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WELL CASING CORROSION AND CATHODIC PROTECTION

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ABSTRACT

This paper is in two parts. Part A of the paper is a review of well casing corrosion, particularly in the province of Alberta. The paper first discusses the mechanisms that contribute to well casing corrosion. Two main sources of information are used to examine well casing corrosion in the province. The first is a report written in 1987 – 1988 entitled External Well Casing Corrosion in Alberta. This report highlights geographic areas of the province and geologic zones that have higher incidence rates of casing corrosion. The second source of information is the Alberta Energy Resources Conservation Board (ERCB) well casing failure database. This database captures information such as well location, drilling date, failure detection date and failure type. The absolute number of casing failures peaked in 1987, dropped to a low in 1997, but appears to be on the rise again. However, if the failures are normalized by dividing by the number of wells in operation, the failure frequency has dropped slightly since 1970. The report will also consider reasons why the apparent failure frequency has dropped.

Cathodic protection has been proved to be a cost effective technique in controlling casing corrosion. Part B discusses the cathodic protection of well casings. Specifically, methods used to determine the amount of current required to protect a well casing and if a well casing is adequately protected.

Key words: casing corrosion, casing cathodic protection, E-log I test, well casing cathodic protection simulations.

PART A – WELL CASING CORROSION

INTRODUCTION

This paper will attempt to determine if there has been a substantial change in the numbers of well casing failures in Alberta. The sources of information for this review are a study performed by Caswell in 1987 – 1988 and the Energy Resources Conservation Board (ERCB) casing failure statistics. The paper will discuss the corrosion mechanisms that contribute to well casing corrosion, as well as examine geographic areas and geologic zones of Alberta which are most prone to external casing corrosion.

One of the most effective methods of protecting a well casing from external corrosion is by the application of cathodic protection. The cathodic protection of well casings will be discussed in Part B of this paper.

CORROSION MECHANISMS

There are several corrosion mechanisms which are generally considered to be the major causes of external (soil side) well casing corrosion. These are:

1. Dissimilar Metal Corrosion
2. Dissimilar Soils
3. Differential Aeration
4. Bacteria
5. “Stray Current” Interference

Dissimilar Metal Corrosion

Dissimilar metal corrosion is caused by dissimilar metals electrically coupled in a common electrolyte. A common example is carbon steel piping electrically connected to a copper grounding system. Another example is the use of metals that are unintentionally caused to be dissimilar because of the manufacturing process of either the steel or the pipe. Mill scale is the dark brown or black oxide layer formed during the hot rolling process of steel. In the galvanic series, mill scale is cathodic to bare pipe steel where the mill scale has been removed. Therefore the bare pipe steel will corrode preferentially to the mill scale. An example of this is the corrosion at the slip and tong marks at the pipe joints. This phenomenon will be aggravated by the large cathode of the mill scale and the small anode of the bare steel created by the tool marks.

Dissimilar Soils

Soil and rock formations may have widely varying compositions and resistivities. Gummow discussed this type of corrosion cell in his paper “Cathodic Protection Corrosion Control Considerations for Storage Well Casings”[1]. He referenced Hamberg et al[2] who stated that dissimilar soils were probably responsible for casing leaks in some Arabian Gulf wells within four years of well completion. A downhole resistivity investigation showed that on these wells there was a salt layer with a resistivity of 200 ohm-cms between two shale formations having resistivities of greater than 2000 ohm-cms. A soil with a resistivity of 200 ohm-cms would be deemed as “very corrosive” while a resistivity of 2000 ohm-cms would be considered as “moderately or mildly corrosive”[3].

Differential Aeration

Another common corrosion mechanism is the differential aeration cell. This occurs where the pipe or casing is in contact with an electrolyte (e.g. soil or water) that has differential concentrations of oxygen. Accelerated corrosion occurs where there is a lower concentration of oxygen. This area becomes the anode of the corrosion cell.

This type of corrosion is typical in the surface casing where the annulus is open to oxygen. In their paper “Use of Oxygen Scavengers to Control External Corrosion of Oil-String Casing”[4], Schremp et al, define this as “water-line corrosion”. They collected a water sample from a casing annulus and adjusted the sample to anaerobic conditions similar to those found in a well casing annulus. They then measured potentials at various levels below the surface of the water sample. They determined that there was a 90 mV difference in potential in the first five to ten mm below the surface of the water as a result of differential oxygen concentration. A nitrogen purge or an oil layer prevented the formation of this oxygen concentration cell. Figure 1 demonstrates the results of this experiment.

In his paper, Schremp also demonstrated that hydrazine was an effective oxygen scavenger[4]. It was particularly effective in preventing well casing corrosion during the first 12 – 18 months following well completion. Hydrazine is a very toxic chemical and most oxygen scavengers now utilize chemicals such as sodium sulphite or ammonium bisulphite instead.

Bacteria

Many drilling fluid systems (i.e. mud systems) are calcium or lime based. Gypsum is often added to calcium based mud systems for drilling shale, gypsum, anhydrite and salt stringers[5]. Starch was a common additive to gypsum based mud for fluid loss control or lost circulation control. However, starches are subject to bacteria attack unless they are protected by a high salinity brine or a bactericide[5]. Many wells were drilled with gyp starch mud and these wells had a higher incidence of failure than wells drilled without starch.

The importance of drilling fluid is evident. Table 1 by Thill[6] gives the estimated time in years to first failure for similar wells in a given field. The most important lessons to be learned from this table are the trends and not the absolute numbers. For example, the addition of an oxygen scavenger can increase the time to failure for both gel and gypsum based mud systems by 30 – 50%. Note also that using a gypsum based mud system with a pH greater than 9.5 can double the time to failure compared to a well drilled with a low pH mud system.

Stray Current Interference

The action of a direct current source, such as an impressed current ground bed, that causes a detrimental effect on a structure that is not part of the cathodic protection system is called stray current interference. For example if a well casing is within the influence of a ground bed but is not connected to the negative circuit of the rectifier, interference may result. Interference can be mitigated by draining some current from the well and restoring the potentials to levels before the cathodic protection system is energized.

EXTERNAL CASING CORROSION SURVEY

One of the first studies of external casing corrosion in Alberta was performed by Caswell in 1987 - 1988. The study was entitled “External Casing Corrosion Survey”[7] and was prepared for the NACE Calgary Section and a number of oil and gas producing companies.

The report was based on 525 casing inspection logs and 160 casing failure reports. The casing inspection logs were supplied by two logging companies and supplemental information was provided by the ERCB and the participating oil and gas companies. There were a number of main conclusions from the report:

1. The ratio of external corrosion to internal corrosion for the wells in the survey was 72.5 to 27.5. These results were consistent with the ratio of 70 / 30 suggested by NACE.

2. The fields with the most severe corrosion rates were Bonanza and Caroline – Westward Ho. Other fields with high corrosion rates, but a lower average age, were Rainbow Lake, Sylvan Lake, Mitsue, Kaybob South and Judy Creek. A list of the fields with the most severe corrosion rates is given in Table 2.

3. The most active geological formations are limestone ($CaCO_3$) formations. In the southern part of the province the most active formations are the Lea Park and the Colorado. The Banff and the Wabamun are the most aggressive formations in the northern area of the province.

4. The majority of casing penetrations, 61%, occur in the top 1500 metres of casing which is generally the open-hole area below the surface casing and above the cement top.

5. Most of the fields with severe external corrosion are located in central Alberta where some of the oldest wells are found. Exceptions to this are Rainbow Lake, Bonanza, Nipisi and Taber. Other geographical areas with moderate or severe areas of corrosion are those zones with folded formations along the Foothills.

6. Wells with strings of mixed casing grades (e.g. J-55 and N-80) show an increased tendency toward external corrosion. The casing grade N-80 is less susceptible to external corrosion than J-55.

7. The occurrence of holes in the production casing located inside the surface casing is strongly related to the presence of severe external corrosion in the remainder of the casing string.

The report concluded that external casing corrosion is responsible for 70% of the casing corrosion problems in Alberta. The main factors affecting the degree of corrosion are the age of the well, the formations penetrated by the well casing and the drilling and completion practices such as the casing grade, the type of drilling mud used and the type and amount of cement used.

ERCB CASING FAILURE RECORDS

In order to determine if there has been a substantial change in the performance of well casings with respect to external corrosion, the ERCB data on casing failures was examined$_8$.

The following is some of the information captured in the ERCB database:

- Report Date
- Current Licence Status (e.g. Abandoned, Amended, Issued, Suspension, etc.)
- Surface Location
- Detection Date and Reported Resolution Date
- Failure Type (e.g. Burst, Hole, Parted, Collapsed, Parted or Thread Leak).
- Failure Top Depth and Failure Bottom Depth (m KB)
- Reported Resolution (e.g. Casing Patch, Well / Zone Abandoned, Packer, Cemented Liner or Replaced Failed Casing).
- Steam Scheme Type (e.g. SAGD, Cyclic Steam Injection).

