SECTION V

CONSTRUCTION, MAINTENANCE, AND INSPECTION

1. Construction

Probably the most critical stage in corrosion control is the construction of the pipeline. This includes trenching, laying, and connecting the pipe; coating; filling the trench; and installing cathodic protection. Of course, before one can intelligently plan a corrosion protection system, it is advisable to make a corrosion survey on the path the pipeline will take. The importance of soil resistivity, solutes, moisture, etc., on corrosivity has been noted previously. It is almost essential to have detailed specifications for all aspects of the corrosion protection system as part of the construction contract.

The prevalence of interference between casings under roadways and roadbeds and cathodically protected pipeline; has been mentioned earlier (22,669 casings shorted and 302 Leaks inside casings reported by the companies surveyed). The research and test results reported in Reference 559 indicate considerable progress toward elimination of the requirement for casing pipelines under roadbeds, i.e., there is evidence to support the contention that casings are unnecessary for safety and are harmful in terns of controlling corrosion. The following comment from the questionnaire is of interest in this regard: "All states should adopt a law similar to California's that would not require casings. Our company, for one, has 'lad shorted casings. At the time these lines were laid, we used the best insulators and seals available. For instance, on 390 miles of 20-22-inch pipe inside 26-inch casing we had over 2,800 feet of coated line shorted to the casing" (Q495).

Following various stages of construction, thorough inspections are desirable. Both good instruments and well trained inspectors are necessary. Electrical methods can be used to determine if proper insulation or connection between joints has been obtained, whichever is desired (227). Inspection of coatings is particularly important. To minimize cathodic protection current requirements, great care must be taken to repair all holidays. Holidays in insulating coatings are normally detected by "jeeping," in which a high voltage electrode is passed over the coating. A holiday is indicated by current passage, as detected by suitable instrumentation. Although specific voltage differences are sometimes recommended (e.g., 403), the really important quantity is the electric field. The field must be sufficient to cause a discharge through air, but not so large as to damage the coating. A field of 120 V/mil across the coating has been recommended (686). Some engineers recommend checking the coating again just after laying the pipeline in the ditch and before covering.

Although elaborate trench dressings are not necessary, it is generally desirable to remove large rocks to avoid damage to the coating. Use of rock shields is very poor practice because they may provide good conditions for microbiological action and insulate piping from cathodic protection currents.

One gas company recommended installation of a Mg anode "inspection system" (555). A Mg anode was installed on the pipe during the first day of construction and the pipe potential was read at the end of each day of construction. A sudden drop in potential signaled contact with foreign structures, shorted casings, or large sections of uncoated or poorly coated pipe. This was particularly useful in laying submarine pipelines.

The conditions under which plant applied coatings or over-the-ditch applied coatings were preferred are listed in Tables 36 and 37, respectively, for the companies surveyed. Some representative standards and specifications for coatings and their application are listed in Table 38.

TABLE- 36

CONDITIONS UNDER WHICH PLANT APPLIED COATINGS ARE PREFERRED

Condition	Number of Companies
All conditions	62
Small jobs	35
Urban areas, poor right of way, and where submarine construction methods are used	27
Whenever economical	15
Small sizes	15
Wintertime conditions	10
Flat terrain	7
New construction	5
When using thin film epoxy or polyethylene coatings	5
When proper handling is assured	3
Cased highway crossings	2
Rugged terrain	2
Centrifugally spun pipe	1
When used for pumping station piping	1

TABLE 37

CONDITIONS UNDER WHICH OVER-THE-DITCH APPLIED COATINGS ARE PREFERRED

Condition	Number of Companies
None	76
Open country, cross country	29
Large jobs, long lines	25
Large pipe sizes	18
Where considered economical	18
At field joints	16
Rocky rugged terrain	15
Summertime conditions	11
Jobs requiring little handling of the coated pipe	10
Recoating on replacement	9
Short runs, odd sizes, or extremely heavy sections	8
Under all conditions	8
New construction projects	7
In the vicinity of pumping stations	1
When work is done by an experienced contractor	1

Table 39 lists the field practices used by the companies surveyed to ensure good coatings.

TABLE 39

FIELD PRACTICES USED TO ENSURE GOOD COATINGS

Practice	Number of Companies
Field inspecting	356
Holiday detecting	322
Rock shielding	248
Sand backfilling in rock areas	279

Most of the companies surveyed used high molecular weight polyethylene jacketed copper cable for cathodic protection conductors. The thermit process was used by 309 companies to attach

TABLE 38

STANDARDS AND SPECIFICATIONS FOR COATINGS

Parameters	Type of Coating	Organization	Date	Ref.
Application	Coal tar	NACE	1957	6177
Application	Various	UK	1966	82,708
Application, inspection	Coal tar enamel for marine environs	NACE	1957	6173
Application procedures	Coal tar and asphalt enamels	NAPCA	1967	480
Adhesion	Paints	ASTM	1967	718
Adhesion	Bituminous	AWWA	1966	588
Composition, weight, strength, saturation	Asbestos felt	NACE	1962	6188
Fungi resistance	Plastic	ASTM	1963	719
Leakage conductance	Insulating	NACE	1957	6191
Materials, application, inspection maintenance	Mastics	NACE	1957	6179
Materials, application	Wrapped, mastic interior asphalt	The Asphalt Institute	1958	720
Material thickness, tear strength, breaking strength, pliability, porosity	Fibrous glass reinforced pipe wrap	NACE	1962 1967	6192 6190
Properties, test methods, use	Wax	NACE	1961	6182
Strength, pliability, porosity	Bituminous saturated glass pipe wrap	NACE	1962	6192
Surface preparation	Paints	Swedish standards Assoc.	1967	731
Testing, application, composition	Asphalt	NACE	1953 1958	6178 6180
Thickness, bendability, impact resistance, weathering, abrasion resistance, penetration, thermal aging, cathodic disbonding, soil stress, water penetration, capacitance	Insulating	AGA	1970	700
Thickness, uniformity, smoothness, brightness, surface finish	Zn, Cd	UK, USA, Germany	1963	243
Weights (per area)	Insulating	NAPCA	1966	481

the conductor to the pipe (Table 40). For high strength (X52 or above) steel pipe the thermit process was limited generally to a 15-gram cartridge. One hundred and three companies apparently have used X-52 or above high strength steel pipe.

TABLE 40

METHODS CURRENTLY USED FOR ATTACHING CONDUCTOR TO PIPE

Method	Number of Companies
Thermit process	309
Solder	23
Conductor brazed to steel coupon welded to pipe	87
Bolted connection	46
Other	22

2. Maintenance

Deterioration begins when a pipeline is completed. In addition to natural processes such as lightning, man often accelerates the process with various earth-moving machines which damage coatings and metal. Thus, regular maintenance is necessary to keep the pipeline operating. In the crudest method, repair is initiated only when leaks manifest themselves. Table 41 lists the methods used to repair corrosion leaks by the companies in the survey.

Repair may consist of replacing old pipe sections with new pipe. As pointed out earlier new pipe is anodic with respect to old pipe, and so should be protected by coating and/or cathodic protection. Table 42 lists the factors that the surveyed companies take into consideration in the replacement or abandonment of corroded pipe.

TABLE 41

METHODS USED TO REPAIR CORROSION LEAKS

Method	Number of Companies
Clamps	226
Replacement	204
Weld leak	85
ANSI B31.8 procedures	11
Welded patches and other devices	10
Insert plastic internally	9
Abandonment	4
Reduce line pressure	4
Redwood or oak plug followed by patch	3
Drill, tap, and plug	1
Recaulk joints	1

Table 43 shows the criteria used for replacement for the water system of a large city. This is a systematic rational approach that could be extended to gas and oil systems.

Internal coatings may be applied, particularly in large diameter lines. In one method for leak repair of gas lines a suspension of rubber particles is pumped through the pipes and plugs the leaks (723). The companies surveyed reported varying experience and preference regarding the effectiveness of available commercial sealants in repairing corrosion leaks.

TABLE 42

FACTORS TAKEN INTO CONSIDERATION IN THE REPLACEMENT OR ABANDONMENT OF CORRODED PIPE

Factors	Number of Companies
Leak history	142
Location of corroded pipe	76
Condition of pipe	68
Age of pipe	67
Operating pressure	47
Present and future plans for pipe	46
Cost of repair versus cost to replace	45
Depth/size of pits and spacing	41
Safety considerations	39
Extent of Corrosion	37
Economics	36
Soil resistivity/soil Type	26
Type of pipe	22
Size of pipe	21
Visual inspection/appearance	18
Feasibility of cathodic protection	14
Damage to area and inconvenience of inoperable line	9
Pipe potential	8
Wall thickness	6
Analysis of sample section	1

TABLE 43

CRITERIA FOR REPLACEMENT OF 12-INCH AND SMALLER MAINS (Q685)

A. Length - The study length used will be approximately 600 feet, or one block the long way, or two blocks the short way.

B. Points Required - A minimum of 10 points will be required to justify relaying.

C. Basis for Points

1. General Considerations

a. Age of Main

1.	over 80 years old	3 points
2.	51 - 80 years old	2 points
3.	21 - 50 years old	1 point
4.	0 - 20 years old	0 points

b. History of Leaks and Breaks

1.	Pipe wall corrosion leak	2 points
2.	Beam break or joint leak	2 points

c. Standards

Material or workmanship not conforming to standards	2 points

2. Hydraulic Considerations

a. Divergency from the Standard Gird

1.	Two or more sizes	2 points
2.	One size	1 point

b. Small Size Mains

1.	4" main	3 points
2.	2" or smaller mains	2 points
3.	3" main	1 point

c. Carrying Capacity

To be reconditioned if less than 5 other points

Flow coefficients (Hazen Williams "C"):

1.	Less than 75	2 points
2.	75 - 100	1 point
3.	More than 100	0 points

TABLE 43
(continued)

a.	Head Loss per 1,000 Feet (Peak Hour Conditions)	
	1. More than 5 feet	2 points
	2. Less than 5 feet	0 points
3.	Corrosion Considerations	
a.	Actual Corrosion of the Main - (5 ft running length)	
	1. Pits more than 75% of the wall thickness	5 points
	2. Pits 50 - 75% of the wall thickness	3 points
	3. Pits less than 50% of the wall thickness	0 points
b.	Soil Resistance in Ohm Cm	
	1. Less than 1,000	3 points
	2. 1,000 - 2,000	1 point
	3. Over 2,000	0 points
c.	Galvanized Pipe	2 points
4.	Special Considerations	

Any one of the following circumstances may, in themselves, be sufficient criteria for main replacement.

1. Divergency from standard depth
2. Extreme external loading

---

3. Inspection

Table 44 indicates the frequency of surveillance or tests performed by the 373 operating companies surveyed. Other than annual measurements of pipe-to-soil potential at test stations, current interference, and line current measurements, most of the measurements are unscheduled, used infrequently, or used only on occasions when the opportunity presents itself.

