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The 5-M Methodology to Control Internal Corrosion of the Oil and Gas Production Infrastructure

Sankara Papavinasam
CorrMagnet Consulting Inc.
6, Castlemore Street
Ottawa, Ontario, Canada K2G 6K8
Email: spapavin@corrmagnet.com
Phone: 1-613-240-7520

ABSTRACT

The oil and gas industry is striving to reach "zero failures." The overall objective of the 5-M methodology is to help the industry to attain this goal. The 5-M methodology consists of five individual elements: modeling, mitigation, monitoring, maintenance and management.

The primary function of modeling is to predict if a given material is susceptible to a particular type of corrosion in a given environment and to estimate the rate at which the material would corrode in that given environment. Modeling helps the corrosion professionals to establish corrosion allowance (i.e., material wall thickness) and to decide if additional corrosion control strategies are required.

The objective of Step 2 – Mitigation - is to develop a mitigation strategy if Step 1 (modeling) predicts that the internal pitting corrosion rate is high, i.e., that at this pitting corrosion rate the minimum thickness of material used as corrosion allowance is inadequate. Cleaning the pipeline using pigs followed by the addition of corrosion inhibitors is the most common and the most cost-effective method to mitigate internal pitting corrosion of oil transmission pipelines.

The objective of Step 3 - Monitoring - is to ensure that the pipeline is performing in the way the model, (Step 1) predicts and that the mitigation strategy (Step 2) is adequate.

All these strategies would fail if a good maintenance strategy was not developed and implemented. A comprehensive and effective program requires maintenance of five interdependent entities: equipment, workforce, data, communication and associated activities.

Corporate management implements a top-down approach (risk-avoidance, goal-based, financial-oriented) to minimize the risk from corrosion. On the other hand, corrosion professionals estimate risk in a bottom-up approach (field-experience, fact-based, technical-oriented). Corrosion management provides a vital and seamless link between the top-down corporate management approach and the bottom-up corrosion professional approach.

This paper describes the application of the 5-M methodology to control internal corrosion of the oil and gas production infrastructures.

1. INTRODUCTION

Total global energy demand in 2030 is projected to be 50-60% more than current demand; energy from nuclear and renewable sources could increase substantially, but energy from hydrocarbons and coal would nevertheless make up to 80%.[1] The industry has produced 1.063 trillion barrels (bbl) of oil since its inception in the late 1800s. The global demand for oil in 2000 was 76 million bbl/day (31.4 billion bbl/year) [2]. In 2030, global oil demand is estimated to be about 37.6 to 50.4 billion bbl/year. The industry has also produced 3,000 trillion cubic feet (Tcf) [85 trillion cubic meters (Tcm)] of gas. The remaining gas reserve is estimated to be 7,000 Tcf (200 Tcm). The global demand for natural gas in 2000 was 88.7 Tcf (2.51 Tcm) per year. In 2030, the gas demand is estimated to be about 130-212 Tcm per year (3.7-6.0 Tcm per year).

Between the sources of the hydrocarbons and the locations in which they are used as fuels, there is a vast network of oil and gas infrastructure. The comprehensive cost of corrosion of various infrastructures was surveyed in USA. The cost of corrosion in the oil and gas industry from that survey is summarized in Table 1; the annual cost for producing oil and gas from conventional sources reaches $ 1.5 billion in USA only.[3] The global minimum cost may at least be double that based on general estimates of oil and gas production from other countries.[4]

The conventional oil and gas production sectors include drill pipe, casing pipe, downhole tubular, acidizing pipe, water generator, gas generator, wellhead, production pipeline, gas dehydration facility, oil separator, lease tank, and waste water pipeline . The conventional oil and gas production sector may be broadly classified into downhole and surface units.

- The downhole unit consists of drill pipe, casing pipe, downhole tubular, acidizing pipe, water generator, and gas generator.
- The surface unit consists of wellhead, production pipeline, gas dehydration facility, oil separator, lease tank and wastewater pipeline.

Failure in any of these units leads not only to a decrease or stoppage of production, but also may lead to inadvertent negative impact in the corrosion control of downstream sectors including transmission pipelines and refineries. For these reasons, the oil and gas production industry is striving to reach “zero failures. The overall objective of the 5-M methodology is to help the industry to attain this goal. The 5-M methodology consists of five individual elements: modeling, mitigation, monitoring, maintenance and management.

This paper describes the application of the 5-M methodology to control internal corrosion of the conventional oil and gas production infrastructures.