The records show that to the end of June 2009, there have been a total of 4920 casing failures in the province of Alberta. Of these failures, six were Steam Cycle Injectors, 22 were SAGD well casing failures and 1715 wells were on Cyclic Steam Service. These failures were not considered for further study because it was thought that factors other than corrosion may have been the main contributor to the casing failures.

The various failure types and the number of failures are shown in Table 3.

There are some difficulties in interpreting the ERCB data. The database only refers to “failures” and makes no distinction between an internal and an external failure. However, to distinguish between an internal and an external leak would be difficult without a casing inspection log. Also, of the approximately 2517 wells that failed due to a “hole”, about 610 records had no data for the “Failure Top Depth”. Therefore, the depth of the failure is unknown.

The initial list included all casing failures, including those failures near the top of the well. Therefore the list was filtered by removing all those with casing leaks above 100 metres. For other wells, a database was consulted to determine the true depth of the surface casing and additional wells were removed from the list. The intent was to analyze, as much as possible, only those wells in which the casing failure occurred below the surface casing.

Another problem was determining the “time to failure”. In some cases the “Detection Date” of the failure was before the “Final Drill Date”. In these cases it was assumed that the well was re-drilled. Those incidents in which the detection date was before the final drill date were also deleted and not considered for further analysis. This reduced the number of wells to about 1910.

It must be emphasized that, because there was no distinction between internal and external failures, the data missing for the depth of failure and the problem with determining the “time to failure”, the following graphs show trends only and cannot be considered accurate.

The wells were sorted by the “Detection Date” from the earliest reported failure to the most recent failure and the numbers of failures per year were counted. The graph of the number of failures per year is shown in Figure 2. The graph starts in the year 1970 since there were only 26 recorded failures in the years from 1956 to 1969. There is clearly an increasing number of well casing failures.

The graph in Figure 2 was not “normalized” by the number of well casings in service, similar to the process of standardizing the number of pipeline incidents by expressing the number as “Number of Incidents Per 1000 Kilometres of Pipeline”. The graph in Figure 3 shows the number of casing failures normalized per 1000 wells by year. The number of wells used was the cumulative number of wells drilled less the number of wells that have been abandoned. The trend line shows an overall decrease from about 0.7 casing failures per 1000 wells in 1970 to about 0.5 casing failures per 1000 wells in 2008. However there seems to be an upward trend from 2001 to 2009.

Age of Wells

A graph of the average age of the well to time of failure is shown in Figure 4. The average age was determined by grouping the wells that failed in a given year and determining the average time to failure of the well. The average age of the well at time of failure has been increasing. The average time to failure is now about 30 years compared to ten to 15 years in the late 1970’s and early 1980’s.

Location of Failures

The study by Caswell in 1988 identified a number of geographic areas that were most prone to corrosion. These are highlighted in Table 2. As a result of studying the ERCB data, the number of failures in these fields was added to the original table. The number of failures was determined by identifying the townships and ranges for a given field from the ERCB “Strike Map” and comparing these areas with the well locations from the database. The number of failures reinforces the work by Caswell with respect to fields that have casing corrosion problems.

Possible Reasons for Decreased Failure Rate and Increased Casing Life

There are a number of possible reasons for the apparent decreasing failure rate and increased casing life. Part of the reason may be the fact that many casing failures go unknown and thus unreported. It is practical to pressure test the casing only for wells having packers. For wells without packers, it is only practical to pressure test the casing when the tubing is pulled out of the well. However there are certainly other contributing factors to the decreasing failure rate and increasing well life:

1. One of the main contributors to well casing corrosion was the drilling fluid used. Now, oxygen scavengers are used and additives such as starch, which are subject to bacteria attack, have been replaced by polymers.

2. Cementing practices have improved, particularly for sour gas wells. The casing string is mechanically raised and lowered during cementing to reduce the risk of channelling. Many wells are now cemented in stages (i.e. stage cementing). The bottom section of the well is cemented first. Then the section above the cement top of the first stage is cemented. This greatly reduces or eliminates the uncemented area above the first cement top and below the surface casing. This area is responsible for about 60% of the casing perforations.

3. The use of mixed grade casing strings is avoided as much as possible. Historically, casing strings may have been made up with any casing that was available. Now, the casing string is more likely a single grade. Strength requirements are met by using different casing weights (i.e. wall thickness) of the same grade of pipe.

4. The numbers of wells that are being abandoned are increasing. From ERCB information, the number of wells abandoned in the 1970's was about 15,200, followed by 20,500 wells during the 1980's, 33,600 throughout the 1990's and increasing to about 38,500 in the 2000's. Once a well is abandoned the risk of having a casing failure is greatly reduced.

5. Although many of the old reservoirs are still producing, many of these fields have cathodic protection on the well casings. The Devonian - Leduc reefs such as Pembina, Bonnie Glen, Redwater and Acheson were found and drilled in the late 1940's and early 1950's. The fields that produce from the Beaverhill Lake formations such as Swan Hills, Kaybob North, and Virginia Hills were discovered in the late 1950's and early 1960's. Kaybob South was discovered slightly later in the late 1960's. The Mitsue and Nipisi fields that produce from the Gilwood Sands in the Slave Lake are were discovered in the mid 1960's. Most of these fields have had cathodic protection on the well casing since the 1980's.

Corrosion within the Surface Casing

Caswell's report concluded that of the 571 wells examined, 10% of the production casings had holes inside the surface casing. Over 60% of the wells had production casing with wall loss of greater than 40% in the surface casing. From the ERCB database, of the approximately 2500 casings with holes, 490 of the holes, or almost 20%, occurred within the top 100 metres of the well. In the discussion on the corrosion mechanisms, Schremp defined this as "water-line corrosion"$_4$ and concluded that it was caused by an oxygen concentration cell. He further determined that adding a layer of oil to the surface of the water reduced the potential of the oxygen concentration cell. It was a common practice to add diesel to the surface casing annulus. However, that practice is no longer environmentally acceptable. The addition of a biodegradable product such as canola or vegetable oil to the annulus would reduce the potential of corrosion inside the surface casing and be environmentally acceptable.

CONCLUSIONS

1. The external casing corrosion study by Caswell identified a number of fields and geological zones where corrosion is more prevalent. The ratio of external corrosion to internal corrosion for the wells in the casing survey was 72.5 to 27.5. These results are consistent with the ratio of 70 / 30 suggested by NACE. The study also identified that the majority of casing penetrations occur in the top 1500 metres of the casing, in the area above the cement top and below the surface casing. Wells with strings of mixed casing grades show an increased tendency toward external corrosion.

2. The number of well casing failures per year is increasing.

3. The "normalized" rate has declined slightly since 1970 and is about 0.5 well casing failures per 1000 wells per year. However, there seems to be a slight upward trend from 2001 to 2009.

4. The average time to failure is now about 30 years compared to ten to 15 years in the late 1970's and early 1980's.

5. Drilling and completion practices have improved, reducing the failure rate and increasing the average age of the well before failure.

6. The ERCB database would be much more useful if all information was included (e.g. the depth of the failure) and additional information was included, such as the depth of the surface casing.

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TABLE 1:
ESTIMATED TIME IN YEARS TO FIRST FAILURE FOR SIMILAR WELLS IN A FIELD

	MUD SYSTEM					
DRILLING MUD TREATMENT PRIOR TO CEMENTING	**LIME**	**GEL**	**GYPSUM Low pH < 9.5**	**GYPSUM High pH > 9.5**	**CORROSIVE AQUIFER**	**CEMENT TO SURFACE**
Without O_2 Scavenger	> 40	12	12	29	Within 2 years	> 40
With O_2 Scavenger	> 40	17	17	40	Within 2 years	> 40

TABLE 2:
FIELDS WITH THE MOST SEVERE CORROSION RATES

FIELD	RANK	AVERAGE AGE OF WELLS LOGGED (YEARS)	AVERAGE CORROSION RATE (MPY)	% OF WELLS WITH CP	NO. OF FAILURES FROM ERCB
Bonanza	Severe	6.5	10.6	15	1
Caroline	Severe	17.5	4.1	3	12
Westward Ho	Severe	17.5	4.1	3	
Sylvan Lake	Severe	16.8	4.6	25	13
Mitsue	Severe	13.5	4.6	32	17
Judy Creek	Severe	20	3.8	22	21
Rainbow Lake - Rainbow South	Severe	16.3	5.1	53	52
Kaybob South	Severe	15.3	4.3	50	22
Utikuma	Severe	16.4	3.8	35	4
Fenn - Big Valley Fenn West	Severe	29.8	3.6	44	87
Gilby	Severe	24.7	2.7	0	19
Taber	Severe	43.3	2.5	2	4
Harmattan	Severe	23.3	2.1	8	21
Acheson	Severe	33.1	2.6	10	7
Sundre	Severe	23.2	2.5	47	
Bonnie Glen	Severe	31.4	3.3	73	43
Redwater	Severe	35.6	1.6	19	22
Virginia Hills	Severe	22.8	1.2	33	6
Nipisi	Severe	16	1.8	41	14
Swan Hills - Swan Hills South	Severe	17.9	1.4	65	94
Bigoray	Watch				1
Kaybob North	Light				15
Zama	Moderate				41
Boundary Lake					4
Innisfail					31
Willesden Green					31

