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Abstract

Managing pipeline integrity can be a daunting task when the pipeline is operating in an environment with several integrity threats present at the same time. The dynamics of monitoring, measuring and analyzing each threat and then implementing remedial action can be a drain on resources if not done in an organized and systematic manner. In addition while the regulatory bodies are demanding transparency in demonstrating compliance to maintaining pipeline integrity, customers are demanding improved efficiency to transporting Oil and Gas. This paper discusses the pipeline integrity regulation requirements in the United States of America and how it can be best implemented to achieve reliability, sustainable profitability and regulatory compliance of pipeline systems.

1. Introduction

Historically transportation of oil and gas by pipelines remains the safest and most economical compared to the other transportation modes. However, pipeline integrity does cause a concern to public and environment along the pipeline route because of it's ever presence at the location during its entire useful life. In the United States of America (US) pipeline failure incidents in late 1990's, accelerated the process of mandating pipeline integrity rules which, when implemented, will assure safe, reliable and environmentally responsible operation of oil and gas pipelines.

The pipeline integrity rule for Hazardous Liquid (CFR 49 § 195.452) and Natural Gas (CFR 49 § 192 Subpart O) pipelines came into effect on May 29, 2001 and January 14, 2004 respectively.

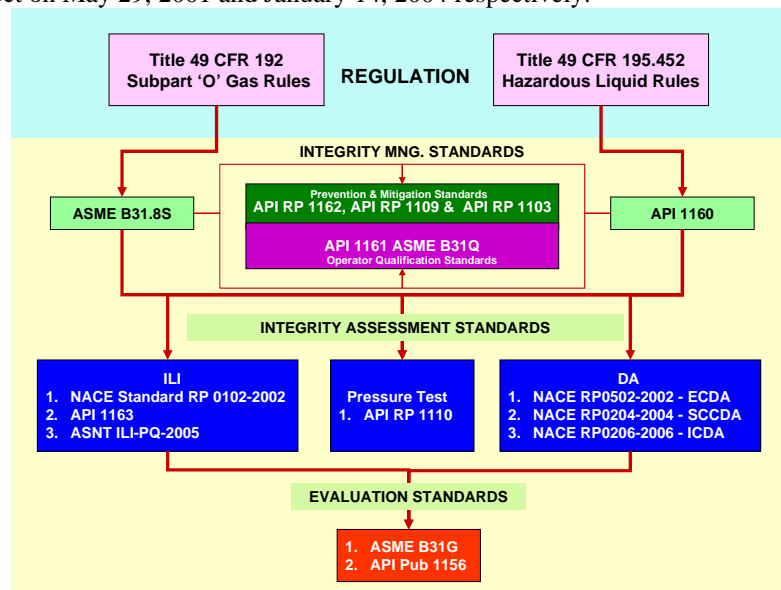


Figure -1 – Standards to Support Pipeline Integrity Management

¹Marine Engineer – ABS Consulting Inc.

These regulations are a result of seven years of technical studies that focused on causes of failure in pipelines and best practices in mitigating these them. These studies identified twenty one failure causes for pipeline that are now categorized into the following nine threat categories to oil and gas pipelines. The integrity rule requires that a pipeline integrity management system be developed and implemented to effectively manage the nine categories of pipeline threats

As the pipeline industry in the United States got ready to implement the new rules, API, ASME, and NACE standard bodies pulled in their resources and presented the industry with a host of standards (Figure-1) to help meet compliance to the pipeline integrity rules. These standards are now being adopted by international pipeline operators as a benchmark, especially in countries where there are no local regulations on pipeline integrity.

2. Key Elements of Pipeline Integrity Management Program

Taking a benchmark of the US pipeline integrity management rule (regulation) we note that it requires Natural Gas and Hazardous Liquid pipeline to develop and implement sixteen (16) and eight (8) elements respectively. The core elements between the two regulations are the same, the additional elements in the Gas pipeline integrity management requirements are related to communication plan, Direct Assessment (DA) plan Management of Change (MOC), quality assurance and environmental and safety risks. The ASME/ANSI B31.8S and API 1160 are the two standards that address the requirements of the integrity rule for gas and liquid pipelines respectively.

