



THE 101 ESSENTIAL ELEMENTS

IN A PRESSURE EQUIPMENT
INTEGRITY MANAGEMENT PROGRAM

JOHN REYNOLDS

Revised & Updated 2014

Elements 1 - 101

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higher level of Asset Integrity Intelligence.

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About the Author

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Preface

This updated publication outlines the 101 Essential Elements (EEs) that need to be in place and functioning well, in order to effectively and efficiently, preserve and protect the reliability and integrity of pressure equipment (i.e. vessels, exchangers, furnaces, boilers, piping, tanks, and relief systems) in the refining and petrochemical industry. Many revisions and updates have been made since the original articles/publication were published in *Inspectioneering Journal* and other technical conferences. In many cases the original 101 Essential Elements have been reordered, renamed, condensed and others added. This updated publication can actually be better described as a “rewrite” instead of a simple “update” since many things have changed in the fixed equipment mechanical integrity (FEMI) discipline since the original publication. Note that throughout this publication, I will use the acronyms PEIM and FEMI interchangeably, but they mean the same thing.

Just as it was when it originally appeared, this publication is not just about minimum compliance with rules, regulations or requirements; rather it is about going above and beyond and about what needs to be accomplished to build and maintain a program of **operational excellence** in FEMI that will permit owner-users to make maximum use of their fixed equipment assets to safely manufacture products and generate revenue. Compliance is not the key to success in pressure equipment integrity management (PEIM); **operational excellence** is.

Each of the 101 work processes outlined in this publication, is explained concisely to the extent necessary, so that owner-users will know what needs to be done to maintain and improve their PEIM program. This publication does not prescribe in any detail how each of these *101 Essential Elements* is to be accomplished, as that description would result in a lengthy book rather than a brief publication. This publication simply outlines almost all the FEMI fundamentals that are necessary to avoid losses, avoid process safety incidents, and maintain reliability of pressure equipment. It pulls together a complete overview of the entire spectrum of programs, procedures, management systems and preventative measures needed to achieve first quartile performance in maintaining FEMI. In that sense, this brief outline of the 101 Essential Elements of PEIM can be thought of as a strategic outline of what needs to be accomplished. The tactical details of how to accomplish the 101 EE's are left to each owner-user to decide.

Many of the details of how each of the *101 Essential Elements* are to be accomplished are contained in API Inspection codes and recommended practices as well as numerous articles that have appeared in ***Inspectioneering Journal*** since its inception in 1995, and in the numerous presentations made at the API Inspection Summit, a biennial conference that has been held since 2007. A few of those articles and presentations have been referenced at the bottom of each of the 101 EEs.

Introduction

There are at least 101 Essential Elements (EEs) in any program aimed at preserving the mechanical integrity of fixed equipment (FEMI), after it has been placed in-service in the hydrocarbon process industry. Each of these 101 EEs may need to be prioritized by site management and FEMI technical leaders, based on risk and the current status of each element, in order to assign resources and schedule improvements in the FEMI work processes over an appropriate period of time. However, the user must keep in mind that each of these 101 elements, regardless of work priority and resource limitations, needs to be implemented effectively, continuously, in order to avoid the potential for pressure equipment incidents. In other words, as important as it is to know about and have a organized total plan for all 101 EEs of FEMI as a whole, equally important are the quality and details within each of the those plans, procedures and management systems. That's where the "rubber meets the road". The individual procedures and management system documents for each of the 101 EEs are like the tires on a high performance racecar. If the tires are not of the quality necessary to win the race over the long haul, it doesn't matter how good the engine and drive train are.

In other words, it is not matter of choosing between the 101 elements and deciding that some are important and others are not, over the long haul. If any one of these 101 EEs is neglected long enough, there will be an increasing potential for incidents involving the breach of containment, and the subsequent consequences, i.e. fires, explosions, toxic releases, environmental damage, personnel exposure to hazardous substances, injuries, lawsuits, government citations/fines, business financial impacts and company reputation damage.

The information in this publication can be used by operating sites to improve the effectiveness of their pressure equipment integrity program, whether the site is just beginning to rebuild their program after their last big FEMI incident, or are just trying to make further improvements in an existing, fairly effective program. One point that I cannot emphasize enough is that this is a description of a program of building excellence in pressure equipment integrity management (PEIM), and not just about compliance with rules, requirements and regulations. In my experience, those who focus too much on "compliance" and not enough on "excellence" will never rate in the upper quartile of our industry in avoiding losses, (asset loses and/or production losses), due to pressure equipment integrity problems. Once again, compliance is not the key to success in PEIM; operational excellence is. Please remember that key issue as you read throughout this publication.

Clearly there is more to complete process safety management (PSM) than just fixed equipment mechanical integrity; but FEMI is clearly one of the most important aspects of a complete PSM program. There is documented evidence (M&M Protection Consultants) that FEMI problems have led, and continue to lead, to some of the largest losses in our industry over the past several decades.

As Vince Lombardi said when he took over a mediocre national football team in a small town in northern Wisconsin back in the late 50s, *if we go back to the basics including blocking and tackling, and do them well, we will win*. He was right, and he proved it, by producing the first NFL Champions in a fairly short period of time. This publication is about "blocking and tackling" for pressure equipment integrity management (PEIM) in our industry.

There is no real secret to achieving success in maintaining pressure equipment integrity at a high level. It's simply doing all the right things (all 101 of them) that need to be done, and doing them well, day after day after day, without let up, regardless of what the "hot program" of the month is, or regardless of what other priorities may start to get in the way. We must not let other distractions get in the way of effectively executing our PEIM programs, every day.

It is important for everyone, including plant management, to understand that the job of protecting and preserving all fixed equipment assets in a hydrocarbon process facility belongs to a multitude of people, not just the inspection and corrosion group. An effective FEMI program includes specific roles for operators, crafts-persons, asset managers, process engineers, project engineers, fixed equipment engineers, as well as inspectors and corrosion/materials specialists. Plants that have specific roles and expectations for PEIM outlined and effectively implemented for each of these contributors will be most effective in

preventing asset losses from breaches of containment.

Hopefully, those who are skilled practitioners of FEMI will read this publication and say, “Well, I already know that!”, and to that I say: that’s fine, and I presume your plant does not have any leaks or pressure equipment reliability problems, as so many others do. Even those of you who know it all, I would encourage you to ask yourselves the questions posed at the end of each of the *101 Essential Elements* to help determine if things are as good as they need to be at your site. Sometimes there is a wide gulf between someone’s knowledge of a FEMI issue and actual practice and therefore end results in application of the issue.

All too often I find that many people outside of our field of endeavor (pressure equipment integrity engineering) have no idea what the magnitude and scope of our job entails. So one of the many purposes of this publication is to “pull it all together” so that others who have an interest in effective FEMI will know what it takes to be really successful, day after day after day, in avoiding pressure equipment integrity incidents. If plant management does not fully comprehend the full scope and depth of our FEMI discipline then they are apt to keep piling other duties on top of us without any knowledge of what FEMI responsibilities are “going to fall off our full platter” when they pile on a few more things for us to do.

Whenever I write or talk about this subject, I’m reminded that the Navy operates huge, complex nuclear aircraft carriers in war and peace, very effectively, and usually without incident. The potential for incidents is high, especially when launching and landing aircraft every few minutes, under stressful, noisy, congested, crowded conditions, and often in the dark. They do it with a cadre of folks of average intelligence with an average age of about 21 years. How do they do it? Procedures, systems, training, discipline, procedures, systems, training, discipline, and so forth. We should be able to perform as well in the hydrocarbon process industry.

One more thing before we begin. You may have already noticed that I have, and will, use the term “effective” on numerous occasions. Webster defines it as “producing a decided, decisive, or desired result”. And that’s exactly how I use it. I’ve seen a lot of time, money, and motion wasted on “supposedly” doing all the things described in this publication, without really being effective. It does no good to write procedures and best practices that are not effectively implemented or adhered to. It does no good if the necessary information to do the job is known by some SME at the plant or in the corporate office, but not transferred effectively to those who need the information on the front lines. It does little good if the following issues are just a “flash in the pan”, and then take a back seat to the next “hot rock” of the day. Watch for the word “effective” through the remainder of this publication and think about what it really takes to get the desired results for each Essential Element. “Effective” does not mean perfect. It simply means sufficient to get the job done right, such that there will be no significant breaches of containment that could threaten the health and safety of people and assets. Again, I’m reminded about what Vince Lombardi said about perfection – **“Perfection is not obtainable; but if you pursue perfection, you will catch excellence.”** That is true in most endeavors in life, including pressure equipment integrity management.

The following essential elements are not in any specific order, though some of the more over-arching ones are covered early on and some related ones are grouped together. Prioritizing them for actions at each site is a job for each operating site, since the priority, which needs to be placed on each element, is very much relative to the current status of each issue at each operating site, i.e. “How well is it being handled right now?” If it’s not being handled well, it will have a higher priority for that particular site than it would if the issue was already being handled very effectively. For instance, a CUI/CUF program for a Gulf Coast operating site may be much higher priority than for an operating site in a state where there is very low humidity and limited rainfall. Identification of all applicable equipment damage mechanisms may be a high priority for a site with no CCD’s but a lower priority for those sites that have already complete, comprehensive CCD’s. That type of need for prioritization will hold true for nearly every one of the EE’s.

Most of the 101 EEs of FEMI are highly integrated with each other in order to achieve excellence in FEMI management at each site. Just as every strand in a spider web is attached to most every other strand directly or indirectly, when one strand breaks, it may impact the total strength and performance of the entire spider web. The same is true of the 101 EEs. If one of the 101 EEs breaks down, it may lead to a FEMI issue and a process safety incident casting doubt and aspersions on the entire FEMI work process at the operating site. As you will see when reading each of the 101 EEs, many of them refer to other related EEs. As such, very few of the 101 EEs are stand alone, but each is an important part of the whole. In the end, I hope that all readers will come to understand that even though each of the 101 EEs is described separately, complete integration between all EEs is the web that holds them all together to produce excellence in FEMI, i.e. no high consequence FEMI leaks, no process safety incidents due to FEMI issues, and no un-

planned production outages due to FEMI issues.

Additionally the entire set of 101 EEs is dynamic, not static. FEMI technologies and methodologies are constantly changing. It's an advancing field of endeavor. Twenty years ago most sites didn't have FFS, RBI, CCDs, IOWs, MOC, many of the advanced NDE techniques and our FEMI codes and standards were few, simple and thin. Yesterday's new FEMI method is part of today's standard FEMI work process and tomorrow's bygone. Keep up or fall behind. The choice is yours.

Another change from the original 101 EEs of FEMI is that in many of the separate EEs, reference is made to other articles or industry standards that may be helpful to the reader to better understand each particular issue. Once again, this set of 101 EEs is only intended to be a highly condensed version of what FEMI issues you need to have in an effective and efficient management system at each operating site; and is not intended to explain how each of the 101 EEs needs to be implemented in detail. That's up to site management with the guidance of their FEMI specialists at each site to determine for themselves.

Acronyms

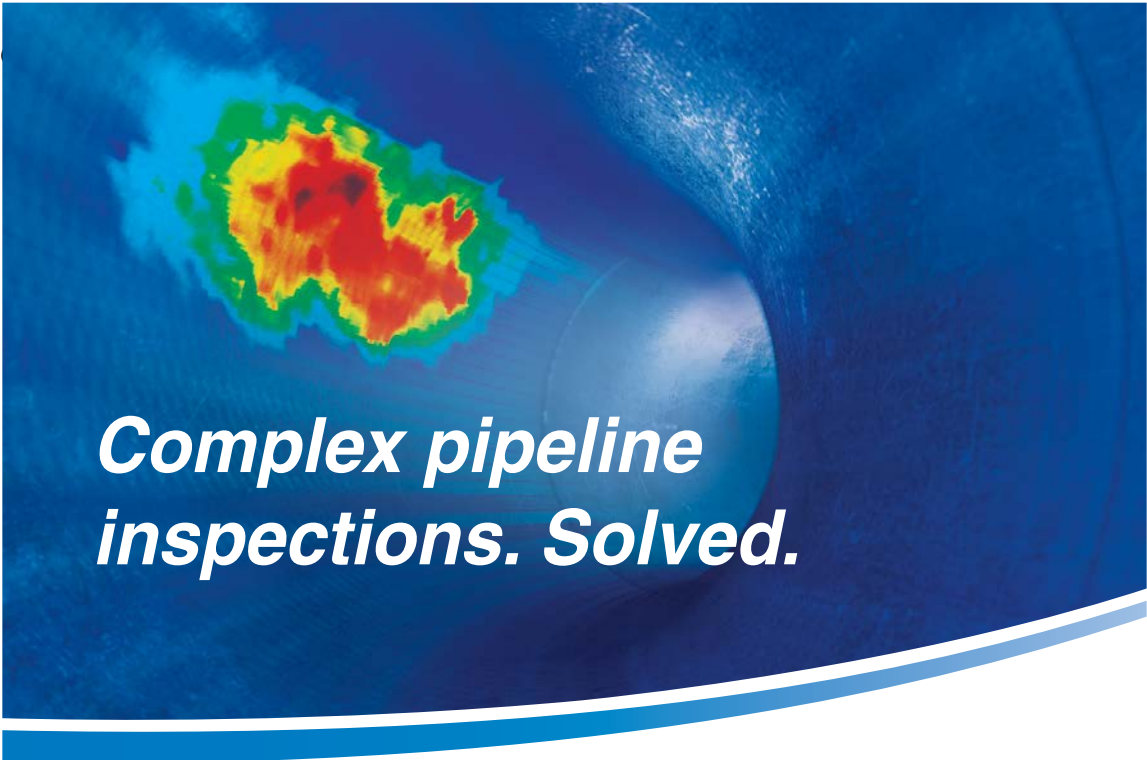
As most of my readers know by now, I use a lot of acronyms in my articles. Here are most of the more common ones you will see throughout this publication. It may be advantageous to the reader to print out this list of acronyms to be able to make quick reference to it as you read through the 101 EEs of FEMI.

AFPM	American Fuels and Petrochemical Manufacturers
API	American Petroleum Institute
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
AST	atmospheric storage tanks
ASNT	American Society for Nondestructive Testing
AUBT	Automated Ultrasonic Backscatter Technique
AWS	American Welding Society
BPVC	boiler and pressure vessel code (of ASME)
CCV	critical check valve
C/M	corrosion and materials
CMB	computerized monitoring button
CML	condition monitoring location
CP	cathodic protection
C/L	coating/lining
CSB	Chemical Safety Board
CUI	corrosion under insulation, including stress corrosion cracking under insulation
CV	curriculum vitae
CWI	certified welding inspector
DM	damage mechanism
DMW	dissimilar metal weld i.e. one alloy welded directly to a different alloy
DUTT	digital ultrasonic thickness testing
EE	essential element (of the 101)
ECSCC	external chloride stress corrosion cracking
ECT	eddy current technique
EMAT	electromagnetic acoustic transducer
EPC	engineering, procurement and construction
ERW	electric resistance welds
ET	eddy current technique
FA	Failure Analysis

FEMI	fixed equipment mechanical integrity
FFS	fitness for service
FRP	fiberglass reinforced plastic
GWUT	guided wave ultrasonic testing
HP/HT	high pressure - high temperature
ICP	Individual/Inspector Certification Program
ID	inside diameter
ILI	in-line inspection
IOW	integrity operating window
ISI	in-service inspection
ISO	inspection isometric drawing
LCM	life cycle management
LDAR	leak detection and repair (refers to fugitive emissions)
LFI	learning from incidents
LHC	light hydrocarbon
LT	long term
MOC	management of change
MAT	minimum allowable temperature
MAWP	maximum allowable working pressure
MDMT	minimum design metal temperature
MDR	manufacturer's data reports
MFD	material flow diagrams (PFDs with construction materials shown)
MFL	magnetic flux leakage
MIC	microbiologically induced corrosion
MMS	maintenance management system, ie. maintenance work order software
MOC	management of change
MT	magnetic-particle technique
MTR	material test report (mill test report)
NACE	NACE International (Formerly National Association of Corrosion Engineers)
NDE	nondestructive examination
NII	non-invasive inspection
NPS	nominal pipe size
OD	outside diameter
OEM	original equipment manufacturer
OJT	on-the-job training
OSHA	Occupational Safety and Health Administration
OSI	on-stream inspection
P&C	paint and coatings
P&ID	pipng and instrument diagram
PCC	Post Construction Committee (of ASME)
PEC	pulsed eddy current
PEIM	pressure equipment integrity management
PHA	process hazards analysis
PM	preventive maintenance
PMI	positive material identification
PQR	procedure qualification record
PRD	pressure relief device

PRT	profile radiographic technique
PRV	pressure relief valve
PSM	process safety management
PT	liquid-penetrant technique
PV	pressure vessel
PVV	pressure vacuum vent
PWHT	post welding heat treatment
QSF	qualified suppliers and fabricators
RA	risk assessment
RAGAGEP	recognized and generally accepted good engineering practices
RBI	risk-based inspection
RBDM	risk-based decision making
RBTAP	risk-based turnaround planning
RCA	root cause analysis
RFID	radio frequency identification devices
RIK	replacement-in-kind
RL	remaining life
RT	radiographic technique or radiography
RTP	reinforced thermoset plastic
SAI	soil-to-air interface
SBP	small-bore piping
SCI	subcommittee on inspection (within the API)
SDO	standards development organization e.g. API, ASME, NACE
SEIP	special emphasis inspection program
SME	subject matter expert
ST	short term
SMYS	specified minimum yield strength
UT	ultrasonic examination (method)
UTT	ultrasonic thickness testing
VCE	vapor cloud explosion
VOC	volatile organic compounds
WOL	weld overlay
WPS	welding procedure specification

Now, let us begin with the first of the *101 Essential Elements of PEIM*.



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Process Piping Inspection

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Of utmost importance to any fixed equipment mechanical integrity (FEMI) program is the process piping inspection program. The petroleum and chemical process industry continues to have more incidents due to breaches of containment related to process piping, than all other pressure equipment combined. Hence, having a very effective piping inspection program in accordance with the latest editions of API 570 Piping Inspection Code and its companion document API RP 574, Inspection Practices for Piping System Components, is foundational to a successful FEMI program. Both of these documents are currently being updated for a planned 2014 publication of their 4th editions. API 570 covers the requirements and expectations of an effective process piping inspection program, while its companion standard, API RP 574, covers the more informational aspects and recommended work practices of a comprehensive piping inspection program. These two standards include guidance on inspection for:

- external corrosion and corrosion under insulation (CUI),
- injection points,
- mix points,
- piping deadlegs,
- buried piping including soil-to-air interfaces,
- small bore piping,
- critical check valves,
- piping material verification,
- piping classification,
- piping circuitization,
- valves and flange joints,
- routine thickness monitoring,
- supplemental inspections, and
- a host of other piping inspection issues.

Each of the above piping inspection topics are in their own right separate issues covered in the 101 Essential Elements of Pressure Equipment Integrity Management, and for that reason, some of the are covered separately. Additionally these two process piping standards cover inspection planning, piping repairs, data taking and evaluation, record keeping and much more. If your piping program is done right and in full compliance with the requirements and expectations of these two documents, you should have an excellent piping inspection program with the result being very few process piping leaks and no major breaches of containment. Unfortunately, that's easier said than done. As I travel from site to site doing FEMI assessments, I find countless errors and omissions in piping inspection programs that cause sites to continue to have significant piping integrity problems. But I'm pleased to say that I also find some sites doing everything outlined in these two standards correctly and thereby having excellent piping integrity and reliability, and thereby are able to meet their business plan. It can be done with knowledgeable, committed FEMI personnel having the necessary resources to accomplish the job. Hopefully, others will read and study the entire 101 Essential Elements of Pressure Equipment Integrity Management as well as the two piping inspection standards and continue their journey up the ladder toward excellence in piping inspection programs.

Does your process piping inspection program contain all the essential elements outlined in API 570 & 574? Is your process piping inspection program as effective as your pressure vessel inspection program, in preventing leaks and process safety incidents? It can be.

Injection Points (IP)

Identifying and monitoring all potentially corrosive injection points (IP) are vital, fundamental aspects of any robust process piping inspection program. This issue surged to the FEMI forefront in 1988, when a refinery on the Gulf Coast suffered a catastrophic incident which claimed several lives and became one of the most costly accidents in the refining industry in the USA. Hundreds of people's lives were impacted; some forever. All because of severe, undetected corrosion, just downstream of an injection point that led to an elbow rupture and VCE. In 2001, another refinery in the UK suffered a very similar incident, but fortunately no fatalities this time. Soon after the first incident, special attention to the issue was provided by API 570, as well as its sister document API RP 574. These documents discuss the how, where, when and why to inspect and manage injection point circuits very carefully⁽¹⁻²⁾.

