Are You Trained, Certified or Qualified to Assess Corrosion, Gouges, Dents, etc. to Meet Today’s Regulatory Requirements?

Justification for

Pipeline Field (Dig) Verification Training, Qualification & Certification

By

Joe Pikas

Joe Summa

Technical Toolboxes Inc.
3801 Kirby Drive, Suite 520
Houston, Texas 77098

Tel: 713-630-0505 Fax: 713-630-0560

Web: www.technicaltoolbox.com
ABSTRACT
Hazardous liquid and gas pipeline operators are tasked with the responsibility of complying with the federal and state regulatory requirements to ensure that field verification data and the gathering of pipe defects are assessed properly after in-line inspection runs, direct assessment or other maintenance activities. Yet too often, the focus has been to hire technicians that are qualified in one task but not experienced in all phases of direct examination of corrosion, gouges, dents, weld defects, cracks, wrinkle bends, SCC, construction defects, etc.

KEYWORDS
Direct examination, field validation digs, corrosion defect assessment, coatings, torsion, mechanical defects, ductility, axial loads, and fatigue.

INTRODUCTION
Defect Assessments
Most defect assessments have been performed by technicians who are operator qualified in one or sometimes two areas but lack the in depth of experience to recognize or assess all type defects found in the field. Many companies use their integrity engineers to review the field data that these technicians are submitting to the main office. However, many of the office engineers have just taken a one, two or three day course but have never spent the required time in the field to be able to analyze and assess these features adequately. Conversely, many technicians have never taken a comprehensive pipeline defect assessment course to give them the understanding to recognize blunt (corrosion) and crack like defects that interact with each other. These technicians have an American Society for Nondestructive Testing (ASNT\(^1\)) level I or II, a Personnel Certification in Non-Destructive Testing (PCN), a NACE\(^2\) coating inspector certification or a Cathodic Protection level 1 certification. Few techs have all certifications that are required for these type of inspections.

Operator Qualifications
The regulatory rules for a pipeline operator's integrity management program must provide that each supervisor has the appropriate training or experience in the area where this person is responsible. Therein lays the problem whereas many integrity engineers have little experience and have just received a one or two day course in this area from their company. Conversely, technicians who evaluate these defects must have the qualifications to assess and how defects interact with each other. What is more amazing is the lack of understanding how interaction rules work. It even gets worse, when the person in charge does not even know what interaction rules they are using.

\(^1\) American Society Nondestructive Testing - 1711 Arlingate Lane Columbus, OH 43228-0518
\(^2\) National Association of Corrosion Engineers - 15835 Park Ten Place Houston, Texas 77084
**Gaps**

The gaps represented here are to discuss how pipeline operators can ensure that this integrity-related process adequately meets QA/QC that is needed for the public, industry and government regulations. One approach is to use third party qualified oversight contractors with this knowledge, experience, certifications and qualifications that could meet these rigorous requirements. This approach is to prevent unanticipated leaks, operators must make a concerted effort to ensure that defect data is assessed properly to meet today’s regulatory requirements.

**Pipeline Field (Dig) Verification**

**Regulations, Standards, Recommended Practices & Operator Procedures**

Field dig verification is all about managing the integrity of a pipeline system at the locations where the rubber meets the road. It must be the primary goal of every pipeline system operator; not the contractor taking and providing information or data. This includes ILI vendors, Direct Assessment and Hydrostatic testing contractors. It is the responsibility of pipeline operators who must provide safe and reliable delivery of product to their customers without adverse effects on employees, the public, customers or the environment. Free of incident is must for the pipeline operator to meet this goal.

A systematic and integrated integrity management program (IMP) is required to address the 22 threats required to ensure the safety of pipelines. ASME B31.8(S)\(^3\), API 1160\(^4\), 1163, NACE Standard Practices on External, Internal and Stress Corrosion Cracking Direct Assessment, ANST and related recommended practices, are required to achieve a good integrity management program. IMP provides the information for an operator to effectively make engineering/integrity assessments in order to allocate the appropriate resources for prevention, detection and mitigation activities. These assessments when done in a systematic process will result in improved safety with a reduction in the number of incidents. It is important to note that zero incidents is a noble goal; however, even with best integrity process in place, there are unanticipated events that may occur.

