APPLICANT'S EXHIBIT 59

Paper No.
3

CORROSION99

Development of a Corrosion Inhibition Model
II. Verification of Model by Continuous Corrosion Rate Measurements Under flowing Conditions with a Novel Downhole Tool

T. G. Martin
Mobil E&P US, Inc.,
12450 Greenspoint Drive
Houston, TX 77060-1991

M. T. Cox
Mobil E&P US, Inc.,
Route 21, Box 130
Guymon, OK 73942

R. H. Hausler
Corro-Consulta
7804 Pencross Lane
Dallas, TX 75248

R. J. Dartez, P. Pratt
Nova Technologies Corp.
3501 Hwy 90E
Broussard, LA 70518

J. C. Roberts
Baker Petrolite
Rte. 2 Box 272
Turpin, OK 73950

ABSTRACT

A novel downhole corrosion monitoring system was used to monitor corrosion rates, and verify corrosion inhibitor effectiveness in the production tubing of a CO_2 flood in the Oklahoma panhandle. The monitoring system was placed in the first tubing joint immediately above the electrical

submersible pump. This location was deemed most corrosive, and therefore requiring the highest inhibitor concentration, due to high CO_2 partial pressure, the elevated temperature, and the extremely turbulent flow. Laboratory evaluations had indicated the approximate effective inhibitor concentration required to attain the desired target corrosion rate under similar environmental and turbulence conditions. The complex problem of translating laboratory flow (high speed autoclave test) to field conditions was attempted empirically using established correlation for the rotating cylinder and tubular flow.

Keywords: target corrosion rate, effective inhibitor concentration, shear stress, high speed autoclave test, CO_2 partial pressure, corrosion inhibition modeling, response surface methodology,

INTRODUCTION

The Postle Field, situated in the Oklahoma Panhandle, north of the city of Guymon, has been in operation since 1958. The field produces form the Morrow Sand at a depth of 6,100 ft and was placed on CO_2 flood in 1995. The field differs from Mobil's other CO_2 flood operations in that it is a sandstone formation, while most of Mobil's West Texas CO_2 flood operations to date have been in limestones.

Initial corrosion control treatment for the Postle followed the program which had been developed for the West Texas limestone floods with a weekly batch treatment into the annulus at a rate of 20 to 25 ppm for inhibitor D[1)]. The treatment procedure was changed from batch treatment (inhibitor with overflush) to continuous when CO_2 breakthrough occurred, but without changing the treatment rate.

Shortly after CO_2 breakthrough occurred the field began to require more frequent well workovers. Severe corrosion on both internal and external surfaces of the production tubing was found with corrosion rates, in some instances being in excess of 300 mpy. Field personnel observed that high corrosion rates appeared to be associated only with wells where large quantities of CO_2 would be produced though the corrosion pattern was complex and initially difficult to predict.

The Postle CO_2 flood, being a sandstone formation, is inherently more corrosive than "limestone floods" mainly because of the low bicarbonate concentration (200ppm) in the produced water from sandstone formations (vs. 2000 ppm bicarbonate from limestone formations), and the attendant lower pH that results in the presence of CO_2.

Table 1 shows the influence of bicarbonate ion on the pH of a CO_2 containing water. The difference between 200 and 2000ppm bicarbonate in the produced brine is one between the formation of an insoluble, protective iron carbonate film on the surface of the metal at higher pH and the absence thereof at the lower pH.

[1)] Some performance data for this inhibitor are given in Ref.4

Table 1

pH in Produced water as Function of CO_2 Partial Pressure and Bicarbonate concentration (Temperature 160 °F, Ref. 1).

P_{CO2} psi	HCO_3^-	
	200 ppm	**2000 ppm**
100	*4.87*	*5.87*
500	*4.18*	5.17
1000	*3.89*	4.87

It has also been shown that commercial inhibitors differ in their ability to inhibit at high and low pH's (Ref 2). In addition, higher flow rates and higher water cuts greatly aggravate corrosion at the lower pH due to increased mass transfer of the corrosion products away from the metal surface, while in the intermediate range, where protective scales might just form, high flow intensity (turbulence) leads to localized corrosion and so called "mesa" attack.

The effective inhibitor concentration (EIC), i.e., the concentration required in the field to reach a low target corrosion rate at which localized attack is minimized, depends on environmental parameters in a complex manner. An attempt is made in Table 2 to summarize these relationships qualitatively.

Table 2

Effect of	Direction of Change	Effect on required Inhibitor Concentration
Decreasing pH on		
Corrosion	↑	↑
Scale Formation	↓	↑
Increasing Flow on		
Corrosion	↑	↑
Scale Formation	↓	↑
Increasing Pressure on		
Corrosion	↑	↑ ↓
Scale Formation	↓	↑ ↓
Increasing Water/Oil Ratio on		
Corrosion	↑	↑ ↓
Scale Formation	↔	↓

As indicated earlier, a decreasing pH increases corrosion while preventing the growth of protective scales with the result that higher EIC's are needed for adequate protection. The flow rate (and by implication the flow intensity at flow upsets) similarly results in a requirement for higher EIC. These relationships have been demonstrated quantitatively in previous publications (Ref. 2,3,4).
The pressure effect is peculiar in that there appears to be a maximum in the Corr.rate / pressure curve for different inhibitor concentrations. This was first demonstrated in studies related to another CO_2 sandstone flood (5). Recently similar studies were performed with Inhibitor C in use at the Postle field. Figure 1 indicates by means of iso-corrosion lines presented as contours in the P_{CO2} vs. rpm (velocity) grid, that at certain velocities, and for certain metals[2)] the pressure effect might have a maximum at certain inhibitor concentrations. These data also indicate that the usage rate of 20 ppm inhibitor in the field very likely was not enough and that under certain high velocity conditions even 100 ppm would not be sufficient.
It was against this background that an attempt was made to establish a model for the effective inhibitor concentration as a function of CO_2 partial pressure, rpm (flow rate), and the water/oil ratio (Ref. 4). The data had indicated that under the most corrosive conditions in the laboratory high concentrations of inhibitor were needed, again depending on the metallurgy. The opportunity then existed to verify the laboratory data in the field by direct real time downhole corrosion measurements.

DESIGN OF FIELD TEST

1. Objectives

The objectives of the field test were formulated as follows:

- Determine the effectiveness of the corrosion inhibitor in terms of degree of protection and EIC.
- Confirm the corrosion inhibition model in a limited number of field tests under the most severe corrosion conditions possible.
- Focus on inhibition of tubing corrosion
- Determine the effectiveness of the inhibitor treatment for different continuous injection modes (various lengths of capillary)

The focus was on tubing corrosion initially because the tubing intervals were where the lowest corrosion inhibitor concentrations were anticipated. Since the corrosion inhibitor dosage was determined on the basis of the total volume of produced fluids, the inhibitor concentration in the annular space was expected to be many times higher in proportion to the overflush relative to the total volume produced. If only 5 percent of the total fluids were circulated, the concentration in the annulus would be 20 times higher than anticipated in the tubing. It could, therefore, be assumed that if the tubing id was inhibited, the casing space would be inhibited as well, even if due to high gas production rate the flow intensity in the annulus was even higher, provided the inhibitor – overflush mixture was not blown out of the casing space because the critical gas velocity had been exceeded[3)].

[2)] This maximum appeared to be present at about 425 psi and 1000 rpm only for J-55 metal. For N-80 and L-80 the maximum might have been shifted to higher CO_2 pressures while the corrosion rates at 100 ppm inhibitor concentration were considerably higher as well.

[3)] The critical gas velocity is the velocity at which liquid is gas lifted out of the casing space.

2. The Tool

A new tool, the downhole corrosion monitoring system had recently become available from NOVA Corporation[4]. The system had been extensively field tested by ARCO Alaska in 1997 (Ref. 6). The corrosion measuring device consists of a standard, cylindrical, electrical resistance probe attached to a power supply, and the electronic measuring and data storage circuitry. The assembly is packaged into a 1.25 inch x 54 inch stainless steel tube which can be placed by special wireline tools at any depth in the production tubing (Figure 2). Because the flow channel was reduced due to the placement of the tool, the first joint above the pump was replaced with a 13% Cr steel joint. This prevented corrosion damage which might otherwise occur to carbon steel in the unusually aggressive conditions found in Postle wells.

3. The Test Wells

A typical completion scheme of Postle wells is shown in Figure 3. Only few wells were equipped with full length inhibitor injection capillaries. Most wells only had a 40 ft stinger capillary to assure that, for continuous inhibitor injection with overflush, the turbulent zone in the annulus near the well head was bypassed, thereby preventing fluids injected into the annulus from being entrained in the gas. A special feature of the downhole completion is the gas separator, placed between the pump intake and the pump itself. It is estimated that the free gas entering the pump intake was separated from the liquids with about 80% efficiency. Measurements actually indicated that almost all free gas was produced out the annulus, while only dissolved gas in equilibrium with the downhole pressure (at the pump intake) was carried with the liquid. The pump intake pressure was controlled by the fluid level above the pump and the flowline pressure on the surface. In those cases where the wells were equipped with only a 40 ft capillary, the fluids below the pump intake could not be inhibited. Carbon steel equipment below that point was therefore subject to corrosion.

4. Selection of the Test Wells

The cost of the test, consisting of the rental of the equipment and three wireline jobs (see below), precluded a broad based test matrix. Therefore, the verification of the inhibitor model was to occur only under the most severe conditions. The criteria for the selection of the test wells were as follows:

- Low level of bicarbonate in the produced water (< 200 ppm)
- High gas rate (>500 MSCFD)
- High liquid flow rates (> 1000 bbl/d)
- Low and high water/oil ratio
- Versatility for inhibitor injection mode

The last criterion was intended for verification of models which helped assessing the critical gas velocity above which liquids are gas lifted out of the casing space. Because of workovers, temporary shut-ins and miscellaneous failures the selection was restricted to a small number of wells and kept changing.

---

[4] NOVA Technology Corporation, 3501 Highway 90 East, Broussard, LA, 70518, formerly a Division of Rohrbach Cosasco Systems, Inc.

5. The Structure of the Downhole Tests

The corrosion monitoring tool was located in the 13% Cr-steel joint immediately above the pump to capture the effects of the high turbulence of the fluids exiting the pump and the maximum downhole temperature expected to be around 150 to 160 ^{O}F. Since a decision had been made to determine the effectiveness of the inhibitor it was necessary to establish the uninhibited corrosion rate prior to inhibitor injection. Therefore an elaborate procedure was worked out to assure removal of all residual inhibitor from the wellbore prior to running the tool into the well. The uninhibited corrosion was monitored for 5 days under normal production conditions in order to establish the steady state uninhibited corrosion rate. Subsequently, inhibitor injection was initiated at the highest rate for about 1 day. The probe was then pulled and replaced with a fresh one. Subsequently it was intended to change the inhibitor injection rate from 300 ppm in 4 steps down to 50 ppm running each concentration for 5 to 7 days.

The liquid flow line of the test well was equipped with a PAIR™ (LPR) meter, an electrical resistance probe, and, where possible, a corrosion coupon. Both meters were continuously reading instruments with data storage capabilities.

The production rates, producing conditions (fluid level, tubing and casing FWHP and FWHT), inhibitor injection rates water analyses and iron counts were recorded as frequently as practical.

The downhole ER-probes were weighed and calipered before and after the test to compare the instrumental read-out with the average weight loss corrosion rate and the appropriate dimensional changes.

Two options existed for the choice of the ER-probes, 10 mil and 20 mil wall thickness with a useful life of 5 and 10 mils respectively. Based on sensitivity considerations it was desirable to use the thin-walled probes for the inhibited test periods. The thick-walled probe, however, had to be used for the uninhibited period because potential corrosion rates of the order of 500 mpy were anticipated, in which case the useful life of the thin probe would have been exceeded in 5 days. These requirements necessitated replacement of the thick-walled probe after the blank test period in order to avoid going into the inhibited test periods with a partially, or fully, used up probe. As it turned out, this precaution was not necessary, because the observed corrosion rates were lower than anticipated.