Potentially corrosive injection points are those that could experience a significant increase in corrosion rates if the injection point fails to perform as designed, or if the area in the vicinity of the IP could have corrosion rates different from the main piping system. An effective IP monitoring system typically depends upon quality input from process unit engineers and operations in order to remain up-to-date with the most recent changes. Injection points are defined by API 570 as locations where chemicals or process additives are introduced into a process stream. Corrosion inhibitors, neutralizers, process antifoulants, desalter demulsifiers, oxygen scavengers, caustic, and water washes are most often recognized as requiring special attention in designing the point of injection. Process additives, chemicals, and water are injected into process streams in order to achieve specific process objectives. Note that injection points do not include locations where two separate process streams join (see EE on mixing points).

Per API 570, injection points that are subject to accelerated or localized corrosion from normal or abnormal operating conditions may be treated as separate inspection circuits in your piping system, and they need to be inspected thoroughly on a regular schedule.

With regard to condition monitoring locations (CMLs) within injection point circuits subject to localized corrosion, API 570 provides the following guidance on the selection of CMLs:

1. establish CMLs on appropriate fittings within the injection point circuit (which is defined in API 570),
2. establish CMLs on the pipe wall at the location of expected pipe wall impingement of injected fluid,
3. establish CMLs at intermediate locations along the longer straight piping within the injection point circuit may be required, and
4. establish CMLs at both the upstream and downstream limits of the defined injection point circuit.

The preferred methods of inspecting injection points are radiography and/or UT, as appropriate, to establish the minimum thickness at each CML. Close grid ultrasonic measurements or scanning methods are more effective, as long as temperatures are appropriate. During periodic scheduled inspections, more extensive inspection should be applied to an area beginning 12 inches (300 mm) upstream of the injection nozzle and continuing for at least ten pipe diameters downstream of the injection point. Users are reminded that corrosion in injection point circuits can be highly localized, so the use of digital spot UT thickness measurements are not advised unless they are used in a very close grid monitoring pattern.

For some applications, it is beneficial to remove piping spools to facilitate a visual inspection of the inside surface. However, thickness measurements will still be required to determine the remaining thickness. NACE Pub 34101 summarizes an understanding of materials of construction issues and corrosion concerns and successful practices that have been used in the design and operation of refinery process mixing points and injection facilities⁽³⁾. Another article appearing in Inspectioneering Journal provides much more guidance on the design, operation, inspection, and management of IPs⁽⁴⁾. One best practice with regards to IPs is to have a data sheet on file that describes all vital aspects of the IP circuit including: purpose of the IP, injected fluids, design and operating conditions including intended flow regime, mechanical design description, materials of construction, quill design, IP circuit sketch, etc. Another best practice is to have a responsible owner (typically the unit process engineer) designated for the IP list for each process unit who is responsible for keeping the list up-to-date as changes occur. Of course, any changes in operating conditions or design of any IP must be subject to a rigorous MOC process. And a third best practice associated with all IP's is to have a pre-established maintenance priority in case the IP should become non-functional (e.g. the injection pump fails, especially during off-hours).

Do you have an up-to-date list of all your “potentially corrosive” IPs? Do you have a data sheet recorded for each IP and is it scheduled for effective inspection in accordance with API 570 guidance? Who is responsible for keeping the IP list up-to-date at your site?

References

1. API 570, Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition, American Petroleum Institute, Washington, D.C., November, 2009.
2. API RP 574, Inspection Practices for Piping System Components, Third Edition, American Petroleum Institute, Washington, D.C., November, 2009.
3. NACE Pub 34101, Refinery Injection and Process Mixing Points
4. [The Many Parts of Injection Points](#), Marc McConnell et al, Inspectioneering Journal, July/August, 2013.

Mixing Point Inspection

Mixing points (MP) are similar to injection points (IP), but different and equally important from a FEMI point of view. MP's are locations in piping systems where two or more different process streams meet, whereas injection points are where a small amount of fluid (often a chemical additive) is added to a process stream for the purposes of treating or changing the properties/composition of the main process stream. The difference in process streams that are combined at MPs may be chemical composition, temperature or any other operating parameter and may contribute to deterioration, accelerated or localized corrosion, and/or thermal fatigue during normal or abnormal operating conditions. Just as with IPs, MPs can lead to serious process safety incidents because of the often highly localized nature of the deterioration of the piping components at the point of mixing. Numerous sites have recently experienced serious localized corrosion or thermal fatigue cracking, and at least one incident that I know of led to two fatalities due to a large pool fire from hot naphtha being released from a pipe rupture. That rupture was because of a very localized eddy flow created at the MP as a result of different temperatures of the otherwise identical process streams being combined. Another refinery reported severe and undetected corrosion at a mix point where two process streams were coming together into one line. One stream was relatively dry, hot and non-corrosive; the other was cooler, wet and contaminated with dissolved salts, but otherwise the hydrocarbons were similar. When the streams came together, the mixing conditions resulted in severe, localized corrosion, right at the mix point that was very difficult to detect with normal spot UT. The increase in frequency of these types of MP piping failures and subsequent process safety incidents has led the API Inspection Subcommittee to put more focus on inspection of MPs in the pending 4th edition of the API 570⁽¹⁾.

Just as with IPs, all potentially problematic MPs (those subject to corrosion or cracking) should be identified by the operating group with the help of the process engineer and reviewed with a corrosion and materials SME to determine if these MPs have an increased susceptibility to damage or rate of degradation as compared to the primary process streams. MPs identified as such should be treated as separate inspection piping circuits (just as IP's should be). These MPs may need to be inspected differently using special techniques, a different scope, and at more frequent intervals when compared to the inspection plan for the parent piping stream(s).

Given the wide variation of mixing point designs and operating parameters, the corrosion and materials and inspection SMEs can then decide what inspection techniques and plans are needed. Those inspection recommendations will require careful review with consideration for mix point design (configuration and metallurgy), stream flow regime, composition and temperature differences, along with expected damage mechanism susceptibilities, and rates of degradation. Depending on flow regime, thermal fatigue cracking at the point of mixing could be a problem at temperatures above 275°F, with the lower temperature more prevalent when a gas stream (e.g. hydrogen) is being mixed into a liquid process stream. More guidance on this issue is anticipated to be part of the next edition of API 570.

Similar to IP circuits, the preferred methods of inspecting MPs include radiography and scanning ultrasonics to determine the minimum thickness and/or the presence of thermal fatigue cracking at each MP. Changes to mixing points, including but not limited to changes in flow regime, stream composition or characteristics, or components of construction and their orientation, should be identified and reviewed with appropriate MOC processes to determine what, if any, changes to the inspection plan may be required.

Do you have an up-to-date list of all your “potentially corrosive” MPs and are they scheduled for effective inspection to find either localized corrosion or thermal fatigue? Who is responsible for keeping the MP list up-to-date at your site?

References

1. API 570, *Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems*, Third Edition, American Petroleum Institute, Washington, D.C., November, 2009 (4th edition in ballot stage).

Small Bore Piping Inspection

SBP (piping less than or equal to NPS2 in process service) cannot be ignored, as it is another important aspect of any robust process piping inspection program. Although it is not as likely to lead to a catastrophic failure when compared with larger primary piping, numerous experiences have been reported in the industry where a SBP failure has led to serious reliability issues (process unit shutdown) and significant process safety incidents, typically due to the secondary effects of an ensuing fire which can cause the failure of other piping and vessels. In fact, a major US refinery had a large process safety incident, where a hydroprocess reactor toppled in the ensuing fire after a one inch line failed. Another small bleeder snapped off during temporary insulation removal leading to a near fatality and large fire⁽¹⁾. As a result of the numerous SBP failures causing process safety incidents, the API/AFPM Advancing Process Safety Program has created a “Focused Improvement” task group to investigate how the industry could improve its handling of SBP inspection programs. That group is just beginning its work as of January 2014.

In the meantime, API 570⁽²⁾ has some good guidance on inspecting and tracking SBP. SBP that is part of primary piping systems should be included in the same program as larger primary piping. API 570 defines primary process piping as process piping in normal, active service that cannot be valved-off or, if it were valved-off, would significantly affect unit operability. Hence, SBP that is part of primary piping systems/circuits should be included in the same program as larger primary piping (i.e. same inspection scheduling and record keeping as any other primary process piping regardless of size). Too often some sites get lulled into the belief that SBP is not as high risk as larger primary process piping and therefore does not receive the inspection and maintenance attention that it deserves, or that it required by API 570.

SBP that is secondary piping (that which can be valved-off without affecting operability of the process unit) should also have piping inspections scheduled based on API 570 requirements. If RBI is not in use, Class 1 secondary SBP must be inspected to the same requirements as primary process piping. Inspection of Class 2 and Class 3 secondary SBP is optional per the 3rd edition of API 570. Secondary class 2 & 3 SBP is often in deadleg service such as level bridles, vents, drains, etc. (see separate deadleg EE). As such, class 2 & 3 secondary SBP systems should be inspected where corrosion has been experienced or is anticipated. Once again, an appropriate risk assessment utilizing the knowledge of a C/M SME is useful to determine the extent and frequency of class 2 & 3 secondary SBP systems. Just do not ignore it assuming its smaller size means low risk. That is not always the case, especially when it is in a deadleg service.

Instrument and machinery piping, typically small-bore secondary process piping that can be isolated from primary piping systems, is typically considered auxiliary piping. Examples include flush lines, seal oil lines, analyzer lines, balance lines, buffer gas lines, drains, and vents. Inspection of auxiliary SBP associated with instruments and machinery is optional and the need for which would typically be determined by an appropriate risk assessment. Per API 570, the criteria to consider in determining whether auxiliary SBP will need some form of inspection include: a) piping classification, b) potential for environmental or fatigue cracking, c) potential for corrosion based on experience with adjacent primary systems, and d) potential for CUI. A major fire occurred at a mid-west refinery when a ¾ inch auxiliary tube in a hydro-process unit ruptured. So once again, auxiliary SBP cannot be ignored or assumed to be low risk without an appropriate risk assessment to plan the appropriate level of inspection.

Inspection of SBP threaded connections should be according to the requirements listed above for small-bore and auxiliary piping. Threaded connections associated with rotating equipment and subject to fatigue damage should be periodically assessed and considered for possible upgrading to welded components. The schedule for such renewal will depend on several issues, including the following: classification of piping, magnitude and frequency of vibration, amount of unsupported weight, current piping wall thickness, whether or not the system can be maintained on-stream, corrosion rate, and whether or not the piping is in intermittent service. Some sites periodically radiograph threaded connections in select services, while others require all SBP threaded connections in process services to be at least schedule 160 pipe. Even though ASME Section VIII, Div 1 and B31.3 still allow threaded connections in process services, because of poor experience, many companies now require all new SBP to be welded connections (typically socket welded), but continue to inspect and maintain threaded SBP in lower risk services.

Finally, in my opinion, the inspection method of choice for nearly all SBP is radiography, not only because

of the difficulty of getting accurate UTT measurements on SBP, but also because of the nature of the corrosion typically experienced in SBP.

Does SBP get the attention it deserves at your operating site? Do you have an adequate inspection program for your primary, secondary, auxiliary, and threaded SBP per API 570 to provide the assurance needed that SBP will not cause process safety or reliability incidents?

References

1. [Small Bore Piping Inspection Program: How a Serious Incident and Investigation Led to a Best Practice](#), Anthony J. Rutkowski, Inspectioneering Journal, November/Decceember, 2013.
2. API 570, *Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems*, Third Edition, American Petroleum Institute, Washington, D.C., November, 2009.

Inspection of Deadlegs

Piping deadleg (D/L) inspection is another very important, fundamental aspect of any robust process piping inspection program and is closely related to the SBP inspection program (see separate EE).

A few years back, a refiner experienced a major loss when a deadleg in a hydrotreater ruptured as a result of undetected, severe corrosion in a D/L in a hydroprocess unit. Most piping systems have deadlegs (piping with normally no flow) that may have different corrosion rates than primary piping. These deadlegs have caused numerous significant process safety incidents in the industry, especially when they were not adequately identified and inspected. All potentially corrosive deadlegs should be identified on piping isometric drawings and tracked in separate circuits in the IDMS. Deadlegs associated with an active piping circuit may be combined into one circuit if their anticipated corrosion rates are similar. Operations representatives are usually best suited to help the inspection group identify all D/Ls in each process unit which will include all vents and drains and other secondary SBP, as well as D/Ls associated with by-passes on CV loops. Inspection tools and techniques that will find localized corrosion are typically necessary for D/L inspection (i.e. NDE techniques other than spot ultrasonic thickness measurements like profile radiography, which is most commonly used; but scanning UT, PEC, and EMAT may be effective in some situations).

D/Ls require focused inspection attention from a corrosion and materials SME if they are deemed potentially corrosive because of issues like the accumulation of contaminated water, the accumulation of solid materials (under deposit corrosion), and even gas phase corrosives like H₂S. Additionally, different temperatures from the main line can cause accelerated corrosion. The accumulation or concentration of corrosive species (e.g. ammonium salts, organic acids, and acidic deposits) can lead to accelerated and localized corrosion. Risk assessment with input from a corrosion and materials SME can be useful in determining which piping system D/Ls may be a higher threat for accelerated corrosion than the active piping circuits. D/Ls that are considered primary piping, especially those greater than NPS 2 should be considered at greater risk because of the inability to valve them off in the event of a leak and the higher potential consequence of a larger leak. (see separate EE on SBP).

Corrosion and materials SME's should be consulted for placement of CMLs on deadlegs due to their potential for localized corrosion, especially with regard to accelerated corrosion above and below liquid/gas interfaces. Infrared thermography may be useful for locating liquid interfaces in deadlegs. Inspections of horizontal deadlegs that may not be liquid full should have examination points in all four quadrants of any CMLs. A major fire occurred on the West Coast of the USA when hot hydrogen sulfide gas accumulated in a horizontal D/L causing undetected accelerated corrosion on the top of the horizontal D/L.

The other nasty surprise happens when a D/L full of process water freezes in particularly harsh winter weather, and then ruptures when the deadleg thaws. A large Mid-West refinery suffered a substantial fatal fire a few years ago when a deadleg full of water froze in a light hydrocarbon processing facility, ruptured and released a cloud of propane. But this was not an isolated incident, as it has occurred to numerous process plants during particularly harsh winter weather. D/Ls that can accumulate process water and freeze need to be identified, drained, and well insulated or removed.

Active consideration should be given to removing potentially corrosive deadlegs that are not needed by operations, thus removing the risk of D/L leaks and their associated process safety incidents. Any time a D/L is created by a physical piping change or an operational change, an MOC should be conducted to determine if focused or different inspection may be needed.

Do you have all your process piping D/Ls identified for each process unit? And do you have an effective inspection program for monitoring any potentially corrosive D/L's or removing them if they are not needed? Do you have D/Ls that may be susceptible to freezing in harsh winter weather?

Mixed Metallurgy Vessels and Piping Systems

Keeping track of and avoiding mixed metallurgy piping systems is another important aspect of any robust process piping inspection program. Sometime back, a US West Coast refinery experienced an intense and destructive fire in a process unit when a carbon steel pipe ruptured, releasing hot hydrocarbons that immediately ignited. As it turns out, the piping system had mixed metallurgy in it, with some carbon steel components and some Cr-Mo alloy steel to resist increasing corrosion rates from sulfidation. The carbon steel was corroding at one rate and Cr-Mo at another rate. As it turns out, the carbon steel components were installed in a specified Cr-Mo piping system during a turnaround after inspectors found some thin piping components near the end of the turnaround. But the Cr-Mo components were not available on short notice, so it was agreed to temporarily install CS components that would corrode faster, but then replace them at the next maintenance turnaround. Well, as these things go, with personnel turnover and less than adequate record-keeping, the site lost track of the temporary CS pipe components and one eventually ruptured. Lesson learned: Don't ever install temporary pipe components of a lesser grade of alloy unless you have a fool-proof method of ensuring that they are monitored and replaced before it is too late. This issue is closely related to the separate EE's on Material Verification & PMI and Low Silicon CS in Hot Sulfidation Service.

A related issue is changing pipe specs in piping systems. It is not uncommon to have piping spec-breaks where a higher alloy piping system connects directly with a lower alloy (or CS) piping system. This is because piping designers make assumptions that at some point in a piping system the higher alloy is no longer needed, often because there is a design temperature change. When that occurs, it is very important that a CML is placed just upstream of the pipe spec-break and just downstream of the spec-break, so inspectors can closely monitor the difference in thickness or the potential for other damage mechanisms. And of course these spec-breaks should clearly show on piping inspection isometric drawings as well as on P&IDs. Sometime back, another West Coast refinery experienced a severed pipe at a piping spec-break, which also happened to be a dissimilar metal weld (DMW) between two alloy materials. As it turns out, the process conditions changed over time with temperatures at the DMW increasing to the point where the lower grade alloy was insufficient to resist HTHA, at which time the weld cracked and pipe severed, creating a huge process safety incident in a hydroprocessing unit.

DMWs should be “avoided like the plague”. There have been many recorded FEMI failures and process safety incidents occurring when DMWs cracked and failed. DMWs should be a very last resort and only used where they are less risky than having the spec-break across a flanged joint, and where a welding metallurgist designs the welding process to connect the two alloys and all but guarantees that the resulting weld will not be susceptible to DMW cracking. This is especially true in the case in HF process equipment and piping where CS is sometimes welded directly to Alloy 400 and ends up with a high hardness zone that is susceptible to cracking⁽¹⁾. This is not to say that some DMWs cannot be successful in-service, but is meant to say that if they are necessary, for some alloy combinations, it takes great attention to detail by SMEs in design and inspectors in QA/QC to ensure that all goes well during design and fabrication in order to avoid cracking in-service.

Do you know where all your mixed metallurgy piping systems, spec breaks, and DMWs are in your process units? And do you have a plan to monitor, inspect, and upgrade them as necessary?

References

1. API RP 751, *Safe Operation of Hydrofluoric Acid alkylation Units*, 4th edition, May, 2013, American Petroleum Institute, Washington D.C.

Low Silicon Carbon Steel in High Temperature Sulfidation Service

High temperature sulfidation is probably the most common high temperature corrosion nemesis in the refining industry, since there are few “sweet” refineries still in operation. Sulfidation corrosion typically is of concern in hot sour oil services starting at temperatures in the 500F (260C) range. API RP 751⁽¹⁾ and 939C⁽²⁾ provide a fantastic overview of high temperature sulfidation, therefore that guidance will not be repeated here.

Back in the 1950s and 1960s a number of refineries were installing carbon steel (CS) in sulfiding services even up into temperatures in the 650F range, but for the most part were specifying that the CS be of silicon-killed (e.g. A106B) grade because even at that time it was known that silicon contents above 0.10% imparted significant resistance to sulfidation corrosion. However, without rigid controls over construction, fabrication, and maintenance activities, non-silicon killed CS pipe segments would sometimes inadvertently get installed. Over the long haul, non-silicon containing fittings and pipe (e.g. A53B) will corrode at significantly higher rates than silicon-killed CS, such that if you do not have condition monitoring locations (CML's) on each of the low silicon containing components, you may be at risk of an unexpected sulfidation failure. There are numerous recorded incidents in the industry of major failures and near-misses (i.e. very thin pipe found) for just that reason; and of course the fairly recent incident on the U.S. West Coast which garnered a lot of attention when a short segment of pipe failed and led to a large fire in a crude unit. This low-silicon CS issue is very similar to the mixed metallurgy Essential Element covered separately.

Hence, if you do not know for sure if all of your CS piping in sulfidation service is silicon-killed, or if you do not have a CML on every single component in such service, it may be necessary to do a one-time survey to find each component under insulation and measure the thickness to provide assurance that you do not have that one or more rogue components corroding at a much faster rate. The primary reason such a survey is necessary is that sulfidation of CS is frequently a relatively uniform corrosion rate over a large area; giving rise to the greater likelihood that pipe failure could be a substantial rupture (i.e. large fire, as opposed to a small leak that is more easily contained). Sometime in the mid to late 1980s, pipe suppliers started to supply double stamped CS pipe (e.g. A106B/A53B), which was all silicon-killed and therefore the potential for inadvertently installing low-silicon pipe components was reduced after that time period.

The inspection process for finding low-silicon pipe components in these older CS systems with unknown pedigree generally consists of real-time radiographic or guided-wave ultrasonic techniques to find all welds under the insulation, and then doing thickness measurements on each component to determine if some may be corroding at higher rates than those that have previously had TMLs and therefore their corrosion rates are known. Some use is also being made of pulsed eddy current (PEC tool) to measure thicknesses of components under insulation and a few others are using more modern PMI tools to measure silicon content during downtime. Note that the 939C task group is now in the process of revising that document to provide much better coverage of the low-silicon CS issue.