A set of guiding principles is the basis for the intent and specific details of this standard. They are enumerated here so that the operator can understand the breadth and depth to which integrity shall be an integral and continuing part of the safe operation of a pipeline system.

**What is Integrity Management (IM)**

IM is a set of principles that pipeline operators can use for guidance which integrity shall be an integral and continuing part of the safe operation of a pipeline system. Below are the basic principles from ASME B31.8S.

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\(^3\) American Society of Mechanical Engineers (ASME) - Two Park Avenue, New York, NY 10016-5990

\(^4\) American Petroleum Institute (API) - 1220 L Street, NW Washington, DC 20005-4070
• Functional requirements for integrity management shall be built into new pipeline systems from initial planning, design and construction.
• System integrity requires senior management commitment and operator qualified (OQ) personnel using comprehensive, systematic and integrated processes to safely operate and maintain pipeline systems.
• An integrity management program is continuously evolving and needs be flexible.
• Information integration is a key component for managing system integrity. Risk assessment is a key element in managing pipeline integrity.
• Assessing risk to pipeline integrity is a continuous process.
• New technology should be evaluated and implemented as appropriate.
• Performance measurement of the system and the program itself is an integral part of a pipeline system integrity management program.

Below is diagram to the more specific and detailed description of each of the components.
Fortunately most large pipeline operators understand and use these basic integrity management principles. However, even today, major incidents occur and the operator misunderstood or ignored some of these basic guiding principles. For more information on the latest incidents, you can visit the PHMSA\(^5\) or NTSB\(^6\) web sites.

There are many places where the system can breakdown from intercommunication within the company, leaving everything up to the contractor to not allocating adequate resources to address the problems. Being a former operator for over 36 years and now working as a consultant for over 11 years, there is no one operator who does not have problems. Let’s just take one factor and it will point out where the majority of the issues have been occurring – **Age of the Pipeline System**. However, the primary focus of the paper is ensure that operator qualified technicians are certified and trained in their respective fields and have the experience to assess pipeline defects and understand pipeline operations in aged systems.

In today’s world we need experienced technical people who can recognize blunt type corrosion defects (MIC, AC, Interference, etc.) to crack like defects from SCC to HIC, to welds and condition, types of coating and condition, excessive loading/depth/subsidence, Abnormal Operating Conditions (AOC), etc. There are 22 threats that are required to be assessed. However, ILI, Direct Assessment, Hydro and Other typically address only the time dependent threats. What about the time independent and manufacturing type of threats? Listed below are the types of threats that must be addressed.

- **Time Dependent** - External Corrosion, Internal Corrosion & SCC
- **Stable** – Manufacturing, Construction and Fabrication & Equipment
- **Time Independent** - Third Party Damage, Incorrect Operations, Weather Related and Outside Forces

Our industry is moving towards Fitness for Service Levels 1, 2 and 3. Many technicians are not sure what these levels mean in field verification of corrosion and other features. Additional education and training is a requirement in today’s litigious environment.

Before an integrity assessment such as ILI, Hydro or Direct Assessment can be conducted, the following data must be collected in support of performing risk assessment and for special considerations such as identifying severe situations requiring more or additional activities:

- Year of installation
- Coating Type
- Coating Condition

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\(^5\) Pipeline Hazardous Material Safety Administration - 1200 New Jersey Ave., SE Washington, DC 20590
\(^6\) National Transportation Safety Board - 490 L'Enfant Plaza, SW Washington, DC 20594
• Years with adequate cathodic protection
• Years with questionable cathodic protection
• Years without cathodic protection
• Soil characteristics
• Pipe inspection reports (bell hole)
• MIC detected (yes, no or unknown)
• Leak history
• Wall thickness
• Diameter
• Operating stress level (%SMYS)
• Past hydrostatic test information

Once this data has been collected then a pipeline operator can conduct an engineering assessment to determine which tool or tools to use (ILI, Hydro or External Corrosion Direct Assessment). Regardless of the tool used to assess the pipe, field validation is the same. Too often these engineering assessments just focus on one or two parameters. What about location, previous history of problems, aggressive soils, subsidence, poor cathodic protection or coatings, corrosion rates, poor welds, etc.?

