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COMPARISON OF CORROSION ASSESSMENT METHODOLOGIES OF DRY NATURAL GAS PIPELINES

Dharma Abayarathna
4427 Pine Landing Drive
Missouri City, Texas 77459

ABSTRACT

Steel pipelines that transport natural gas are subjected to a variety of threats including external and internal corrosion. Pipeline owners and operators implement policies and procedures for control and mitigation of corrosion. Furthermore, in the US, interstate and intrastate pipelines are subjected to federal and/or state regulations for safe transportation of gas. The law dictates the minimum requirements for an integrity management program that includes integrity assessments on any gas transmission pipeline. NACE Standard Practices SP0206-2006 (Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)) and SP0502-2010 (Pipeline External Corrosion Direct Assessment Methodology (ECDA)) are procedures developed by NACE to evaluate the threat of internal and external corrosion, respectively. Application of these two guidelines satisfy the assessment of the integrity of pipelines for minimum safety required by law.

The 5-M methodology developed originally in Canada is a process that assesses the status and then implement strategies to improve internal and external corrosion control of an asset based on key performance indicators established. This paper compares the internal and external corrosion threat assessments of a dry gas pipeline based on NACE DG-ICDA and ECDA with that based on 5-M methodology.

INTRODUCTION

Steel pipelines and piping systems provide the safest means of gathering, transporting, and distributing natural gas, crude oil, and petroleum products in oil and gas industry. However, pipelines are subject to a variety of threats that can lead to leaks or catastrophic ruptures. Pipeline failures can result in unexpected disruptions to operations, fires or explosions, property and environmental damage, costly repairs, personal injuries and sometimes fatalities.

External and internal corrosion are two major threats to pipelines. Pipeline owners and operators follow guidelines and standards during the design, construction, and operation of pipelines for prevention and mitigation of corrosion. These guidelines include industry best practices as well as mandates by regulatory authorities. In the US, the Code of Federal Regulation, 49 CFR 192[1] prescribes the minimum safety requirements for the operation of pipeline facilities and the transportation of gas. Subpart O of Part 192 details minimum requirements for an integrity management program on any gas transmission pipeline. Regulatory requirements include the baseline and continued assessment of the integrity of pipelines in high consequence areas (HCAs) at prescribed time intervals. Acceptable assessment methodologies include use of internal inspection tools, pressure testing or direct assessments.

NACE Standard Practices SP0206-2006 (Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)) and SP0502-2010 (Pipeline External Corrosion Direct Assessment Methodology (ECDA))[2,3] provide guidelines to evaluate the threat of internal and external corrosion, respectively. Not only these assessments satisfy minimum safety required by law but they also reduce the impact of internal and external corrosion on pipeline integrity and hence improve the safe operation of pipelines.

The 5-M methodology[4-6] originally developed in Canada requires establishment of key performance indicators (KPIs) to evaluate and then to implement strategies to improve and maintain internal and external corrosion control of an asset. This paper compares the internal and external corrosion threat assessments of a dry gas pipeline based on NACE DG-ICDA and ECDA with that based on 5-M methodology.

NACE DG-ICDA

NACE DG-ICDA is an internal corrosion assessment methodology applicable to pipelines carrying normally dry gas. DG-ICDA is a structured four step process that is designed to assess the presence of internal corrosion in a dry gas pipeline and to ensure pipeline integrity. The four steps include pre-assessment, indirect Inspection, detailed examination and post assessment.

Pre-Assessment

The pre-assessment step includes collection and evaluation of several data elements to determine whether DG-ICDA is feasible on a given pipeline. The data required include pipeline physical information, and current and historical data including operating and maintenance history as well as prior integrity evaluations and inspection reports over the life of the pipe. The collected data are integrated and analyzed thoroughly in order to determine the feasibility of applying DG-ICDA process and then to define DG-ICDA regions. The following conditions must be satisfied for the applicability of DG-ICDA:

1. The pipeline does not normally contain any corrosive electrolytes.
2. The pipeline has always been used for natural gas service.
3. The pipeline is not routinely inhibited (with chemical agents or glycols).
4. The pipeline does not have an internal coating that provides corrosion protection.
5. The pipeline does not have a history of top of the pipeline internal corrosion.
6. The pipeline does not have a history of pig (maintenance or other) runs.
7. The pipeline does not have any known accumulation of solids, sludge, biofilm/biomass or scale.

