

CATHODIC PROTECTION CORROSION CONTROL CONSIDERATIONS FOR STORAGE WELL CASINGS

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by

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**CORROSION
SERVICE**

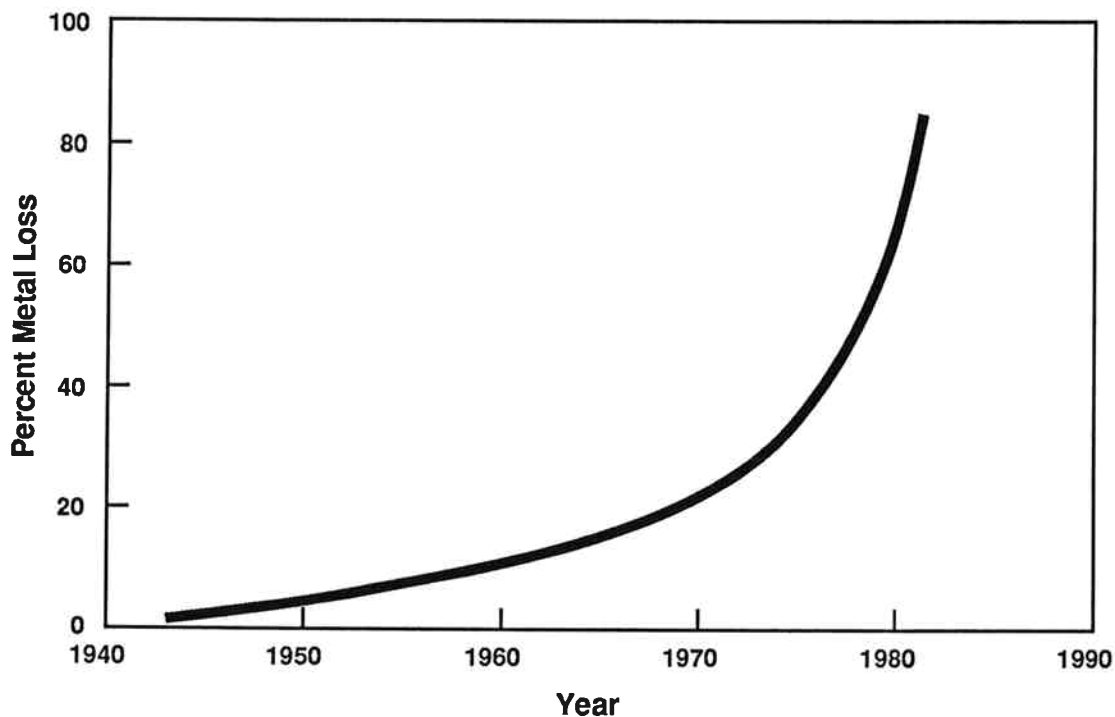
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INTRODUCTION

A 1954 survey by NACE Subcommittee TP-1H[1] on oil-string casing corrosion indicated that 79% of failures on producing gas or oil wells in the U.S. were due to corrosion. Battle (3) extrapolated the NACE 1954 survey to estimate the number of casing failures in the U.S. on all wells to be 1294. Considering that almost 35 years have passed since that survey, it is safe to assume that the number of production wells is now in the millions and the average age is much greater than the 15 years in the 1954 survey. Many production wells originally expected to have relatively short service life based on the initial production forecasts and on estimated recoverable reserves, are still in service since production enhancement techniques have improved, and the price of gas and oil has increased.

As wells age and environmental constraints increase however, the integrity of the well casing, which is the most important structural member in the well, has received increasing attention in recent years. The greatest threat to well casing integrity is corrosion, particularly as the well casing accumulates age since even very modest corrosion rates can ultimately produce perforations. Storage well casings unlike production casings have a much longer anticipated service life and therefore it is unlikely that storage wells would be taken out of service after a short service

history. The impact of time on corrosion activity has been presented by Gentges[2] on gas storage wells in Michigan as indicated in Figure 1. In this study ANR Pipeline Company, which operates 1290 gas storage wells, logged 970 wells since 1970 in which 285 exhibited corrosion



**FIGURE 1 – GAS STORAGE WELLS
PLOT OF PERCENT METAL LOSS VS. YEAR
(Typical Well Completed In 1944)**

penetration greater than 60% of the wall thickness. The logging of these wells, some of which date back to 1944, was done using a magnetic flux leakage tool and the results were verified in some instances by pulling joints of pipe for detailed examination. With experiences like this, it is understandable that considerable effort has been expended over the last two decades in addressing corrosion problems on well casings.

Corrosion Mechanisms

Corrosion is a natural process driven by the Gibb's Free Energy locked into the steel at the smelting stage. When steel is exposed to soil or most aqueous media, corrosion activity initiates owing to metallurgical differences between one point on the structure and another. These localized corrosion cells are very close together and their rate of activity is very much dependent on the local oxygen concentration and diffusion conditions. In most soils, this micro-corrosion attack has a very modest rate of penetration in the order of 1 to 2 mils per year which would not threaten the integrity of even the oldest well casing. The corrosion cells which usually cause casing perforation are due to macro corrosion cell activity arising from gross dissimilarities in soils, and soil aeration as well as from stray current interference and bacteriological inducement.

Corrosion By Dissimilar Environmental Conditions

Illustrated in Figure 2 is a typical corrosion cell established by differences in soil conditions, in this case between a salt water formation and adjacent shale layers with the corrosion attack confined to the casing in the salt water. This type of corrosion cell has been reported to have caused leaks in some Arabian Gulf wells within 4 years of well completion.[4] A downhole resistivity investigation indicated that on these wells there was a low resistivity salt layer having a resistivity of 200 ohms-cm surrounded by two higher resistivity layers having electrical resistivities greater than 2000 ohms-cm.

A similar macro corrosion cell can be developed between the production casing and the surface casing or the flow lines and sometimes both as illustrated in Figure 3. This macro-corrosion cell is created by differential aeration between the upper granular soil and to the lower layer