Various inspection methods have been designed to locate problems before leaks develop. Several of these are aimed

TABLE 44

FREQUENCIES OF SURVEILLANCE METHODS

Type of Surveillance Test	A*	B	T	Q1	Q2	S1	S2	O1	W	M	U	R	X	O2
Aerobic bacteria	0	3	0	0	0	0	0	0	0	0	32	18	42	0
Anaerobic bacteria	2	1	0	0	1	0	0	0	0	0	40	30	50	0
Bell hole inspection (coating and pipe condition)	7	0	0	0	0	0	0	0	10	1	73	192	18	6
Coating conductance survey (local)	7	1	0	0	0	0	0	0	1	0	68	22	45	4
Coating conductance survey (longline)	12	1	0	0	0	0	0	0	1	0	68	18	45	4
Coating Discontinuity Survey (Pearson)	1	0	0	0	1	0	0	2	0	1	82	25	78	1
Earth current test (pipe vicinity)	6	1	0	0	0	0	0	0	1	0	55	20	33	0
Line current measurement	77	6	0	0	0	0	1	0	1	4	71	43	32	3
Surface potential survey close interval	21	7	2	0	4	0	0	0	1	1	94	44	36	5
Continuous	10	1	0	0	1	0	0	0	0	1	65	21	26	0
Pipe-to-soil potential survey (at test stations)	191	38	1	0	1	0	0	0	3	38	11	5	3	20
Redox potential	0	0	0	0	0	0	0	0	0	0	28	4	29	1
soil resistivity survey	11	1	0	0	0	0	0	0	1	1	105	75	41	7
Chemical analyses	1	1	0	0	0	0	0	0	0	0	40	18	54	2
Current interference	59	4	0	0	1	1	0	0	3	5	89	90	11	7
Other	0	2	1	0	0	0	0	0	0	17	3	1	3	4

*A = Annually
B = Biannually
T = Triennially
Q1 = Quarterly
Q2 = Quinquennially
S1 = Sexennially
S2 = Septennially
O1 - Octennially

W = Weekly
M = Monthly
U = Unscheduled
R = On occasions when opportunity presents itself
X = Infrequently
02 = Other than the above

at the coating, which may be the part of the system most vulnerable to problems. The general condition of an insulating coating on buried pipelines is indicated by the average current density required for cathodic protection or by the leakage conductance of the coating (6191). A large gas pipeline company classifies pipe as "bare" if 1 ampere or more is required per mile of 3-inch equivalent pipe (Q403). Specific coating defects may be located by several instruments. One of the most common is the Pearson holiday detector (60). Generally, an operator walks along the pipeline while audio-frequency current is conducted to ground through metal cleats in his shoes. A second operator walks 20 feet behind with an audio detector. Sudden increases in signal occur when even a small holiday is present. Experience is needed to understand the signal fluctuations and to locate flaws in the coating (608).

A surface potential survey is useful for revealing "hot spots" in systems not having cathodic protection. In one procedure two $CuSO_4$ electrodes are connected to a potentiometer (601). The rear electrode is placed directly over the line and the lead electrode extended directly over the pipe. The electrodes are then "leap-frogged" one separation distance until the survey is completed. Corroding sections of pipe are indicated by sharp peaks or changes of polarity.

Potential surveys may also be performed by passing a rolling electrode along the pipe, with the other side of the potentiometer connected directly to the pipe. If a recorder is attached by gears to the rolling electrode, then potential versus distance is automatically displayed. It has been pointed out that potential surveys cannot detect small, localized corrosion cells, which would be expected on bare pipelines (6172).

Care must be taken when electrical contact must be made directly to the piping.* Probes cause holidays, and if bright metal is created by scratching it may corrode rapidly, being anodic. A better approach is to install test reference leads on the piping at the time of construction.

Unfortunately, methods requiring electrical contact to the soil are difficult to use when the pipe passes under concrete or rock. Thus, methods have been devised not requiring electrical contact of an electrode to the soil. In one method, pick-up loops are employed to detect the magnetic field generated by current flowing in the pipe. Sudden drops in output with distance signify current leakage through the coating (403).

At this time, the best indicator of pipeline corrosion appears to be close monitoring and interpreting of the pipe potentials. Since it is current leaving a buried structure that causes corrosion, the optimum measurement would be the determination of the current leaving the structure. In the near future it may be possible to measure the current flow patterns in the pipe by a magnetic gradiometer. The use of a magnetic gradiometer may allow the detection of the variation changes in the magnetic field of the pipe current and pinpoint location, direction, and amplitude of current flow. Additionally, this instrument can conceivably be used at speeds from 20 to 200 miles per hour external to or in the pipeline (799).

*Interview with A. W. Peabody, 1970.

The industry is in need of easy-to-use, accurate instruments that combine as many corrosion related factors (soil resistivity, pH, pipe potential, etc.) as would be practical (Q252, Q220, Q505, Q606, Q8.2, Q490, Q699). Automated surveys and remote instruments will become more desirable with future increases in cathodic protection and interference (Q282).

Hydrostatic testing can be used to detect leaks and corrosion weakened areas (598, 599). Progressively smaller flaws are detected as pressure is increased. Surprisingly, the hydrostatic proof test acts favorably on surviving flaws, probably by causing plastic deformation at the tip of cracks and pits (599). This decreases the stress concentration there and introduces favorable residual stresses -- mechanical stress relief.

Pipeline interiors can also be monitored for corrosion. A magnetic survey instrument has been developed which travels in the line and locates pitting and general metal loss (335). Small diameter television cameras have been developed which travel in the line. Ultrasonic thickness detectors may either be used internally or externally on exposed pipes.

Leaks may be detected in several ways. The least desirable method, but very commonly used, is to note leakage when a sufficient amount has taken place to be apparent. In long pipelines large leaks are sometimes noticed by discrepancies in inventory or transported product, i.e., less product emits from the pipeline than is introduced. Leaks can be located by closing off sections of the pipe system and observing pressure decay in sections containing leaks. Gas leaks are sometimes located by "sniffing" instruments which detect gas. Discoloration of vegetation is also used as a leak indicator.

The theory and fundamentals of leakage testing are discussed in Reference 812. Test categories, reasons for testing, choice of procedures, test planning, flow characteristics, and guidelines for writing specifications are included, A detailed description of test methods is given which covers the use of standards, mass spectrometers, gas detectors, pressure and flow measurements, bubble detection, radioactive tracing, halide torches, sonic methods, electromagnetic energy absorption, chemical indicators, high potential discharges, ionized gases, thermal conductivity gages, and several special applications. An extensive listing of characteristics and sources of commercially available leak detectors includes addresses of manufacturers, code symbols for types of equipment, trade names, and characteristics of the equipment. Properties of trace gases and safety measures for their use are also discussed.

Supplemental observations during the inspection of corrosion leaks by the surveyed companies are shown in Table 45. The "other" observation (Part E) consisted of pipe potentials, stray currents, location and depth of pits, electrical continuity of gasketed joints, soil resistivity, and the review of cathodic protection reports to determine if there had been any deterioration or interruption of cathodic protection prior to leaks.

Many companies have developed correlations (Table 45, Part F) with leak frequency and with some of the observations made

TABLE 45

SUPPLEMENTAL OBSERVATIONS ON THE INSPECTION OF CORROSION LEAKS

Observations	Number of Companies Yes	No
(A) General Condition of Coating, including Bond to Pipe	304	20
(B) Soil Type and/or Texture	282	40
(C) Soil Moisture	236	71
(D) Proximity of Other Pipelines or Structures (Possibility of Cathodic Interference)	269	50
(E) Other	79	33
(F) Have Any of these Observations Been Correlated with Leak Frequency?	109	214

during leak inspections. One of the most common methods used to develop correlations was to file a report when a leak had been repaired. The contents of the report generally indicated the type of leak, location on the perimeter of the pipe, type of corrosion causing the leak, soil type, soil resistivity, amount of cathodic protection, type of repair made, etc. The leaks were plotted by geographic location on a yearly basis. Over a period of time hot spots were located and soil resistivities were known by areas, so that future piping could be initially laid with adequate protection applied and old piping could be economically scheduled for replacement before serious problems arose. A second commonly used system, which is very much like the first system, was to record the soil resistivity when a leak was repaired and maintain a graph plotting leaks as a function of soil resistivity. As in the previous system, this gave a basis for judgment when a section of pipe should be reconditioned or replaced and also indicated levels of protection required on new piping by geographical area according to the soil resistivity. The third system was to plot cumulative leakage as a function of time on semilog graph paper and augment preventive measures when a sharp increase in the slope of the graph was observed. A theoretically better method would be to plot cumulative leakage as a function of time on log-log graph paper as indicated by Equation 10. The log-log plot should be linear and may give valid extrapolations of future leaks. It should be noted that leak data on the number of leaks repaired during evening shifts are apt to be inflated.

A standard record system should be developed by the industry associations that will allow statistical correlations between corrosion variables and other variables such as leak frequency on a regional or nationwide basis (Q250, Q114). An excellent example on this type of correlation on 22,000 miles of coated pipelines is reported in Reference 474.

Two typical leak reports are shown in Tables 46 and 47.

TABLE 46

UNDERGROUND PIPE INSPECTION REPORT (Q685)

Make Separate Report for Each Size, Kind, and Individual Line

Date ____________

MAINS

Trunk Feeder Distributor

PIPE DATA

Size ________ Galvanized ____ Cast

Kind: Steel ______ C.A. ______ Conc. ______ Iron ______

Date Laid: ____________

nspected ____________

LEAKAGE

Pipe Wall ________ Joints ______ Fittings ________

Tap. ____________

CONDITION OF PIPE

Class	Cast Iron	Steel
A	No graphitization No scale, No pits	Perfect
B	Graphitization or pitting to 1/3 thru wall	Scale or pitting to 1/3 thru pipe wall
C	Graphitization or pitting from 1/3 to 2/3 thru wall	Scale or pitting from 1/3 to 2/3 thru wall
D	Graphitization or pitting 2/3 or more thru wall	Scale or pitting 2/3 or more thru wall
E	Graphitization or pitting thru pipe wall	Perforations

SOIL RESISTIVITY

Ohm-CM ________

Location ________

Remarks ________

PIPE TO SOIL POTENTIALS

Native ________

Protected ________

PROTECTIVE COATING DATA

Condition

Good ____ Fair ____ Poor ____

Bond ________

Moisture Present Under

Coating: Yes ____ NO ____

Bare Spots ________

Pockets ________

Sagging ________

Type	Color
Red Rock	White
Dec. Granite	Gray
Shale	Black
Gravel	Yellow
Sand	Brown
Loam	Red
Clay	Blue
Silt	Green
Peat	

REPLACEMENT DATA

Age ________

Leaks ________

(Min. 2/yr.-3in5 yrs)

Pitting ________

Soil Resistivity ________

Galvanized Pipe ________

CATHODIC PROTECTION

Size ________

SOIL DATA

Check All Applicable Items

Agglomeration

Boulders	Many
Stones	
Pebbles	Few
Hard Lumps	

Texture	Packing
Fine	Loose
Medium	Medium
Coarse	Hard

Inspected by:

TABLE 47

LEAK REPAIR REPORT (Q114)

Location: ______________________ of   RO No. __________
Street   Ft.

