria or SRB's.
Cathode – (opposite of anode) The electrode of an electrolytic cell at which reduction is the principal reaction and electrons flow toward the cathode in the external circuit. Typical cathodic processes are cations taking up electrons being discharged, oxygen being reduced and the reduction of an element or group of elements from a high to a lower valence state.
Cathodic protection, or CP - A technique to reduce the corrosion rate of a metal by making it the cathode of an electrochemical cell. Accomplished utilizing paint, coatings, anodes, or ground beds and impressed current systems. Current systems use a negative charge to prevent corrosion.
Cation - A positively charged ion that migrates through the electrolyte toward the cathode under the influence of a potential gradient. See also anion and ion.
Cavitation corrosion –Cavitation caused by severe turbulent flow often leads to cavitation damage: May include loss of material, surface deformation, or properties or appearance changes.
Chloride – Major inorganic ion in all produced water acting as an electrolyte in the corrosion cycle. The greater the chlorides the higher the conductivity.
Copper Sulfate Electrode, CSE, or half-cell - Comprised of a piece of copper, a saturated solution of copper sulfate, and a porous membrane. The line of continuity goes from instrument to copper, copper to copper sulfate, copper sulfate to (salt bridge) to soil. (Farwest Corrosion Co.)
Corrosion - The chemical or electrochemical reaction between a material, usually a metal, and its environment that produces a deterioration of the material and its properties.
Corrosion-erosion - Corrosion that is increased because of the abrasive action of a moving stream; the presence of suspended particles greatly accelerates abrasive action.

Corrosion potential (Ecorr) - The potential of a corroding surface in an electrolyte relative to a reference electrode measured under open circuit conditions.
Corrosion product – Substance formed as a result of corrosion: Rust, Iron Oxide, Ferric Oxide
Corrosion protection - Modification of a corrosion system to mitigate corrosion damage.
Corrosion resistance - Ability of a metal to withstand corrosion in a given corrosion system
Corrosion Resistant Alloy, CRA - Nonferrous alloys where any one or the sum of the following alloy elements exceeds 50%: titanium, nickel, cobalt, chromium, and molybdenum.
Corrosion Resistant Material, CRM - Ferrous or nonferrous alloys that are more corrosion resistant than low alloy steels, includes CRA's, duplex, and stainless steels.
Corrosivity - Tendency of an environment to cause corrosion in a given corrosion system.
Crevice corrosion - Localized corrosion of a metal surface at or immediately adjacent to an area that is shielded from full exposure to the environment because of close proximity between the metal and the surface of another material.
Current - The net transfer of electric charge per unit time: amperes or amps, A.
Deposit - Foreign substance that comes from the environment, adhering to a material surface
Deposit corrosion - Localized corrosion under a deposit or material on a metal surface.
Dielectric Isolation – Isolating protected pipelines from non-protected pipelines.
Electrochemical cell - A system consisting of an anode, a cathode, a metallic contact, and immersed in an electrolyte. Anode and cathode may be different metals or dissimilar areas on the same metal surface.
Electrolyte – Soil or water that contacts both the anode and cathode in which the flow of current is accompanied by movement of matter.
Electromotive Force Series (EMF) - List of elements arranged according to their standard electrode potential; "noble" metals (gold) - positive, "active" metals (zinc) - negative.
Environmental cracking - Brittle fracture of a normally ductile material in which the corrosive effect of the environment is a major factor, including hydrogen embrittlement.
Faraday's law - The amount of any substance dissolved or deposited in electrolysis is proportional to the total electric charge passed.
Galvanic - The current resulting from the coupling of dissimilar electrodes in an electrolyte
Galvanic anode - A metal, which because of its relative position in the galvanic series, provides sacrificial protection to metals, that is more noble in the series when coupled in an electrolyte.
Galvanic cell - A cell in which chemical change is the source of electrical energy. It usually consists of two dissimilar conductors in contact with each other and with an electrolyte or of two similar conductors in contact with each other and with dissimilar electrolytes.
Galvanic corrosion – Accelerated, aggressive, and localized corrosion of a metal because of an electrical contact with a more noble metal or nonmetallic conductor in a corrosive electrolyte.
Galvanic couple - A pair of dissimilar conductors, commonly metals, in electrical contact.
Galvanic series - List of metals and alloys arranged according to their relative corrosion potentials in a given environment. Compare with electromotive series.
Galvanized steel - Steel coated with a thin layer of zinc to provide corrosion resistance in underbody auto parts, garbage cans, storage tanks, or fencing wire. Can be either hot dipped or electro galvanized.
General corrosion - Deterioration distributed more or less uniformly over a surface with little or know localized penetration, also known as uniform corrosion.
Half-cell - Electrode immersed in electrolyte designed for measurements of electrode potential.
Holiday – Defect or imperfection in pipeline coating detected utilizing a jeep, so called because of the sound made when holiday identification is discovered.
Hot dip coating - A metallic coating obtained by dipping the base metal into a molten metal.

Hot spot cp - Install at time of leak repair: 2” line - one 17 lb magnesium anode every 40 ft: 3” line - one 17# magnesium anode every 30’, 4” line - one 17 lb magnesium anode every 25’. Install extra anode at leak site.
Hydrogen embrittlement - Process resulting in a decrease of the toughness or ductility of a metal due to hydrogen (from H2S)being absorbed by solid metals.
Industrial atmosphere - An atmosphere in an area of heavy industry with soot, fly ash, and sulfur compounds as the principal constituents.
Inhibitor - Chemical substance(s) that prevent or reduce corrosion without significant reaction with the components of the environment.
Ion - An atom that has gained or lost one or more outer electrons and carries an electric charge.
Positive ions (cations) deficient in outer electrons. Negative ions (anions) excess outer electrons.
Localized corrosion - Corrosion at discrete sites: pitting, crevice, and stress corrosion cracking.
Mill Scale – Very brittle, Ferric Oxide layer formed during hot fabrication of metals.
Oxidation - (1) Loss of electrons by a constituent of a chemical reaction, or an increase in valence. (2) A corrosion reaction in which the corroded metal forms an oxide usually with.
Oxygen concentration cell - Galvanic cell resulting from difference in oxygen concentration between two locations.
Passivation - (1) A reduction of the anodic reaction rate of an electrode involved in corrosion. (2) The process in metal corrosion by which metals become passive.
Passivator - A type of inhibitor that appreciably changes the potential of a metal to a more noble (positive) value.
PH - Measure of the solution acidity or alkalinity; negative logarithm of the hydrogen-ion activity; it denotes the degree of acidity or basicity of a solution. 7.0 is neutral, below 7.0 increasing acidity; above 7.0 increasing alkalinity. Increasing corrosivity with decreasing ph. PH of 3.0 is 100 times more acidic than ph of 5.0 and 10 times more than a ph of 4.0
Pickling – treating a metal with mild acid bath to remove surface mill scale and rust
Pitting - Localized corrosion of a metal surface, confined to a point or small area that takes the form of cavities or pits. Most common form of corrosion due to incomplete chemical protective films, insulating, or barrier deposits of dirt, iron oxide, and foreign substances at pipe surface.
Polarization - Current flowing onto a steel pipeline results in the formation of a pipeline deposit consisting of calcium and magnesium hydroxides. The result is an increase in the pH at the soil to pipeline interface and the formation of a film of hydrogen on the pipeline surface.
Potential - Any of various functions from which intensity or velocity at any point in a field may be calculated or the driving influence of an electrochemical reaction.
Primer or prime coat - The first coat of paint applied to a surface. Formulated to have good bonding and wetting characteristics but may not contain inhibiting pigments.
Protective potential - Threshold value of the corrosion potential that has to be reached to enter a protective potential range, or the minimum potential required to suppress corrosion.
Rectifier ground bed – Anode bed with AC/DC power source used to protect pipelines.
Reducing agent - A compound that causes reduction, thereby itself becoming oxidized.
Reduction - A reaction in which electrons are added to the reactant, i.e., the addition of hydrogen or the abstraction of oxygen. Contrast with oxidation.
Reference electrode - A non-polarizable electrode with a known and highly reproducible potential used for potentiometric and voltammetric analyses. See also calomel electrode.
Rust - Visible corrosion product consisting of hydrated oxides of iron (Corrosion product)
Sacrificial protection - A form of cp accomplished by galvanically coupling it to a more anodic metal, typically magnesium or zinc.
Saturated calomel electrode - A reference electrode composed of mercury, mercurous chloride (calomel), and a saturated aqueous chloride solution.

Shop Coat – One or more coats of primer paint applied in the shop prior to shipping. Not intended for extended field use, should be painted with top coat as soon as possible.
Soil Resistivity – measured in ohm-centimeters, ohm-cm, measured utilizing a single probe, terminal, electrode, cane, pin, two-pin, or four-pin Wenner Method.
Stray-current corrosion - Corrosion resulting from direct current flow through foreign line crossing an existing protected system.
Steel – An alloy of carbon and iron with iron as the principal element at 97-99%.
Stress-corrosion cracking (SCC) - A cracking process that requires the simultaneous action of a corrodent and sustained tensile stress. May occur in combination with hydrogen embrittlement.
Sulfate Reducing Bacteria – SRB's are any organism that metabolically reduces sulfate to H_2S.
Thermite, or Cadweld - A process for making connections from prepackaged anodes to pipe.
Voltmeter – An instrument to measure pipe to soil potential
Wenner Four Pin Test Method - Test setup utilizes the mechanics of the "Four Electrode Method," which was developed by the National Bureau of Standards and is commonly known as the Wenner 4-pin Method. The resultant resistivity is the average resistivity of the soil (electrolyte) to a depth equal to the spacing between adjacent electrodes (soil pins). The maximum depth (pin spacing) of this standard test set has been designed for 20 feet, which is the recommended standard survey.