The core elements common to oil and gas pipelines where the bulk of the resources are required are:

- i. Identifying High Consequence Area (HCA).
- ii. Data collecting and comprehensive analysis to identify pipeline failure threats of concern and performing risk assessment based on probability of failure from each identified threat and its consequences.
- iii. Implementing preventive and mitigative measures to protect high consequence areas.
- iv. Performing a prioritized integrity assessment on segments in HCA's using tools and methods capable of detecting defects associated with identified threats.
- v. Evaluating integrity assessment results, identifying and performing prioritized repairs.
- vi. Establishing a integrity assessment interval, collecting, analyzing and performing a risk assessment periodically on new pipeline data, and
- vii. Measuring performance

It is essential to note that these core elements are designed to use a risk management approach to pipeline integrity management. Identification of high consequence areas, identifying failure threats, assessing risk to prioritize integrity assessment and repairs, performance monitoring and feedback are all elements of risk management program. A risk management program for pipeline integrity when integrated with an operators business practices provides a comprehensive management decision support required to ensure that pipelines are suitable for continued safe, reliable and environmentally responsible service.

Each of the core pipeline integrity elements is briefly discussed here in regard to the requirement, the rational and resources required for effective implementation of each element.

2.1. Identification of High Consequence Area (HCA)

2.1.1. Requirement

Gas Pipelines – HCA are identified by

- i. *Class location.* All Class 3 and 4 locations. All Class 1 or 2 locations, where the area within the Potential Impact Circle (PIC) contains 20 or more Structures Intended for Human Occupancy (SIHO).

or

- ii. *Area within PIC* contains 20 or more SIHO or an identified site.

The Potential Impact Circle illustrated in Figure 2 is for natural gas and is calculated by the formula given in ASME B31.8S – 2004 paragraph 3.2

Hazardous liquid pipelines – HCA for hazardous liquid pipelines is identified by location of pipeline with respect to following areas:

- i. *Populated Area*
Population concentration per square mile, city, town, village or designated commercial or residential areas
- ii. *Commercial Waterways*
Considerable commercial navigation and use by utilities
- iii. *Environment*

Drinking water or ecological resource areas sensitive to environmental damage from a pipeline release

The difference in the method of identifying the HCA for gas and hazardous liquid pipelines is because of the likely consequences of a leak from the gas and liquid pipeline. While gas pipeline leak are more likely to cause an injury and/or fatality and less likely to cause environmental damage, but hazardous liquid pipeline is likely to cause both injuries/fatality and environmental damage. Also because a liquid spill can transport itself to locations other than the actual location of the pipeline due to land topography or presence of river or stream it is essential that at the time of identifying HCA an analysis be made of pipeline segments that *could affect* a nearby HCA by the help of flow modeling.

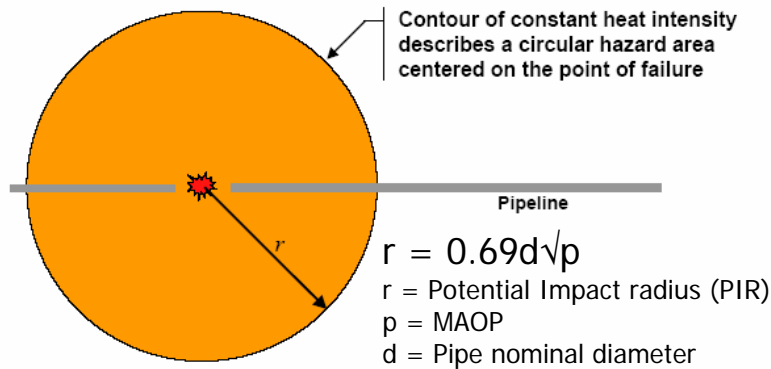


Figure -2 Potential Impact Circle

Source - GRI-00/0189 – C-FER Report 99068

2.1.2. The Intent of identifying HCA

The rationale for identifying HCA is that it gives the operator the consequence knowledge of those segments of the pipeline that are likely to cause significant safety and environmental related incidents due to a failure in pipeline integrity. This knowledge in turn helps the operator to

- i. Focus the integrity management resources on those pipelines segments that are in HCA or can affect HCA.
- ii. Estimate the consequence of a leak and ultimately the risk posed by the segment of the pipeline.
- iii. Prioritize preventive and mitigation measures to protect HCA.

2.1.3. Implementation

Effective implementation of this element will require access to updated information, data and maps along the pipeline Right-of-Way. The information, data and maps include:

- i. Population densities, class locations, number of SIHO, identified sites, cities, towns etc.
- ii. Commercial waterways (ports or navigable rivers with commercial shipping routes), rivers, power plants and desalination plants with intake from waterways
- iii. Drinking water and ecological unusually sensitive areas.

