Mechanical And Economic Aspects Of Chemical Treatment For Corrosion Control In Oil And Gas Wells

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Abstract

This paper outlines some of the economic factors to be considered in the chemical treatment of oil and gas wells for corrosion control. It also presents several advantages and disadvantages of some mechanical application equipment and the economics involved in using the equipment. The paper also describes and evaluates several chemical applicators which are economical to use.

Corrosion is the chemical reaction between a metal and the gas or liquid around it. The metal most used in the oil fields is iron. For corrosion comparisons, cast iron, wrought iron, and most mild steels are merely different form of iron. This paper, then, in referring to "iron," includes all such metals, and the chemical treatment for the prevention or control of that corrosion. This paper does not discuss chemicals as such, but deals with the mechanical equipment employed in corrosion inhibition programs.

Two kinds of corrision occur in oil wells. These are internal and external corrosion. Internal corrosion is caused by acid brine produced by the wells. External corrosion is usually caused by oxygen from the air, soil, or sea. This paper refers to the equipment used for control of sub-surface corrosion, and therefore when we refer to corrosion we mean internal, subsurface corrosion within the bore of the well.

An oil-field brine may contain acid when it is produced from the underground rock, or acids may have been added to the produced fluid during well stimulation treatments. The acids used for well stimulating are normally treated, however, to reduce the corrosion of iron. In addition, treating acids are present in the well for only a few hours. Corrosion damage from such acid, is rare. As brine is produced, it may contain acid gases and liquid organic acids. The acid gases are hydrogen sulfide and carbon dioxide. The organic acids are acetic acid and some of its chemical relatives. The acid gases usually cause about 99 percent of all oil field internal-corrosion damage.

The degree of corrosion, then, will depend upon how much acid gas is in the brine. This is one reason that deep wells are more likely to corrode than shallow wells. In deep wells, the brine and acid gas are under great pressure. This pressure makes the acid gas dissolve in the brine, just as carbon dioxide is dissolved in a bottle of soda water. In shallow wells there is usually less pressure and therefore less acid gas dissolves in the brine.

Acid brine must be in contact with iron to cause corrosion. If a well produces only a small percentage of brine, the greater volume of oil produced in the well fluid usually prevents this contact. Some crude oils are more efficient in this than others. The high-gravity crude from condensate wells usually is much less effective than a medium-or low-gravity crude from oil wells. The method of production, and the rate, also influence the amount of contact between the metal and the brine.

Corrosion is a problem only when it affects safety or costs.

Safety is, of course, the first consideration. Because corrosion treatments are wide spread, corrosion rarely affects safety in today's operations. Nevertheless, safety should be the first subject considered when applying corrosion control measures.

Corrosion control costs have been reduced over those encountered when corrosion first became recognized as a major problem. Control programs are inherently tied to economics, because of the costs, they affect the size of the profit that is realized from each well, each field, and each operation carried on by the producer. You are members of this producer 'family," and therefore should be interested in these costs.

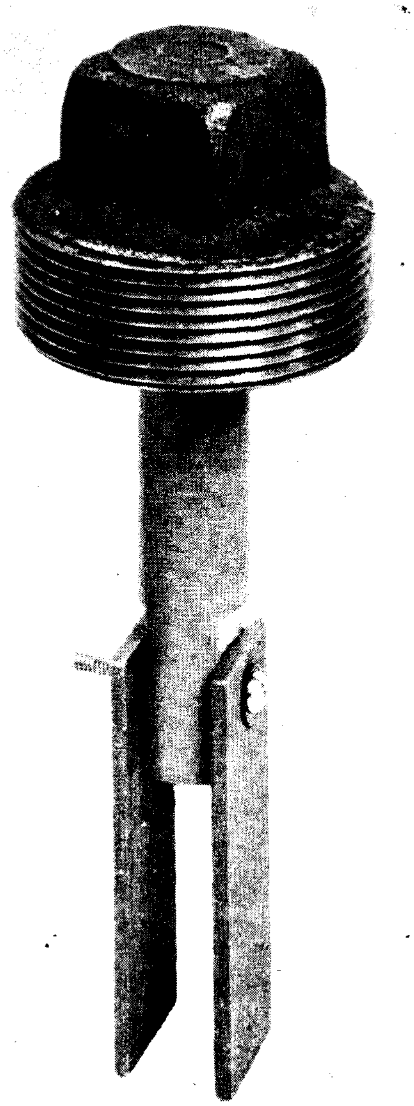

Figure 1 (Slide 1)—Flow Line coupons and holder.

There are three parts to a sound corrosion control program. These are:

1. Measurement.
2. Treatment.
3. Cost Comparison.

Measurement of corrosion is the first part. The real need is to measure the cost of the corrosion. It is necessary to measure metal loss, or the rate of metal loss in order to measure costs. Often we must compromise and measure something else which may then be related to an equal rate of metal loss. Then we estimate the total cost of the lost metal and call this term the "estimated cost of corrosion."

Measurement is needed to learn whether the corrosion is costing enough to merit our attention. Probably every piece of iron corrodes a little bit. Corrosion, in these cases, seldom costs enough to pay for treatment. Therefore measurement is needed to learn whether treatment will "pay."

Measurement is accomplished in four ways:

1. By counting equipment failures due to corrosion.
2. By measuring the rate (or metal thickness) of iron removed by corrosion by the use of one of the following methods:
   A. General Surface Inspection.
   B. Specific Sub-surface Inspection.
   (1) Corrosion Surveys (Otis Calipers).
   (2) Pipe Grading Service (Dia-Log).
3. By weighing the iron removed from test coupons placed in either the flow line, or beneath the surface (Fig. 1 and 2).
4. By measuring the iron content as dissolved into the corrosive fluid.

All of these methods are subject to the human variable. None of them can sort out corrosion damage from wear damage and combination erosion-corrosion damage. All of these measurements cost money and thus they too add to the cost of corrosion.

