Paper No.
ICP32

17-20 September 2017
Mumbai, India

Inspection, Monitoring, Model: Past, Present, Future

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ABSTRACT

The title of the paper denotes two attributes:

Attribute #1: "Inspection" reveals "past" events, i.e., inspection technologies determine the corrosion rate "after" corrosion had caused loss of material
"Monitoring" reveals "Present" situation, i.e., monitoring techniques determine the corrosion rate at the time of monitoring
"Model" predicts the "future" situation, i.e., modeling predicts the "futuristic" corrosion rate based on system operating conditions.

Attribute #2: The paper discusses "past" developments, "present" status, and "future" advancements of inspection, monitoring, and modelling technologies.

The main objective of the paper is on Attribute #2.

- In the past, the number of internal corrosion related incidences was more than 3 per 1,000 kilometers (KMs) of pipelines per year

In the present, the number of internal corrosion related incidences hovers around 0.5 per 1,000 KMs of pipelines per year

In the future, the industry's goal is to bring the number of incidences to "ZERO".
This paper explains "effective" and "economical" actions that are required to achieve the "ZERO" incidence goal.

Keywords: 5-M methodology, Corrosion control, corrosion management, integrity management, asset integrity management, pipeline integrity management, inspection, monitoring, model

INTRODUCTION

Between the sources of the hydrocarbons and the locations of their use as fuels, there is a vast network of oil and gas industry infrastructures. The oil and gas industry includes production, transmission, storage, refining, and distribution sectors. Failure in any units of these sectors not only disrupts its operation but also negatively impacts the operation of units in the upstream and downstream sectors[1].

Therefore, an appropriate corrosion management best practices should be developed and implemented. The central and core activity of the corrosion management is the determination of corrosion rates. This paper reviews the past and current practices of determining corrosion rates; and explains how corrosion rates will be determined (or will need to be determined) in the future.

For the purpose of discussion, this paper uses internal corrosion control experience of Canadian conventional oil and gas production sector (Fig. 1)[2] and defines 3-time frames as:

Past: Before Year 2000; during this time frame, the number of internal corrosion incidences were above 3 per 1,000 kilometers (KMs) of pipeline per year

Present: Between 2000 and 2020; during this time frame, the number of internal corrosion incidences hovers around 0.5 per 1,000 KMs of pipeline per year

Future: The target with which the industry is comfortable with is "zero incidence".

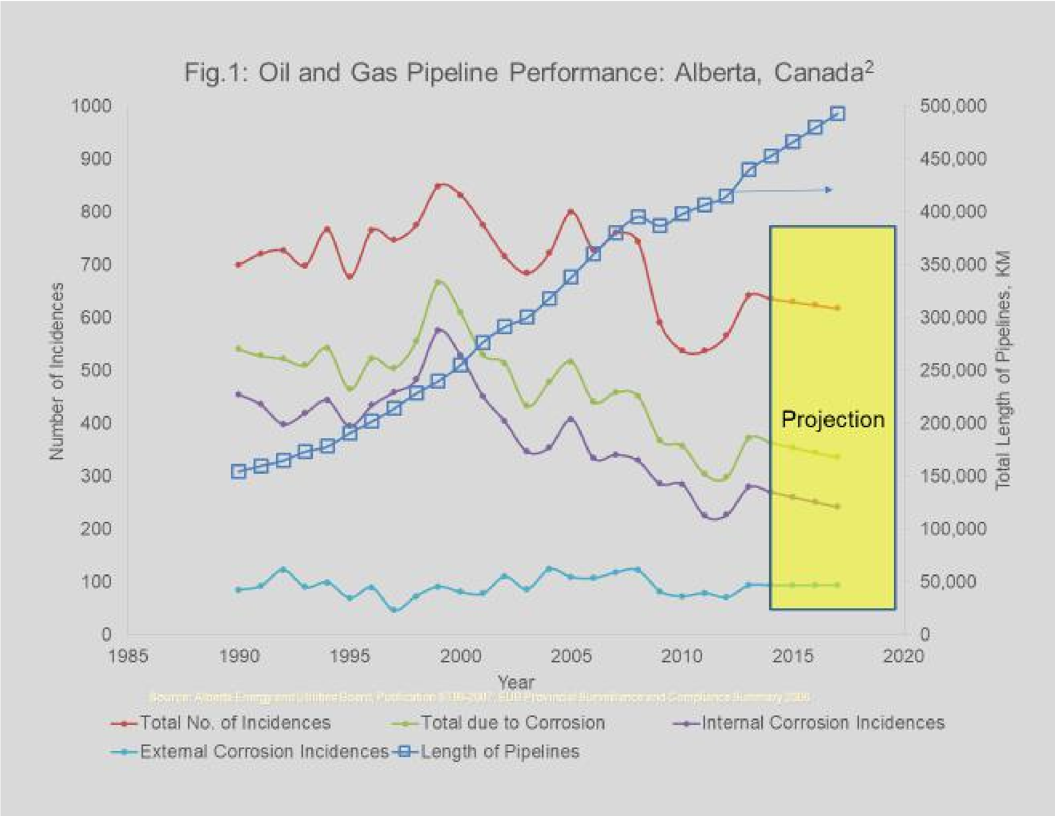


Fig.1: Oil and Gas Pipeline Performance: Alberta, Canada[2]