Might you have older CS piping systems in sulfidation service that may have a few non-silicon killed CS components included that are corroding at a faster rate than those components with CMLs? If so, have you done a 100% survey to find and measure the thickness on all CS pipe components?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, Second Edition, American Petroleum Institute, Washington, D.C., April, 2011.
2. API RP 939C, *Guidelines for Avoiding Sulfidation Corrosion Failures in Oil Refineries*, First Edition, American Petroleum Institute, Washington, D.C., May, 2009 (2nd edition in preparation).

Flare and Pressure Relief Piping System Inspection

Flare and pressure relief piping (FPRP) systems need to be inspected routinely for fouling and corrosion. Clearly, when we need our FPRP systems to operate in accordance with design under emergency relief conditions, we want to be assured that they are not fouled or degraded so that they will perform per design when an unpredictable demand occurs. Radiographic inspections for fouling material at strategic points will sometimes reveal that the FPRP lines are partially plugged with coke or other process deposits; in which case, some maintenance and/or operating measures to clear the obstruction will be necessary, such as mechanical or chemical cleaning/flushing. Ultrasonic scanning techniques and/or radiographic inspections (profile and/or density RT) for thinning and localized corrosion are also vital to integrity management of FPRP systems. Do not assume that spot DUTT measurements at distributed CMLs will find localized corrosion in FPRP piping.

I can recall one major disaster that occurred when a flare line in a CCU, known to be thinning, ruptured and fell to the ground due to slug flow conditions during an emergency relief scenario. Another incident occurred in a refinery when a buried flare line ruptured in the middle of a process plant during an emergency release. It is not uncommon for flare piping systems to be inadequately sloped for drainage, thus trapping corrosive fluids, aqueous solutions, and fouling deposits, and leading to localized corrosion, including interface corrosion, between the liquid phase in low spots in the bottom of FPRP piping and the gaseous phase above it. Some FPRP systems are routinely subject to corrosive fouling deposits that lay in the bottom of FPRP systems (e.g. hydrofluoric and sulfuric acid alkylation units and hydrocarbon process units that dump sour solutions into FPRP systems).

FPRP systems are often difficult to schedule for out-of-service inspection, especially when they service multiple process units. In such cases, risk analysis involving C/M SMEs knowledgeable in the corrosive nature of the fluids being handled in the flare system is useful to determine the degree of risk the site may be carrying by prolonging intervals between flare system inspections. On the other hand, a great deal of information on the condition of FPRP systems and vessels can be gained with appropriate on-stream inspection (NDE) techniques conducted using appropriate safety practices. Flare tip inspection is a special issue. I am familiar with three cases where highly elevated flare tips were inspected from a crane basket (personal case), from the ground with high powered binoculars (looking for obvious visual damage), and from a helicopter.

FPRP systems subject to occasional slug flow upsets (e.g. large dynamic forces) should have their supports/shoes inspected for potential movement relative to design positions, especially after an increased demand due to a significant emergency relief scenario. I have seen welded shoes on FPRP systems slide completely off their supports under such circumstances and then get hung up on one side or the other of the pipe rack support member, thus putting large piping stress on the flare piping due to the unusual restraint because the shoes could not return to their design location.

Are your flare systems “out of sight – out of mind”? Or do you conduct scheduled monitoring and/or periodic maintenance for both corrosion and fouling to gain assurance that your very important emergency control FPRP systems will perform in accordance with design, when you need them the most?

Selection and Placement of Corrosion Monitoring Locations (CMLs)

Certainly one of the fundamental activities in any FEMI program is condition monitoring. In the 3rd edition of API 570, we converted from the thickness monitoring locations (TMLs) to condition monitoring locations (CMLs) in recognition of the fact that when we are examining equipment and piping with NDE, we are often looking for damage mechanisms other than just corrosion (i.e. metal loss). For example, at some CMLs, we may be looking for environmental cracking, embrittlement, signs of creep, CUI, HTHA, etc. When looking for damage other than corrosion, a variety of different NDE techniques are applicable; for example, when inspecting for thickness, if the corrosion is likely to be localized, then radiography, scanning ultrasonics and other NDE techniques would be applicable. So the CML concept is simply an expansion of the TML concept, while recognizing that thickness monitoring is still the most prevalent type of NDE being conducted at CMLs. Sections 5.6 and 5.7 of API 570⁽¹⁾, along with the referenced sections of API RP 574, provide exceptional guidance on the selection, placement, and monitoring of CMLs on piping, while sections 5.6 and 5.7 of API 510⁽²⁾ do the same for vessels. Hence that guidance is referenced in conjunction with this EE, but will not be repeated here. If you have not read it lately, I encourage you to do so.

It is important to note the difference between a CML and an examination point. CMLs are: “Designated areas on piping systems where periodic external examinations are conducted in order to directly assess the condition of the piping. CMLs may contain one or more examination points and utilize multiple inspection techniques that are based on the predicted damage mechanism to give the highest probability of detection. CMLs can be a single small area on a piping system (e.g. a 2 inch diameter examination point) or can be plane through a section of a nozzle or pipe component where examination points exist in all four quadrants of the plane.” Whereas an examination point is: “An area within a CML defined by a circle having a diameter not greater than 2 in. (50 mm) for a pipe diameter not exceeding 10 in. (250 mm), or not greater than 3 in. (75 mm) for larger lines and vessels.” As I travel around the world performing MI assessments at various refineries and chemical plants, I find a great deal of confusion between the two definitions. CMLs can contain numerous examination points (e.g. one CML on a pipe may have an examination point in four quadrants of the CML), and one CML may be an entire elbow (e.g. an NPS10 elbow might have numerous examination points on the extrados, intrados, top, bottom, sides, etc.), and various NDE methods may be employed within a given CML for internal metal loss, potential cracking mechanisms, CUI, etc.

As I travel from site to site reviewing the quality of FEMI programs and offering suggestions for improvement, I am sometimes struck by how many times I find the selection and placement of CMLs to be inadequate for the type of damage that may be prevalent in any piece of equipment or piping circuit. Since most operating site corrosion, cracking or other damage we need to monitor is not relatively uniform, it is imperative that knowledgeable C/M SMEs help to carefully select proper locations for CMLs in order to provide the best chances of finding and quantifying deterioration. I am not enamored by the concept of randomly placing CMLs on vessels and piping components, except in the very rare case where we expect only relatively uniform metal loss. In the other 90+% of the cases, I believe you should seek the guidance of C/M SMEs for what causes corrosion, cracking, and other forms of deterioration, so that you can place CMLs at the spots where deterioration is likely to be the worst or at least more likely to occur (i.e. placing CMLs on the “weak links” in our piping chains). This advice is especially true for injection points, deadlegs, hydrodynamic corrosion, erosion-corrosion, dew point corrosion, and a host of other localized damage mechanisms indicated in API RP 571. Too often I have reviewed piping isometrics and vessel layout drawings and found the CMLs located in spots that do not make much sense and/or where you are likely to miss the most significant potential for deterioration. In fact, I have found CMLs every 30 feet on a non-corrosive natural gas pipe, every few hundred feet on a non-corrosive steam line, and every 12 inches on a line that suffered from rapid, extremely localized hydrodynamic corrosion from ammonium hydrosulfide. In the latter case, the corrosion penetrated the wall and caused a major fire in between two closely spaced CMLs where radiography or scanning ultrasonic techniques would have been a far better choice than spot DUTT. The guidance of C/M SMEs can also help you determine what inspection techniques and tools to use to provide greater assurance that you will find the type of deterioration that is most likely to cause failure. The best quality CCDs (see separate EE) will contain advice on the placement of CMLs relative to the identified damage mechanisms in the CCDs.

Are your CMLs placed with the advice and counsel of persons knowledgeable in the corrosion mechanisms

that are of concern in your piping and equipment, in order to place your CMLs in the areas of highest probability of occurrence and highest rates of deterioration?

References

- 1. API 570 *Piping Inspection Code: In-Service Inspection, Rating, Repair and Alteration of Piping Systems*, 3rd edition, November 2009 (4th edition in ballot stage as of 1Q/14).
- 2. API 510 *Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair and Alteration*, 9th edition, June 2006 (10th edition approved and pending publication as of 1Q/14).

Piping Circuitization

To accomplish thickness trending calculations for corrosion rates, remaining life and next inspection due dates in your IDMS, owner/users need to create piping corrosion circuits. Piping circuits are defined in API 570⁽¹⁾ as: “A section of piping that is exposed to a process environment of similar corrosivity and the same expected damage mechanisms and is of similar design conditions and construction material. Complex process units or piping systems are divided into piping circuits to manage the necessary inspections, calculations, and record keeping. When establishing the boundary of a particular piping circuit, the inspector may also size it to provide a practical package for record keeping and performing field inspection.” Large vessels and columns may also be segregated into circuits for the same purpose (e.g. a tall crude distillation column might have an O/H corrosion circuit, a mid-range distillate corrosion circuit and a heavy bottoms corrosion circuit because of the significant differences in temperature, process fluids, corrosivity, and sometimes even materials of construction).

Thickness monitoring schedules should then be managed at the corrosion circuit level of the IDMS hierarchy rather than at the CML level. While the IDMS should trend thickness data for each CML, trying to manage inspection schedules for tens of thousands of CMLs (hundreds of thousands of CMLs for some operating sites) would be an enormous and inefficient effort. The concept of using corrosion circuits allows the inspector to trend thickness data without having to measure every CML at each scheduled thickness monitoring inspection. For example, a piping corrosion circuit with thirty CMLs, that is being monitored for high temperature sulfidic corrosion, has an operating temperature such that the corrosion rate is reasonably low and consistent (e.g., 0.005 inches per year or 5 mpy). In this circuit, with non-localized corrosion and an adequately recorded history, the inspector might choose to only inspect 50-60% of the CMLs at each given thickness monitoring inspection, rotating which CML's get inspected at each inspection, while ensuring that the CML with the highest corrosion rate is measured at each thickness inspection and that every CML is measured at least every third inspection. Of course this example assumes that steps have already been taken to assure the owner/user that all low silicon components in such circuits exposed to hot sulfidation have representative CMLs, since they might be corroding at a much higher rate than other CMLs (see separate EE).

In my visits to many refineries and process plants over the years, I have seen a number of sites that do not adhere to the above circuitization philosophy very well (i.e. most often I see circuits that have too wide a range of operating conditions which lead to a wider range of corrosion rates; sometimes I see mixed metallurgy; sometimes I see deadlegs which are more corrosive in the same circuit as active piping which has lower corrosion rates, etc). Typically, piping circuits would never extend beyond going from one piece of equipment to the next (especially heat exchangers), and if there were a process mixing point in the middle of a circuit, that would likely require a break point between two circuits. And per API 570, injection points should always be in a separate circuit. It will pay off to review your piping circuitization to make sure that the circuits are the right size and that they adhere to the API 570 philosophy. I find that not every inspector knows how to best circuitize process piping and should not be left on his/her own to do it without guidance from C/M and/or FEMI SMEs. It is also useful to involve a process engineer who is knowledgeable in the specific process conditions in each process unit in the discussions over how to best circuitize each unit.

One misinterpretation of API 570 circuitization that I have seen is when operating sites skip over the due dates for lower priority piping circuits in the mistaken belief that each circuit does not need to have CMLs measured on some scheduled frequency. That is not what API 570 intended. While it is okay to not inspect every CML in each circuit every time the entire circuit comes due (where your IDMS allows for statistical analysis based on circuit averaging of corrosion rates), API 570 did not intend for sites to skip over entire circuits based on inspecting other circuits. Each piping circuit should have a scheduled frequency.

Do you have all your piping systems properly circuitized in accordance with the circuit definition in API 570?

References

1. API 570, *Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems*, 3rd Edition, American Petroleum Institute, Washington, D.C., November, 2009.

Corrosion Control Documents (CCDs)

Of all the important 101 EEs of FEMI, one primary EE stands out as a critical foundational block to support the entire FEMI work process; and that is to create CCDs for each process unit as the primary repository of information that will help to minimize the chances of unanticipated failures/leaks/ruptures of fixed equipment from in-service damage mechanisms. So what is a CCD? It's basically a document that tells users almost everything they need know about the mechanical integrity issues of fixed equipment in each process unit in order to help avoid unexpected deterioration of materials of construction and how to manage corrosion and other damage mechanisms that afflict fixed equipment in service. One way to think of it is that it takes the type of generic information available in API RP 571⁽¹⁾ and creates a document that is very specific to the chemistry and degradation mechanisms in each individual process unit in an operating site. While API RP 571 is an excellent document covering (in brief) nearly every damage mechanism known to refining and petrochemical manufacturing, knowledgeable technical SMEs need to translate that useful generic information in API RP 571 into more useful information as it applies to each specific process unit. Several other of the 101 EEs in this publication will present information that should be found in or linked to each process unit CCD.

That process specific information is then recorded in something called a Corrosion Control Document (CCD), or perhaps a document known by other names like Damage Mechanism Control Manuals, Corrosion Control Manuals, etc. I use CCDs to describe the document because that's one of the terminologies used to describe the documents in the new API RP 584⁽²⁾ on IOWs. However, I recognize that the name "Corrosion Control Manual" is a bit of a misnomer since some damage mechanisms that afflict fixed equipment in service are not strictly "corrosion", such as fatigue cracking, embrittlement mechanisms, brittle fracture, etc. So the reader must think in terms of the broader use of the term "corrosion", which is of course why the API chose the terminology "damage mechanisms" in the title of API RP 571.

This EE describes the contents of a comprehensive and thorough CCD and a work process to create them. That process is not dissimilar to the process needed to assess and record damage mechanisms for use in the application of most any type of RBI per API RP 580⁽³⁾. In fact, some companies have created CCDs as a forerunner to implementing RBI in each process unit, since damage mechanism assessment is one of the most important aspects of implementing RBI. However the contents of a CCD usually go well beyond the simpler assessment of damage mechanism needed for RBI implementation and describe an overall strategy for managing equipment deterioration in service and not just a process for planning inspections based on risk analysis.

Why are CCDs so important to FEMI? Because, when they are created by competent, experienced SMEs, they capture nearly everything that is known about how equipment degrades in a particular fluid service and how to avoid it. As the saying goes, "maintaining the integrity and reliability of fixed equipment is not rocket science". All we have to do is to seek and apply existing knowledge about FEMI. There is rarely anything new when it comes to the body of knowledge for fixed equipment degradation mechanisms. Perhaps once every 15-20 years something relatively new comes along in the petrochemical industry such as wet H₂S cracking in 1984 and HTHA cracking of carbon steel below the Nelson curve in 2010. But the industry keeps experiencing major failures from degradation issues that have been known for decades. Why? Because all the people at each operating site who need to know about these degradation mechanisms and how to avoid and control them don't know what is known by FEMI SMEs. Creating and implementing CCDs is the best way I know to solve that knowledge gap.

Contents of a CCD and the Work Process to Create a CCD

Space is too limited in this publication to detail the entire work process to create a CCD and everything that a comprehensive CCD should contain; so the reader is referred to the pending publication of API RP 584 on IOWs⁽²⁾ to understand the work process and to see a list of everything that should be included in it. Until that consensus standard is published, the reader is referred to an article that appeared in *Inspection Engineering Journal* for a lot more information of the CCD work process and contents⁽⁴⁾. Finally, the API believes that CCDs are so important to minimizing the chances of FEMI failures, that it has approved a new standard to be written on how to create them. As of this writing, the first organizational meeting has been held, so publication of the new standard is likely three years in the future (~2016).

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, Second Edition, American Petroleum Institute, Washington, D.C., April, 2011.
2. API RP 584, *Integrity Operating Windows*, First Edition, American Petroleum Institute, Washington, D.C., May, 2014.
3. API RP 580, *Risk Based Inspection*, Second Edition, American Petroleum Institute, Washington, D.C., November, 2009 (3rd edition in preparation as of 4Q/13).
4. [Corrosion Control Documents - One High Priority Approach to Minimizing Failures of Fixed Equipment](#), John T. Reynolds, *Inspectioneering Journal*, Sep/Oct 2012.

Identification of Process Unit Damage Mechanisms

This EE is closely related to the EE on Corrosion Control Documents (CCDs) and RBI in that it is a major part of what needs to be done during the assembly of a CCD and is certainly one of the most important steps required for RBI. Identification of the probable damage mechanism for each process unit can only be done with the involvement of a competent, experienced, knowledgeable C/M engineer who is also knowledgeable in the chemistry for the particular process unit being reviewed. Note that I said “probable” DMs, rather than possible or some other all encompassing word. Too often I’ve seen the results of DM reviews that were completed by individuals who either were not well versed in DMs for the petrochemical industry, or did not really understand the chemistry of the process unit being reviewed; and hence the resultant DM report was not very useful in that it was just the result of a “dart throwing” exercise at a board containing the titles of all 67 DMs listed in API RP 571⁽¹⁾. Hence, where outside resources are hired for this job, it’s up to the buyer (site) to fully vet not only the company, but also the SME who will be doing the DM review for them to make sure they are truly qualified to deliver a high quality DM report.

As described in the first edition of the new API RP 584⁽²⁾, it takes effective teamwork of a group of SMEs pooling their knowledge and skills to effectively identify all the potential DMs to which each process unit might be susceptible. The DM/CCD team should include such SMEs as:

- Site corrosion engineer/specialist/metallurgist,
- Unit process engineer/technologist specialists,
- Unit inspector,
- Unit pressure equipment/inspection engineer,
- Experienced unit operations representative(s),
- Unit maintenance/reliability engineer (as needed, ad hoc),
- Process chemical treatment vendor (as needed, ad hoc), and a
- Facilitator/team leader knowledgeable in the DM identification work process, which is often an industry experienced C/M engineer.

The qualifications of the team members and the quality of the development process, and therefore the quality of the CCDs produced (home of the identified DMs), are dependent upon the collaborative effort from the interaction in this group of knowledgeable, experienced SMEs. Because of the conflicting business priorities, the team members and their management have to consider their participation on the team as a high priority in order to produce a high quality CCD in a reasonable period of time. The attitude and support of site management can’t be understated. To get all the DMs identified and the CCDs created in a reasonable period of time, it takes a very enlightened site management that believes that the prevention of process safety incidents caused by FEMI failures is one of their highest priorities.

In a previous article in *Inspection Engineering Journal*, there is a list of 34 generic questions for the DM/CCD team to ask themselves about potential damage mechanisms in a process unit⁽³⁾. Most of these issues have caused repeated, high consequence incidents in our industry. And most of the FEMI issues are well documented in the latest editions of industry codes and standards dealing with FEMI issues. The C/M specialist on the DM team should be aware of and bring to the table all types of potential FEMI issues like these that might affect asset integrity and therefore process safety risks in any particular process unit. Plus the C/M specialist will be able to ask the appropriate follow-on questions to each of these issues to help determine the likely probability of occurrence for each DM, where in the process unit each DM might be expected to occur, under what process conditions each DM might be expected to occur, etc., thus providing a lot of focus for the inspection group when looking for each type of damage mechanism.

Has your site used the team process to identify all the probable DMs that might afflict each process unit so that the proper IOWs and inspection plans can be implemented to avoid FEMI failures?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, Second Edition, American Petroleum Institute, Washington, D.C., April, 2011.
2. API RP 584, *Integrity Operating Windows*, First Edition, American Petroleum Institute, Washington, D.C., May, 2014
3. [Managing the Risks Associated with Fixed Equipment Mechanical Integrity Issues](#), John T. Reynolds, *Inspection Engineering Journal*, May/June, 2013.

Integrity Operating Windows (IOWs) for Fixed Equipment Mechanical Integrity

A comprehensive IOW program⁽¹⁾ is another vital EE for success of the total FEMI program, without which FEMI failures and their consequences are probably going to continue, no matter how good the rest of your FEMI program is. In fact, an IOW program for avoidance of FEMI failures is so important, the API has created a new standard, API RP 584 to describe the entire work process needed to create and implement IOWs at an operating site⁽²⁾. It takes solid team work between operations, process engineers and corrosion engineers, among others to establish and maintain an effective IOW program that will help to avoid FEMI incidents. In API RP 584, there are systems and procedures that describe how IOWs are created and implemented, including how operators and others are to respond (corrective actions) to IOW alarms and variances (as well as how quickly they need to respond). Additionally, the RP includes how changes are to be made to IOWs once they are approved and implemented in the field. Further, the RP describes what process monitoring techniques and process sampling may be needed to provide assurance that the process stays within the established IOW limits.