Indirect Inspection

The indirect inspection of DG-ICDA process involves performing pipeline flow modeling calculations and identifying locations most likely to have internal corrosion by integrating the results with the pipeline elevation profile within each defined DG-ICDA region.

The flow modeling calculations can be completed using any valid approach applicable to the given system. A simplified flow modeling approach is provided in the DG-ICDA which is bound by pipe size (0.1 m < OD <1.2 m) and operating pressure (P < 7.6 MPa). Integration of pipeline flow modeling results with the pipeline elevation profile provides the locations most likely to accumulate water that leads to internal corrosion.

Detailed Examination

The detailed examination step determines if internal corrosion exists at locations identified as most likely to accumulate water in the indirect inspection step. During the detailed examination, the locations that are most susceptible to internal corrosion are excavated, inspected and wall thickness data are collected to assess the overall condition of the ICDA region. Although corrosion monitoring and mitigation are not included in the DG-ICDA, it is recommended to install corrosion monitoring devices at excavation sites that are most likely to suffer internal corrosion. This would aid pipeline operators to monitor their system as well as determine inspection intervals.

Post Assessment

The post assessment step assesses the overall effectiveness of the DG-ICDA process by correlating corrosion found at excavations with the predicted liquid accumulation locations. This step also includes the determination of re-assessment intervals based on corrosion growth rate at a selected site on the pipe itself, corrosion monitoring data at a predicted liquid accumulation site, corrosion rate model prediction using accurate operating data or laboratory developed data under simulated field conditions.

The procedures used, data collected and decisions made during all four steps of the DG-ICDA must be documented in a final post assessment report, retained with the DG-ICDA records and kept for the life of pipeline. The report needs include corrosion monitoring records, planned mitigation activities and feedback for continuous improvement also.

NACE ECDA

NACE ECDA is an external corrosion assessment methodology applicable to buried onshore pipelines made out of ferrous materials. ECDA is a structured four step process that is designed to assess and reduce the impact of external corrosion to improve safe operation of a pipeline. The four steps include pre-assessment, indirect Inspection, direct examination and post assessment.

Pre-Assessment

The pre-assessment step includes review and evaluation of a multitude of data elements to determine whether ECDA is feasible on a given pipeline, identification of ECDA regions and selection of indirect inspection tools. The data from five categories listed below are required for this step including pipeline data, operating and maintenance history, corrosion survey records, aboveground inspections records as well as prior integrity evaluations and inspection reports over the life of the pipe.

1. Pipe related
2. Construction related
3. Soils/environment related
4. Corrosion control and
5. Operational data

The collected are integrated and analyzed to verify the applicability of ECDA process and the indirect inspection tools. ECDA regions are then identified based on pipe and soil characteristics, past and expected future corrosion conditions and the use of indirect inspection tools.

Indirect Inspection

The indirect inspection step identifies the most severe coating faults, other anomalies and areas at which corrosion may have occurred or may be occurring. This step includes conducting indirect inspections using at least two complementary aboveground indirect inspection tools over the entire length of each ECDA region.

Direct Examination

ECDA direct examination step includes analysis of indirect inspection data to prioritize indications based on severity and to select excavation sites. The selected sites are then excavated, inspected for external coating condition and data are collected from the pipe and the environment to assess corrosion activity. At sites where defects are found, remaining strength is evaluated and repairs are done as necessary. Determination of root causes and implementation of mitigation activities are also required for found defects. A process evaluation is conducted to assess the indirect inspection and direct examination data.

Post Assessment

The objectives of the post assessment step is to assess the overall effectiveness of the ECDA process and to define reassessment intervals. The post assessment activities include remaining life and reassessment interval calculations based on corrosion growth rate of found corrosion, reclassification and reprioritization process, assessment of ECDA effectiveness and feedback.

The data collected, procedures used and results obtained during all activities of each ECDA step must be documented, retained with the ECDA records and kept for life of pipeline including feedback for continuous improvement.