RESULTS AND DISCUSSION

1. PUMU 9-6

1.<u>The Field Test</u>
The first test well was PUMU-9-6. The production was about 200 bbl/d oil, 250 bbl/d brine and 182 Mscfd gas. In this respect, the well did not correspond to the selection criteria, but it did have both a full length and a 40 ft capillary and water analyses prior to the test showed low bicarbonate content. Figure 4 shows the test sequence in the form of a timeline. Prior to the installation of the downhole probe the procedure of removing all inhibitor from the well was executed. The uninhibited test period lasted 3

days. The thick walled downhole probe used in the blank run was then replaced with a thin walled one, and the inhibitor injection rate was reduced from 300 ppm to 200 ppm because neither the surface nor the downhole ER probes had shown any corrosion toward the end of the blank test period. When it appeared that still no corrosion was observed during the next few days, the inhibitor concentration was reduced to 20 to 25 ppm and left there for the next 25 days. At this point the test was terminated.

Figure 5 shows the response of the downhole ER probe along with the temperature record. The temperature of the fluids immediately at the exit from the pump was about 176 ^{O}F (80 ^{O}C) and increased gradually toward 180 ^{O}F during the 4 day run. This was considerably higher than what had been expected (140 to 150 ^{O}F for the formation temperature) and included the heat generated by the downhole pump motor and the pump itself (friction). The ER trace goes through an initial minimum which has never been fully explained. Presumably both the battery and the electronic circuitry go through a period of adjustment to the higher downhole temperature, during which time the battery voltage increases and the circuits reach a steady state. After this initial minimum, a period of high corrosion (117 mpy) is followed by rapid passivation (presumably scale formation and/or natural inhibition).

Figure 6 shows a complete evaluation of the ER probe response for the first test period. An initial corrosion rate of 117 mpy is observed for about a day. Afterwards, a full day prior to the injection of the inhibitor, passivation occurs and the corrosion rate decreases to about 1.5 mpy. Figure 7 shows the surface ER probe trace during the same period. Unfortunately some data for this period were lost. Nevertheless, there is a good indication that the downhole passivation process is mirrored in the surface probe.

The main result from this period is that for some time the downhole corrosion was 117 mpy. (This compares favorably with subsequent data – see below). The corrosion rate on the surface for this short period was only 34 mpy. Passivation occurred in both instances.

After the new thin walled ER probe had been run into the well the inhibitor concentration was reduced to 200 ppm for a few days, and when it became obvious from the surface probes that corrosion was not increasing, the concentration was further reduced to 20 to 25 ppm. There was never any indication that the corrosion rate, downhole or on the surface was any larger than the detection limits of the instruments (0.1 mpy) for the period of observation.

2. Discussion

This test showed that carbon steel corrosion was inhibited naturally by the produced fluids. The weight loss corrosion rate obtained from the downhole ER probe matched the integral of the electronic readout. Extensive calipering showed no measurable loss in the diameter. The downhole ER probe was judged very reliable. Table 3 indicates that the production rates held steady over the entire test period. The answer for the absence of corrosion in this well under the prevailing conditions, therefore, must be found in the chemistry of the produced fluids.

Table 4 lists water analyses from shortly before, during and after the test. It appears that there has been a shift of the bicarbonate concentration causing a shift in pH from 4.3 to 4.9, i.e. from a non-scaling ($FeCO_3$) to a scaling condition. The iron carbonate saturation pH is estimated at about pH 4.4 to 4.5 at 180 ^{O}F (Ref. 1). Additionally, the produced oil proved to be paraffinic in nature (as judged from paraffin deposits on the surface probes). It is, therefore, concluded that the combination of relatively low production rates, higher than expected downhole temperature, an unexpected shift in pH favoring iron carbonate film formation, the low water/oil ratio, and the paraffinic nature of the oil all worked together to generate a non corrosive condition.

2. HMAU 54

1. <u>The Field Test</u>

The second test well was HMAU-54 with an average production of 2500 to 2800 bbl/D brine, 140 to 150 bbl/d oil and 230 to 250 Mscfd gas. The CO_2 content in the gas was of the order of 80% and the fluid level was consistently high between 1500 and 2000 ft above the pump. This well was also equipped with a full length capillary (see Fig. 3) and a 13% Cr-steel joint had just been installed immediately above the pump where the tool was to be placed. Prior to running the probe into the well, all remaining inhibitor from the previous treatment was flushed out of the casing and tubing. Table 5 shows water analyses from before and during test. The bicarbonate levels appeared to be quite low. The test sequence and timeline is shown in Figure 8.

Figure 9 shows the downhole ER probe response during the uninhibited (blank) period. The corrosion rate starts out at 120 mpy (vs. 117 mpy on the PUMU 9-6 for the first hour), and reaches a steady state of 82 mpy after 1 day. The inhibitor injection was initiated at 265 ppm after 4.5 days. The delay of the probe response is due exactly to the time it took for the inhibitor to fully displace the xylene in the capillary. The inert solvent had been used to purge all inhibitor from the capillary and was left there during the blank period. As soon as the inhibitor reached the pump intake, the corrosion rate decreased to a very low level of 2.2 mpy. The downhole temperature during the blank run was 154 ^{O}F and held steady during the entire period. Figure 10 shows the response of the surface ER probe. The initial corrosion rate decreased from 90 mpy to 67 mpy during the first 5 days. After the inhibitor reached the surface a corrosion rate of 4.7 established. The blank test was terminated before steady states had been established, either downhole nor on the surface. The surface probe mirrored the downhole trends, albeit at a somewhat lower level. Prior to starting the inhibited period of this test, new probes were installed in both locations.

Figure 11 shows the record of the downhole ER probe during the inhibited period. It took a few hours for the inhibited corrosion rate to establish itself on the new probe. The steady state leveled out at 1.3 mpy. During the transient a corrosion rate of 17 mpy was extrapolated from the data. (Not enough points could be recorded to extrapolate a good number from the somewhat noisy data). After the injection rate was changed from the 265 ppm to 150 ppm the corrosion rate increased from 1.3 mpy to 4.1 mpy over a very short period of time. (The "film" life was only 3 to 5 hours at best). The same behavior is seen on the new ER probe on the surface as shown in Figure 12. It took a few hours for the corrosion probe to become fully inhibited. At 265 ppm the corrosion rate is practically zero, or so low (>1 mpy) that no meaningful value could be extracted from the 48 hour record (the statistical trend of the data is negative). At 150 ppm a corrosion rate of 1.2 mpy could be determined from the 7 day record.

After the inhibited period had been running for about 10.5 days an upset occurred. The surface flowline was accidentally shut in such that the pump deadheaded for a period of time. During this period and before the pump shut down, the fluid temperature reached 350 ^{O}F (see Fig. 11). The corrosion rate increased to about 15 mpy, but when the temperature had receded to 149 ^{O}F, the corrosion rate stabilized at a level of about 0.5 mpy under stagnant conditions. Whether the low corrosion rate is due to passivation or inhibition is impossible to determine. However, the temperature excursion did not cause any damage, which was confirmed by subsequent workover.

The behavior of the LPR probe is shown in Figure 13. During the uninhibited period a corrosion rate of 2.5 mpy can be averaged out from the extremely noisy data with some confidence. However, during the inhibited period, the measurements were practically zero. All fluctuations are due to the electronic bit-noise off zero.

2. Discussion

Table 6 summarizes the results from the second test. The downhole corrosion protection at 265 ppm was 98.4 % and 95 % at 150 ppm inhibitor concentration. This is probably for the first time that such high degrees of protection have been shown in the field under downhole conditons for any corrosion inhibitor. The degrees of protection derived from the surface data are even better, 99.4 % and 98.2% for 265 and 150 ppm, respectively. This points to the important fact, long suspected but never quantitatively demonstrated, that surface corrosion rate measurements do not reflect the real downhole situation. Qualifying comments need, however, be made. While inhibition may have been favored by the lower temperature on the surface, suspected turbulent conditions may have tempered this effect. It has been calculated that gas break-out from the liquid in the tubing occurred at about 2000 ft from the surface. The mixture velocity was thereby accelerated from 9 to 16.7 ft/sec. The surface probe was therefore exposed to a much higher flow rate and much greater turbulence than the downhole probe. In the absence of such gas break-out, inhibition on the surface might have been even better. The LPR probe response was many times lower than the ER responses even though the water/oil ratio was from 12 to 14, a water cut usually thought to be very favorable to LPR measurements. Two effects may have been responsible for this. It had already been observed in extensive autoclave corrosion measurements (Ref. 4) that with Inhibitor C the weight loss/LPR ratios were quite high. They generally increased with inhibitor concentration and could be as high as 20 with an average around 5 to 10. This phenomenon depends on the nature of the inhibitor and of course the water cut. On the other hand, the high gas volume commingled with the fluids on the surface (about 45 vol% gas and 55 vol% liquids) no doubt was also responsible for the low LPR readings as well as the extreme noise observed in the data. All this points to the need for caution in interpreting surface corrosion measurements. The difference between an instrumental reading of 4 mpy (general corrosion rate) and 1 mpy is not trivial in view of possible localized corrosion (pitting factor). It had been shown in the previous paper, by means of autoclave testing and extensive pit measurements, that localized attack occurs under partially inhibited conditions when corrosion rates exceed 1 mpy. A surface corrosion rate reading of 1 mpy (with concomitant downhole corrosion of 4 mpy) is no assurance that pitting or localized attack (FILC) has been inhibited downhole. The customary pitting factor of 20 often accepted in the oil field as relating general corrosion to localized corrosion seems to confirm these conclusions.

Iron counts had been measured occasionally during these tests. The average tubing corrosion rates derived therefrom for bare tubing are independent of the presence of inhibitor or its concentration. The tubing furthermore had been internally plastic coated. All this confirms that soluble iron was produced with the brine from the formation and that iron count measurements therefore would be useless for the purpose of monitoring inhibitor effectiveness.

In summary it can be concluded that this new corrosion monitoring system is an excellent tool with which one can begin to resolve a number of open questions related to monitoring of corrosion and corrosion inhibition. Differences between downhole and surface corrosion rates must be interpreted carefully and some commonly used tools for measuring corrosion rates at surface may not be entirely reliable. At the least it has been possible to put in perspective the reliability of some of the more common oil field practices. More importantly, it has been shown that the degree of inhibition in the field under realistic conditions is much higher than commonly believed. The factors which control the degree of inhibition will be discussed below.

INHIBITION MODEL

The objective of modeling corrosion inhibition is to extract from the accumulated laboratory (Ref. 4) and the newly acquired field data a means to predict the effective corrosion inhibitor concentration (EIC) which would result in a predetermined (target) corrosion rate under field conditions. Since almost every producing well in a CO_2 flood exhibits different producing conditions the EIC for each well is different. A corrosion inhibition model is, therefore a prerequisite for optimizing the inhibitor program cost field wide and by implication minimizing the maintenance expenditures.

The modeling process begins by setting a target corrosion rate, determined by the life expectancy of the field, the anticipated pitting factor, the acceptable treatment cost, or any other operational parameter which might be considered a priority. The target corrosion rate is, therefore, subject to a decision by the operator of the field. Once the target corrosion rate has been established, the inhibitor performance curves are used to define the EIC's for different pressure and velocity conditions. The methodology has been described in detail in the previous publication (Ref. 4). From an array of EIC's defined for different CO_2 partial pressures and different flow conditions, contour plots are generated for constant inhibitor concentration. These curves are generated from laboratory data obtained by means of the high speed autoclave test. The velocity vector is therefore expressed in rpm of the rotating cage. In order to verify this laboratory developed model and give it practical utility, one needs to translate the flow intensity of laboratory conditions to those prevailing in the field. To achieve this task explicitly is a real challenge since the rotating cage used to generate the laboratory data is not really a rotating cylinder, and the downhole ER-probe used to generate the field data is not necessarily exposed to the same flow intensity as the tubing walls in which it resides during the test. In the face of these difficulties, and the absence of an abundance of data, only a qualitative attempt can be made at the comparison of the two data sets. The approach, as intuitive as it might be, may stimulate further efforts in this direction, and perhaps begin to put in perspective the many misleading and erroneous claims being made about the art of chemical corrosion inhibition.

In analogy to Efird's work (Ref. 7) the wall (or surface) shear stress was used to link the laboratory results with the field data. The overall methodology was as follows:

- Determine the shear stress of the rotating cage (τ_{rc}) as function of rotating speed of the cage (rpm_{RC}).
- Determine the shear stress at the downhole tool in terms of the tubing shear stress (τ_{tbg})
- From the correlation of (rpm_{RC}) = f(τ_{rc}) determine the "apparent equivalent" (rpm_{tbg}) using (τ_{tbg})
- Enter the apparent equivalent shear stress into the contour plot for the effective inhibitor concentration.
- The difference between the EIC extrapolated for (rpm_{tbg}) and the (rpm_{RC}) corresponding to the concentration used in the field will yield an empirical factor by means of which (rpm_{tbg}) is to be adjusted in order to make the contour plot (laboratory data) predictive in terms of the

concentration which needs to be used in the field in order to achieve the target corrosion rate for which the contour plot has been defined.