So what are IOWs? Basically, in order to operate any process unit, one needs a set of operating ranges and limits that are established for process variables, within which the process unit operators need to control the process in order to achieve the desired results, i.e. spec product, safe operation, reliability, etc. IOWs are a segment of that set of operating limits (in this case called operating windows) that address the controls necessary on any and all process variables that might affect the integrity or reliability of the process unit. As such, IOWs are those preset limits on process variables that need to be established and implemented in order to prevent potential breaches of containment that might occur as a result of not controlling the process sufficiently to avoid unexpected or unplanned deterioration or damage to pressure equipment.

One of the simplest examples of IOWs is the establishment of heater tube temperature limits to avoid premature rupture. At some established limit, say 800 F, a furnace tube designed for 775 F would have a shortened service life, so operators would be directed to regain control of heater firing to get back below 775 F within a preset amount of time. That limit of 775 F would be an IOW limit for those furnace tubes. Now if the operator has 4 hours to regain control at the 775 F limit, we might call that limit a standard limit. However, if the heater firing exceeds the 800 limit, and the operator is given just 30 minutes to correct the situation or he/she has to shut down the furnace, then we might call the next higher limit, a critical limit. So you see, there can be different levels of process limits that have different actions associated with them and/or different urgencies for those actions, depending upon the seriousness and extent of the exceedance.

While the above is an example of upper temperature limits, there may also be lower temperature limits that need to be maintained in order not to impair pressure equipment integrity. An example of that might be where a process abnormality could cause temperatures of construction materials to fall below the Minimum Design Metal Temperature (MDMT) and thereby make the equipment susceptible to brittle fracture in service.

One of the first steps in defining IOWs for any process unit is to fully understand all the potential and likely types of degradation and modes of failure that could occur in each piece of process equipment (see separate EE on Identification of Damage Mechanisms). Once that process is complete, then the same group of SMEs looks at the process variables that can have an impact on the type and rate of deterioration that can occur and begin to set the limits on those process variables.

Risk analysis may/should be applied in the IOW establishment process to determine what is the level of risk that equipment might be exposed for each type of exceedance of each designated process variable (see separate EE on Risk Assessment). Clearly this risk assessment would then help to determine what actions the operator needs to take and how fast the operator needs to act before things get too far out of hand i.e. the higher the risk, the sooner the operator may need to respond and the more definitive the response may need to be.

Once the complete list of IOWs is established, we're only half done. The other half of the task is equally important, which is implementing the IOW list in the field so that effective actions are taken each time an exceedance occurs. In other words, a comprehensive list of IOWs sitting on the shelf or in some unknown

electronic file is almost worthless unless it is effectively implemented. To do that, systems and procedures need to be established to notify the operator when an exceedance has occurred. That will likely involve monitoring instruments and/or sampling points for each IOW variable. If it's a monitoring instrument, then instrumented displays and alarms will likely be needed. If it's a sample point, then procedures and practices will be needed to analyze a designated process stream and report it back to the operator within a predetermined amount of time so that the appropriate action can be taken.

Finally there's the issue of updating IOWs to account for process changes or new information about degradation mechanisms, or perhaps even a variable that was overlooked in the original IOW establishment process (not uncommon). The MOC process should be applied whenever IOW variables are being revised or updated (see separate EE on MOC for FEMI).

A healthy, properly designed inspection program depends on IOWs being established and implemented to avoid exceedances having an unanticipated impact on FEMI. Inspection programs are not generally designed to look for unanticipated impacts of processes that are not adequately controlled. Inspection programs generally assume that the next inspection should be scheduled on the basis of what is already known about equipment degradation from previous inspections. Without effective process control, based on a robust list of IOWs, inspections might need to be scheduled on a frequent time-based interval to look for anything that might occur from lack of process control and all the unknowns associated with that. How often would that need to be? Every year? Every few months? Clearly that's not economically sensible, practical or safe, since it would be just guess work. In my experience each process unit would have something in the range of 30-50 IOWs (~one sigma range) established, depending upon the complexity of the process and the amount and type of damage mechanisms that could occur. Except for the most simple and benign process units, if you only have 5-10 IOWs identified for any particular process unit, you may be overlooking some important process variables that should have an IOW. Without a comprehensive program of IOWs being implemented, operators and process engineers typically don't know what 'little' changes they might make (for seemingly good process reasons) could affect FEMI. If space permitted, I could relate numerous major FEMI incidents that were caused because of a lack of adequate IOWs.

How thorough and effective is the IOW program at your site? Do you get the proper feedback when an IOW exceedance occurs? Do you find unanticipated degradation in your equipment and piping that may be due to lack of IOWs being adequately established and implemented?

References

1. [The Importance of Integrity Operating Windows in the Process Safety of Pressure Equipment](#), John T. Reynolds, *Inspection Engineering Journal*, March/April 2005.
2. API RP 584, *Integrity Operating Windows*, First Edition, American Petroleum Institute, Washington, D.C., May, 2014.

Management of Change (MOC) for Pressure Equipment Integrity

MOC for FEMI issues is another one of the most important of the 101 EEs⁽¹⁾. There is a multitude of incidents in the refining and petrochemical industry that can be traced to changes that were made in the hardware (physical changes) or process conditions without effective MOC that eventually caused a breach of containment. Changes to the hardware are typically easier to recognize and deal with through proper MOC. Changes to the process that might affect FEMI are more difficult to recognize. Both must be included in the comprehensive MOC process to assure its effectiveness. Unfortunately, many who are involved more in the operation and process side of our business sometimes make changes to equipment and process variables, assuming that any change in material degradation will be found in the next inspection. As I indicated in the EE on IOWs, that's simply not the way the inspection process works. An effective MOC process is vital to the success of any FEMI program in order for the inspection group to anticipate changes in corrosion or other damage mechanisms anticipate other potential effects and alter the inspection plan to account for those changes. Even when MOC is triggered for a process or hardware change to the facility, if experienced, knowledgeable people are not involved, asking the right questions, then the MOC process for avoiding breaches of containment could be flawed, leading to breaches of containment.

It is vital that the FEMI discipline be interlocked with the PSM group on the MOC process. I find that if the two disciplines are not closely coupled, then critical MOC issues that affect FEMI can be missed, sometimes until a breach of containment occurs. While operators, process engineers, and others outside of the FEMI discipline may be able to readily identify most physical changes that require the MOC process, such is not always the case with process changes. It is vital that someone knowledgeable in corrosion and damage mechanisms, i.e. a C/M SME be involved in assessing process changes for their potential impact on FEMI. And that does not mean that they are called upon after someone else has identified a potential process change issue, but rather that they are the ones that look at ALL potential process changes to determine if MOC needs to be implemented. The MOC process for FEMI needs does not work well enough, if the FEMI discipline is called upon to participate when someone else thinks they need to be involved, or worse yet the FEMI discipline simply receives action items from the MOC process without their involvement. This whole MOC process for process variable changes is completely dependent upon having a comprehensive list of IOWs for each process unit.

While most physical changes are somewhat obvious to those outside of our FEMI discipline, some are not. Here are just a few examples of physical changes that should not be overlooked for MOC applications:

- Recommissioning of equipment that has been out of service for some time,
- Installation of temporary equipment or temporary repairs,
- Re-pumping of clamps or boxes,
- Rerating of equipment or resetting of a PSV set pressure,
- Deletion or addition of insulation,
- Shutting down a cathodic protection system for buried piping or tank bottoms,
- Continued operation when piping supports have changed, i.e. hangers broken, spring hangers bottomed-out, pipe shoes lifted off their supports, etc.,
- Changes in equipment numbering that will require drawing and records updates.

As mentioned above, process changes that require MOC for PEI reasons are not as easy to identify for those who are not knowledgeable in process corrosion mechanisms. Here are just a few examples of some less obvious process changes that should instigate an MOC:

- Continued operation outside of the boundaries of an established IOW variable,
- Continued operation of equipment that is leaking, even the vapor space of tanks and heat exchanger bundles,
- Operating with furnace tube or refractory lined equipment hot spots,
- Continued operation when chemical injection, wash water or neutralization injection systems are down for maintenance,
- Continued operation with steam tracing leaks under insulation,
- Postponing a turnaround or an inspection due date,
- Opening or closing of any by-pass line that might change process conditions downstream,

- Changing crudes or the composition (even slight) of other raw or intermediate process materials,
- Creating a dead leg by closing a valve or blinding off some piping or nozzle,
- Revising start-up procedures,
- Changing equipment from continuous operation or intermittent operation or vice versa,
- Changing heating or cooling rates of equipment, especially heavy walled equipment,
- Changes in process velocity, fluid phase, or flow regime,
- Carry-over of liquid streams into areas not designed for them,
- Introduction of air or moisture into process streams that are not designed for them,
- Process changes that might shift the dew point from one place to another.

There are dozens more examples of physical and process changes that might affect pressure equipment integrity. For each of those changes listed above, I can cite a FEMI incident that occurred because adequate MOC was not implemented. Inadequate MOC is one of the most common root causes of FEMI incidents in our industry.

In-kind replacements are another potential MOC trap, as they are explicitly excluded from the OSHA PSM regulation in the USA (1910.119 L1). But I say “owner beware”! If someone not familiar with process corrosion issues replaces a piece of carbon steel piping (in-kind) that has suddenly experienced accelerated corrosion, then it certainly should not be done without the involvement of competent C/M SMEs, as the same problem that caused the accelerated corrosion will likely still be present. So even though such a case may not be an explicit MOC regulatory issue, it should not be handled as if it were not a potential FEMI issue.

I’m also a proponent of doing an MOC (formal or informal) when there are changes in staffing in the FEMI discipline. The site needs to completely understand the upside and downside of eliminating an inspector position, increasing inspection workload, deleting normal Inspection/NDE contract services, changing PEI staffing needs for turnarounds or decreasing the amount of available engineering support.

How closely involved is the FEMI discipline at your site in the MOC process for FEMI issues? Are competent, knowledgeable FEMI persons involved up front to help decide what changes need to be put through the MOC process? Do you have an indisputably good track record for assessing changes that might impact FEMI at your site?

References

1. [Management of Change and Integrity Operating Windows for PEI&R](#), John T. Reynolds, *Inspectioneering Journal*, March/April 2010.

Inspection for Localized Corrosion

Localized corrosion is one of inspectors' most significant nemeses. It has been the source of an untold number of large FEMI incidents in the industry, many involving huge fires, explosions, severe injuries and fatalities. As such, it is clearly one of the top ten FEMI issues that we must get right when it comes to managing our FEMI programs, especially piping inspection. Several of the more common forms of corrosion in our process equipment and piping that are summarized in API RP 571⁽¹⁾ are highly localized in nature and therefore require specialized inspection techniques in order to locate it from external surfaces. Hence, it is vital that we know when and where localized corrosion is a potential threat to the integrity of our equipment/piping. The C/M SME plays a key role in this knowledge transfer process (see separate EE).

A C/M SME can identify the common (and not so common) localized corrosion mechanisms and situations (e.g. deadlegs, injection points, mix points, ammonium salt corrosion, water drop and dew points, oxygenated fluid interfaces, sensitized stainless steel welds, ERW welds, low-silicon components, under deposit corrosion, erosion, erosion-corrosion, MIC, galvanic corrosion, crevice corrosion, CUI, and the list goes on and on). Once the areas of potential localized corrosion have been identified and recorded in CCD's and/or on MFD's/P&IDs/Inspection isometric drawings (ISOs), a NDE SME (see separate EE) can assist with determining the most cost-effective way of monitoring for localized corrosion. Because of the large number of asset integrity assessments that I have conducted over the last 4+ decades, I am aware of numerous process plants where the CMLs were incorrectly stationed by inspectors and other personnel who did not have a clue where most localized corrosion issues were likely to occur. More guidance on CML placement and inspection practices for localized corrosion is contained in both API 570⁽²⁾ and API RP 574⁽³⁾.

If localized corrosion is an issue for your equipment, it does little good to inspect with standard spot digital ultrasonics (DUTT). Your chances of finding highly localized corrosion with spot DUTT is something less than 1%, unless you are using very close interval grid-pattern examination. Standard spot DUTT at distributed CMLs is only useful where corrosion rates are fairly uniform over a wide area. When localized corrosion is an issue, one should employ profile and density radiography, scanning ultrasonics, or a variety of other more effective NDE techniques with which a NDE SME can assist. I am aware of several major multi-million dollar asset losses that occurred when inspectors were using standard spot DUTT hoping to find localized corrosion, and in at least one case, monitoring a line every 12 inches before a rupture occurred between close grid CMLs.

One of the nasty surprises that crops up in RCA reports on FEMI incidents in our industry on a fairly frequent basis is corrosion where contaminated water or deposits have settled out of a hydrocarbon stream. This situation is common in deadlegs, in low horizontal runs, in pipe sags between supports, and especially in crude oil and oil condensate piping! After collecting in a low point, the contaminated water or deposits can then proceed to corrode the pipe to failure, undetected by standard inspection practices. In fact, a few years back, an entire refinery in the Middle East was almost wiped out when a LHC line ruptured after corroding at a low point in the line which then developed into a major leak and failure. Another common problem occurs when salty and/or oxygenated water from produced crude or intermediate feedstock (that is saturated with water) or in an oily-water line, drops out of suspension and lies along the bottom of the line. That bottom layer of contaminated water and sediment can eventually cause full penetration pits or localized thinning in the bottom of the line. This is a BIG problem with the United States Coast Guard, when that crude line is over the water on a dock or wharf structure.

Ammonium salt localized corrosion is another major issue in the refining industry, as it has caused numerous destructive fires/explosions in high-pressure hydrocrackers and other types of hydro-process units, as well as cat crackers and cokers. With some process conditions, ammonium salts form and cause highly accelerated localized corrosion that cannot easily be detected. A large number of those refinery fires/explosions have occurred where higher nitrogen feeds are prevalent, especially in overhead exchanger and air cooler systems. A joint industry project sponsored by the API a few years back provided a better understanding of all the variables that cause ammonium hydrosulfide (bisulfide) corrosion and under what conditions. The old rule of thumb for maximum velocity of 20 feet/sec at 2% percent of ammonium hydrosulfide is no longer applicable to all process regimes. Localized corrosion from ammonium chlorides is also a significant problem where wet chlorides drop out of hydro-process systems, causing very

high rates of localized corrosion. Those refineries with hydroprocess units should be thoroughly familiar with the contents of API RP 932B⁽⁴⁾!

Do you know if and where the many localized corrosion mechanisms may be occurring in your equipment/piping? Are your CMLs placed accordingly and are you using the appropriate NDE tools and techniques to find localized corrosion? Or are you relying largely on spot DUTT measurements at CML locations placed by people unfamiliar with where are all the locations expected to be susceptible to localized corrosion?

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1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, Second Edition, American Petroleum Institute, Washington, D.C., April, 2011.
2. API 570, *Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems*, Third Edition, American Petroleum Institute, Washington, D.C., November, 2009.
3. API RP 574, *Inspection Practices for Piping System Components*, Third Edition, American Petroleum Institute, Washington, D.C., November, 2009.
4. API 932B *Design, Materials, Fabrication, Operation, and Inspection Guidelines for Corrosion Control in Hydroprocessing Reactor Effluent Air Cooler (REAC) Systems*, Second Edition, American Petroleum Institute, Washington, D.C., March, 2012.

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Low Temperature Issues

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On the opposite end of the temperature spectrum from furnaces is the need to have an effective program in place for the prevention of brittle fracture. An in-service brittle fracture is one of those very low probabilities – very high consequence events that must be avoided no matter what. Hence inspectors, engineers and operators must be knowledgeable in the potential for brittle fracture of materials operating below their brittle-to-ductile transition temperature (that’s metallurgical speak for operating below a temperature range where they break like glass instead of resist stress). API RP 571⁽¹⁾ has an article on brittle fracture which outlines some effective inspection and prevention steps to take to avoid brittle fracture. Special care and operating procedures are necessary to control cooling and heating rates of heavy wall equipment in hydroprocess environments, especially those that might be susceptible to temper embrittlement during service. API RP 579⁽²⁾ also provides excellent guidance on how to assess the potential for brittle fracture of equipment. The API 510 Code⁽³⁾ and its sister standard API RP 572⁽⁴⁾ also contain good guidance on avoiding brittle fractures in service. Gas plants processing light hydrocarbons are more susceptible to brittle fracture than other higher temperature operating plants.

The issue in a “nut shell” is that many standard carbon steels have very poor toughness (resistance to brittle fracture) at ambient and low temperatures, whereby very small flaws that are normally present in equipment (about the size of your finger nail clippings) can become “critical size defects” and cause instantaneous fast fracture. Inspection is not a very effective strategy for avoiding brittle fracture; design, maintenance, heat treatment, careful control of pressure testing, operating practices and other mitigation strategies outlined in API RP 571⁽¹⁾ are needed. In addition to low inherent toughness, some steels can become embrittled in service by various mechanisms outlined in API RP 571⁽¹⁾ and thus become susceptible to brittle fracture. The best practice for avoiding any potential for brittle fracture in service is to have a FEMI program that identifies all equipment that could be susceptible to brittle fracture because of temperature excursions, shutdown and startup or in-service embrittlement that outlines various mitigation strategies per the standards listed in the references below. Having the appropriate Integrity Operating Windows (IOWs)⁽⁵⁻⁶⁾ in place to identify and control process variables that might give rise to brittle fracture is key to prevention for in-service pressure equipment.

Every few years I read about an enormous, catastrophic loss from brittle fracture. The last big incident that I’m aware of was in a gas plant in Victoria, Australia, which resulted in two fatalities and a very large loss for the company, as well as a huge impact on customers. The book that chronicled the incident and associated RCA is the best learning opportunity I have ever had on the causes and prevention of brittle fracture in the industry⁽⁵⁾. Prior to that, a nozzle fractured and fell off an operating column in an ethylene plant at a mid-west petrochemical plant, resulting in a catastrophic incident. Another brittle fracture occurred on a CCU vessel undergoing coke removal with pneumatic chipping guns during maintenance in cold weather. Periodically I read about incidents that occur during hydrotesting, or worse yet, during pneumatic pressure testing. Pneumatic pressure tests should never be carried out on equipment that may be susceptible to brittle fracture without strict controls overviewed by a person highly knowledgeable in brittle fracture because of the potential for enormous destructive energy being released instantaneously (i.e. imagine a pressure vessel blowing up and producing shrapnel like a grenade). It has happened.

Do all the right people at your operating site know the minimum design metal temperature (MDMT) of all your equipment and how to avoid the potential for brittle fracture, especially during operating upsets, shutdown or startup? Would your operators know how to respond to an ice ball formation on the outside of vessels or piping from unusual operation? Do you have all the right IOWs in place on your equipment that might be susceptible to brittle fracture?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, 2nd Edition, American Petroleum Institute, Washington, D.C., April, 2011.
2. API Standard 579-1/ASME FFS-1, *Fitness for Service*, 2nd edition, American Petroleum Institute, Washington, D.C., June 2007 (3rd edition pending publication as of 4Q/13).
3. API 510 *Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair and Alteration*, 9th edition, American Petroleum Institute, Washington, D.C., June 2006 (10th edition pending publication as of 4Q/13)

4. API 572 *Pressure Vessel Inspection Practices* 3rd edition, American Petroleum Institute, Washington, D.C., November 2009.
5. *Lessons from Longford – The Esso Gas Plant Explosion*, Andrew Hopkins, CCH Australia Ltd, April 2000.
6. API RP 584 *Integrity Operating Windows*, 1st edition, American Petroleum Institute, Washington, D.C., May, 2014.
7. [The Importance of Integrity Operating Windows in the Process Safety of Pressure Equipment](#), John T. Reynolds, *Inspectioneering Journal*, Mar/Apr, 2005.