Of all the methods, the fourth one is the most indirect, and the least reliable. But it has merit. If every pound of iron that corroded away stayed in the fluid, a simple chemical analysis of the fluid could measure the corrosion. Moreover, it would measure the rate of corrosion. It is only necessary to know the amount of fluid flowing, and to sample the fluid on both ends of the piping. There is no lost production. The piping remains in service while the sampling takes place. The field work may thus be limited to measuring flow rates and taking samples. This saves time and does not diisturb production. Results are quickly known. But all field conditions must be known.

A modification of this sampling method is often applied to oil and gas

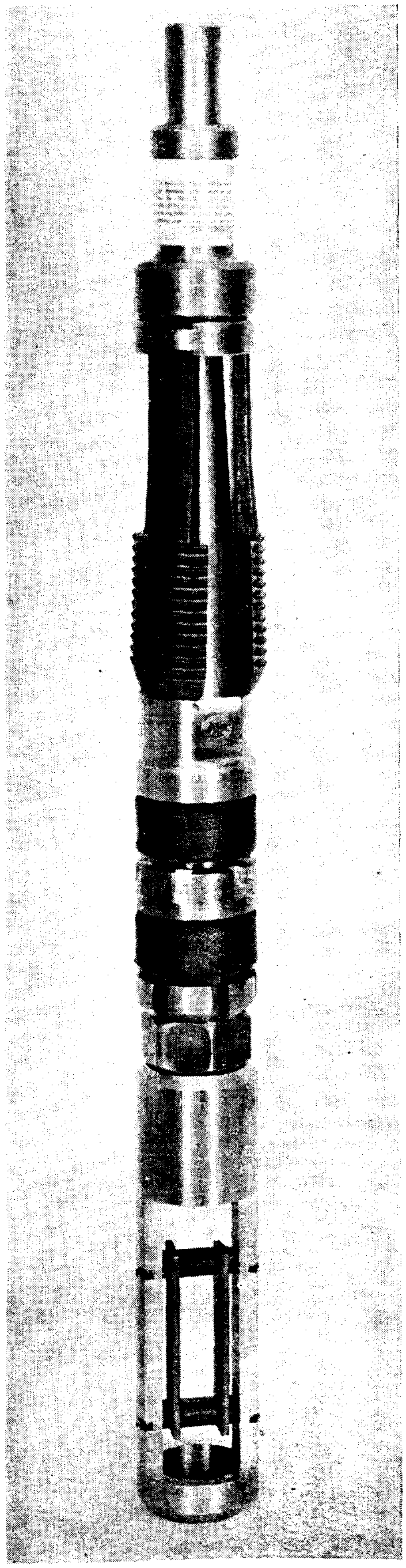

Figure 2 (Slide 2)—Sub-surface coupon holder and coupons for use at any elevation in a tubing string.

wells. The sampling is done only at one end of the piping. The upper-most end, or some point down stream near the upper end is selected as the sampling point.

It is very expensive to sample the fluids and obtain reliable information at the lower end of the piping during productive periods of the well. It has been so expensive in the past, that practically all attempts to do this today have been abandoned. This one point sampling method, while a compromise, is a practical tool used today to judge the effectiveness of corrosion control treatments.

A defect in the one-point sampling method is the appearance of great accuracy when it doesn't really imply that at all. No analysis can be better than the samples from which it was made. The analysis may be correct to one part per thousand, and the actual well pitting factor not closer than one part in five. Hence this "greater accuracy" is actually useless.

Another defeat of this method is the assumption when using it that all the products of corrosion are dissolved in the fluids. Such may not be the case.

Thus we can see a need for measurement of corrosion. And this measurement costs money. The quicker methods are less accurate. No method is foolproof. The most accurate measurement is, of course, the tubular measurement (I. D.) method. Therefore, the method to be used is one which is only as accurate as needed. No measurement is worth more than the corrosion problem for which it was intended. Sometimes (if the problem is severe enough) it may even be wise to use one method of measurement as a base, and another method as a periodic check.

Having measured the corrosion and appraised (or evaluated) its magnitude, the next thing to do is to treat it. There are five basic ways to do this:

1. Mechanical.
8. Alloy Materials.
3. Coating.
4. Electrical.
5. Chemical.

1. *Mechanical Treatment*: The mechanical treatment can be described by listing four things to avoid. There are:

A. Speed.
B. Stress.
C. Corroding Chemicals.
D. Exposure of the metal.

Usually a slow-moving fluid corrodes slowly. Turbulence is local speed, and speed assists erosion, and thus exposes more new metal to be corroded. Stress causes metal stretch or compression and this loosens corrosion products so that more metal may be corroded. Any means for eliminating a corrosive chemical will reduce corrosion. And metal does not corrode when it is not exposed. This last rule has been put in simple words, "What ain't, cain't!"

2. *Alloy Treatment*: Some metals and alloys do not corrode because the metal itself is not reactive. Gold and platinum are metals of this kind. Other metals do not appear to corrode because they are covered with a tight impervious film of corrosion products. Aluminum and the stainless steels are alloys of this kind. The corrosion-resistant alloys which are used in the oil field are usually of the latter kind. It is clear that alloys should be carefully chosen when they are used to control corrosion. Few will be found to be useful in all kinds of fluids. Even different fields producing the same kind of crude may need different alloys. This can only be learned by careful field testing.

3. *Coating Treatment*: Coatings protect metal because they prevent contact with the corroding fluids. Coatings may consist of organic materials and metals. Some alloys form corrosion resistant coatings. A combination of properties is sometimes obtained by the use of coatings which cannot be equalled in a metal or alloy. The abrasion resistance of resilient plastic coating is often greater than that of the best alloys.

4. *Electrical Treatment*: The electrical method of treating corrosion is called cathodic protection. It is used only for corrosion resulting from the soil and the sea. It is based upon the fact that metal which dissolves in a fluid carries an electric charge. If the electric charge does not leave the metal surface, the metal cannot corrode. The practice is aimed at "over protection" so that more electrical charges are added to the surface of the metal than are lost.