5-M METHODOLOGY

The 5-M methodology is designed to evaluate and implement strategies to control internal and external corrosion in oil and gas production infrastructures. The 5-M methodology consists of five individual elements, namely modeling, mitigation, monitoring, maintenance and management. These five elements are associated with 50 KPIs that are developed based on industry surveys and failure analysis. The KPIs established for control of internal and external corrosion are listed in Tables 1 and 2 respectively. These KPIs are associated with (1) modeling the system to evaluate corrosion threat, (2) implementation of mitigation strategies to control corrosion and (3) monitoring the system to ensure success of corrosion control. However, in order to succeed with the corrosion control program, sound maintenance and management programs must be developed and implemented. KPIs established for maintenance and management programs are provided in Tables 3 and 4 respectively. It should be noted that KPIs 6, 7, 9, 10, 11, 14, and 32 are common for both internal corrosion and external corrosion.

Table 1
KPIs Established for Internal Corrosion Control

5-M Element	KPI Number	KPI Description
Model	6	Materials of construction
	7	Corrosion allowance (wall thickness)
	9	Potential upset conditions in the upstream sector affecting this sector
	10	Potential upset conditions in this sector affecting downstream sector
	11	Mechanisms of corrosion
	12	Maximum corrosion rate (Internal)
	14	Installation of proper accessories during construction
	39	Internal corrosion rate, after maintenance activities
	40	Percentage difference between targeted and mitigated internal corrosion rate
Mitigation	16	Mitigation to control internal corrosion – is it necessary?
	17	Mitigation strategies to control internal corrosion
	18	Mitigated internal corrosion rate, target
	19	Percentage time efficiency of internal corrosion mitigation strategy
Monitoring	24	Internal corrosion monitoring techniques
	25	Number of probes per square area to monitor internal corrosion
	26	Internal corrosion rate, from monitoring technique
	27	Percentage difference between targeted mitigated internal corrosion rate and corrosion rate from monitoring technique
	32	Frequency of inspection
	33	Percentage difference between targeted mitigated internal corrosion rate or corrosion rate from monitoring techniques and corrosion rate from inspection technique
Measurement	35	Measurement data availability
(Subset of monitoring)	36	Validity and utilization of measured data

Table 2
KPIs Established for External Corrosion Control

5-M Element	KPI Number	KPI Description
Model	6	Materials of construction
	7	Corrosion allowance (wall thickness)
	9	Potential upset conditions in the upstream sector affecting this sector
	10	Potential upset conditions in this sector affecting downstream sector
	11	Mechanisms of corrosion
	13	Maximum corrosion rate (External)
	14	Installation of proper accessories during construction
	41	External corrosion rate, after 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
Mitigation	20	Mitigation to control external corrosion – is it necessary?
	21	Mitigation strategies to control external corrosion
	22	Mitigated external corrosion rate, target
	23	Percentage time efficiency of external corrosion mitigation strategy
Monitoring	28	External corrosion monitoring techniques
	29	Number of probes per square area to monitor external corrosion
	30	External corrosion rate, from monitoring technique
	31	Percentage difference between targeted mitigated external corrosion rate and corrosion rate from monitoring technique
	32	Frequency of inspection
	34	Percentage difference between targeted mitigated external corrosion rate or corrosion rate from monitoring techniques and corrosion rate from inspection technique
Measurement	35	Measurement data availability
(Subset of monitoring)	36	Validity and utilization of measured data

Table 3
KPIs Established for Maintenance Program

5-M Element	KPI Number	KPI Description
Maintenance	8	Main operating conditions
	15	Commissioning
	37	Procedures for establishing the maintenance schedule
	38	Maintenance activities
	43	Workforce - Capacity, education, and training
	44	Workforce - Experience, knowledge, and quality
	45	Data management - Data to database
	46	Data management - Data from database

Table 4
KPIs Established for Management Program

5-M Element	KPI Number	KPI Description
Management	1	Segmentation of the infrastructure
	2	Corrosion risks
	3	Location of the infrastructure
	4	Overall corrosion risk (Risk times consequence)
	5	Life of the infrastructure
	47	Internal communication strategy
	48	External communication strategy
	49	Corrosion management review
	50	Failure frequency

The 5-M methodology assesses the status of internal and external corrosion control programs of a given oil and gas production infrastructure including dry gas pipelines by evaluating and ranking above mentioned 50 KPIs. The ranking includes a score between 0 and 5 for each KPI that is accounted toward pipeline corrosivity and corrosion control, and an associated color as detailed in Table 5. The final result shows the status of the corrosion control programs in place. An example of final result is shown in Figure 1. Based on these results, actions can be taken to improve and maintain internal and external corrosion control of the system.