______________ ______________   Map No. __________
Street   City

Date __________

Size & Type of Pipe:
(")C.I. (")ML & CS (")Galv. (")A.C.
(")W. Iron (")Bituminous Coated Steel

1. What part was damaged?

   a. ( ) Pipe Barrel
   b. ( ) Joint
      Type: ( ) Welded ( ) Lead ( ) Cement
      ( ) Mineral lead ( ) Flanged
   c. ( ) Valve
   d. ( ) Flanged nuts, bolts, tie rods
   e. ( ) Other (Explain on back)

2. What type of corrosion damage?

   a. ( ) Pitting
   b. ( ) General corrosion
   c. ( ) Graphitized cast iron
      (Pipe looks OK, but has little strength because the iron has dissolved, leaving mostly carbon.)
   d. ( ) No corrosion damage

3. What repairs were made?

   a. ( ) Leak clamp   c. ( ) Recaulked joint
   b. ( ) Welded   d. ( ) Replaced section
   e. ( ) Other ______________

4. Should the pipe be replaced?

   a. ( ) Yes   b. ( ) No   c. ( ) Not sure

5. How big was the leak?

   a. ( ) Circumferential break   c. ( ) Large hole
   b. ( ) Small hole (under 1")   d. ( ) Split

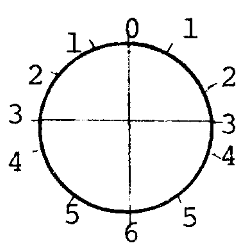
6. What is soil like?

   a. ( ) Clay or adobe   c. ( ) Sandy
   b. ( ) Loam   d. ( ) Gravel

7. Was a 32-pound anode installed?

   a. ( ) Yes   b. ( ) No (omit anode only if no corrosion damage is found.)

8. Where was the leak? (Circle number closest to leak)



Foreman: ______________________

SECTION VI

ECONOMICS

Economics are the scale by which the effects of corrosion and the methods of controlling corrosion are measured. Ideally, enough economic data would be available to enable one to calculate the optimal course of action for all conceivable situations. Unhappily, there is a real paucity of data available, and much of what is published is probably based on speculation and unsupported estimates. No economic information was unearthed in the replies to the questionnaire.

Corrosion is expensive. Valuable products are lost when pipelines leak. Lost pumping time is never recovered. Escaped products may ruin crops, injure wildlife, despoil natural beauty, and damage property. Costs could and should be assigned to property damage and hazards. Toxic, flammable, and explosive products constitute hazards to human life and well-being. The damage resulting from a leak depends on the pressure in the pipeline, the fluid it carries, and the location of the pipeline. Leaks are expensive to locate and to repair. When pipe sections must be replaced, flow is interrupted with consequent loss in revenue. It has been estimated that the extra pumping costs due to rust on the interior of pipes amounts to $40,000,000/year in the U.S. (493).

A 1950 survey in Arkansas, Kansas, West Texas, and New Mexico revealed that 44 percent of the sour crude oil wells were economically affected by corrosion (6185). In Arkansas the corrosion costs averaged $1250 per well per year. In Kansas, the average was about $2000 and in West Texas-New Mexico $270. Use of the corrosion inhibitors reduced the costs to $100, $225, and $220 per well per year, respectively, for corrosion control plus remaining corrosion costs. Corrosion could cost about $1000 per year per well in sweet oil wells when the salt water content is above 40 percent (553). In a 1963 survey (6193) of 8919 oil and gas wells, the ratio of reported savings to corrosion control costs was about 5:1. Much larger ratios were found in offshore operations. Nevertheless, many operators have made little or no attempt to control corrosion.

In use of coatings the important factor is really the cost/effectiveness ratio or the ratio of savings to cost over the life of the pipe. To obtain valid comparisons on such a basis is not simple, however. If all coatings cost the same on a volumetric basis then one could simply prepare specimens having the same thickness -- but costs vary widely. One cannot compare coatings prepared so that the cost per unit length is the same because the effectiveness of a coating increases with thickness, but in an unpredictable manner. A thorough study would utilize a range of thickness for each type of coating and then compare the minima in cost/effectiveness (or maxima in savings/cost) of each. This has not yet been done. There are little published data on either cost of application and maintenance or on savings.

The costs for control of internal corrosion in two average sour crude oil gathering lines are compared in Reference 793. It was concluded that concrete linings and corrosion inhibitors appeared most economical in the larger, longer lines. Concrete linings, internal plastic coatings, and plastic pipe appeared most economical for shorter, smaller lines. Protective measures provided savings of 9 cents to 25.5 cents per foot of pipe per year.

The cost of cathodic protection depends greatly on the quality of the coating, the isolation, and the mechanical joint bonds (158). The Cast Iron Pipe Research Association has asserted that cathodic protection of pipe systems adds at least 10 percent to the total project cost (789). Presumably, this figure is for bare cast iron pipe. The installation cost of cathodic protection on bare oil storage tank bottoms was found to be about 3 percent of the tank bottom investment (793). The total annual operating expense was about 1.25 percent of one repair job or about 25 percent of the annual repair cost without protection. Payout for cathodic protection was estimated at 1.5 years. Installation of cathodic protection on modern coated pipelines is claimed to cost less than 0.5 percent of the total costs, with maintenance and operating costs less than $28 per mile year (492). A total cost of 4.2 cents/ft was estimated for 30 years of protection of a 100,000-foot long, 5/8-inch OD pipeline (474).

Galvanic cathodic protection reduced the maintenance costs per overhaul of U.S. Navy destroyers by $10,000 to $20,000 (491). Bare offshore pipeline was protected by zinc bracelets for an estimated cost of $40/mile/year as compared to $100/mile/year for an impressed-current system (728). For an estimated 40 years of protection the cost of the bracelets was 0.5 percent of the pipeline. It was claimed that the lowest total costs are obtained by cathodic protection combined with "reasonably" coated lines (793). "Reasonable" appears to mean an adherent insulating coating of long lifetime but without any attempts to make it holiday-free.

Some pipe system operators install cathodic protection at some time after laying the pipe. It has been estimated that only about 15 percent of a pipe system will be subject to rapid corrosion (601). One procedure is to perform a survey of pipe potential and protect only those areas containing "hot spots." The payout period for the cost of the survey and the cathodic protection was found to be 2 to 5 years. A total of $258/mile/year was saved on one line over a 6-year period.

Another procedure is to install cathodic protection to an area only when leaks have already developed. With bare pipe it has been found to be cheaper to apply cathodic protection than to replace the line with new coated pipe (592). Although savings were realized by cathodic protection after several years, a large gas company found that more money would have been saved by application before leaks had developed (589).

In calculating costs and savings of various protection methods, one must not only attempt to account for all direct and indirect expenses, but also take into account the time value of money. Several different methods of accomplishing this have been used (e.g., 591, 493, 705). The effect of accounting for interest and desired profit is to increase the cost of present capital investments as compared to expenses occurring later.

SECTION VII

OTHER PROBLEMS ASSOCIATED WITH CORROSION OF PIPELINES

1. Training of Corrosion Engineers and Technicians

According to Reference 305 few engineering graduates have received any training in corrosion control. As a result the acquisition of the necessary skills to perform well as a corrosion engineer is largely a personal responsibility. Amateur bungling is common in corrosion control work, particularly in cathodic protection; to help alleviate this situation, the British Association of Corrosion Engineers was formed to provide education in corrosion control and professional qualification standards.

A variety of well subscribed short courses are offered in all parts of the U.S. NACE will soon publish a basic corrosion course. However, there appears to be a need for more courses at more advanced levels. Evening courses are given by some universities. Many books and papers are available for self-teaching, as illustrated by the references for this report. Informal information flow among practicing corrosion engineers is probably as great as in any other technical specialty, and is particularly noticeable at local NACE meetings. Nevertheless, one senses a real deficiency of understanding of fundamental and theoretical aspects of corrosion control, although regard for corrosion consultants is somewhat mixed. Ninety-five of the surveyed companies used consultants in their corrosion control efforts.

Unfortunately, no satisfactory method of determining or certifying competence of corrosion engineers and technical personnel exists in the United States. The fact that corrosion control has developed as an art rather than a science is exemplified by the extensive use of undefined terms and misnomers; e.g., pipe to soil potential is generally used for the potential between a buried pipe and a half cell located on the soil surface; a saturated copper-copper sulfate half cell is one in which the copper sulfate, rather than the copper, is saturated; terms such as "zero swing" are used without precise definition.

Table 48 lists the publications and information sources which were thought to contribute the most to the responding companies' corrosion control program.

TABLE 48

PUBLICATIONS AND INFORMATION SOURCES WHICH HAVE BEEN FOUND TO CONTRIBUTE MOST TO CORROSION CONTROL PROGRAMS

Source	Number of Companies			
	Most	2nd	3rd	4th
American Gas Association	2	11	9	1
American Petroleum Institute	1	1	9	0
Committees/Meetings	37	53	29	9
Consultants	14	9	14	6
Electrochemical Society	0	0	0	1
Monthly Magazines	31	67	38	28
NACE Publications	54	36	21	6
National Bureau of Standards	0	0	1	1
Pacific Coast Gas Association	1	1	0	3
Short Courses/Seminars	138	60	35	8
Text Books	17	21	11	2

2. <u>Interference with Small Piping Systems</u>

While the pipeline industry has been highly successful in minimizing corrosion caused by cathodic interference between its members, there remains a substantial quantity of pipe in custody of operators of small water and gas companies, ranches, industrial plants, restaurants, other businesses, home owners, etc., which is subjected to interference. To comprehend the hazard, it is only necessary to point out that 30 microamperes are sufficient to cause a leak in one year if the pit in a 1/8-inch pipe wall has the form of a paraboloidal segment with depth and surface radius equal to the wall thickness of the pipe. Further, operating pipelines may be subjected to small, undetected interference currents. Cathodic interference may be anticipated under the following conditions.

a. If the surface or deep well anode is less than 1000 feet distant from the pipeline of concern.

b. If the offended pipe is inferior in coating as measured by conductance, and (1) crosses the protected pipe or (2) parallels within 15 diameters of the protected pipe.

The foregoing are not performance rules but are indicators for concern.

3. <u>Grounding of Electric Circuits on Water Pipe</u>

Stray currents caused by grounding of electrical circuits on water pipes are a corrosion hazard to all underground piping. This common practice penalizes the owner of the piping. For the owner it is economically better to pay the initial cost of installing a separate grounding electrode than to have a deteriorated piping system at a later date. It is also safer to install a separate grounding electrode.

4. Mechanical Damage to Piping

Mechanical damage to piping has been established as one of the major causes of pipeline accidents. When a pipeline is ruptured by mechanical equipment, the cause is obvious. A more insidious problem arises when mechanical equipment contacts piping and damages the coating and/or pipe without rupturing it. At a later time corrosion takes its toll and another accident or leak is chalked up to corrosion.