The contour plot is used to facilitate the understanding of the methodology. The same procedure can be formulated analytically as will be shown later. The shear stress calculations for the rotating cage were based on a discussion by Silvermann (Ref. 8, 9). The results are shown in Figure 14 along with an empirical correlation equation which was extracted solely for ease of future calculations. The tubing shear stress was calculated on the basis of Efirds discussion (7). For the conditions found in HMAU 54 (tubing diameter 2 3/8 inch, brine production 2800 bbl/d, oil production 150 bbl/d, temperature 150 ^{O}F) the tubing shear stress (τ_{tbg}) was found to be 13 N/m^2. This results in an apparent equivalent tubing rpm (rpm_{tbg}) as extrapolated from Fig. 14 of 706.
The CO_2 partial pressure in the fluids above the pump was estimated at 550 psi. Referring to Figure 15, the contour plot for 1 mpy, one can see that the apparent equivalent tubing rpm would, at 550 psi CO_2, predict an EIC of about 90 ppm. From the field data one knows however, that the target corrosion rate of (about) 1 mpy was attained with 265 ppm which corresponds to 1411 rpm. The relationship between (rpm_{tbg}) and (rpm_{RC}) therefore is almost exactly a factor of 2. From a practical point of view this means that if the apparent equivalent tubing rpm is determined from the actual tubing shear stress and multiplied by a factor of two, one can determine the effective inhibitor concentration from the contour plot for any pair of production rate and CO_2 partial pressure. The procedure is confirmed by the second field data point from HMAU 54. Figure 16 shows the contour plot for 4 mpy. The production conditions are the same as above. Extrapolation of the EIS for the apparent equivalent rpm of 706 results in an apparent EIC of 60 ppm. However, 4 mpy was obtained in the field with 150 ppm corresponding to a cage rpm of 1420. The factor of two is thereby confirmed.

Efird (7) has shown that at equal shear stress the corrosion rate obtained on a rotating cylinder is about two to three times less than that observed in tubular flow. Equal corrosion rate would therefore require a higher shear stress (higher rpm) on the rotating cylinder by about the same factor as observed above. Since a higher corrosivity requires more inhibitor to achieve the same target corrosion rate [5)], and since a lower tubular shear stress represents a higher corrosivity than equal rotating cylinder shear stress, it is clear that both the inhibitor concentration as well as the cylinder rpm would have to be increased to match the field conditions. It appears, therefore, that the data presented here and their interpretaion, albeit dealing with corrosion inhibition rather than corrosion itself, find confirmation in the work presented by Efird.

In order to develop the model quantitatively the data for the EIC's as a function of rpm and CO_2 partial pressure were expressed in diagnostic equations rather than contour plots. The equations were obtained by means of a multiple linear regression using JMP™ software[6)]. The equations for 1 mpy and 4 mpy are:

$$EIC_{1mpy,J-55} = -117.1 + 0.105 \bullet P_{CO_2} + 0.2285 \bullet rpm$$

and

$$EIC_{4mpy,J-55} = -62.4 + 0.0692 \bullet P_{CO_2} + 0.121 \bullet rpm$$

[5)] It has been shown time and again that the more corrosive a system the more inhibitor is needed for equal protection in terms of the target corrosion rate (see also for example Ref. 10).
[6)] JMP™ is statistical software from SAS Institute Inc., Cary, NC.

respectively. In analogy to the above methodology one first determines the actual tubing shear stress which is then converted to the apparent equivalent tubing rpm. This latter number is then multiplied by two and inserted in the above equations in order to arrive at the EIC associated with the particular production conditions.

This model for corrosion inhibition clearly has limited applicability. While the contour plots do account for the non-linearity observed in the pressure effect, the correlation equations do not. The effect of this on the predicted EIC is small, but must be kept in mind. The correlation equations as well as the contour plots strictly have validity only within the experimental parameter range. More important, however, is the fact that the results presented here are both field- and inhibitor specific. The same inhibitor in high bicarbonate brine would result in lower EIC values, while different inhibitors in the same field can vary dramatically in their respective EIC requirements. Superimposed on this are the different responses obtained from different metals. It has been pointed out that L-80 under high flow intensity requires much higher EIC's. This highlights the notion, often glossed over in practice, that for optimum inhibitor applications field specific evaluation under realistic conditions is unavoidable. On the other hand, the model does show a way to define the EIC specifically for each well in a field and thereby opens a way toward economic optimization of inhibitor treatments, and selection of corrosion mitigation scheme on more meaningful cost data.

SUMMARY

Downhole corrosion rate measurements were made with a new tool by NOVA Technology Corporation which is based on electrical resistance technology. The tool was used in two wells to verify the effectiveness of the corrosion inhibitor used field wide. In the first test well, PUMU 9-6, it was found that the inherent uninhibited corrosion rate might be of the order of 120 mpy. This rate was sustained only for a short period of time before passivation set in. Passivation is due to a combination of factors: mild flow conditions, high temperature, high bicarbonate concentration in the brine, and a low water to oil ratio. The steady state corrosion rate was essentially zero, a fact which was also attributed to the natural corrosion inhibiting properties of the produced oil.

The second test was performed under more severe flow conditions, a very high water cut, and higher CO_2 partial pressure. Realistic steady state blank corrosion rates were measured downhole and on the surface. Upon adding inhibitor at 265 and 150 ppm degrees of inhibition of 98.4% and 95%, respectively, downhole, and 99.4 and 98.2 %, respectively, on the surface were achieved. Such high degrees of inhibition were previously thought to be unrealistic under field conditions. It was also observed that surface corrosion measurements consistently reflect lower aggressiveness than prevails downhole and therefore, higher inhibitor effectiveness. The importance of this is seen in the fact that in order to prevent failures by pitting and/or flow induced localized corrosion, the general corrosion has to be inhibited below a certain level. A surface corrosion rate of 1 mpy which may correspond to a downhole rate of 4 mpy is no guarantee that localized downhole corrosion has been inhibited.

An attempt was made to model the field results within the framework of the laboratory data using the wall shear stress to translate the field flow conditions to the laboratory flow conditions generated by rotating cage in the high speed autoclave test. Because the calculated shear stress for the cage is higher than the calculated shear stress for tubing at equal corrosion rates, the tubing shear stress (or in the model the apparent equivalent tubing rpm) need to be adjusted upwards in order to estimate the EIC from laboratory data. The proportionality factor is about two and is confirmed by the work of Efird. The model expresses the general experimental findings that the EIC is a function of partial pressure, flow intensity and to a lesser extent the water to oil ratio. It must be stressed, however, that the model is relative. While qualitatively such relationships have been shown for a large number of inhibitors, they differ quantitatively, and depend not only on the inhibitor, but also on the metal to be inhibited and the environment, notably the pH of the brine. While the industry would like to have one simple correlation applicable to all types of carbon steel, all inhibitors and a wide range of environmental conditions, reality defeats such an approach. The notion that oil wells should be treated with 20 or 30 ppm of inhibitor regardless of the nature of the environment and the producing condition is unrealistic. This notion may have been the result of simplified inexpensive laboratory testing procedures and has by now been thoroughly discredited in many parts of the world. Rather, for aggressive conditions as they are found at Postle corrosion inhibitors must be qualified by field specific evaluation. The model, however, can predict the EIC for individual wells in a field. This has been confirmed by in situ, downhole corrosion rate measurements in real time. The novel downhole corrosion monitor has therefore been a big step forward toward in improving understanding of these problems.

REFERENCES

1. **C. DeWaard, U. Lotz,** Prediction of CO_2 Corrosion of Carbon Steel, in Predicting CO_2 Corrosion in the Oil and Gas Industry, European Federation of Corrosion Publications, No. 13, published by the Institute of Materials, p30, 1994
2 **R. H. Hausler, D. W. Stegmann, R. F. Stevens,** The Methodology of Corrosion Inhibitor Development for CO_2 Systems, Corrosion 45 (10), 857, 1989
3 **R. H. Hausler, D.W. Stegmann,** Studies relating to the Predictiveness of Corrosion inhibitor Evaluations in Laboratory and Field Environments, SPE Production Engineering, August 1990, p. 286
4 **R.H. Hausler, T.G. Martin, D.W. Stegmann, M.B. Ward,** Development of a Corrosion Inhibition Model: Laboratory Studies, paper to be presented at CORROSION/99, NACE 1999, paper No. 002
5 **R.H. Hausler,** Inhibierung der Erosions Korrosion, Werkstoffe und Korrosion, 44. 21, 1993
6. **D.J. Blumer, R.L. Barnes, A. Perkins,** Field Experience with a New High Resolution Programmable Downhole Corrosion Monitoring Tool, CORROSION/98, NACE 1998, paper 56;
7. **K.D. Efrid,** Correlation of Steel Corrosion in Pipe Flow with Jet Impingement and rotating Cylinder Tests, Corrosion 49. (12) 992, (1993)
8. **D. Silvermann,** Rotating Cylinder Electrode for Velocity Sensitive Testing, Corrosion, 40 (5) 220, (1984)
9. **D. Silvermann,** Rotating Cylinder Electrode- Geometry Relationships for the Prediction of Velocity-Sensitive Corrosion, Corrosion 44. (1) 2, 1988.
10. **G. Schmitt, T. Simon, R.H. Hausler,** CO_2 Erosion Corrosion and its Inhibition under Extreme Shear Stress, I. Development of Methodology, NACE Corrosion/90, paper 022, 1990.

Table 3

Production Data from PUMU 9-6 During Corrosion Rate Test With Downhole Continuous Corrosion Monitor

Date	Oil Bbl/d	Water Bbl/d	Gas MSCFD	CO_2 %	Csg Pres. psi	Tbg Pres. psi	Csg Temp F	Tbg Temp F	Fluid Level ft
9/23/97	196	244	182	45					
9/24/97					188	180	98	103	
9/25/97	205	295	158		185	170	96	106	1005
9/27/97	216	298	175	60					
9/28/97					160	260			
9/29/97					170	285	92	102	
10/2/97					182	268	93	100	
10/3/97	199	260	137						
10/4/97					165	262	101	105	
10/5/97	188	269	132						
10/8/97					170	280	88	94	
10/13/97					172	290	91	98	
10/16/97					168	292	93	101	
10/21/97					173	310	91	94	
11/4/97					170	205	85	94	

Table 4

Postle Field Water Analyses

Field Unit: PUMU

Well Number: 9-6

Analysis Date	Chloride mg/l	Bicarb. mg/l	Calcium mg/l	Magnesium mg/l	Iron mg/L
3/15/96	30442	239	3414	552	3.5
2/26/97	32251	302	3365	620	26
7/8/97	34873	317	3575	641	19
10/8/97	39475	927	4378	856	89
10/10/97	39172	966	4047	664	78
3/26/98	41117	1552	3050	693	127

Table 5

Postle Field Water Analyses

Field Unit: HMAU

Well Number: 54

Analysis Date	Chloride mg/l	Bicarb. mg/l	Calcium mg/l	Magnesium mg/l	Iron mg/L
11/4/96	79571	171	9737	1390	24
7/1/97	93746	42	10602	1444	48

Table 6

HMAU 54 Corrosion Test with Downhole Corrosion Monitor
Comparison of Different Corrosion Rates

Inhibitor Concentration	Downhole		Surface			Corr. Rate from Fe cnt.
	ER- Corr. Rate (mpy)	Percent Protection	ER- Corr. Rate (mpy)	Percent Protection	LPR Corr. Rate (mpy)	
Blank (0 ppm Inhibitor)	82	*0*	67	*0*	2.5	157
265 ppm CRO-396	1.3	*98.4*	0.4	*99.4*	0	174
150 ppm CRO-396	4.1	*95*	1.2	*98.2*	0	n.a.