Item (ii) and (iii) above apply to hazardous liquid pipelines and includes quadrangle maps, aerial photographs, and/or field observation or terrain knowledge so that appropriate analysis may be performed to determine whether a segment should be designated an HCA pipeline segment.

Periodic review of the above information and data along the ROW is necessary to verify if changes necessitate the designation of new HCA segments.

2.2. Threat Identification and Risk Assessment

2.2.1. Requirement

Based on the extensive studies funded by the Gas Research Institute, pipeline business unit and with inputs from operators, an improved basis of pipeline failure root cause analysis and incident classification was established

The figure 3 provides the study results of gas pipeline failure incident data analyzed and classified by the Pipeline Research Committee International (PRCI) into 21 root causes (note: the actual number of failure causes were 22 and one was reported as “unknown” i.e. no known root cause). The 21 causes are grouped into 9 categories of related failure types according to their nature of growth characteristics and further delineated into time-related defect types.

Likelihood of Failure

A very comprehensive data collection effort has to be made in relation to each of the 9 categories to determine the likelihood of failure and identify which of the 9 categories of threats are of concern to the pipeline. Periodic monitoring and measurements of pipeline threat attributes related to threat categories identified are to be performed.

The data and information collected on each of the treat attribute should be organized and aligned to the segments of the pipeline in such a manner that a comprehensive assessment can be made on the segments likelihood of failure as well repair and mitigation decision.

Risk Assessment

Each segment risk is to be calculated based on the likelihood of failure and the consequence of leak. The segments are to be prioritized based on the risk for mitigation measures, integrity assessment, repairs and implementing preventive measures.



Figure -3 Pipeline Failure Threats

2.2.2. Rational for Threat Identification and Risk Assessment in Integrity Program

The rational for identification of threat is based on the fact that the characteristic of pipeline defects corresponding to each threat category is different; therefore selection of the integrity assessment tool is dependent on the threat. In other words by identifying the threat it helps selection of the most suitable In-Line Inspection (ILI) tool that can specifically detect the threat characteristics such as metal loss, crack detection, dent, buckling, hot spots etc.

The rational for risk assessment is prioritization of integrity assessment, repairs, mitigation and preventive measurements.

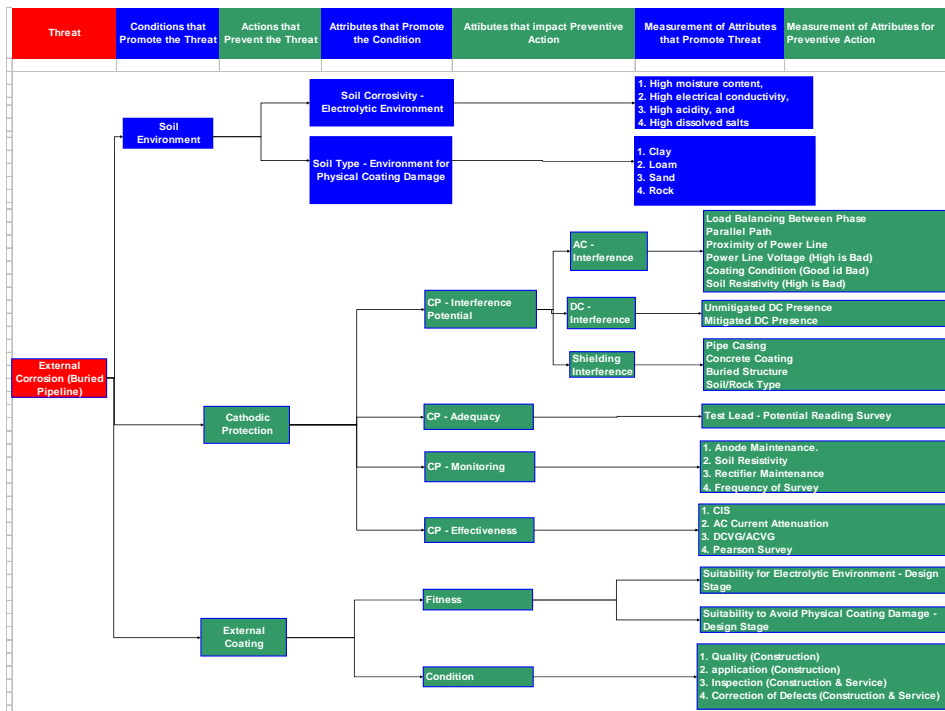


Figure 4 – External Corrosion Flow Chart for Threat Attributes and Monitoring Data

2.2.3. Implementation

Threat identification requires pipeline threat monitoring, measurements, data collection and integration of data. This is no easy task. As an example Figure 4 illustrates an overview of the data and information that should be collected to determine the treat due to external corrosion.