2. THE 5-M METHODOLOGY

2.1. Modeling

The primary function of modeling is to predict if a given material is susceptible to a particular type of corrosion in a given environment and to estimate the rate at which the material would corrode in that given environment. This prediction may be based on laboratory experiments and/or based on field experience. Modeling helps the corrosion professionals to establish corrosion allowance (i.e., material wall thickness) and to decide if additional corrosion control strategies are required.

One significant contributing factor in the degradation of pipelines in the conventional oil and gas production is internal pitting corrosion. Therefore, enormous efforts are directed to controlling internal pitting corrosion. To predict internal pitting corrosion accurately, two parameters are needed:

- Identification of locations susceptible to corrosion
- Localized pitting corrosion rates in those locations.

The flow in almost all units of oil and gas production sector is multiphase (i.e., oil, water, gas and solids). To predict the locations of water accumulation in multiphase flow the knowledge of flow regimes is required. The types of flow regimes are presented in Table 2 and their characteristics are available elsewhere.[5] The flow regime is determined from the pipe diameter, orientation, and flow rates and from the fluid properties,. The use of a computer software program facilitates the determination of the flow regime.

The pitting corrosion rate depends on water, oil, gas, solid, temperature, pressure, H_2S, CO_2, sulphate, bicarbonate and chloride. Table 3 presents equations to predict the influence of these parameters. The values of these parameters are assumed to be constant for the entire length of the pipeline except for pressure and temperature. The variation of pressure and temperature over the length of the pipeline is determined based on the initial values at the upstream end of the pipeline.

Each one of the operational parameters in Table 3 can individually alter the pitting corrosion rates as predicted by their equations. The ultimate rate at which the pits will propagate depends on the combined effect of all of the operational parameters. Whereas the individual effect of each of the parameters can be predicted deterministically, predicting the combined effect of these variables needs the application of statistical principles because the driving force for the pitting corrosion is a "distributed parameter."

It is assumed that each operational variable produces an individual pit growth rate (resulting in 11 different pitting corrosion rates, Table 3). Using the eleven calculated pitting corrosion rates, the mean initial pitting corrosion rate, PCR_{mean}, is calculated using Eqn. 1:

$$PCR_{mean} = \frac{\sum PCR}{11} \tag{1}$$

Where $\sum PCR$ = (sum of the 11 pitting corrosion rates)

The average pitting corrosion rate, $PCR_{(average)}$, over multiple years is calculated using Eqn. 2:

$$PCR_{(average)} = \frac{\frac{PCR_{mean}}{1} + \frac{PCR_{mean}}{2} + \frac{PCR_{mean}}{3} + ... + \frac{PCR_{mean}}{t}}{T} \tag{2}$$

Where "T" is the total number of years between the start date and current date and t is the number of years.

Pits will not continue to grow at a constant rate for various reasons including reformation of the surface layers, local solution saturation, change of corrosion potential and local increase of pH. As a result, the pit growth rate diminishes parabolically as a function of time. If the production conditions are constant over the years, the average pitting corrosion rate is calculated using Eqn. 2. If the production conditions change for a particular year, the value of "T" is set to unity for that year and the "T" values for subsequent years increase as per Eqn. 2. Table 4 provides the boundary conditions to determine if the production conditions change or not.

The $PCR_{average}$ predicted using Eqn. 2 is influenced by several other factors and hence its values are modified as follows:

- In addition to influencing the type of flow, the flow regimes also change the corrosion rate. Table 5 provides the correction factors to account for flow regime on corrosion rate. These correlations were based on an analysis of several field production data.[5]
- The influence of microbiologically influenced corrosion (MIC) is accounted for using Eqn. 3:

$$PCR_{MIC} = PCR \times \left(\frac{MIC\_Risk\_Score}{50}\right) \tag{3}$$

Where *PCR* is the corrosion rate adjusted for flow regime as per Table 5, and *MIC_Risk_Score* is the MIC factor, calculated using Table 6.

Using this integrated model, locations in oil and gas production sectors that are susceptible to internal pitting corrosion and the resulting pitting corrosion rates in those locations can be predicted. However, before this integrated model can be used extensively, its validity should be evaluated using actual field data.

2.2. Mitigation

The objective of Step 2 – Mitigation - is to develop a mitigation strategy if Step 1 (modeling) predicts that the internal pitting corrosion rate is high, i.e., that at this pitting corrosion rate the minimum thickness of material used as corrosion allowance is inadequate.

Cleaning the pipeline using pigs followed by addition of corrosion inhibitors is the most common and the most cost-effective method to mitigate internal pitting corrosion of oil transmission pipelines.

