STEM-Corrosion™

Paper Number: 2015-05

Analysis and Evaluation of 50 Key Performance Indicators from Colombian Transmission Pipelines

Érika Natalia Remolina Galvis, M.Sc.
Chemical Engineer and Master in Material's Engineering
Universidad Industrial de Santander
Colombia, Santander
Email: erikanatalia99@hotmail.com

ABSTRACT

In order to implement an effective corrosion control in oil and gas transmission pipelines in Colombia, 50 KPIs were evaluated. The KPIs will provide a clear and organized way to access information pertaining to corrosion control. This analysis has shown that the KPIs on materials and operational conditions are well established and implemented; KPIs on mitigation, monitoring, maintenance, and management are not fully established and implemented.

1. INTRODUCTION

Colombia has approximately 5,592 miles of oil pipelines and 2,346 miles of gas pipelines. They vary in diameter between 4 and 36 inches. These lines may be above-ground or underground. Underground pipelines are buried between 3 and 6 feet deep[1,2].

Colombia has a variety of topography with elevation profiles, and climate in the different regions. Variety of soil, topographical and climate change in Colombia creates corrosive environments in both the internal and external surface of the pipelines.

Several "re-launching" or reinforcement" stations are present along the pipeline to transport of oil from the production centers to the terminal stations. The pipelines are monitored in the reinforcement stations and along the pipeline to safety and efficiency to transport oil through pipelines[2,3]. In spite of all precautions incidents and accidents due to corrosion, natural forces (landslides caused by rains) and third party damage are experienced.

2. CONTEXT OF CORROSION CONTROL

The transmission pipelines mostly are located in environments far away from urban areas and 80% of the pipelines are underground. However higher percentage of the pipelines are in areas near water resources. Therefore any failure of them could cause serious damage to the environment.

The material used for the construction of most transmission pipelines in Colombia is AISI 1020 carbon steel. AISI 1020 carbon steel has good resistance to corrosion. The wall thickness is chosen to provide a lifetime of approximately 15 years. Over the period corrosion risk of carbon steel increases. The main cause in Colombian transmission pipelines is internal corrosion due to the combination of CO_2, variation in the operating pressure and temperature, and microorganism. The external surface of the pipelines are protected with coatings and cathodic protection. The pipelines traverse through several environments and soil that have vastly different physical and chemical properties. The pipelines are subjected to localized external corrosion when the coatings fail and when the cathodic protection does not adequately protect the locations where coatings have failed.

No system is in place to segment transmission pipelines to manage corrosion. However, injection points for corrosion inhibitor injection to control internal corrosion and coatings and CP to control external corrosion are installed. Further close interval survey (CIS) and direct current voltage drop (DCVG) survey are routinely carried out. But other internal corrosion monitoring techniques (coupons, sampling and inline inspection (ILI) are installed due lack of access ports and problems due to third party interaction (e.g., theft of hydrocarbons).

3. INTERNAL CORROSION

3.1 Model

The thickness of 1020 carbon steel is suitably adjusted to include corrosion allowance. The corrosion allowance is established based on corrosivity of fluids, operating temperature and pressure, and use of corrosion inhibitors. The corrosion inhibitors used are generally amine base compounds.

Consistent establishment of an integrity management program that performs failure analysis and trains the operators the consequences of their action (or inaction) in reducing corrosion related will be valuable. However, such an integrity management program in which feedback on the performance of the pipelines to the operator is not established. Further, it is observed that corrosion professionals often do not follow-up the implementation of corrosion control strategies, e.g., corrosion professionals lack information on the installation of accessories and corrosion probes to monitor corrosion.

Individual stations/facilities have established main corrosion mechanisms that would affect their stations and facilities based on simulations and their own experiences. Recently, the companies have undertaken a study to identify a commercial model that can predict internal corrosion based on their operating conditions. However the information collected by the field operators are not relevant to predict internal corrosion or to use internal corrosion model. Further no database and reliable data that can be used to understand long-term trend is available.

3.2 Mitigation

In Colombia, at the design stage adequate attention is not paid to select and implement corrosion mitigation strategies. Mitigation strategies can be implemented in some cases after the operation. Most mitigation strategies to control internal corrosion involve application of corrosion inhibitors. In a few transmission pipelines methanol is injected to mitigate corrosion.

The inhibitors are mostly amine-based and their concentration varies depending on the type of fluid and concentration of corrosive agents. The criteria for application of corrosion inhibitors are established based on "trial and error" method. The corrosion inhibitor concentration is maintained so that a constant minimal corrosion is established in the field and the possibility of premature failure does not occur.

Inline inspections are not performed due to the high cost of implementation. In some pipelines inline inspection is performed approximately every 10 years. In some cases, information on the effectiveness of corrosion inhibitors is deduced from monthly-physicochemical measurements and use of corrosion coupons.