TABLE 3:
FAILURE TYPES AND NUMBER OF FAILURES

FAILURE TYPE	**NO. OF FAILURES**
Buckle	17
Not Converted	61
Collapse	94
Burst	99
Thread Leak	104
Blanks (No data)	109
Parted	170
Hole	2517
TOTAL	3171

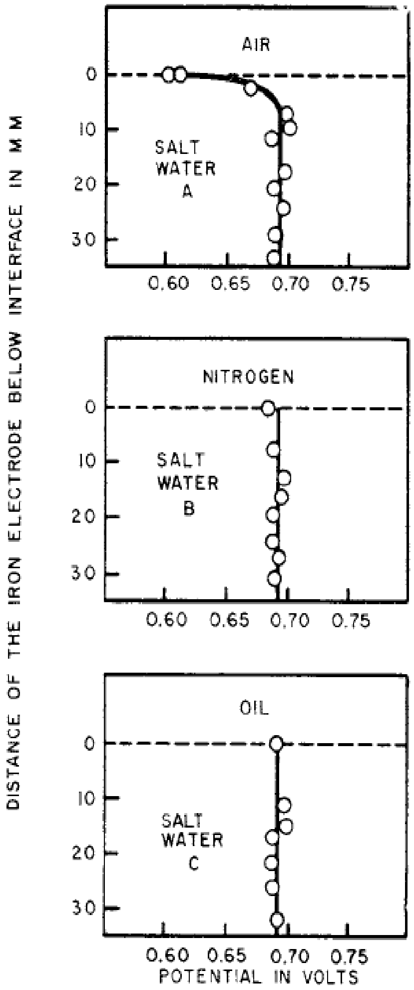

FIGURE 1 – Effect of Immersion Depth on Potential of Corrosion Cell

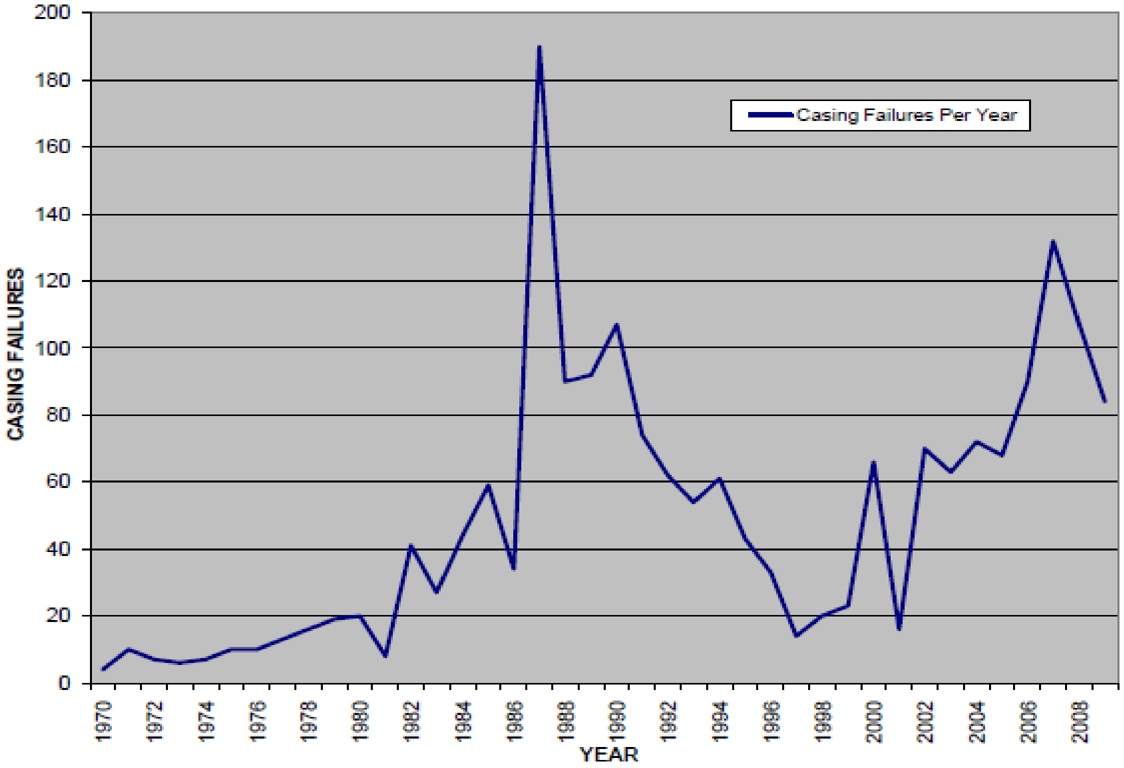

FIGURE 2 – Casing Failures per Year

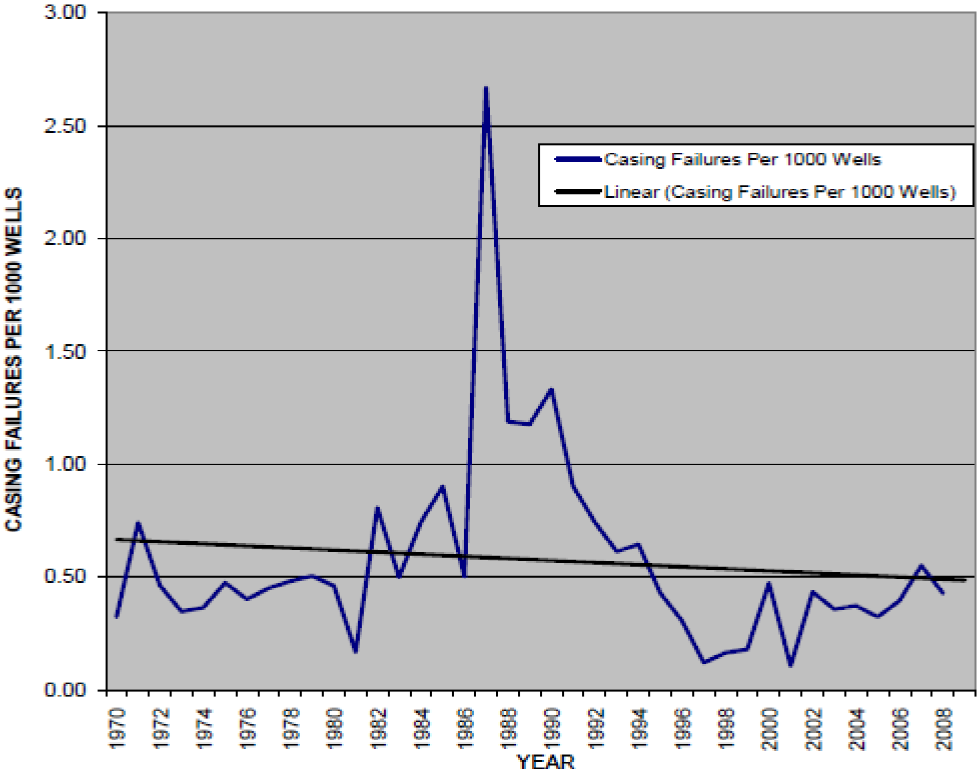

FIGURE 3 – Casing Failures per Year per 1000 Wells

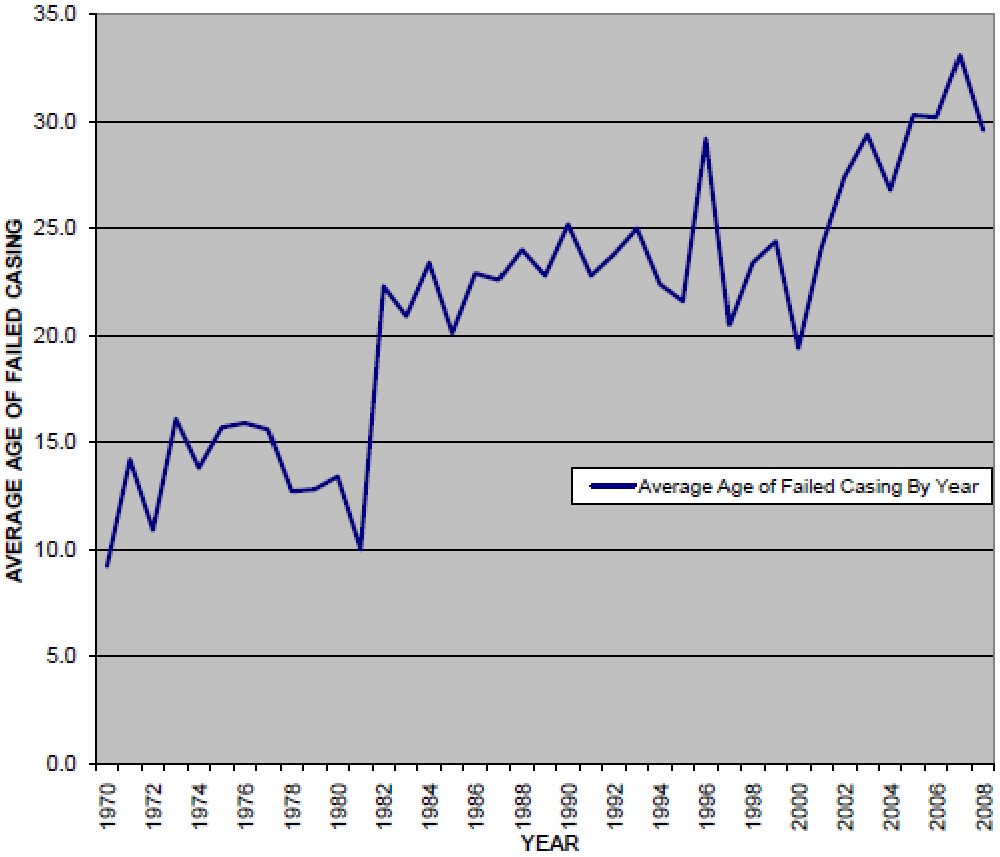

FIGURE 4 – Average Age of Failed Casing

PART B – CATHODIC PROTECTION OF WELL CASINGS

The application of cathodic protection to a well casing has proven to be a cost effective means of controlling external or soil side corrosion. Literature regarding well casing cathodic protection goes back over 60 years$_1$. The NACE standard, SP0186-2007 for "Application of Cathodic Protection for External Surfaces of Steel Well Casings" was originally prepared in 1986$_2$. This standard has many references for criterion for CP and current requirements, design of CP systems and control of interference currents. This section of the paper will deal primarily with current requirements and criterion for cathodic protection.

CURRENT REQUIREMENTS

There are a number of methods to determine the amount of current required to cathodically protect a well casing.

Current Density

Average current density may be used to determine the amount of current required to prevent external corrosion. Current densities vary considerably depending upon formation resistivities and the presence of cement. An average current density of 1 – 2 mA / ft^2 (10.76 – 21.5 mA / m^2) is a typical range for bare steel. A value of 0.5 mA /ft^2 (5.4 mA / m^2) is a nominal current density that Kroon et al used for well casings in North America while an average of 0.76 mA / ft^2 (8.2 mA / m^2) is more appropriate in some areas of the Middle East$_3$.

E-Log I

The procedure for performing E-log I tests is given in the NACE International Standard Practice SP0186-2007 (formerly RP0186-2001), "Application of Cathodic Protection for External Surfaces of Steel Well Casings", Appendix "B"$_2$.

The test procedure is to first take the "native" state potential, or the potential before any current has been applied. Current is impressed through a ground bed at predetermined current increments, depending upon the estimated final current required, and at specified time intervals, typically two to three minutes. At the end of the prescribed time interval, the current is interrupted. Upon interruption there will be an abrupt drop in potential, followed by a period of slow decay. The potential should be measured and recorded immediately upon interruption. This is often called the "Instant Off" potential. A higher current should then be applied at the next predetermined interval. It is important the time periods are consistent throughout the test. The casing potential measurements are plotted against the current on a semi-logarithmic scale. A typical E-log I graph is shown in Figure 5$_2$. The current required is taken as either the intersection of the two segments, Point A, or the first point on the Tafel slope, Point B.

The use of E-Log I tests for the design of well casing CP systems is referenced many times in the literature. Kroon et al described the use of the E-Log I test on wells in the United Arab Emirates$_3$. Cathodic protection had to be upgraded on more than 1300 wells. They conducted

E-log I tests on 37 representative wells. The current required from the E-log I tests ranged from a low of 12 A to a high of about 18 A with an average of 14.8 A. Current densities were calculated based on the current required for the E-log I tests. Current densities ranged from 0.57 mA / ft^2 (6.1 mA / m^2) to a high of 0.85 mA / ft^2 (9.1 mA / m^2) with an average of 0.76 mA / ft^2 (8.2 mA / m^2).

Based on the author's experience in North America, he assumed a nominal current density of approximately 0.5 mA / ft^2 (5.4 mA / m^2). This relatively low current density compared to current densities for surface structures is a result of the lack of oxygen at greater depths. The higher current densities for Abu Dhabi compared to North America are required to compensate for some high salinity aquifers in the Middle East.

Another recent paper was written by Bazzoni et al, entitled "Cathodic Protection of Well Casings in the Attahaddy Gas Field"[4]. This paper discusses the application of cathodic protection to 28 well casings in the Attahaddy Field in Libya.

The Attahaddy gas wells typically have four casing strings and have a total depth of about 3350 metres (10990 ft). The total casing surface area is about 3000 m^2 (32,280 ft^2) and all casing strings are nominally fully cemented. E-log I tests were performed on 16 production wells. The E-log I tests were performed and interpreted in accordance with NACE RP018-94, Appendix "B". A current increment of 1.5 amps and a time period of 30 minutes were used. An example of an E-log I from the Attahaddy Field is shown in Figure 6.

The average current required using Point A from the E-log I plot is 10.6 amps and the average current required using Point B is 17.0 amps. The results of all 16 of the E-Log I tests are given in Table 4.