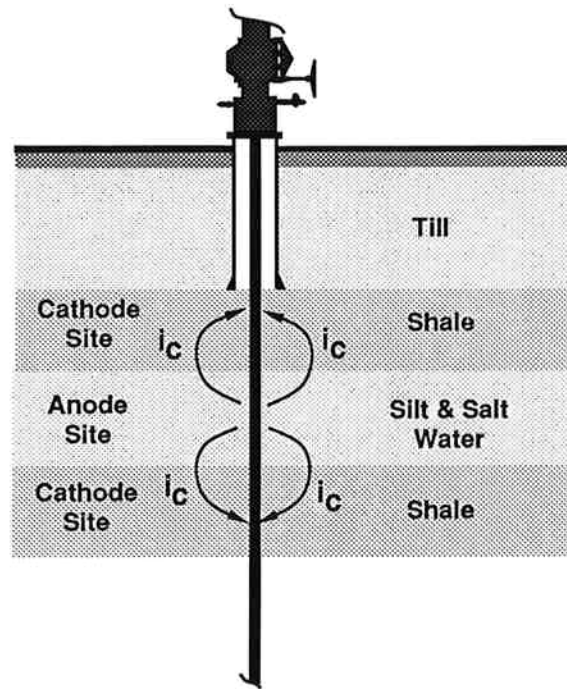


FIGURE 2 – CORROSION CELL DUE TO DISSIMILAR SOILS

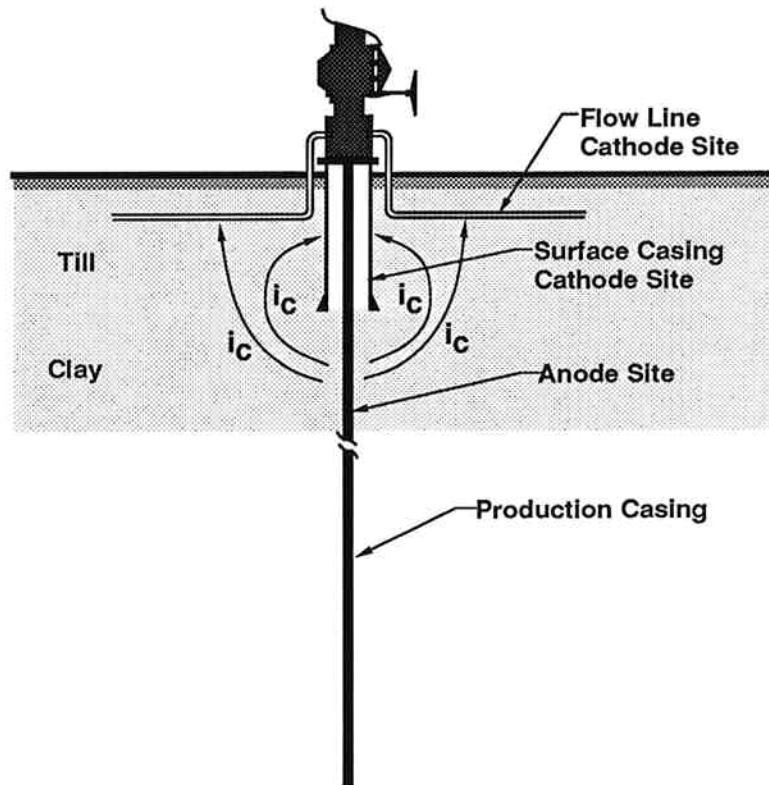


FIGURE 3 – DIFFERENTIAL AERATION CORROSION CELLS

of clay soil. Here the casing immediately in the clay becomes the anode and corrosion is driven by the surface casing and the flow lines which are surrounded by well aerated soil. This type of corrosion cell often accounts for the observance of corrosion just below the shoe of the surface casing since this casing is often terminated at the bottom elevation of granular overburden. A differential aeration macro-corrosion cell was responsible for most of the corrosion which occurred in the ANR gas storage fields in Michigan. Here the differential aeration corrosion was primarily in the annular space between the production casing and the surface casing after water had accumulated in the annular space. Failure occurred at the water/air interphase.

The cementing of a casing on the soil-side can also initiate macro-corrosion cells as illustrated in Figure 4. In this case, where the concrete is not properly distributed around the casing, the steel

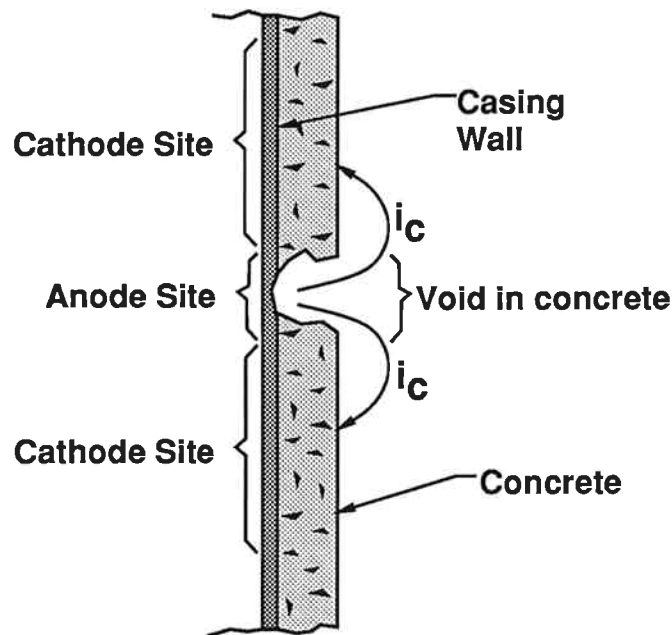


FIGURE 4 – CORROSION CELL AT A CONCRETE VOID

exposed to the soil will have a more negative corrosion potential than the steel exposed to the concrete. Accordingly, a corrosion cell is set up in which the steel exposed to the earth becomes the anode site and the steel underneath the adjacent concrete, becomes the cathode site. This cell can be particularly aggressive where the concreted area of steel is much greater than the void area. One dramatic illustration of this kind of corrosion cell was in the South Belleridge Field[5] where the corrosion pattern was in a spiral configuration which coincided with missing concrete. This was not simply a case of the casing corroding because it was exposed to corrosive soil, but principally because the corrosion was accelerated by the cathodic area beneath the concrete.

Interference Corrosion

Corrosion can occur from stray DC current originating from impressed current cathodic protection systems as illustrated in Figure 5.

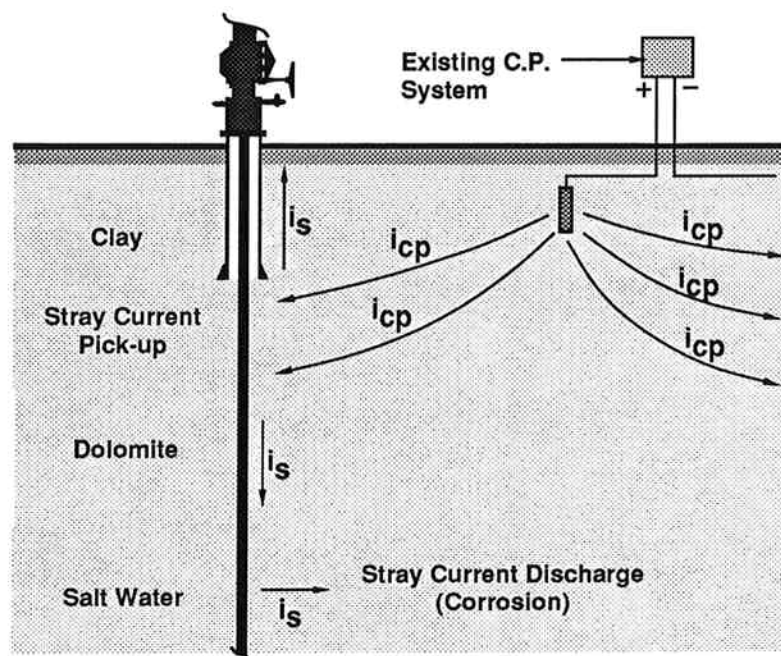


FIGURE 5 – CORROSION DUE TO STRAY CURRENT INTERFERENCE

Although all the impressed current from the cathodic protection system in this illustration was intended to protect another structure, some current can be intercepted by the steel casing and this current must return to the source. In doing so it can flow both ways and the current that flows down the casing, discharges to the earth usually where there is a low resistivity soil strata. Where the current discharges, corrosion of the casing will occur. Corrosion can also occur if the current flowing up the casing does not have an electronic path back to the negative of the power supply which would be the case, for instance if the well head was electrically isolated from the flow lines. Should this be the case, then stray current could also discharge off the top of the casing causing corrosion near the surface. Roberson[6] has reported interference on well casings from cathodic protection systems which were more than a mile away from the interfered-with casing. The degree of severity produced by stray current corrosion will be a function of the magnitude of the interfering stray current and the discharge current density. The relative preference for the casing as a current path is a function of the soil resistivity and its relative stratification and the relative positioning of the casing with respect to the current source and to the structure which was intended to be protected.