Coating and cathodic protection work well together. The electric current protects the metal at the "holidays" in the coating. It reduces any damage which occurred to the coating. And the coating reduces the amount of current needed to protect the metal.

Today cathodic protection is being used on well casings, and surface equipment.

5. *Chemical Treatment includes*:

A. Changes in temperature.
B. Changes in pressure.
C. Changes in composition of the corroding fluids.
D. Additives to the fluids which "inhibit" the fluids' corrosive action.

Changes in temperature affect the rate of corrosion. Where an increase of temperature occurs, and the top limit of change is below the boiling point of water, an increase in corrosion will result. This is true because oil field corrosion requires liquid water; and acids are more active at high temperatures.

When a temperature is above the boiling point of water, no corrosion occurs. In this instance, any decrease in temperature below the boiling point would cause liquid water to form and corrosion to begin. In some gas wells liquid water may form as the gas cools as it travels up the tubing; or a subsurface control may cause a sudden drop in temperature so that corrosion may occur at and above this point. Turbulence may also be a factor in increasing the speed of the fluids, and an accelerated corrosion condition may exist at this point.

Changes in pressure affect the rate of corrosion because more acid gases are forced into solution in the water as the pressure increases.

By the use of bottom-hole chokes, the flowing pressure of a gas well can be reduced. This would decrease the pressure of acid gases above the choke but corrosion would only be reduced from "moderate" to "mild," at best. This is seldom useful. However, a combination pressure reduction-inhibitor program may be feasible.

A third chemical means of changing corrosion rates is by changing the composition of the fluid. This can be done mechanically by water shut-offs. It is also posible to change the amount of acid by using caustic in a well. Acids can be neutralized by caustic soda, soda ash, ammonia, or water glass. All of these are used in gas wells.

The amount of acid gas produced by a corrosive well is more than the amount of liquid neutralizer which can be put into it. It is only the acid brine on the surface of the metal which need be destroyed. Because all of the gas is not dissolved in brine on the metal surface, all of it is not neutralized. For this reason, a small amount of caustic or other alkali has a large effect on corrosion. It may also have a large effect in plugging the well if certain formation waters are produced. For this reason, neutralizing treatments must be used with care.

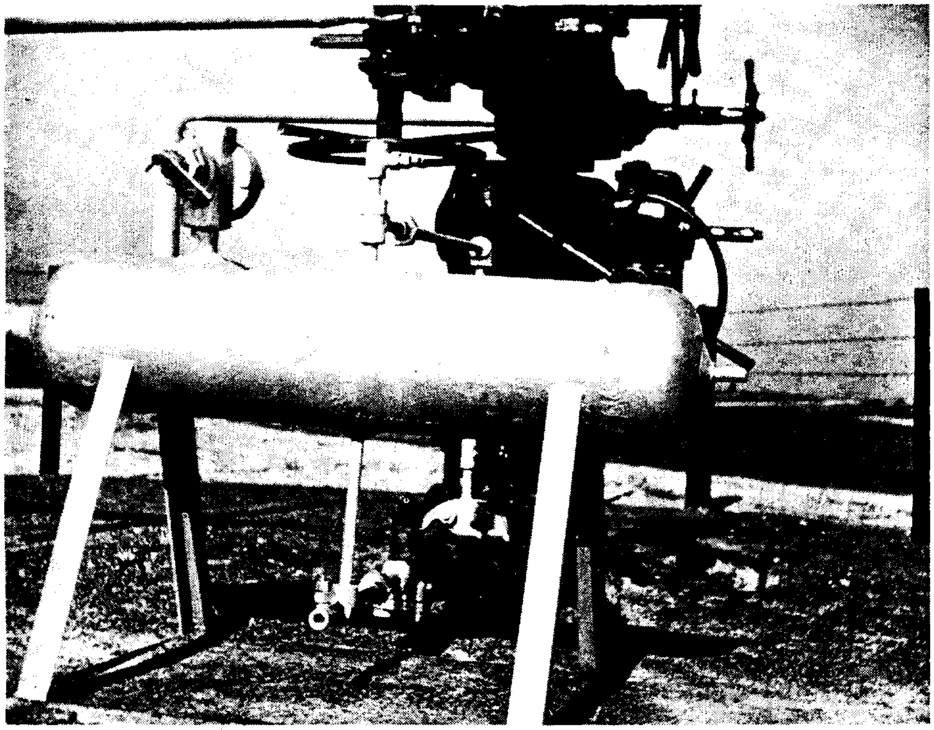

Figure 3 (Slide 3)—"Boll Weevil Gravity" Lubricator.