The operator should develop similar flow charts to identify the threat attributes as well as the monitoring and measurement data that must be collected for each threat category. The data must be organized in a manner that it can be easily integrated to identify the threat of concern. For example coating damage identified as a result of Close Interval Survey (CIS) when integrated with the Third Party Activity level data may conclude the coating damage due to a third party contact rather than due to external corrosion environment for the concerned pipeline segment.

The risk assessment methodology should be sufficiently detailed so that the intent of the requirement is met by prioritization of integrity assessment, repairs and mitigation measures. There is no specific risk assessment method specified and an operator may use qualitative or quantitative method. However, it is important to use caution while using a qualitative method because lack of information when treated more conservatively may skew the risk results to a threat category which is not of high concern. On the other hand quoting the words from B31.8S "...a pipeline segment may rank extremely high for a single threat but rank much lower for the aggregate of threats compared to all other pipeline segments. Timely resolution of the single highest threat segment may be more appropriate than resolution of the highest aggregate threat segment." This statement is very true and illustrated as an example in figure 5 for external corrosion threat on segment 3. However, here again the decision to prioritize the highest external corrosion threat segment rather than highest risk index segment will depend on the reliability of the external corrosion threat evaluation data.

EXAMPLE

Segment Prioritization	Threat					Probability of Failure Factor	Consequence Factor	Risk Index
	External Corrosion Probability of Failure	Internal Corrosion Probability of Failure	SCC - Probability of failure	Third Party Damage Probability of Failure	Climate and External Forces Probability of Failure			
1	6	5	4	7	2	24	7	168
2	7	5	0	6	2	20	6	120
3	9	5	0	4	0	18	6	108
4	6	5	0	3	5	19	5	95
5	5	5	0	5	2	17	5	85

Figure 5 – Threat Ranking Vs Risk Index Ranking

2.3. Implementing preventive and mitigative measures to protect high consequence areas.

2.3.1. Requirement

An operator must take additional measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. The additional measures must be based on the threats identified to each pipeline segment.

Such additional measures are to include, installing Automatic Shut-off Valves or Remote Control Valves (Emergency Flow Restriction Device EFRD), installing computerized monitoring and leak detection systems, providing additional training to personnel on leak response procedures, conducting drills with local emergency responders, implementing additional inspection and maintenance programs etc..

2.3.2. Rational for Including Preventive and Mitigative Measures in Integrity Program.

Preventive and mitigative measures identified immediately after the initial risk assessment are the low hanging fruits of a pipeline integrity management program that can considerably lower the risk of a pipeline leak. Preventive measures are actions that reduce the likely hood of failure due to identified threat attributes. Mitigative measures are those that reduce the consequences of a leak. Collectively preventive and mitigative measure lower pipeline risk.

2.3.3. Implementation

Immediately after the data collection analysis and risk assessment, the results of the risk assessment must be reviewed specially for the segments that rank high for risk. The review must look at the following two aspects of the risk assessment:

1. The threat attributes that are driving the likelihood of failure higher

2. Segments of the pipeline with high consequence of failure.

Reducing the likelihood of failure will require enhancing the preventive measures already in place e.g. the depth of burial is a prevention and a safeguard against third party damage. Implementing additional third party damage prevention programs such as public awareness, one call system would further reduce the likelihood of failure due to third party damage.

For segments where the consequence of leaks are high, additional measures for controlling the leak release quantity by installing EFRD and Automatic Shut of Valves or leak detection systems may be necessary and must be installed after careful analysis.

2.4. Performing Prioritized Integrity Assessment

2.4.1. Requirement

Integrity assessment is the key in determining the actual condition of the pipeline using either of the following integrity assessment methods:

3. In-Line Inspection (ILI or Intelligent Pigging)
4. Direct Assessment (External Corrosion Direct Assessment, Internal Corrosion Direct Assessment or Stress Corrosion Cracking Direct Assessment)
5. Pressure Test

The baseline plan as referred to in the integrity rule is a result of data collection and risk assessment for the very first cycle of assessing the integrity of the pipeline when implementing a pipeline integrity program for the first time. Thereafter the integrity assessment has to be performed based on the required assessment interval established. This is further discussed in paragraph 2.6.