Figure 1: Contour Plot of Iso-Corrosion Lines for J-55 at 100 ppm Inhibitor C Evaluated in High Speed Autoclave Test

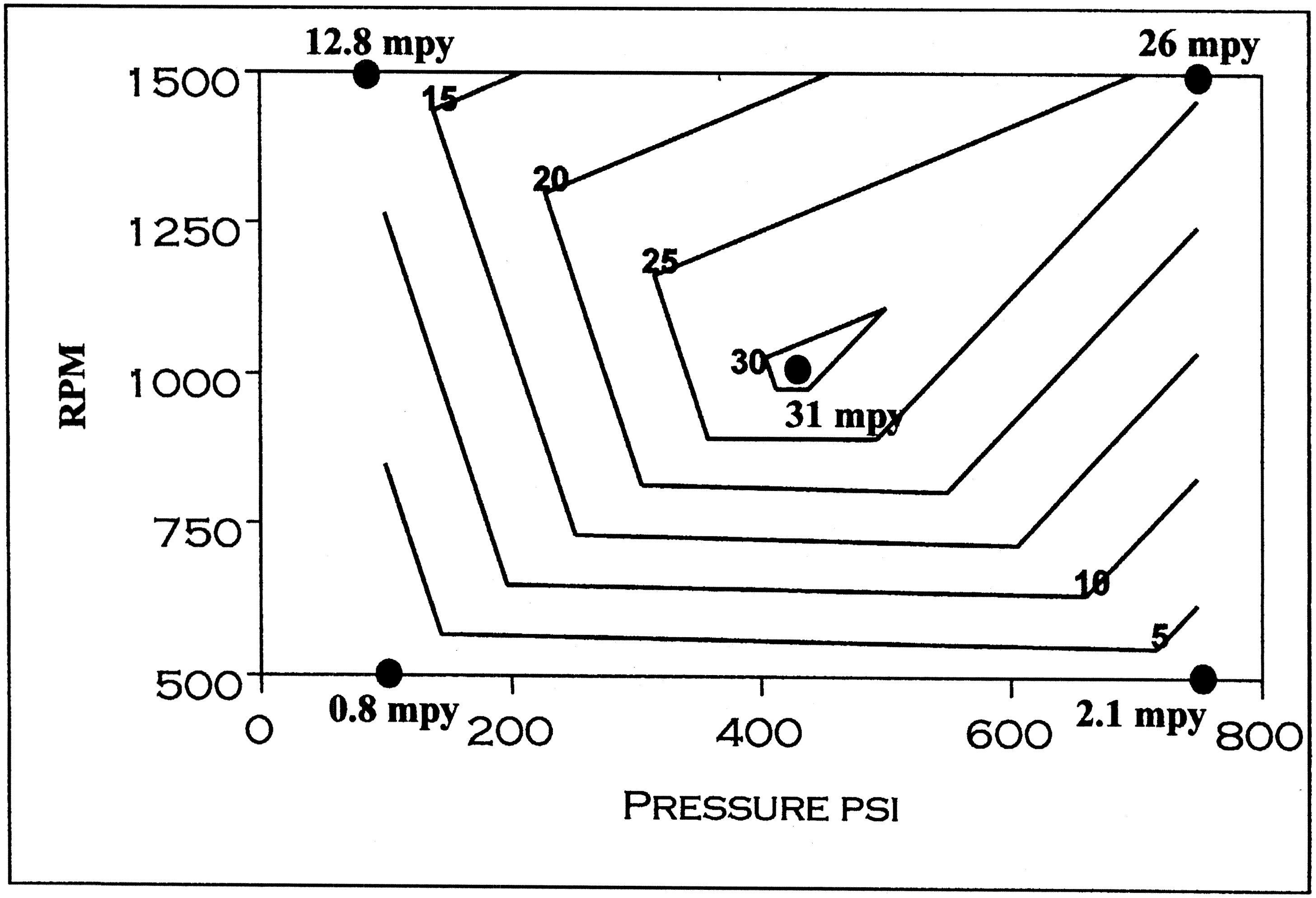
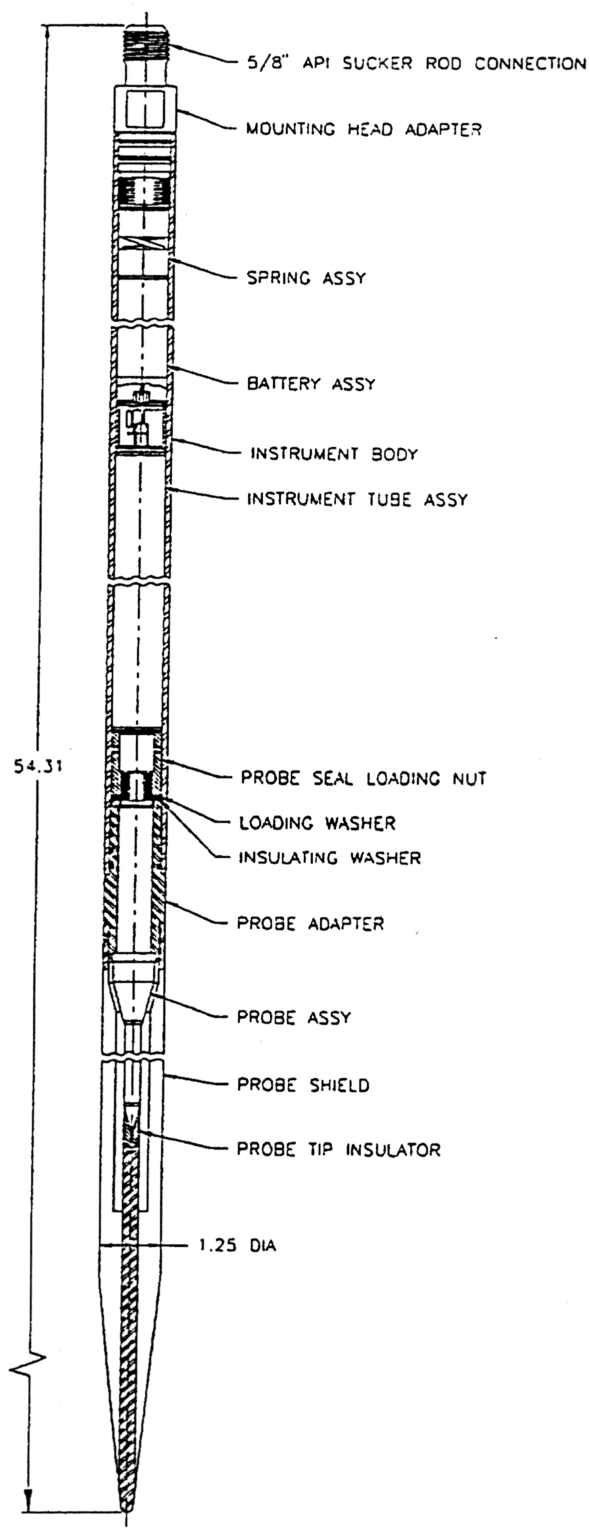


Figure 2: Cross-Sectional View of Fully Assembled Downhole Corrosion Monitoring System



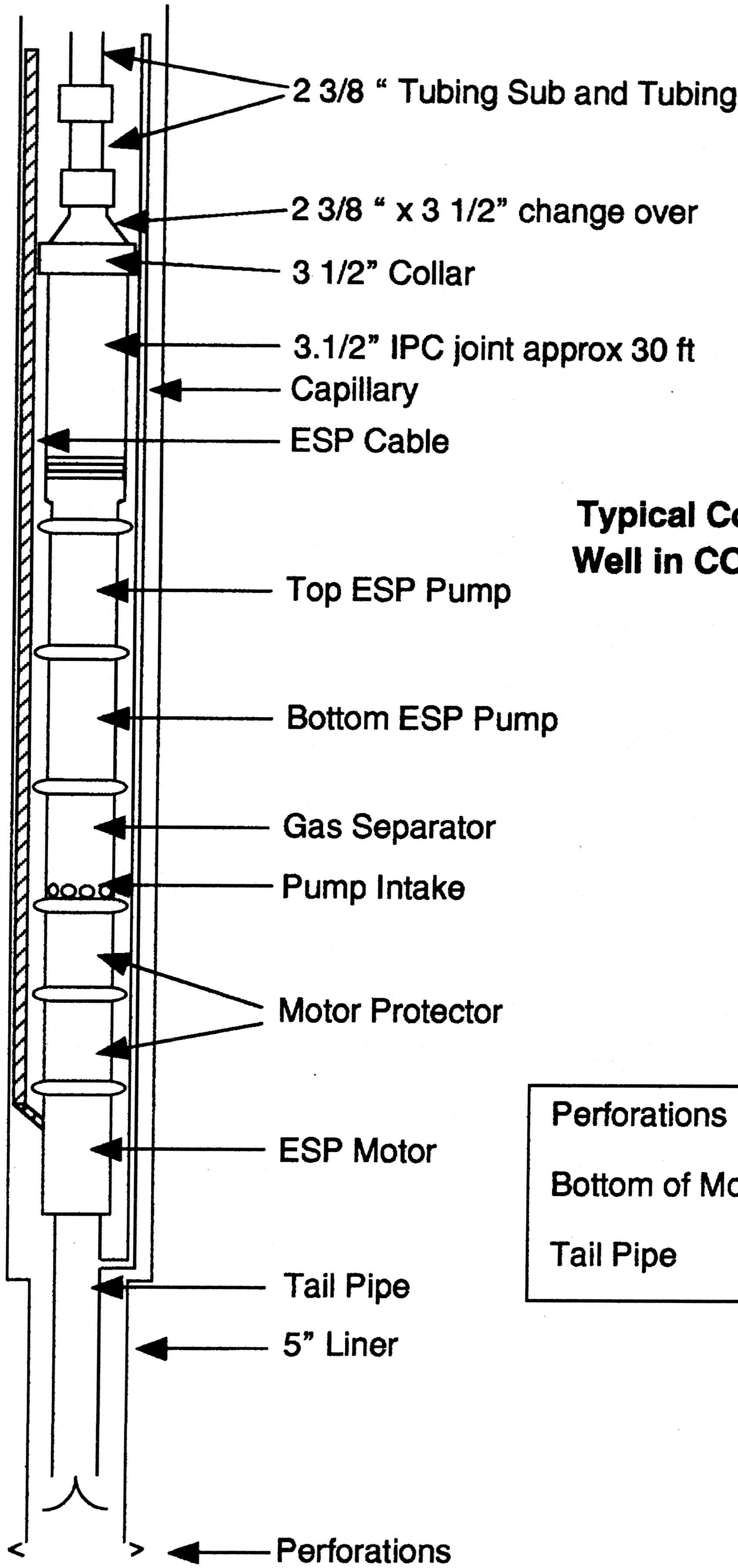


Figure 3

Typical Completion of Producing Well in CO_2 Flood with full length Capillary

Perforations	approx 6150 ft
Bottom of Motor	approx. 6000 ft
Tail Pipe	approx. 100 ft