Bacteria Induced Corrosion

The fact that the casing extends to considerable depths means that soils which are generally lacking in oxygen will be encountered. This condition is conducive to the existence of anaerobic sulphate reducing bacteria which can produce corrosion failures in a very short period of time as has been reported in the Ventura field.[7] In this field the average time between completion of a well and the development of a leak was about 55 months, with a range from 11 to 136 months. Bacterially induced corrosion pits are often distinctive in appearance since they are very localized, relatively steep sided and smooth in appearance. Corrosion is thought to occur as a result

of the bacteria reducing sulphates to sulfides which in turn depolarizes the cathode of local action corrosion cells. In the Ventura field, an unusually high percentage (eg. 1.38% by weight) of sulfide was identified in the casing scale. This amount of sulfide was consistent with percentages identified in scale at other corrosion sites known to have been bacterially induced.

PREVENTION MEASURES

The wide range of corrosion causes and the relative inaccessibility of the corrosion sites presents a challenge to the application of common corrosion control techniques. There are a number of corrosion prevention measures however which have met with varying degrees of success. Generally one solution will not be effective for all situations.

Electrical Isolation Between Anode and Cathode

When the principal corrosion mechanism is a result of a corrosion cell between the casing and flow line, electrical isolation of the flow line from the casing has some benefit. Ewing and Bayhi[8] indicated in the Loudon pool, where the first leak occurred within 34 months of well completion, corrosion failures were caused by a casing/flow line corrosion cell with the anode in a salt water tar sand formation. Subsequent electrical isolation of the flow line from the casing substantially reduced the leak rate. As part of their testing, they were able to identify open circuit potential differences between the flow line and casing ranging from a 117 mV to 331 mV and short circuit corrosion currents between 54 mA and 2.4 Amp. Electrical isolation is of course impractical for other types of corrosion cells where both the anode and cathode are located on the casing surface or where interference corrosion exists. In the latter case, the use of isolation may cause stray current interference due to the interruption of a stray current electronic

return path. Accordingly, electrical isolation as a corrosion mitigation technique should be used only where the principal corrosion mechanism is due to a corrosion cell developed between the casing and the flow lines.

Concrete and Alkaline Mud

Battle[1] in his analysis of the NACE 1950 survey of well casing failures recommended that most failures resulting from external corrosion of the casing by soil waters could have been prevented by using concrete or alkaline mud around the casing. Both concrete and alkaline muds create a high pH at the surface of the steel which inhibits corrosion activity and aids in the formation of a passive film on the steel. By installing casings surrounded by concrete or highly alkaline muds, general corrosion activity can be eliminated providing the entire surface of the casing is covered with this alkaline medium. As mentioned previously, should areas of the casing not be completely covered by concrete then a severe corrosion can result. Cementing is also beneficial should the operator or owner choose to apply cathodic protection, since the alkaline environment maintained by the concrete or alkaline mud will reduce the current required to achieve cathodic protection.

Protective Coatings

Applying a protective coating to a casing is not an effective corrosion control measure unless the application is pinhole free and remains intact after installation. Otherwise at voids or damaged areas a corrosion anode site will develop which will result in premature perforation of the casing. Although considerable coating damage might be expected due to handling and installation, tests reported by Horton, Hamburg and Smith[9] indicated that 95-98% of the epoxy coatings remained intact after installation. Protective coatings therefore have their primary benefit in a

secondary role by minimizing stray current pick-up, by reducing the current requirements for cathodic protection and by improving the uniformity of cathodic protection current distribution.

Cathodic Protection

Cathodic protection is probably the most dominant and effective method of controlling external corrosion on well casings. This technique involves causing a DC current to flow between the earth electrolyte and the steel, as shown in Figure 6, to produce a potential change at the casing surface thereby eliminating the potential differences produced by corrosion cell activity. The effectiveness of cathodic protection was reported by Gast[10] on about 2178 wells in which

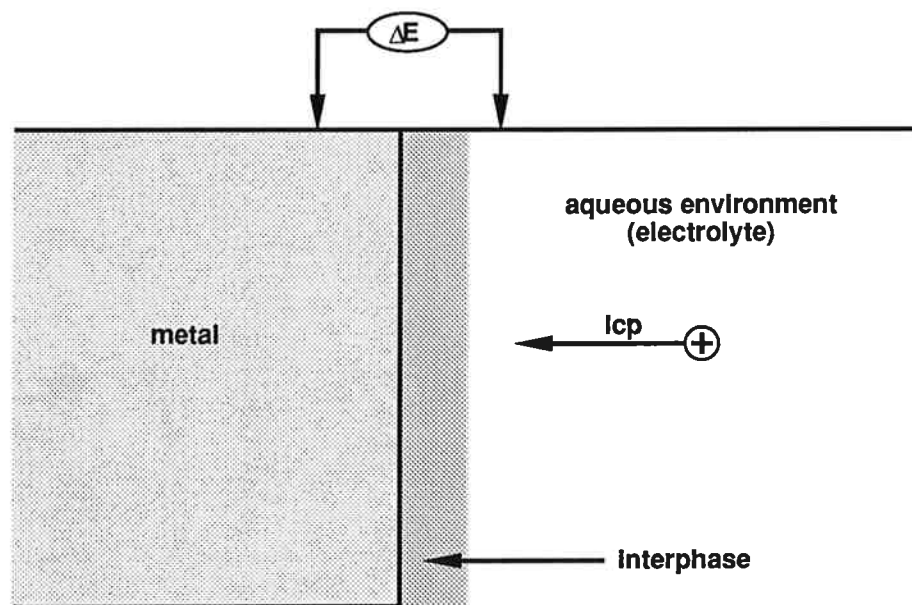


FIGURE 6 – CATHODIC PROTECTION

88% were protected cathodically. Figure 7 illustrates how leaks were virtually stopped as a result of the application of cathodic protection in one particular field. Cathodic protection applied in a field in Florida however, was not nearly as effective as the Texas field results. The leak history in the Florida application after the application of cathodic protection is shown in Figure 8 and indicates that there are situations and conditions where cathodic protection may not be completely effective.