There has been much discussion about the usefulness of E-log I tests. Part of the discussion is due to the substantial difference in current required, depending upon whether Point A or Point B is used. Husock believes that the E-log I is a method only for establishing a current requirement. It is not an indication of the current distribution on the casing or whether the applied current is adequate at providing cathodic protection[5]. Dabkowski stated that "the breakpoint exhibited by the E-log I curve for a homogeneous parameter casing is a function of the average casing corrosion density rather than an indicator of when an adequate cathodic protection level is achieved for local corrosion cells"[6].

Other variables that may lead to differences in the current determined from the E-log I test are the current increment and the time interval used. Hewes reported on E-log I test results on Saskatchewan well casings in a Technical Bulletin published in March 1954[7]. These wells were typically 1566 metres (4,500 ft) to 1463 metres (4,800 ft) in total depth with 183 metres (600 ft) of surface casing and with the production casing cemented to a depth of 914 metres (3,000 ft). The results of these E-log I tests are shown in Table 5.

A smaller current increment, 0.25 A compared to 1.0 A, results in a lower current requirement. Also a longer time interval for the applied current also results in lower current requirement. The basic reason for this is the time / polarization effect.

In summary, E-Log I tests, when properly run and evaluated with other factors such as current density, are a useful tool to determine the cathodic protection current required. However, further tests such as casing potential logs, remote potentials or well simulations must be performed to determine if that current is adequate.

Casing Potential Logs

One of the best methods of determining if a well casing is receiving adequate cathodic protection is to perform a casing potential profile log. A schematic of a profile tool is shown in Figure 7. A casing potential profile tool consists of two contacts positioned 3 to 8 metres (10 to 26 ft) apart and separated by an electrical insulator. The contacts make intimate contact with the casing by spring-loaded knives or cutter wheels. The tool measures a potential difference between the two contacts. The tool can be run with no current applied to the casing (e.g. static) or with various levels of current applied.

A typical plot from a casing potential profile log is shown in Figure 8. The curve shown to the left of the vertical axis gives the profile with no cathodic current applied. The curve to the right of the vertical axis shows the potential plot once current is applied.

Although this method is probably the best tool to use to verify if cathodic protection is being attained, it is not practical to run a casing log on every well in a given field. Downhole logging is expensive and requires that the tubing is pulled from the well. The well must also have a non-conductive fluid in the hole.

Mathematical Modeling

Various mathematical models have been developed to predict the levels of downhole cathodic protection. One model was developed by Schremp et al and uses an attenuation equation[8]. Data such as the production and surface casing length, weight and grade must be known. The native state potential of the casing must also be known before current is applied. Finally, the applied current to the casing and the remote “On” and “Off” potentials of the well are measured. The program calculates the bottomhole “On” and “Off” potentials. The calculated potentials are typically within 3% of the measured values from a casing potential log.

Another computer model was written by Dabkowski for the Pipeline Research Committee of the American Gas Association (AGA). The initial report dated January 1983 was entitled “Assessing the Cathodic Protection Levels of Well Casings”[9]. It was later presented in the Materials Performance magazine in January 1986[10]. The model accommodates multiple casing strings for an individual well and allows ground resistivity variations with depth. This results in a more accurate simulation. However it requires detailed information such as production and surface casing length, weight and grade and soil resistivities for the entire depth of the well.

Dabkowski’s program was written in the AGA publication and is public knowledge. Several different simulations were performed for a well with 244.5 mm (9 5/8 in.) surface casing to a depth of 405 metres (1330 ft) and 177.8 mm (7.0 in.) production casing to a depth of 3526 metres (11570 ft). Simulations were performed with a current of 10 amps and varying the distance of the ground bed from 20 metres (66 ft) to 400 metres (1312 ft). The graph in Figure 9 shows the current density for ground bed distances of 20, 100, 200 and 400 metres. Note that there is a very high current density at the top of the casing when the ground bed is only 20 metres from the well. There is a much lower current density than the other cases at greater depths. There is little difference in the other cases. It has been found through many simulations and field experience that a distance from the well to the ground bed of 1/20 of the depth of the well, or 5% of the depth of the well, yields good current distribution. The graph in Figure 10 shows the current profiles for the same conditions.

