Studying Corrosion Electrochemical Mechanism in Tube Line and Gas Wells

Amir Samimi

Young Researchers club, Central Tehran Branch, Islamic Azad University, Tehran, Iran

(amirsamimi1161@gmail.com)

Abstract- High cost of corrosion is the very most important issue in country corrosion engineering and it is necessary to reduce this cost in petrochemical, gas, oil industry of country. Corrosion in oil and gas well have electrochemical mechanism when this system reach to below dew point, this moisture transform to liquid and there are drops on tube wall. Water has electrolyte role in electrochemical reaction. Water is not corrosion. When acidic gases such as CO_2, H_2S solvent in water it's create acidic space that cause intensive corrosion near steel. Sometimes oxygen in oil well is corrosion gasses but in the gas wells this is not this problem. H_2S gas resources can be sedentary in earth layers, a cillary product of producing gas, oil or bacteria activity.

Keywords- *Corrosion Engineering, Electrochemical Reaction, Tube Wall, H_2S Solvent*

I. INTRODUCTION

High cost of corrosion is the very most important issues in country corrosion engendering and it is nasality to reduce this cost in petrochemical, gas oil industry of country. Now 10% of producing cost is spend at relegated industry corrosion. Corrosion cost rate in the world is 42 to 80 cent for each of crude oil barrel. Corrosion cost in country oil industry is affected by special climate situations country refinery Background and producing kind of crude oil. Cost of corrosion in Iran is 58 cent for each barrel.

II. CORROSION MECHANISM

Oil and gas well divided in 3 categorization

Oil well: is well that its main product is liquid hydrocarbon.

Gas well: is well that its main product is gas hydrocarbon.

Condensate well: is well that exit form it considerable amount of liquid hydrocarbon with allitle gas in high temperature and pressure. Each of this wells divided in to sweat or sour. Sweat well has a little H_2S and sour well has much H_2S. Because there is not explicit border between sweat and sour some of wells dividing in each of kinds. But amount little than 1% (Trace) of H_2S is enough to naming one well as sour well. Other gasses such as Co_2 or Acid acetic or other aliphatic acids with short chains might produce in little or much amount. Present of this gasses and Acids complicated corrosion control problem. Gas and oil wells corrosion have electro chemical mechanism when system reach below dew point this moisture trams form in to liquid and make several drops in tube wall. Water has electrolyte gas in electrochemical reaction. This water is not corrosion. When Acidic gas such as Co_2, H_2S solvent in water, they create acidic environment that has corrosion. Sometimes oxygen is oil well is kind of corrosion gases but there is not oxygen problem in gas wells. H_2O gas source can be sediment in earth layer, Ancillary product of gas and oil production process or Bacteria's activity. H_2S solvent can made HS ions (Biosolfid) and CO_2 can made HCO_3 (Bicarbonate). PH of such system in not below that can make S,CO_3 much of destruction in gas well is due to local corrosion, local corrosion that can create under insulator, sediments or by batteries, can 10 to 100 times faster than monotony corrosion can be destructive. Another kind of local corrosion is due to detects or FILC. Destruction surface form is different in this situation.

FILC detects in CO_2 present is needle form or torn. We can divide corrosion due to CO_2 in gas wells to 3 temperature section:

Below 14^0F (60^0C): corrosion product doesn't protect of surface and there is intensive corrosion.

Above 30^0F (150^0C): they make magnetite and environment has little corrosion until little salt water.

Between 140-1300^{0}F (60-150^{0}C): Carbonate iron product layer has protective role and even we don't need to preventive. But this layer might destruction in present of destructive ions such as Hydrogen solid or color ions or high speed of fluid. This layer in 10m/s high speed and fluid flow is inconstant.

Ikada believed that incomplete grow of ($FeCo_2$) can create one little Anode environment don loop shows that manganese sulfide impurity can destruction carbonate protective layer. Although only corrosion gas in the system is H_2S and is enough in system. One protective layer of Hydrogen sulfide is made in the surface that readily protection of metal surface. But if salt water is contain HCO_3 also. This layer destruct against color ion. Sometimes we Observe iron

chloride below hydrogen sulfide layer that can be a factor for local corrosion.

(FeS_2) pipit product in metal surface is consistence thermodynamic. Cally above 100^0 C. but speed of forming this layer is low in low temperature and increase corrosion. Solvency of sulfide iron layers is depend on environment PH and solve sulfide iron in PH low (below 4) and is not protective. Laboratory studying show that at first corrosion due to hydrogen sulfide has high speed and after that decreases corrosion, usually corrosion is occur in sour wells (contain H_2S gas). That has density lower than 2000 ppm and between 5 to 6/5 PH. If we can consider PH=6.25 as average and we can evaluate different value of these gases we can see that with increasing H_2S gas of 100 ppm to 2000 ppm these speed become 4 times.

III. CORROSION PRODUCTS

We are studying Morphology of corrosion kinds.

A: sulfide hydrogen corrosion that included monitors and cavity corrosion products in each of 2 kinds is black. Surface in cavity corrosion can be smooth, shine or cavity. But products in monotonous corrosion are containing one thin, soft and black layer.