5, Improper Use of Cathodic Protection

It has been noted that there has been some ineptitude among those engaged in' corrosion mitigation through cathodic protection; this incompetence is manifested in real or incipient failures ranging from one to many incidences. They include:

a. Deliberate resistance coupling below ground of anode and cathode cables to match the current and voltage output with the rectifier capacity.

b. Connecting and operating rectifiers in reverse polarity, i.e., with the cathodic cable from the pipeline connected to the positive terminal of the rectifier.

c. Cathodically protecting unbonded mechanically coupled pipe including leaded cast iron joints.

SECTION VIII

GAPS IN THE TECHNOLOGY AND COMCLUSIONS

The following conclusions have been drawn from the collective information of the literature search, the questionnaire results, personal interviews, meetings attended, and personal experience.

On existing pipelines, it may not be practicable to totally eliminate all corrosion. The goal is rather to bring corrosion to an acceptable level for the lowest cost. This is not to say that allowing a "few" leaks to develop is considered "acceptable," in view of the potential hazard to life and property. On the other hand, it is not rational to insist on eliminating all corrosion when a reasonable corrosion control program will prevent corrosion leaks during the useful life of a pipeline.

Much could be learned about corrosion mechanisms under authentic field conditions by detailed examination of corroded pipelines. Pits and cracks and surrounding environs should be particularly investigated. This should include micro pH measurements, microscopic examination cf the corrosion product, X-ray analysis of solid corrosion products, metallographic sectioning and microscopic examination, chemical analyses, bacteriological cultures, etc. Much would. be gained if the industry knew more about the basic corrosion mechanisms associated with pipelines.

Steel pipe seldom fails by uniform corrosion. It. fails predominantly by localized ettack in the form of pits. The pits are initiated by some sort of inhomogeneity. Chloride ion seems to be particularly implicated as a causative agent for pitting, as well as for crevice corrosion.

Stray direct currents from electric railways, high voltage direct current (HVDC) power transmission, pick-up from overhead AC power lines, and cathodic protection have caused and will continue to cause serious corrosion problems. Ideally, electric railways and power transmission lines should not contact the soil, much less use soil return for any portion of the power. Further studies on the effect of KVDC are needed, and methods of reducing the corrosion effects of HVDC need to be developed. The influence of AC on corrosion has not been well explored, but is known to cause some corrosion. The practice of grounding AC power to water lines should be discontinued.

Cathodic protection interference is generally being handled well by private groups but will continue to be a persistent problem. Cathodic protection of pipes in areas containing a high density of underground metallic structures creates severe interference problems and may be ineffective due to electrical shielding. Methods for avoiding interference and shielding in some such situations do not appear to be available or known. Unqualified cathodic protection enthusiasts may unwittingly create intolerable corrosion hazards to unbonded mechanically coupled underground facilities. Anodes discharging 10 or more amperes of current may create a hazardous gradient within a radius of 1000 feet. Endangered structures may include ground wires, reinforcing bars in concrete, and the like, in addition to lead covered cables and utility piping.

The various types of mechanical corrosion effects in the underground environment are not well understood. In particular, no certain method is known for avoiding catastrophic failure by stress cracking of high strength steels. Hard spots in the pipe due to manufacture and welding should be avoided. It is not even certain that stress cracking is limited to high strength steels. There is some evidence that cathodic protection may cause hydrogen embrittlement of some steels, but more fundamental knowledge is badly needed. Caustic ernbrittlement cracking may take place downstream from compressor stations when cathodic protection is applied, but this possibility has not been adequately investigated.

Twenty-two leaks were attributed to hydrogen blistering by the surveyed companies. Hydrogen is generated both by corrosion in an acid environment and by cathodic protection, especially at high potentials. Metals with voids and inclusions are particularly susceptible.

Intergranular corrosion of many stainless steels is rapid when the thermal cycle of welding generates certain types of inhomogeneities.

Temperature has an effect on corrosion. In frozen soils, no corrosion of steel pilings was observed. This cannot be extrapolated to transportation of petroleum in cold environments, since the pipes would be heated in such cases. Stress corrosion cracking is more common in pipe leading from compressor stations, presumably because of elevated temperatures there.

Although corrosion occurs on all steel buried underground, the corrosion rate can be negligibly low. It has been found that leaks in a pipeline occur predominantly in soils low in resistivity. Pitting of pipelines in statistically uniform soils was found in at least one instance to occur only at points where the resistivity was below about 1200 ohm-cm. Noncorrosive soil is generally indicated by a high resistivity, 5000 ohm-cm or higher. It should be noted, however, that resistivity may change, for example by application of chemical fertilizers. There is a growing realization that other factors, including the change in soil resistance, the chemical species in the soil, the moisture, and the texture, can also influence corrosion.

Chloride ion is known to accelerate corrosion. Hydrogen sulfide accelerates corrosion and can cause sulfide stress cracking. Carbon dioxide pressures over 30 psi in wet oil and gas cause corrosion. Calcium ion and low carbonate concentrations are often beneficial in that $CaCO_3$ protective scales can be formed.

The splash and tidal zones in seawater are the most corrosive marine environment. Furthermore, cathodic protection is ineffective there. For pipe in seawater, however, no coatings are necessary with cathodic protection because the current caused heavy protective deposits to form. The best coatings have been found to be formed at lower current densities (<150 mA/sq ft) and to consist primarily of calcium carbonate. One can cause similar deposits to form on buried pipe by adding calcium bicarbonate to the backfill and applying cathodic protection.

It is known that products of microbiological metabolism can accelerate corrosion. Sulfate reducing bacteria cause H_2S formation under anaerobic conditions and accelerate corrosion. The extent to which micro-organisms contribute to pipeline corrosion is uncertain. Very little good field data are available. There tends to be a significant polarization of opinion on this subject. The use of biocides has been limited.

In the atmosphere, corrosion is accelerated by moisture, wind-blown sea salt, sulfur dioxide, and to some extent, ozone. The combined effect of dilute sulfuric acid and ozone is worse than the sum of their individual effects.

Although no ferrous metal is untouched by corrosion, the extent of corrosion is significantly influenced by the exact composition of the metal and by thermal and mechanical treatments. Unfortunately, most of the additives which markedly improve corrosion resistance are probably too expensive for use in large pipeline systems.

Welds are noted to be particularly susceptible to corrosion. Greater understanding of the effect of welding conditions on corrosion is needed. The influence of metal inhomogeneities is scarcely understood, but is probably serious. Methods of producing pipes could probably be developed to avoid such problems.

Although most corrosion occurs externally, internal corrosion is also a problem when moisture and chloride ion, hydrogen sulfide, or carbon dioxide are present. This has been controlled by removing moisture, adding inhibitors, or coating. Proper inhibitors are selected empirically. The mechanism of inhibitor action is poorly understood. In particular, it is not yet possible to confidently specify an inhibitor for any given application. Quantitative investigations of inhibitor effectiveness and application procedures are needed and should be published in the open literature. It is important to note that many inhibitors accelerate corrosion if their concentration is too low.

The corrosion failure rate of unprotected pipelines tends to increase with time. A widely used method of corrosion control is the application of coatings. Although metal coatings are effective under some conditions, thick organic coatings are generally favored for underground use where protection is required for long periods. These coatings are ideally water impervious, electrically insulating and tough. Generally, tight adhesion to the pipe is also required, although good results have been reported with loose fitting plastic sheaths. The requirement for water permeability is probably even more severe when the coating is not bonded to the pipe. It should be noted that no perfect coating material exists, and so continued search for improved materials is justified.

The most common circumstance for leaks developed in coated pipe was physical damage of the coating. The second most common circumstance was corrosion at improperly applied coatings. Microorganisms attack most, if not all, organic coatings. Therefore, one cannot assume that once a pipe is coated, it remains effectively coated forever. Inspection and repair are necessary not only when laying pipe, but also periodically thereafter. The maintenance requirements are probably particularly severe when cathodic protection is not employed simultaneously.

Although seldom used for pipes carrying gas and oil, concrete coatings car, provide effective corrosion control. Concrete's effectiveness is largely due to its high pH. Again, proper application is required including choosing the proper concrete mix.

In cathodic protection, corrosion is reduced by making the pipe negative with respect to the adjacent soil. Cathodic protection is not a panacea for all corrosion problems. Neither is the proper application of cathodic protection a trivial matter. Increased corrosion due to cathodic protection has actually been observed when steel was continuously or intermittently heated and intermittently wetted. Such conditions would be expected on pipes just downstream from compressor stations in areas where the soil is intermittently dry and wet. Cathodic protection can increase the leak rate at first when applied to old pipe by loosening adherent rust scale which previously covered small holes. Cathodic protection may either be accomplished by externally applied DC power or by attachment of sacrificial anodes, such as Mg, Zn, or Al, which are slowly consumed. Either method works when properly installed and maintained.

Theoretical considerations give reason to suspect that higher than normal cathodic protection voltages may be required to suppress active sulfide corrosion if, indeed, it is possible at all. This apparent necessity in turn induces excessive applied voltages that tend to destory and to loosen the coating, thus starving both the disbonded. and remote areas of current, further requiring added current. This cyclic process leads ultimately to loss in control of cathodic protection, and leaks may develop both in proximity to the point of current drainage and at remote areas.

The difficulty in achieving acceptable protection with coatings alone has caused many companies to supplement coatings with cathodic protection. On the other hand, cathodic protection used alone can generally provide adequate protection, except that large currents are required and interference with structures that may be nearby is likely. When used with coatings, only enough current is required to protect areas where holes have developed in the coatings. Thus, coatings and cathodic protection are often used in conjunction. Even though the data from the surveyed companies indicated a lower corrosion leak rate with coated and cathodically protected pipe than with unprotected pipe, some leaks did develop on protected pipes. Thus the control measures do not appear to be totally effective. In many cases, this may reflect improper use of either coatings or cathodic protection, or both.

Use of cathodic protection and coatings together is not without problems. Cathodic protection may cause disbonding of the coating. Cavities under disbonded coating are ideal for crevice corrosion and microbiological corrosion. To a large extent, cathodic protection is ineffective in disbonded areas. Cathodic protection increases pH in the surrounding electrolyte, which can cause saponification and destruction of bituminous and silicone coating materials. The extent to which cathodic protection will damage old coatings is unknown. This is important when one is considering application of cathodic protectior to old piping not previously protected. A test on a section of the old pipe would probably be necessary in each case.

The present methods of verifying cathodic protection are imperfect. This is proven by the fact that corrosion leaks occur even with cathodic protection. There appears to be no entirely satisfactory criterion for verifying that cathodic protection has been achieved. Potentials cannot be made too negative or coatings are disbonded. Most of the surveyed companies used a pipe potential of 0.85 volt relative to the copper sulfate electrode as their criterion for cathodic protection. Although satisfactory in many instances, the use of a fixed pipe potential is known to be deleterious under certain conditions. The second most common criterion used by the surveyed companies was a 300 mV difference between the energized and the original open circuit potentials, which is similar to the fixed pipe potential criterion in advantages and disadvantages.