PAST (BEFORE YEAR 2000)

The oil and gas industry began its journey in North America from Petrolia, Southern Ontario, Canada (Near the famous Niagara falls!) in 1858 (Fig. 2). The industry flourished in Canada from 1930s with the discovery of several oil and gas fields in Western Canada (especially in the province of Alberta). Currently, the Canadian oil and gas production sector operates more than 500,000 kms of pipelines (Fig. 3) and the oil and gas transmission sector operates more than 60,000 kms of pipelines.

Fig. 2: Photo of the location (Petrolia, Southern Ontario, Canada) in which Oil was first produced in 1858.

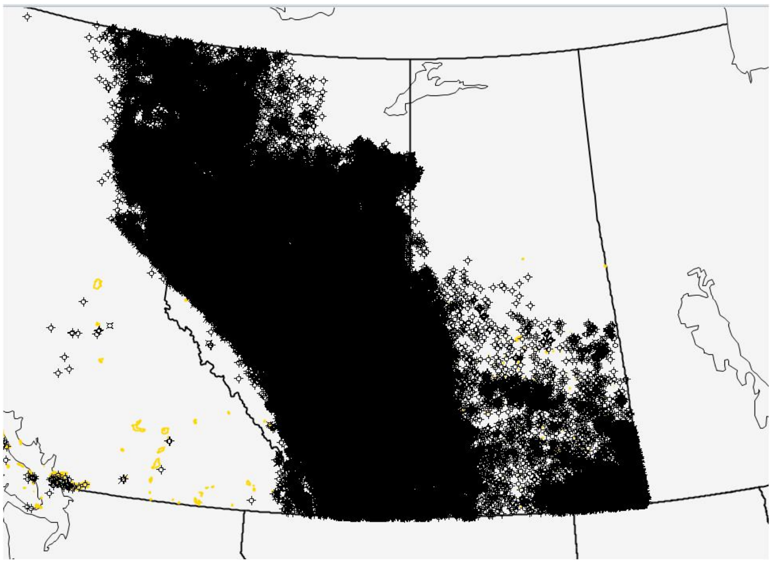


Fig. 3: Oil and Gas Producing Wells in Western Canada of Area ~ 660,000 KMs (Each black dot represents at least one production well)[3].

During this period, the industry experienced and overcame several integrity issues – among which internal corrosion was the leading cause (Fig. 3)[2]. More than 50% of failures had occurred due to internal corrosion.