Recommended Web Sites for Corrosion Information
Corrosion - Leeward Community College, Hawaii, USA:
http://naio.kcc.hawaii.edu/chemistry/everyday_corrosion.html

Corrosion Basics - Corrosion Doctors, USA
http://www.corrosion-doctors.org/mod-basics.htm

Corrosion - Iverson Software Co., MN, USA
http://www.iversonsoftware.com/reference/chemistry/Corrosion.htm

Types of Corrosion - E/M Company Engineered Coating Solutions, USA
http://www.emcoatings.com/solved/corrosion/default2.htm

Corrosion: What is Corrosion? - Rebuild America Coalition, Washington, DC, USA
http://www.rebuildamerica.org/reports/corrosion.html

Corrosion - USGS, USA
http://wwwrcamnl.wr.usgs.gov/sws/cableways/corrosion.htm

Galvanic Corrosion - University of Delaware, USA
http://www.ocean.udel.edu/mas/masnotes/corrosion.html

Corrosionsource.com - The corrosion Portal
http://www.corrosionsource.com/index.htm

NACE Course: Cathodic Protection - Design I - five-day course, cp design, principles, methodology, and financial advantages in designing a system to include cp.
http://www.nace.org/naceframes/Education/edgenindex.htm

Companies that Provide Cathodic Protection Services:
http://www.delweg.com/cp/company1.htm

Glossaries:
http://www.delweg.com/library/exhibit/exbmain.htm
http://www.corrosionsource.com/handbook/glossary/
http://www.hghouston.com/glossary.html Corrosion Related Terms - The Hendrix Group, TX
American Iron and Steel Institute **http://www.steel.org/learning/glossary/g.htm**

Technical Information:
http://www.mesaproducts.com/

Deep Anode Ground-bed Design:
http://www.lidaproducts.com/technical/techmain.htm

Training:
http://www.delweg.com/cp/trainpos/cptrnmain.htm

Website Links for Vendor Information for Various Corrosion Related Products

Accurate Corrosion Control
Alltrista Zinc Products
Anode Systems Company
ARK Engineering
Borin Manufacturing
Brite Products
Buried Pipeline Services
CC Technologies
CLI International
Coffman Engineers
Corrosion Control, Inc.
Corrosion Control Systems
Corrosion Solutions, Inc.
Corrpro Companies, Inc.
Cott Manufacturing
CSIR North America
Dairyland Electrical Industries
Edgewood Electric
EDSI-Houston
ELK Engineering Associates
Farwest Corrosion Control Company
Gerome Manufacuring
Guardian Corrosion Control, Corp.
The Hendrix Group
Holmberg Corrosion Control
Innovative Corrosion Control
J A Electronics
JET Drilling
The Kehl Companies
Loresco
MATCO Associates
The Mears Group, Inc.
Metretek, Inc.
MSES Consultants
Norcure
Norton Corrosion Limited
Raychem
M. J. Schiff & Associates
SESCO
Southern Cathodic Protection
Styco, LLC
Techni-Cor, Inc (TCI)
Tierra Dynamic
Tinnea & Associates
Universal Rectifiers, Inc.

Allied Corrosion Industries
American Construction & Supply
Anotec Industries
Bass Engineering Co.
Brance-Krachy Co., Inc.
Brown Corrosion Services
Cathodic Rectifiers
Caproco
Coastal Corrosion Control
Concorr, Inc.
Corrosion Control Products Company
Corrosion Service
Corrosion Testing Laboratories
CorrTech, Inc.
CP Masters, Inc.
DACCO SCI, Inc.
D C Corrosion Corp.
EDM Services, Inc.
Electrochemical Devices
EnergySouth Corrosion Services
Galvotec Corrosion Services
Graphtek LLC
Hanson Survey and Design
Henkels & McCoy
Huron Tech
Integrity Inspection Services
J&D Mechanical Industries
Kadlec Associates
Leigh Engineering
M & B MAG
MATCOR
MESA Products, Inc.
M. C. Miller Co.
National Corrosion Service
Northern Arizona Wind and Sun
Ormat
J. D. Rellek Company
Safe Engineering Services and Technologies
Specialized Environmental Equipment
D. E. Stearns Stuart Steel Protection Corporation
Sullins International
Tepsco, L.P.
Tinker & Rasor
Toal Associates, Inc.
Universal Technical Resource Services, Inc.

Recommended Sources of Information

- Champion Technologies – Oil Field Corrosion Detection and Control Handbook - Free
- Appalachian Underground Corrosion Short Course, Morgantown West Virginia, Held annually in May, Total cost including room and board ~$500. Website is http://www.aucsc.com
- Peabody's Control of Pipeline Corrosion Fundamentals
- Guidance Manual for Operators of Small Natural Gas Systems, USDOT - Free
- Corrosion of Oil and Gas Well Equipment, API, 1990
- Oil and Gas Production Corrosion Control – Petroleum Extension Service of the University of Texas at Austin, catalog number 3.30110: ISBN 0-88698-110-7
- Pipeline Corrosion and Cathodic Protection, Gulf Publishing, M. Parker and E. Peattie
- SPE Reprint No. 46 - Corrosion

Paint Information and Guidelines

Paint Primer: One of the main defenses against corrosion is the regular and proper application of paint to most surface structures. Paint is effective due to its ability to isolate the structure from moisture and therefore stop the corrosion cycle. ***Proper surface preparation is essential to good painting results.***

Paint - Definition: The group of emulsions generally consisting of pigments suspended in a liquid medium for use as decorative or protective coatings.

History: Paint made its appearance about 30,000 years ago by cave dwellers. The first recorded paint mill in America was reportedly established in Boston in 1700 while in 1867, D.R. Averill of Ohio patented the first prepared or "ready mixed" paints in the United States. In the mid-1880s, paint factories began springing up in population and industrial centers across the nation. Virtually every product created on an assembly line makes extensive use of paints and coatings to beautify, protect and extend the life of the manufactured goods. Historically, the industry readily responded to environmental and health concerns by altering the chemistry of its products to control risks. Industry consensus standards limiting the use of lead pigments date back to the 1950s. The most frequently used steel primer paint in the nation until the mid 1970's was commonly known as Red Lead, and was outlawed because of the lead pigment. The replacement steel primer paint was known as Basic Lead Silico-Chromate consisting of a chromated lead silicate pigment dispersed in an alkyd resin vehicle. The paint was still easy to apply, it was very forgiving in terms of application oversights and a good durable coating was achieved. Over coats for this system were traditionally pigmented alkyd paints.

Major Paint Companies: Tnemec, Vanguard, Rustoleum, Sherwin Williams, Benjamin Moore, and Pittsburgh Paints.

From Pittsburgh Paints Performance Guide

Paint Composition: Paints consist of the following four basic components: Pigments, Binders, Solvent, and Additives.

Pigments: Particles used to give paints color, hiding power, and density. Typically white pigments are titanium dioxide, red pigments - iron oxide, yellow pigments - lead chromate, and green pigments– cobalt and chromium salts.

Binders: Bind pigments and additives together and provide resistance properties and adhesion to the substrate, or surface. Binders include Acrylic, Alkyd, or Epoxy resins.

Solvents: Cause the pigment and binder solids to behave as a fluid for application purposes and evaporate completely for all practical purposes. Solvents are typically aliphatic (mineral solvents) and aromatic hydrocarbons (toluene). Water and glycol solvents are used in water based or latex paints.

Additives: Special purpose ingredients to help paints perform better. Generally used in small amounts but contribute greatly to overall paint performance, including anti-skinning agents, mildewcides, coalescents, defoamers, thickeners, preservatives, and surfactants.

Gloss levels are categorized from Flat, Eggshell, Lo-Lustre, Satin, Semi-Gloss, to Gloss.

Paint types include latex, alkyds, epoxies, and aliphatic urethanes.

Latex paints: Synthetic resins, usually acrylic or vinyl acrylic, and are low in volatile organic compounds (VOC), low odor, fast drying, non-yellowing, and easy to clean up. Drying occurs when the water evaporates from the film allowing the coalescence of latex particles. Acrylics are used primarily to provide extra moisture resistance, wet adhesion, and color/gloss retention.

Alkyd paints are much harder than ordinary oils and drying occurs when the solvents evaporate from the film and the resin cures by oxidation. The drying action bonds a tough paint film to the applied surface.

Epoxy paints are tough two component finishes with outstanding hardness, abrasion resistance, alkali and acid resistance, and good adhesion when dry. The finish is smooth, easy to clean and lasts for years under the most severe conditions. Acrylic epoxies provide resistance to staining, yellowing, and scuffing of acrylic resins combined with the toughness and durability of epoxies.

Aliphatic Urethanes are two component products recommended for areas that demand superior chemical and stain resistance, plus superior gloss and color retention. The color and gloss retention and chemical resistance of acrylic urethane coatings will exceed those of more conventional high performance coatings.