Table 5
Ranking of KPIs

KPI Status	Ranking Score	Ranking Color
Not-relevant	0	Blue (N/A)
Accounted for adequately	1	Green (good)
Accounted for inadequately	2 to 3	Yellow (fair)
Not adequately accounted for	4 to 5	Red (poor)
Not analyzed	5	White

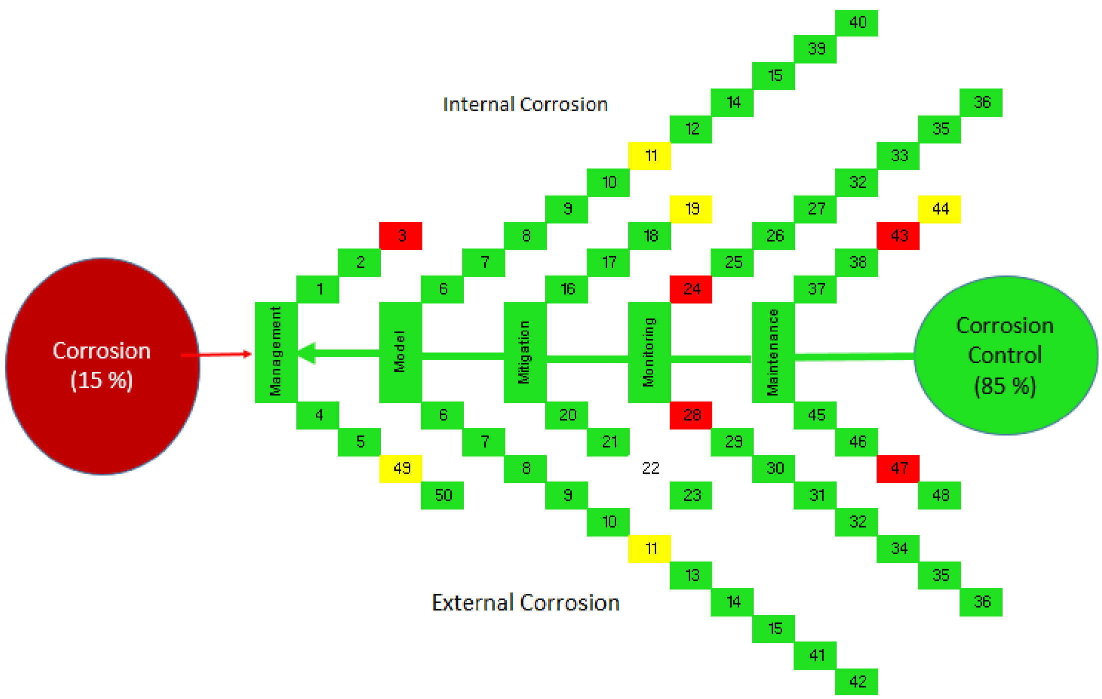

Figure 1 – An Example of Display used in the 5-M Methodology to Display the status of corrosion control program

DISCUSSION

DG-ICDA and 5-M Methodology

Some of the data collected and reviewed during the DG-ICDA pre-assessment are same as some KPIs identified to evaluate internal corrosion threat under 5-M methodology (see Table 6). These KPIs belong to model, maintenance and management elements. Since 5-M methodology evaluates status of corrosion control, it considers additional KPIs which are not considered in DG-ICDA .

Table 6
Data for DG-ICDA Pre-assessment and KPIs of 5-M Methodology

DG-ICDA Pre-assessment Data	KPIs of 5-M Methodology
Pipe data (WT, year)	7 (Model), 5 (Management)
Upsets	9, 10 (Model)
Operating history	8, 15 (Maintenance)
Maintenance data	38 (Maintenance)
HCAs	3 (Management)
Failures	50 (Management)
Region identification	1 (Management)

During the DG-ICDA detailed examination step, recommendations are provided to install corrosion monitoring devices at excavation sites to aid pipeline operators to monitor their system and to determine inspection intervals. These recommendations are similar to the KPIs 24, 26 and 32 under monitoring and measurement that are used to evaluate and enhance the effectiveness of a corrosion control program. Since 5-M methodology is a corrosion control program, other KPIs are included under mitigation and monitoring (18, 19, 25, 27 and 33) to improve corrosion control.