The simulation can also be used to show the effects of stray current interference. In this example the ground bed is located at a distance of 200 metres (656 ft) from the well and it is discharging 10 amps. However, the current being drained from the well is zero amps and the current is being picked up by the pipelines (i.e. simulating that the cable to the well has been broken). Note that current is being picked up by the casing in the top approximately 540 metres (1772 ft) then the current density turns negative (Figure 11). This point where the current density turns negative coincides with the inflection point at the bottom of the current curve (Figure 12).

Special Cases

In some instances where wells are very deep or wells are closely spaced, it is very difficult to get adequate current distribution or sufficient current to the bottom of the well. In these cases, pulse current rectifiers may be a viable alternative. Bich and Bauman reported on the use of pulse current rectifiers in their paper, "Cathodic Protection of Well Casings by Pulsed Current"[11]. Cathodic protection by pulse rectifiers involves applying current pulses of several hundred volts for very brief periods of time, several thousands cycles per second. The concept was originally applied by Doniguian on clusters of wells in Huntington Beach, California[12]. Bich and Bauman discussed the use of pulse current rectifiers on a cluster of wells in Midale, Saskatchewan and on five wells in Alberta. They concluded that the "pulse current rectifier can protect single and clustered well casings to significantly deeper levels than conventional DC current" and "Pulse Rectifier Technology (PRT) is more effective at supplying current to the production casing in a uniform manner versus DC current"[11].

Another technique to improve current distribution on congested wells is to coat the casing. In 1960 the United Fuel Gas (UFG) Company of West Virginia reported the results of tests to determine the durability of coatings for use on well casings[13]. The UFG drilled ten wells to a depth of 773 metres (2536 ft). The bottom 276 metres (905 ft) were coated with different coatings. Their testing showed that some of the coatings remained 95% intact.

In 1970, the Pacific Gas and Electric Company drilled 60 closely spaced wells for gas storage[13]. The wells had a depth of 1646 metres (5400 ft) and were completed with 34 cm (13 3/8 in.) surface casing and a 24 cm (9 5/8 in.) long string. All but one of the wells was coated to the total depth with a coal tar epoxy. Cathodic protection current requirements were less than 0.5 amps per well indicating the coating was 95% to 98% intact. The wells were cathodically protected in the late 1970's with no leaks for almost ten years. The previous leak history for the bare well casings was significant.

Orton et al discuss the use of coated well casings in their paper "Cathodic Protection of Coated Well Casing"$_{13}$. They discuss the cathodic protection of wells in Saudi Arabia for the Arabian American Oil Company (ARAMCO). The wells had two coated casing strings; one string of 34 cm (13 3/8 in.) and a second casing of 24 cm (9 5/8 in.) diameter to a depth of 1298 m (4258 ft). A third casing with a diameter of 18 cm (7 in.) was installed to a depth of 2072 m (6800 ft). This third casing was left bare to ensure that an adequate cement bond was achieved. Similar wells in this field with bare casing required 30 A for cathodic protection. It was shown that the wells with coated casing could be protected with about 4.8 amps of current.

Another valuable learning from this paper was the effect value of time and polarization. It is not easy to document the effects of polarization because casing potential logs are seldom conducted sequentially on the same wells. Table 6 illustrates the current requirements for five random wells over a period of 20 months. The current indicated was that current required to maintain a polarized potential of -1.0 volt. It is believed that the increased current for Well #4 is the result of interference from adjacent cathodic protection systems.

Leak Frequency

The most important criteria to determine if a well casing cathodic protection program is effective is that the leak frequency has decreased. The Sun Exploration and Production has been involved in well casing cathodic protection programs since at least the mid 1960's. Kirklen originally wrote about the success of the well casing CP programs in 1973$_{14}$. The graph in Figure 13 on semi-log graph paper shows the well casing leak frequency for the Clairemont Field in Kent County, Texas. The time in years is shown on the "X" axis and the cumulative number of failures is shown on a logarithmic scale on the "Y" axis.

A typical well in this field has 122 metres (400 ft) to 213 metres (700 ft) of surface casing cemented to surface and 2012 metres (6,600 ft) to 2042 metres (6700 ft) of production casing. The cement top in the production casing is typically at the 1676 metre (5,500 ft) level. Nine casing leaks had occurred among the 55 wells in this field when cathodic protection systems were installed in 1966. A current of six amps was maintained on the well. The dashed line shows the extrapolation of the number of casing failures if nothing had been done. The solid line indicates the cumulative number of failures after the cathodic protection was installed. In this instance, the cathodic protection was 88% effective.

CONCLUSIONS

1. There are four main methods of determining design current requirements: average current density, the E-log I test, casing potential profiles and mathematical modeling.

2. E-Log I tests, when properly run and evaluated with other factors, are a useful tool to determine the cathodic protection current required. However, further tests such as

casing potential logs, remote potentials or well simulations must be performed to determine if that current is adequate.

3. Casing potential profiles are the best technique to determine if the applied cathodic protection current is adequate. However, they are expensive to run and are not practical to perform on all wells.

4. The Schremp / Newton attenuation model is able to calculate downhole potentials within 3% of measured values determined by casing potential profiles.

5. The Dabkowski model is able to model multiple wells and ground beds.

6. Pulse current rectifiers are able to protect single and clustered well casings to significantly deeper levels than conventional DC rectifiers. They also provide more uniform current distribution than conventional rectifiers.

7. Coated well casings result in much better current distribution and lower current requirements. Current requirements are typically about 1/5 of the current required for an uncoated casing.

8. Current requirements are much less once cathodic protection current has been applied for a period of time and the well becomes polarized.

9. Graphing the cumulative number of leaks versus time on a semi-log plot is an effective method of determining the success of a well casing cathodic protection program.

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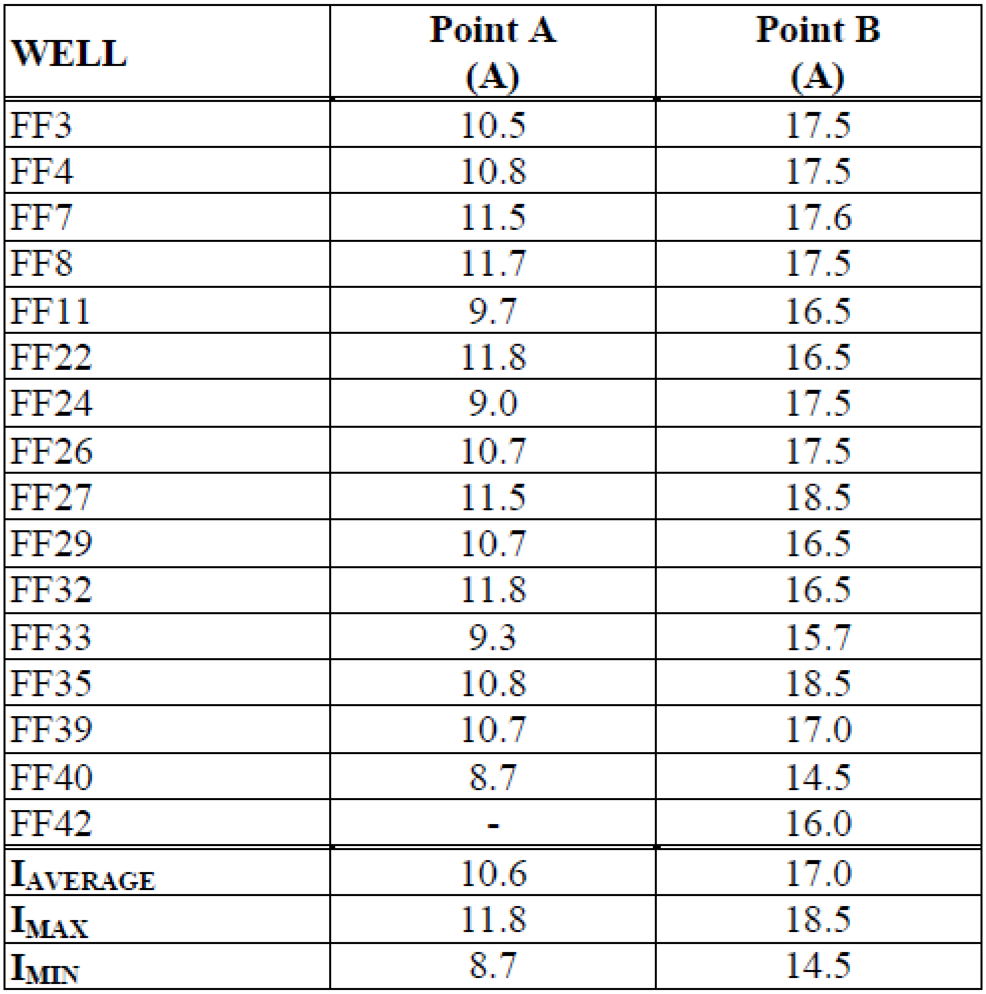
TABLE 4:
RESULTS OF 16 E-log I TESTS FROM THE ATTAHADDY FIELD