High Temperature Issues

Just as there is a special category of low temperature issues (see separate EE), there are a number of higher temperature issues that deserve special attention from an asset integrity viewpoint. Among others, these high temperature issues include:

- **High Temperature Hydrogen Attack (HTHA)** (See separate EE)
- **Oxidation** – This may be the most common high temperature corrosion phenomena in the hydrocarbon process industry, typically occurring on the firebox side of heater tubes. API RP 571⁽¹⁾ has a chart of oxidation rates for most commonly used steels and alloys at increasing temperatures. Oxidation of steel becomes an issue over about 1000°F (538°C), and the more Cr in the alloy, the more oxidation resistance is attained. As the metal loses thickness from the formation of oxide scale, it of course becomes susceptible to premature failure due to the loss of strength of the component.
- **Sulfidation** – This is one of most common forms of high temperature corrosion in refineries because of the presence of H₂S and other reactive sulfur species in most crude oils. It starts to become a problem in the vicinity of 500°F (260°C) and affects the commonly used carbon steel and low alloys in refineries. Corrosion is accelerated by the presence of hydrogen. Carbon steels with low silicon content typically have accelerated sulfidation rates and have been receiving a lot of attention lately in FEMI programs (see separate EE). API RP 939C⁽²⁾ is a good source of information on sulfidation and its prevention.
- **Embrittlement** – Embrittlement phenomena are most common in high temperature – high pressure hydroprocess equipment and primarily affect 1.25Cr–0.5Mo and 2.25Cr–1Mo alloy steels. These are insidious damage mechanisms that often involve loss of toughness and therefore a susceptibility to cracking and potentially brittle fracture under the right conditions. Much research has been done on embrittlement phenomena for these steels which is referenced in the API 934 series of documents A⁽³⁾, B⁽⁴⁾, C⁽⁵⁾ and D⁽⁶⁾ for those of you that have reactors, exchangers and other vessels constructed of these alloys.
- **Spheroidization** – A metallurgical phenomenon that causes softening of the steel and consequent loss of mechanical properties that can affect carbon and most lower alloy steels. It starts in the vicinity of 850°F (440°C).
- **Strain Aging** – This is also a degradation phenomena that mostly affects older carbon and carbon-1/2Mo steels (produced prior to 1980) operating at intermediate temperatures. This phenomena causes hardening of the steel and consequent loss of ductility and toughness; which means it makes the steel more susceptible to cracking.
- **Graphitization** – a form of embrittlement involving loss of mechanical properties that is relatively uncommon nowadays, especially with newer carbon and lower alloy steels. Starts in the vicinity of 800°F (427°C).
- **Creep and Stress Rupture** – This is a slow deformation under load at high temperatures that affects all materials above specific temperatures and if left unchecked can lead to rupture. It most commonly (but not exclusively) occurs in heater tubes in the hydrocarbon process industry. For carbon steels, it starts in the 650-700°F range (343-370°C) and for the more common Cr-Mo low alloy steels, it starts in the 800°F range (427°C).
- **Short Term Overheating and Stress Rupture** – This is a fairly rapid deformation that often results under design loading because of significant localized overheating (e.g. flame impingement), again most commonly occurring in fired heaters. The resultant failure is usually bulging and rupture (typically “fish mouth” looking ruptures of heater tubes). Since it is a time-temperature-stress phenomena, the more the material temperature exceeds design conditions, the faster it occurs.

All of these high temperature damage mechanisms (and a few more) are summarized in API RP 571⁽¹⁾. I strongly recommend you pick up a copy of that standard for much more information/references, which have not repeated in this short introduction. The purpose of this EE is simply to draw the reader’s attention to these damage mechanisms in order to make sure that equipment operating at elevated temperatures has the right inspection and/or asset integrity monitoring strategy in place so that inadvertent and unexpected equipment failure does not occur as a result of unanticipated high temperature degradation. And do not just pay attention to heater tubes and their components, as equipment and piping downstream of fired heaters is also susceptible. If you are not sure if the right high temperature inspection and asset integrity strategies are in place at your operating site, a good place to start is to survey your entire oper-

ating site for equipment and/or piping operating above about 500°F (260°C), and then have a competent C/M SME determine which high temperature damage mechanisms may apply to that equipment and/or piping, and then document the appropriate inspection, prevention, and control strategies in a CCD (see separate EE).

Does all of the equipment and piping operating at elevated temperatures at your site have the appropriate inspection and asset integrity monitoring strategies in place for high temperature damage mechanisms listed in API RP 571?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, Second Edition, American Petroleum Institute, Washington, D.C., April, 2011.
2. API RP 939C, *Guidelines for Avoiding Sulfidation Corrosion Failures in Oil Refineries*, First Edition, American Petroleum Institute, Washington, D.C., May, 2009 (2nd edition in preparation).
3. API RP 934A *Materials and Fabrication of 2 1/4Cr-1Mo, 2 1/4Cr-1Mo-1/4V, 3Cr-1Mo, and 3Cr-1Mo-1/4V Steel Heavy Wall Pressure Vessels for High-temperature, High-pressure Hydrogen Service*, American Petroleum Institute, Washington, D.C. Second Edition, May, 2008.
4. API RP 934B *Fabrication Considerations for Vanadium-Modified Cr-Mo Steel Heavy Wall Pressure Vessels*, First Edition, American Petroleum Institute, Washington, D.C. April, 2011.
5. API RP 934C, *Materials and Fabrication of 1 1/4Cr-1/2Mo Steel Heavy Wall Pressure Vessels for High-pressure Hydrogen Service Operating at or below 825 degrees °F (441 degrees °C)*, First Edition, American Petroleum Institute, Washington, D.C. May, 2008.
6. API TR 934D, *Technical Report on the Materials and Fabrication Issues of the 11/4CR-1/2Mo and 1Cr-1/2Mo Steel Pressure Vessels*, First Edition, American Petroleum Institute, Washington, D.C. Sept., 2010.

Hydrogen Related Damage Issues

While HTHA may be the most prominent hydrogen damage mechanism (DM) in many people’s minds these days, there are several other hydrogen damage mechanisms involved in different types of corrosion and cracking mechanisms in the hydrocarbon process industry. These other DMs are sometimes confused with the HTHA damage mechanism (see separate EE on HTHA), however they are very different. The other hydrogen corrosion and/or cracking mechanisms include, but are not limited to, the following:

- Hydrogen embrittlement (HE);
- Hydrogen cold cracking (a HE weld cracking issue);
- Hydrogen blistering (often a wet H₂S cracking issue);
- Hydrogen chloride corrosion (HCl acid corrosion);
- Hydrogen sulfide cracking (a form of HE);
- Hydrogen stress cracking (an HF stress cracking issue);
- Hydrogen assisted cracking (a wet H₂S cracking issue);
- Hydrogen induced cracking (a wet H₂S cracking issue);
- Others where hydrogen evolution or atomic hydrogen is involved.

Each of these other DMs is covered in API RP 571(1), and I encourage the interested reader to enlighten themselves on the differences between the variety of hydrogen related DMs. The reader should not be confused between HTHA and the numerous other corrosion and cracking DMs above that involve hydrogen. A few of the above noted hydrogen DMs do have some aspects in common with HTHA and may even occur coincidentally with HTHA; but the major difference is that HTHA occurs at elevated temperatures, while most of the above DMs (but not all) involve some type of aqueous corrosion where hydrogen is evolved in the corrosion reaction, giving rise to atomic hydrogen penetrating the material of construction and potentially causing damage. As such, most of the DMs listed above occur at lower temperatures, whereas HTHA involves higher temperatures and higher partial pressures of hydrogen, generally greater than 450-500°F (260°C) (see separate HTHA EE).

Are you clear on the differences in the various hydrogen-related damage mechanisms that afflict process equipment in the hydrocarbon process industry; when they occur, the key factors involved in each, and the different prevention methods?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, American Petroleum Institute, 2nd Edition, April, 2011.

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HTHA is being given special attention as a stand-alone EE even though it is just one of 70+ damage mechanisms summarized in API RP 571⁽¹⁾ because it has been and continues to be a difficult issue to deal with in the hydrocarbon process industry and has resulted in some major incidents associated with hydroprocessing equipment. Its importance as a damage mechanism is highlighted by the fact that HTHA has its own API standard⁽²⁾ which was originally based on work by George Nelson of Shell Development Co. in 1949. API RP 941⁽³⁾ is once again being reviewed and updated with an 8th edition anticipated in the not too distant future because of some major new learnings associated with non-post weld heat treated (PWHT) carbon steel equipment and piping.

In this brief EE summary of HTHA it's not possible to even begin to “scratch the surface” of knowledge associated with this complex and still developing damage mechanism in the petrochemical industry. One article in which the reader can begin to learn a bit more about the prevention of and inspection for HTHA was published in *Inspection Engineering Journal*⁽³⁾.

Avoiding HTHA failures in existing equipment takes a multi-faceted approach. Selecting the proper construction materials for equipment in high pressure, high temperature hydrogen service is just the first step. After that, owner-users of equipment in HTHA service need to:

- Adhere to recommendations in API RP 941 and be cognizant of the information on HTHA contained in API RP 571,
- Be aware of the controversy and history of C-1/2Mo equipment in hydroprocess service mentioned in API RP 941, and plan appropriate inspections accordingly. Too many refiners are not using the best available technology and techniques summarized in API RP 941 when it comes to inspecting for HTHA damage,
- Be aware of the numerous, recent industry experiences with non-PWHT'd carbon steel equipment being susceptible to HTHA below the Nelson curve and plan their inspections and mitigation accordingly,
- Understand the potential for thermal history, localized stress and welding issues that may increase the potential for HTHA and certain modes of HTHA degradation,
- Fully understand the differences between design and actual operating conditions and operating history when it comes to high temperature – high pressure hydrogen services,
- Be aware of any process variables creeping upward over time such that equipment that used to operate in the HTHA safe zone may now operate in the HTHA susceptible zone,
- Have all the appropriate HTHA IOW's⁽⁴⁻⁵⁾ established and implemented by SMEs who are knowledgeable and experienced in the HTHA damage mechanism,
- Have all the necessary process monitoring and control instrumentation in place for the established HTHA IOW's,
- Apply effective MOC for any changes (physical and process) that could increase the potential for HTHA,
- Apply risk analysis to prioritize and plan the need for HTHA inspections and additional mitigation resources or work processes,
- Do the appropriate inspection planning using AUBT and other NDE methods where HTHA is a suspect degradation mechanism,
- Utilize the services of organizations that can provide adequately trained, experienced and skilled AUBT technicians utilizing the entire series of HTHA NDE examinations noted in API RP 941 Table E.1. and
- Continue to stay abreast of new information with regard to HTHA that is being discussed and evaluated by the API RP 941 Task Group.

Do you know where all your equipment in high temperature-high pressure hydrogen service is operating relative to the Nelson curve, and are you monitoring it with AUBT in accordance with API RP 941 to provide assurance that it is not degrading in service?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, 2nd Edition, American Petroleum Institute, Washington, D.C., April, 2011.
2. API RP 941, *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*, American Petroleum Institute, 7th Edition, August, 2008.
3. [Avoiding HTHA Failures in Existing Equipment](#), John T. Reynolds, Inspectioneering Journal, Nov/Dec, 2010.
4. API RP 584 *Integrity Operating Windows*, 1st edition, American Petroleum Institute, Washington, D.C., May, 2014.
5. [The Importance of Integrity Operating Windows in the Process Safety of Pressure Equipment](#), John T. Reynolds, Inspectioneering Journal, Mar/April, 2005.

Inspection for Environmentally-Assisted Cracking

Environmentally-assisted cracking damage in process equipment is much more insidious than metal loss from corrosion, and therefore, much more difficult for which to plan inspections. Obviously the best method to prevent environmentally-assisted cracking is to specify the proper materials of construction and fabrication techniques, and control the process such that environmentally-assisted cracking does not occur. But that is not always possible or feasible, and process conditions can change from those envisioned during design.

An effective inspection program must be in place if there is a potential for any of the multitude of possible environmentally-assisted cracking mechanisms in the various environments mentioned in API RP 571⁽¹⁾ (e.g. caustics, amines, chlorides, wet hydrogen sulfide, carbonates, hydrofluoric acid, polythionic acids, ammonia, dearators, ethanol, sulfates, nitrates, etc.). It is important that a C/M SME is involved in identifying the potential, likelihood, and suggested inspection locations for each environmentally-assisted cracking mechanism in your process streams. That information should then be documented in a CCD or similar document (see separate EE). An effective prevention and/or control program, specified by the C/M SME will also be vital; but when there is still a potential for environmentally-assisted cracking, an effective inspection program (tools, techniques, procedures, methods) must be in place to detect the presence and extent of environmentally-assisted cracking. These inspection programs, including the required surface preparation, must be sensitive enough to detect and quantify the damage that is occurring, if any. NDE SMEs may be needed to help determine how to most effectively find, characterize, and size any such cracking present in your equipment. Inspecting for environmentally-assisted cracking mechanisms is not a “one size fits all” proposition; nor are the prevention and control methods. Typically, the only practical way to conduct such inspections are during planned TARs, so detailed TAR planning for each potentially affected piece of equipment will be necessary.

In some cases, repairs to environmentally-assisted cracking damage can be made, but more often than not you will be presented with new equipment or piping materials and fabrication techniques more resistant to environmentally-assisted cracking than their predecessors. But be careful with repairs to environmentally-assisted cracking damage, as it can be a “fool’s paradise” without other changes to ensure the cracking does not recur. In some cases, changing the process chemistry or process conditions will be necessary; in others, rigorous controls to prevent contamination or exposure to the cracking species will be required (e.g. chlorides, moisture, ammonia, etc.). In many cases, proper PWHT is effective in substantially reducing the likelihood of environmentally-assisted cracking. Note the word proper, as it is not uncommon to have insufficient PWHT temperatures or soak times achieved for resistance to environmentally-assisted cracking if the controls and/or QA/QC on the PWHT job are insufficient.

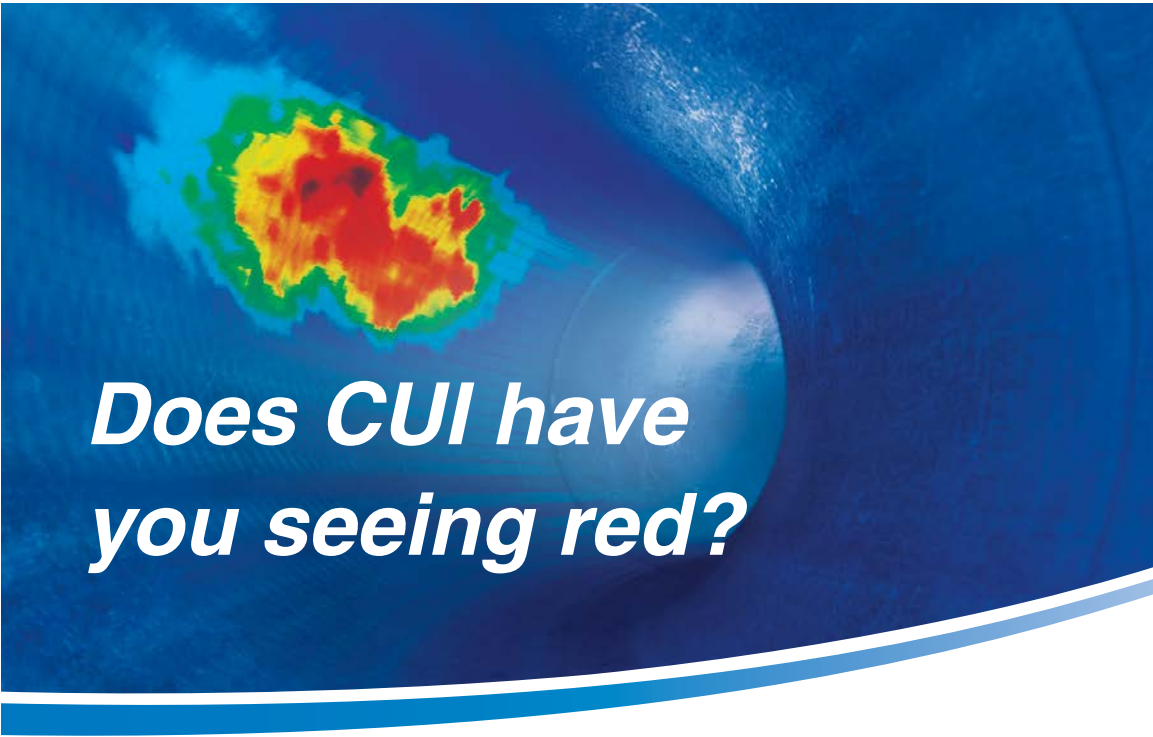
It is not easy to generalize how to prevent or inspect for environmentally-assisted cracking in the hydrocarbon process industry, as there are major differences between the thirteen different kinds of environmentally-assisted cracking mechanisms summarized in API RP 570⁽¹⁾. There is simply no substitute for having a thorough understanding of the specific environmentally-assisted cracking DMs that are a potential threat to your FEMI.

Are you sure that you have all potential environmentally-assisted cracking mechanisms identified and documented, and appropriate inspections planned in order to avoid environmentally-assisted cracking failures in your process equipment?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, Second Edition, American Petroleum Institute, Washington, D.C., April, 2011.

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CUI/CUF is often an out-of-sight, out-of-mind type of insidious problem until the first CUI leak shuts down an operating unit and/or causes a safety incident or near miss. Nearly every operating unit has to deal with the CUI/CUF problem and has a history of CUI leaks. Those in high humidity and high rainfall areas are apt to have the worst CUI/CUF problems/leaks while those in relatively dry climates have much less of a problem, while still not being immune to them. I'm aware of one refinery on the Gulf Coast of the USA that had to set up a CUI/CUF special emphasis inspection project that cost \$30 million after experiencing a number of costly process unit shutdowns due to CUI leaks. Even those in relatively dry climates have equipment downstream of cooling tower plumes and steam tracing leaks that cause CUI.

CUI/CUF is another one of the most significant and wide spread damage mechanisms covered in API RP 571⁽¹⁾, that it has its own API standard, API RP 583⁽²⁾ that should be the go to source for all FEMI personnel in the industry for information on CUI/CUF inspection and prevention techniques. It covers the design, maintenance, inspection, and mitigation practices for pressure equipment, piping, and storage tanks due to CUI/CUF. It describes all the variables that give rise to CUI including: temperature range, coating type and age, insulation types, climate effects, insulation maintenance practices, etc. and provides a method of risk ranking equipment for CUI potential based on the primary factors that affect the potential for CUI. It also covers external chloride stress corrosion cracking (ECSCC) of stainless steels under insulation as well as general and localized metal loss of steels. It also covers most of the more modern methods of NDE for inspection for CUI without having to remove the insulation. The first edition of this standard was published in May, 2014. Furthermore, both API 510 and API 570, and their companion standards, API RP 572 and 574 have condensed sections on CUI which provide guidance on what makes equipment susceptible to CUI and guidance on the most susceptible locations in which to inspect for CUI. NACE also has a useful publication on CUI/CUF⁽³⁾.

Not long ago, a refinery down under had an unscheduled hydrocracker outage due to a CUI leak in a light hydrocarbon reflux line, which occurred soon after the completion of a successful unit turnaround. An effective management program needs to be in place to prevent CUI with appropriate insulation maintenance for susceptible systems. Likewise, an effective inspection program needs to be in place where insulation management has been lacking or the age of susceptible equipment means that CUI is likely to be present. CUI corrosion rates are typically in the 5-15 mils per year range, but can be up to 40 mils per year in some of the worst CUI environments. That means that a lot of susceptible piping and vessels may be nearing failure in older sites. Don't make the mistake of treating potential CUI problems as only potential, reliability issues; as CUI failures have occasionally led to significant process safety incidents, too. And don't ignore the potential for corrosion under fireproofing (CUF) on vessel and column skirts, as well as a piperack support columns. I'm aware of a major Midwest refinery that suffered the embarrassment of having to install temporary wooden supports for a large piperack that sagged badly after several columns gave way simultaneously due to CUF.

The use of solid austenitic stainless steels can be fraught with difficulties, none the least of which is the potential for ECSCC under insulation. We all know that it's nearly impossible to keep insulation systems entirely dry over the long haul. Some insulation systems, in fact, are prone to contain chlorides (such as calcium silicate-based insulation systems). Others get contaminated with chlorides from coastal environments, deluge systems, fire water monitor testing, etc. A large refinery on the Texas Gulf Coast incurred an enormous reliability hit when they had to shut down three large, hydroprocess trains to replace hundreds of feet of solid stainless steel piping that started to leak from ECSCC under insulation. One of the most interesting issues associated with these leaks is that the operating temperatures were in a region high enough to normally preclude the potential for chloride cracking of stainless steel i.e. 600 F, but the site was routinely testing their fire water deluge system during turnarounds, this soaking their insulation. So beware, it's not just an issue for systems operating in the CUI susceptibility temperature range. In a different case, I vividly remember seeing photos of the top surface of three solid 316 SS columns that had to be replaced in an unscheduled shutdown due to ECSCC. They were riddled with the typical spider web crack patterns that we so often associate with chloride cracking.

Do you have an effective CUI/CUF inspection program; and more importantly, does it have a CUI prevention program on equipment and piping that is susceptible to CUI?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, 2nd Edition, American Petroleum Institute, Washington, D.C., April, 2011.
2. API RP 583, *Corrosion Under Insulation*, 1st Edition, American Petroleum Institute, Washington, D.C., May, 2014.
3. NACE SP0198-2010, *Control of Corrosion Under Thermal Insulation and Fireproofing Materials*.

Atmospheric/External Corrosion

In addition to CUI/CUF inspection and prevention, many bare piping components can be susceptible to external corrosion, where paint and coating systems have not been adequately maintained. Not long ago, there was a fatal accident on the Gulf Coast of the United States when a high-pressure light hydrocarbon line ruptured. The failure resulted from external corrosion on the pipeline and the ignition occurred when someone drove a vehicle into the escaping vapor cloud. Sadly, the driver died. Another serious incident occurred on the Gulf Coast when a bare, sweating line, operating below dew point ruptured, releasing over 70,000 pounds of LPG containing about 3% H₂S. Ten firemen were hospitalized in that incident because of exposure to toxic gases; however it could have been much worse had the release found an ignition source.