Primer Selection

Primers are a vital component in a finished paint job looking good and performing as expected. Primers seal the surface, promote adhesion to the surface, block out stains, reduce surface preparation, and improve topcoat coverage. A primer helps paint from being absorbed unevenly. Specific primers can also provide corrosion resistance on metals. A primer should be used to repaint when the surface is uneven or badly deteriorated, jobs when the paint has been stripped or worn down to the original surface, on slick surface like tile and high gloss enamels, and on iron and steel that need protecting form corrosion.

General Surface Preparation

Good results and long paint life are more dependant on correct surface preparation for exterior painting than interior as a rule, but adequate surface preparation is important to both. *If basic problems are not corrected before the paint is applied, no paint will perform satisfactorily. Probably more than anything else, proper surface preparation is very important prior to painting. The performance of any paint or coating system is directly related to the quality and thoroughness of the surface preparation before painting.*

- Facility should be mowed prior to surface preparation
- Scrape and wire brush any loose material, paint, rust, debris
- Correct any moisture related problems
- Be sure surface is clean and dry.
- Remove mildew
- Remove gloss and chalking
- Temperature should be between 50 and 90
- Relative humidity should be below 85%.

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Identification of the Effects of Corrosion on Stripper Well Operations

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Abstract
This paper is the result of research to develop methodologies, diagnostic tools, and a procedure guide to identify the effects of corrosion on stripper well operations. Prior research performed for the Department of Energy determined that one of the major problems contributing to abnormal production decline in stripper gas wells was mechanical failure due to corrosion. The methodologies developed as a result of this study guide the stripper well operator to systematically identify cost effective corrosion mitigation procedures.

This case study includes more than 450 stripper wells located in the State of Ohio, although the methodologies developed are believed applicable to stripper wells in all geographical areas.

The prior study and identification of the corrosion control problem indicated that many operators fail to recognize and evaluate the economics of proper corrosion mitigation methods to stripper wells, resulting in additional expense and prematurely abandoned wells. Experience indicates that due to the marginal production associated with stripper wells, the correction of mechanical failures due to corrosion is even more problematic later in the life of wells when capital expenditures for repairs of any nature are often cost prohibitive. The current study revealed that although the subject of corrosion is very complex, stripper well operators can benefit through the simple application of planning, painting, and plastics. Therefore, it was the goal of the of this research program to develop an application guide detailing cost effective corrosion mitigation procedures.

The systematic methodology developed benefits every producer by increasing the efficiency of problem assessment and implementation of corrosion solutions, ultimately resulting in increased production, reserves, and profitability of stripper wells.

This study was specifically developed for stripper well operators in a cost-sharing venture between James Engineering, Inc., the Stripper Well Consortium, and the National Energy Technology Laboratory under the Subcontract No. 2283-JE-DOE-1025.

Introduction
Prior research performed for the Department of Energy found that 270 of 376 wells evaluated, or over 70%, exhibited some form of abnormal production decline during the past five years. Nearly 23% of the 270 abnormal production declines were caused by mechanical failure due to corrosion, which resulted in both decreased reserves and revenue. Even though corrosion has been historically evident throughout all phases of the production process, the frequency of mechanical failures due to corrosion represents a significant opportunity for improvement. Through the proper application of corrosion identification and mitigation practices, stripper well operators can better maintain mechanical integrity, economically remediate corrosion affected wells, and minimize premature abandonment.

The prior research indicates that stripper well operators often fail to properly evaluate the economics of corrosion mitigation over the entire life of the well, even when the problems are recognized. The current study found that all wells experience corrosion and that failure to maintain an adequate corrosion mitigation program resulted in decreased equipment value, decreased mechanical integrity, added expense, loss of product, potential environmental impact, and loss of wells. Current study results also indicate that many of the corrosion mitigation methods utilized by large oil and gas production companies, gas transmission companies, and gas storage companies are cost prohibitive for most stripper well operators. However, due to lack of training, over a decade of low product prices, and the marginal production associated with stripper wells, many stripper well operators fail to employ consistent, available methodologies to address historical corrosion problems leaving the effects of corrosion unrecognized or un-addressed.

Stripper well operators are faced with multiple challenges in operating stripper wells and corrosion is often not a pressing concern until mechanical failures occur. These challenges include multiple managerial duties, limited staffs, marginal production, aging wells, and the multiple ownership of wells accompanied with a broad range of associated problems. Generally with ownership changes, stripper well operators are left with consolidating a hodgepodge of wells with previous attempts at production or corrosion prevention, requiring a considerable effort just to restore wells to daily operation. In spite of the many obstacles, stripper well operators must be able to quickly identify and focus on areas where corrosion poses the greatest threat.

Stripper wells are defined as those wells with production less than or equal to 60 mcfd or 10 bopd, while the national average is significantly less at 15 mcfd and 2 bopd. The Appalachian Basin represents 205,000 of the nation's 646,000 stripper wells, but the average stripper well in the Appalachian Basin only produces 11 mcfd and 0.4 bopd. So even when stripper well production is maximized, the amount of capital available for repairs or enhancements is limited.[ii]

Therefore, it is absolutely necessary that the corrosion mitigation methods employed by stripper well operators be effective, economical, and easy to implement. The procedure guide developed as a result of this study provides methods for identifying and selecting corrosion mitigation techniques for primary production stripper wells.

Theory

James Engineering, Inc. proposed to study the major factors affecting corrosion in stripper wells that lead to mechanical failures, and to determine the appropriate application of corrosion mitigation technologies. The goal of the study was to develop a procedure guide detailing selective procedures for cost effective corrosion mitigation procedures and operating practices using data collection forms and decision trees.

The study included the following:

- Perform a literature search
- Develop data collection forms
- Perform a field review
- Summarize the results of the field review
- Develop decision trees to identify and implement corrosion mitigation
- Test the decision tree analysis
- Prepare a procedure guide
- Transfer the technology

Perform a Literature Search

The literature search identified numerous books, papers, articles, and information related to corrosion and corrosion mitigation. The search included the SPE website, the Internet, the Marietta College Library, the American Petroleum Institute, the National Association of Corrosion Engineers (NACE), the Appalachian Underground Corrosion Short Course, and the South West Petroleum Short Course CD paper database.

Several key words for the searches included corrosion, corrosion mitigation, cathodic protection, painting, types of corrosion, and plastics.

Of particular interest were a paper written by Harry Byars in 1961 entitled "Patches on our Oil Patch Pockets" and a 2002 study published by the NACE entitled "Corrosion Costs and Preventive Strategies in the United States" . Mr. Byars' paper alluded to the general poor condition of the oil industry in 1961 due solely to the effects of corrosion. The 2002 NACE study stated, "the materials and corrosion control technologies used in the traditional onshore production facilities have not significantly changed since the 1970's." This information indicates that 1.) The corrosion problem for stripper well operators is not a new one, and 2.) Corrosion control methods have not changed significantly in over thirty years. However, stripper well operators still struggle with the identification and application of effective corrosion mitigation methods.

In addition to the literature search, interviews were completed with a large independent producer, three major oilfield supply companies, a plastic tank distributor, and two paint company representatives. Further inquiries were made to several companies on operating practices, and a corrosion company was contracted for corrosion mitigation recommendations. Additional information was gathered at a PTTC Produced Water Seminar, a cased hole logging seminar, and a PTTC Corrosion Management Workshop.

The literature search, interviews, and seminars not only identified the costs of corrosion, but also identified the basics of corrosion: definition, components, chemistry, electrode potential, types, and primary agents, corrosion identification methods, soil assessment methods, corrosion mitigation methods, and the importance of field personnel.

The Cost of Corrosion

The study identified the direct and indirect costs associated with corrosion, the 2002 NACE corrosion study, Artex Oil Company's corrosion related capital expenditures, and the economics of corrosion.

Corrosion results in the direct costs of repair or replacement of casing, rods, tubing, separators, production tanks, pipelines and corrosion inhibition, and in the indirect costs of lost or deferred production, lower equipment salvage values, environmental damage with associated penalties, and decreased safety.

Research identified a 2002 study entitled "Corrosion Costs and Preventive Strategies in the United States", initiated by NACE International, mandated in 1999 by the U.S. Congress, and conducted by CC Technologies Laboratories, Inc. of Dublin, Ohio determined the cost of corrosion control methods and services, the economic impact of corrosion for specific industry sectors, extrapolated individual sector costs to a national corrosion cost, assessed barriers to effective implementation of optimized corrosion control practices, and developed implementation strategies and cost-saving recommendations.

The 2002 NACE study identified that the petroleum industry spends millions of dollars every year developing new oil and natural gas reserves, and yet additional millions are spent maintaining existing production facilities from the effects of corrosion. The NACE study estimated that all United States industries combined spend $276,000,000,000 annually on corrosion. It is estimated that the onshore oil and gas industry alone spends over $300,000,000 per year. The effects of corrosion are so extensive that the replacement of corrosion damaged materials alone accounts for approximately 20% of the annual iron produced in the United States.