Figure 4: Time Line for PUMU 9-6 Downhole Corrosion Monitoring Test

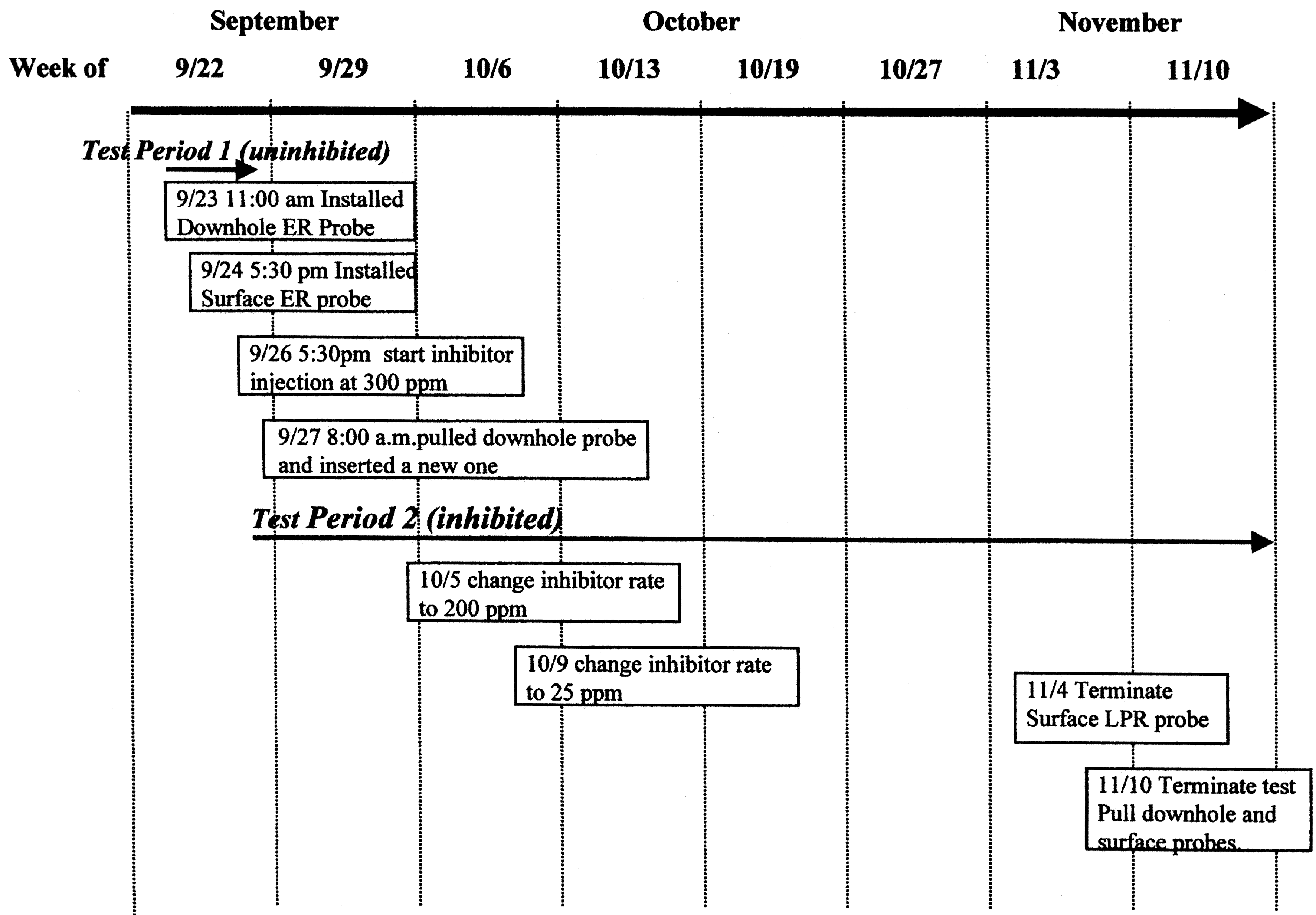
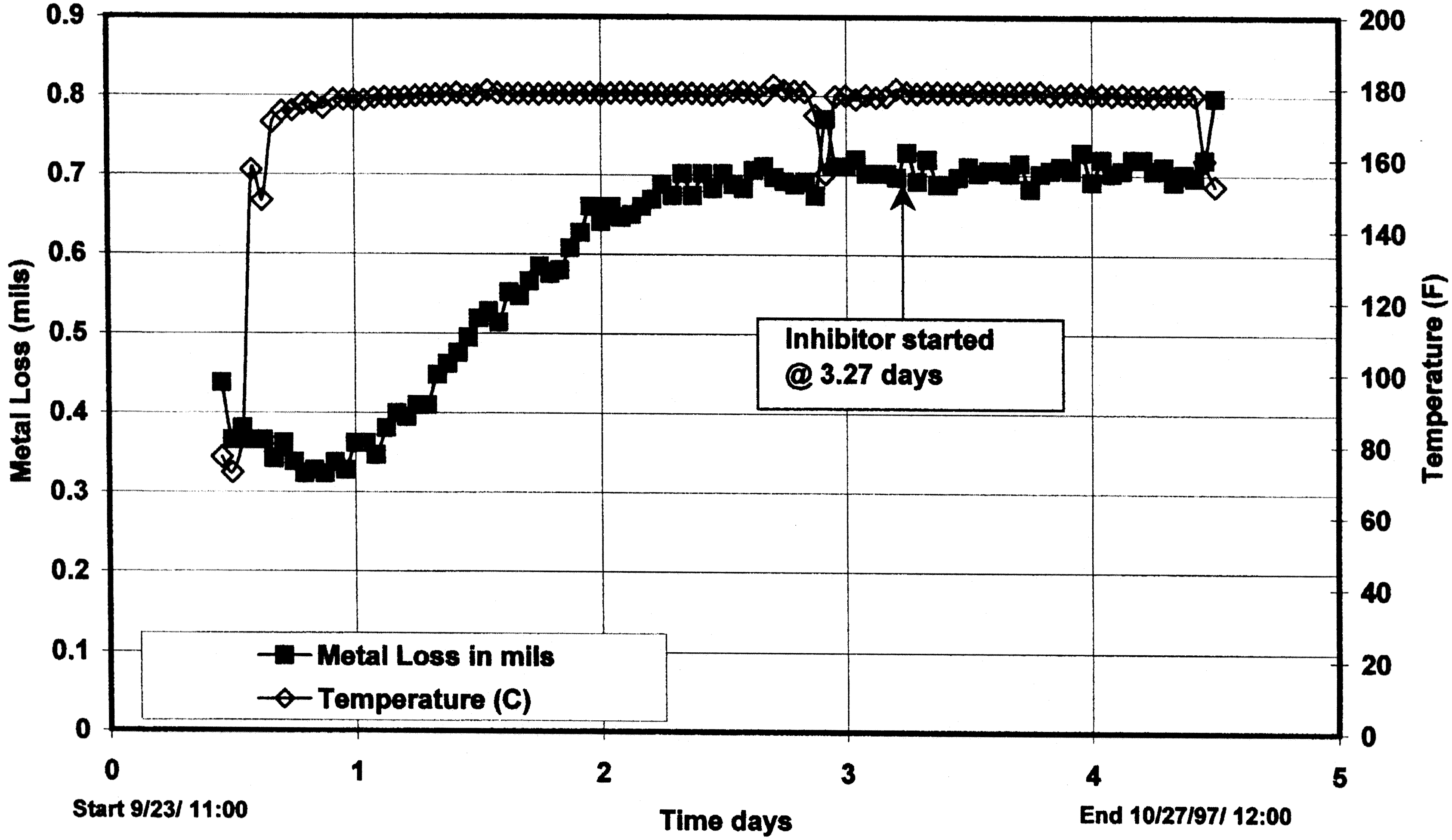


Figure 5: Pumu 9-6 Downhole Temperature and Corrosion Rate Measurements; Uninhibited Period