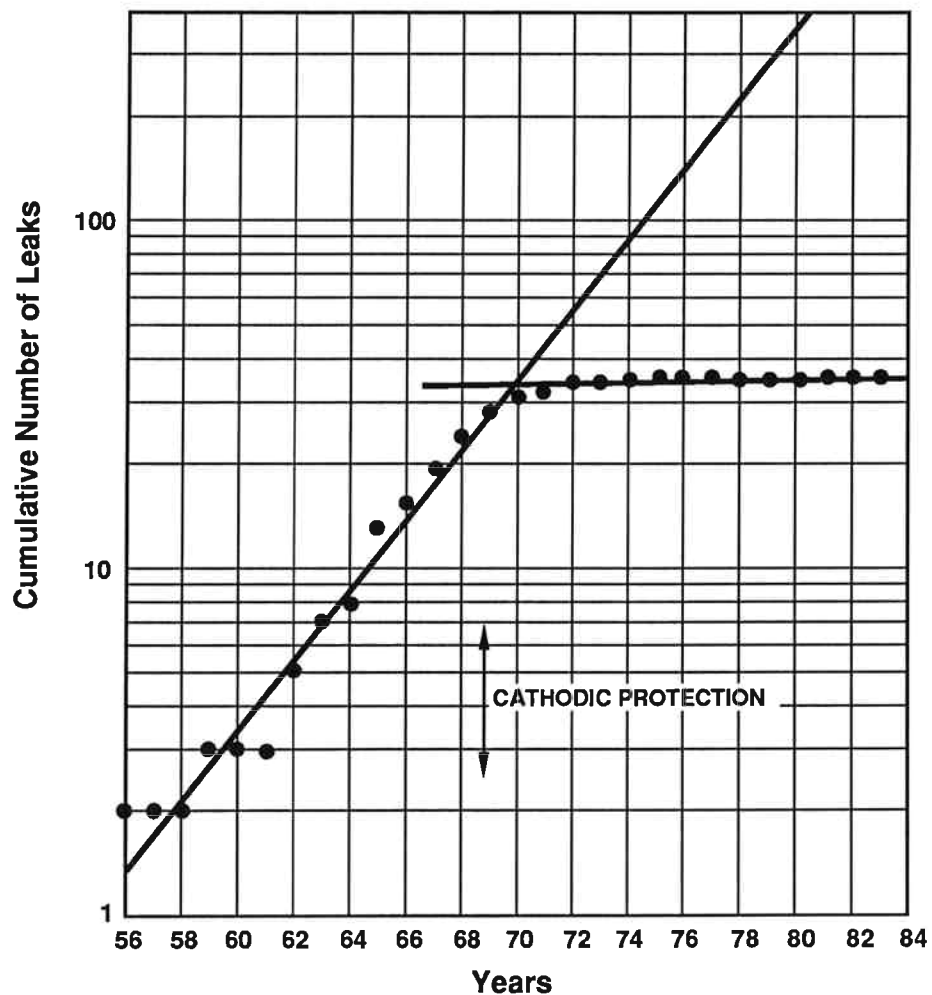


FIGURE 7 – CASING LEAK HISTORY WITH CATHODIC PROTECTION APPLIED IN A TEXAS FIELD

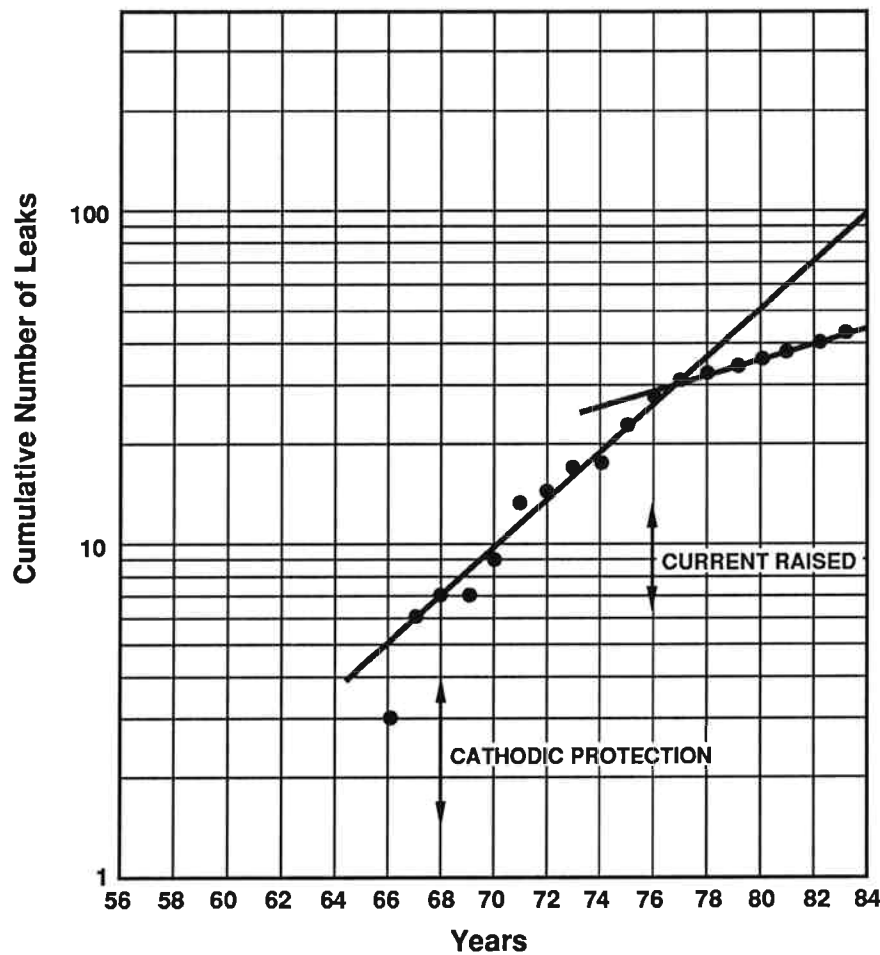


FIGURE 8 - CATHODIC PROTECTION APPLIED IN A FLORIDA FIELD

CASING CATHODIC PROTECTION CONSIDERATIONS

The fundamental definition of cathodic protection was postulated by Mears and Brown[11] who predicted that in order for cathodic protection to be entirely effective the cathode sites must be polarized to the open circuit potential of the most electronegative anode site(s). In existing corrosion cells it is virtually impossible to interrupt the corrosion cell to determine the open circuit potential of the anode and consequently other indirect criteria must be used since this true criterion cannot be determined in practice.

Most criteria are related to a potential across the steel-to-soil interface as in a minimum of -850 mV with reference to a copper sulphate electrode or a minimum potential shift of 100 mV.

The most used criterion for well casing cathodic protection however is a minimum current rather than a potential. The minimum current is normally derived from a field test which produces a cathodic polarization curve often termed an E log I curve. A typical current requirement test in the field is set up as indicated in Figure 9. A DC power supply provides a DC test current which