The 2002 NACE study suggested the following preventative strategies to impact the corrosion costs associated with the oil and gas industry: Increase consciousness of corrosion control costs and potential savings, change the perception that nothing can be done about corrosion, advance design practices for better corrosion management, change technical practices to realize corrosion cost savings, change management policies to acknowledge that throwing money at the problem after the leak occurs should not be considered a cost-effective strategy, advance life prediction and performance assessment methods, advance technology through research, development, and implementation, and improve education and training for corrosion control.[iii]

A review of the Artex Oil Company's capital expenditures for the five-year period of 1998 - 2002 identified the capital expenditures to correct corrosion related problems. The review categorized the effects of corrosion into downhole casing leaks (CL), pipeline repairs (PL), top joint tubing change outs (TJ), wellhead repairs or leaks in the production casing in the wellhead area (WH), production storage tank repairs (TR), and general facilities costs (GF), see Table 1.

Table 1
Corrosion Related Problems - Artex Oil Company

Category	**CL**	**PL**	**TJ**	**WH**	**TR**	**GF**
No.	40	124	9	27	15	12
No, %	18%	57%	4%	12%	7%	5%
Total, M$	**$446**	**$168**	**$42**	**$24**	**$12**	**$6**
M$, %	64%	24%	6%	3%	2%	1%
Avg, M$	**$11.4**	**$1.4**	**$4.7**	**$0.9**	**$0.8**	**$0.5**

Two hundred and twenty-seven corrosion related incidents were identified at a cost of $696,900, or an average of $3,125 per incident. These total incidents represent an average occurrence of one out of every two wells operated over the five-year period. Table 1 identifies the distribution by category of the number of incidents, the percentage the number represents of the total incidents, the total cost, and the average cost per incident. The above costs are for repairs only and do account for the costs of lost production or reserves.

The forty downhole casing leaks represent 18% of the total incidents, 64% of the total costs, and averaged $11,400 per incident. Casing leaks generally originate on the exterior of the casing near hydrogen sulfide bearing limestone or exposed coal seams. These casing leaks normally represent the loss of the well due to the influx of water and loss of production unless repaired. Casing repair costs include service rig time, packer, tubing, clean out, swabbing, dozer, company supervision and may include the installation of a second string of tubing, rods, pump, and pumping unit. Chemical inhibition is effective in mitigating downhole casing leaks, however, primary cementing over the H_2S or coal interval is the preferred method.

The one hundred twenty-four pipeline repairs represent 57% of the incidents, 24% of the total costs, and averaged $1,400 per incident. Experience indicates that the leaks originated on the exterior of the pipeline. While an occasional gathering system leak is to be expected, the total number of leaks indicates significant opportunity for improvement. The pipeline leaks include production line leaks with associated oil spills. Stripper well operators generally continue to operate existing production lines and gas systems until mechanical failures occur. Repairs are then made utilizing clamps, joint replacement, or full replacement with plastic lines.

To better understand the pipeline expenditures a summary was prepared of the gas gathering system associated with approximately 120 wells, see Table 2. The summary identified a total of 369,400' of pipeline with five different diameters comprised of both steel and plastic. The summary is representative of similar systems many stripper well operators maintain as a result of acquisition consolidation.

Table 2
120 Well Gas Gathering System Summary

Type	**Steel**				**Plastic**		
Size	6"	4"	3"	2"	3"	2"	1 ½"
M Ft.	27.6	105.6	50.0	72.6	23.0	79.6	11.0
%	8%	28%	14%	20%	6%	21%	3%

The nine top joint tubing replacements represent 4% of the incidents, 6% of the total costs, and averaged $4,700 per incident. These leaks originate on the exterior of the tubing occurring near the packing. Corrosion occurs circumferentially until insufficient material remains to maintain mechanical integrity and repair is necessary for continued operation of the well. The corrosion is due to localized corrosion caused by the accumulation of rain in the packing area, and aggravated by chlorides in the produced fluids. Regular painting can minimize this type of corrosion.

The twenty-seven wellhead casing leaks represent 12% of the incidents, 3% of the total costs, and averaged $900 per incident. These leaks originate on the exterior of the casing, result in pressure and product loss, and require repair for continued well operation. The location of the leak is at or near the packing and is due to atmospheric corrosion, the accumulation of rain in the packing area, and is aggravated by chlorides in the produced fluids. Casing repair costs include service rig time, welder, company supervision, and the temporary installation of a packer just below the affected area during the repair. Regular painting can minimize this type of corrosion.

The fifteen tank repairs represent 7% of the total incidents, 2% of the total costs, and averaged $800 per incident. Tank failures affect well operations by lost production and environmental liability. Tank corrosion can be internal or external, occurring in the top, sides, bottom, or heater tube and is normally due to insufficient maintenance and coating, improper setting, atmospheric conditions, and the fluids stored. Corrosion is aggravated by leaking valves, connections, and tank inlet lines. Corrosion is easily identified and corrected on the tank exterior, but are not for the tank interior and bottom. Experience indicates that the bottom of the tank represents the most significant area affected by leaks that require immediate attention. Painting, proper tank setting, and the application of coal tar to the tank bottoms are effective corrosion mitigation methods for steel tanks. The use of plastic tanks for storage of brine significantly reduces the effects of corrosion and is a common practice for many stripper well operators. Table 4 identifies the distribution of the 835 tanks for Artex Oil Company.

Table 4 Tank Size and Type Distribution						
Size, barrels	210	100	50	35	25	Cmt Vaults
No.	**116**	**477**	**166**	**15**	**35**	**26**
% of Total	14 %	57 %	20 %	2 %	4 %	3%

The twelve general facilities repairs accounted for 5% of the total incidents, less than 1% of the total costs, and averaged $500 per incident. The general facilities category accounted for the remainder of corrosion related incidents including valves, gas sales meters, etc. Many valves do not receive regular maintenance, become corroded, and are impossible and dangerous to operate or replace.

General Corrosion Related Economics

Lost production income due to corrosion can often outweigh the expenses associated with regular maintenance. For example, a 5-mcfd loss due to corrosion in an aging gathering system at $5.00 per mcf represents a loss of $9,000 per year. A five-barrel oil spill due to corrosion could cost $5,000 to remediate, with the majority of the cost associated with spill clean up rather than the line or tank repair. Stripper well operators should seriously consider the potential benefits of regular corrosion maintenance, line replacement, and the identification of specific wells or lines where corrosion could have environmental impact. Specific areas for line replacement may include those near streams and lakes, or lines where fluid is pumped up a hill. The lost opportunity costs, time and effort addressing leaks, which could have been spent increasing production or addressing other issues must also be considered.

The Basics of Corrosion

Corrosion Defined

Corrosion is defined as "the deterioration of a material, usually a metal, due to a reaction with its environment." In regards to oilfield operations, corrosion generally involves carbon steel reacting with soil, water, moisture, oxygen, carbon dioxide, and/or hydrogen sulfide, resulting in the formation of rust. When observed with the naked eye, rust appears to be very commonplace, but is actually the product of very complex electrochemical reactions that require four components to occur.

The Components of Corrosion

The four required components for a corrosion cell are an anode, a cathode, a metal path, and an electrolyte.

The anode is always where corrosion occurs. The anode is where electrons are lost, metal is dissolved, and current leaves the metal and enters the electrolyte. The cathode is where no corrosion occurs, current is picked up, and rust deposits occur. The metal path connects the anode and the cathode allowing electrons to flow. The anode, cathode, and metal path are generally located on the surface of the individual grains of steel. The electrolyte is a conducting medium for metal ions and current flow, present as water in the soil or moisture in the atmosphere as rain, dew, or humidity.

The Chemistry of Corrosion

It is well established that the corrosion of buried metallic structures such as pipelines is associated with: 1.) the flow of electricity, and 2.) the chemical interaction between the metal and the surrounding soil, or an electrochemical reaction.

The amount of electricity flowing in the corrosion cell is directly related to the amount of metal being removed and the number and size of the anodic and cathodic areas on the steel. The chemical reactions of oxidation and reduction occur in the anodic and cathodic areas respectively.

Anodic and cathodic areas are created during refining and fabrication affecting the metallurgical properties of the steel, and further affected by field operating factors. It is important to recognize that fabrication does not result in a solid steel product with uniform properties, but a conglomeration of unique grain structures with a natural tendency to exchange ions from one grain to another.

Some refining factors leading to grain structure variations include dirty steel, improper heat treatment, improper stress relief, and inadequate melting sequences, while fabricating factors include folds, seams, inadequate heat treatment, inadequate cleaning of mill scale, improper welding, excessive cold straightening, and general surface damage. Field operating factors include additional surface damage, improper welding, cold bending, acidic water, water deposited scales, and corrosion product scales.

The oxidation and reduction reactions that explain the corrosion of steel starts with a transfer of electrons. First, metal loss begins to occur at anodic areas when atoms of iron, Fe^0, go into solution as Fe^{++} ions in the electrolyte, according to the formula $Fe^0 \rightarrow Fe^{++} + 2e^-$, or oxidation. Then the rate of corrosion slows as Fe^{++} ions accumulate near the anodic surface until precipitated as rust product due to the presence of oxygen allowing the corrosion process to continue. The electrons, e^-, released from the atoms of iron, Fe^0, flow through the metal path creating electricity until their charge is neutralized through reduction with hydrogen or oxygen ($O_2 + 4H^+ + 4e^- \rightarrow 2\ H2O$ or $O_2 + 2H_2O + 4e^- \rightarrow 4OH$).