The instantaneous open circuit potential (the polarization potential) and other possible protection criteria have been poorly exploited. There is a need for a critical review of possible protection criteria, statistical methods for analyses and of correlations with basic electrochemical concepts.

Improved methods are badly needed both for detecting small leaks and for detecting areas which will soon fail. A standard record system should be developed that will allow correlations between leak frequency and such variables as soil properties, coating properties, cathodic protection conditions, location, etc. Accurate leak records are valuable and may serve a number of purposes including predicting future leaks, locating areas for reconditioning or cathodic protection and indicating precautions to take when laying new pipe. The records, however, should clearly indicate causes so that damage by others may not be confused with leaks caused by corrosion alone.

Casings around pipes under roadbeds and railroad tracks have been shown to be not only unnecessary in most cases, but deleterious from a corrosion standpoint as well. When the metal casings are shorted to the pipe, cathodic protection is ineffective. Much money is being needlessly wasted on unnecessary casings.

One of the greatest needs is for more data on the economics of corrosion control. This is particularly noticeable in discussions of coatings, where one wishes to maximize the ratio of savings to cost. Ideally, the optimum coating thickness for each type of coating should be known on this basis. Estimates for installation of cathodic protection range from less than 0.5 percent to over 10 percent of the total project cost, and yet actual costs are almost never reported.

Short courses and seminars were felt to be the most important information source for the surveyed companies' corrosion control programs. This reflects the fact that corrosion engineering is not treated as a separate academic discipline in the universities. Thus, the art and science of corrosion control is learned "on the job" by experience, self-study, meetings, short courses, and evening courses. There seems to be a need for more short courses which go into detail on specific aspects of corrosion control, e.g., a cathodic protection course, a basic electrochemistry course, a coatings course, etc. However, corrosion courses alone do not constitute adequate background for a competent corrosion engineer. Experience, good judgment, and a solid fundamental technical education are also needed.

Because degrees are not granted in corrosion engineering, there is need for an adequate method of judging the qualifications of corrosion engineers and technicians. The present methods are not adequate. Competence of practicing engineers, consultants, and technicians varies widely and is difficult to evaluate. Nationwide expansion of corrosion control programs in the near future would be hindered by the lack of sufficient numbers of trained and competent personnel.

Much of the research literature available on corrosion is too sophisticated and complicated for use by the operating companies. More research directed toward the specific corrosion problems of the pipeline industry is needed.

APPENDIX I

EXAMPLE ABSTRACT RETRIEVAL RUN

ABSTRACT RETRIEVAL RUN *

COLUMN	CODE	KEYWORDS
7- 8	10	CARBON STEELS
11-12	1	UNDERGROUND
13- 14	30	ANAEROBIC BACTERIAL CORROSION

SOURCE STATEMENT - THE FOLLOWING IN AN ABSTRACT (*** COMMENT -) INDICATES THAT WHAT FOLLOWS IS A COMMENT WRITTEN BY MRI. NACE IS THE SOURCE OF THE OTHER ABSTRACTS.

REPORT NO CLASSIFICATION CODE

538 538101010 130 0 02010 IVERSON,W. 1968
MICROBIAL CORROSION, W.P.IVERSON, NBS AD-670501 (1968) APR. ***COMMENT- STUDIES OF EFFECT OF MICROORGANISMS, PARTICULARLY SULFATE REDUCERS (DESULFOBIVRIO), ON MARINE CORROSION WERE INITIATED. THE INABILITY OF SULFATE REDUCERS TO GROW ON THE AGAR SURFACE TF MEDIA APPEARS TO BE DUE TO THE PRESENCE OF THE FERROUS SALT USED AS AN INDICATOR FOR HYDROGEN SULFIDE. EVIDENCE INDICATES THAT PHOSPHATE MAY BE AN ELECTRON ACCEPTOR IN THE CATHODIC DEPOLARIZATION OF STEEL. IRON PHOSPHIDE AND DIVIVIANITE WERE PRODUCED BY DESULFOBIVRIO GROWING IN CONTACT WITH MILD STEEL. THE ORGANISM REDUCES PHOSPHATE IN THE PRESENCE OF HYDROGEN TO FORM A VOLATILE PHOSPHOROUS CONTAINING COMPOUND WHICH IS NOT PHOSPHINE. LIGHT INCREASES THE CORROSION RATE OF STEEL AS INDICATED BY POLARIZATION MEASUREMENTS. THE CATHODIC PROTECTION CURRENTS REQUIRED TO MAINTAIN A POTENTIAL OF 0.8 VOLTS ON A STEEL SPECIMEN IN INDIRECT SUNLIGHT WAS FOUND TO BE 1.5 TIMES THAT REQUIRED IN THE DARK.

549 549301010 130 0 020 0 IVERSON,W. 1969
ANAEROBIC CORROSION OF MILD STEEL BY DESULFOVIBRIO, W.P.IVERSON, NBS, NACE CONF. HOUSTON, (1969).***COMMENT EXPERIMENTS WITH BENZYL VIOLOGEN IN PLACE OF SO4 HAVE PROVER THAT ANAEROBIC BACTERIA PRODUCE CATHODIC DEPOLARIZATION. PHOSPHATE IS ALSO REDUCED TO PRODUCE FE2P AND A GASEOUS PHOSPHOROUS COMPOUND, NOT PHOSPHINE. HOWEVER, THE CORROSION RATES ATTRIBUTABLE TO CATHODIC DEPOLARIZATION DO NOT ACCOUNT FOR HIGH CORROSION RATES SOMETIMES OBSERVED IN THE FIELD. THESE MAY BE DUE TO FORMATION OF DIFFERENTIAL OXYGEN CELLS, THE ACTION OF H2S, OR ALTERNATE ANAEROBIC AND AEROBIC CONDITIONS TO PRODUCE SULFURIC ACID.

5015 50156010 0 130 0601010 GANSER,P. 1964
CATHODIC PROTECTION FOR AN UNCOATED GAS DISTRIBUTION SYSTEM, P. GANSER, A COLLECTION OF PAPERS ON UNDERGROUND PIPELINE CORROSION, V. 8, P. 241-253, (1964).***INVESTIGATION OF AN INCREASING LEAK RATE OF UNDERGROUND MAINS INDICATED THE PRINICPAL CAUSE TO BE ANAEROBIC BACTERIA. CATHODZC PROTECTION WAS INSTALLED TO KILL MICROBES. TO MAKE LINE CONDUCTIVE A NEW

* This is an example of a very selective Abstract Retrieval Run. The run is not complete. A typical run may select several hundred pertinent abstracts.

TECHNIQUE WAS DEVISED FOR SPOT WELDING CONDUCTORS ACROSS PIPE CONNECTIONS USING ONLY A VERY SMALL (4 INCHES BY 18 INCHES) OPENING. OPERATING COST INCLUDING ELECTRICITY, MAINTENANCE AND ENGINEERING COST IS 4.6 CENTS/FT. OF PIPE.
"

5102 51021070 0 130 0 020 0 BUTLIN,K.R. VERNON,W.H. 1952
INVESTIGATIONS ON UNDERGROUND CORROSION. K.R. BUTLIN, W.H.J. VERNON AND L.C. WHISKIN. IRON STEEL INST. SPECIAL REPT. NO. 45, 29-38 (1952), WATER + WATER ENG., 56, NO. 671, 15-18 (1952) JAN.***FUNDAMENTAL STUDIES ON SULFATE-REDUCING BACTERIA, AND INVESTIGATIONS OF THE EFFECTS OF THESE BACTERIA ONIRON IN ANAEROBIC CONDITIONS ARE DESCRIBED. DETAILS OF FIELD TESTS ON BARE AND PROTECTED BURIED IRON PIPES ARE GIVEN. SPECIMENS OF COPPER, LEAD, AND GALVANIZED STEEL PIPE ARE INCLUDED IN TESTS NOW IN PROGRESS.***

5598 55983070 0 13030 020 0 MINCHIN,L. 1954
CORROSION OF PIPES BY BACTERIA. L.T. MINCHIN. GAS AGE, 114, 8, 45-47, 101-102, 104 (1954) OCT. 7.***EUROPEAN SURVEY OF MICROGIOLOGICAL ANAEROBIC CORROSION WITH SPECIAL REFERENCE TO EXPERIENCE IN LOW COUNTRIES. TABLE, PHOTOGRAPHS. 7 REFERENCES.

6123 61233070 0 130302020 0 STARKEY,R. WRIGHT,K.M. 1947
ANAEROBIC CORROSION OF IRON IN SOIL WITH PARTICULAR CONSIDERATION OF THE SOIL REDOX POTENTIAL AS AN INDICATOR OF CORROSIVENESS. R.L. STARKEY AND K.M. WRIGHT AGA. CONDENSATION CORROSION 3, 227-232 (1947) MAY.***DISCUSSION IS PRESENTED ON THE ANAEROBIC CORROSION OF IRON IN SOIL, DATA PRESENTED ON THE CHARACTERISTICS OF CORRODED IRON AND STEEL SURFACES, ORIGIN OF SULFIDE IN SOIL, CHARACTERISTICS OF BACTERIA CAUSING ANAEROBIC CORROSION, IMPORTANCE OF SULFATE REDUCTION, MECHANISM OF THE PROCESS OF MICRO-BIOLOGICAL ANAEROBIC IRON CORROSION, EVIDENCE FOR ELECTRO-CHEMICAL THEORY OF ANAEROBIC CORROSION, UTILIZATION OF HYDROGEN AND THE REDUCTION OF SULFATE BY BACTERIA, DETECTION OF MICRO-BIOLOGICAL ANAEROBIC IRON CORROSION IN SOILS, OXIDATION-REDUCTION POTENTIAL, FIELD TESTS OF DEGREES OF CORRELATION BETWEEN SEVERITY OF CORROSION AND THE SOIL REDOX POTENTIAL AND OTHER SOIL CHARACTERISTICS, AND RESISTANCE OF SOME PIPE WRAPPING MATERIALS TO DECOMPOSITION IN SOIL. 203 REF.***

APPENDIX II

QUESTIONNAIRE

Form Approved: Budget Bureau No. 04-S69052

OFFICE OF THE SECRETARY OF TRANSPORTATION
WASHINGTON, D.C. 20590

TO WHOM IT MAY CONCERN

The Department of Transportation is currently conducting research on the subject of the corrosion processes, their detection, control and repair, as it applies to ferrous pipelines. This research is to develop background information from a wide range of source materials and personal experiences. Hopefully this can be aahieved by asking those persons exposed to the problems of corrosion to answer specific questions regarding corrosion problems. Answering of these questions is entirely voluntary, and there is no legal or statutory obligation to do so.

It is our hope that the results obtained from this questionnaire will consolidate knowledge and understanding of corrosion and corrosion related problems, and concurrently increase everyone's ability to combat it.

We have selected the firm of Mechanics Research, Inc., an engineering firm headquartered in Los Angeles, California, to carry out this research.