**FIELD VERIFICATION STRATEGY FOR RESPONDING TO INDICATIONS IDENTIFIED BY ILI, DIRECT ASSESSMENT, HYDRO OR OTHER**

Measurements of coating damage and corrosion defects must be performed during field verifications. Bell holes are an invaluable source of data such as soil geology and chemistry, drainage characteristics, ground water chemistry, soil stresses and other phenomena, all of which can contribute to the root causes of coating damage noted. The remaining wall thickness profiles will be used to predict the size and number of the scheduled and monitored corrosion defects that are left unexcavated.

All corrosion wall loss indications found in excavations should be analyzed and documented first using ASME B31G or (RSTRENG†. The remaining strength calculations will determine if the failure pressure causes the defect(s) to be classified as an immediate repair.

During the inspection activities the operator may discover other data that should be used when performing integrity assessment for other threats. For example, when conducting and ILI with an MFL tool, dents may be called out on the top half of the pipe. This may have been caused by 3rd party damage. It is appropriate then to use this data when conducting integrity assessment for the 3rd party damage threat. Below is the type of

† Trade Name
data required when corrosion is found. This basic information is needed to conduct a root cause analysis and determine re-assessment intervals.

- **Data Prior to and During Excavation (Before Coating Removal)**
  - Safety First
  - Soil Resistivity at Grade
  - Soil Type and Condition
  - Soil and Water Samples in Ditch
  - Soil Chemistry (pH, Chlorides, Sulfides, Sulfates, Conductivity, etc.)
  - pH Underneath Coating
  - MIC Analysis
  - Depth of Cover
  - Structure to Electrolyte Potentials
  - Photos of before, during and after excavation

- **Coating Condition and Corrosion Product Data Analysis**
  - Coating Type, Condition and Thickness
  - Color and texture of metal under disbonded coating
  - Microbial colonies found on steel surface
  - Corrosion product analysis
  - Mapping of Coating Defects
  - Coating samples
  - Photo Documentation

- **Measured Pipe Wall Loss and Interactions**
  - How Pipe was Cleaned
  - Pipe Temperature
  - Other Damage
  - Corrosion Defects, Length, Width and Depth
  - Corrosion Defect Table
  - Corrosion Defect Sketch
  - Remaining Wall Thickness using UT gage
  - Photographic Documentation

- **Remaining Strength Evaluation and Root Cause Data**
  - Gridding
  - Interaction Rules
  - Understanding River Bottom Profiles
  - Type and Condition of Pipe
- Type and Condition of Girth Welds
- Type and Condition of Longitudinal Seams
  - Pre-1970 ERW
  - Porosity, Cracking, Undercut, etc.
- Use of ASME B31G/RSTRENG Calculations (Line Pipe)
- Specific Limitations of ASME/RSTRENG Calculations
  - Mechanical Defects (3rd Party Damage)
  - Stress (Installation, Bending, etc.)
  - Welds
  - Fittings
  - Overburden
  - Combined with other defects
  - Greater than 45 degrees circumferentially
  - Crack Like Defects
  - Greater than 80% depth
- MAOP calculations
- Root Cause Determination
- Type of Survey(s)
- Remedial Action to Correct Root Cause
- General comments

These basic requirements are needed to conduct field verifications are the minimum to assess the integrity of the line. The flow diagram that was highlighted in yellow requires a comprehensive understanding of defects to be identified such as corrosion, metallurgy, third party damage, cracking, geotechnical issues, soils and soil types, nondestructive techniques, pigging, cathodic surveys, risk, integrity, regulations, industry codes, etc.