Recently several standards have been developed to evaluate corrosion inhibitors:

- ASTM G202, "Standard Test Method for Using Atmospheric Pressure Rotating Cage"
- ASTM G184, "Standard Practice for Evaluating and Qualifying Oil Field and Refinery Inhibitors Using Rotating Cage"
- ASTM G185, "Standard Practice for Evaluating and Qualifying Oil Field and Refinery Inhibitors Using Rotating Cylinder Electrode"
- ASTM G208, "Standard Practice for Evaluating and Qualifying Oil Field and Refinery Inhibitors Using Jet Impingement Apparatus"

Using these standards, most appropriate corrosion inhibitors can be selected. An appropriate inhibitor for a particular application should not only have higher inhibitory efficiency but also have other suitable properties. These properties are known as secondary corrosion inhibitor properties. They include water/oil partitioning, solubility, emulsification tendency, foam tendency, thermal stability, toxicity and compatibility with other additives and materials. ASTM G170, "Standard Guide for Evaluating and Qualifying Oil Field and Refinery Corrosion Inhibitors in the Laboratory" provides methodologies to evaluate these secondary inhibitor properties.

Experience indicates that an integrated program with both batch and continuous treatments ensures successful application and maintenance of an inhibitor film. Thus for best protection, the inhibitor application is carried out in three steps:

1. Batch treatment at a higher concentration of inhibitor over a short time span to establish initial inhibitor film on the surface
2. Continuous application at medium concentration to ensure integrity of the inhibitor film on the surface
3. Continuous application at a lower concentration to maintain the inhibitor film on the surface.

Whatever may be the inhibitor application methodology, it is important that the inhibitor is available 100% of the time. If the inhibitor is not available 100% of the time, the corrosion rate fluctuates between the uninhibited and inhibited corrosion rate.

For practical reasons, the inhibitor need not be available 100% of the time because of the persistency of corrosion inhibitor, i.e., the duration for which the inhibitor film is present on the surface without damage. If the events that make inhibitors unavailable can be corrected within the duration of the film persistency of corrosion inhibitors, they can be considered as non-events. For example, if the inhibitor persistency is 10 hours, and if a failed inhibitor injection pump is repaired and back on service within 10 hours, such an event is considered as insignificant.

2.3. Monitoring

The objective of Step 3 - Monitoring - is to ensure that the pipeline is performing in the way the model (Step 1) predicts and that the mitigation strategy (Step 2) is adequate.

Corrosion monitoring may occur in three stages:

- In the laboratory at the design stage to evaluate the suitability of a given material in the anticipated environment. (This activity is normally carried out in the "modeling" step).
- In the field during operation the oil transmission pipeline in monitored to determine the actual corrosion rate and to optimize pigging frequency, corrosion inhibitor dosage and inhibitor application frequency.
- In the field during operation the oil transmission pipeline is inspected to ensure that the material is continued to be safe under the field operating environment, i.e., to ensure that the corrosion allowance thickness has not been exceeded.

NACE Standard report 3T199, "Techniques for Monitoring Corrosion and Related Parameters in Field Applications" describes more than 40 different internal corrosion monitoring techniques. A recent survey provides feedback on various monitoring techniques currently being used in the oil transmission pipelines.[8]

2.4. Maintenance

All strategies (selection of appropriate materials that can withstand corrosion in a given environment, development of appropriate models to predict the behavior of the system, implementation of mitigation strategies to control corrosion and monitoring of system to ensure that the corrosion of the system is under control) would fail if a good maintenance strategy was not developed and implemented. A comprehensive and effective program requires maintenance of five interdependent entities:

- Equipment
- Workforce
- Data
- Communication, and
- Associated activities.

2.5. Management

Corporate management implements a top-down approach (risk-avoidance, goal-based and financial-oriented) to minimize the risk from corrosion. On the other hand, corrosion professionals estimate risk in a bottom-up approach (field-experience, fact-based and technical-oriented). Corrosion management provides a vital and seamless link between the top-down corporate management approach and the bottom-up corrosion professional approach. In a way, the corrosion management is a combination of art and science to balance financial and technical requirements.

Corrosion management is thus a systematic, proactive, continuous, ongoing, technically sound and financially viable process of ensuring that the people, infrastructure and environment are safe from corrosion. The activities of corrosion management include:

- Evaluation and quantification of corrosion risks during design, construction, operation, shutdown and abandonment stages, and identification of factors causing, influencing and accelerating these corrosion risks.
- Establishment and implementation of organizational structure, resources, responsibilities, best practices, procedures and processes to mitigate and monitor corrosion risks.
- Maintenance and dissemination of corporate strategy, regulatory requirements, finance, information affecting corrosion and records of corrosion control activities.
- Review the success of implementation of corrosion control strategies and identify opportunities for further correction and improvement.