It would be appreciated if you could provide them with all possible cooperation regarding this matter when they contact you. If you or your organization feels that information of a confidential or proprietary nature is involved and you wish to have it kept confidential, please identify it and it will be kept in confidence and not made public.

We plan to make the general results obtained from this study available to the operating industry and other interested parties in order to further knowledge in the corrosion control area.

All information and questionnaires furnished by participating organizations are the property of the U.S. Government and will be returned to the Office of Pipeline Safety immediately upon completion of the contract,

If further clarification or information regarding any aspect of this project is required, please contact me (phone A.C. 202, 96-26000).

Sincerely yours,

Joseph C. Caldwell

Joseph C. Caldwell
Deputp Director
Office of Pipeline Safety

Forn Approved: Budget Bureau No. 04-S69052

No. ____________

QUESTIONNAIRE

CORROSION PROCESSES, DETECTION AND CONTROL OF FERROUS PIPING

The purpose of the questionnaire is to develop background information on corrosion. This information is solicited on a strictly voluntary basis and is intended only to develop general research type information regarding corrosion and its control. Unpublished information bearing on any corrosion or corrosion control process is particularly sought and may be returned with the questionnaire.

The questionnaire also seeks to develop state-of-the-art information on corrosion and corrosion control processes particularly where pertinent investigative and research results lay dormant. The existence of standards directed to the general subject of corrosion of pipe internally and externally when buried or submerged is recognized. Do not cite existing codes or standards.

If respondent is other than an owner or operator of gathering, transmission or distribution piping operations, answer only those questions which respondent has knowledge of and which will contribute to the purpose of the questionnaire.

Many situations in the field of corrosion are unique and if the respondent wishes to qualify his answers in any way, he should feel free to do so.

GENERAL COMPANY DATA

1. Name and address of company ______________________________

____

2. Name of person who may be contacted for follow-up on the questionnaire ______________________________

Phone No. ______________

RETURN COMPLETED QUESTIONNAIRE TO:

Mechanics Research, Inc.
1200 University Bivd., N.E.
Albuquerque, N.M. 87106

Form Approved: Budget Bureau No. 04-S69052

No. ____________

QUESTIONNAIRE

PART A: GENERAL PIPELINE SYSTEM DATA

1. Indicate if respondent is an: Operating Company ☐ , Consulting Company ☐ , Research Company or Organization ☐ , Other (Specify) ________________________________

2. Submit a separate questionnaire response for each of the following as applicable, and check below the single area that this report covers.

(a)	Gas Gathering	☐	(g)	Oil Distribution	☐
(b)	Gas Storage Gathering	☐	(h)	Petroleum Product Transmission	☐
(c)	Gas Transmission	☐	(i)	Petroleum Product Distribution	☐
(d)	Gas Distribution	☐	(j)	Water	☐
(e)	Oil Gathering	☐	(k)	Other (Specify)	☐
(f)	Oil Transmission	☐			

3. Estimated total miles of ferrous pipe covered. by this report ____________

4. For the system indicated in Question 2, estimate the miles

	Cathodically Protected 3/	Not Cathodically Protected	Cathodically Protected	Not 'Cathodically Protected
(a) Steel Pipe				
(b) Wrought Iron Pipe				
(c) Cast Iron Pipe				

5. Estimate the number of corrosion leaks 2/ per linear mile occurring in calendar year 1969 for each of the above materials, (a), (b), (c), and (d) from Question 4, in the following age groups:

	BARE PIPE 1/															
	Cathodically Protected				Not Cathodically Protected				Cathodically Protected 3/				Not Cathodically Protected			
	(a)	(b)	(c)	(d)	(a)	(b)	(c)	(d)	(a)	(b)	(c)	(d)	(a)	(b)	(c)	(d)
Over 30 years																
21-30 years																
11-20 years																
6-10 years																
0-5 years																

1/ Rare pipe is defined as pipe which has never been coeted. Pipe coated with mill primer shall be considered as bare pipe.

2/ A corrosion leak, as used herein, means unintended escape of gas or liquid. caused by corrosion.

3/ Cathodically protected means under protection for at least two years.

PART B: CAUSE AND CONTROL OF CORROSION

Section I - Inspection and Cause of Corrosion Leaks

1. Does your company have a corrosion control program? ☐ Yes ☐ NO

2. If yes, briefly describe the program indicating but- no% limited to the following information: years in effect, type and frequency of surveys, reports and record procedures, length of time records are kept, and analysis of results, etc. (Answer on a separate sheet or on the back of this sheet.)

3. If you do not have a corrosion control program, state why not.

4. With reqard to corrosion leaks, is the probable type of corrosion determined:

☐ Yes ☐ No

If no explain:

5. For your system indicate the most prevalent cause for corrosion leaks. Use the numeral 1 for most frequent, then 2, 3, etc. (as applicable), for less frequent causes:

(a) Galvanic cell ____________

(b) Stray current (including cathodic interference) ____________

(c) Stress corrosion cracking ____________

(d) Corrosion fatigue ____________

(e) Hydrogen embrittlement ____________

(f) Caustic embrittlement ____________

(g) Microbiological corrosion ____________

(h) Other (specify) ____________

6. Indicate the most prevalent circumstance under which corrosion leaks of coated pipe have been found during the last 5 years. Use the numeral 1 for most frequent, then 2, 3, etc., in less frequent order.

	Order of Frequency	
	Cathodically Protected 3/	Not Cathodically Protected
(a) Corrosion at improperly applied coating	______	______
(b) Corrosion where coating has clearly been damaged during construction or subsequently abraded by others	______	______
(c) Corrosion where coating is ruptured by soil stress or root growth	______	______
(d) Corrosion beneath unbonded coating	______	______
(e) Failure of the coating material	______	______
(f) Other (specify)	______	______

7. Have corrosion leaks occurred inside your pipeline casings at road crossings, etc.?

☐ Yes ☐ NO

If yes, how many? (Give best estimate)______________

8. Do you have casing shorted to carrier pipe? ☐ Yes ☐ No ☐ Dc Not Know

If yes, estimate number shorted ___________

9. Estimate total number of cased crossings______________

10. Estimate the number of corrosion leaks during 1369 that have occurred at

(a) Longitudinal factory welds ____________

(b) Spiral factory welds ____________

(c) Field welds ____________

11. Indicate the total number of corrosion leaks that have been caused by:

(a) Hydrogen blisters ____________

(b) Cracks ____________

(Explain the existing exposure conditions for each case such as temperature of pipe, vibration, pressure, pipe potential, presence of nicks or scratches, hard spots, analysis of cause of crack such as hydrogen stress cracking or stress corrosion cracking, etc.)

12. Is the inspection of corrosion leaks supplemented by any of the following observations:

	Yes	NO
(a) General condition of coating including bond to pipe	☐	☐
(b) Soil type and/or texture	☐	☐
(c) Soil moisture	☐	☐
(d) Proximity of other pipelines of structures. (Possibility of cathodic interference.)	☐	☐
(e) Others (Explain fully)	☐	☐

	Yes	No
(f) Have any of these observations been correlated with leak frequency?	☐	☐

(g) If so, explain the system established and the results.

13. Check which of the following measurements you have usually heretofor used as supplement identification of causes of corrosion leaks.

(a) Coating thickness ☐

(b) Chemical analyses of soil ☐

(c) Pipe potential ☐

(d) Maximum pit depths at adjacent corroded areas within the excavation ☐

(e) Metallurgical analysis ☐

(f) Redox potential ☐

(g) Soil pH ☐

(h) Soil resistivity ☐

(i) Qualitative field test for sulfide ion ☐

(j) Potential or current with respect to foreign structure ☐

(k) Others (specify) ☐

14. Has the company experienced corrosion of pipe by bacterial activity?

	Yes	Very Rarely	No	Do Not Know
(a) Anaerobic	☐	☐	☐	☐
(b) Aerobic	☐	☐	☐	☐

15. Do you know of any instance where bacterial corrosion has caused a leak or rupture on your system? If so, please explain fully.

16. If the corrosion leak occurs at a joint in a piping system, indicate the number occurring in 1969 for each of the following categories:

(a) Compression couplings __________

(b) Threaded couplings and flanged joints __________

(c) Other (Explain) __________

17. Indicate the principal equipment you use in conducting pipe-to-soil potential surveys.

(a) High-resistance voltmeter 100,000 ohms/volt or more ☐

(b) Potentiometer voltmeter ☐

(c) Vacuum tube voltmeter ☐

(d) Low-resistance voltmeter 20,000 ohms/volt or less ☐

(e) Other (specify) ☐

18. Methods to repair and control corrosion leaks:

(a) List the current methods used to repair corrosion leaks.

(b) Are internal sealants used to repair corrosion leaks?

☐ Yes ☐ No

(c) If (b) is yes, which type/s have proven most effective?

19. List the factors you take into consideration in the replacement or abandonment of corroded pipe.

20. Does your Company transport gas or oil containing materials which in the presence of free moisture may be the cause of internal corrosion?

☐ Yes ☐ No

If so, list these materials.

21. If yes, which of the following procedures are utilized to control internal corrosion?

(a) Dehydration ☐

(b) Inhibition ☐

(c) Internal coating ☐

(d) Other (specify) ☐

22. What publications and information sources (such as conferences, seminars, etc.) has the company found to be most informative and contribute most to your corrosion control program. Please list 3 or 4 in order of importance.

Section II - Protective Coatings

1. Identify the major types of protective coatings used by your company during the last 5 years by order of use.

	List Types in Order of Use
Asphalt	______
Coal-Tar	______
Mastic	______
Prefabricated film	______
Wax	______
Others (specify)	______

2. What factors and properties do you consider in selecting particular coating materials and wrapping for specific applications, such as bonding, resistance to deterioration from soil contaminents, economics, resistance to soil stress, past experience, permeability, electrical properties, high temperature deterioration, etc.

3. Application of pipe coating material to pipe:

(a) Under what conditions do you prefer plant applied coatings?

(b) Under what conditions do you prefer over-the-ditch applied coating?

(c) Check the following field practices which your company uses to insure good coatings?

(1) Field inspecting ☐

(2) Holiday detecting ☐

(3) Rock shielding ☐

(4) Sand Backfilling in rock areas ☐

(5) Other (specify) ☐

4. Application of coating materials to pipe at joints and appurtenances:

(a) List the materials currently used to coat field joints and appurtenances:

(b) Do you use a holiday detector to check the effectiveness of coatings applied to field joints, main line valves, flanges, taps, etc.