<u>Figure 6</u>: PUMU 9-6 Downhole Corrosion Rates; Uninhibited Period

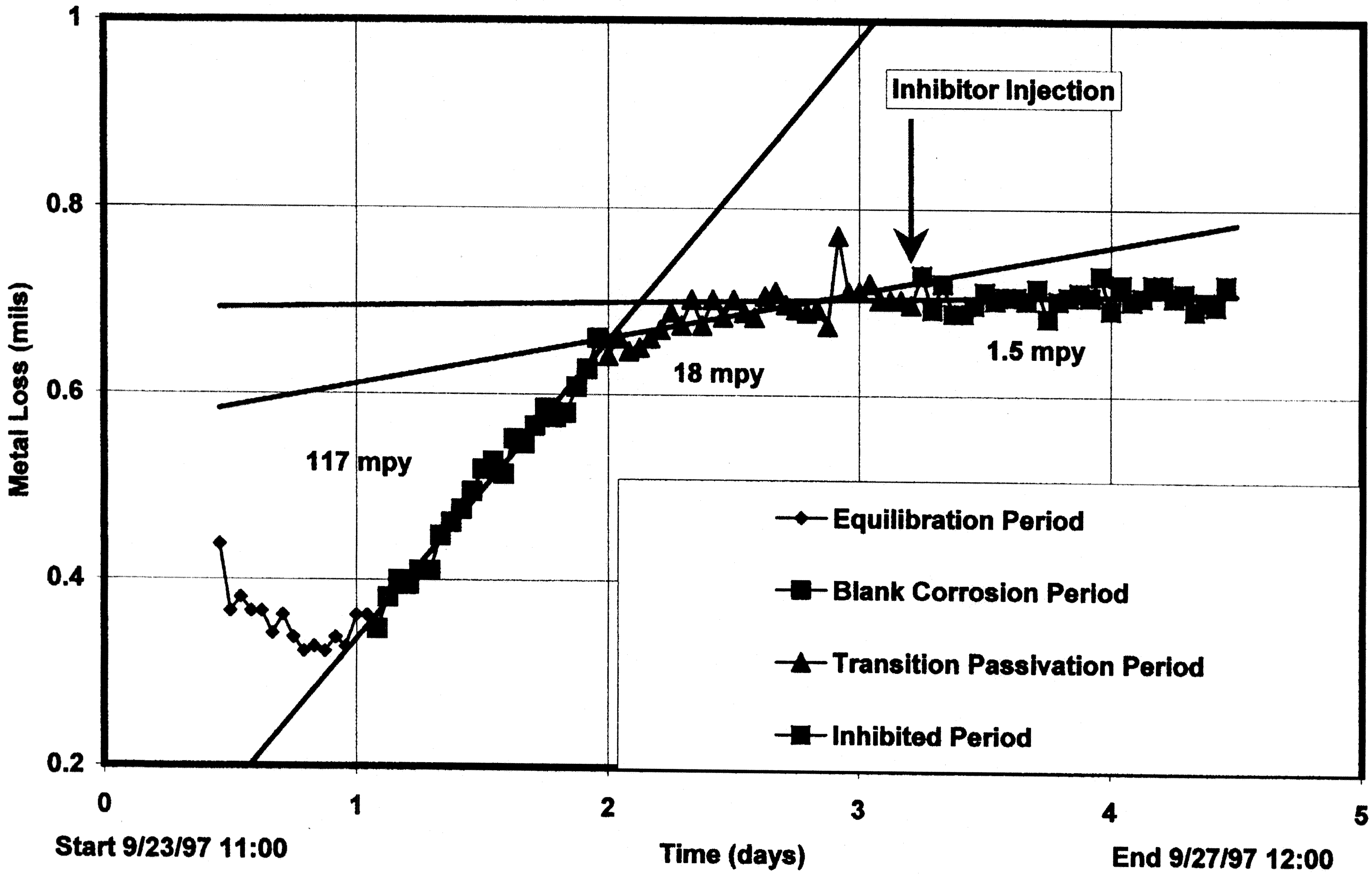


Figure 7: PUMU 9-6 Surface Corrosion Rate

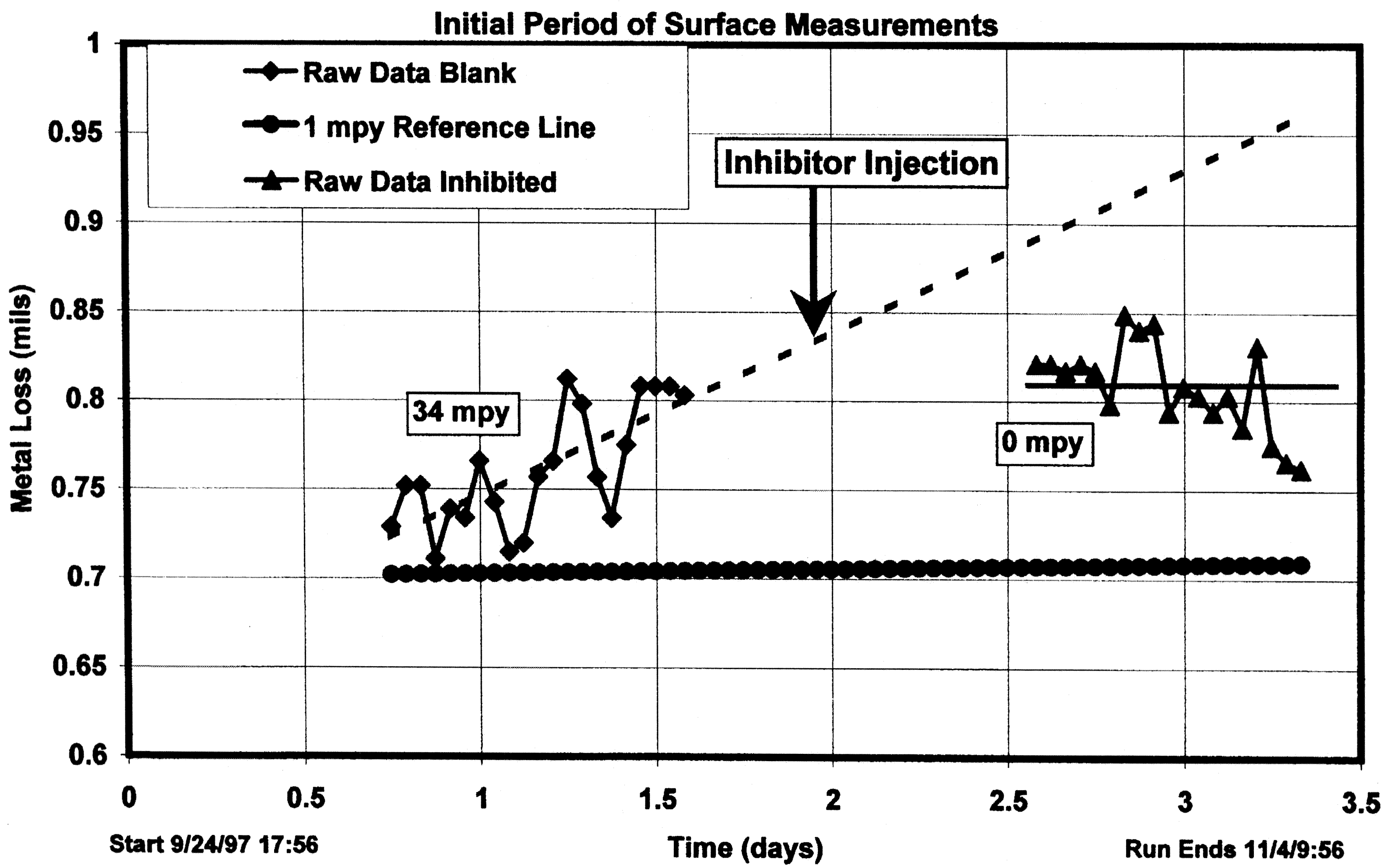


Figure 8: Timeline for HMAU 54 Downhole Corrosion Monitoring Test

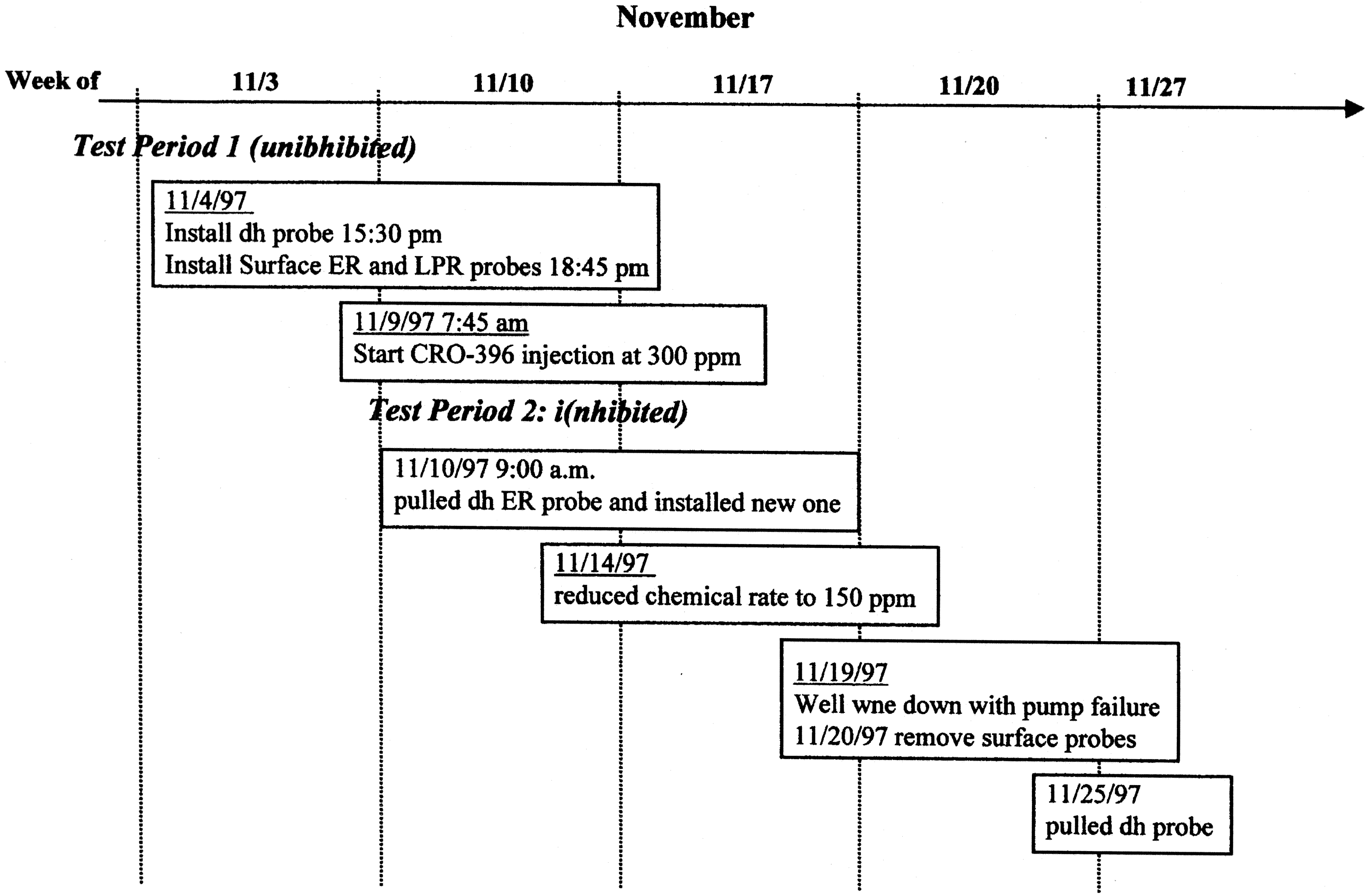


Figure 9: HMAU 54 Downhole Corrosion Tool

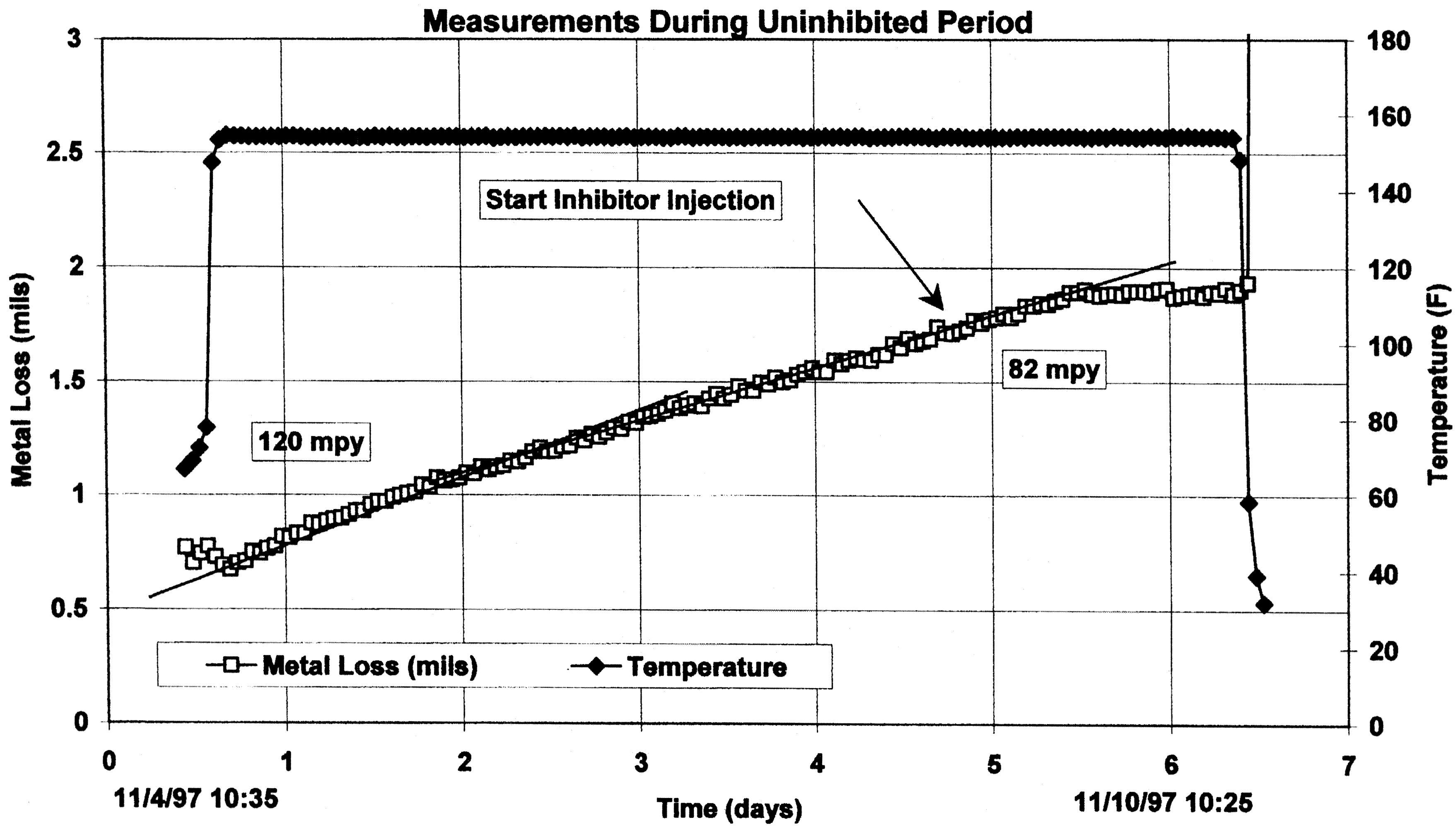


Figure 10: HMAU 54 Surface ER Probe
Uninhibited Period

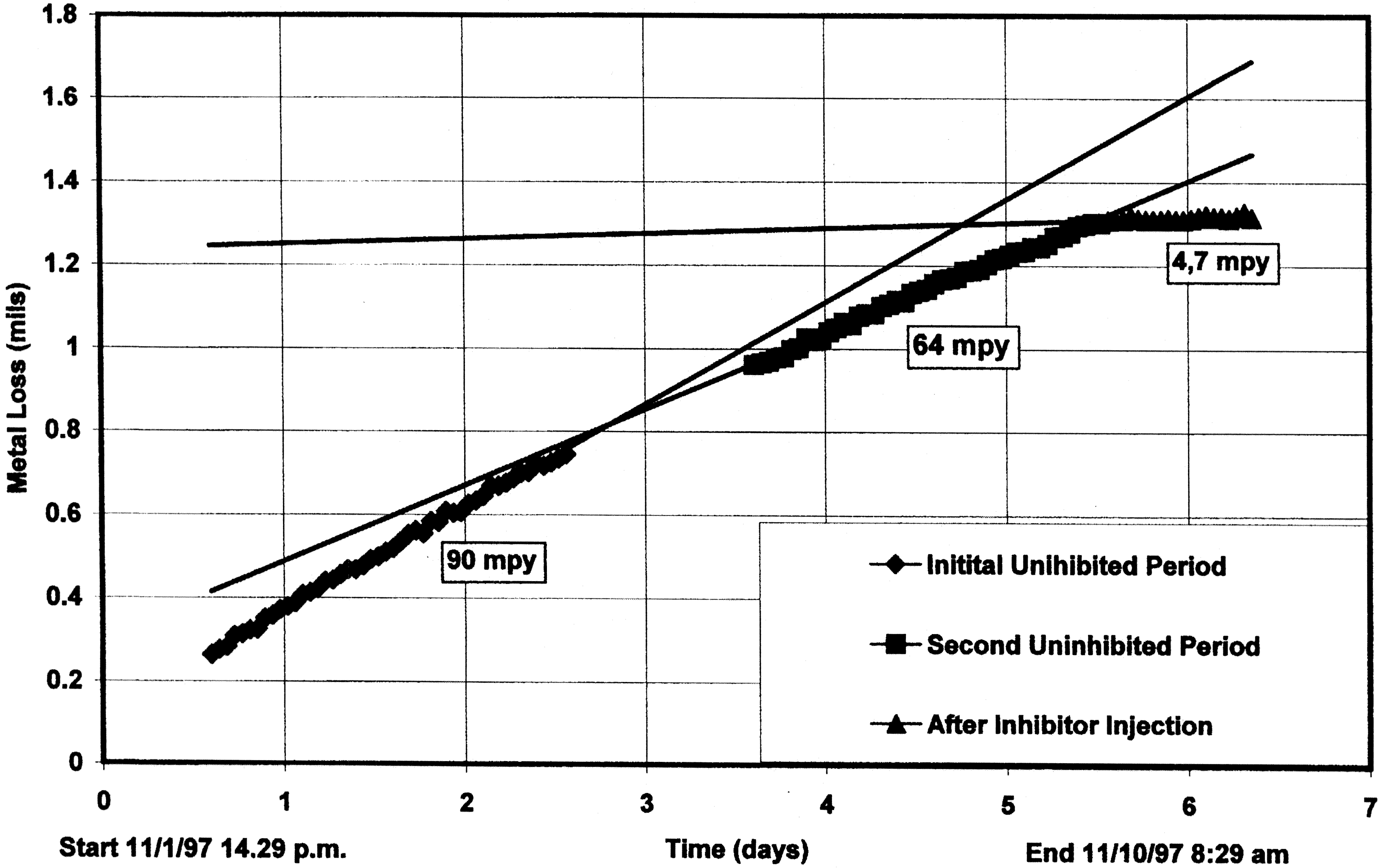