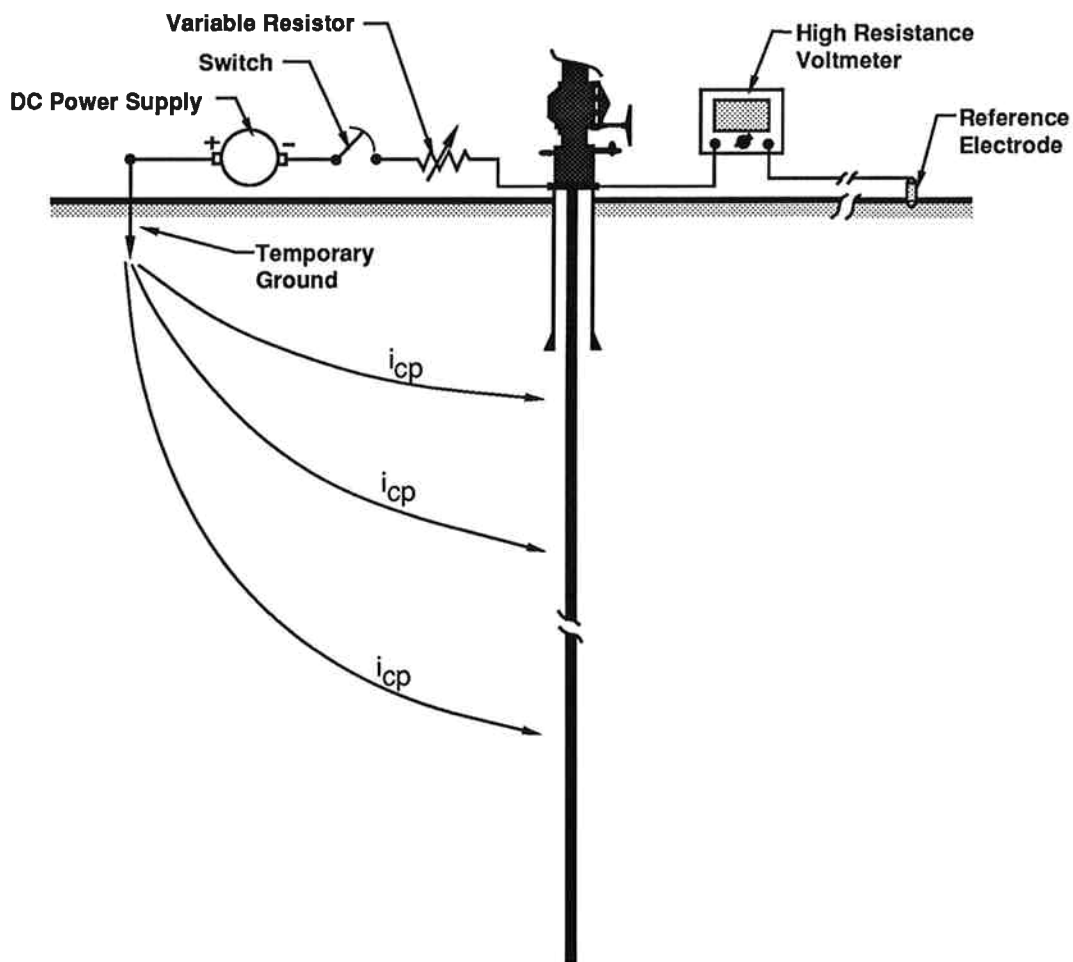
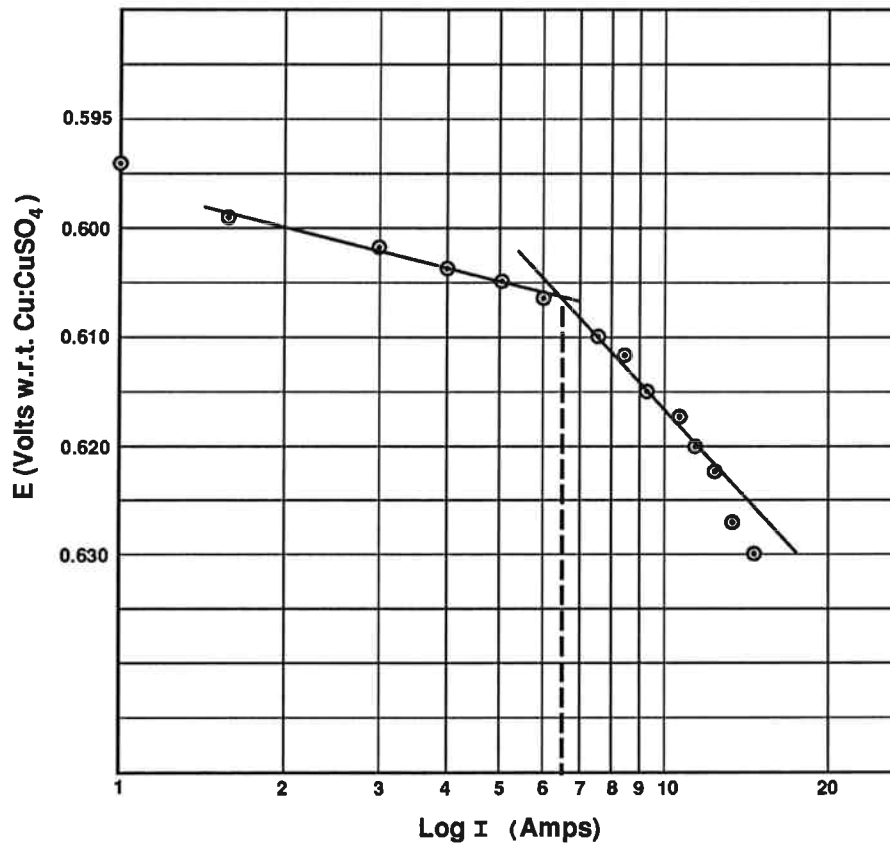


FIGURE 9 – CURRENT REQUIREMENT TEST ARRANGEMENT

can be adjusted by the variable resistor. Normally the impressed current is increased incrementally and the casing potential is measured using a high resistance voltmeter connected between the casing and a remote reference electrode (usually Cu:CuSO₄). The measured polarized potential for each current output is then plotted as shown in Figure 10 for an actual test[12]. Straight lines are normally drawn through points at each end of this curve and the point



**FIGURE 10 – CATHODIC POLARIZATION CURVE
(E LOG I CURVE)**

where the straight lines intersect is considered to be the current required for protection of the well casing (eg. in this case about 6.5 Amps). The validity of this interpretation about the break point on a cathodic polarization curve has been long disputed, partially because it requires a

certain amount of judgment to draw straight lines on what are quite often curved data. Furthermore the break point is, in the opinion of Dabkowski[13], only a function of the average casing corrosion current density in homogenous casing and soil conditions rather than an indicator of when an adequate level of cathodic protection has been achieved. Haycock[14] has tested the validity of E Log I technique in the lab and in the field and has suggested that a modification in the technique be made since the break point current was in some cases inadequate to stop corrosion. He suggested the correct interpretation of this method should be the current which coincides with the first point on the straight line portion of the curve after the break point (eg. at about 7.5 Amps instead of 6.6 Amps).

The current determined by the E Log I curve for a particular well can be used to calculate the average current density based on the surface square footage of the well casing. The magnitude of the current density required to achieve complete protection is a function of the polarization characteristics of the well casing which are affected to a considerable degree by the oxygen content in the soil adjacent to the steel as well as the existence of concrete or a protective coating. In this regard, current requirements can range from 20-30 micro-amps per sq. ft. for coated casings[9] to 100 micro-amps per sq. ft. for casings surrounded by concrete[4] and about 1 to 1.5 milli-amps per sq. ft. for bare casing in relatively deaerated soil conditions (14, 15).

Current Distribution

Calculating the total current required for a well based on an average current density can lead to an underestimation of the actual current needed since such a simple calculation assumes that there is even distribution. Uniform current distribution is seldom the case as indicated in

Figure 11[4] which shows rather uneven current density with depth. In this case the lower