☐ Yes ☐ No

Section III - Cathodic Protection

1. Check the types of rectifiers used by your company:

   (a) Selenium ☐

   (b) Silicon ☐

   (c) Copper oxide ☐

   (d) Other (specify) ☐

2. Give the number of generators used by the company:

   (a) Fuel powered ______

   (b) Pulse ______

   (c) Solar ______

   (d) Thermoelectric ______

   (e) Wind ______

   (f) Other (specify) ______

3. Indicate the relative quantity of galvanic anodes installed by your company with the numerals 1, 2, 3, ... in order of decreasing use:

   (a) Aluminum ______

   (b) Magnesium ______

   (c) Zinc ______

   (d) Other (specify) ______

4. Identify by number 1 (best), 2, 3, ... or (E) experimental, the following nongalvanic anodes according to performance:

Anode Material	Earth Exposure	Marine Exposure
(a) Graphite in coke breeze	______	______
(b) Graphite	______	______
(c) Lead	______	______

4. (continued)

Anode Material	Earth Exposure	Marine Exposure
(d) Lead-Silver alloy	____	____
(e) High silicon cast iron in coke breeze	____	____
(f) High silicon cast iron	____	____
(g) Scrap iron in coke breeze	____	____
(h) Scrap iron	____	____
(i) Platinized titanium	____	____
(j) Platinized tantalum	____	____
(k) Other (specify)	____	____

5. Cathodic Protection Conductors:

(a) List types of cathodic protection conductors used by your company:

(b) Check method currently used by your company for attaching conductor to pipe:

(1) Thermit process ☐

(2) Solder ☐

(3) Conductor brazed to steel coupon welded to pipe ☐

(4) Bolted connection ☐

(5) Other (specify) ☐

(c) What procedure is used to attach conductor to high-strength (X52 or above) steel pipe?

(d) Do you post-heat conductor connections to high-strength steel pipe?

☐ Yes ☐ No

If so, at what temperature? ________________

6. Identify by number 1, 2, 3, ..., the following galvanic anodes according to decreasing performance?

Anode Material	Earth Exposure	Marine Exposure
(a) Aluminum	________	________
(b) Magnesium	________	________
(c) Zinc	________	________
(d) Other (specify)	________	________

7. Protection Criteria:

(a) For the purpose of this questionnaire, the following definitions will apply:

Pipe-to-soil (electrolyte) potential: The voltage difference between a buried pipe surface and the electrolyte as measured with a saturated copper-copper sulfate half cell in contact with the electrolyte.

Open-circuit Potential: The difference in voltage between a pipe surface and a saturated copper-copper sulfate half cell in contact with the electrolyte under a condition of no current flow.

Voltage Shift: The negative voltage shift as measured between the pipe surface and a saturated copper-copper sulfate half cell in contact with the electrode. This is the difference in pipe-to-soil potential before and after the application of protective current, (the latter being made with the current applied).

Polarization Voltage Shift: The negative voltage shift measured between the pipe surface and a saturated copper-copper sulfate half cell contacting the electrolyte. This polarization voltage shift is determined by interrupting the protective current and measuring the polarization decay.

Tafel segment, Tafel line, Tafel slope, Tafel diagram: When a pipe surface is polarized, it frequently will yield a current potential relationship over a region which can be approximated by:

$$n = \pm B \log \frac{i}{i_o}$$

where n = change from open-circuit potential, i = the current density, B and i_o = constants. The constant (B) is also known as the Tafel slope. If this behavior is observed, a plot on semilogarithmic coordinates is known as the Tafel line and the over-all diagram is termed a Tafel diagram.

(b) In the two columns of the table below, show voltage values at which your company considers protection has been achieved.

Criterion (ia) Used	Protected Voltage or ΔV shift (Volts) Bare	Protected Voltage or ΔV shift (Volts) Coated
Pipe-to-soil potential	______	______
Voltage shift	______	______
Polarization voltage shift	______	______
Voltage based on Tafel segment of E-log-I curve	☐ (Check if used)	

Describe any other method your company may use in determining when pipe is protected such as measurement of current loss and gain on the structure or current tracing in the electrolyte perpendicular to the pipeline, or polarization potential, etc.

(c) With reference to protected pipe, where does your company normally place its reference electrode?

	Bare	Coated
On surface over pipe	______	______
Remote from pipe	______	______
If remote, perpendicular distance from pipe	______ Ft.	______ Ft.
Immediately adjacent to pipe	______	______
Other (specify)	______	______

(d) What is your maximum pipe-to-soil potential (numerically) or instantaneous open circuited potential at the rectifier location? Check the potential that best describes the company practice.

Pipe-to-Soil Potential (Volts)		Inst. Open Circuit Potential (Volts)	
up to 1.5	☐	up to 1.00	☐
i.6 to 2.5	☐	1.01 to 1.05	☐
2.6 to 3.5	☐	1.06 to 1.20	a
3.6 to 5.0	☐	Other (specify and explain)	☐
Other (specify and explain)	☐		

(e) Does your company design its cathodic protection installations or are consultants employed to do this work?

(f) Do corrosion oriented technical personnel check the adequacy of the installed cathodic protection? (If yes, describe the procedure.)

Section IV - Surveillance, Control and Maintenance

1. If your company uses the following surveillance methods, write the letters or numerals "W" (weekly), "M" (monthly), 1 (annually), 2 (biannually), . . .5 (quinquennially), . . . "U" (unscheduled), . . ."R" (on occasions when opportunity presents itself), . . . or "X" (infrequently) in the appropriate column to indicate the frequencies of such surveys.

Type of Surveillance or Tests	
(a) Aerobic bacteria	____________
(b) Anaerobic bacteria	____________
(c) Bell hole inspection (coating and pipe condition)	____________
(d) Coatiny conductance survey (local)	____________
(e) Coating conductance survey (longline)	____________
(f) Coating discontinuity survey (Pearson)	____________
(g) Earth current test (pipe vicinity)	____________
(h) Line current measurement	____________
(i) Surface potential survey	
close interval	____________
continuous	____________
(j) Pipe-to-soil potential survey (at test stations)	____________
(k) Redox potential	____________
(1) Soil resistivity survey*	____________
(m) Chemical analyses	____________
(n) Current interference	____________
(o) Other (explain in detail)	____________

*Clarify by adding the appropriate letter(s) "P" (probe), "WE" (Wenner method), or "S" (Soil Box).

PART C: INTERFERENCE, RESEARCH AND CASE HISTORIES

Section I - Current Interference

1. List all electrolysis or corrosion interference committees in which your company participates.

2. Use the numbers 1, 2, 3, etc., to indicate the major sources of information about the presence of interference currents:

   (a) Electrolysis or corrosion interference committees ________

   (b) Direct communication from other companies ________

   (c) Current and Voltage measurements ________

   (d) Other (specify) ________

3. How many drainaqe bonds between the company's piping and other structures are existing? Describe major bonds.

4. What criterion(a) is (are) used to determine when interference has been mitigated?

Section II - Research

1. Is your company currently or has it, in the past:

   (a) Engaged in corrosion research? ☐ Yes ☐ No

   (b) Sponsored or contributed to corrosion research? ☐ Yes ☐ No

2. If yes, state the major areas covered.

3. Is your research work primarily: Field ☐ Laboratory ☐

4. What information or research do you feel is needed in the future for corrosion control of underground and underwater piping?

5. Do you know of any outstanding unpublished works on corrosion which are not generally available to the corrosion engineering profession? Obtain clearance from author(s) and/or company of such unpublished works before responding affirmatively.

☐ Yes ☐ No

6. If yes, please list title, author, and how they can be secured.

PART D: ADDITIONAL INFORMATION

Please discuss underground or underwater piping corrosion problems not specifically mentioned in the questionnaire or expand on any question.

PART E: PIPELINE CASE HISTORIES

At your company's option, supply case history information for piping installations which you feel would be of benefit.

APPENDIX III

ALPHABETICAL LISTING OF ELECTROLYSIS OR CORROSION INTERFERENCE COMMITTEES

TABLE 49

ELECTROLYSIS OR CORROSION INTERFERENCE COMMITTEES

AGA Corrosion Committee

Arizona Corrosion Correlating Council

AWWA National Underground Corrosion Committee

Baltimore-Washington Electrolysis Committee

Birmingham Electrolysis Committee

Canadian Gas Association Corrosion Control Committee

Central California Cathodic Protection Committee

Central Ohio Corrosion Coordinating Committee

Chicago Area Joint Electrolysis Committee

Chicago Region Committee on Underground Corrosion

Cleveland Committee on Corrosion

Columbus and Central Ohio Committee on Corrosion

Connecticut Committee on Corrosion

Corpus Christi Coordinating Committee

Corrosion Subcommittee of Kentucky Gas Association

Dade County Utilities (Florida)

Dayton, Ohio, Corrosion Committee

Denver Metropolitan Committee on Corrosion (not active)

Des Moines Electrolysis Committee

Detroit and Michigan Committee on Electrolysis

East Bay Electrolysis Coordinating Committee (Oakland, California)

Eastern Montreal Electrolysis Committee

Eastern New York Corrosion Coordinating Committee

Eastern Ohio Corrosion Coordinating Committee

Eastern Pennsylvania Corrosion Committee

El Paso Area Corrosion Correlating Committee

Flagstaff, Arizona, Underground Corrosion Correlating Committee

Greater Boston Electrolysis Committee

Greater Indiana Corrosion Committee

Greater New York Committee on Corrosion

Illinois-St. Louis Committee on Underground Corrosion

Indiana Corrosion Committee

Indiana Gas Association Subcommittee

Indianapolis Committee on Corrosion

Inter-Association Steering Committee on HVDC

Joint Committee for the Protection of underground Structures in Alameda and Contra Costa Counties (California)

Kentucky Corrosion Coordinating Committee (Kentucky Gas Association)

Lafayette, Louisiana, Underground Corrosion Correlating Committee

Los Angeles, California, Underground Corrosion Correlating Committee

Louisiana Coordinating Committee

Louisville Electrolysis Committee

Maryland State Public Service Commission

Massachusetts Committee on Corrosion

Midwest Gas Association (Wisconsin)

Milwaukee Area Corrosion Committee

Minnesota Corrosion Committee (inactive)

National Association of Corrosion Engineers (NACE)

National Task Force on HVDC

New Jersey Committee on Corrosion

Northeastern Ohio Corrosion Coordinating Committee

Northwest Electrolysis Coordinating Committee (San Francisco)

Northwest Electrolysis Coordinating Council (Oregon/Washington)

Northwest Pacific Electrolysis Coordinating Council (Vancouver, B.C.)