WELL	Point A (A)	Point B (A)
FF3	10.5	17.5
FF4	10.8	17.5
FF7	11.5	17.6
FF8	11.7	17.5
FF11	9.7	16.5
FF22	11.8	16.5
FF24	9.0	17.5
FF26	10.7	17.5
FF27	11.5	18.5
FF29	10.7	16.5
FF32	11.8	16.5
FF33	9.3	15.7
FF35	10.8	18.5
FF39	10.7	17.0
FF40	8.7	14.5
FF42	-	16.0
$I_{AVERAGE}$	10.6	17.0
I_{MAX}	11.8	18.5
I_{MIN}	8.7	14.5

TABLE 5:
CURRENT REQUIREMENTS FOR SASKATCHEWAN WELLS

Current Increment	Time Interval	Typical Current at Indicated Break
1 A	5 min.	8 – 10 A
0.5 A	5 min.	7 – 9 A
0.25 A	5 min.	6 – 8 A
0.25 A	10 min.	5 – 7 A

TABLE 6:
CATHODIC PROTECTION CURRENT REQUIREMENT OVER TIME

CP CURRENT REQUIREMENT (AMPS)			
WELL	**START-UP**	**8 MONTHS**	**20 MONTHS**
1	11	9	5
2	9	7	2
3	12	14	4
4	21	10	18
5	25	14	3