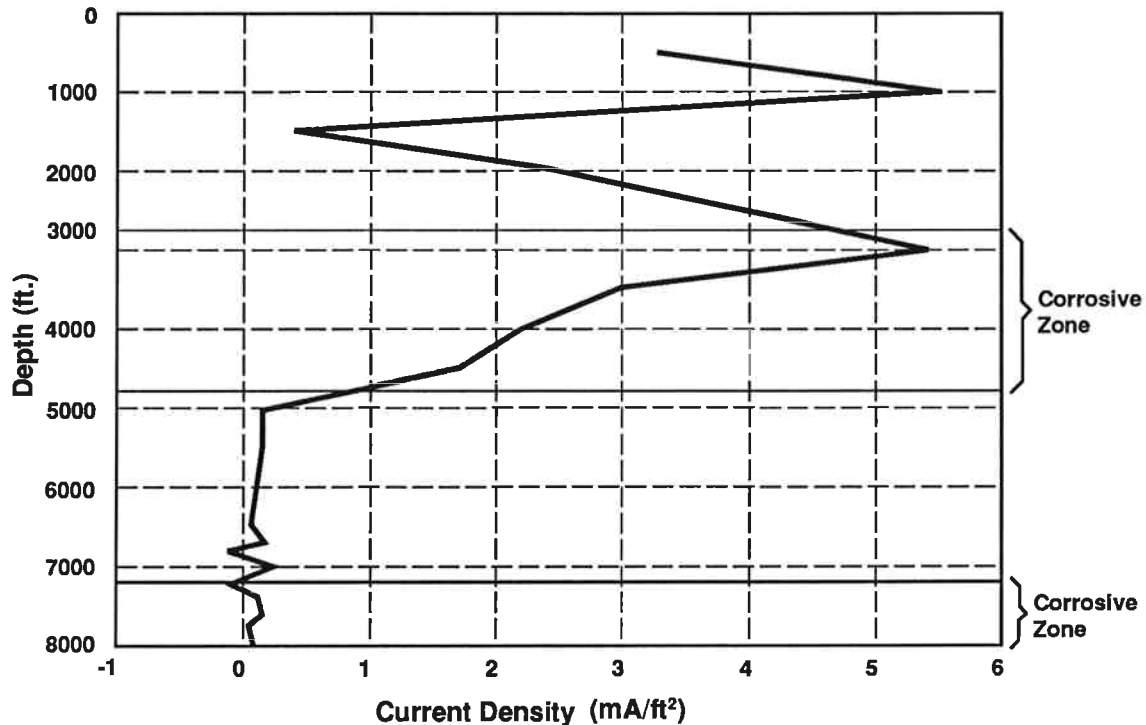


FIGURE 11 – NON-UNIFORM CURRENT DISTIRBUTION

corrosive zone receives very little current density. Poor current distribution to a well casing can result from an inappropriate groundbed location, from a high resistivity layer of soil underlying the groundbed, or from mutual interference from adjacent wells and flow lines. Some authors have indicated serious limitations[4,7] in the ability of current to penetrate to either the bottom of a casing or to at least the zone where serious corrosion is occurring. Accordingly, only by running a downhole CPP log at the time of the field current requirements test can one determine whether or not current is reaching the lowest depths of the casing.

Figure 12[4] illustrates the improvement in current distribution from top to bottom of the casing as the cathodic protection anode is moved further from the well casing. In some cases, it is not

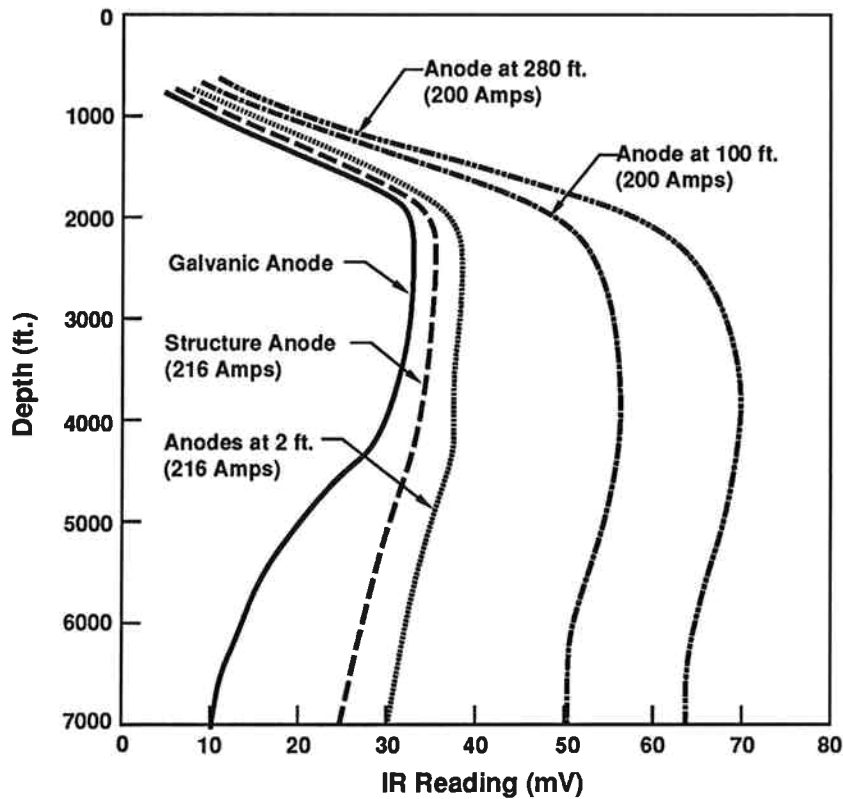


FIGURE 12 – CHANGES IN CURRENT DISTRIBUTION WITH INCREASING ANODE-TO-STRUCTURE SPACING

only necessary to move the cathodic protection anode remote from the casing but also to install it sometimes at a depth below a high resistivity soil layer which may be restricting current flow to the casing bottom. In addition if there is more than one well to be protected then the geometrical configuration of the groundbed relative to all the casings is important. One owner[16] recommends that a common anode groundbed be used for a four well array where the groundbed is located at the geometric centre of the four wells and separate negative connections brought from each well. Ewing and Bayli[8] found, for instance, in the Loudon Pool that 1500 foot long casings could be protected with a cathodic protection current of 1 to 1.5A and the groundbed located approximately 200 ft. from the wellhead.

A typical layout of a cathodic protection system relative to multiple wells is shown in Figure 13 [12]. In this example, the flow lines are being used as the negative return path for the protection current. Since this procedure and soil stratification variability can cause some mutual interference between storage wells; it is preferable to bring separate negative connections back from each well so that resistors can be placed in the negative leads and adjusted to eliminate mutual interference.