Simply stated, corrosion is the release of the energy required to convert iron ore (iron oxide) into steel, that is, there exists a natural tendency for iron ore to return from its higher energy state as steel to its lower energy state of native iron ore as rust (iron oxide). The essential difference between ordinary steel and pure iron is the carbon content from low with 0.3% carbon to ultra high with 1.2% – 2.0% carbon.

Electrode Potential of Anodes and Cathodes

Similar to the differences between grains of the same material, when two metals are connected in an electrically conducting environment, they react by forming a galvanic corrosion cell. The driving force behind the rate of these reactions is related to the electromotive force (EMF) potential of the materials involved, measured in volts. The materials involved in a galvanic cell tend are either more noble (cathodic) or less noble (anodic). Table 1 identifies the EMF for some of the more common metals (after AUCSC Intermediate Course, Table 1-1). Note that a material may be anodic to one material, but cathodic to another depending on its location in the table.

Table 1 EMF Table of Potentials

More Anodic	**Material**	**Emf, V**
More Corrosive	Potassium	-2.92
More Noble	Barium	-2.90
	Calcium	-2.87
	Sodium	-2.71
	Magnesium	-2.40
	Aluminum	-1.70
	Manganese	-1.10
	Zinc	-0.76
	Iron (Ferrous)	-0.44
	Nickel	-0.23
	Tin	-0.14
	Lead	-0.12
	Iron (Ferric)	-0.04
	Hydrogen	0.00

More Cathodic Less Corrosive Less Noble	Copper	+0.34
	Silver	+0.80
	Platinum	+0.86
	Gold	+1.36

Primary Agents of Corrosion

The primary agents that affect oilfield corrosion are oxygen, carbon dioxide, hydrogen sulfide, hydrochloric acid, organic acids, and chlorides. Factors affecting the rate of corrosion include temperature (>150°), pH, bacteria, and environment. The rate of corrosion generally increases as the concentration of these factors increases, with the exception of pH, which becomes more corrosive as it decreases.

Types of Corrosion

Because the categories of corrosion vary according to specific industries, for the purposes of our study, corrosion was divided into two fundamental types: general and localized. General corrosion is characterized by a uniform layer of corrosion, or metal loss, with no pitting. Localized corrosion was further categorized as galvanic, pitting, crevice, inter-granular, stray current, microbiologically induced, de-alloying, erosion, and stress. Localized corrosion may occur as a combination of any of the previously mentioned categories.

Galvanic corrosion occurs due to the EMF difference between two different materials. Pitting corrosion is confined to a small area and is evidenced by cavities or holes produced in the materials that are either trough shaped or sideways pits. Corrosion product or rust generally covers most pits. Crevice corrosion occurs in shielded areas under gaskets, washers, insulation material, fastener heads, surface deposits, disbonded coatings, lap joints, and clamps due to changes in the local chemistry. Intergranular corrosion is localized attack along the grain boundaries, or immediately adjacent to grain boundaries, while the bulk of the grains remain largely unaffected. Stray current corrosion occurs when a foreign line crosses another line cathodically protected by impressed current, is very aggressive, and mechanical failure can occur in days rather than months or years. Microbiologically induced corrosion (MIC) is corrosion initiated by the presence of microorganisms, bacteria or fungi and often results in pitting and crevice corrosion. Oil transport lines and waterflood operations often have to address MIC. The remaining forms of corrosion; de-alloying, erosion, and stress, do not appear to be major factors in stripper well operations**.**

Corrosion Identification Methods

Corrosion identification methods include visual inspection, physical observation, pressure and production monitoring, electronic inspection, soil analysis, chemical analysis, and metal coupon analysis.

Visual inspection is limited to external surfaces, but is beneficial to stripper well operations due to the low cost and general effectiveness. Visual inspections identify potential problems with wellheads, exposed sections of casing and tubing, separators, production units, meters, storage tanks, and surface lines. Well tenders or production managers should complete visual inspections for prioritizing maintenance, repairs, or replacements.

Physical observation identifies corrosion resulting in the loss of pressure and product in wellheads, tanks, or pipelines. Well tenders, landowners, and production variance reports assist in identifying mechanical failures. Physical signs of a natural gas leak include an odor, a hissing sound, dirt or water being blown into the air, bubbling in wet areas, patches of dead vegetation, fire burning above the ground, dry spots in moist fields, areas of abnormally hard or dry soil, or a white vapor cloud close to the ground. Oil spills are generally identified as seepages or as rainbow sheens.

Well tenders often identify mechanical failures through monitoring operating pressures and production volumes. Decreases in normal operating pressures may indicate a casing or pipeline failure while decreases in gas production or increases in fluid production often indicate a casing failure.

Electronic inspection allows for the review of the internal surfaces of production casing and pipelines. Large production companies, gas transmission companies, or natural storage companies utilize electronic logging to regularly monitor casing and pipelines to identify pitting or general corrosion for corrective action prior to catastrophic mechanical failure. Stripper well operators generally rely on the more cost effective methods of prevention or repair, rather than incur the expense of electronic inspection.

The electronic identification equipment used by stripper well operators includes portable gas detectors, pipeline locators, gps units, and portable gas analyzers. Electronic gas detectors identify gas leaks even when an odor is not perceived. Pipeline locators identify the location of steel pipelines and the tracer lines installed with plastic pipelines. Gps units identify pipeline routes and leak locations in remote areas for later repair or maintenance. Portable gas detectors are also helpful in determining the presence of H_2S or CO_2. An H_2S concentration of 250 ppm or more and ph of 6.5 or less indicates a corrosive environment. For CO_2, a 7-psi partial pressure with a ph of 7 or less, and a count of 100 ppm or greater indicates a corrosive environment.

Soil analysis identifies the conductivity of the soil to determine the potential corrosivity. This testing can be accomplished in-house with some training by stripper well operators, but is generally too expensive to contract out to experienced companies. Due to the complex nature of this subject, further discussion is addressed as a separate subject under soil assessment methods.

Chemical analysis, performed by trained oilfield chemical company personnel, identifies potentially corrosive elements in a production stream. Specifically, chemical analysis typically identifies the presence and concentrations of iron, sodium, potassium, calcium, magnesium, chlorides, sulfates, carbonates, resistivity, hydrogen sulfide, pH, and total dissolved solids. The increased concentration of these factors generally increases the corrosive environment with the exception of ph. Continuous monitoring of fluids is required for waterfloods due to the interaction of injected water and reservoir fluids.

ph is defined mathematically as the negative logarithm (base 10) of the hydrogen ion and is calculated in powers of 10, that is, a solution with a ph of 1.0 is 10 times greater than one with a ph of 2.0. Significant corrosion is unlikely where water or soils have a ph higher of 7 or higher, alkaline. However, as the ph lowers from 7 corrosion increases greatly. Any ph of 6 or less will provide an environment for the occurrence of significant corrosion and probable pitting.

Corrosion coupons identify internal pipeline corrosion by providing a quantitative measurement of metal loss in millimeters per year (mils per year, or MPY). Pre-weighed coupons are put in line, left for one month to one year, removed, and analyzed. Coupons are then photographed, cleaned, visually inspected, dried, re-weighed, and re-photographed. The corrosion rate is then estimated based upon the weight of coupon material lost. Champion Technologies recommend that a coupon test of less than 5 MPY and no pitting indicates corrosion is unlikely, less than 5 MPY with pitting indicates isolated corrosion, while greater than 5 MPY indicates active corrosion. Further, the most frequent causes of pipeline internal corrosion is improper welding, too high or low of velocity, inadequate pigging leading to scale buildup, liquid buildup, and bacteria growth, or use of the wrong inhibitor.

It is important to document all analyses, visual identifications, observations, and leak repairs to assist in the mitigation of future mechanical failures.

Soil Assessment Methods

Measuring resistivity is important to identify pipeline soil resistivity variations, since steel pipelines are susceptible to galvanic corrosion due to soil resistivity variations. Pipeline portions with lower soil resistivities become anodic relative to other portions of the pipeline, and therefore corrode.

Soil resistivity, measured in ohm-centimeters, is the accepted industry standard as the primary indicator of soil corrosivity. As soil resistivity decreases, current flows easier through the soil. Soil resistivity is a function of the moisture content, soil temperature and soil type, Table 2.

Increased moisture or electrolyte (brine) content decreases resistivity, Table 3, with soils below 10,000 ohm-cm indicating rapid and severe pipeline deterioration. Resistivity increases substantially when moisture content falls below 10% or temperatures fall below freezing. High organic soils have low resistivity and retain high moisture levels. Sandy soils drain faster, have lower moisture content, and higher resistivity, while solid rock has little moisture and high resistivity.

Table 2: Soil Resistivity as a Function of Soil Type	
Soil Type	**Ohm – Cm**
Well graded gravels	60,000 – 100,000
Poorly graded gravels	100,000 – 250,000
Clayey gravel	20,000 – 40,000
Silty sands	10,000 – 50,000
Clayey sands	5,000 – 20,000
Silty or clayey fine sands	3,000 – 8,000
Fine sandy or silty soils	8,000 – 30,000
Gravelly clays	2,500 – 6,000
Inorganic clays	1,000 – 5,500

Table 3 – Soil Resistivity as a Function Of Moisture Content and Soil Type			
Moisture Content (%)	**Top Soil**	**Sandy Loam**	**Red Clay**
	Ohm-cm	**Ohm-cm**	**Ohm-cm**
2		185,000	
4		60,000	
6	135,000	38,000	
8	90,000	28,000	
10	60,000	22,000	
12	35,000	17,000	180,000
14	25,000	14,000	55,000
16	20,000	12,000	20,000
18	15,000	10,000	14,000
20	12,000	9,000	10,000
22	10,000	8,000	9,000
24	10,000	7,000	8,000

Soil Resistivity Measurement

The most common methods to analyze soil resistivity are the Wenner four-point method, the three-point method, the two-point method, and the copper-copper sulfate reference electrode. The Wenner four-pin method measures the average resistivity of large volumes of soil based on the spacing of the measuring pins. Readings are typically taken every 400 feet over the length of pipeline by a two to three man crew.