**ASSESSMENT ISSUES**

**Basic Pipe Parameters**

Before starting a corrosion assessment, loading, material strength, ductility, fatigue, toughness safety factors, etc. are the basic pipe parameters a technician or engineer should understand before he or she starts an integrity assessment process of defects.

When the pipe is being evaluated for defects, has this type of loading been evaluated? This could range from tension, compression, bending, shear, torsion, internal and external loading.

What about ductility and brittleness? Can the pipe be ductile enough to bend during construction or will it become dented which results in a permanent deformed condition. This could result in wrinkle bends or related defects. Toughness is another measure of
the pipe materials to tolerate cracks. Ductility and toughness have commonality; whereas the when the temperature decreases so does the toughness and ductility.

Our main focus is corrosion so how does this impact corrosion? Line pipe needs to be tough enough to withstand the corrosion defects that are found in the pipeline. If there is any concern about specified toughness of the pipe material being assessed, there are tests such as the Charpy test that could measure in relation to temperature, grade and age.

Fatigue is another issue that may occur is hazardous liquid lines when the cyclic stresses can lead to failure of even a minor defect. This is a result of these stresses causing fatigue cracking from the repeated cycles and hammer effects during pressure variations in a liquid line. These type failures can occur both in offshore and onshore pipeline spans and risers.

One must understand the safety margins between design, hydro test and failure. This is a minimum requirement before a defect assessment can be made. Defect assessment relates to the severity of a defect to the pipeline operating conditions (both past and
present) by rigorously evaluating defect and crack growth using guidance based on sound metallurgical engineering principals.

Does the technician or engineer understand these relationships in order that his company will not experience a failure. Is it better to replace or repair the line? How many composite or welded sleeves need to be installed before some says, there are too many band aids on this pipe.

**Case 1**

A large pipeline operator just completed an in-line inspection run and has hired a contractor (lowest bid) whose technicians are ASNT level 1 certified and has attended an eight hour course on measurement of corrosion pitting and similar defects. There are three spreads or digging operations going simultaneously and one company inspector. Unfortunately, the ASNT level 1 technicians were not certified by NACE as either a Coating Inspector or a Cathodic Protection (CP) Tester or better yet a CP Level 1. Company inspector is NACE certified and is using his span of control to check all three sites. What is wrong with this picture?

1. Depending on the certification organization (Veriforce/NCCER) span of control is typically within talking distance of the person being monitored to do the task. It could be 1 to 1 or 1 to 3 ratio span of control. Since this technician is ASNT 1 certified, he does not need to be monitored for corrosion pitting. However, other defects other than corrosion pitting may or may not be recognized and assessed properly.

2. Regarding coating inspection, the technician may or may have not be operator qualified for the task of identification of coatings. It should be noted that it takes years of experience to become a good coating inspector. NACE offers 3 weeks of certifications of coatings and it is based on testing and experience and this could take place over a period of 5 to 10 years.

**Case 2**

There are a variety of corrosion defects found on a pipeline that exhibit both axial and circumferential dimensions. The pipe is located in an area where mud slides are common in the Northwest area of the USA. Will the technician or engineer be able to recognize that when the circumferential length is greater than the axial length the requirements to determine for a circumferential type failure mechanism. Does he or she understand the calculations for failure under pressure loading and due to axial loads?

Even though the technician is an ASNT Level I or II, this type of information is not taught to achieve this certification. Unless they have worked on a pipeline for years or have
been though courses that teach beyond the measurement technique, these defect make
go unrecognized as being a problem.

**Case 3**

When is an axial defect no longer a blunt corrosion defect? If a technician or engineer
was using a corrosion program to determine the remaining strength of pipe, when does a
defect change from an ideal corrosion defect to one with sharp edges? Example,
microbial influenced corrosion (MIC) can have steep edges. Does this change it from a
blunt corrosion defect to one that needs to be addressed differently?