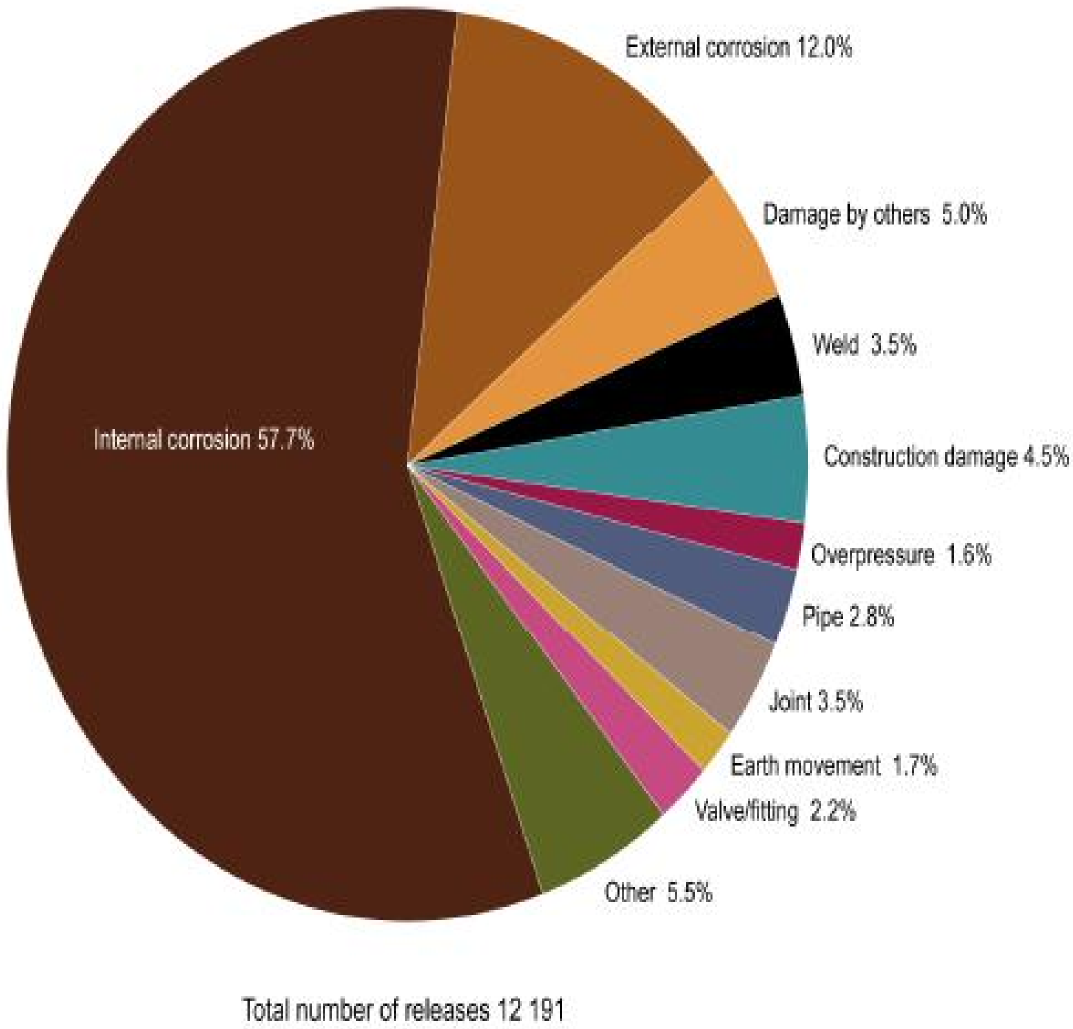


Fig.3: Causes of Incidences in Western Canadian Convention Oil and Gas Production[2].

During this period, to control internal corrosion several advancements were made and some were implemented in the industry; Table 1 summarizes the most significant technologies developed and implemented to control internal corrosion.

During this period, the industry depended mostly on field operators experience and monitoring techniques to determine corrosion rates. Commonly used monitoring techniques include mass loss coupon; electrical probe; handheld, non-intrusive ultrasonic measurement; and, in a limited way, inline inspection. In its quest to implement "innovation", the industry also voluntarily introduced some technologies described in Table 1, mostly on "trial and error" basis.

During this period, failures leading to release of oil and gas to the environment were considered as normal "nuisance" occurrences. Failures mostly occurred in remote locations – away from general public. The industry repaired the locations in which failures had occurred and moved on to produce more oil and gas!

Table 1: Significant Advancements in Determining Corrosion Rates until 2000

Year	Significant Advancement
1905	Tafel Equation - Relationship between "potential" and "current" (corrosion rate)[a]
1919	Butler-Volmer Equation - Relationship between "potential" and "current" [a]
1929	Evans Diagram – Relationship between "potential" and "current" (corrosion rate)[a]
1938	Wagnet and Traud (Mixed Potential Theory) - Development of the concept of local anodes and local cathodes[a]
1942	Hickling - Introduction of the term "Potentiostat"[a]
1942	Introduction of cleaning pigs[b]
1950	Pourbaix - Development of the potential and pH Diagram[a]
1957	Stern and Geary – Relationship between polarization resistance and general corrosion rate[a]
1960	Epelboin - Development of electrochemical impedance spectroscopy (EIS)[a]
1964	Introduction of pig based on magnetic flux leakage (MFL) technology to inspect the pipeline[b]
1968	Iverson - Observation of potential fluctuations (first observation of electrochemical noise)[a]
1986	Introduction of ultrasonic pig for inspecting liquid pipelines[b]
1990	First publication of ASTM Standard Guide G96, "Online Monitoring of Corrosion in Plant Equipment (Electrical and Electrochemical Methods)"
1998	NACE Publication 35100, "In-Line Nondestructive Inspection of Pipelines"
1999	First publication of NACE 3T199, "Techniques for Monitoring Corrosion and Related Parameters in Field Applications"
2000	NACE SP0102, "In-Line Inspection of Pipelines"

[a]These developments enabled "instantaneous" measurement of corrosion rates using electrochemical techniques both in the laboratory and in the field.

[b] These developments enabled "inspection" of pipeline to determine remaining wall.

PRESENT (2000 – 2020)

During this period, oil and gas industry, especially production and transmission pipelines started sharing their right-of-way with other industries including railways, bridges, electrical transmission towers, and general public infrastructures. For these reasons, public awareness of the existence of oil and gas infrastructures has increased. Consequently, they undergo tremendous public and regulatory scrutiny.

This period signifies the public, environmental group, and regulatory attention turning on the oil and gas industry. To address their concerns and to control internal corrosion effectively and economically the industry has developed and implemented several strategies (Table 2); among them the introduction of 5-M Methodology and Internal Corrosion Direct Assessment (ICDA) are very significant. Table 3 compares steps/processes in various strategies to control internal corrosion.

5-M Methodology

The 5-M methodology[4, 5] was developed and implemented based on several brain-storming sessions and based on practical experience by "field operators", and it consists of five individual elements: model, mitigation, monitoring, maintenance and management.