The post assessment activities, record keeping and use of assessment data in future assessments, are similar to data management KPIs 45 and 46 (maintenance). The planned mitigation activities are related to KPIs 16 and 17. The feedback corresponds to KPIs 47 and 49 (management).

Since DG-ICDA is a methodology for the assessment of internal corrosion, it does not directly address following KPIs established for internal corrosion control:

1. 6, 11, 12, 14, 39 and 40 under model (some flow modeling may support KPIs 11 and 12)
2. 18, 19, 25, 27, 33, 35 and 36 under mitigation and monitoring related to corrosion control program improvements (though detailed examination data supports KPIs 33 and 35)
3. 37, 43 and 44 under maintenance (though detailed examination data supports 37)
4. 2, 4 and 48 related to corrosion risk and external communication under management

ECDA and 5-M Methodology

Some of the ECDA pre-assessment data collected are similar to some KPIs established for the evaluation of external corrosion threat under 5-M methodology as presented in Table 7. These KPIs belong to model, mitigation, maintenance and management elements. There are no KPIs corresponding to “soil/environment related” data. Standard practice of controlling external corrosion on pipelines is by application of coatings and cathodic protection (CP). Typically, a specified CP level is applied and maintained for regulatory compliance and/or per company policy. The maintained CP level does not provide an actual corrosion rate although it reveals compliance status with regulations and company policy. Therefore, KPIs 28 – 34 under corrosion monitoring and measuring are not directly associated with the ECDA pre-assessment.

Table 7
ECDA Pre-assessment and KPIs of 5-M Methodology

ECDA Pre-assessment Data	KPIs of 5-M Methodology
Pipe related (material, WT)	6, 7 (Model)
Construction related (route, year)	3, 5 (Management)
Soils/environment related	
Corrosion control (CP)	14 (Model); 20, 21 (Mitigation); 38 (Maintenance)
Operational data (Op data, failures)	8 (Maintenance); 50 (Management)
Region identification	1 (Management)
Indirect inspection activities	31, 34 (Monitoring)

The KPIs that are similar to ECDA direct examination and post assessment steps are provided in Table 8. Since 5-M methodology is a corrosion control program, other KPIs are included under mitigation and monitoring (22, 23, 28 - 31, 41 and 42) to improve corrosion control.

Table 8
ECDA and KPIs of 5-M Methodology

ECDA	KPIs of 5-M Methodology
Corrosion rate	34 (Monitoring)
Record keeping	45, 46 (Maintenance)
Reassessment interval	32 (Monitoring)
Mitigation	20, 21 (Mitigation); 38 (Maintenance)
Feedback	47, 49 (Management)

ECDA methodology does not directly address following KPIs established for external corrosion control:

1. 9, 10, 11, 13, 41 and 42 under model (though direct examination data may confirm the predicted mechanism (11))
2. 22, 23, 28 – 31 and 34 - 36 under mitigation and monitoring related to corrosion control program improvements (though direct examination data supports KPIs 34 and 35)
3. 15, 37, 43 and 44 under maintenance (Though direct examination data supports 37)

4. 2, 4 and 48 related to corrosion risk and external communication under management

CONCLUSIONS

1. DG-ICDA and ECDA are processes that are designed to assess the presence of internal and external corrosion, respectively and to ensure integrity of pipelines whereas 5-M methodology is designed to evaluate and implement strategies to control internal and external corrosion.
2. Some of the data collected analyzed during pre-assessment of DG-ICDA and ECDA are same as some KPIs established in 5-M methodology, i.e., DA and 5-M Methodology processes are not mutually exclusive.
3. There are no activities in DG-ICDA and ECDA steps similar to KPIs established for corrosion control.
4. The results of DG-ICDA and ECDA assessments can be used in 5-M methodology to improve corrosion control. Some established KPIs provide pre-assessment data for ECDA and DG-ICDA.

REFERENCES

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