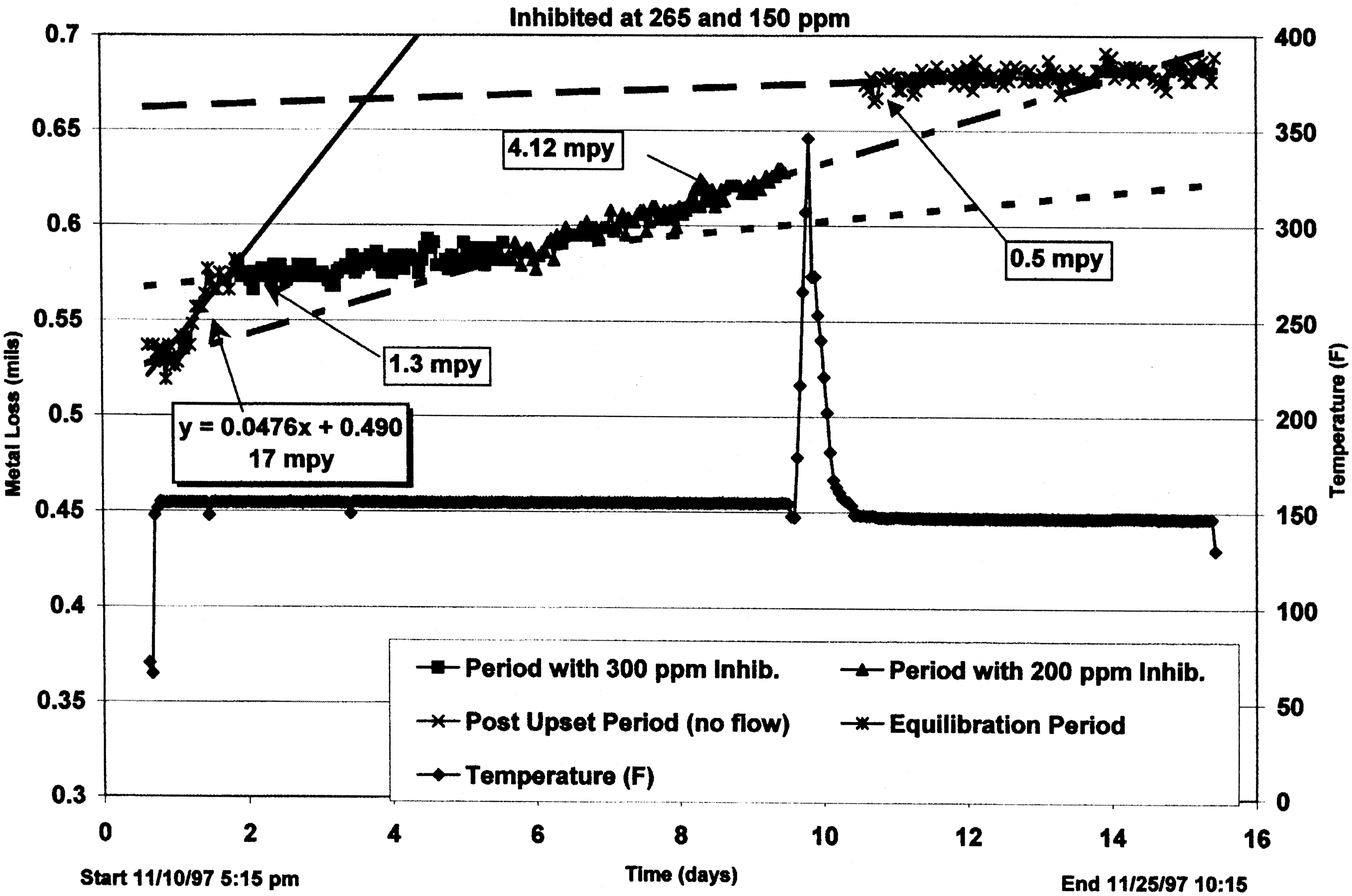


Figure 11: HMAU 54 Downhole Corrosion Monitor: Inhibited Periods



<u>Figure 12</u>: HMAU 54 Surface ER Probe Inhibited

1st Period 265 ppm, 2nd Period 150 ppm

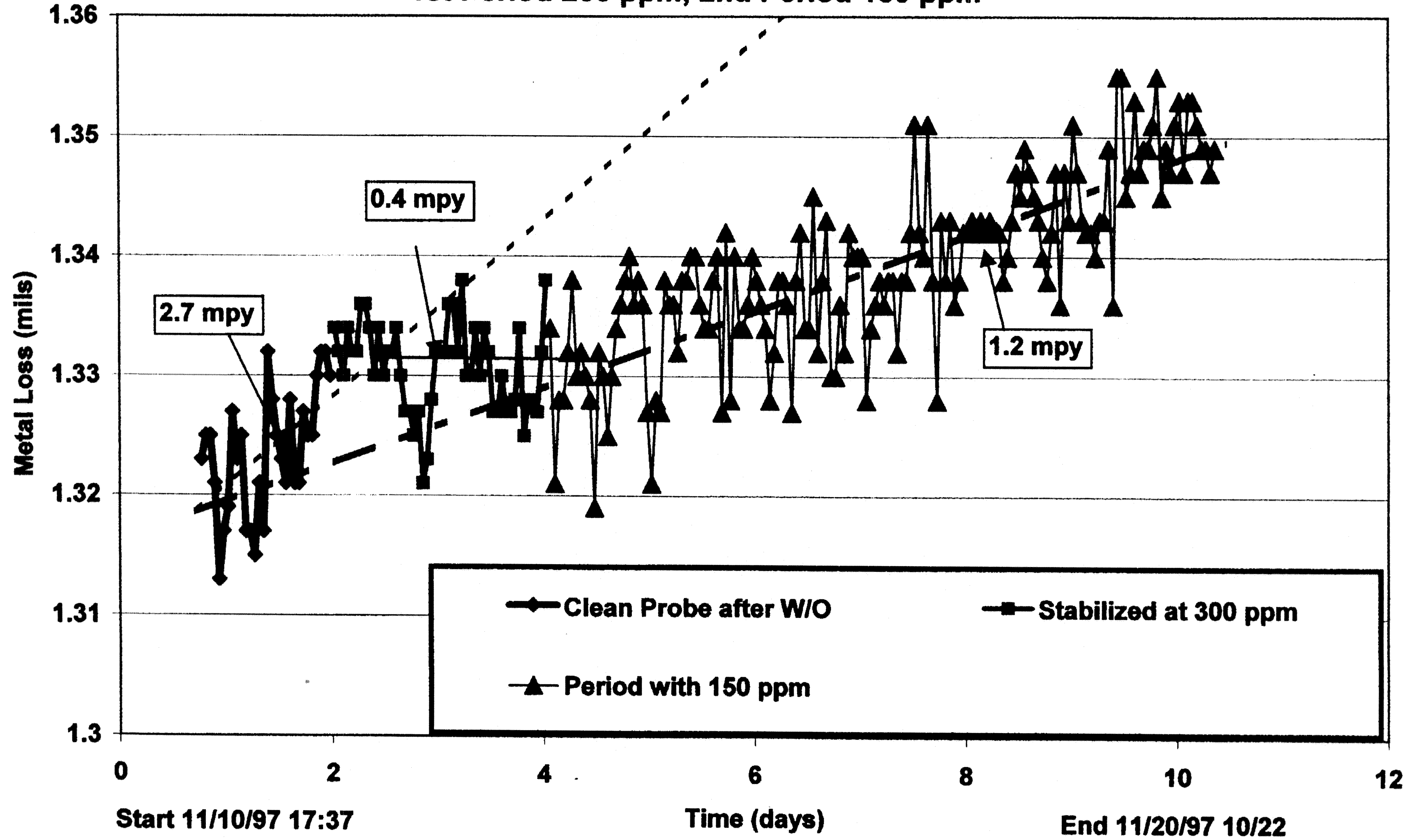


Figure 13: HMAU 54 Surface LPR Corrosion Monitor

Blank Period and Inhibited at 265 and 150 ppm

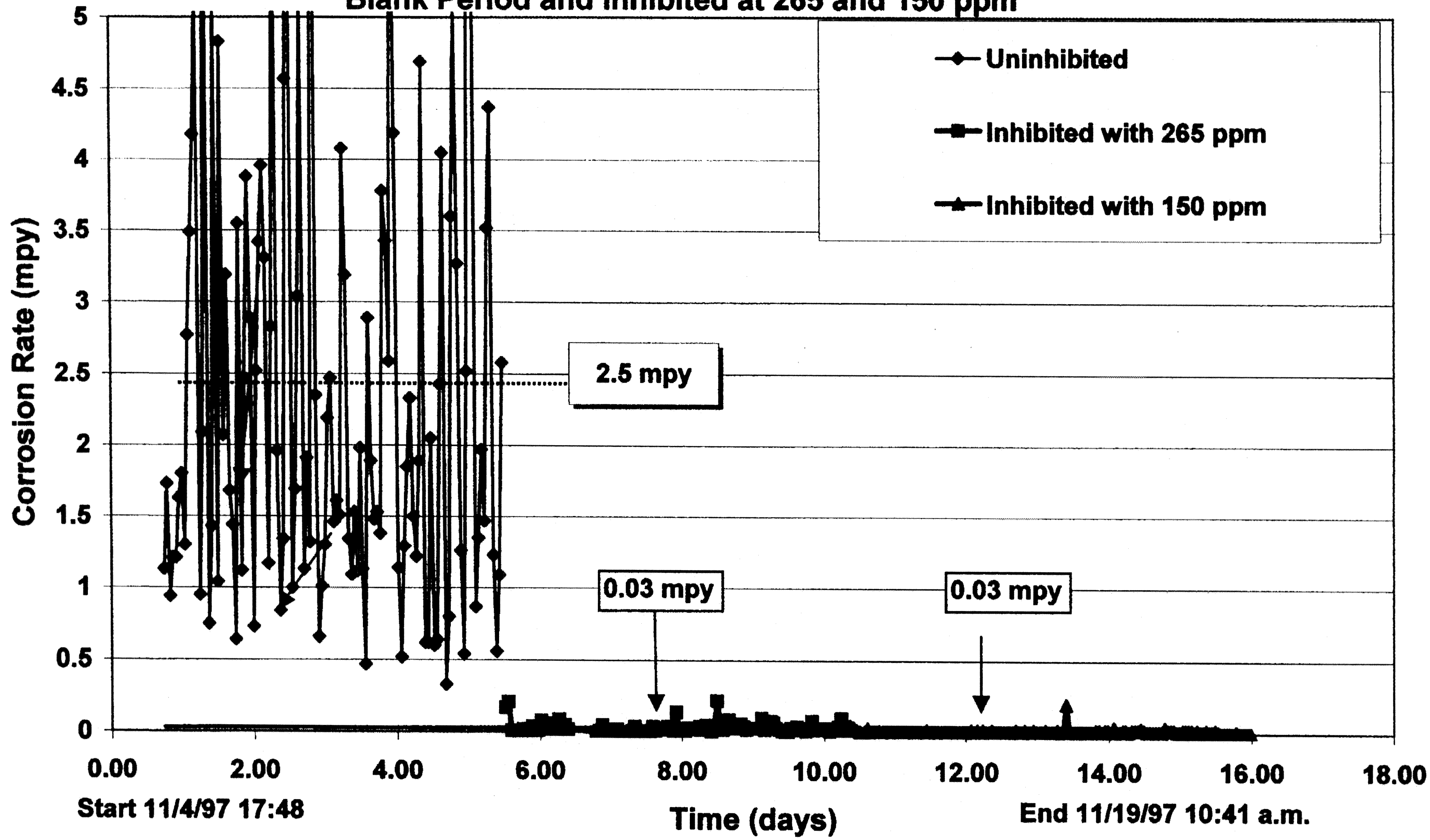


Figure 14: RPM as function of Shear Stress for Rotating Cage
(Empirical fit to calculated data points)