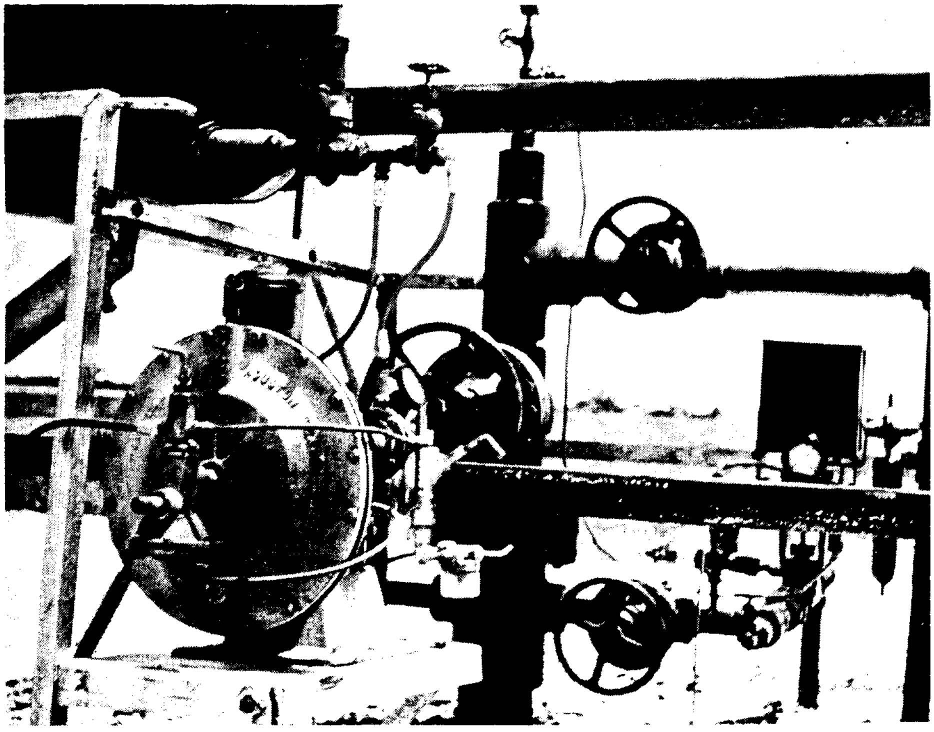

Figure 4 (Slide 4)—Rate controlled pump injector.

Corrosion inhibitors are materials which are added to the corroding fluid to reduce the rate of metal loss. In one sense, they may be said to form a thin coating between the metal and the fluid. This film is about as thick as the film on a resistant alloy—about one or two molecules. When the film on an alloy is damaged, it is "repaired" by the metallurgical properties themselves. When the film of inhibitor is damaged, it is replaced by the inhibitor in the fluid.

This suggests some advantages of inhibitors. First, they protect all the metal the fluid touches. Usually, this means all the metal exposed to corrosion. Second, because the film is thin, very little inhibitor is needed. Common dosage is 10 to 15 parts per million. Third, because the film comes from the fluid, the size or shape of the metals present no problems (sand blasting and coating are difficult for some shapes.) Fourth, inasmuch as inhibitors protect common steels, no special alloys need be bought and kept separate in field use.

Almost all well corrosion can be controlled by inhibitors, but the cost depends upon the volume of fluid handled. At high water-oil ratios, inhibition may be too costly. There is no inhibitor today which works in every well. Choosing the right one is not always easy and may require long testing.

There are several limitations to the use of inhibitors. Some inhibitors may protect metal for as much as a week or longer after treatment is stopped. Field labor to treat the well frequently costs more than the inhibitor itself. Inhibitor treatment may require shutting the well in from production and result in lost production. Getting the inhibitor where it is needed may not be easy. Usually it is needed at the bottom of the hole. Packers, high fluid levels, and tubing chokes can make placement difficult.

In spite of these limitations, inhibitors are the main method for controlling well corrosion.

We are now at the point of application of this paper. It is not our intent to discuss inhibitors, but rather the equipment and processes by which these widely used corrosion inhibitors are introduced into the well bore. The several methods which have been used are applicable to two different types of wells:

1. Wells with no packer.
2. Wells equipped with a packer.

Wells with no packer lend themselves particularly to inhibitor treatment using:

1. Gravity flow lubricators.
2. Batch dumping devices into the tubing-casing annulus.
3. Rate controlled pumps.

All of these methods are fairly economical, if the right inhibitor, and the right rate of injection are used. Figures 3 and 4 illustrate typical injectors of this type. They are simple, rugged, and require a minimum amount of time. Therefore, the inhibitor, and the labor to service and maintain these items, are the important expense when comparing these corrosion control costs.

Wells which are equipped with a packer present particular problems to the corrosion conscious operator. There are several methods of treating the tubing and the tubing-casing annulus. In the area of multiple completions where only one packer and one tubing string are used, inhibitors may be introduced in several ways into the tubing-casing annulus:

1. Gravity "boll weevil" lubricator (Figure 3).
2. Rate controlled pump injector (Figure 4).
3. Batch dumping (gas operated pump).
4. Inhibitor squeeze.

The tubing interior of multiple-zone and single-zone wells may be treated with inhibitors in several ways:

1. Bottom hole chemical injection equipment using injector valves (Figures 5, 6 and 7).
2. Inhibitor squeeze.
3. Batch treatment.
4. Stick type treatment (Figure 8).
5. Dump bailer (wire-line method) (Figure 9).
6. Free piston type applicators:

A. Bottom Hole Injector (Figure 10).

B. New types of automatic return devices.

The bottom hole injection equipment was an early development for "down the hole" treatment on a continuous, or batch, system of injection. It entails filling the tubing-casing annulus with a fluid mixture of inhibitor and well fluids. It also requires the use of a surface rate controlled meter injector and a small storage facility at the well site of inhibitor.

Some of the advantages of this equipment are:

1. The operator has positive control, at the surface, of the amount of inhibitor actually needed to protect against corrosion.
2. It is the only method applicable to wells equipped with a packer, at present that enables an operator to protect three surfaces in one operation—inside and outside of the tubing and the inside of the casing. Also, rods and pumps are protected in pumping wells.
3. The valve will admit chemical at a predetermined rate, regardless of varying tubing pressure. The chemical mixture may be injected continuously or "batched" in, as desired.
4. The method is adaptable to gas wells or oil wells, flowing or pumping.
5. Well pressure is kept off the casing since the annulus is filled with fluid and a packer is set.
6. No intermediate protective liner is needed.
7. Production is not interrupted during treatment of the well.

Some of the disadvantages are:

1. Higher initial equipment costs.
2. Larger amount of fluid inventory requirements (volume of annular space) to fill the system. This must be replaced each time the sub-surface equipment is serviced. And sometimes it is serviced often.

The inhibitor squeeze technique is really a variation of the batch treatment with the exception that enough inhibitor fluid mixture is used to actually squeeze some of the inhibitor back into the formation. The idea is that the "sand" would absorb the inhibitor, and desorb slowly to form an adequate protection during the production period of the well. This is an experimental method and has been tried on several gas-lift wells. The practice has been to pump 55 gallons of pure inhibitor into the tubing, then follow this with 15 barrels of oil mixed with two quarts of demulsifying agent, and this is in turn followed by sufficient brine or oil to displace the volume of the tubing downward and force the chemical into the formation. This "calculated" forcing of the chemical into the formation is subject to change with each well application. In one field, out of eleven wells so treated, one went to 100 percent brine production, one well changed from 8 bbl. oil and 85 bbl. brine to 92 bbl. oil and 550 bbl. brine production. No change in production other than a slight lag (considered normal for this field even when wells are just shut-in) was experienced in most of the other wells. In daily production volumes for several days, however, the production gradually increased to previous volumes.