Unfortunately, there is not much specified on these type defects; therefore, it would
behoove the engineer to take the most conservative approach in addressing these type
defects (See picture on next page which show how MIC has attached the heat affect
zone, body of pipe and weld area – this coupon was donated to Kilgore College can be
seen in their display section).

Below is a picture of a coupon that show a variety of corrosion defects from girth weld
corrosion, heat affected corrosion to body pipe corrosion as a result of microbiological
influenced corrosion (MIC).

![Coupon taken from 30” Diameter x .312 WT Pipe](image)
Case 4

Assessment of corrosion in weld areas is another interesting area of concern. There are criteria differences between B31.G and Modified B31.G regarding corrosion in submerged arc welds, field data has shown that these welds are as resistant as defects as the pipe material. However, the factors that must be considered are that the weld properties be similar to the pipe strength and toughness. Electric resistance welds (ERW) are another case and must be addressed differently.

Did the technician understand that the pipe he or she was measuring corrosion defects had pre-1970 ERW pipe? Were there no visible longitudinal seams present on this pipe? Were there areas of selective seam corrosion? Were there high dielectric type materials applied to the girth weld or line pipe? Was the CP adequate? Did the technician check the pipe?

RECOMMENDATIONS

Use Technically Qualified and Certified Engineers and Technicians

It only takes one mistake to leave an anomaly that has been misidentified as a defect less than what it is. Because of the number of defects that must be assessed during an in-line inspection run, it is too easy for defects not to be assessed accurately. Having a technically qualified third party overseeing the operation ensures that fewer errors will take place.

No operator could afford to have errors that result in a leak failure especially if it was recently excavated and examined. The liability is too great versus the small amount of money to spend and address quality control. Because these lines must operate without interruption, it behooves the operator to have a checks and balances within their integrity program.

Maintain Test Data and Records for Internal and PHMSA Audits

Data management and accurate field data are a must in today’s litigious environment. In addition, I could remember when an operator dug up the same indication three times even though they had a very sophisticated Geographic Information System to monitor this defect assessment. No one bothered to enter the data while the dig forms were kept locally. This particular anomaly was assessed, cleaned and re-coated twice before someone realized during the third dig, maybe we this was already assessed. Having a qualified contractor to take the responsibility for the data input ensures that likelihood of defects are being recorded accurately and to avoid these costly pitfalls. In addition, on this same pipeline system there were at least three other defects that was assessed twice.
Consult with Clients Daily and Schedule Meetings for Mitigation and Maintenance Issues

Giving the operator updated daily reports and having regularly scheduled meetings on these type of defects found is a must. Smart pigs are only accurate +- 10% (80% of the time). This means that there are going to be outliers that need to be addressed quickly and decisions on whether to cut out a cylinder of pipe, lower pressure, use composite or steel sleeves or other means must be communicated effectively. Having qualified integrity engineers/technicians working with the operator can assist in the scheduling of making one blow down or taking the line out of service versus multiple times is good project management. Again this is saving dollars and making good engineering assessments.

Lesson Learned & Conclusions

Lessons learned can reduce very costly mistakes. The cost of excavation, collateral damage during excavation, not assessing the defect(s) properly, and not maintaining a useful data base is like doing nothing at all or going back to the old days of burying our mistakes. This used to be the way pipelines operated, but not completing all the tasks at hand simply does not cut it in today’s environment.

Operators cannot afford to dig up the country side more than once due to the high liability associated with these type operations. The likelihood of causing damage to theirs or someone else’s facilities is too great. However, when an operator must excavate, **he or she must assess the integrity of the pipeline judiciously.** This point cannot be emphasized enough. Investing in trained, certified and technically qualified third party consultants just makes good economic sense. Unanticipated failures can occur, but not to have assessed the pipe adequately only places the operator at the mercy of the jury, public and regulators. Now who is minding your store?

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