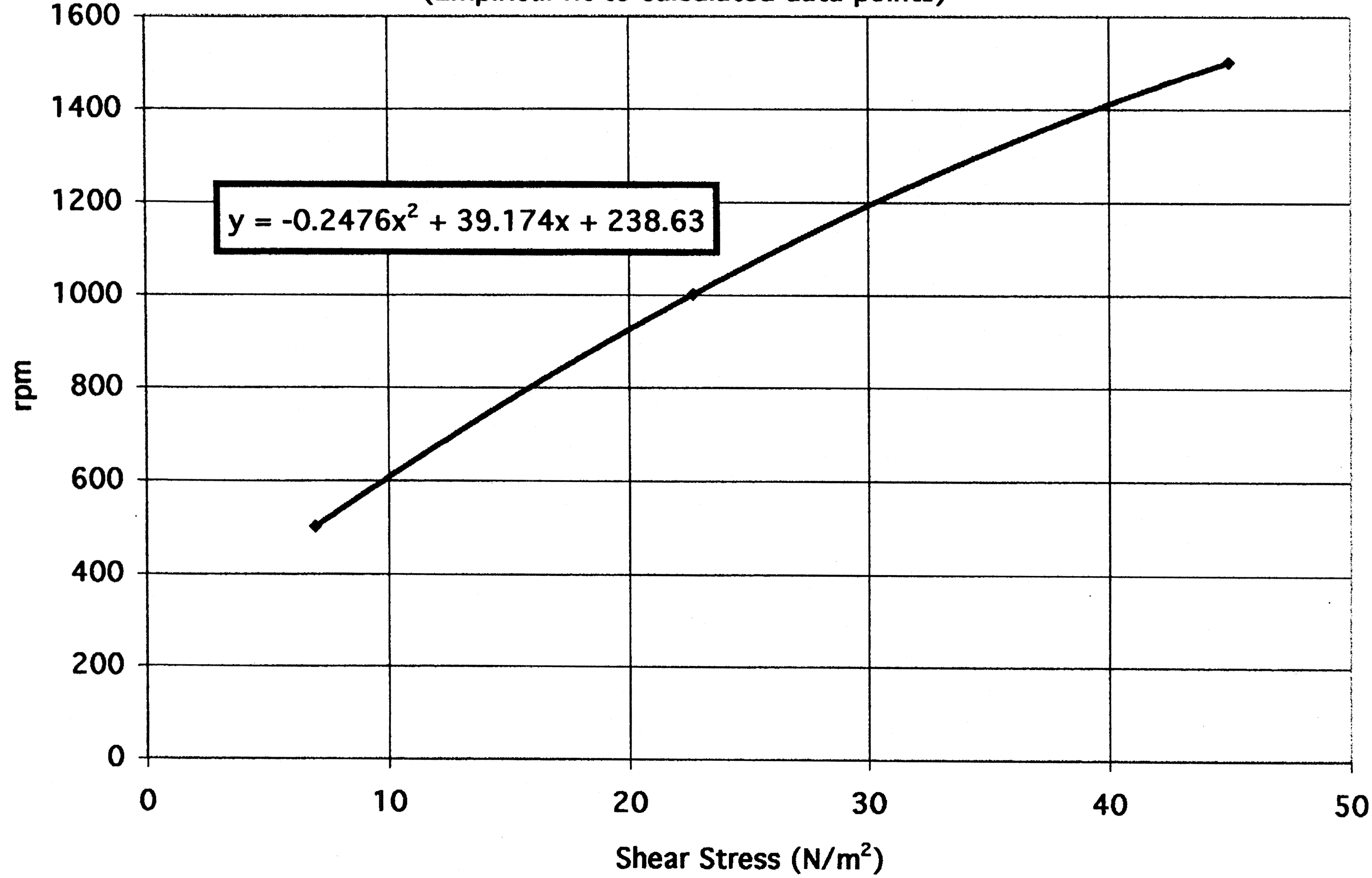
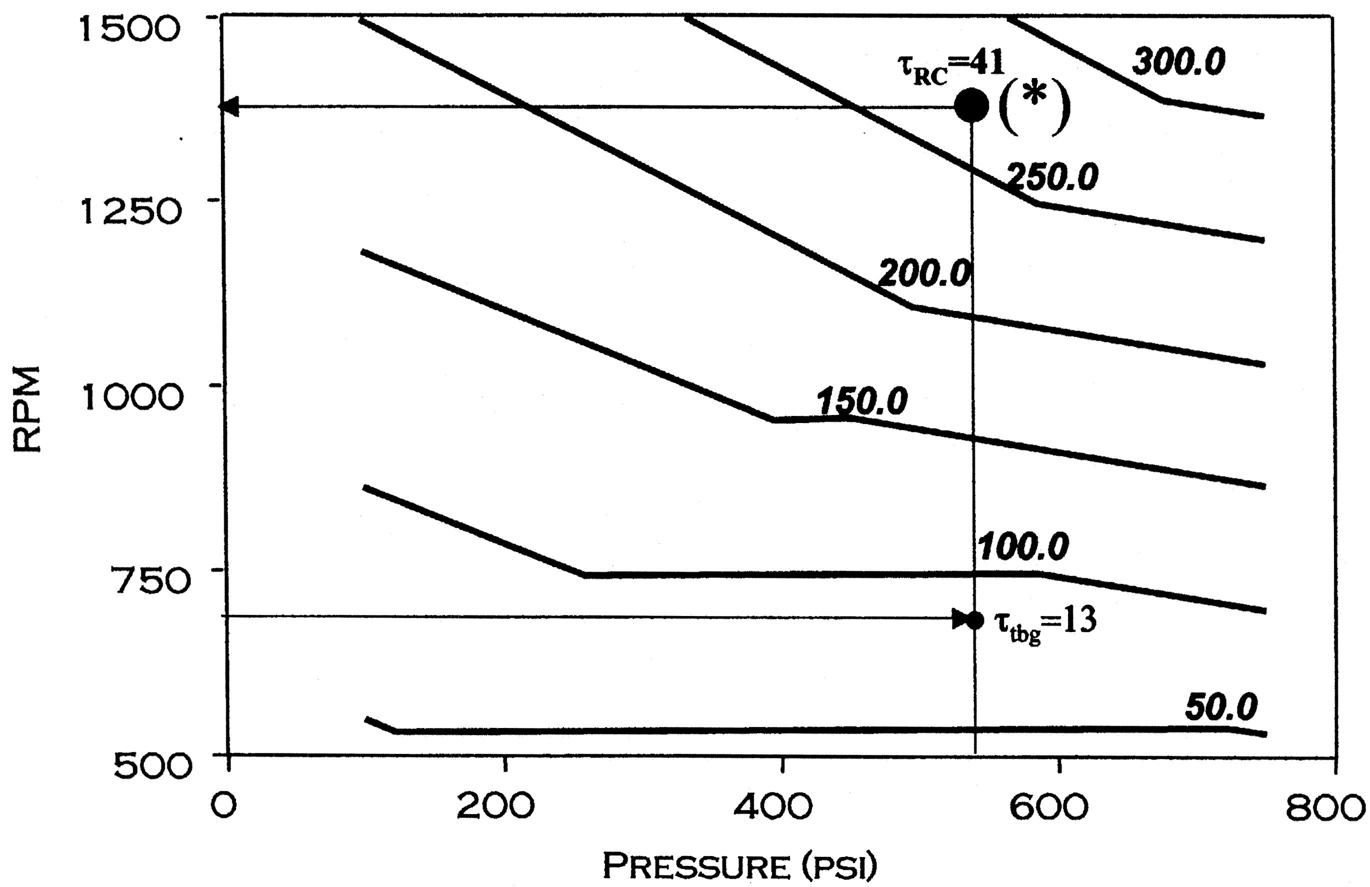
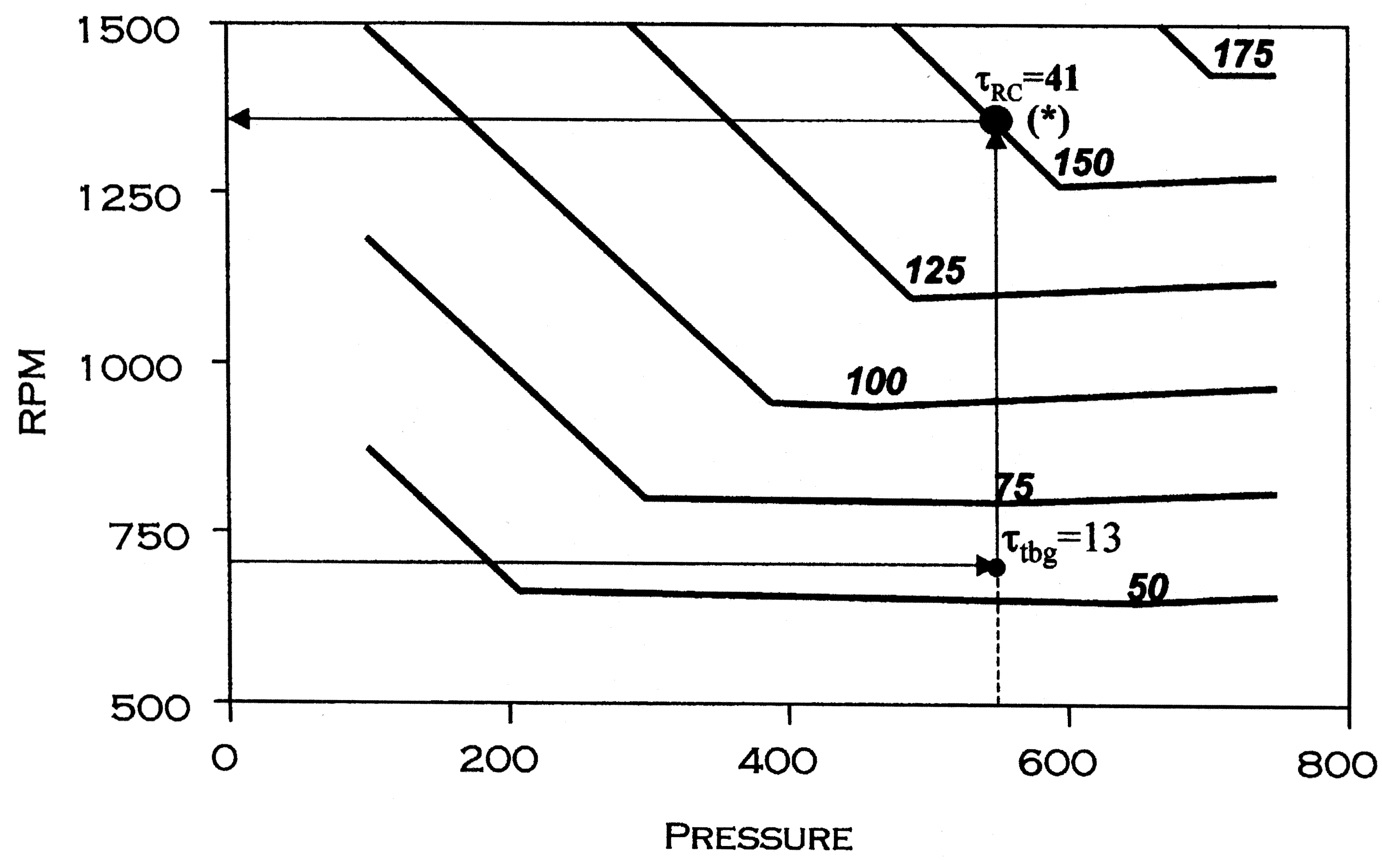


Figure 15: Contour Plot for Constant Effective Inhibitor Concentration Necessary to Achieve 1 mpy Target Corrosion Rate on J-55



(*) Field Corrosion Rate Measurement

Figure 16: Contour Plot for Constant Effective Inhibitor (C) Concentration Necessary to Achieve 4 mpy Target Corrosion Rate on J-55



(*) Field Corrosion Rate Measurement