Some chemical is lost, apparently from one to ten gallons, using this method, and this loss is greatest at the time of the first "squeeze." Subsequent squeezes always gave longer periods of protection than when the wells were first treated.

The results one operator obtained from inhibitor squeezing in the Placedo Field (gas-lift installations) indicate an economy of this method over the batch type treatment which he had used previously. However, this method is still in the experimental stage.

The "stick"-type treatment was also an early development as a means of introducing chemical inhibitors to the bottom of a well. This is simply a stick of a given diameter which will fall freely down in the tubing (or casing).

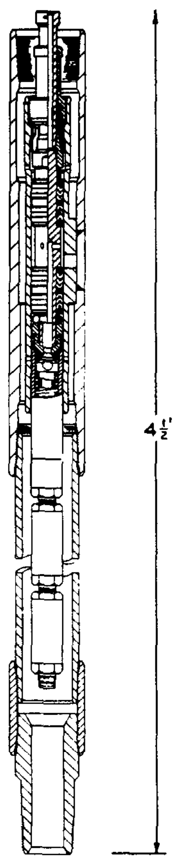

FIGURE 5

MACCO-OTIS "BYPASS" ASSEMBLY WITH RETRIEVABLE CHEMICAL INJECTOR IN PLACE. AN EXTRA LARGE BYPASS AREA (2 SQ. IN.) AROUND THE INJECTOR HOUSING PROVIDES AN UNRESTRICTED FLOW AREA TO THE WELL FLUIDS.

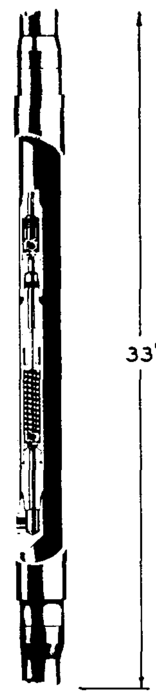

FIGURE 6

MACCO-OTIS "PACKOFF ANCHOR" MANDREL AND CHEMICAL INJECTOR. MACCO'S MANDREL IS ADAPTED TO AN OTIS PACKOFF ANCHOR ASSEMBLY AND RUN <u>INSIDE TUBING</u> BY WIRE-LINE. THIS RETRIEVABLE TYPE ASSEMBLY UTILIZES THE MACCO METHOD OF BOTTOM HOLE CHEMICAL INJECTION WITHOUT THE NECESSITY OF PULLING THE TUBING OR DISTURBING THE PACKER.

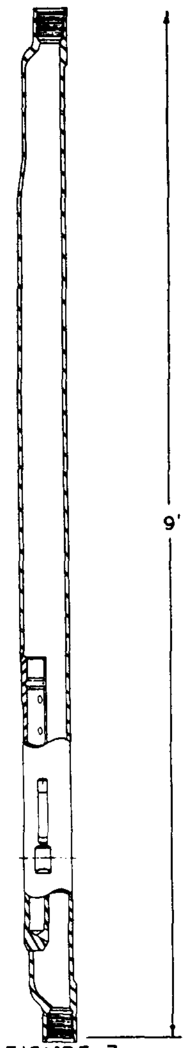

FIGURE 7

CAMCO "SIDEPOCKET" MANDREL FOR RETRIEVABLE CHEMICAL INJECTOR VALVE. THE "SIDEPOCKET" ASSEMBLY HAS A FULL OPENING MANDREL.

Figures 5, 6 and 7 (Slide 5)—By-Pass nipple with removable injector valve. Pack-Off anchor to be equipped with injector valve. Side-Pocket mandrel equipped with removable valve.

It consists of a temperature melting matrix which contains a chemical inhibitor dissolved in it. The "stick" is solid at most ground temperatures and must be placed in an environment of elevated temperatures before it will melt and release its "charge" of inhibitor. This method of corrosion treatment found wide acceptance. It was inexpensive and simple. One man could place the sticks in the well with the use of a simple lubricator.

It had, and still has, some disadvantages, even though the comparison costs are quite good. But what good is that if it doesn't do the job? Some of the disadvantages are:

1. Melting of the sticks occurs over a wide range of temperatures. This causes the danger of plugging the tubing if too many are dropped too quickly.
2. Premature melting prevents full coverage by the inhibitor. Only the upper reaches of the tubing are adequately treated.
3. The wax and paraffin base matrix sometimes causes fouling of surface valves and equipment.
4. Absence of protection below the effective melting point of the stick.

Table 1 illustrates some of the costs associated with the use of the stick-type treatment. It is a very practical method, but because of its recognized disadvantages, furthur efforts have been made to find a similar but better means of introducing liquid inhibitors into the bottom of the tubing.

One such device is a go-devil type tool that is filled with a liquid and dropped to the bottom of the tubing. It remains there, metering out small quantities of inhibitor during the production period until the liquid chamber is emptied. Then it automatically returns to the surface and is retrieved in a small lubricator. This tool is only in the development stages and no additional data is available at this time.