Complete description of the 5-M methodology is presented elsewhere[1] and only salient features are described in the following sections.

Model

The primary function of modeling is to predict the types of corrosion (corrosion damage mechanism (CDM)) a given material will suffer from in a given environment and to estimate the rate at which the material would corrode in that given environment. Models also help to identify locations where corrosion may take place; to predict the CDM, and to predict anticipated corrosion rate considering all CDMs. Model thus helps the corrosion professionals to establish material of construction, corrosion allowance (i.e., material wall thickness to account of loss due to corrosion), and to decide if corrosion mitigation strategies are required.

Mitigation

Mitigation strategies are implemented if model predicts that the corrosion rate would be high, i.e., at the corrosion rate anticipated under operating conditions, the minimum thickness of material used as corrosion allowance is inadequate. Time tested and proven methodologies to control internal corrosion include cleaning (pigs), corrosion inhibitors, and internal liners. Corrosion rates measured by monitoring techniques are often used to ensure the mitigation strategies are working properly.

Monitoring

Monitoring helps to understand the current condition of the infrastructure. Corrosion monitoring may occur in three stages:

- At the design stage, to anticipate the corrosion rate of the material in the anticipated environment, i.e., model corrosion rate.
- In the field, during operation, to determine the actual corrosion rate, i.e., field monitoring.
- In the field, during operation, to ensure that the wall lost has not exceeded corrosion allowance, i.e., field inspection.

Maintenance

A comprehensive and effective maintenance program requires implementation of five **interdependent** entities: equipment, workforce, data, communication, and associated activities.

Management

Corrosion management is 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.

Table 2: Some Significant Advancements Made between 2000-2020 in Internal Corrosion Control

Year	Advancements
2000	Introduction of NACE Internal Corrosion Course (Basic)
2001	NACE SP0206, “Normally Dry Gas Internal Corrosion Direct Assessment”
2002	Introduction of NACE Internal Corrosion Course (Advanced)
2002	Canadian Association of Petroleum Producers (CAPP) Recommended Practice for Mitigation of Internal Corrosion in Sweet Gas Gathering System
2003	Canadian Association of Petroleum Producers (CAPP) Recommended Practice for Mitigation of Internal Corrosion in Sour Gas Gathering Systems
2003	Field Guide for Investigating Internal Corrosion of Pipelines - Book
2006	NACE 0106, “Control of Internal Corrosion in Steel Pipelines and Piping Systems” (This standard was originally published in 1970s and was withdrawn in 1990s as it was not revised on time. NACE resurrected this in 2006 due to regulatory requirement after Carlsbad incident)
2007	First Tutorial on “5-M Methodology” at 2007 Banff Pipeline Workshop
2008	NACE SP0208, “Liquids Internal Corrosion Direct Assessment”
2009	ASTM G199, “Standard Guide for Electrochemical Noise Measurement”
2010	NACE SP0110, “Wet Gas Internal Corrosion Direct Assessment”
2011	Metallurgy and Corrosion Control in Oil and Gas Production - Book
2013	Corrosion Control in the Oil and Gas Industry – Book
2014	First Online Course on “Science, Engineering, Technology, and Management (STEM) of Corrosion in the Oil and Gas Industry”
2015	Oil and Gas Pipelines: Integrity and Safety Handbook - Book
2015	NACE Technical Report 21410, “Selection of Pipeline Flow and Corrosion Models”
2015	ISO 17093, “Corrosion of Metals and Alloys – Guidelines for Corrosion Test by Electrochemical Noise Measurements”
2016	NACE SP0116, “Multiphase Internal Corrosion Direct Assessment”
2016	Corrosion and Asset Integrity Management for Upstream Installations in the Oil/Gas Industry: The Journey of a Corrosion/Integrity Engineer – Real Life Experiences - Book
2017	NACE Technical Report 21413, “Prediction on Internal Corrosion in Oilfield Systems from System Conditions”
2017	Second tutorial on “5-M Methodology” at 2017 Banff Pipeline Workshop and Industry Feedback on the Status of “Key Performance Indicators” on Internal Corrosion Control
2017	Trends in Oil and Gas Corrosion Research and Technologies: Production and Transmission - Book

Internal Corrosion Direct Assessment (ICDA)

NACE International started working on Internal Corrosion Direct Assessment (ICDA) standards as a consequence of an unfortunate accident in Carlsbad, New Mexico, USA that resulted in 14 fatalities. Currently there are four (4) ICDA standards (Table 2). All four ICDA standards follow the same four step process:

- Pre-assessment (Collection of data for assessment)
- Indirect Assessment (Prediction of locations susceptible for water accumulation; Estimation of corrosion rate in wet-gas and multiphase ICDAs only)
- Detail Examinations (Direct determination of wall thickness, and hence corrosion rate)
- Post-assessment (Determination of next integrity assessment interval and validation of ICDA process)

Inline Inspection (ILI)

ILI involves insertion and transportation of a device (containing sensors) inside the pipeline to inspect the condition of the pipe wall. The sensors measure defects in the pipe wall using ultrasonic and magnetic flux leakage techiques. Therefore, it is a direct indication of the condition of the pipe wall. The type of defects detected depends on the type of ILI tool used. Industry currently extensively uses ILI for the integrity assessment and to establish corrosion rates.