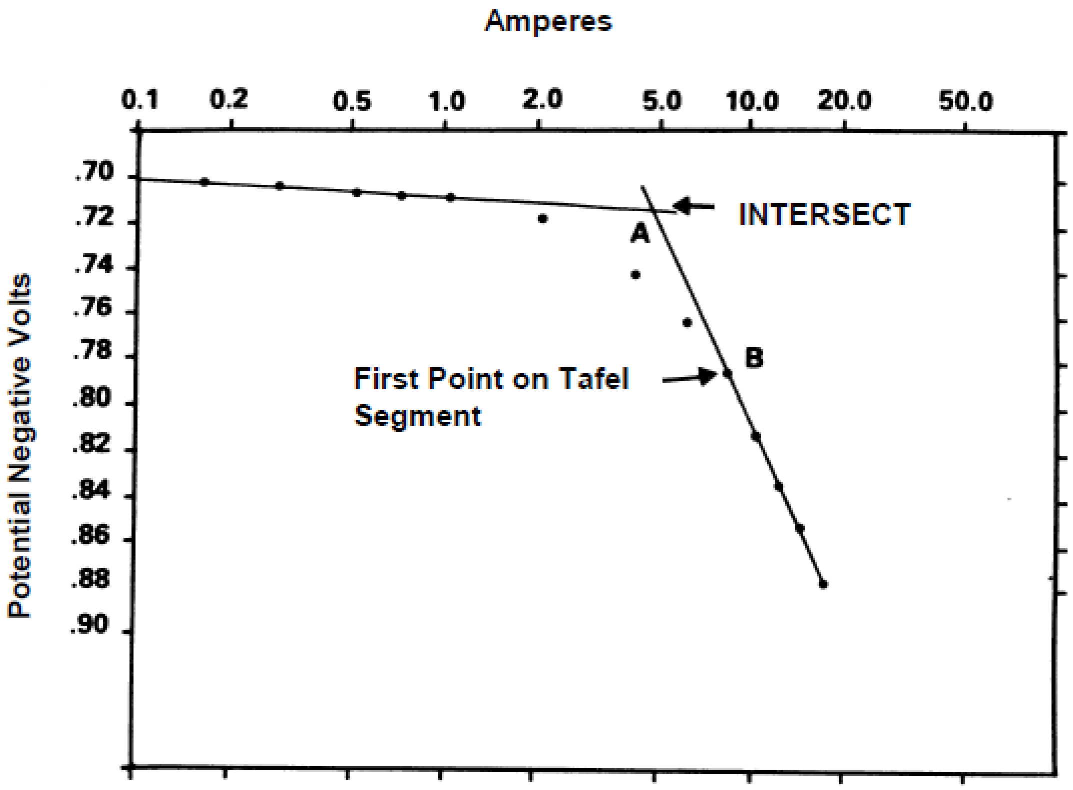


FIGURE 5 – Typical E-log I Plot

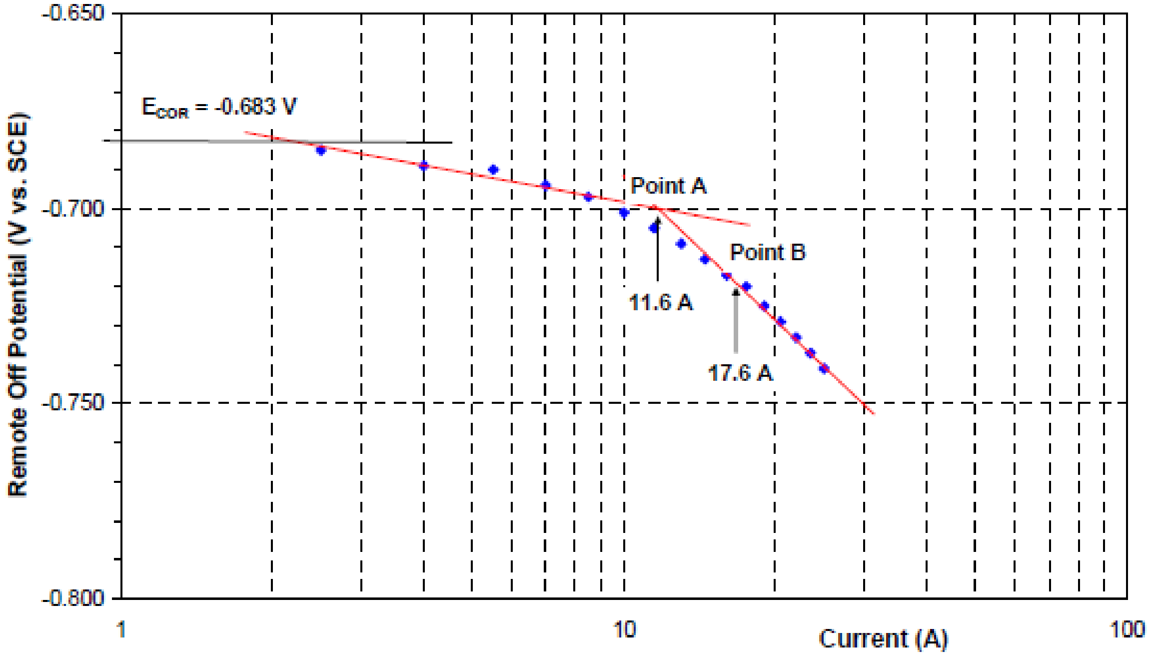


FIGURE 6 – Example of E-log I Test from the Attahaddy Field

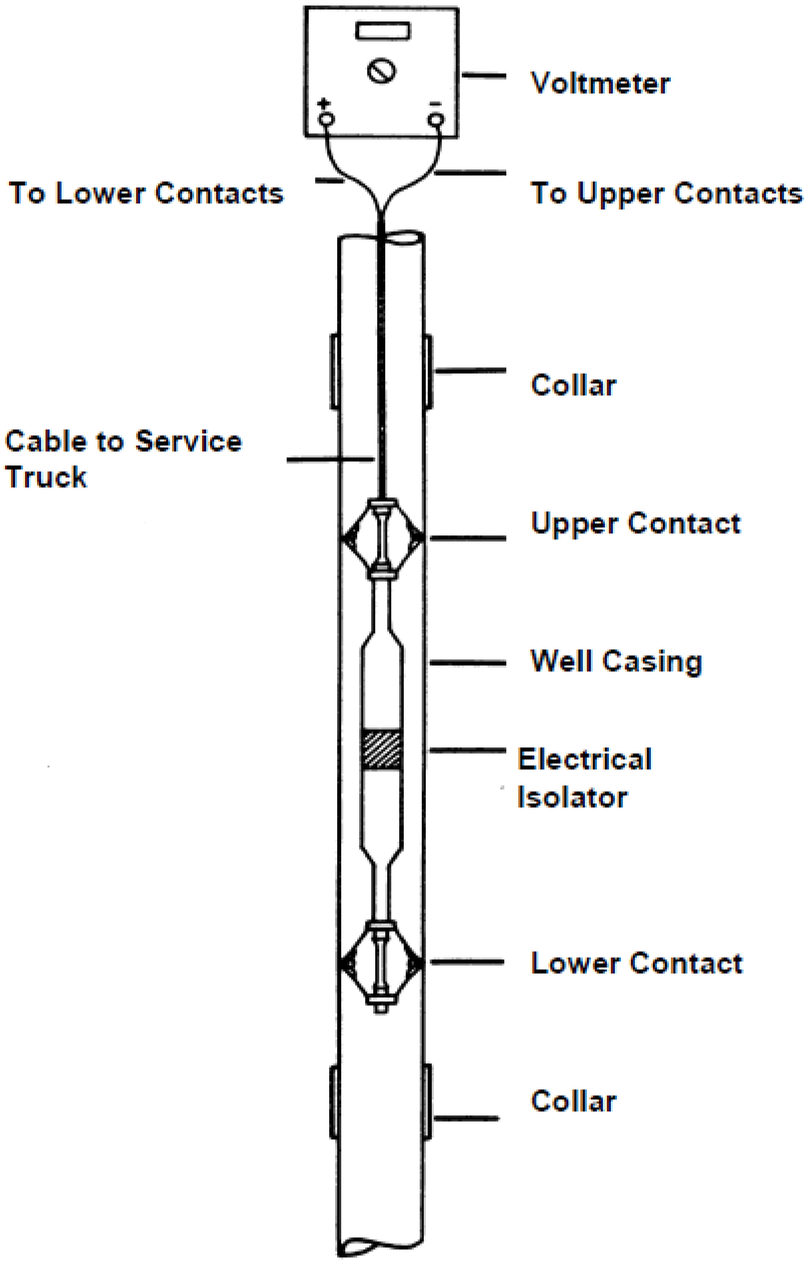


FIGURE 7 – Schematic of Casing Potential Profile Tool

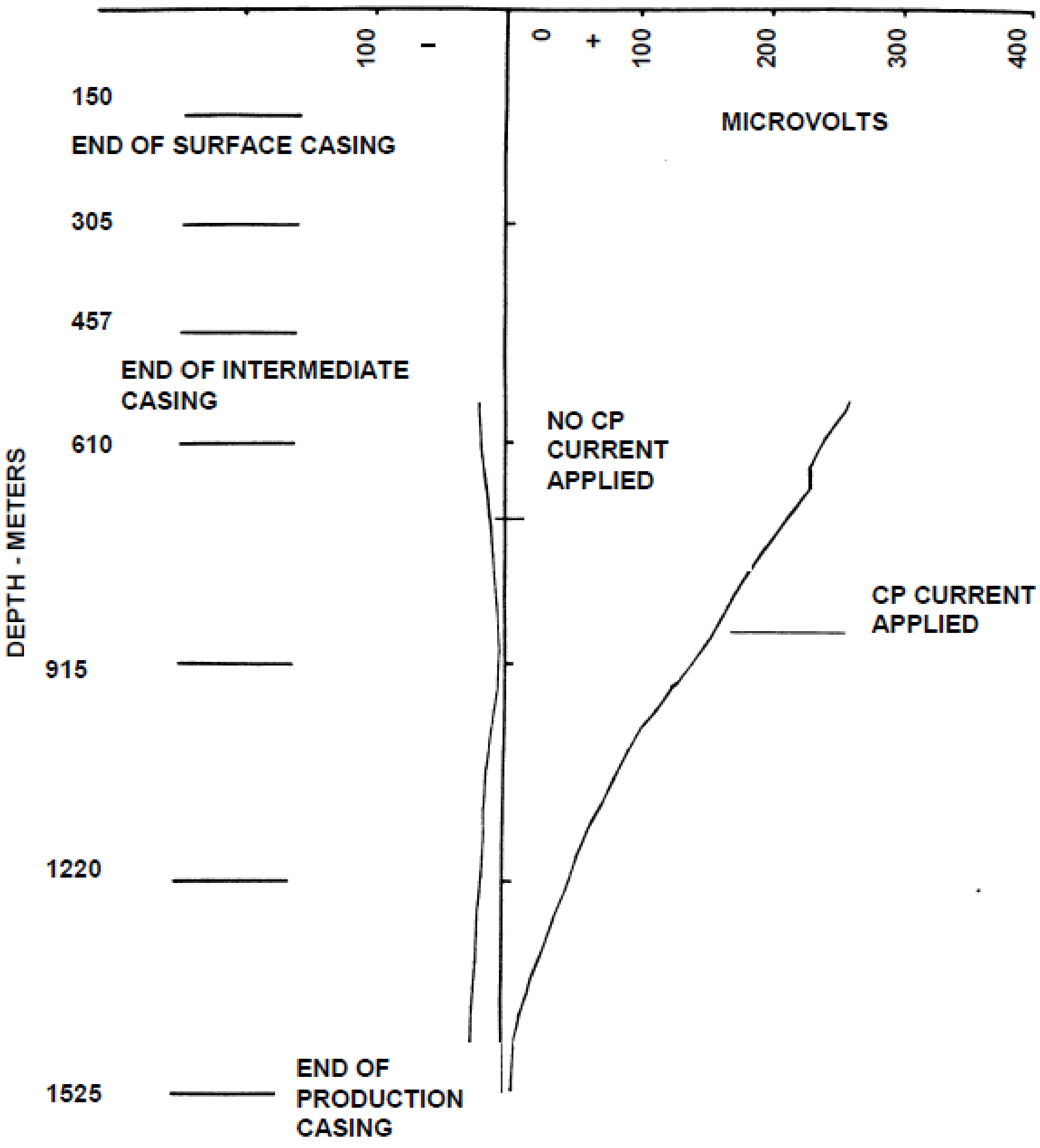


FIGURE 8 – Typical Casing Potential Profile Plot

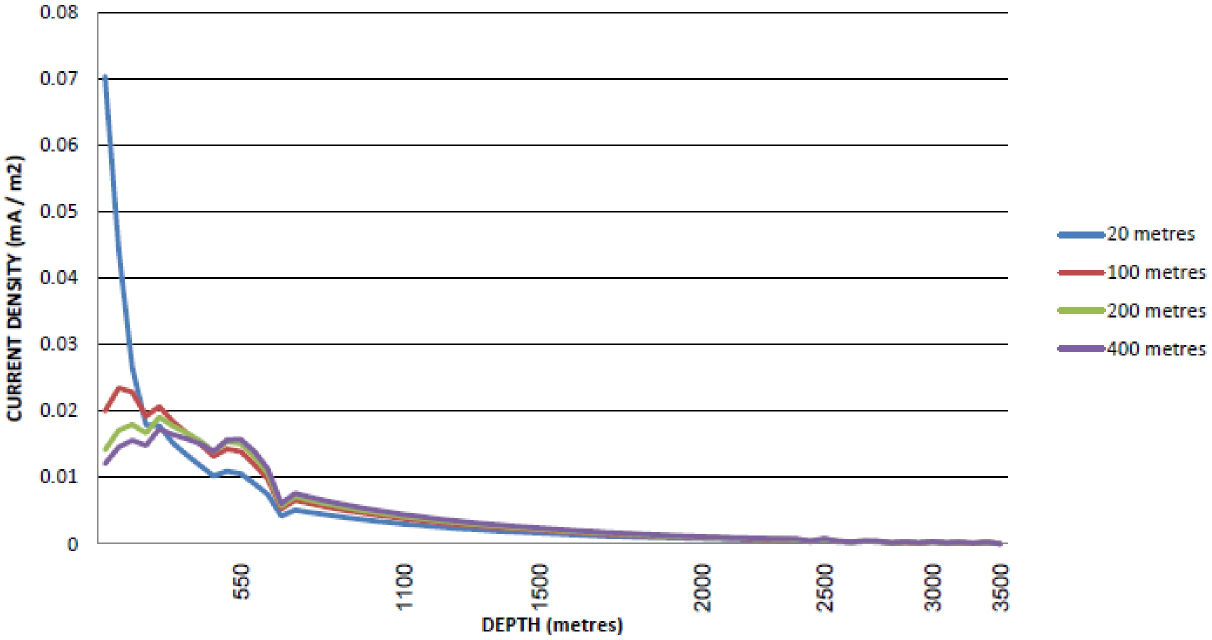


FIGURE 9 – Current Density – Groundbed at Various Distances from Well