3.3 Monitoring

Several intrusive and non-intrusive techniques are available to monitor internal corrosion. However, due to the problems of theft and due to hard terrains in Colombia, it is difficult to access the pipelines frequently and to obtain important information from all critical points. Further, lack of organization structure does not allow the systematic collection and analysis of monitoring data.

4. EXTERNAL CORROSION

4.1 Model

Unlike internal corrosion, the external corrosion issues are not seriously considered in the design stage. This is partly because all underground infrastructures are fully protected by coatings and cathodic protection.

Currently, the industry is creating a model for predicting external corrosion. The process involves collection of variables affecting external corrosion and modeling the corrosion rate in an iteration process. However, high diversity of soil types and climates in Colombia, collection of reliable information is a quite expensive and complicated work.

4.2 Mitigation

All underground transmission pipelines are adequately protected with coatings and cathodic protection. However, testing the coatings under the aggressive Colombian soil conditions is not performed. This is mainly because of the cost of testing and lack of knowledge on the importance of laboratory testing and evaluation.

4.3 Monitoring

Close interval survey (CIS) and direct current voltage drop (DCVG) survey are annually carried out by qualified personnel. The frequency of survey may change depending on the condition of the pipeline. Furthermore, collection of soil samples is performed annually. However, as in the case of internal corrosion due to rough terrains and elevation profile in Colombian, it is not possible to monitor all areas of the pipelines.

5. MEASUREMENT

Unfortunately, in Colombia no proper procedures have been established to measure, collect, and store data. For this reason, measured data available in the companies are ambiguous.

6. MAINTENANCE

Normally, transmission pipelines operate under conditions developed in the design. The design has also established appropriate safety margin. During operating stage the transmission pipelines are annually cleaned using by pigs. Some high risk pipelines are cleaned every 6 months. For external corrosion, the cathodic protection systems are inspected monthly to ensure that they are in good conditions to apply adequate current to protect the external surface. Furthermore, the coatings are monitored every two years (or more frequently depending on the results of previous inspection).

Corrective actions are taken when the pipelines are in poor conditions or when the operating conditions change. However due to logistics issues implementation of corrective actions take long time. Currently new environmental laws are being implemented in Colombia. Consequently many maintenance activities are increasingly being streamlined. Also a system is being implemented to systematically inspect and monitor the pipelines and organise the data so that they can be easily accessible.

In Colombia the average years of experience of technical workers is between 3 years and 5 years. But, the oil and gas industry has never implemented a plan in which new personnel can learn from experienced person. Further, the political situation in Colombia is quite critical that resulted in the workforce losing more than 4,000 qualified persons.

7. MANAGEMENT

In case of any incident or accident, informational, educational, corrective and preventive actions are taken by an organisation called CLOPAD (CLOPAD – Comité Local para la Prevención y Atención de Desastres, i.e., local committee for prevention and disaster relief). This organisation is also responsible for informing neighbouring community and industry of incidence or accidence in the oil and gas industry.

8. SUMMARY OF STATUS OF KPIs AND STATUS OF INFRASTRUCTURE

Figure 1 presents summary of typical implementation of 50 KPIs in transmission pipelines in Colombia[4]. Table 1 describes the status of implementation in detail. In general corrosion control practices in Colombia is fair. Areas for improvement are:

- Life of pipeline exceeding design life (KPI 5)
- Insufficient probes for monitoring internal corrosion (KPI 25)
- Lack of measurement data (KPI 35)
- Lack of workforce capacity, education, and training (KPI 43)

Further, improvements in planning and implementation of corrosion control strategies, a more organized method to collect and storage data, and implementation of training plans will further improve the success of corrosion control practices in Colombia

9. REFERENCES

1. INDUSTRIA Y COMERCIO SUPERINTENDENCIA: “La promoción de la competencia en el acceso a oleoductos”, Bogotá, Colombia [En línea]. Disponible en: http://www.sic.gov.co/drupal/sites/default/files/files/Estudio%20Transporte%20por%20oleoducto.pdf
2. UNIDAD DE PLANEACIÓN MINERO ENERGÉTICA: “La cadena del gas natural en Colombia”, Bogotá, Colombia [En línea]. Disponible en: http://www.upme.gov.co/Docs/Chain_Gas_Natural.pdf
3. PROCOLOMOBIA: “Oportunidades de inversión”, Bogotá, Colombia [En línea]. Disponible en: http://www.inviertaencolombia.com.co/acerca-de-proexport/36-sectores/servicios/bienes-y-servicios-petroleros/413-oportunidades-de-inversion.html
4. SANKARA PAPAVINASAM, 2014: “Corrosion control in the oil and gas industry”, Elsevier Inc.