Unfortunately, paint and coatings maintenance often takes such low priority that the economic impact on some operating sites becomes just the opposite of what was intended when the paint and coatings budget was cut to save costs; and the result is higher long term costs. Maintaining external paint systems on piping costs only 10-20% of what it would cost to have to start over with grit blasting once the paint systems deteriorate badly (i.e. you get beyond the slight “rust blooming” or primer exposure stage), especially where special precautions are required to handle waste from the removal of lead-based paints. Hence, a cost-effective paint and coatings maintenance program can result in substantial monetary savings, let alone contribute significantly to work place aesthetics.

Too often operating sites think of their external paint/coating program as primarily for aesthetics (i.e. “keep the place good looking”), but the incidents mentioned above and numerous others like them reinforce that paint and coatings go well beyond aesthetics, and offer substantial external corrosion protection. However, aesthetics can be important too. My observations over the last 4+ decades in the FEMI business tell me that the better a plant looks, the more the employees care about the equipment and their responsibilities related to that equipment. If your plant looks like a junkyard, employees are likely to act like junkyard employees, and junkyard workers are usually not very productive, efficient, or effective working around hazardous substances that must be “kept in the pipes”. But if economics and aesthetics are not enough reason to maintain your external coating systems, in the United States there is a legal. OSHA 1910.106 discusses the handling of flammable products and requires that equipment subject to corrosive external environments be protected from deterioration. I quote: “All piping for flammable or combustible liquids, both aboveground and underground, where subject to external corrosion, shall be painted or otherwise protected.” This is especially important for API 570 class 1 piping systems that would produce an immediate high hazard upon release to the environment.

Clearly those operating sites located in environments where the humidity is high or there is above average rainfall, or in warm marine environments where sea salt can become airborne, are going to have more problems with external corrosion (atmospheric corrosion rates in the 10-20 mpy range) than those in relatively arid inland climates. But even those operating sites without these more severe atmospheric conditions will likely experience some external corrosion issues because of cooling tower mists, corrosion under pigeon poop (CUPS), exposure downwind of steam vents, contact with cooling water oversprays, and other industrial pollutants in the air. The point being, we cannot ignore the potential for full penetration corrosion from undetected external corrosion, even though it may not be the highest priority FEMI issue on our platter. Any one of the 101 EEs that is treated with too little attention can eventually lead to FEMI failures and process safety incidents. Hence the importance of keeping up with the required external inspection and maintenance programs outlined in both API 510 & 570.

Bolted joints are particularly susceptible to external corrosion. Most of us have seen bolts that were necked down to a small fraction of their original size from external corrosion. And not just pressure boundary bolted joints, but critical structural bolting like anchor bolts, are particularly susceptible to external corrosion. Contact points where pipes rest on support members are particularly susceptible to external corrosion because of moisture being trapped in deposits collecting between the pipe and the support. Guy wires on heater stacks and elevated flares have broken because of external corrosion. Overwater piping on wharf structures will typically have a much higher rate of atmospheric corrosion than overland piping; and the coast guard does not react kindly to overwater leaks from atmospheric corrosion.

Is the external paint and coatings program at your site treated with such low priority that your site may in

fact be exposed to piping and bolted joint leaks and failures? Are your external inspections of piping and vessels adequately recorded, and are you entering work requests for coating repair that will keep long term painting costs at the lowest total cost level?

Sudden Inadvertent Contamination of Process Streams

One of the most insidious FEMI issues to combat has to do with the sudden and usually inadvertent contamination of a process stream with highly corrosive contaminants, eventually (and often rapidly) causing unanticipated cracking or corrosion failures. There are plenty of examples in the industry of sudden jumps in corrosion rates from just a few known mpy to thousands of mpy. There are also other examples of the introduction of a new damage mechanism because of sudden inadvertent contamination that was not anticipated in equipment design and materials selection. A few examples include:

- caustic containing solutions contaminating hydrocarbon and steam systems;
- chloride contamination of a variety of process streams that caused chloride cracking of solid austenitic stainless steel equipment;
- ammonium salt carry-over into hydroprocessing systems;
- changing to higher nitrogen containing feeds to hydroprocessing systems;
- wet chloride break-through with reformer hydrogen to other H₂ consuming units;
- chloride break-through from crude desalter mis-operation into crude unit O/Hs;
- liquid mercury globs in some crude oils;
- production well fluids being dumped into crude oils;
- organic chloride contamination of crude oil and other intermediate streams;
- catalyst carry-over into FCCU fractionator bottoms;
- acid carry-over in HF & H₂SO₄ Alky Plants;
- moisture contamination in otherwise dry process environments;
- tramp amines in crude oils added as oil handling scavengers in transportation; and
- a variety of other contaminants in hydrocarbon streams.

One of the most significant that has recently afflicted the refining industry is that of organic chloride contamination of crude streams that come overhead into naphtha hydrotreaters and cause corrosion rates to accelerate by two orders of magnitude. A Louisiana refinery had that problem occur not long ago. The result was a large, intense fire that burned one individual critically and caused extensive damage to the process unit. Several other refineries have experienced similar incidents. In these cases, refiners are finding that crudes which normally have very low levels of organic contamination can pick up substantial levels of contamination between the well head and the inlet to the crude unit. Most typical crude assays do not test for organic chlorides, so this problem can go undetected unless owner-users specifically use test methods for revealing organic chloride contamination.

For all of the various et-sundry cases of contamination like those mentioned above, the routine inspection of these systems goes “merrily down the garden path”, assuming nothing has changed and preparing to make the next inspection based on known historic results of previous inspections. This is the way our programs are designed to operate if MOC does not forewarn inspectors of changes.

A big part of the solution to these inadvertent contamination issues is the creation and implementation of IOWs (see separate EE) per the new API RP 584⁽¹⁾ (approved and pending publication). IOWs should be established for any recognized potential threat of sudden contamination. Tightening up on crude oil assay requirements is another method of prevention. Conducting MOC on any anticipated or potential change in process stream composition and/or process conditions is also effective. Relying on inspection to find the changed corrosion rates or damage mechanisms is generally ineffective, as the accelerated corrosion or damage is often far too rapid to catch in scheduled inspections, which are based on known damage mechanisms and known recorded damage rates.

Are your IOW and MOC work processes rigorous enough to pick up the existence of contaminants (potential as well as actual) in your process streams and mitigate the problem and/or alert the inspection group that something has changed before you end up with surprise equipment failures?

References

1. API RP 584, *Integrity Operating Windows*, First Edition, American Petroleum Institute, Washington, D.C., May, 2014.

Water and Chemical Treatment for Corrosion Control

Some small site managements are fooled into thinking that their chemical treatment vendor is all they need for corrosion control. Nothing could be further from the truth unless that site is one of the very few remaining small operating sites that still has a long established steady sweet crude diet (an almost extinct type of site). As important as these chemical treatment services are to plant FEMI programs, they are but one small aspect of the entire corrosion control program, as you can see from the large number of the 101 EEs that deal with corrosion prevention and control, as well as the number of topics in API RP 571 that do not have anything to do with chemical treatment for corrosion control.

I believe a C/M SME needs to have a clearly defined role of working with and overseeing the activities and results of the water and chemical treatment vendors. After all, they are primarily in business to sell chemicals and chemical treatment services, and if a knowledgeable C/M SME is not overseeing their services, the program can get costly and inefficient, let alone ineffective. I know one operating company which had a chemical treatment SME on staff in the corporate office who, not too long ago, went around to each of the company refineries to do a detailed assessment of the efficiency and effectiveness of each of their operating site chemical treatment programs. The bottom line of the entire company-wide assessment was an average savings of 20-25% on the program for chemical treatment in the company with no reduction in effectiveness in corrosion control. Considering the amount of money each refinery spent every year on chemical treatment corrosion control, the savings were substantial. That said, I am familiar with a number of excellent chemical treatment vendors and professional representatives that do an excellent job.

The best programs that I am familiar with have a documented management system for how the entire corrosion control chemical treatment program works at the operating site, and require the involvement of a C/M or FEMI SME to oversee the results on a periodic basis, as well as an annual review with the vendor of the effectiveness of each chemical injection in the entire program. The better programs also maintain an up-to-date list of each injection site for chemical treatment that details the injection fluid and rates, the purpose of each injection, and provides a maintenance priority for repair in the event that an injection pump or other malfunction should occur.

Do you know for sure if your corrosion control chemical treatment program is as effective and cost-efficient as it needs to be? How effectively are your chemical control injections in your column overhead systems? Are you getting ten year cooling water HX bundle service lives?

Coatings and Linings

Coatings and linings (C/L) cover a wide variety of corrosion barriers including external paints and coatings, polymeric linings, metallic linings, and refractory linings. This topic is of course closely related to the Materials Selection EE. In my experience, this EE is within the purview of a C/M SME, without which the operating site may fall victim to “vendor salesmanship” rather than being able to select and install the best (i.e. most cost-effective coating or lining to meet their needs over the entire life cycle of the equipment). Some of the larger operating sites and companies have in-house C/L SMEs, but those that do not may need to seek guidance from competent third party, independent consultants for applications where failure could be very costly, not to mention result in safety or environmental incidents.

Hopefully everyone at this stage knows that specifying and monitoring the installation QA/QC of C/Ls applications is equally, if not more, important than specifying the type of C/L. There probably is not an operating site in the industry that has not fallen victim to poor installation practices of a properly specified C/L and ended up with a relatively poor service life, especially with polymeric coatings. And unfortunately these experiences with deficient installation often reflect poorly and unfairly on the type of coating rather than the poor installation practices. Performance of C/L systems depends heavily on how well the substrate or surface is prepared for coating applications. In my experience, it is well worthwhile to have a coatings inspector certified by NACE (or equivalently trained and knowledgeable) involved in any critical or expensive coatings application. Such a person will be familiar with and prepared to enforce the SSPC/NACE joint surface preparation standards⁽¹⁾ that will probably be included in the C/L application specification. Typically on fixed equipment, visual inspection of surface preparation is required and will consist of surface profile measurements, visual surface comparison, and verification of blasting medium. Coating systems are usually specified in the contractual and engineering documents, and will likely involve multiple coating applications. The method of inspection of these coating systems usually includes a dry film thickness (DFT) gauge per SSPC-PA 2⁽²⁾, with which the NACE certified inspector will be familiar. In addition to purchase order requirements and company standards, coating manufacturer’s recommendations will generally provide the necessary details for a proper coatings application. Typical issues that the certified inspector will look for include: raised areas, pinholes, soft spots, disbondment, delaminations, blisters, holidays, bubbling, fisheyes, runs and sags, uniformity, mechanical damage, orange peel texture, adhesion, and mud flat cracking.

Similarly, when refractory linings are involved, installation practices are also equally as important as the material specification, and if not done properly, will likely lead to poor service life of the refractory lining. In this case, an API certified refractory inspector⁽³⁾ (or equivalently training and knowledgeable) inspector should be involved in the application and in-service inspection of refractory linings. I am familiar with one case where such a qualified inspector was not involved in the inspection of an FCCU regenerator lining during a TAR, and subsequently, a 150 square foot area of refractory lining fell to the bottom of the regenerator during operation and caused an expensive, unscheduled shutdown for repair.

Likewise, when a furnace is down for inspection and maintenance, inspectors and engineers, knowledgeable in potential deterioration mechanisms of refractory linings, need to specify and implement an effective inspection and QA/QC effort. I am aware of another incident where a plant suffered a blow out and fire on a refractory lined effluent transfer line on a steam-methane reformer heater. The refractory had failed, leading to the hot spot and eventual line rupture because it went undetected. An effective thermography inspection program can successfully detect and measure hot spots on refractory lined equipment and fired heaters. Temperature sensitive paint can also serve as a warning when refractory failure has occurred on the inside diameter of refractory lined equipment. Once detected, it is very important that experienced, knowledgeable engineers and inspectors are involved in evaluating and monitoring the hot spot in order to ensure that blow out conditions do not develop. Equipment can operate reliably for long periods of time with temporary, yet adequate hot spot mitigation measures in place; but only if they are properly designed and implemented.

Do you have the proper procedures and QA/QC work practices in place to provide the necessary assurance that your coatings/linings will be correctly installed and inspected by properly trained and knowledgeable personnel to yield optimum equipment service life?

References

1. SSPC/NACE *Joint Standards for Surface Preparation*, SP 1-8, Society for Protective Coatings and NACE International, Houston, TX
2. SSPC PA 2 *Procedure for Determining Conformance to Dry Coating Thickness Requirements*, Society for Protective Coatings, May, 2012.
3. API Standard 936 *Refractory Installation Quality Control Guidelines Inspection and Testing Monolithic Refractory Linings and Materials*, 3rd Edition, American Petroleum Institute, Washington, D.C., Nov 2008.

Non-Metallic Equipment/Piping Inspection

In addition to the primary metallic materials of construction, some non-metallic materials are prevalent in process plants. To properly inspect and maintain non-metallic construction materials you need to have a special set of skills. Non-metallics include mostly refractory and polymeric materials in the petroleum and petrochemical industry, but can also include other materials, like glass-lined equipment. This EE will only cover refractory and FRP materials.

Refractory materials are generally used in equipment linings for insulation, erosion/corrosion resistance, and heat resistance. Fiber glass reinforced plastic (FRP) materials, also known as glass reinforced plastic (GRP) are those materials of construction that consist of a composite thermo-setting resin material reinforced with some sort of fiber, typically glass fiber in our industry. The polymer resin is usually an epoxy, vinyl ester, or polyester. FRP piping finds applications in the petroleum and petrochemical industry when cost and weight savings justify their use, or where FRP pipe/equipment is better suited to resist the aggressive corrosive properties of some fluids.

Both refractory and FRP construction materials require a specialized knowledge and skill to competently inspect and test them for deterioration that may occur in service. Refractory inspectors should have passed the API ICP exam on API Standard 936; however, this standard and exam are all about QA/QC during new refractory installation. So the owner-user has to determine how much experience the inspector has had inspecting refractory-lined equipment after exposure to in-service conditions. Some of the typical refractory problems experienced in lined equipment in the petroleum and petrochemical industry that the competent in-service refractory inspector should be looking for include:

- Hot spots on the heater casings or shells of lined piping or vessels,
- Spalling and cracking of linings,
- Erosion and deterioration from the operating environment,
- Coking or dew-point corrosion (from condensation) behind the lining,
- Partial melting and degradation of the lining,
- Deterioration, cracking, breakage of anchors from exposure to process fluids, and
- Abuse during maintenance activities during shutdown.

Inspection for in-service damage to refractory linings during shutdowns is primarily visual inspection using light hammer tapping in an experienced hand. Thermography is a useful tool for finding spots where internal refractory lining is failing or allowing by-passing. Temperature sensitive paint on the shell or casing of refractory lined equipment is also common.

Like refractory systems, FRP equipment/piping has its own set of damage mechanisms that an experienced inspector should be looking for, including:

- Loss of internal corrosion barrier from corrosion/erosion,
- Loss of external corrosion barrier from UV (sunlight) damage,
- Permeation of aggressive fluids into the FRP substructure,
- Mechanical damage (e.g. star crazing and cracking),
- Blistering, delamination, and
- Thermal damage from high or low temperature (e.g. creep or freeze damage).

Inspection methods for FRP equipment are mostly visual, but can be supplemented by AET and destructive testing from coupon cut outs by someone experienced in FRP testing. The best guide that I know of for FRP piping inspection is MTI-129-99⁽²⁾.

Do you have access to the special set of skills necessary to properly inspect and maintain refractory and FRP materials?

References

1. API Std 936 *Refractory Installation Quality Control-Inspection and Testing Monolithic Refractory Linings and Materials*, Third Edition, November, 2008, American Petroleum Institute.
2. MTI 129-99, *A Practical Guide to Field Inspection of FRP Equipment and Piping*, mtiproducts.org

Corrosion and Process Condition Monitoring

We frequently assume things about how our process conditions affect corrosion rates that may not always be true. Hence, there is often a real need for corrosion and process condition monitoring to validate our assumptions and verify that our materials of construction are the right choices. These are two different monitoring methods; so let's be clear what I am talking about. When I speak of corrosion monitoring, I am not talking about the thickness measurements that we take to calculate corrosion rates per API 570; that is called thickness measurements for corrosion rate calculations (see separate EE). When I refer to corrosion monitoring, I am talking about the typical electronic and potentiostatic methods by which we can quickly ascertain if changes in corrosion rates are occurring when process conditions or fluids are changing (e.g. electric resistance (ER) probes and linear polarization (LP) measurements⁽¹⁾).

Two classic cases come to mind of when there is a need for effective application of corrosion monitoring (though there are several more):

1. when we change process fluids that may impact our historic corrosion rates in ways that we are not sure about, and
2. when we have a new process or process change for which we do not have historic data to effectively estimate corrosion rates and future service life of equipment⁽²⁾.

A classic application of corrosion monitoring methods is in the overhead systems of refinery fractionation columns where small changes in the column operation or effectiveness of chemical treatment could cause accelerated corrosion in the overhead piping and vessels. Such probes can be connected to local data acquisition instruments or even directed to operating control consoles allowing operators to react more quickly to corrosion rate changes. Typically, a C/M SME would be involved in the application of corrosion monitoring probes and instrumentation.

Process condition monitoring is a different, but related issue, and is also very important for effective FEMI programs. It is especially important in those processes that are prone to, or susceptible to, changes in process conditions and where IOWs⁽³⁾ have been established for process variables that can affect FEMI (see separate EE on IOWs). If we are to rely on our selected materials of construction that will resist certain process conditions, but will deteriorate more rapidly outside of a given set of conditions or may be exposed to a new DM, then we should be monitoring those conditions that could give rise to significant changes in equipment and piping deterioration. Temperature monitoring is fairly common, but often there are several other variables that need to be watched closely. For example: pH limits, hydrogen partial pressures, chloride contents (inorganic and organic), moisture contents, percentages of salts or other contaminants, sulfide content, organic acid contents, amine/caustic carryover, conductivity, iron in solution, oxygen contents, and a many other process specific variables that impact IOWs. And of course, it is equally important to ensure you are monitoring in the right places in the operating process. Only with appropriate process monitoring (instrumentation or sampling) will we know if we are experiencing an IOW exceedance that needs prompt attention by operators or FEMI SMEs.

Are you monitoring sufficient process variables and corrosive conditions such that you would know quickly if something has changed that could threaten the integrity of your equipment or piping?

References

3. NACE Corrosion Monitoring Handbook, NACE International, Houston, TX.
4. Corrosion Monitoring Basics, NACE International, Houston, TX.
5. API RP 584, Integrity Operating Windows, First Edition, American Petroleum Institute, Washington, D.C., May, 2014.

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FEMI engineering support for inspectors and site engineers is yet another vital FEMI EE. There are a number of engineering specialty disciplines that FEMI personnel sometimes need to access in order to solve more difficult or unusual issues. Maintenance and reliability engineers are often FEMI generalists in that they may have a broad knowledge of many FEMI issues and are able to handle a lot of routine FEMI issues. However, facility personnel occasionally need SME assistance with more complex or infrequent FEMI issues associated with:

- Corrosion/Materials (C/M)
- Atmospheric Storage Tanks (AST)
- Piping and pressure vessel design, stress analysis and rerating
- PRDs
- Fired heaters
- Polymeric coatings and linings
- Refractory linings
- Inspection Data Management Systems (IDMS)
- Risk assessment and RBI
- Fitness for Service (FFS) assessments
- Advanced NDE techniques
- Cathodic protection (CP)
- Failure analysis
- Specialized welding
- And a few other FEMI issues

Only the largest sites or largest companies with multiple sites will have most of these skills on site or within the company. For those sites that don't have in-house access to such skills, the key to handling this EE successfully is in knowing when you need extra help and how to access it quickly, when the time comes. Nearly every operating site, large or small, will eventually need some SME assistance in the listed kinds of FEMI issues. Sometimes engineers on site are hesitant to indicate that they need (or wish for) SME assistance for fear someone might think they are not the “all knowing – all seeing – all solving” engineer who can handle everything that comes their way. In such cases, it will be up to an alert management to hopefully be able to recognize when additional SME talent is needed before specific issues turn into a big cost, or a process safety or environmental risk.