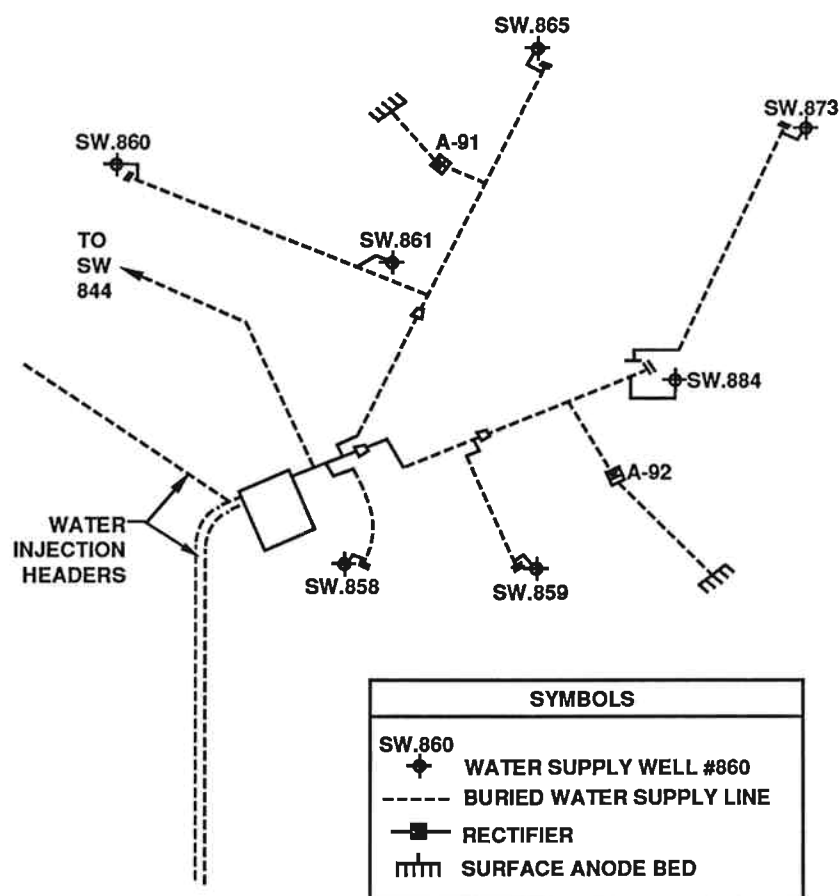


FIGURE 13 – CP ARRANGEMENT FOR MULTIPLE WELLS

Although the CPP Log is useful for indicating the relative current distribution, it can be misleading to conclude that it indicates when protection is achieved. It can however, as illustrated in Figure 14[10], indicate when a stray current interference effect has been compensated for. As shown the curve left of the zero vertical line indicates current discharge off the casing whereas the IR drop measured in the casing with the cathodic protection current applied is to the right of the vertical zero line indicating that cathodic protection current is being received along the full length of the casing. This type of log will not detect the elimination of local action corrosion cells nor corrosion cells which are circumferentially configured.

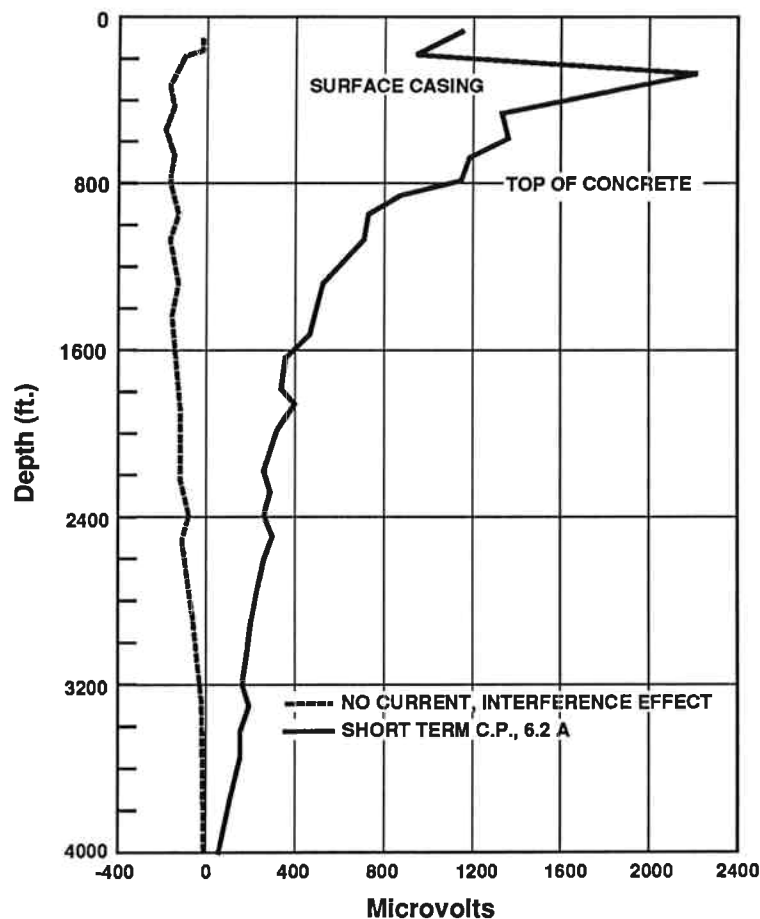


FIGURE 14 – CPP LOG INDICATING CATHODIC PROTECTION SUPPRESSION OF AN INTERFERENCE EFFECT

Monitoring and System Performance Evaluation

As difficult as it is to obtain uniform current density on a given casing owing to variations in soil resistivity with depth and the proximity of other structures which can interfere with uniform distribution, the measurement of system performance can be equally as difficult. Unlike a pipeline where the reference electrode can be moved and positioned on the surface of the soil immediately above the pipeline the positioning of a reference electrode close to the casing throughout its length is not practical. One is therefore limited to placing a reference electrode at some point on the ground surface.

Various authors have developed[17,18,19] mathematical methods and models to calculate both current and potential distribution from top to bottom on a well casing. All of these methods require considerable knowledge of the casing structure and arrangement as well as of the soil resistivity and its stratification. One method developed by Dabkowski[13] models the well casing in sections as illustrated in Figure 15 whereby the well casing can be sectionalized

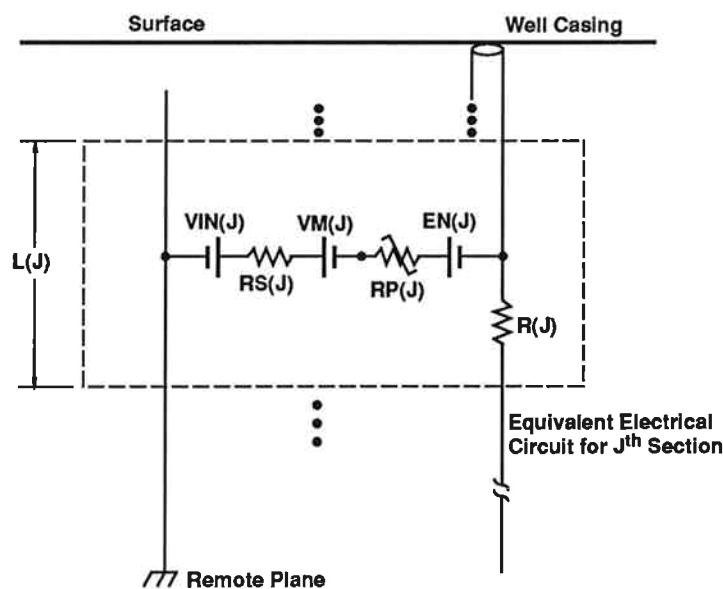


FIGURE 15 – WELL CASING MODEL

for every change in either a casing or soil parameter. This model also allows for mutual stray current interference effects to be calculated. In this model $EN(J)$ is the natural corrosion potential of a particular section, $RP(J)$ is a variable resistance due to polarization as a result of applying a cathodic protection current, $VM(J)$ is the potential developed as a result of the application of a cathodic protection current, $RS(J)$ is the shunt resistance to remote earth, and $VIN(J)$ represents an interference potential caused by a current flow from groundbeds or to other wells.

To utilize these mathematical techniques requires a comprehensive analysis of the casing and soil parameters. The complexities involved in obtaining this information will preclude the use of these methods in most instances. The usual monitoring method is to simply measure the casing potential using a high resistance DC voltmeter connected between the casing and a copper copper sulphate reference electrode in contact with the surface soil as shown in Figure 16.