Table 3: Processes/Steps in Various Internal Corrosion Control Strategies

5-M Methodology	ICDA	ILI
• Model • Mitigation • Monitoring • Maintenance • Management	• Pre-assessment • Indirect assessment • Detailed examination • Post-assessment	• Inspection

Status of Internal Corrosion Control Strategies

In order to understand the state-of-the application of various internal corrosion strategies, a 25 Key Performance Indicator (KPI) questions survey was recently carried out. Table 4 lists the KPI questions. Descriptions of all 25 KPIs and procedures for analyzing the results are available elsewhere[6]. Only **current pipeline owners and operators** (total 16 operators/owners of upstream, midstream, and downstream pipelines) of oil and gas pipelines filled the surveys. Figure 4 summarizes the results; Fig. 5 presents the relevancy of KPIs to control internal corrosion; and Fig. 6 projects number of internal corrosion incidences anticipated using currently available strategies.

Based on the survey, the overall score of "internal corrosion control" is 59% and that of "internal corrosion" is 41%, indicating that industry in general effectively implements effective control measures. The overall survey results are in line with previous survey results[6]. The surveys and subsequent discussions identified several areas of improvement and Table 5 summarizes them.

Fig. 4: Status of KPI to Control Internal Corrosion of Oil and Gas Pipelines

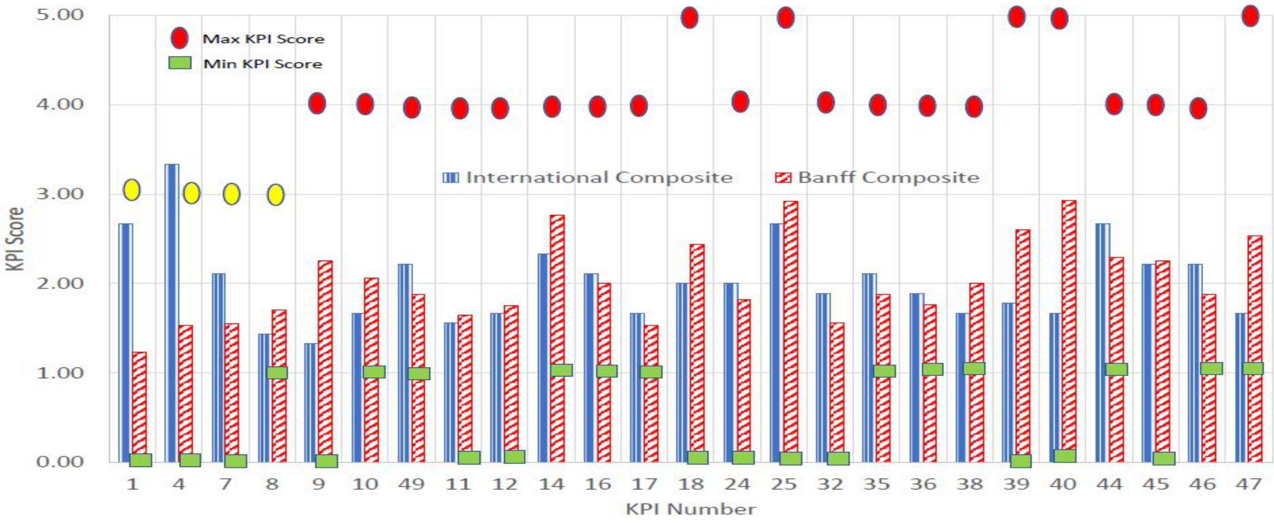


Fig.5: Relevancy of KPI in Controlling Internal Corrosion

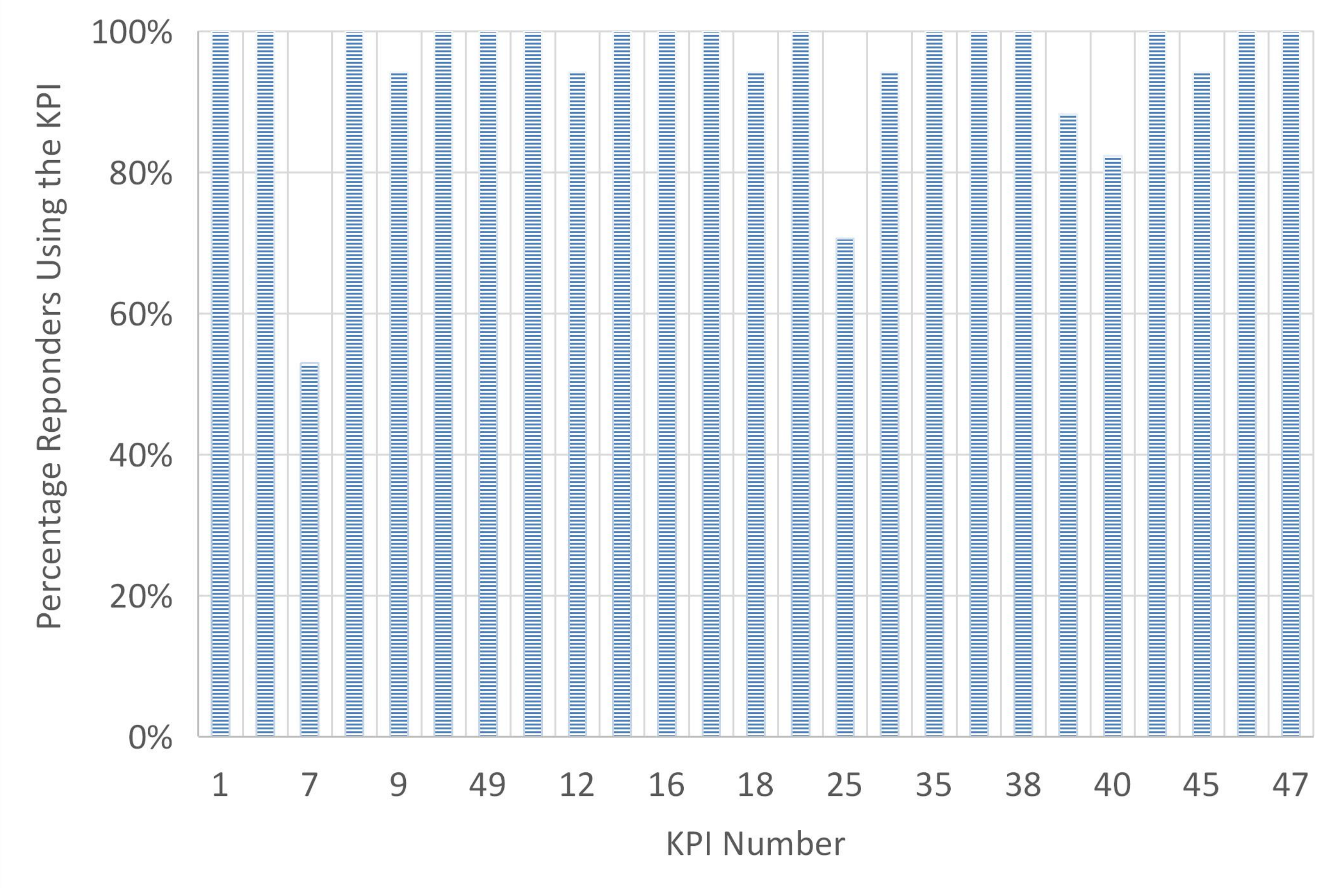
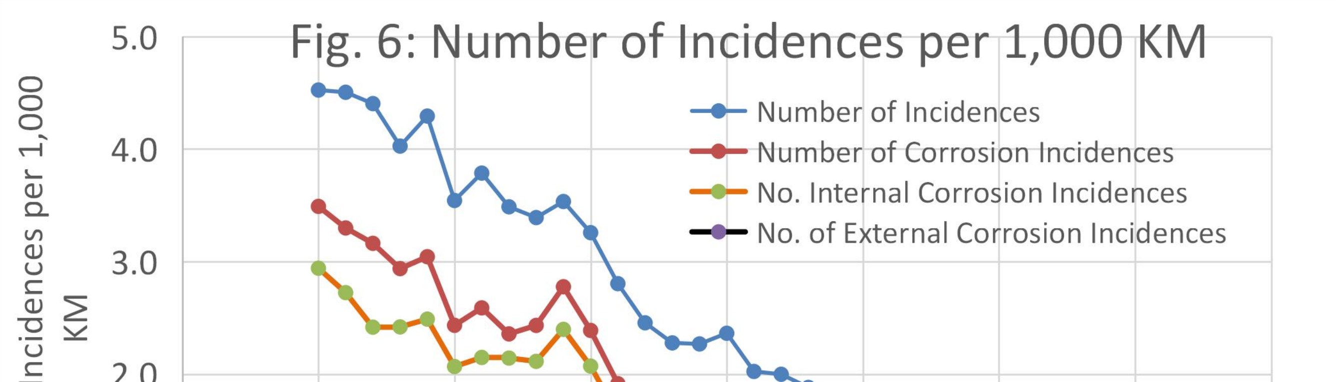