The baseline plan must identify the threats to the pipeline and the integrity assessment method selected corresponding to the threats along with a prioritized schedule for assessment.

2.4.2. Rational for Performing Prioritized Integrity Assessment.

One of the most important aspects of this element is that integrity assessment is performed after data collection, threat identification and risk assessment. Threat identification aids the selection of integrity assessment method and risk assessment aids prioritized planning of integrity assessment thereby making the integrity assessment process efficient and effective.

2.4.3. Implementation

The prioritized schedule is to be based on the risk assessment result and the integrity assessment methods are to be based on the threats identified on the segment. For example in reference to figure 5 above, the segment 3 will require metal loss ILI tool to detect internal and external corrosion as well as geometry tool to detect dents due to third party damage, however, it will not require an integrity assessment method/tool to detect defects that are attributable to climate and stress corrosion cracking.

2.5. Evaluating Integrity Assessment Results and Performing Prioritized Remediation

2.5.1. Requirement

Within 180 days of performing the integrity assessment, the operator must obtain sufficient information on the anomalous conditions reported in an In Line Inspection report in order to make a determination on those conditions that pose a threat to the integrity of the pipe. The pipeline operator must develop a schedule that prioritizes conditions discovered on the pipeline for evaluation and remediation.

The remediation schedule for hazardous liquid pipelines and gas pipelines are categorized for following conditions based on the defect characteristics such as percentage of metal loss, depth of indentation and its location

Hazardous Liquid Pipelines

1. Immediate repair conditions
2. 60 days repair condition
3. 120 days repair condition
4. Other conditions

Gas Pipelines

1. Immediate repair conditions
2. One year repair condition
3. Conditions that are to be monitored

2.5.2. Rational for Condition Evaluation and Prioritized Remediation.

This process provides a prioritized repair excavation list for each segment based on the criticality of the anomalous conditions found during the integrity assessment.

2.5.3. Implementation

The following three steps should be addressed for implementation

1. Discovery of the pipeline segment condition that presents a significant threat to its integrity. Discovery of a condition occurs when adequate information is made available about an anomaly to determine if the condition presents a potential threat to the integrity of the pipeline segment.
2. Prioritizing a remediation schedule on all conditions that present an integrity threat. All prioritized schedules will commence from the date of discovery that is dependent on the integrity assessment method. As an example, when an ILI assessment method is used, this discovery may occur during either of the following activities:
 - the confirmation excavation on receipt of preliminary internal ILI inspection report,
 - gathering and integration information from other indirect inspections or the periodic evaluation, excavating the anomaly, or
 - when the final ILI inspection report is received.
3. Performing evaluation and repairs based on the prioritized schedule. Schedules are based on defect characteristics and are specified in the regulation. For guidance purposes the following provides a generic definition for each schedule category for hazardous liquid pipeline
 - Immediate – when the condition of the defect shows that it is at failure point.
 - Within 60 days – when the condition of the defect shows that it is significant but not at failure point.
 - Within 180 days – when the condition of the defect is determined to be less significant than the 60 day criteria.
 - Monitored – when the condition of the defect shows that it will not fail before next inspection.

2.6. Continuously Collecting, Analyzing and Performing a Risk Assessment on New Pipeline Data and Establishing an Integrity Assessment Interval.

2.6.1. Requirement

After the baseline assessment the pipeline operator is required to continue monitoring and measuring the pipeline threat attributes of concern and periodically perform data analysis and risk assessment as well as periodic integrity assessment. The integrity assessment intervals specified are 5 Years for hazardous liquid pipelines and for gas pipeline as specified in Figure 6.

The integrity assessment interval for gas pipelines may be extended beyond the specified period if the pipeline operator can demonstrate that the calculated remaining life of the maximum sized remaining flaw can extend beyond the reassessment interval of 5 years. The reassessment interval can be extended to a maximum of five years provided predicted failure pressure or the pressure test pressure meets the requirement of Table of B31.8S and a confirmatory direct assessment is performed after 7 years of the last integrity assessment.

2.6.2. Rational for Continual Risk Assessment and Establishing Periodic Reassessment Interval.

Continuous monitoring of threat attributes and risk assessment is a road to improving performance of the pipeline. The reassessment interval establishes safe operation of the pipeline at the same time has the mechanism to credit extension of reassessment interval to pipelines that have demonstrated the reliability beyond specified reassessment intervals.