B: cavity corrosion nearby CO_2

In this situation corrosion products can be brown to black that has little cohesion and its cavities are small.

C: corrosion product nearby perch or salt water (PH=6-7).

Level of water PH reaches to 7 in salt water without Acidic gasses. This cause to monotony corrosion that has several little depths and its weight rate is low.

D: corrosion product with 15% HCI and acidic gasses.

Corrosion product in this situation has extended and needle form.

E: friction and corrosion product.

Sometimes corrosion is accompanied with friction in high speed flow. In this situation, corrosion product removed due to friction. And provided ready and clean surface in front of corrosion environment, and decreasing weight rate is very high.

F: corrosion product due to sulfate reduced bacteria.

Corrosion section covers with adhesive and UN penetrable film. In the early stage of corrosion, they create big cavity in steel.

IV. TEMPERATURE

Temperature effect on corrosive flow in gas and oil industries is similar to other chemical environments. Temperature in much of temperature corrosive reactions can lead to increasing corrosive speed, in the way that for each 20^0F (11^0C) increasing temperature, corrosive speed is 2 times. There are 3 kinds of temperature style in steel corrosive nearby CO_2.

1) Carbonate iron below 60^0C is soft and unproductive and corrosive rate is function of CO_2 with little pressure.
2) One layer of carbonate iron is forming in between 60^0C and 150^0C that is unproductive and its rate is reach to one acceptable level.
3) Magnetic layer have above 150^0C that is entirely perfective and is resistance to high speeds and intensive turbulence. And is sensitive only to chloride ion. Although these 3 kinds of style is whiteout considering salt water composition effect, flow speed and proportion of H_2S gas with little gas to CO_2 gas to corrosive rate. These factors should be considered in determining layer protective.

V. PRESSURE

Gas wells high pressure is effective in corrosion gases solvency. Gas pressure can reach to 12000 psi. One important point is little pressure on corrosive gasses. Corrosion amount of one well based on CO_2 gas amount is as below:

CO_2 pressure below psi 7 uncorrosive environment

CO_2 pressure between 7-30 corrosive environments

CO_2 pressure above 30 psi intense corrosive environment

Dewaard & milldams investigating quantity effect of CO_2 gas little pressure and temperature on corrosion rate. Dewaard introduce controller process of corrosive speed as acid carbonic surveying and provide this relationship for corrosion of steel without cover.

Log V = 167 (log PCO_2) +C

In this relationship V is corrosive rate, PCO_2 is CO_2 gas little pressure & C is constant. This equation is applying for early corrosive rate in high pressure of 2 bar CO_2 gas and environment temperature to 60^0C.

VI. FLOW ROLE IN CORROSION

Experiment show usually wells that have corrosion problem that amount of water percent in flow total is much than 85%. But it has some exception. Emulsion amount in well flow effect on conductive and efficiency flow as one flow. As a whole wells that produce much water (without emulsion) have much corrosive than wells with little cut water and much emulsion. National association of corrosive engineering and producer's organization of Natural gas defined 2 kind of corrosive in gas wells.

Water independent corrosion: It is kind of corrosion in sour, sweat, gas & oil that their level water is below 1%. In this kind of well, corrosive is begin with first drops of water.

Water dependent corrosion: This kind of corrosion in gas & oil wells begins when that produces much of salt water. In the wells that have such corrosion, corrosion might not observe several years after production start.

Bergman believes that corrosion in condensate well has the most important problem. In these wells ratio of gas to hydrocarbon is high and have high pressure. Producing high

level of hydrocarbon with a little water can lead to dense Acid in nearby metal surface. This water contains high level of lipid Acids and CO_2. Authors have several studied for determining flow corrosion in one wells. Bradben evaluated 20 different wells and consider water and CO_2 as variable. He found if producing water is much, amount of solvent CO_2 gas in nearby Wales in much and create much corrosion.

Hassle and his college evaluated 45gas well contain CO_2 & H_2S form corrosion rate and water amount. And find this relationship:

Average corrosion Rate (mpy) = $K^G + Q_{H_2o}$

Producing water amount for each BPMMCF and K^G is proportion factor relate to gas produce Rate:

$$\text{Log } K^G = \log C_h + K° log Q_{gas}$$

Q_{gas} : produce gas rate with C_h, $K°$ & MMCF unit are constant that relent to system chemical. This relationship show monotony corrosion and don't apply for local corrosion and unfortunately we saw local corrosion in wells.

Krolet and Bunis have several investigated about local corrosion. They found that each kind of crack, impurity & cavity can change PH and create intensive local corrosion.

Flow speed: Flow speed has mayor role in determining flow style, and flow style is determining corrosion kind and efficiency of each inhibitor.