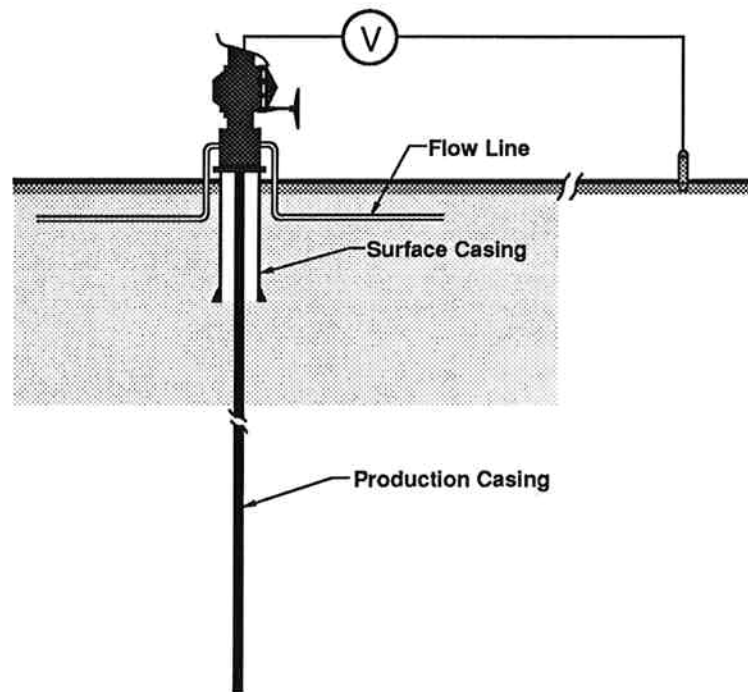


FIGURE 16 – CASING-TO-SOIL POTENTIAL MEASUREMENT

Normally the impressed current source is cyclically interrupted to facilitate recording the polarized potential of the casing free of any IR drop errors due to the cathodic protection current flowing in the earth between the reference position and the well. The measured potential will be a function of the distance between the reference cell position on the ground and the well as indicated in Figure 17[15].

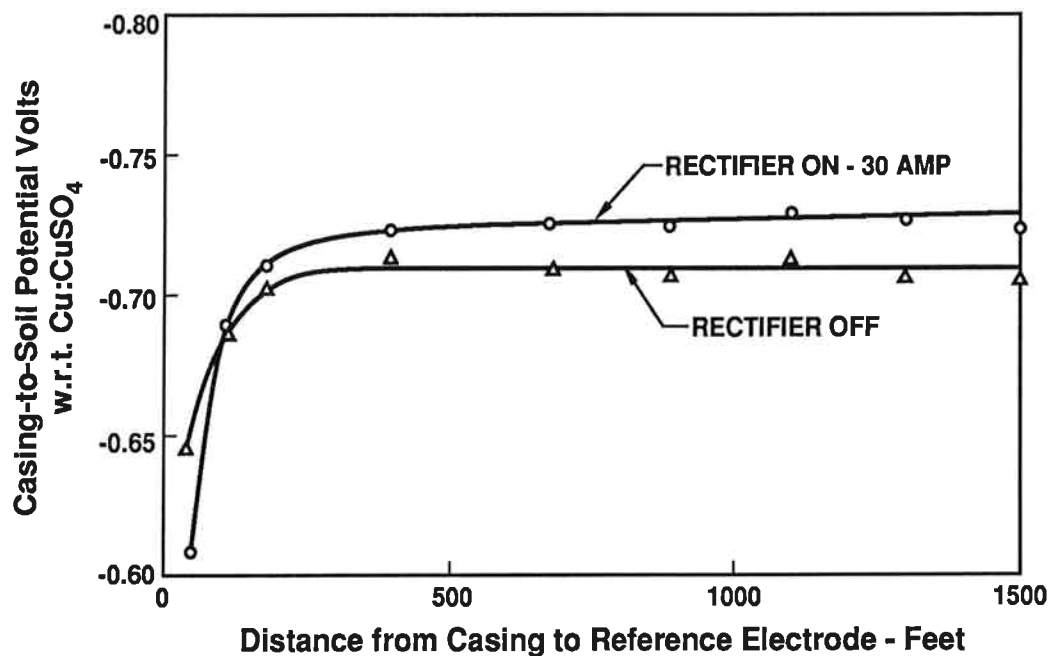


FIGURE 17 – CASING-TO-SOIL POTENTIAL WITH CHANGES IN REFERENCE ELECTRODE POSITION

As the reference is positioned increasingly further from the well the 'OFF' potential readings show little change beyond about 300 ft. in this example. The potential recorded with the remote reference positioning is an approximation of the average casing potential throughout its length. This measured potential should be compared to the natural casing potential before cathodic protection application to determine whether or not a -100mV shift has been obtained. This shift criterion is appropriate if the casing is bare (uncoated) since it will require the least amount of current to achieve compared to other potential criteria.

In test results obtained by Haycock[14] potential shifts of less than 100mV were found to reduce corrosion significantly. For instance he found that corrosion rates could be reduced by a factor of 350 with a polarization change of -50mV. He further concluded that 75% of the actual current required to give complete protection would suppress 90% of the total corrosion.

The polarization achieved on a well casing is not only a function of the current density and soil characteristics but also a function of time as shown in Figure 18[15]. Here it is apparent that polarization increases with time and hence performance evaluation testing should not be carried out until several weeks after the cathodic protection system has been energized.

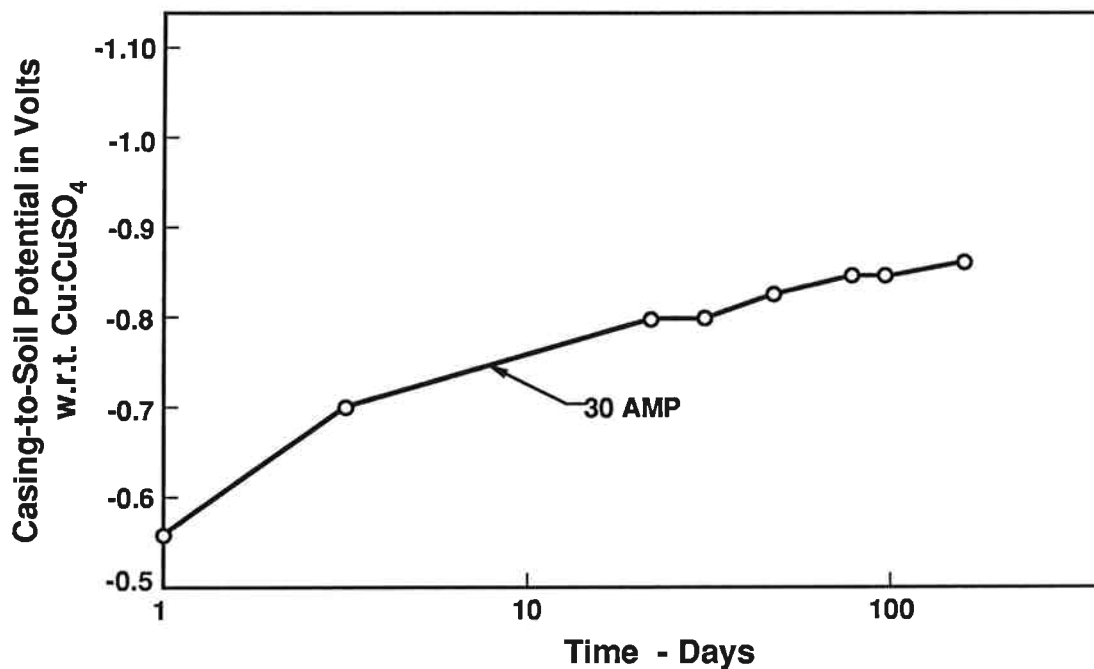


FIGURE 18 – EFFECT OF TIME ON LEVEL OF CATHODIC POLARIZATION

SUMMARY

Cathodic protection is a relatively effective and economical method of reducing corrosion on well casings provided the cathodic protection system is properly designed for the particular site and casing conditions. Other corrosion control measures such as electrical isolation and using concrete or alkaline mud are often used independently or in conjunction with cathodic protection.

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