For example, not using FFS SME when needed might result in making unnecessary repairs or replacements that could be much more costly or even add additional risks. Another example that I have seen is not using failure analysis when needed to be able to learn the real cause of a failure. In one case, a refinery had three identical piping failures from the same cause one right after the other because the engineers on site “thought” they knew what the problem was instead of conducting a failure analysis to find out the facts. I know of another case where a refinery did not understand the magnitude of refractory deterioration in their regenerator, so they made a few make-shift repairs in a turnaround and then experienced a major refractory failure on-stream, causing an extended unplanned eight week outage of the CCU. I could go on and on with many such examples. But the point is that if you think hiring outside engineering services is expensive, try having a significant failure on-stream because you didn't have the expertise to make the right decisions when you had the opportunity.

There are a number of engineering service companies in the petrochemical industry that can provide these types of services when needed. Some of these services are so important to successful FEMI programs that they are covered under a separate EE in this publication. Some sites plan for their occasional engineering support needs in advance by lining up open-ended contracts or establishing partnerships with trusted sources that they can access quickly under urgent circumstances. Those trusted engineering support services should be included on the site list of Qualified Suppliers and Vendors (see separate EE). It's very important that those support services are not just from “low bidders”, but are from companies with capable, experienced SMEs that have been vetted and approved by your FEMI group. Most of the larger engineering support suppliers have a list of billing prices that is dependent upon the knowledge and experience level of each engineer. Remember, you can't get a 25+ year veteran SME who works for

pauper's wages. Not long ago I had the opportunity to review the results of a large contract for engineering support placed by a refinery and concluded that they wasted many thousands of dollars because the report was not worth the price of the paper it was printed on. You must vet each person assigned to your specific project to make sure they have the experience and knowledge level you expect; and if you are going to accept low wage contractors, you best make sure that their work is reviewed and approved by the "gray beards" at the contractor's office.

Does your site know the limits of their FEMI expertise and seek experienced, knowledgeable SMEs from external sources when really needed?

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Materials and Corrosion Engineering

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Routine access to SME's in corrosion and materials (C/M) is paramount for any process unit that is or has the potential for being corrosive or otherwise causing materials degradation that could lead to unexpected equipment failure and therefore a release of hazardous chemicals. This topic is an all inclusive one that cannot be covered in just one EE of PEIM, even in a condensed manner; so it is separated into many C/M related topics throughout the 101 EEs. C/M expertise needs to be brought to bear, pro-actively, to prevent C/M problems as well as reactively to understand and solve C/M problems that occur. To be most effective C/M SME's need to work very closely with inspectors, as well as maintenance and process engineers familiar with each process unit in order to plan the most appropriate type of inspections necessary. There are very few C/M problems in the petrochemical industry that can be adequately solved by someone other than a C/M SME who simply picks up a book/standard and reads about it. At last count there were over 70 different C/M damage mechanisms that afflict the petrochemical industry summarized in API RP 571. Time and time again, when I do FEMI assessments on operating plants, I find operating sites trying to deal with complex C/M issues without accessing C/M SME's. Many of those sites are simply taking thousands of UT thickness readings hoping that that strategy will keep them out of trouble. That is a terribly naive approach to inspection. The chance of finding most of the 70+ damage mechanisms with simple spot UTT at CML's is slim and none.

The most well rounded C/M SME's should be knowledgeable, not just in metallurgy and materials selection, but also in process chemistry, C/M degradation mechanisms, the wide range of C/M degradation prevention and mitigation strategies which are covered elsewhere in the 101 EEs, and what inspection and NDE techniques will be needed to find, characterize and size the wide variety of C/M degradation mechanisms that afflict the petrochemical industry.

For one reason or another, not all owner-user organizations will have a full time or even part time C/M SME on staff. In those cases, then the C/M SME can be a third party contractor, consultant, or a service supplied by the corporate headquarters that serves multiple operating sites. But for sure, in my 46 years of experience in our industry, nearly every operating site needs the services, to some extent, of a competent, experienced C/M SME in order to achieve excellence in FEMI, without which there are many C/M degradation traps to fall into. And those traps can lead not only to avoidable cost issues, but unanticipated breaches of containment with multiple ensuing consequences. Too often smaller sites try to muddle their way through difficult and complex C/M issues which they don't fully understand without the input of C/M SME's to solve problems.

Do the inspectors and engineers at your site have ready access to C/M SME's that can provide C/M guidance and knowledge transfer, in order to be able to predict where and when degradation will occur in each process unit, so that the appropriate inspections and NDE techniques can be scheduled to avoid unexpected breaches of containment?

References

1. See the related EE on Engineering Support for FEMI
2. [The Role of Corrosion Control in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, May/June, 2010.

Materials and Metallurgy

Every inspector should have a minimum amount of materials and metallurgy (M&M) knowledge in order to perform at their best. That is not to say that every inspector must be a metallurgist or corrosion SME, or be an expert in API RP 571, but material properties (both mechanical and physical) and how they are affected by heat treatment are important pieces of knowledge for an inspector (let alone an inspection support engineer) to have in order to be effective on the job. A very brief summary of M&M information for inspectors is in section 10 of API RP 577⁽¹⁾. That section covers the structure of metals, including: castings and wrought products, welding metallurgy and weldability, physical and mechanical properties, heat treatments, hardening of metals and MTRs. For more detailed M&M information, most operating sites should also have copies of Metallurgy for the Non-Metallurgist⁽²⁾ and the applicable volumes of the ASM Handbooks⁽³⁾.

One of the important aspects of M&M is post-weld heat treatment (PWHT). PWHT produces both mechanical and metallurgical effects in carbon and low-alloy steels that will vary widely depending on the composition of the steel, its past thermal history, the temperature and duration of the PWHT and heating and cooling rates employed during the PWHT. The need for PWHT is dependent on many factors, including chemistry of the metal, thickness of the parts being joined, joint design, welding processes and service or process conditions. The temperature of PWHT is selected by considering the changes sought in the equipment or structure. For example, a simple stress relief to reduce residual stresses will be performed at a lower temperature than a normalizing heat treatment.

The primary reason for PWHT is to relieve the residual stresses in a welded fabrication. Stresses occur during welding due to the localized heating and severe temperature changes that occur. Proper PWHT releases these residual stresses by allowing the metal to creep slightly at the elevated temperature.

However, PWHT is accomplished for other reasons besides stress reduction, including reduction in weldment hardness and improved resistance to a variety of cracking mechanisms after equipment is placed into service. These other reasons may not be closely detailed in fabrication specifications so inspectors should be particularly aware of these potential extra requirements when allowing, authorizing or inspecting in-service repairs. Unfortunately, operating sites are finding more and more cases of inadequate PWHT after some sort of cracking failure has occurred, or after residual stresses have been measured. Some fabricators just do not take PWHT seriously enough and merely heat up the component, cool it down and deliver it as fast as they can. Time is money and it takes time and serious QA/QC to do PWHT correctly (or any heat treatment for that matter). There needs to be adequate placement of thermocouples (TCs) on the equipment/piping to reveal the true temperature and required thermal cycle experienced by the equipment being heat treated. There needs to be recording charts on all critical TCs. There needs to be proof that the full soak time at temperature was experienced. The correct temperature for the material being heat treated needs to be specified and enforced. Special attention needs to be provided to equipment with a variety of thicknesses and configuration to ensure that the heaviest section is adequately heat treated and that the thinnest section is not overheated and badly oxidized. Adequate support should be provided during any PWHT to prevent sagging that could occur during the heat treatment. Inspectors need to be involved in heat treatment operations to make sure they are done properly and thereby will not leave equipment susceptible to cracking during operation.

Hardening of the weld and HAZ are important because of the potential for hydrogen-assisted cracking that can occur in carbon and low-alloy steels. As the hardness of the HAZ increases, so does the susceptibility to hydrogen-assisted cracking. Hardness in excess of the 200 BHN limit for carbon steel and 225-241 for low alloy steels can result in both hydrogen-assisted cracking soon after welding is completed and stress corrosion cracking in service due to the presence of sulfides in refinery processes. Inspectors should satisfy themselves with sufficient hardness testing that these limits are not exceeded.

Do inspectors at your operating site have the minimum amount of M&M knowledge necessary to function effectively in their jobs? Do you have adequate QA/QC and PWHT procedures to ensure that you are getting a full and effective PWHT so that your equipment does not fail prematurely in service?

References

1. API RP 577, *Welding Inspection and Metallurgy*, Second Edition, December, 2013, American Petroleum Institute, Washington, D.C.
2. *Metallurgy for the Non-Metallurgist*, Second Edition, ASM International, Materials Park, OH
3. ASM Handbooks, a series of 28 volumes on materials and metallurgy, ASM International, Materials Park, OH

Materials Selection

With few exceptions, generally the input of a C/M SME is needed for selecting equipment materials in the hydrocarbon process industry; not only for design purposes, but also for replacement and repair decisions after a piece of pressure equipment has failed to perform as expected or has leaked. Even if equipment is a replacement in kind (RIK), a C/M SME should at least consider why it is being replaced and if it failed because of some C/M issue. They should also consider if it really is a RIK or if some change in materials selection is needed or recommended. On the other hand, if it is a new vessel or piece of piping being placed in an existing service where the materials are already performing satisfactorily with known DM's and corrosion rates and an adequate inspection history, perhaps the input of a C/M SME is not needed for that particular piece of equipment. But the primary reason a C/M SME's input should be seriously considered is because there are so many issues to be reviewed when selecting materials. Besides the obvious need for resistance to the corrosive aspects of process fluids, the C/M SME must:

- Assess all potential DM's that may be encountered over the lifetime of the equipment,
- Know the various pros and cons of each construction material,
- Understand the necessary mechanical properties (especially toughness if low temperatures might be encountered),
- Be able to recognize a need for CUI resistance,
- Understand the issues and economies with regard to solid material construction vs. application of linings,
- Understand weld overlays,
- Understand claddings and coatings,
- Recognize design features that will enhance service life,
- Identify a need for heat treatment,
- and a host of other important construction materials issues.

Speaking of the pros and cons of each material choice, I cannot remember the number of times I have encountered a failure of austenitic stainless steel equipment or piping because the person who “upgraded” the material to type 304SS did not understand the risk of chloride stress corrosion cracking or some other problem lurking in the material selected. There are many such advantages and disadvantages for each material choice. Excellence in materials selection is foundational in any FEMI program for avoiding most breaches of containment and all materials of construction should be well documented in the CCD for each process unit (see separate EE). You would not believe how many failure analyses I have been involved with or read about over the last half century that could have been avoided by proper selection of materials of construction. Entire books are devoted to materials selection issues in the petroleum and petrochemical industries. The API, ASM, and NACE have a number of useful publications and recommended practices dealing with materials selection issues (see just a few at the bottom of this EE).⁽¹⁻⁵⁾

One important aspect of materials selection is the Total Cost of Ownership (TCO) or Life Cycle Cost (LCC) evaluations (which are largely the same thing). Too often project organizers are rewarded primarily for completing a project at or below budget, which often means a lot of emphasis on low initial costs that drive engineering and purchasing decisions. However, the smarter companies are now adhering to a TCO/LCC purchasing philosophy, whereby purchases are made to minimize the total cost of ownership over the entire service life of the equipment, not just the initial cost. This means that the cost to inspect and maintain a piece of equipment throughout its service life, as well as the longer term risk costs associated with low first-cost investments, are taken into consideration when selecting materials of construction. TCO/LCC purchasing also means that the future risk of process safety incidents with your pressurized equipment will likely be lower. TCO/LCC purchases often result in the selection of longer lasting materials of construction, designs that minimize corrosion under insulation, designs that minimize deadlegs, an avoidance of dissimilar welds that have a higher propensity for failure, designs that take into consideration the potential for contamination of the process stream with corrosive or cracking agents, more QA/QC to make sure the specified equipment is actually delivered, etc., etc. Basically, TOC/LCC purchases take into consideration any of the applicable 101 EEs of FEMI that could impact future operating, inspection, and maintenance costs.

Are the equipment and piping at your facility being designed, purchased, fabricated and installed with

TOC/LCC evaluation in mind by a C/M SME during the engineering and construction phase of the project (large and small)?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, 2nd Edition, American Petroleum Institute, Washington, D.C., April, 2011.
2. ASM Metals Handbook, *Corrosion in Petroleum Refining and Petrochemical Operations*, Vol 13, ASM International, Metals Park, OH.
3. NACE 37519, *Corrosion Data Survey, Metals Selection*, 5th edition, NACE International, Houston, TX.
4. NACE Corrosion Book, *Corrosion Control in the Refining Industries*, NACE International, Houston, TX, 1999.
5. API RP 581, *Risk-Based Inspection Technology*, American Petroleum Institute, Washington, D.C., Sept., 2008

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FFS assessments are vital for choosing among the various FEMI options when planning mitigation and/or maintenance repair activities. The development of the FFS standard, API RP 579, in the later part of the last century was a major break-through in our industry when it comes to making engineering decisions about how and when to make repairs to critical fixed equipment. The API/ASME FFS standard⁽¹⁾ represents breakthrough engineering technology for the petroleum and chemical industry, and the API Inspection Subcommittee recognizes (and references) the benefits of API/ASME FFS assessments within their existing API Codes/Standards (510/570/653). Nearly every flaw or inspection finding can be evaluated using the various sections of the API/ASME FFS standard⁽¹⁾ in order to determine whether or not the flaw is actually a defect requiring repair. One common benefit of FFS analysis is to help the owner-user determine when and if temporary repairs can be made that will allow the equipment to continue safely in service for some period of time (using remaining life analysis) before additional or more permanent repairs are needed. In a similar vein, conservative design life “retirement thicknesses” for equipment can usually be extended for some period of time using valid FFS analysis that allow the equipment to continue safely in service for some period of time beyond what was originally calculated by unnecessarily conservative construction design rules.

Everyone in the FEMI business uses FFS assessments, whether they know it or not. Each time a piece of equipment is inspected, decisions are made about whether or not repairs or maintenance are needed, based on the results of the inspection. All these decisions are FFS type decisions, even when engineering is not involved. In the vast majority of cases, FFS assessments are made on the basis of experience and knowledge of the inspectors and engineers directly involved with the FEMI issue, with guidance contained in API 510⁽²⁾ for pressure vessels, API 570⁽³⁾ for piping and API 653⁽⁴⁾ for storage tanks. In a few cases, more engineering analysis is needed, and we need to turn to API RP 579-1/ASME FFS-1 Fitness for Service Analysis⁽¹⁾ for a more detailed assessment. The API/ASME FFS standard contains 3 levels of engineering FFS analysis with varying levels of detail:

- Level 1 type FFS analysis for fairly quick, rule of thumb, screening type analysis for relatively conservative FFS decision-making. If a flaw is large enough that it does not pass a level one screening analysis, then the owner-user has the choice of making repairs or replacements, or turning to level two FFS analysis to determine if the equipment can continue in service without unnecessary repairs.
- Level 2 type FFS analysis for a more detailed engineering analysis that will produce more precise results. In the very few cases, where the size and type of flaw does not pass level 2 analysis then the owner-user has the choice again of making repairs or replacements, or turning to level three FFS analysis to determine if the equipment can continue in service without unnecessary repairs.
- Level 3 type FFS analysis for the most detailed engineering analysis that will produce the most precise results. This level of FFS analysis typically involves things like FEA and other numerical and/or experimental analysis.

There are several good reasons to use engineering FFS methodologies to assess the severity of flaws found during inspection, not the least of which is that it is not uncommon for defects that develop during repairs to lead to failures and even breach or containment at a later stage in the equipment service life; so it behooves us to avoid unnecessary repairs that might result in more problems than they solve.

Does your operating site achieve the benefit (economic and process safety) of applying API RP 579-1/ASME FFS-1 for FFS decision making by properly trained and qualified individuals to avoid conducting unnecessary repairs when they are not warranted and/or to extend the safe service life of equipment?

References

1. API RP 579-1/ASME FFS-1, *Fitness for Service Analysis*, American Petroleum Institute, Washington, D.C., Second edition, June, 2007.
2. API 510 *Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair and Alteration*, 9th edition, American Petroleum Institute, Washington, D.C., June 2006
3. API 570 *Piping Inspection Code: In-Service Inspection, Rating, Repair and Alteration of Piping Systems*, 3rd edition, American Petroleum Institute, Washington, D.C., November 2009.
4. API 653, *Tank Inspection, Repair, Alteration, and Reconstruction*, American Petroleum Institute, Washington, D.C., Forth edition, April, 2009.

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Pressure Equipment and Inspection Codes/Standards

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Effective application of our industry codes and standards (C/S) is the foundation of any effective PEIM program⁽¹⁾. I have spent a large part of my PEI career, along with numerous dedicated colleagues, trying to create, improve and keep up-to-date, our API and ASME post construction codes. From my experience, I can assure you that some of the best brains with the most experience in our industry have contributed toward making these C/S high quality documents. I have personally benefitted immensely in my PEI knowledge and skills by my long standing participation in those industry C/S committees (especially API & ASME), and I encourage readers who have a passion for excellence in the PEI discipline to do the same. The success of the API & ASME FEMI committees in putting together “Recognized and Generally Accepted Good Engineering Practices” (RAGAGEP) is dependent upon knowledgeable PEI specialists participating in the ANSI consensus process applied by most SDOs to continuously create and update our industry PEI C/S. The application of the ANSI standardization process for these C/S provides assurance to the user that the contents of these documents goes through a rigorous, fair, detailed, controlled work process of drafting, revising, and balloting the contents multiple times before new editions of all such documents are published. This standardization process is tedious and lengthy, but assures the end user that the contents of every standard are fully vetted before publication and that the contents really do represent RAGAGEP for our industry. New and updated technologies, methodologies, and work practices are constantly being reviewed for inclusion in these PEI standards; so the user that is still using outdated editions is not getting the full value of the latest information and work practices in each of the C/S.

Space does not permit me to name all the important C/S for PEIM, so please refer to ASME PTB-2-2009⁽²⁾ which summarizes over 150 of the codes, standards, recommended practices, specifications and guidelines that can be used by manufacturers, owners, users, regulators, engineers and all other stakeholders in the total life cycle management (LCM) of pressure equipment. As most of you know, there is a very wide array of such documents available and to the best of my knowledge up until recently, there has been no comprehensive guide on how all these documents can be tied together in the cradle-to-grave management of pressure equipment, from concept to decommissioning. ASME PTB-2-2009 fills that void. In my 45 years of experience in investigating PEI incidents and auditing PEI programs at well over 100 refineries and chemical plants, I continue to be amazed that the large majority of process safety incidents associated with fixed equipment failures could have been avoided by simply following the guidance contained in our industry C/S, especially the API series of in-service inspection C/S. In-service C/S covers all the PEI issues for each piece of pressure equipment after it is placed in service and before it is retired (permanently removed from service). The price of all of the API in-service inspection and maintenance C/S is very small compared to the value of the knowledge contained in them and especially small compared to the cost avoidance of applying their guidance to the fullest extent possible to avoid PEI incidents at each operating site.

Are you keeping up-to-date with, and applying the knowledge and practices in the latest edition of industry codes/standards for in-service inspection and maintenance?

References

1. [The Role of Industry Codes and Standards in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, *Inspectioneering Journal*, May/June, 2011.
2. ASME PTB-2-2009, *Guide to Life Cycle Management of Pressure Equipment Integrity*. The American Society for Mechanical Engineering, New York, First Edition, 2009.

Recognized and Generally Accepted Good Engineering Practices (RAGAGEP)

Because of the OSHA PSM Rule, there's been lots of controversy and concern in our industry about what is and what is not considered RAGAGEP. The term RAGAGEP was first coined in 1993 by an associate of mine in the industry soon after the PSM rule was published in the USA by OSHA. In that rule (OSHA 29CFR 1910.119 (j)(4)(ii), it states: "Inspection and testing procedures shall follow recognized and generally accepted good engineering practices." That certainly sounds reasonable. But what happened is that a few overzealous OSHA inspectors started citing operating sites for not following everything in our industry codes and standards to the letter, even where some practices were not mandated by industry standards. Industry codes/standards like API 510, 570, 653 and the entire list of recommended practices that accompany and support those codes/standards are considered RAGAGEP because most are formulated and promulgated under the rigorous consensus building process of the American National Standards Institute (ANSI) to ensure they are appropriate to be broadly applied across their target audience in industry. Because of the ANSI consensus building process in API committees where numerous companies are represented with numerous SMEs, then these codes, standards and recommended practices truly do represent recognized and generally accepted good engineering practices. That's what standardization is all about.

The controversy arises because many of the API FEMI and inspection codes/standards contain mandatory language e.g. "shall do *this*" as well as non-mandatory language e.g. "should do *this*". It was never the intent of the API or those of us involved in the API/ANSI process that non-mandatory statements in our recommended practices would become mandatory because of a misinterpretation of one statement in the OSHA PSM rule. The API and the SMEs that formulate these codes/standards recognize that even though we believed that non-mandatory language e.g. "shoulds" represent "best practices" or "recommended practices", that they are not be mandatory under all circumstances, especially in low-risk situations. So the non-mandatory language allows the users to decide for themselves if they have a better way of doing something or if a recommended practice may not be fully applicable under all circumstances at their operating site.