We should consider 3 temperature divisions for determining speed effect on corrosion without considering flow style. Experiments show that if flow style is same in field and experiment environment, also mechanism and corrosion rate is the same in 2 situations. For corrosion due to CO_2 in low temperature (below 20^0C) in corrosion division depend on CO_2 Hydrolyze speed and is independent of speed. Speed has not major role in corrosion between 20 to 60^0C because is slower process of CO_2 penetrate reaction. But friction speed cans much than 15 m/s in high temperature situation (above 150^0C) than forms magnetic layer. Without harm to corrosion product layer until there are factors such as ion and chlorate.

So if temperature of well above is much that 150^0C and there is not chloride ion, then there is not any corrosion until flow speed is much than 15 m/s but if temperature is below that 150^0C only well entry have corrosion.

But whole of well corrosion if well produce water, Sometimes in this region there is consistent situation that productions layer solvency layer is equal to their production speed. Its cutting tension duce to flow speed can decrease protective productions layer thin. And corrosion rate prediction is impossible in gas wells in $80-150^0C$.

Flow composition: As we noted earlier salt water composition in water is not corrosive and can only destruct carbonate layer & corrosion rate increase. Existence of condensate gasses can prevent of corrosive even some of them are natural inhibitors but cannot avoid of local corrosion.

Met logy: Morphology: and Aliag kind in system affect on amount and kind of corrosion perlits can create corrosion in J-

55 steel, but we observed less local corrosion in Martzini steel such as N-8 & C-75

Ring worm corrosion all served in thermal processing steels. Steels inclined to crash in nearby hydrogen sulfide. This crack is depend on Alliages elements phase structure and their hardness. They predicted one proper guide for selecting steel in sour systems of if 166 NACE standard. Steels have CSS or tension corrosion near H_2S, that Hydrogen on common surface of metal electrolyte is major factor for these cracks. Figures 189 present result foe hardness steels thermal operation in martnezit decrees. Murtniz is major factor in sulfide hydrogen attack and usually thermal operation consistent steel with corrosive environment.

VII. CORROSIVE GASSES

H_2S & CO_2 gasses are corrosive factors in oil & gas wells. These gasses can protect in proper situation. For example hydrogen sulfide in above 100^0C produce stable pipit (FeS_2) that produce metal surface. When these 2 gasses are mixing have complex effects on corrosion. Mr. Danloop believes that in this situation if proportion of CO_2 to H_2S is less than 500, H's form sulfide layer. Husler & Estegman says that in above temperature situation this number become large when CO_2 gas little pressure proportion to H_2s little pressure is above 2000. Hydrogen sulfide cannot destruct carbonate Iron layer.

Corrosion control ways

We can sue of below ways for corrosive control and protect of tubes and gas wells walls.

a. Creating plastic resistance cover inside tube.
b. Use of corrosion resistance Alloys.
c. Use of not metal material.
d. Use of PH fixing.
e. Corrosion inhibitor material injection.

a. Creating plastic resistance cover inside tube is not proper approach for high pressure and temperature because polymer composition has not proper resistance.

b. Use of corrosion resistance Alloys is not cost effective in wide scope and in gas & oil industry only make vital place of this quality.

c. Non – metal material use as composition material currently is common in gas industry and tube lines and fortunately internal company begin use of these tubes. These tubes not only have less weight but also sometimes have hardness and doesn't have earlier tube lines corrosion problem. These tubes are applied in fields that doesn't have earlier tube lines corrosion problem. These tubes are applied in fields that doesn't use of them. Their quality is carbonic steel and we should offer others alternatives.

d. PH fixing way: this method is one of the new ways for corrosion control and is used in 283 phase of southern phase. This ways controlled corrosion with confidence of PH in entire tube is much than certain amount. In this Ph limitedness we have not corrosion. We add one material for PH fixing to MEG

(Monoethilen Glicol) that inhibit of hydrating. This fixer can be MDEA or mineral composition such as carbonate sodium & Hydroxide potassium. All of this material with certain density can increase PH to certain amount. Increasing PH can lead to forming one protective and stable of carbonate Iron or sulfide Iron that can protect tube lines against corrosion.

This method is approved in corrosion engineering international conference NACE and we simply use of it in sweat system when we need gelicol.

But applying this method is mew in sour systems. To TAL FINA ELF in 1998 select PH fixing method for 283 phase Iran southern pars region. 2 line of gas tube with 105 Km (132 inch) in southern pars Gas Organization Sea protect witch this method. These surveys show that corrosion Rate increase with high speed of liquid and cutting tension. So corrosion situation is different in several patterns of flowing. If flowing pattern is consistence with field in laboratory situation corrosion Rate & mechanism is same. When we speak of protective and corrosion we should considered flow pattern kind in multiphase tube lines.

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AMIR SAMIMI (*CORRESPONDING AUTHOR)*

(16/05/1983, Isfahan City, Isfahan Province, Iran)
Studied M.SC Chemical Engineering, Master at Islamic Azad University, The Member of IAENG, Have 2 Years Experience in Oil Refinery Company, Member of Young Research, and Have 14 Articles in the International Journal, Conference (U.S.A, France, Italy, Indonesia, India, Australia, Europe Chemical Engineering Conference) and More than 45 Articles in the National Journal, Conference in Iran