One of the most common methods to measure structure to soil resistivities utilizing a voltmeter and the copper–copper sulfate electrode (CSE). The positive terminal of the voltmeter is connected to the CSE reference electrode and the negative terminal to the pipeline, tank, or other structure. Pipe to soil potentials are generally negative under corrosive conditions when measured with a CSE. Digital meters, rather than analog, are recommended due to their ease of use and resistance to damage if the polarity is reversed.

In summary, soil resistivity measurements provide a direct indication of the corrosive properties of soil. Soils with resistivities of 50,000 to 100,000 ohm-cm are mildly corrosive; 30,000 to 50,000 are moderately corrosive, and those with less than 30,000 ohm-cm are very corrosive.

Stripper well operators usually find contracted services to conduct soil resistivity measurements cost prohibitive but can be completed by in-house personnel with nominal training. The general condition of most gathering system right of ways, un-mowed and unmarked, increase the time required for soil resistivity surveys. An estimated cost for a three-man soil survey crew for one mile is approximately $1,000 per day.

Common Methods of Corrosion Control

The most common methods of corrosion control are cathodic protection, coatings, corrosion resistant materials, insulating joints, and chemical inhibitors.

Cathodic protection reduces pipeline corrosion rates by utilizing sacrificial anodes or rectifier ground bed systems to make the pipeline cathodic. Cathodic protection allows other materials to corrode, become anodic, and pipeline anodic areas to be protected. The current requirements for pipeline corrosion protection are reduced through the coatings. Cathodic protection requirements are established through soil resistivity measurements taken before and after pipeline and cathodic protection system installation. Stripper well operators typically do not utilize soil testing but some other method based on experience to determine cathodic protection requirements.

Sacrificial anode systems accomplish protection by coupling a magnesium or zinc anode to the pipeline for current to flow from the anode to pipeline, progressively destroying (sacrificing) the anode and protecting the pipeline. Typical anode sizes are either 17 or 34 pound. Sacrificial anodes can be used for hot spot protection on previously unprotected lines, and is effective when replacing line sections or applying repair clamps. Sacrificial anode advantages include no external power required, low voltage output, no voltage variance, easy installation, location adaptable, no maintenance required, and no inspection required. One disadvantage is that too many anodes are required for adequate protection of new bare steel lines.

Cathodic protection rectifier ground bed systems include an AC power supply, a rectifier unit, a ground bed of anodes, connecting cables, and the pipeline. The rectifier utilizes a transformer to step down high AC line voltage to low AC voltage, then utilizes a rectifying element to converts the low AC voltage to DC which is transferred by a single cable to a high silicon iron or graphite anode ground bed located 150 to 450 feet from the pipeline. Rectifier ground bed system advantages include variable D.C. voltage application, protection of bare steel lines, and automation for varying moisture conditions. Disadvantages include possible foreign structures interference, unintentional current interruption, required regular maintenance, and higher operating costs.

All coating systems are susceptible to defect, but are for most part very effective in corrosion prevention. Coatings for cathodic protection for most surface equipment include the application of primer and paint. Coatings should be inspected annually, while well tenders should casually inspect the facility with every visit. Any coating defects should be addressed as soon as possible, or noted for the annual maintenance program. Once a facility has been properly coated, repainting should not be necessary for at least five to ten years except in extreme conditions. Wax coatings are also used to minimize wellhead fluid contact

Pipelines are corrosion protected to ensure reliable service over a long time. Coating systems include a one-coat epoxy, a two-layer system of adhesive and polyethylene topcoat, and the three-layer system of epoxy powder, adhesive, and polyethylene topcoat. Pipeline coatings are most effective when installed in combination with cathodic protection due to the defects associated with all coatings.

Experience indicates that stripper oil and gas operators can generally achieve good success utilizing either plastic pipe, or a combination of coated pipe and sacrificial anode system for protecting most small diameter (2" – 4"), low-pressure (5 – 250 psi) gas gathering systems. Larger diameter (>4"), high pressure systems (>250 psi) should be reviewed for the relative benefits of utilizing an impressed current over the sacrificial anode system. Existing systems without coating or cathodic protection will benefit by the application of hot spot protection during repairs or replacements.

Corrosion resistant materials can be non-metallic or corrosion resistant alloys. Materials utilized for stripper well applications include plastic, stainless steel, and fiberglass, while plastic is the predominant product of choice for both fluid storage tanks and pipeline material. General limiting factors in applying plastic are its maximum pressure rating, temperature rating, and susceptibility to damage during installation or by offset construction. Plastic is also utilized for lining tubing or coating packers in corrosive downhole environments. Stainless steel needle valves are used extensively throughout the industry for pressure gauges. Fiberglass use has diminished due to the limited number of manufacturers and the superior attributes of plastic.

Insulating joints are used to interrupt current flow and are typically inserted between protected and unprotected pipelines. This type of corrosion control is utilized to limit cathodic protection, reduce the effects of stray currents, and to separate dissimilar metals. Insulating joints are typically a requirement by most gas transmission companies between their lines and a stripper well operator's gas gathering system.[iv]

By definition, chemical inhibitors are added in a small concentration to an environment to effectively reduce the corrosion rate of the exposed metal in that environment. Chemical inhibitors types include passivating, cathodic, organic, precipitation, and volatile corrosion inhibitors. Inhibitors are oil soluble, oil soluble brine dispersible, water-soluble, oxygen scavengers, and surfactant based. Application areas include tubing, gathering systems, water disposal lines, oil or water storage tanks, and gas sweetening or dehydration units. Treatments can be by batch or continuous injection with batch injections varying from every two weeks to three months. Chemical treatments, generally effective only on internal corrosion, can be effective on external corrosion control of wells with H_2S.[v]

The Importance of Field Personnel

Experience and results of the study show that field personnel are the primary line of defense in corrosion identification and mitigation. The API Corrosion of Oil Well Equipment Handbook identified three critical areas for field personnel: corrosion problem recognition, record keeping, and carrying out control procedures. Well tenders and field personnel will normally observe preliminary indications of corrosion leading to mechanical failure and can advise management on maintenance or repair requirements, therefore, it is important to provide appropriate training to be able to identify conditions that aggravate corrosion.

Data Collection Form Development

One form was developed to identify the most common areas of corrosion for stripper well operators based upon literature review results and the analysis of Artex Oil Company's capital expenditures related to corrosion. The data collection form was developed to use during the field review and for use later by stripper well operators to evaluate the effects of corrosion on surface facilities. The form provides a systematic means of assimilating data to identify and evaluate the most common areas of stripper well corrosion and corrosion mitigation methodology, and was designed for completion by either field or office personnel. A goal of the form is to provide sufficient information to assist production managers in allocating financial resources and scheduling annual maintenance.

The four part form addresses wellheads, casing, tubing, production storage tanks, pipelines, and surface facilities. Part 1 addresses general information, Part 2, specific identification and description, Part 3, corrosion correction method, and Part 4, comments.

Part 1, general information, identifies the area to be inspected (Lease, Pipeline, or Other), the person completing the inspection, the date of inspection, the GPS location number, and the photograph identification numbers.

Part 2, identification and description, identifies the specific review area, the visual extent of the corrosion classified either as minimal, moderate, or severe, the type and cause of the corrosion, a brief description of the corrosion, and the correction recommended. Common areas of corrosion for review include downhole production casing and tubing, wellhead side nipples and valves, top joint casing and tubing, pipelines, master valve, needle valves, other valves, production tanks (210 bbl, 100 bbl, or 50 bbl), fittings, production unit, separator, riser, vent, or pipeline marker, ladder, casing plunger or tubing plunger lubricator, plunger, or pumping unit.

Part 3, methods of correction, includes cleaning, protecting, repairing, or replacing. Cleaning methods include sandpaper, sand blasting, high pressure washer, scraper, and wire brush. Protection methods include painting (primer and topcoat), insulating, or installation of a dielectric flange. Repair methods include tightening, clamping, top joint of casing repair, top joint of tubing replacement, or downhole packer installation. Replacements include pipeline sections, fittings, vales, controls, or slip lining plastic line inside existing steel lines. Tank correction includes replacement of same type and size of tank, removal of tank, or replacement of a steel tank with a plastic or fiberglass tank. All methods of correction were number coded for ease of use.

Part 4 provides a section for noting any additional comments regarding corrosion inspection, maintenance, repair, or replacement.

Perform Field Review

A field review was completed of several well tenders routes accounting for more than 200 wells. The review included visual inspection of most wells and associated surface facilities. The goal of the field review was to gather information regarding the effects of corrosion on stripper well operations through visual inspection, data collection forms, photographing specific corrosion areas, and recording well tender conversations. Additional reviews included wellhead repair procedures, equipment storage areas, and general shop refurbishing of used equipment.