Re-Assessment Interval

Gas Pipelines

Assessment Method	Criteria (CFR Title 45 part 192.939)		
	AT or Above 50% SMYS	AT or Above 30% up to 50% SMYS	Less than 30% SMYS
In-line Inspection, Hydrostatic Test or Direct Assessment	10 Years ⁽¹⁾	15 years ⁽¹⁾	20 Years ⁽²⁾
Confirmatory Direct Assessment	7 Years	7 Years	7 Years
Low Stress reassessment	Not Applicable	Not Applicable	7 years ⁽³⁾

Notes

1. A Confirmatory Direct Assessment (CDA) will be conducted by year 7 of a 10 year interval and years 7 and 14 of a 15 year interval.
2. A CDA or a low stress assessment must be conducted at 7 and 14 year of the 20 year interval
3. Low Stress Reassessment

Figure 6 –Re-assessment Intervals Gas Pipeline

2.6.3. Implementation

Continual monitoring and measurements of threat attributes with an annual data analysis and risk assessment provides opportunities to improve the performance of the pipeline and provides opportunities to prioritize the prevention and mitigation measures.

2.7. Measuring Performance

2.7.1. Requirement

An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S, section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A.

2.7.2. Rational for Performance Measurement

The intent of performing performance measurements is to verify that the objectives of implementing a pipeline integrity management program are achieved i.e. the integrity of the pipeline is capable of safe, reliable and environmentally responsible operation.

2.7.3. Implementation

The performance metrics can be made in two main areas to cover the requirements as well as monitor effective performance improvement.

i) Threat Metrics

The failures and repairs related to the threats should be measured six monthly as shown in figure 7. The root cause of failure should be established in each case to the threat that caused it.

Pipeline Failure by Threat Categories												
Threat Category	Failures During Pressure Test	Repairs resulting from I/I	Repairs resulting from DA	Leaks/Failure/Damage due to Threat and Threat Attribute								
				Direct Threat Related	Girth welds or Coupling	Bends	Fabrication welds	Regulator Valve	Relief Valve	Gasket O-ring	Vandalism	Audit Findings
External Corrosion	5	50	10	2								
Internal Corrosion	15	75	5	8								
Stress Corrosion Cracking	1		2									
Manufacturing Defect	4			1								
Construction Defect					1	1	1					
Equipment Failure									1	4		
Third Party Damage		2	3	1							1	
Incorrect Operation				1							5	
Weather related			1	2								
Fatigue Failures												
Total	25	127	21	15	1	1	1		1	4	1	5

Figure 7 – Threat Metrics

ii) Overall Program Metrics

(1) Miles Inspected

Collect information on the integrity assessment completed in miles for the pipeline. Completion of integrity assessment means that the integrity of the recorded miles has been assessed and the conditions are scheduled for evaluation and repairs

(2) Repairs Completed.

Collect information on the repairs completed in the category of “immediate”, “60-Day” and “180-Day” or “1 Year” (Gas lines) schedule for the pipeline.

3. Optimizing Pipeline Integrity Expenditure

Operators are now integrating these seven pipeline integrity processes into their business model to optimize the operation and maintenance expenditure.

The 80/20 rule commonly referred to as the Pareto Principal when applied to pipeline integrity using the seven processes discussed above concludes that most of the integrity issues (the 80%) are a result of a smaller number of failure causes (the 20%). This can be further explained as follows.

1. Targeting pipeline segments in HCA (the 20%) allows resource allocation to pipeline segments that are likely to cause major consequence (the 80%) in an event of an integrity failure.
2. The task of finding defects from each of the nine threat categories and twenty one failure causes can be appalling and a drain on resources. The data collecting and analyzing process identifies those threat attributes (the 20%) that have the potential to initiate the majority (the 80%) of the failures.
3. The Risk assessment process prioritizes pipeline segments and associated threats based on risk.
4. By identifying the top few (the 20%) of the concerning threats focuses on the real problems and optimize the cost of integrity assessment.
5. The repair decision process is critical in meeting the objectives of performance goals; this is a stage where the operator values the old proverb "A stitch in time saves nine". By prioritizing repair conditions for immediate repairs, 90 day repairs and 180 day repairs the good old 80/20 rule is at play.

When pipeline integrity processes are implemented diligently, the 80/20 rule helps in budgeting and optimizing the operation and maintenance cost. However, it should be noted that at the start of implementing, the risk assessment will get to the problems that are easy to detect but once the low lying fruits are taken, the next stage risk assessment will result in decisions that have a higher impact on maintenance cost and should be seen as efforts to achieving higher performance goals.