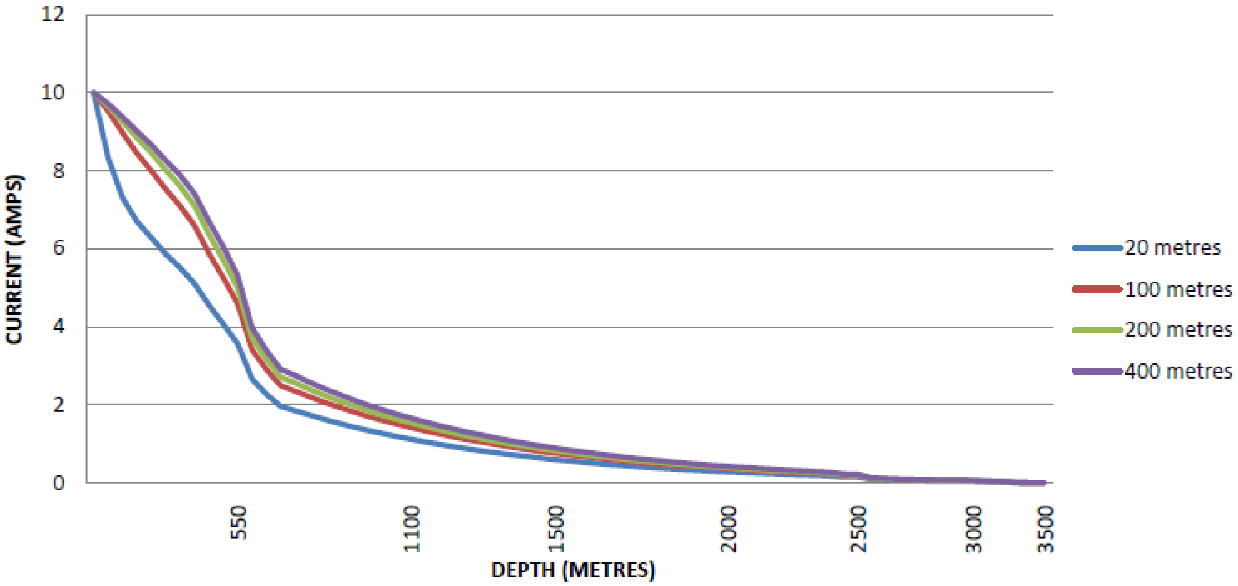


FIGURE 10 – Current – Groundbed at Various Distances from Well

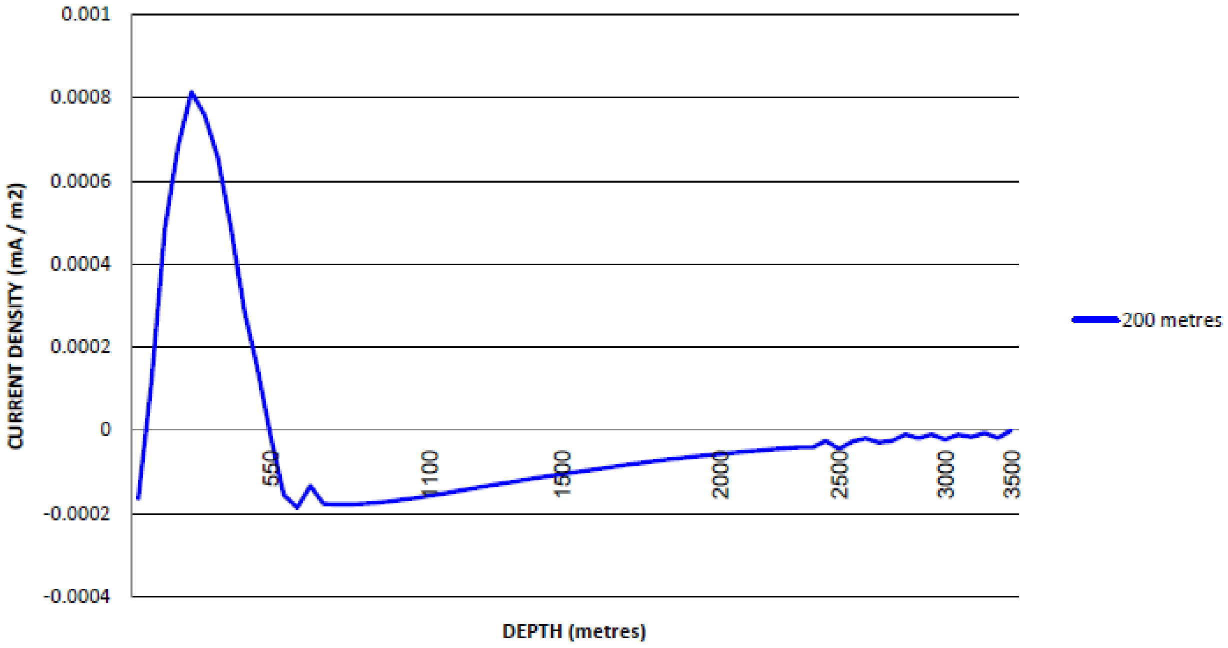


FIGURE 11 – Current Density – Groundbed at 200 Metres from Well

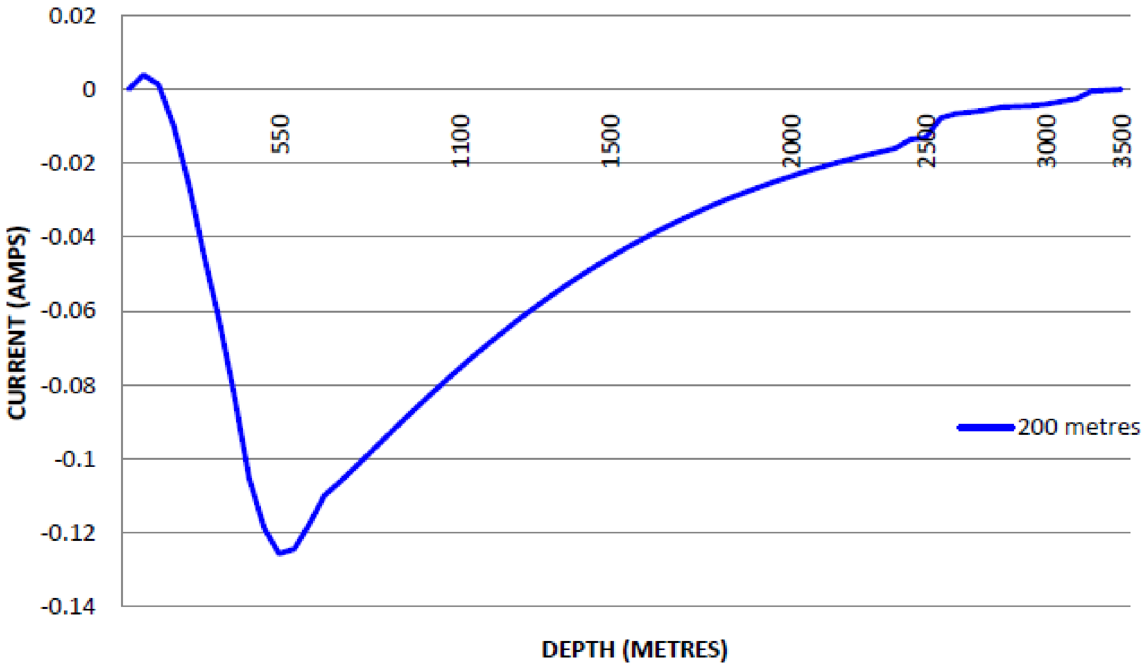


FIGURE 12 – Current– Groundbed at 200 Metres from Well

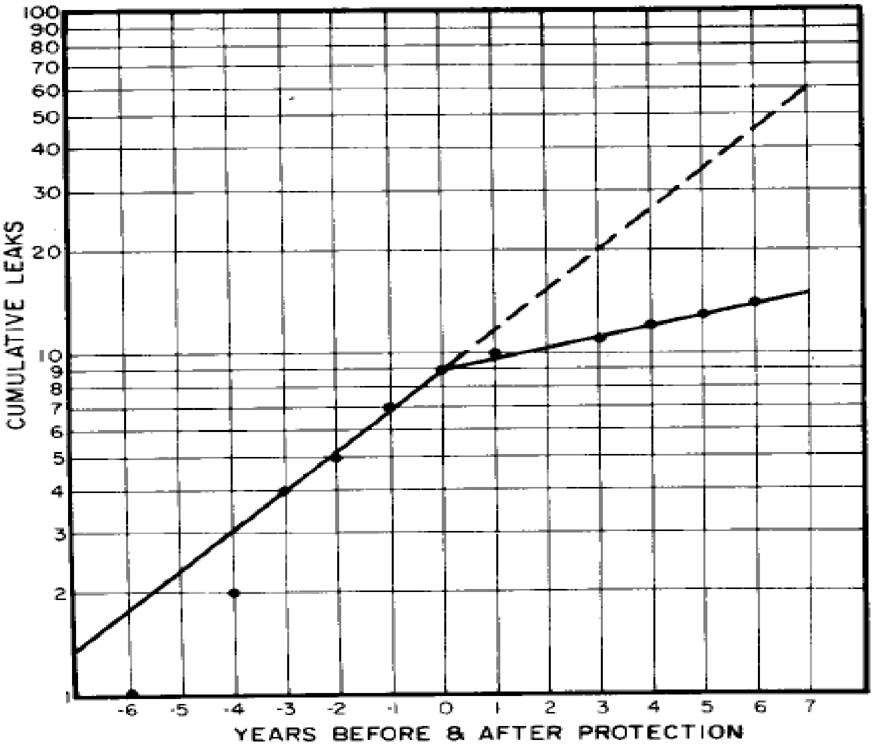


FIGURE 13 – Cumulative Leaks versus Time on a Semi-Log Plot