3. IMPLEMENTATION OF 5-M METHODOLOGY TO CONTROL INTERNAL CORROSION

All 5 elements must be implemented to control internal corrosion of oil transmission pipelines effectively. In order to facilitate the implementation of the 5-M methodology a 100-point scoring system has been developed.

Ideally, the risk from internal corrosion becomes zero when the score reaches 100. Practically, depending on the status of the oil transmission pipelines, one or two elements may be avoided, i.e., the risk from internal corrosion is kept low even when the score does not reach 100.

As illustrated in Table 7, for infrastructure A implementation of three of the five elements is sufficient to reduce the risk from internal corrosion to a low level. On the other hand, for infrastructure B, implementation of three of the five elements may not be sufficient to reduce the risk from internal corrosion. By adequately implementing additional elements, the risk of infrastructure B can be reduced.

4. SUMMARY

- It is important to keep the risk due to internal corrosion of upstream oil and gas production sector at a low level so that production does not stop/reduce and failures in the upstream sectors do not cause cascading effects downstream in transmission and refinery sectors; the 5-M methodology has been developed to achieve both these objectives.
- The five elements of the 5-M methodology are: modeling, mitigation, monitoring, maintenance, and management.
- A scoring system has also been developed to effectively and economically implement the 5-M methodology and to choose appropriate cost-effective solutions to reduce internal corrosion risk.

5. REFERENCES

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6. TABLES

Table 1: Annual Corrosion Cost in Major Sectors of USA Oil and Gas Industry[1]

Sector	**Annual Cost of Corrosion in US (Million US Dollars million)**
Production*	1,372
Transmission- pipeline	6,973
Transportation-Tanker**	2,734
Storage	7,000
Refining	3,692
Distribution	5,000

*The amount is only for production from conventional sources (corrosion cost for production from non-conventional and renewal sources is not included); **World total

Table 2: Two-Phase and Three-Phase Flow Regimes

Pipe Orientation (ϴ is the inclination angle)	**Flow Regime**
Horizontal Pipe	
$ϴ = 0^o$	• Dispersed Flow; Bubble Flow; Slug Flow; Stratified Flow; Wave Flow; and Annular Flow
Vertical Pipe	
Pipes with inclination angle $ϴ > 10^o$ are assumed to be vertical pipes when the flow is downward	• Annular Mist and Annular Flow (Assumed to be annular flow); Oscillatory Flow; Slug Flow; and Bubble Flow (Assumed to be slug flow)
Pipes with inclination angle $ϴ > 45^o$ (Assumed as vertical pipe - upward flow)	• Annular Flow; Wispy Annular Flow (Assumed to be annular Flow); Churn flow; Plug Flow; and Bubble Flow
Inclined Pipe	
$0^o < ϴ \leq 10^o$ Flow = "down"	• Dispersed Flow; Stratified Flow; Slug Flow; and Annular Flow
$0^o < ϴ \leq 10^o$ Flow = "up"	• Dispersed Flow; Bubble Flow; Slug Flow; Wave Flow; and Annular Flow
$10^o < ϴ \leq 45^o$ Flow = "up"	• Bubble Flow; Slug Flow; Stratified Flow; and Annular and Annular Mist Flow (Assumed to be annular flow)

Table 3: Summary of Carbon Steel Pitting Corrosion Rate Equations

Operational Parameter	Pitting Corrosion Rate Equation
Production rate of oil	$PCR_{oil} = -0.33\theta + 55$
Production rate of water	$PCR_{water} = 0.51\%W + 12.13$ ($\%W$ is water cut)
Production rate of gas	$PCR_{gas} = 0.19W_{ss} + 64$ (W_{ss} is wall shear stress)
Production rate of solid	$PCR_{solid} = 50 + 25R_{solid}$
Temperature	$PCR_{temp.} = 0.57T + 20$
Pressure	$PCR_{pressure} = -0.081P + 88$
Partial pressure of H_2S	$PCR_{H2S.} = -0.54p_{H2S} + 67$
Partial pressure of CO_2	$PCR_{CO2.} = -0.63p_{CO2} + 74$
Concentration of sulphate ion	$PCR_{sulphate} = -0.013C_{sulphate} + 57$
Concentration of bicarbonate ion	$PCR_{bicarbonat.} = -0.014C_{bicarbonat} + 81$
Concentration of chloride ion	$PCR_{chloride} = -0.0007C_{chloride} + 9.2$