Summarize Results of Field Review

It was significant, but not unexpected, that corrosion was observed at every location, however, the presence of corrosion was generally not an indication of immanent mechanical failure.

The following discusses the use of the data collection forms, obstacles to inspection, the effect of acquisitions, the effects on equipment pulled from service, the importance of coating at the time of initial installation or replacement, the effect of containment dikes, and details on specific areas of corrosion, including the various environmental and operating conditions affecting corrosion.

The original data collection form proved too burdensome and complicated during the first inspection to complete while inspecting the well site, selecting areas to photograph, and traveling between locations in a pick up truck or four-wheeler. Therefore, in order to maximize the number of locations reviewed, further reviews utilized spreadsheets of wells and associated equipment by welltender route, accompanied by brief field notations and photographs. Stripper well operators would find this methodology more effective for completing field reviews, making specific notations regarding painting,, repair, or replacement.

Obstacles to visual inspection included well access, recent painting, and weeds. When well access was impossible due to road conditions, only the associated tank batteries near the main road were reviewed. Where recently painted surfaces made corrosion inspection difficult, the painting results were then reviewed. Weeds and un-mowed areas obstructed visual inspection especially around wellheads or bottoms of tanks. Field reviews should be coordinated to coincide with site maintenance. that is, after mowing and before painting.

It is important to note that most of the wells reviewed were the result of various acquisitions and it was evident that the previous maintenance affected the current condition of many of the wells. Previous operators could be identified based upon the current condition of the facility.

The field review and prior experience identified that corrosion is accelerated when equipment is pulled from service and left open to the atmosphere where oxygen is plentiful. Therefore, equipment should be returned to service quickly or left in service until needed. Tubing or casing pulled from service should be kept on storage racks and have all thread ends cleaned and lubricated for corrosion protection.

It was determined as a result of the field review that the best time to provide equipment with the most effective corrosion protection is upon initial installation or replacement. This typically involves a good coating of paint for most surfaces and coal tar for tank bottoms. A good primer and enamel topcoat will provide many years of effective protection and should be applied soon after installation. Care should be taken during installation not to scrape the protective coating from hard to access areas. Touch up painting should be completed prior to final hook up with any bright metal marks from pipe wrenches or field cut threads temporarily coated with spray paint to minimize the effects of corrosion.

The following discussion focuses specifically on field review results regarding wellheads, casing, tubing, separators, tanks, and pipelines.

Wellheads, Casing, and Tubing

The field review identified that wellheads experience corrosion in valves, connections, and in the top joints of the casing and tubing. Surface corrosion appeared due to improper maintenance, leaking connections, and partially covered wellheads. Downhole casing problems were mainly related to H_2S and coal bearing zones caused by insufficient primary cementing.

Corrosion was evidenced on the top joints of the production casing and tubing near the packing due to wellhead designs that leave a bowl for water to collect. Lack of protective coating further provides a corrosive atmosphere enhanced by produced brine chlorides from leaking connections. Pipe wrench marks and field cut threads were observed to leave areas of bright metal exposed for corrosion to occur.

Wells on pump that produce oil benefit from the corrosion protection afforded by leaking stuffing boxes. The small amount of oil and paraffin that gets by the stuffing box provides an effective barrier to moisture and therefore corrosion. While a leaking stuffing box is not a recommended practice, the result is a coated and protected wellhead.

Portions of some wellheads were partially covered with soil due to location regrading, thereby masking any possible corrosion in valves or connections set below ground level. Even when not buried below ground level, corrosion frozen valves are difficult and dangerous to open or remove. All valves should be lubricated and operated at periodic intervals to minimize the potential for a freezing up due to corrosion. Finally, any exposed threaded outlets should be coated to prevent corrosion of threads and preserve their usefulness.

Experience indicates that downhole casing leaks are caused by H2S or coal bearing zones on the outside of the production casing. Mechanical failures are accompanied by decreased gas production, increased fluid production, discolored or muddy water, an H_2S odor, and decreased wellhead pressures. Instead of exact casing leak location identification, stripper well operators can generally remediate by setting a packer into the cemented portion of the well, then utilizing chemical inhibitor to mitigate any additional damage. Some wells may require a second string of tubing or the addition of slim hole rods and a pumping unit to maintain effective fluid removal.

H_2S can be due to formations that produce H_2S or the occurrence of sulfide reducing bacteria, or SRB's. H_2S bearing formations are generally area specific and can be delineated by most operators. Primary cementing over these intervals can prevent future costly corrosion remediation. SRB's reduce sulfates in oilfield waters to form H_2S. H_2S reacts with iron in tubulars to form iron sulfide, causing failures and leaks in flow lines, valves and process equipment. Treatment of the un-cemented section of the production casing and SRB's can be controlled through chemical inhibition. The known corrosiveness, toxicity, flammability of H_2S make it hazardous to well tenders and adjacent landowners. Therefore, stripper well operators should identify all facilities with H_2S , and then assess the potential health hazards.

Decision trees and procedures for the maintenance and repair of wellheads, casing, and tubing were documented and incorporated into the procedure guide.

Separators and Production Units

Field review identified that most separators and production units reviewed were in fair condition with the exception of those affected by leaking connections or missing control covers. Leaking connections typically involved produced brine rather than oil causing additional corrosion damage. Regulators and fluid level control unit corrosion seemed associated with missing or improperly closed covers. Regular painting, eliminating leak, and restoring covers to separator controls should effectively mitigate most occurrences of corrosion. Production units or separators pulled from previous service, due generally to abandonment, will benefit from shop restoration rather than field repair prior to returning to service.

Production Storage Tanks

The field review provided for a review of the extent of corrosion, the storage vessels utilized, the areas of corrosion, mechanical failure identification, the effects of dike construction and tank setting, general operating practices, a used tank storage area, and summer painting crews.

Corrosion was evidenced on every steel tank reviewed with affected areas including external surfaces, tank ladders, heater tubes, behind labels, and tank inlets and outlets. Tanks reviewed varied from cement, plastic and steel composition, and from 25 to 210 barrel. Although a number of in-ground cement vaults were reviewed, few were being utilized due to cracks. The condition of the steel tanks varied from excellent to those that had been completely corroded. Steel storage tanks have a significant tendency to corrode due to the varying fluid levels and fluid types contained, with significant internal corrosion when only brine is present. Most tanks were experiencing localized exterior corrosion with pitting occurring and appeared due mainly to improper maintenance and leaking connections.

Well tenders reported that most mechanical failures are identified by visible seepage, although static or decreasing tank fluid levels with normal gas production and operating pressures were also indicative of a hole in the bottom of the tank. Leaking tanks are drained, pulled from service, and taken to a storage area where a number of tanks can be efficiently repaired at the same time. Tank replacement decision trees and repair procedures are included in the procedure guide.

Improper tank setting in containment dikes can often promote premature failure due to the moist environment associated with dikes. Tanks should be set slightly elevated from the remainder of the dike and the dikes drained regularly. Tanks were observed to be set on gravel, clay, and railroad ties. Some other operators also reported tanks set on cement. Since visual inspection of the bottom external surface of a steel tank is impossible, it is important for operators to properly coat the bottom of a tank with mastic and then set the tank without affecting the coating. The remainder of the tank exterior can then be regularly painted to maintain corrosion protection. A review of tanks returned to the equipment yard for repair generally revealed a few areas of pitting rather than uniform bottom corrosion.

Additional corrosion was observed behind tank labels where the top of labels had parted from the tank allowing water to collect. Well tenders should replace loose labels, while annual maintenance should remove damaged labels prior to repainting. It was also observed that some heater tubes on tanks were noted to be welded shut due to leaking associated with extended use.

Tank ladders can be a significant safety issue for well tenders when proper maintenance is ignored and ladders allowed to deteriorate. Repainting ladders is not easy, so oftentimes maintenance crews do not properly clean or paint corrosion troubled areas.

One beneficial field practice identified was introducing two to three barrels of crude into steel tanks where only salt water was produced to provide a coating to oxygen. One detrimental practice was draining small quantities of salt water into the diked area while transferring saltwater to observe when oil had been reached. The cumulative effect of drainage and leaking valves further aggravates the already corrosive environment at the bottom of tanks.

Well tenders reported that load lines experience internal corrosion at tank inlets where saltwater continually lays at the bottom of the line. An un-repaired leak in this area can then initiate corrosion on the exterior of the tank.

A review of the painting practices of two summer crews revealed that surface preparation of tanks and separators could stand some improvement, however, paint or primer were generally applied to most surfaces. Surface preparation was generally limited to a wire bush and scraper. Hard to access areas generally did not receive a lot of attention, either in surface preparation or painting. Previously painted areas that were not properly prepared had blistered and will require re-treatment. Some operators report utilizing high pressure washers or air tools for some maintenance.

Plastic tanks are used for initial installation or replacement of steel saltwater storage tanks. Oilfield supply companies and operating company inquiries confirmed the predominant usage of plastic tanks for saltwater storage. Plastic tanks are superior to steel and fiberglass tanks in cost, impact resistance, and availability. Plastic tanks have also proved superior to in-ground cement vaults due to the cracking associated with cement vaults. There has been general good success utilizing plastic tanks, although some improperly installed tanks experience failure at the tank inlet, possibly due to repeated surges while attempting to remove wellbore fluids. Most plastic tanks reviewed were coated with paint to reduce the degrading effects of ultraviolet rays.