Northwest Pipe Line Operators (Oregon/Washington)

Ohio Area Committee on Underground Corrosion

Ok-Ark-La-Tex Corrosion Committee

Omaha and Council Bluffs Electrolysis Committee

Oregon Corrosion Committee, Dalles

Pacific Coast Gas Association Corrosion Mitigation Committee (San Francisco)

Philadelphia Electrolysis Committee

Pittsburgh Public Service Coordination Committee

Public Utilities Commission Corrosion Committee (Ontario, Canada)

San Diego County Underground Corrosion Committee (California)

San Francisco Electrolysis Committee

Southern California Cathodic Protection Committee

Southern Idaho-Eastern Oregon Underground Corrosion Committee

Southern Ontario Council on Electrolysis
Northern Technical Committee
Western & Central Committee

Southern West Virginia Corrosion Coordinating Committee

South Florida Corrosion Council

Southwest British Columbia Electrolysis Coordinating Council

St. Louis, Missouri, Underground Corrosion Correlating Committee

Tidewater Corrosion Control Committee (inactive)

Toledo and Northwestern Ohio Committee on Corrosion

Western Inter-Utility HVDC Committee for Earth Current and Inductive Coordination Studies

Western New York State Corrosion Committee

Western Ohio Corrosion Coordinating Committee

Western Pennsylvania Corrosion Coordinating Committee

Wisconsin Utilities Association

Wyoming Underground Corrosion Coordinating Committee

APPENDIX IV

ALPHABETICAL LISTING OF ORGANIZATIONS AND SOCIETIES WITH INTERESTS IN CORROSION AND CORROSION CONTROL

ORGANIZATIONS AND SOCIETIES

Table 50 lists many organizations concerned in one way or another with corrosion and corrosion control. Activities include research, meetings, short courses, publication of monographs and journals, advice and problem solving, promotion of commercial interest, promulgation of standards and specifications, lobbying, legal representation for some particular industry, etc.

TABLE 50

ORGANIZATIONS AND SOCIETIES WITH INTERESTS IN CORROSION AND CORROSION CONTROL

American Academy of Microbiology (AAM)
P. O. Box 897
Vero Beach, Florida 32960

American Chemical Society (ACS)
1155 Sixteenth Street, NW.
Washington, D.C. 25036

American Concrete Institute (ACI)
P. O. Box 4754
Redford Station
Detroit, Michigan 48219

American Concrete Institute
Dept. of the Army, Jackson Installation
Concrete Division, P. O. Drawer 2131
Jackson, Mississippi 39205

American Concrete Pipe Association
1815 North Fort Myer Drive
Arlington, Virginia 22209

American Concrete Pressure Pipe Association
1815 North Fort Myer Drive
Arlington, Virginia 22209

American Gas Association
655 Third Avenue
New York, New York 10016

American Institute of Biological Sciences (AIBS)
2000 P Street, N.W.
Washington, D.C. 20036

American Institute of Chemical Engineers (AIChE)
345 East 47th Street
New York, New York 10017

American Institute of Chemists
79 Madison. Avenue
New York, New York 10016

American Institute of Consulting Engineers (AICE)
345 East 47th Street
New York, New York 10017

American Institute of Industrial Engineers (AIIE)
345 East 47th Street
New York, New York 10017

American Institute of Mining, Metallurgical, and Petroleum Engineers
345 East 47th Street
New York, New York 10017

American Institute of Planners
917 Fifteenth Street, N.W.
Room 800
Washington, D.C. 20005

American Institute of Plant Engineers (AIPE)
1347 Meier Street
Cincinnati, Ohio 45208

American Material Handling Society
815 Superior Avenue, N.E.
Cleveland, Ohio 44114

American Meteorological Society
45 Eeacon Street
Boston, Massachusetts 02108

American Municipal Association (AMA)
1612 K Street, N.W.
Washington, D.C. 20006

American Petroleum Institute (API)
1271 Avenue of the Americas
New York, New York 10020

American Petroleum Institute
Pipeline Division
1101 Seventeenth Street, N.W.
Washington, D.C. 20005

American Pipe & Construction Company
400 South Atlantic Avenue
Monterey Park, California 91754

American Public Works Association (APWA)
1313 East 60th Street
Chicago, Illinois 60637

American Railway Engineering Association
59 East Van Buren Street
Chicago, Illinois 60605

American Society of Biological Chemists (ASBC)
9650 Wisconsin Avenue
Washington, D.C. 20014

American Society of Civil Engineers (ASCE)
Pipeline Division
345 East 47th Street
New York, New York 10017

American Society of Mechanical Engineers
345 East 47th Street
New York, New York 10017

American Society of Microbiology (ASM)
115 Huronview Boulevard
Ann Arbor, Michigan 48103

American Society of Safety Engineers (ASSE)
5 North Wabash Avenue
Chicago, Illinois 60602

American Society for Metals
Metals Park, Ohio 44073

American Society for Testing and Materials
1916 Race Street
Philadelphia, Pennsylvania 19103

American Water Works Association
2 Park Avenue
New York, New York 10016

American Welding Society
345 East 47th Street
New York, New York 10017

Asphalt Institute, The
University of Maryland
College Park, Maryland 20742

Association of American Railroads
59 East Van Buren Street
Chicago, Illinois 60605

Association of Consulting Chemists and Chemical Engineers
501 Fifth Avenue
New York, New York 10017

Association of Oil Pipelines
Suite 1208, RCA Building
1725 K Street, N.W.
Washington, D.C. 20006

Battelle Memorial Institute (BMI)
505 King Avenue
Columbus, Ohio 43201

British Association of Corrosion Engineers
London, England

British Cast Iron Research Association (BCIRA)
London, England

British Electrical and Applied Industries
Research Association
London, England

British Iron & Steel Research Association (BISRA)
London, England

Cast Iron Pipe Research Association (CIPRA)
Suite 3440, Prudential Plaza
Chicago, Illinois 60601

Cast Iron Soil Pipe Foundation
6723 South Western Avenue
Los Angeles, California 90047

Central Electrochemical
Research Institute
Karaikudi, India

Centro Sperimentale Metallurgico
Rome, Italy

Clay Pipe Institute
2600 Wilshire Boulevard
Los Angeles, California 90057

Copper Development Association, Inc.
405 Lexington Avenue
New York, New York 10017

Corrosion Center
Ohio State University
North High Street
Columbus, Ohio 43210

Corrosion Engineering & Research Co.
130 North San Miguel Road
Concord, California 94520

Council of State Governments (CSG)
1313 East 60th Street
Chicago, Illinois 60637

Department of Water: Resources
State of California
P. O. Box 388
Sacramento, California 95814

Electrochemical Society (Corrosion Division)
30 East 42nd Street
New York, New York 10017

European Corrosion Federation
Brussels, Belgium

European Federation of Corrosion
Budapest, Hungary

Federation of Societies for Paint Technology (FSPT)
121 South Broad Street
Philadelphia, Pennsylvania 19107

Fluid Power Society
P. O. Box 49
Thiensville, Wisconsin 53092

Highway Research Board
Division of Engineering and Industrial Research
National Academy of Sciences-National Research Council
2101 Constitution Avenue, N.W.
Washington, D.C. 20418

Homer Research Laboratory
Bethlehem Steel Company
Bethlehem, Pennsylvania 19016

Hydraulic Institute
122 East 42nd Street
New York, New York 10017

Independent Oil Producers Agency
714 West Olympic Boulevard
Los Angeles, California 90015

Institution of Corrosion Technology
London, England

Institute of Electrical and Electronics Engineers
Box A, Lenox Hill Station
New York, New York 10021

Institute of Materials Research
National Bureau of Standards
Gaithersburg, Maryland 20760

Institute of Physical Chemistry
Bucharest, Rumania

Institute of Physical Chemistry
Academy of Sciences
U.S.S.R.

International Nickel Company, Inc.
67 Wall Street
New York, New York 10005

Lead Industries Association, Inc.
292 Madison Avenue
New York, New York 10017

Manufacturers Standardization Society of the Valve
and Fitting Industry
420 Lexington Avenue
New York, New York 10017

Massachusetts Institute of Technology
Cambridge, Massachusetts 02138

Metallurgical Society of AIME
345 East 47th Street
New York, New York 10017

Midwest Oil Register, Inc.
Drawer 7248, Southside Station
Tulsa, Oklahoma 74105

Montgomery Research, Inc.
555 Walnut Street
Pasadena, California 91101

National Association of Corrosion Engineers
2400 West Loop South
Houston, Texas 77027

National Association of Pipe Coating Applicators
2504 Flournoy-Lucas Road
Shreveport, Louisiana 71106

National Board of Boiler and Pressure Vessel Inspectors
1155 North High Street
Columbus, Ohio 43210

National Bureau of Standards
Washington, D.C. 20234

National Certified Pipe Welding Bureau
666 Third Avenue, Suite 1464
New York, New York 10017

National Petroleum Council (NPC)
1625 K Street, N.W.
Suite 601
Washington, D.C. 20006

National Research Center
Dokki-Cairo
United Arab Republic

Natural Gas Processors Association
429 Kennedy Building
Tulsa, Oklahoma 74103

New England Water Works Association
73 Tremont Street
Boston, Massachusetts 02108

Office of Pipeline Safety
U.S. Department of Transportation
400 Sixth Street, S.W.
Washington, D.C. 20024

Ohio State University
Department of Metallurgical Engineering
116 West 19th Avenue
Columbus, Ohio 43210

Petroleum Industry Research Foundation
60 East 42nd Street
New York, New York 10017

Pipe Line Contractors Association
National Bankers Life Building
202 South Ervay
Dallas, Texas 75201

Portland Cement Association
5420 Old Orchard Road
Skokie, Illinois 60076

Societé Pétroliére de Géranee
37 Avenge Pierre 1er De-Serbie
Paris 8 , France

Society of Consulting Corrosion Engineers
205-627 Eighth Avenue
Calgary 2, Canada

Society for Experimental Stress Analysis
21 Bridge Square
Westport, Connecticut 06880

Society for General Systems Research (SGSR)
787 United Nations Plaza
New York, New York 10017

Society of Materials Science
Tokyo, Japan

Society for Non-Destructive Testing (SNT)
914 Chicago Avenue
Evanston, Illinois 60202

Society of Petroleum Engineers of AIME
6300 North Central Expressway
Dallas, Texas 75206

Society of Plastics Engineers, Inc.
65 Prospect Street
Stamford, Connecticut 06902

Southern California Meter Association
1333 Sombrero Drive
Monterey Park, California 91754

Stanford Research Institute
Transportation of Logistics Department
Menlo Park, California 94025

State of California Transportation Agency
Department of Public Works
Division of Highways
Materials and Research Department
Route 1, Box 1900
West Sacramento, California 95691

State Research Institute for the Protection
of Materials
Prague, Czechoslavakia

Steel Pipe Fabricators Association
19 South LaSalle Street
Chicago, Illinois 60606

Titanium Metals Corporation of America
233 Broadway
New York, New York 10007

United States of America Standards Institute
(Formerly American Standards Association)
10 East 40th Street
New York, New York 10016

United States Committee on Large Dams of the International
Commission of Large Dams
345 East 47th Street
New York, New York 10017

University of California at Berkeley
111 Mechanics Building
Berkeley, California 94720

University of California at Los Angeles
Depratment of Engineering
Los Angeles, California 90024

University of Texas
Austin, Texas 78712

Ural Scientific Research Institute
of Ferrous Metals
U.S.S.R.

U.S. Bureau of Reclamation
Engineering Laboratories
Denver Federal Center
Denver, Colorado 80225

U.S. Naval Civil Engineering Laboratory
Port Hueneme, California 93041

U.S. Department of Interior
Washington, D.C. 20024

Valve Manufacturers Association
60 East 42nd Street
New York, New York 10017

Washington State University
Division of Industrial Research
Pullman, Washington 99163

Welding Research Council
345 East 47th Street
New York, New York 10317