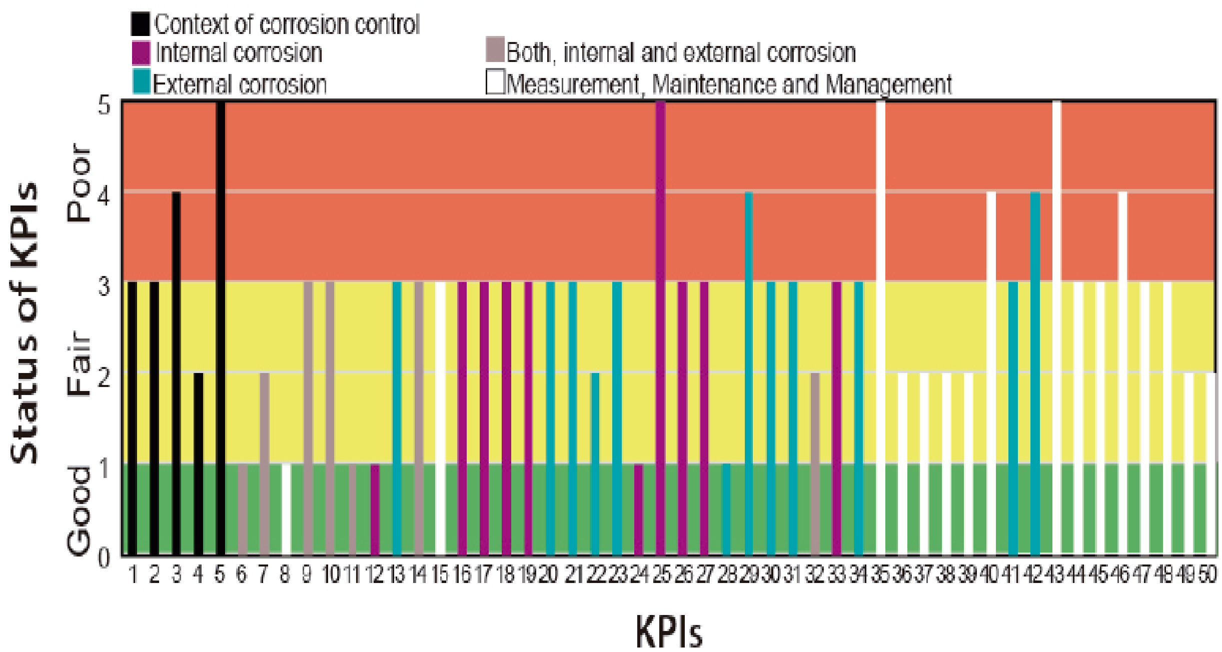

Fig. 1: Summary of Status of KPIs in Transmission Pipelines in Colombia

Table 1: Summary of Status of KPIs in Colombian Transmission Pipelines

KPI No.	KPI description	Status of KPI	Description of Status
1	Segmentation of the infrastructure	3	Segment area varies
2	Corrosion risks	3	For secondary corrosion risk
3	Location of the infrastructure	4	Consequence of failure is high
4	Overall corrosion risk (Risk times consequence)	2	Overall risk from corrosion is relatively medium - mitigation is relatively medium - mitigation and monitoring strategy should be considered to reduce the risk
5	Life of the infrastructure	5	Life is more than 10 years
6	Materials of construction	1	Material selected based on corrosion consideration
7	Corrosion allowance (wall thickness)	2	Corrosion allowance more than mitigated corrosion rate times anticipated life
8	Main operating conditions	1	Operating conditions within the range established for the entire duration of the project
9	Potential upset conditions in the upstream sector affecting this sector	3	Potential influence of upset conditions upstream understood and communication plan established with upstream team to obtain information in case if there is an upset
10	Potential upset conditions in this sector affecting downstream sector	3	Potential influence of upset conditions in the sector on downstream operation is understood and communication plan established with downstream team to provide information in case if there is an upset
11	Mechanisms of corrosion	1	All corrosion mechanisms are considered and most prominent ones determined
12	Maximum corrosion rate (Internal)	1	Maximum corrosion rate is based on model, laboratory experiment, simulation, or documented similar field experience
13	Maximum corrosion rate (External)	3	No basis for the selection of maximum corrosion rate
14	Installation of proper accessories during construction	3	Corrosion professional involved during the construction but unable to ensure that accessories are installed properly due to construction schedule