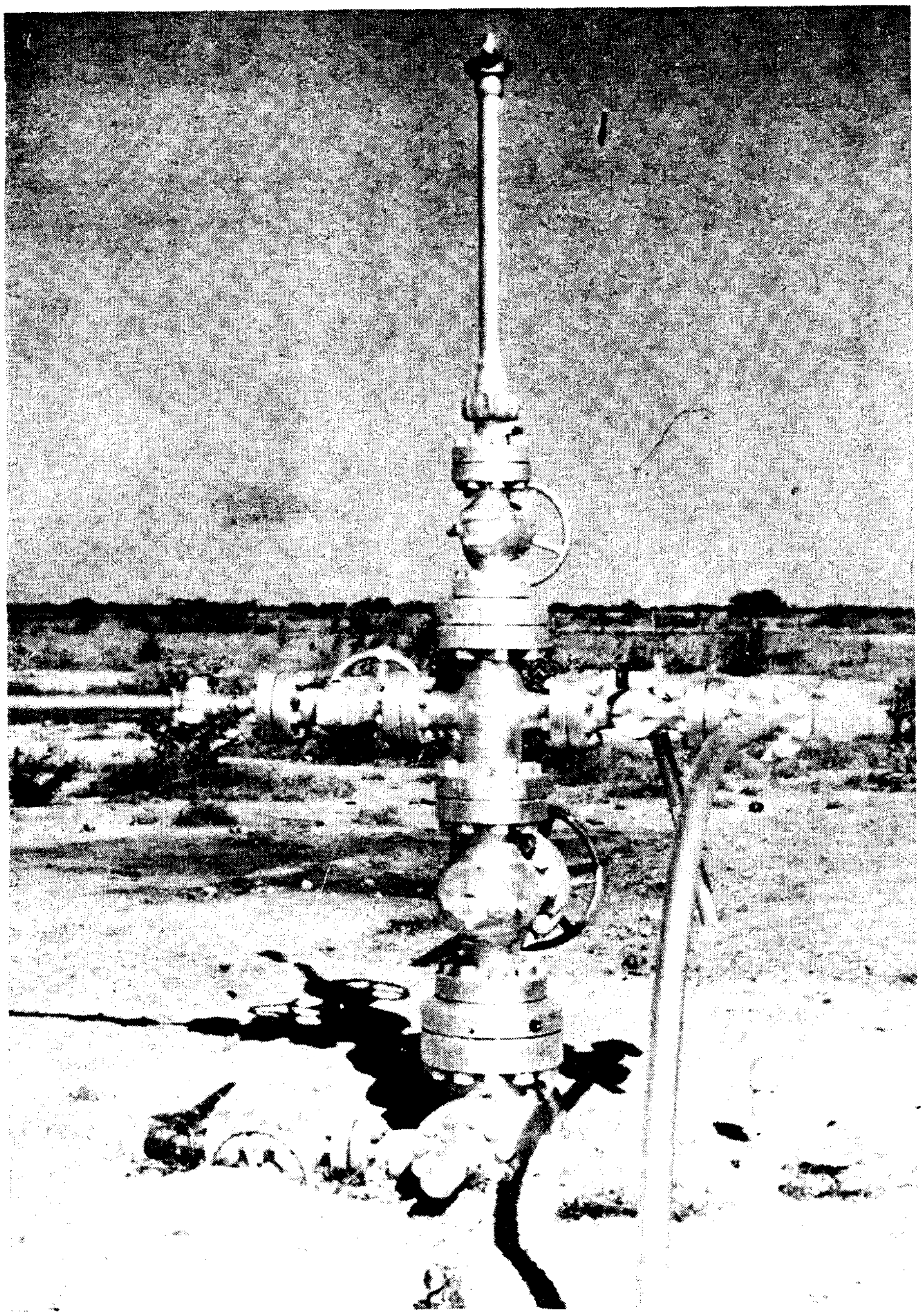

Figure 8 (Slide 8)—Stick Lubricator.

Several companies have used a wire line dump bailer to deposit a small quantity of inhibitor at the bottom of the well. One such type has been developed by a Mr. Oxford with Sun Oil Company. It has a mechanism which prevents the tool from returning to the surface until the inhibitor is dumped. Cost figures are available on this type of tool and will be discussed later.

The Oxford tool is practical, and depending upon the operator's needs and the well conditions, it may solve your tubing treating problems. However, if all equipment which is necessary for this type of operation must be charged to the corrosion control program for a single well, the price may be out of line. But if the program be for a number of wells, this equipment might indeed be considered.

The bottom hole injector (Figure 10) is another new development for inhibitor application. This is one of the go-devil type tools. It has several unique features other tools do not have. It has a packing element which smears the inhibitor onto the wall of the tubing. The packing element also serves as a positive interface between the well fluids below the tool, and the mixtures of fluids above the element. It has a temperature-controlled valve which opens at any pre-set temperature. It has a ball joint for passing tubing bends. And it has a pulling neck so that it may be retrieved from the well without flowing the well.

When the tool is dropped in the tubing, the packing element is locked in a stretched position (and thus a reduced diameter) Fig. 11 until the tool contacts a collar stop, or a bull plug in the tubing. The trigger-plunger is actuated by this contact and the packing element is released and expanded, by spring action compressing the element outward to the tubing wall. At the same time this plunger closes a bypass through the lower end of the tool. At this time the tool may be flowed back to the surface.

The temperature controlled plunger, which forces a ball off of its seat is moved by the action of a stack of bi-metal dish-shaped discs. These discs have been calibrated so that the ball seat valve may be opened at any desired pre-set temperature. When the ball seat valve is opened, a concentrated liquid inhibitor can then flow by gravity out of the liquid chamber and down onto the expanded packing element, and the tool rises to the surface smearing the inhibitor onto the wall of the tubing and is left there in the form of a microscopic film to desorb gradually into the well fluids.

This tool is retrieved at the surface by a small lubricator (Figure 12). The tool holds approximately 1 quart of concentrated liquid inhibitor weighs 18 lbs. and is about 1 - 3/4" x 65" overall. The Two-piece lubricator, weighs about 58 lbs. This assembly was designed for a simple, one-man operation and the heaviest piece of equipment to be handled weighs approximately 30 lbs.

Because of these developments in inhibitor-applicators a group of cor-

·osion people requested a practical ield trial of these methods in order o compare them and form an evaluaion for reference in the future. Accordingly, a gas-condensate well was nade available by Arkansas-Fuel Oil Company for these purposes. Well conlitions were as follows:

Surface pressure 3,100 p.s.i.