Pipelines

No pipelines were visually reviewed during the field review process, however, some areas of previous replacements were reviewed and one example of stray voltage corrosion was also investigated.

The following discusses general stripper well operation, obstacles to leak identification, pipeline monitoring methods, pipeline repair methods, the use of plastic, and hot spot protection.

Experience indicates that pipelines represent a significant investment for most stripper well operators with pipeline corrosion resulting in a loss of mechanical integrity and an associated loss of product. As previously discussed, stripper well gas gathering systems are often a conglomeration of acquisitions resulting in systems comprised of various materials, diameters, and ages, but generally neither coated nor cathodically protected. Unless problems arise as leaks or pressure restrictions, existing lines are utilized and not inspected until dug up for system changes, repair, or replacement.

Major obstacles to leak identification and overall system understanding include inadequate maps, unidentified lines, poor pipeline right of way maintenance, and well tender responsibility for large numbers of wells over wide geographic areas. Well tenders are often responsible for leak identification in addition to their other duties.

Pipeline mechanical integrity is monitored daily by well tenders through production and pressure monitoring of check and master gas sales meters. Production managers further identify line loss by monthly or weekly production variance reports. Electronic metering was observed to provide regular monitoring of remote sites for comparison to weekly individual well chart integrations. Well tenders are constantly on the lookout for the physical signs of gas leaking during normal operations.

Pipeline corrosion is addressed first by repair if possible, then by replacement when necessary. Repairs are often completed by roustabout crews using a shovel and a clamp where possible. It is not unusual to have "several" clamps on small sections of line. Stripper well operators sometimes struggle with the economics of line repair over replacement.

When line replacement is necessary, plastic is utilized wherever possible and practical. Plastic pipe is often used for initial installations, replacement of existing steel sections, or as a slip liner within existing steel lines. The use of plastic either as a complete replacement or as a slip liner inside existing pipelines is recommended where operating pressures are appropriate.

The apparent phenomena of successive leaks in steel lines once initial repairs are made or the accelerated corrosion of replacement sections is explained as follows. The surrounding top soil is oxygenated (made cathodic) when it is dug up creating increased potential for corrosion compared to soil beneath the line. Similarly, new steel pipe experiences accelerated corrosion compared to the previously corroded steel. Hot spot corrosion protection utilizing sacrificial anodes may be an effective method of preventing future corrosion in these two circumstances.

Decision trees are provided in the procedure guide to assist stripper well operators in managing the effects of pipeline corrosion.

Decision Tree Development

Decision trees were developed for the common areas that are affected by corrosion problems in stripper wells, then to select the most appropriate corrosion mitigation method. One decision tree provides a general methodology for stripper well operators to develop a plan for addressing the overall problem of corrosion, while additional decision trees are provided on specific areas of corrosion including downhole casing, wellheads (casing and tubing), production tanks, and production and pipeline leaks. The decision trees utilizes database and field gathered data to assist the operator in selecting the proper corrosion mitigation methods.

General Methodology

The general methodology decision tree, Figure 1, provides a four-phase process to systematically assess corrosion problems associated with stripper wells. The form provides a methodology to evaluate the application of corrosion mitigation methods for stripper gas wells by focusing on the most common areas of corrosion. The form is divided into four sections, Phase 1 – Identify the Problem, Phase 2 – Measure the Problem, and Phase 3 – Solve the Problem, Phase 4 – Monitor the Problem.

Phase 1, Identify the Problem, prepares a database of information to review potential areas of corrosion based upon field review, wellbore schematics, map preparation, and leak repair summaries.

Phase 2, Measure the Problem, determines the priority through review, additional decision trees, cost estimates and preliminary economics. Stripper well operators should be aware that protect fifty percent of wells and associated systems will result in protecting probably ninety percent of total value.

Phase 3, Solve the Problem, confirms the expense justification based upon payout, npv or other method. Decisions are then made to complete the proposed work or rather to sell or plug and abandon. Based upon an annual budget estimate, schedules are then prepared for maintenance, repairs, or replacements.

Phase 4, Monitor the Changes, monitors the effects of corrosion through gas sales variance reports, weekly well tender meetings, annual facility reviews and pipeline inspections, documenting maintenance and repairs, and reviewing pipeline repairs to identify trouble areas. It is critical to monitor the corrosion mitigation methods employed compared to the results desired to continuously improve the process.

Specific Decision Trees

Study results indicate that common areas of corrosion include un-cemented H_2S or coal bearing zones, top joints of tubing or casing, unprotected wellheads, leaking connections, steel salt water tanks, heater tube areas, bottom of steel storage tanks, and bare steel pipelines in corrosive environments.

Stripper well operators are directed to the use of the specific decision trees in Phase II of the general decision tree including casing, tubing, wellheads, separators, tanks, and pipelines.

Decision Tree Test Analysis Results

The decision trees are based upon commonly available information, process identification, and steps to alert the stripper well operator to the identification and mitigation of common corrosion areas. Continued analysis of the methodologies are currently in progress. The results of the decision tree testing will be provided in the final report to the Stripper Well Consortium.

Procedure Guide Preparation

Based upon the research performed in this study, a procedure guide was prepared that details the utilization of the Data Collection Forms, and the Decision Trees.

The procedure guide provides a detailed description of the corrosion process, corrosion identification and mitigation guidelines, potential failure paths, and diagnostic tool designation are also provided. Diagnostic tools include wellbore schematics, weekly well tender reports, gas sales variance reports, swab reports, gas sales charts, gas leak detectors, portable gas analyzers, gas line detectors, and soil analyzers.

Additional sections are provided in the procedure guide appendix on surface preparation and painting guidelines, and plastic pipe usage guidelines. Definitions, abbreviations, and lists of manufacturers, suppliers and information sources are also provided including complete addresses, phone numbers, and website addresses.

The methodologies developed as result of this research will be presented at Petroleum Technology Transfer Council (PTTC) meetings and provided to the Department of Energy to include as a resource on their web site.

The goal of the procedure guide is to assist operators in economically evaluating and identifying the appropriate corrosion mitigation methods for stripper well operators based upon commonly available data.

Should any additional information be required, all subjects previously discussed are amplified within the text of the final report presented to the Stripper Well Consortium under the Subcontract Number 2283-JE-DOE-1025, as sponsored by the Department of Energy.

Conclusions

Corrosion affects every stripper well to some degree and if left unchecked results in the repair or replacement of casing, rods, tubing, separators, production tanks, and pipelines. Additional effects include lost or deferred production, lower equipment salvage values, environmental damage and associated penalties, and decreased safety.

The costs associated with corrosion, while substantial can be managed best when considered as a cost of doing business. Proper planning should significantly reduce the amount of time and expense that would otherwise be required for addressing corrosion related issues.

Stripper well operators face multiple challenges, cannot afford to utilize the same corrosion control methods as major transmission and natural gas storage companies, but still require economic, efficient, easy to use techniques for corrosion mitigation.

Stripper well operators should develop in-house expertise through education, and training through the West Virginia University Appalachian Underground Corrosion Short Course. It is important that stripper well operators employ consistent methodologies that includes an equipment database, cost estimates, economic prioritization, an annual budget, scheduled maintenance, documentation, and monitoring when planning to effectively mitigate the effects of corrosion.

While the process of corrosion is complex and often misunderstood, it is largely controllable. Primary cementing of production casing over H_2S or coal bearing zones or chemical inhibition should eliminate most downhole casing problems. Regular maintenance through surface preparation, painting, and leak correction would eliminate many wellhead and tank related problems. Proper tank setting and bottom coating would significantly reduce most tank bottom corrosion related incidents. Utilizing plastic tanks for salt water storage would eliminate most of the problems associated with steel tanks. Finally, coated pipe, cathodic protection, hot spot protection, and the use of plastic for pipeline replacement would significantly reduce many pipeline corrosion problems.

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Figure 1
Decision Tree Form For Corrosion Mitigation

Phase I: Identify the Problem
1. Complete field review form by well tender
2. Prepare well equipment inventory
3. Prepare wellbore schematics for problem wells
4. Prepare map identifying wells and pipelines
5. Estimate average production per well, mcfdeq
6. Prepare gas sales variance report
7. Prepare leak, repair, or replacement summaries

Phase II: Measure the Problem
1. Sort wells by gathering system then by descending mcfdeq
2. Determine system priority by mcfdeq, variance, and environmental concerns
3. Review maps, schematics, and leak summaries
4. Utilize appropriate equipment decision tree form
5. Estimate costs for maintenance, repair, or replacement
6. Prepare economics by well and gas system

Phase III: Solve the Problem
1. Confirm expense justification: payout, npv
2. Complete work, sell, or plug and abandon
3. Estimate annual budget for expenditures
4. Prepare repair schedule
5. Prepare maintenance schedule
6. Prepare replacement schedule

Phase IV: Monitor the Changes
1. Prepare monthly gas sales variance reports
2. Conduct weekly well tender meetings
3. Complete annual review of all facilities
4. Complete annual pipeline inspection
5. Document maintenance and repairs
6. Review pipeline repairs to identify trouble areas

Endnotes

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