15	Commissioning	3	Infrastructure is properly hydrotested and the water used in the hydrotest is properly removed, but baseline conditions are not established
16	Mitigation to control internal corrosion	3	Yes. Based on the analysis performed at the conceptual and design stages
17	Mitigation strategies to control internal corrosion	3	Mitigation strategy is standardized by trial and error method under the operating conditions and is proven to be effective
18	Mitigated internal corrosion rate, target	3	No basis for the selection of maximum corrosion rate
19	Percentage time efficiency of internal corrosion mitigation strategy	3	Mitigation practices are implemented 95 to 99% of time
20	Mitigation to control external corrosion – is it necessary?	3	Yes. Based on the analysis performed at the conceptual and design stages
21	Mitigation strategies to control external corrosion	3	Mitigation strategy is standardized by trial and error method under the operating conditions and is proven to be effective
22	Mitigated external corrosion rate, target	2	No basis for the selection of maximum corrosion rate
23	Percentage time efficiency of external corrosion mitigation strategy	3	Mitigation practices are implemented 95 to 99% of time
24	Internal corrosion monitoring techniques	1	Two or more complimentary techniques that are proven to be effective in monitoring the corrosion type occurring in the segment are used
25	Number of probes per square area to monitor internal corrosion	5	Number of working probes not enough to cover all critical areas
26	Internal corrosion rate, from monitoring technique	3	The corrosion rate from two or more different types of monitoring probes agree with one another within 11 to 25 %
27	Percentage difference between targeted mitigated internal corrosion rate and corrosion rate from monitoring technique	3	The corrosion rate from two or more different types of monitoring probes agree with one another within 11 to 25 % and they agree with mitigated corrosion rate within 25%
28	External corrosion monitoring techniques	1	Two or more complimentary techniques that are proven to be effective in monitoring the corrosion type occurring in the segment are used
29	Number of probes per square area to monitor external corrosion	4	Number of working probes not enough to cover all critical areas
30	External corrosion rate, from monitoring technique	3	The corrosion rate from two or more different types of monitoring probes agree with one another within 11 to 25 %
31	Percentage difference between targeted mitigated external corrosion rate and corrosion rate from monitoring technique	3	The corrosion rate from two or more different types of monitoring probes agree with one another within 11 to 25 % and they agree with mitigated corrosion rate within 25%
32	Frequency of inspection	2	Frequency established based on some engineering process, but the process followed to make the decision is not clear and is not documented
33	Percentage difference between targeted mitigated internal corrosion rate or corrosion rate from monitoring techniques and corrosion rate from inspection technique	3	The corrosion rate from inspection technique and from the monitoring probes (or mitigated corrosion rate) agree with one another within 11 to 25%
34	Percentage difference between targeted mitigated external corrosion rate or corrosion rate	3	The corrosion rate from inspection technique and from the monitoring probes (or mitigated corrosion rate) agree with one another within 11 to 25%

	from monitoring techniques and corrosion rate from inspection technique		
35	Measurement data availability	5	Not all measurement data required for deciding corrosion conditions of the segment are available
36	Validity and utilisation of measured data	2	The measured data is utilised without any validation process and the measured data is properly integrated to establish the corrosion rate
37	Procedures for establishing the maintenance schedule	2	When the risk moves from ALARP to high risk stage, i.e., when conditions indicate that failure is imminent if the maintenance is not executed
38	Maintenance activities	2	The work is generally carried out as per planned maintenance activities planned but not per schedule due some delay in the coordination of various team deliverables
39	Internal corrosion rate, after maintenance activities	2	Corrosion rate after the maintenance activities is same as that before maintenance activities
40	Percentage difference between targeted mitigated internal corrosion rate or corrosion rate from monitoring or inspection technique (whichever is decided in activity 27) and corrosion rate before maintenance activities.	4	Corrosion rate before the maintenance activities is higher by more than 10% than the corrosion rate established in activity 27 indicating the maintenance activity should have been carried out earlier.
41	External corrosion rate, after maintenance activities	3	Corrosion rate after the maintenance activities is same as that before maintenance activities
42	Percentage difference between targeted mitigated external corrosion rate or corrosion rate from monitoring or inspection technique and corrosion rate before maintenance activities.	4	Corrosion rate before the maintenance activities is higher by more than 10% than the corrosion rate established in activity 27 indicating the maintenance activity should have been carried out earlier.
43	Workforce - Capacity, education, and training	3	The number of workers is not enough to ensure quality of work - the workers feel over worked; the educational and training requirements of the workers are not known
44	Workforce - Experience, knowledge, and quality	3	Key personnel have at least five years of experience and knowledge in similar work and others are gaining experience and knowledge under these key personnel and such arrangement is formally implemented
45	Data management - Data to database	3	Data from different activities, measurements are manually and systematically transferred to the database with human intervention and coordination central to data transfer
46	Data management - Data from database	4	Data transfer from the database is not well established or no data management practice exists
47	Internal communication strategy	3	Internal communication strategy between only some entities is established, and communication with others is only on adhoc basis
48	External communication strategy	3	External communication strategy and communication person(s) with only some entities is established, communication with others is only on adhoc basis
49	Corrosion management review	2	The corrosion control activities are reviewed between every 2 to 5 years
50	Failure frequency	2	Less than 5 failures due to corrosion but none in high consequence area