7"—23 lb. x 2" packer set at 6,980 eet.

Two 2-1/2" 6,000 lb. test, F. E., W. K. M. master valves.

One 2 1/2" O. C. T. union on top nd capped with a blind plug: and 2-1/2" E.U.E. 8rd. thd. machined internlly in the lower side of the union.

This well was successively treated with stick type inhibitor, batch type, dump bailer, and the bottom hole liquid injector. The inhibitor employed in each type of treatment was of a comparison nature as to effectiveness and cost. The production volumes of this well were held constant during these trials at three million cubic feet per day. When the trial data were available, the group then calculated the total control costs for this well, and reduced them to a unit figure for comparison. A one year write-off of all equipment and labor, except where noted, was used. The well was making a "count" of iron between 180 and 240 PPM, untreated.

The following tabulation shows a fairly reliable indication of corrosion treating costs, including a 1/2-ton pick-up, one man treating a minimum of five wells per day and performing this operation once a week. The costs shown here are actual, calculated costs, based upon the performance of the tools employed. All are applicable to only the well under test.

Wire Line Bailer (Contract by outside contractor).

1. Iron Count: Avg. 43 PPM.
2. Per Well Cost: $24.00.
3. Two Men Needed: Includes trailer, reel, wire line, lubricator and tools.

Figure 9 (Slide 9)—Wire-Line Dump Bailer.

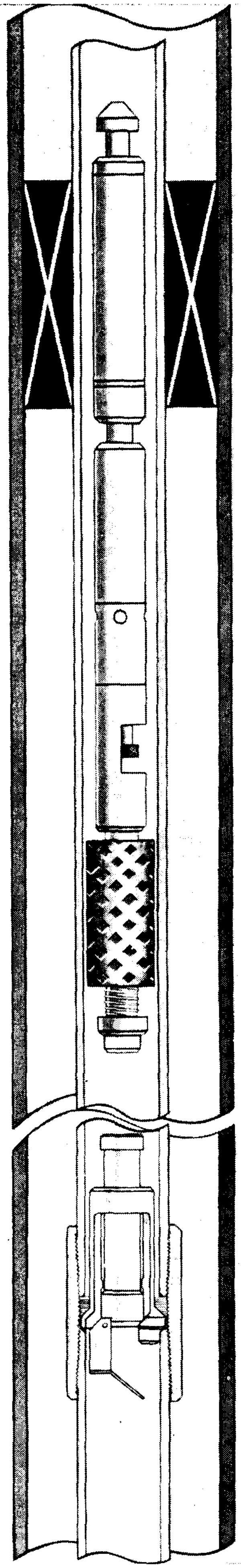

Figure 10 (Slide 10)—Bottom Hole Injector.

Stick Type Treatment

1. Iron Count: 80 to 50 PPM, Avg. 38 PPM.
2. Per Well Cost: $5.68 per treatment.

Batch Treatment From Truck (Down the Tubing):

1. Iron Count: Avg. 42 PPM.
2. Per Well Cost: $7.44 per treatment.

Bottom Hole Injector

1. Iron Count: Avg: 40 PPM.
2. Treat Five Wells, one per week:

A. One lubricator and one injector moved from well to well: $7.68 per well per treatment.

B. Five lubricators and one injector moving only injector from well to well: $6.67 per well per treatment.

Another company using the dump bailer arrived at similar costs in another field, and they feel that they may have a one-year write-off, less chemical at $4.70 per well per treatment; they use an inhibitor priced at $2.00 per quart. This, then, brings the control cost to this well to $6.70, or a comparable figure with the go-devil figure. However, this firm already has lubricators, reels, wire lines and wire line equipment which is not charged to control and which would tend to increase these costs. They also compute the batch-truck treatment using 2 gallons of liquid inhibitor per treatment (once a week) at $20.70 per treatment down the tubing.

Here is an example of what this firm has accomplished in its comparison of corrosion costs to corrosion control costs. This firm has a district with several hundred wells under its management. In early 1952, this firm started treating all of the wells in the district at a total cost to the district of about $4,000.00 per year. At the end of the first year, the firm had reduced its work-over costs (due strictly to corrosion failures) approximately $30,000.00. At the end of the second year, and a slightly increased cost of treatment ($6,000.00) they had reduced work-over costs approximately $60,000.00, and the district was still producing the same number of wells.

Therefore, it would seem that with costs so variable from location to location some types of treatment are acceptable where certain others are not, and further, are not even applicable.

Thus, the comparison of costs become the final test of any treatment. Usually, costs (both of corrosion, and corrosion-contral treatments) are compared when a treatment is on trial. The results are thus more important than the well, or wells, being tested. Tests always require manpower that might otherwise be used on other work. Then, the comparisons should be done by the most reliable process available. This is where dollars are saved through corrosion control.

No corrosion control cost is worth more than the total corrosion cost.

REFERENCES:

Condensate Well Corrosion, 1953 by N.G.A.A. Corrosion Committee.

Corrosion in Oil and Gas Production

EXAMPLE WELL - MARIPOSA FIELD
BROOKS COUNTY, TEXAS

TABLE 1

DEPTH - 8200'
5½" Casing @ 9920'
2 3/8" Tbg. @ 8158'