Table 4: Boundaries to Determine if the Production Conditions Change or Not

Parameter	**Boundaries**
Temperature (^oC)	$X \leq 25$
	$25 < X \leq 50$
	$X > 50$
Pressure (psi)	$X \leq 100$
	$100 < X \leq 500$
	$X > 500$
H_2S (psi)	$X \leq 2.5$
	$2.5 < X \leq 10$
	$10 < X \leq 50$
	$X > 50$
CO_2 (psi)	$X \leq 2.5$
	$2.5 < X \leq 10$
	$10 < X \leq 30$
	$30 < X \leq 100$
	$X > 100$
SO_4^{2-} (ppm)	$X \leq 750$
	$750 < X \leq 1000$
	$1000 < X \leq 1500$
	$1500 < X \leq 2500$
	$X > 2500$
HCO_3^- (ppm)	$X \leq 500$
	$500 < X \leq 1000$
	$1000 < X \leq 2000$
	$2000 < X \leq 4000$
	$X > 4000$
Cl^- (ppm)	$X \leq 10000$
	$10\,000 < X \leq 20\,000$
	$20\,000 < X \leq 40\,000$
	$40\,000 < X \leq 60\,000$
	$60\,000 < X \leq 80\,000$
	$80\,000 < X \leq 100\,000$
	$100\,000 < X \leq 120\,000$
	$X > 120\,000$

Table 5: Variation of Carbon Steel Pitting Corrosion Rate as a Function of Flow Regimes

Flow Regime Type	**$PCR_{Average}$ Modification**
Slug Flow	No Change
Plug Flow	$PCR_{Average\ x\ 0..98}$
Bubble Flow	$PCR_{Average\ x\ 0.96}$
Dispersed Flow	$PCR_{Average\ x\ 0.94}$
Oscillatory Flow	$PCR_{Average\ x\ 0.92}$
Annular Flow	$PCR_{Average\ x\ 0.90}$
Churn Flow	$PCR_{Average\ x\ 0.88}$
Wave Flow	$PCR_{Average\ x\ 0.86}$
Stratified Flow	$PCR_{Average\ x\ 0.84}$

Table 6: Risk Scores for Carbon Steel MIC

Influence of	Range of Parameter	Unit	MIC Risk Score
Temperature	Less than -10	^oC	0
	-10 – 15		1
	15 – 45		7– 10
	45 – 70		7 – 4
	70 – 120		4 – 1
	Above 120		0
Pressure	Greater than 20	pCO_2/pH_2S	10
	Less than 20		2
Flow rate	Above 3	m/s	1
	2 – 3		2 – 12
	1 – 2		12 – 18
	0 – 1		18 – 20
pH	Less than 1		0
	1 - 4		5
	4 – 9		10
	9 – 14		1
	Above 14		0
Langelier Saturation Index (LSI)	Less than -6		10
	-6 – -1		10 – 5
	-1 – 1		0
	1 – 8		1 – 8
	Greater than 8		8
Total Suspended Solids (TSS)	Present		10
	Present		0
	Absent		0
Total Dissolved Solids (TDS)	Less than 15,000	Ppm	1
	15,000 – 150,000		1 – 10
	Greater than 150,000		10
Redox potential (Eh)	Less than -15	Mv	1
	-15 – +150		1 – 10
	Greater than 150		10
Sulphur content	Present		10
	Absent		1

*The sum of all the MIC risks is 100. Note that when determining the MIC risk for an item with a range of values, the MIC risk scales in linear proportion.

Table 7: Illustration for implementing 5-M methodology to control in internal corrosion

5-M element	**Oil production flow line (A)**		**Oil production flow line (B)**	
	Conditions	**5-M score**	**Conditions**	**5-M score**
Model	• Water cut less 15% • Water-in-oil emulsion* • Oil-wet* • Inhibitory oil* *As per ASTM G205	20/20	• Water cut 35% BS&W • Oil-in-water emulsion* • Wettability of oil not known • Inhibitory nature of oil not known *As per ASTM G205	15/20
Mitigation	Not implemented	0/20	• Continues inhibitor treatment	20/20
Monitoring	Not implemented	0/20		0/20
Maintenance	• Equipment properly serviced as per established practice • Data routinely analysed	20/20		0/20
Management	• Activities for internal corrosion control strategies implemented • The corrosion control strategies periodically reviewed and corrections, if necessary, are implemented	20/20	• Activities for internal corrosion control strategies implemented	15/20
Corrosion risk	• Low	60/100	• Likely high	50/100