Fig. 6: Number of Incidences per 1,000 KM



KPI Number*	Description/Question
1	Has the pipeline been segmented quantitatively, logically, covering the entire pipeline length to address internal corrosion?
4	What is the overall risk (due to internal corrosion)?
7	Is the corrosion allowance used enough to account for corrosion loss over the entire design life?
8	Has the pipeline been operating within the normal operation conditions for the entire duration of its life?
9	Has the potential influence of upset conditions upstream been understood and plan has been established with upstream team to avoid or minimize the effect of such upstream upset conditions in the current sector?
10	Has the potential influence of upset conditions in this sector on downstream operation been understood and has plan been established with downstream team to avoid or minimize the effect of such upset conditions in the current sector on downstream operation?
11	Have all corrosion damage mechanisms been considered and most prominent ones determined?
12	Is the maximum (internal) corrosion rate based on all corrosion damage mechanisms (CDMs)?
14	Have appropriate accessories installed on time and at right places in consultation with corrosion professionals?
16	Have internal corrosion mitigation strategies established based on the analysis performed and have strategies implemented (e.g., use of corrosion-resistant alloys) at the conceptual and design stages?
17	Has no mitigation strategy implemented (as per KPI 16) or mitigation practice implemented is time-tested and proven to control the predominant mechanism of corrosion occurring under the operating conditions of the infrastructure?
18	How are the targeted mitigation strategies established?
24	Are appropriate monitoring techniques that are proven to be effective in monitoring the corrosion damage mechanism occurring in the segment used?
25	Are the number of working monitoring probes enough to cover all critical areas and some non-critical areas?
32	How is the frequency of inspection established?
35	Are all measurement data required for deciding corrosion conditions of the segment available in a readily usable format?
36	Is the validity of the measured data is established using a standard practice and is the measured data properly integrated to establish the corrosion rate?
38	Is the maintenance work carried out as per planned maintenance activities with all teams delivering their services as per schedule?
39	What is the internal corrosion rate after the maintenance work?
40	What is the percentage difference in internal corrosion rate before and after maintenance activities?
44	What is the composition of work force?
45	Are all data properly entered in a database?
46	Are all data easily retrievable from the database?
47	What are the internal communication strategies?
49	Are regular review meeting conducted to identify opportunities for improvement?

*In total 50 KPIs are used to evaluate the status of corrosion control, but only 25 KPIs relevant to internal corrosion were used in the survey. Therefore, the KPI numbers are not continuous. Further the users can include addition KPIs.

Table 5: Issues to Overcome to Further Improve Industry Performance

No.	Issues	Opportunities for Improvement	Who can do or who does it
1	Wide variation in industry experience	Some variations in experience is anticipated. • To understand where your company stands, first carry out an inhouse KPI survey and compare the results with other results, e.g., with the date presented in Fig. 4. • Repeat the process at least once a year to identity what works and what require improvement. • Add/delete KPIs as needed.	• Owners/operators.
2	Is converting general corrosion rate to predict localized pitting corrosion using an arbitrary factor correct?	Absolutely not; Vast amount of scientific knowledge and long-term field test clearly indicate that there is NO correlation between general and localized pitting corrosion rates. Certain commercial software can address different corrosion damage mechanisms (CDMs) and predict the overall pitting corrosion rate (PCR). The common CDMs are: **1. Localized pitting corrosion** 2. Microbiologically influenced corrosion (MIC) 3. Top of the line corrosion (TLC) 4. Under deposit corrosion (UDC) 5. Flow induced localized corrosion (FILC) 6. Corrosion influenced erosion (CIE) 7. Erosion influenced corrosion (EIC) 8. Erosion corrosion 9. Crevice corrosion 10. Corrosion under coating (CUC) – if internal liner is	• Model/software developers. • Field owner/operators should verify if the software they select address CDMs relevant for their pipeline. • Company "Internal Corrosion Document" should emphasize appropriate model/software selection and elaborate selection criteria (See NACE TR 21410[7]).

Table 5: Issues to Overcome to Further Improve Industry Performance

No.	Issues	Opportunities for Improvement	Who can do or who does it
		present 11. Galvanic corrosion (if there are dissimilar metals present) 12. Weld-zone corrosion (WZC) 13. General corrosion (almost never occurs)	
3	Proprietary information (Certain "tool" providers do not disclose information)	• Have non-disclosure agreements (NDAs) with vendors to obtain proprietary information (Aware that even for filing "patent" one has to disclose the nature "innovation"). Vendors who do not disclose "proprietary" information, may not perhaps have "technically sound information" to disclose! • Test the software for several conditions and use the result to establish the sensitivity of the model/software to various inputs.	• Some commercial software products disclose fully "all scientific" and "interim" parameters. • Owners/operators need to understand "scientific validity" of tools before using the tool (See NACE TR 21410[7]).
4	Lack of trackability (Tools advance every day and it is difficult to track tool performance)	• Tool suppliers and pipeline owner/operator should work together and tool develop should develop trackability procedure. • Unity plots for ILI and "Model software" must be established for quality assurance, tool tolerance, and confidence interval.	• Some standards require unity plots for ILI: o 49 CFR 192.911 o ASME/ANSI B31.8S • Some pipeline. owners/operators use unity plots for internal corrosion software validation.
5	Several internal corrosion control documents available and there is no link between them	• Standards have been developed and revised at different time periods and the link between standards will be established eventually. • Note the standards are only minimum requirements.	• Some pipeline owners/operators already interlink various standards in their internal documents/requirements, e.g., Corrosion Control Documents. • Standardisation organisations such as NACE International.
6	Four ICDA	• ICDA and 5-M Methodology are	• Some pipeline