As of 9-1-55 (Wellhead Pres. - 1793#
(BHT - 220°
(BHP - 2210#

DATE	AV. ppm IRON ***	TREAT-MENT	AMT. CHEM.	DAYS	AMT. DAY	COST	GAS PROD. MMCF	COST OF TRM. PER MMCF	WAT PRO. BBL DAY
2-23-54 to 3-25-55	16*	"A" 188° F.	5 sticks per week @ $1.25 ea.		0.71	$ 6.25 per wk.	18.2 per wk.	$ 0.36	24
3-26-55 to 4-18-55	40	None	None	24			62.3		23
4-19-55 to 5-8-55	21	"B" 180-200° Dist. Sol.	27 sticks @ $1.25 ea.	19	1.42	33.75	53.81	0.63	23
5-9-55 to 5-22-55	14.8	"C" 165-200° Mixture	24 sticks @ $1.25 ea.	13	1.8	30.00	37.19	0.81	22
5-23-55 to 6-24-55	14.4	"C" 165-200°	27 sticks @ $1.25 ea.	33	0.82	33.75	86.39	0.39	21
6-25-55 to 7-23-55	15.5	"D" Liquid	4 quarts @ $2.00 ea.	29	0.14 qt.	8.00	77.63	0.10**	20
7-29-55 to 9-12-55	16.6	"E" 140° F.	40 sticks @ $1.10 ea.	46	0.87	44.00	120.58	0.37	18
9-13-55 to 11-4-55	23.1	"A" 188° F.	40 sticks @ $1.10 ea.	53	0.76	50.00	138.57	0.36	17
11-5-55 to 11-30-55	18.4	"F" 185°-195° Dist. Sol.	23 sticks @ $1.10 ea.	26	0.88	25.30	68.04	0.37	16
Present treatment 12-13-55		"C" 165-200° F. Mixt. Stk.	6 sticks per week @ $1.10 ea.		0.86	6.60 per wk.	18.3 per wk.	0.36	16

Note: Water production was estimated by using a straight line average between two known values.
*These iron analysis were run by "A" representative.
**Price of the bottom hole "Otis Chemical Injection Tool" is $750.00.
***Iron content was determined by using a colormetric comparator method (In Alice office)

Table I (Slide 11)—Comparison costs "Sticks" versus liquid chemical, in Mariposa Field.

A.P.I. Paper No. 926-1-B, 1956, by E. W. Wallace.

Corrosion Control of Gas-Lift Wells A.P.I. Paper No. 906-1-M, 1956, by R. H. Goodnight and J. P. Barrent.

Corrosion Control of Gas-Lift Wells A.P.I. No. 926-1-D, 1956, by Poetker and Stone.

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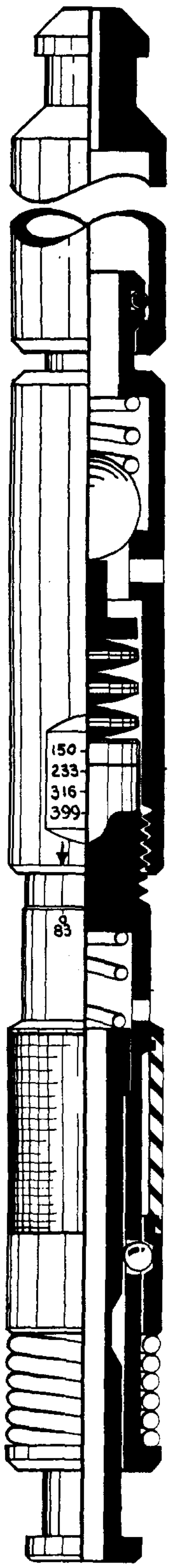

Figure 11 (Slide 12)—Schematic Cross-Section of Injector.

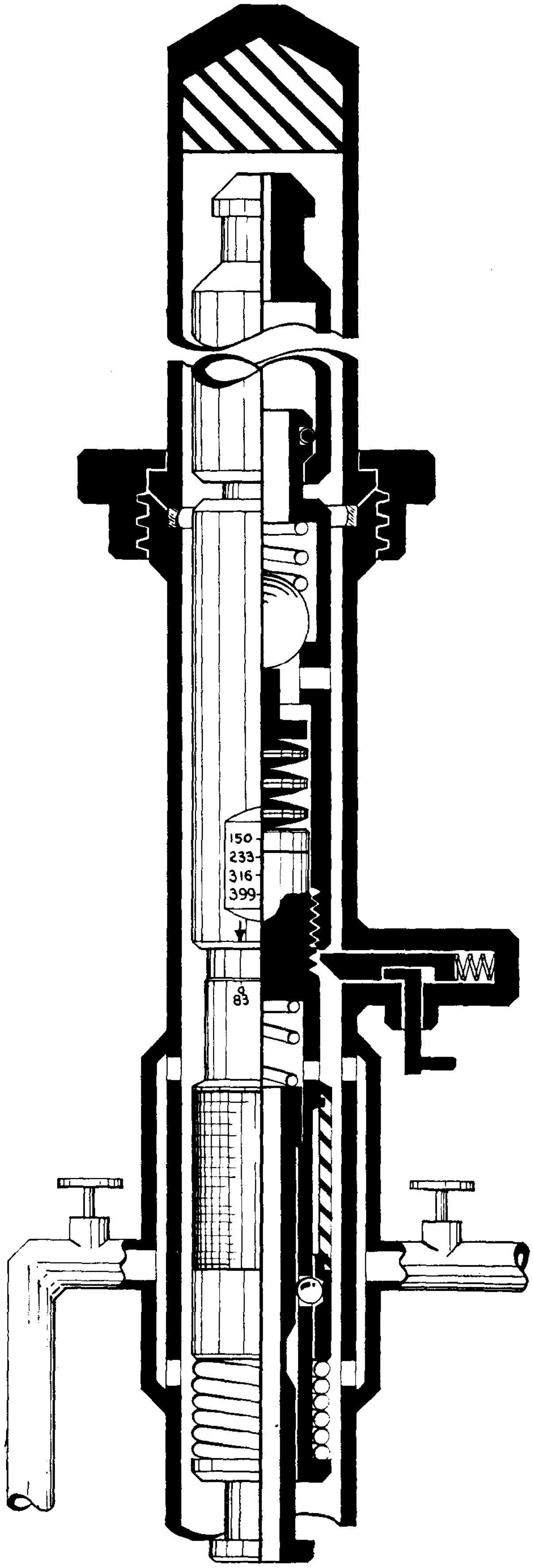

Figure 12 (Slide 13)—Bottom Hole Injector in place in Lubricator (Schematic).