Table 5: Issues to Overcome to Further Improve Industry Performance

No.	Issues	Opportunities for Improvement	Who can do or who does it
	documents with slightly different philosophies	only "thought-processes". They should be treated as "general guidelines" and not as "Cost in stone" documents.	owners/operators have developed their own guidance. • NACE International.
7	We depend heavily on "tool" providers and "SMEs"	• Buyer be aware of the merits and limitations of various tools/products. • Ignorance/complacent is not an excuse. • SME does not stand for "Subject Matter Expert" but stands for "Subject Matter Educationist" or "Subject Matter Enabler". • True SME imparts knowledge and empowers users; and does not take away projects for his/her "financial benefits".	• Online education courses are available that require participants to work with real field data/situation[8-17] and to develop understanding of science, technology, engineering, and management aspects.

FUTURE (BEYOND 2020)

Canadian oil and gas industry has made tremendous progress and advancements over the past two decades. Consequently, the incidences of internal corrosion related failures have tremendously decreased (from more than 3 per 1,000 KMs per year to less than 0.5 per 1,000 KMs per year) over the past two decades[2]. This has been achieved in spite of increase of total length of pipeline from ~ 250,000 KMs to ~500,000 KMs. However, continued improvements and further advancements must be made because of two reasons:

- There are still about 250 failures per year due to internal corrosion.
- Public tolerance towards pipeline related incident is low or zero.

For these reasons, the industry has collectively taken the decision of moving towards "Zero Incidence" due to internal corrosion. Nobody in the industry is comfortable with a target other than "Zero Incidence". It is recognized that this does not mean "Zero risk". Corrosion is a spontaneous process and hence there is always an inherent risk from internal corrosion. But, with appropriate implementation of currently known/used strategies the internal corrosion risk can be kept to the minimum value and with appropriate implementation of "additional" strategies the internal corrosion incidence can be targeted to "Zero". Some additional strategies are described in the following paragraphs.

It is "And", Not "Either-or"

Currently we determine internal corrosion rates based on model, monitoring, or inspection. Even though we utilize the data from one technique to validate other techniques, we use information from one of the techniques. Vast amounts of industry experience and knowledge indicates that no one technology is 100% accurate. Therefore, we need to use a combination of at least two techniques to compensate the weakness of one with the strength of the other (Such practice is common in controlling external corrosion).

Cost-Benefit Analysis

Based on the previous strategy it may be concluded that the cost of using two technologies will double the cost. But if both technologies are used alternatively the benefit will double without necessarily doubling the cost. Table 6 presents an illustration.

Table 6: Cost-Benefit Analysis of using Several Techniques to Determine Corrosion Rate

No.	Options	US dollar (for illustration only)			Total cost after 10 years (with three runs in year 0, 5, and 10)
		ILI[a]	Model[a]	Average cost per run	
1	ILI run only every five years	100,000	0	100,000	300,000
2	Model only every five years	0	80,000	80,000	240,000
3[b]	Combinations of ILI and model	100,000	80,000	90,000	280,000[c] 260,000[d]

[a]Average of dollar values provided to the authors by various companies; both processes include validating the corrosion rates/wall thickness from these techniques with those from another independent method, e.g., non-intrusive measurements and developing unity plots; [b]Implementation of option 3 has projected a saving of 2 million dollars per year in an oil and gas company;.[c]ILI in year 0 and 10 and model in year 5; [d]Model in year 0 and 10 and ILI in year 5.

For Operators, By Operators, and Of Operators

Owners and operators should take lead and be aware of long-term implication of strategies being developed, implemented, and standardized. Blind reliance of “tools”, “consultants”, and “SMEs” will not help. SMEs who have knowledge, experience, and wisdom could enable company personnel. We all should work collectively. After all the competition is not against each other but against “corrosion”. We, in the Corrosion Control” team should win against “corrosion”, more importantly should not score “self-goal”.

5-M Methodology

Several strategies including ICDA and 5-M Methodology are just thought processes to help us to organize the information and utilize them effectively and economically. Many steps/processes used in these strategies are common and, hence, the strategies are not mutually exclusive. When properly understood all strategies will "walk like" and "quack like" the all-encompassing "5-M Methodology".

Industry Score Card

The benefits of developing industry score card, using for example KPI survey, are several, including:

1. One can compare their company score with composite score to understand the status of corrosion control of their infrastructures.

2. One can use the composite results to investigate the status of corrosion control in their infrastructures.

3. Repeat of such survey in individual companies may help to sequence large net work pipelines in terms of corrosion control status.

4. Companies can not only develop effective and economical strategies to control internal corrosion but also demonstrate that they have "exercised" due intelligence.

5. Will help to separate "bad" actors from "good" actors

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