In my mind, other suggested industry FEMI practices contained in books, articles, conference proceedings, internal company standards and other public documents are not RAGAGEP. They may be "good engineering practices" (GEP); but they are clearly not "recognized and generally accepted" GEP, i.e. not RAGAGEP because they have not been scrutinized, reviewed, balloted, approved and published by a wide group of SMEs in a Standards Development Organization (SDO) using a rigorous, audited standards development process. When a trade association contracts with a few authors to write a book about mechanical integrity, that does not make that book RAGAGEP. Such a book simply represents the views of those who wrote and/or reviewed the book, which is just fine until OSHA inspectors begin to believe that they need to enforce such things. Of course, when a company receives an unwarranted citation under questionable interpretations of the PSM Rule, such as those mentioned above, that the recipient always has access to due process, hearings, etc. in which to dispute such citations. It has been my experience that when such appeals are made by recipients of unwarranted citations, that they are often withdrawn or otherwise negated during due process proceedings.

Is your operating site applying FEMI RAGAGEP as intended by the API/ANSI process or do have some managers quivering in fear that they might get cited for not mandating every recommended practice?

Site Procedures, Work Processes, Management Systems, and Best Practices

This is another top priority EE to accomplish consistency and sustainability for your FEMI programs across your operating site(s). For purposes of this EE, I will use the acronym SP&WP which stands for Site Procedures and Work Practices, generically to apply to a wide variety of names for the various documents used by operating sites for maintaining FEMI that may include company and operating site standards, standing orders, procedures, management systems, best practices, specifications, recommended practices, guidelines, publications, training documents, etc. Together they comprise all the documented information about what needs to be done, how it is to be done, who will be involved and how they will be involved, how work groups are integrated to get the job done, when things need to be done, responsibilities, accountabilities, etc. in order to maintain FEMI. Everything that needs to be accomplished to maintain FEMI by each site group needs to be described in sufficient detail that it transcends any one individual or group at the site, such that there can be a smooth transition when personnel turnover occurs or a new hire comes on board i.e. nothing gets lost or “dropped between the chairs”, when there are personnel transitions. Space does not permit me to write about all the different, important SP & WP in this EE, so for more information and for multiple examples of FEMI issues/activities that each site might want to consider documenting, please refer to a previous article in the *Inspectioneering Journal* on the subject⁽¹⁾.

These SP&WP documents may exist in several different operating departments and/or be contained in site wide procedures and practices which apply to all departments that have a role in FEMI. The largest number of FEMI SP&WP will typically be contained in the site department/organization which has the primary role in maintaining FEMI. It doesn't really matter what the department is called, but it is the one that has the lead technical role in maintaining FEMI. However, generally there will also be some SP&WP responsibility for FEMI issues in operations, maintenance, engineering, procurement and receiving. Each of these groups has a vital role in maintaining FEMI, as the Inspection Group cannot do it alone⁽²⁾. In my mind it's very important that the Inspection/ FEMI Department be fully informed and involved in creating and maintaining the FEMI SP&WP that exist in other departments where employees have a role in maintaining FEMI so that everyone has a clear understanding of and appreciation for their FEMI role.

One of the key purposes of SP&WP is to indicate which of the many industry codes and standards (C/S) applies at each operating site and how each applies. To accomplish that task, most companies and their individual operating sites typically have their own company and/or site-specific standards, procedures and work processes; the purpose of these being to fill in gaps in the industry standards and to make the industry standards site-specific. Industry C/S (see separate EE) provide a lot of valuable technical information, requirements and recommended practices to accomplish excellence in FEMI; but because these industry C/S need to be generic to apply to a wide range of organizations and practices in industry and because industry standards don't yet cover all vital FEMI issues, some amount of site/company-SP&WP are necessary in order to accomplish all the necessary FEMI tasks at each site.

Does your operating site have all the necessary SP&WP to provide consistency and sustainability for all your important FEMI programs and all the 101 EEs of PEIM, or are you dependent upon a few key individuals who supposedly know what's suppose to be done?

References

1. [The Role of Site Procedures and Work Processes in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, Nov/Dec, 2011.
2. [Management Leadership and Support for PEI&R](#), John T. Reynolds, Inspectioneering Journal, Jan/Feb 2010.

Inspection Scheduling

A management system needs to be in place to determine/set inspection plans for pressure equipment and piping to ensure that the appropriate inspections are carried out; not only for API Code compliance, but also to ensure that equipment/piping is inspected using proper practices and tools at the right time intervals. Those plans need to cover internal, on-stream, and external inspections. With recent revisions to the three API Codes (510/570/653), the inspection strategy and frequency can/should now be risk-based, in lieu of the condition-based inspection (CBI) or time-based inspection (TBI). CBI planning is the type that is based on half-life calculation of inspection intervals, while TBI planning is based on maximum intervals like those that require inspections based on TAR intervals. RBI strategies are usually more economical and result in a more reliable facility, by making sure that the higher risk equipment is inspected at higher frequencies and with more effective inspection methods (see separate EE). Once an effective inspection scheduling program and process is in place (be it RBI/CBI/TBI), then an effective strategy must be executed to prevent/control overdue equipment and keep it to an absolute minimum (see separate EE).

Both API 510 & 570 codes contain a section on inspection planning requiring that inspection plans be established for all vessels and piping systems, as well as associated pressure relieving devices (PRDs), within the scope of the codes. These codes define inspection plans as: “documented plans for detailing the scope, extent, methods, and timing of inspection activities for pressure vessels and piping systems, which may include recommended repair and/or maintenance.” The inspection plan must be developed by the inspector and/or pressure equipment engineer based on the inspection history and consultation from a C/M SME, as needed. The C/M SME is needed in some cases to identify/clarify potential damage mechanisms and specific locations where degradation may occur, especially where localized corrosion or cracking mechanisms may be involved. Both codes make extensive reference to API RP 571⁽¹⁾ for inspection planning for specific types of damage mechanisms that may afflict your equipment.

The methods and the extent of NDE planned for inspections must be evaluated to ensure that they can adequately identify the damage mechanisms and the severity of damage. Regardless of whether you employ TBI, CBI or RBI, examinations must be scheduled at intervals that consider these issues:

- type of damage mechanisms anticipated,
- rate of damage progression,
- tolerance of the equipment to the type of damage,
- capability of the NDE method to identify the damage,
- maximum intervals as defined in codes and standards,
- extent of examination, and
- any MOC issues that have occurred since the last inspection relative to any specific pieces of equipment.

Both codes go on to specifically indicate all issues that must be included in inspection plans.

Do you have individual inspection strategies for each vessel and piping system? Does your inspection scheduling software handle external, on-stream, as well as internal inspection frequencies, and does it allow you to schedule special inspections like: CUI, HTHA, and SCC inspections?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, 2nd Edition, April, 2011, American Petroleum Institute, Washington, D.C.

Risk Based Inspection (RBI) Planning and Scheduling

One of the most significant advancements to come along in the FEMI business in the past two decades is the application of RBI for inspection prioritization, planning, and scheduling. The most important standard for RBI in the petroleum and petrochemical industry is API RP 580⁽¹⁾. The second edition includes many important updates and improvements that everyone involved with RBI should be aware of, including an entirely new chapter covering the potential pitfalls that many users have experienced when implementing a RBI program. The third edition is now in the balloting stages where the committee is planning on changing some of the RBI work process recommendations to requirements (i.e. a number of “shoulds” will be changed to “shalls”). Publication of the third edition is expected in early 2015.

API RP 580 is intended to provide guidance on implementing a RBI program for fixed equipment and piping. It includes: all of the key elements of RBI, how to implement a RBI program, how to sustain a RBI program, initial planning for RBI, RBI data gathering, identification of damage mechanisms, how to assess probability of failure (POF) and consequence of failure (COF), risk calculations, managing inspection activities with RBI, RBI reassessments, and documenting the results. After implementation, risk-based inspection strategies are usually more economic and often result in a more reliable facility by ensuring that higher risk equipment is inspected at higher frequencies and with more effective inspection methods. Note that I said “after implementation”, as there is clearly an up-front investment in RBI implementation in order to achieve the long term benefits. As of the date of this publication, it appears to me that the industry is close to the 50% mark of refineries that have converted (or are in the process of converting) their inspection planning programs from the more traditional rule-based and/or time-based planning to risk-based (RBI).

API RP 580 is intended to supplement API 510, API 570 and API 653. Each of those API inspection codes and standards allows owner/users latitude to plan their inspection strategies and increase or decrease the specified code allowable inspection frequencies and activities based on the results of a thorough RBI assessment. The assessment must systematically evaluate both the probability of failure and the associated consequence of failure. The probability of failure assessment must be evaluated by considering all credible damage mechanisms in any process unit (see separate EE on identification of DMs).

Keep in mind that the API RP 580 RBI standard is a general RBI guidance document that provides all the guidance and information needed to make sure that your RBI program is all inclusive and covers all of the important aspects of the RBI work process. As such, it is differentiated from its sister document API RP 581⁽²⁾ which provides users with a step-by-step process that describes exactly how software can be compiled to conduct RBI in compliance with API RP 580 and 581. Other RBI software is available from several commercial sources or has been developed independently by owner-users. One of the most important steps in choosing the specific RBI method you wish to employ is to make sure it complies with the entire RBI work process outlined in API RP 580. Do not just assume any particular commercial method complies with API RP 580 because their marketing pitch says it does; make sure you inquire into the important issues outlined in each section of API RP 580 to better ensure that any particular RBI program and accompanying software that you may be considering will deliver all of the vital aspects covered in API RP 580.

API RP 580 and 581 are both based on the knowledge and experience of numerous RBI practitioners with extensive experience in RBI implementation. It was not written in a vacuum by just a few “experts”. Both API RP 580 and 581 were written, reviewed, balloted, and approved following the rigorous ANSI standardization process by many engineers, inspectors, risk analysts and other personnel that have been involved in implementing an RBI program.

I have seen several sites make “false starts” when implementing a RBI program that failed to deliver what was expected; and with those false starts, RBI gained a bad reputation at the operating site. In my experience, all such false starts resulted from a failure to closely follow the guidance provided in API RP 580. If you short-cut the process or do not follow the guidance in API RP 580, you are likely to end up with poor results and frustrated, disappointed stakeholders that then falsely blame the “RBI” work process for their own failure to implement the RBI process effectively. The sites that have been most successful at RBI implementation have done so under the guidance of a full-time, knowledgeable RBI “champion,” with full backing and proactive support from site management for both human and capital resources. As API

RP 580 indicates, the RBI work process is dependent upon an effective team of SMEs with knowledge of inspection, corrosion/materials, fixed equipment mechanical integrity, process engineering, and operations. Site management must recognize the need for those resources and provide them for the RBI team efforts on a timely basis, or the process will be unnecessarily prolonged and frustrated.

Another cause for RBI false starts that I have witnessed at operating sites occurs when site management decides not to implement a RBI program with focused resources (e.g. a separate project), and instead just piles the entire RBI implementation project on top of the existing inspection resources that are already fully loaded with day-to-day operating, maintenance and engineering support.

Has your site gained the efficiency, cost-effectiveness and improved process safety associated with implementing a competent, risk-based inspection planning and scheduling program? If not, you may be falling behind the industry leaders.

References

1. API RP 580 *Risk Based Inspection*, 2nd edition, November, 2009, American Petroleum Institute, Washington, D.C. (3rd edition in ballot as of 1Q/14)
2. API RP 581 *Risk Based Inspection Technology*, 2nd edition, September, 2008, American Petroleum Institute, Washington, D.C. (3rd edition in ballot as of 1Q/14)

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Probably the biggest change in FEMI since the original publication of the 101 EEs of PEIM is the increasing use of risk analysis (RA) in the FEMI discipline⁽¹⁾. Utilization of RA is the key to effective decision making in almost all facets of our business, but especially when it comes to issues involving FEMI issues. Not only are more operating sites converting to RBI (see separate EE on RBI), but many sites are using RA for Risk-Based Turnaround Planning (RBTAP)⁽¹⁾, RA associated with FEMI issues in PHAs⁽²⁾, RA associated with Corrosion Control Documents (CCDs)⁽³⁾, risk-based heat exchanger tubular inspection⁽⁴⁾, and risk-based Integrity Operating Windows (IOWs)⁽⁵⁻⁶⁾ and a basic Risk-Based Decision Making (RBDM) work process⁽¹⁾. RBDM is being used in a wide variety of everyday decision making including: what to do with piping deadlegs that are no longer of use, finding reasonable alternatives to conducting hot taps, assessing risks associated with using NDE in lieu of pressure testing, assessing risks associated with third party owned equipment that is being operated on site, assessing risks associated with buried vessels and piping, etc. With little imagination this list could include 100+ such FEMI issues where risk assessment is now more commonly being used to make better decisions.

More advanced sites using a variety of RA work process also have a systematic process in place to assure that asset managers, unit process engineers, maintenance and operating personnel are not only aware of, but also involved in, the highest risk FEMI issues that are of concern in each process unit. The corrosion engineer and/or unit inspector should not be the only ones concerned about or aware of the high risk FEMI issues. A multi-functional team of key stakeholders should periodically conduct the risk based prioritization and decision making analysis of the Top Ten FEMI risks in each process unit, so that FEMI issues end up being properly prioritized with all other “hot rocks” of the day and other issues on the “want to do list”. (See EE on Shared Stewardship of Assets).

In the RBTAP process, sites are making much more widespread use of risk analysis for turnaround planning (TAP) of FEMI issues, with and without RBI. The RBTAP process engages folks from operations, engineering, maintenance planning, and inspection in the risk assessment work process, which significantly improves the quality of TAP decisions, as well as the buy-in of all the right stakeholders. It actually makes TAP decision making easier, when we prioritize all the things we need to do and want to do, using risk assessment. Every decision has risks and benefits associated with it. When you use a systematic process to set your premises for the next operating run, identify all the threats to the success of that operating run, identify the potential consequences of each threat, determine the likelihood that the identified consequences will occur, then you have the basis for making intelligent, non-emotional, risk-based TAP decisions. Without that kind of process, you can end up with decisions made by “pushing and shoving”, “screaming and shouting”, competition between groups, “strong-arming” by the powerful, or arbitrarily made by “he who owns the budget”. The risk sharing that occurs in RBTAP effectively eliminates this type of behavior and draws functional groups into closer working relationships. What a pleasure the risk-based way is, relative the historic past!

Does your site use effective, risk-based priority setting and decision making for most FEMI issues?

References

1. [The Role of Risk Assessment and Inspection Planning in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, *Inspectioneering Journal*, Sept/Oct, 2010.
2. [Managing the Risks Associated with Fixed Equipment Mechanical Integrity Issues](#), John T. Reynolds, Principal Consultant, Intertek/Moody AIS, *Inspectioneering Journal*, March/April edition, 2013.
3. [Corrosion Control Documents - One High Priority Approach to Minimizing Fixed Equipment Failures](#), John T. Reynolds, *Inspectioneering Journal*, Sept/Oct, 2012.
4. [Heat Exchanger Tubular Inspection – A User's Perspective](#), John Reynolds and David Wang, *Inspectioneering Journal*, July/August, 2008.
5. [Management of Change and Integrity Operating Windows for PEI&R](#), John T. Reynolds, *Inspectioneering Journal*, March/April 2010.
6. API RP 584, *Integrity Operating Windows*, First Edition, American Petroleum Institute, Washington, D.C., May, 2014.
7. [Why Some Operating Sites Just Don't Get It](#), John T. Reynolds, Principal Consultant, Pro-Inspect, Inc., *Inspectioneering Journal*, May/June edition, 2007.
8. API 580 *Risk Based Inspection*, 2nd edition, November, 2009, American Petroleum Institute, Washington, D.C.(third edition in ballot stage as of 4Q/13)
9. API 581 *Risk Based Inspection Methodology*, 2nd edition, September, 2008, American Petroleum Institute, Washington, D.C. (third edition in ballot stage as of 4Q/13)

Tracking Top FEMI Risks

One of the most important EEs for FEMI risk management is keeping a list of the top ten FEMI risks in front of all stakeholders at each operating site. The site corrosion and materials (C/M) SME and/or unit inspectors should not be the only people concerned about or aware of the issues that could threaten FEMI. A systematic process should be in place to ensure that asset managers, unit process engineers, maintenance and operating personnel, as well as senior management at each site are not only aware of these FEMI risks, but also involved in resourcing and decision making for the highest risk FEMI issues that are of concern in each process unit. Risk-based prioritization and decision making are useful work processes for dealing with issues that could cause the failure of fixed equipment (see separate EE). A multi-functional team of key stakeholders, including asset managers should periodically conduct risk-based prioritization and decision making analysis, so that FEMI issues end up being properly prioritized and resourced with all other “hot rocks” of the day, pet projects, and other demands on the site’s limited budget.

The reliability bad actor list does not serve this purpose very well, as they bring more focus to reliability issues rather than integrity issues, and more focus on frequency of equipment failure than on potential magnitude of equipment failure. Bad actor lists certainly serve a good purpose for rotating equipment, electrical and instrumentation systems and perhaps a few fixed equipment issues like hydroprocess flange leaks, dripping hot oil flange leaks, alky plant leaks caused by acid excursions and heat exchanger head gasket leaks. But FEMI issues on bad actor lists might have you chasing around after steam condensate leaks, buried fire water piping leaks, and other lower priority, lower risk FEMI issues.

Typically the highest FEMI risks are generally not bad actors, because they do not cause failures “frequently”, but when they do fail, it is generally a major process safety event (i.e. major releases, fires, explosions, etc.). Examples of such FEMI issues that might make the top ten FEMI risk list, but not the bad actor list include such things as:

- low silicon CS components in hot sulfidation services,
- equipment that may be susceptible to HTHA,
- potential for brittle fracture in auto-refrigeration services,
- potential for highly localized corrosion from ammonium salts in hydroprocess services,
- potential for localized deadleg corrosion or freezing,
- potential for highly localized corrosion at mixing points,
- potential failure from unintentional substitution of CS components in an alloy piping system,
- and a host of other FEMI issues that are not frequent, but tend to be catastrophic when they occur⁽¹⁾.

The top ten FEMI risk list should be updated and reviewed with appropriate stakeholders (including management) periodically (I suggest quarterly) so that management remains aware of the FEMI risks, just as they do PHA action items and environmental exceedances. Too often site action item tracking software programs and spreadsheets are chock full of lower priority operating risks at the expense of higher priority FEMI risks. Another good thing to do with these lists is to make sure that every PHA revalidation has access to the list and the opportunity to integrate these FEMI risks into the PHA.

Does your site keep lists of the top ten highest FEMI risks? Are those lists updated at least quarterly and reviewed for progress with operating and senior management?

References

1. [Managing the Risks Associated with Fixed Equipment Mechanical Integrity Issues](#), John T. Reynolds, Inspectioneering Journal, May/June, 2013.

High Temperature-High Pressure Equipment Inspection

The focus of this EE is on inspection needs for high temperature and/or high pressure (HT/HP) equipment generally used in hydroprocess or other HT/HP units. A reader might wonder why there is not an EE on ordinary pressure vessel (PV) inspection. The reason is that the topic is so well covered by API 510 and 572, that I have nothing significant to add to those standards, whereas there are a number of important issues to cover with regard to HT/HP PV inspection with which I have seen some sites struggle.

However, the issue of degradation of HT/HP equipment is so important that API is publishing a series of recommended practices and technical reports on the subject⁽¹⁻⁵⁾. Few pieces of equipment are more critical to operating sites than heavy wall HT/HP vessels like hydrocrackers, hydrotreaters, and other associated HT/HP equipment. Degradation issues to which HT/HP equipment is subject, and that have been experienced by some operating sites, include:

- Cracking of RTJ flanges in the gasket groove,
- Cracking of tray support ring attachment welds to the shell,
- Weld overlay cracking in the through wall direction,
- Weld overlay disbonding,
- Base metal damage from HTHA, creep and embrittlement phenomena e.g. temper and hydrogen embrittlement,
- Sigma phase and polythionic acid cracking of weld overlay,
- Skirt attachment weld cracking,
- Lifting lug attachment weld cracking,
- Cracking of nozzle and main seam welds including in-service growth the original weld flaws,
- Bulging and/or heat damage from high temperature excursions, and
- Corrosion of vessel walls and internals

The potential for each of these damage mechanisms should be evaluated by a C/M SME (see separate EE) with knowledge and experience in HT/HP damage mechanisms. The results of such evaluations should be recorded in the process unit CCD's (see separate EE). Detailed inspection plans utilizing appropriate NDE techniques should then be formulated; potentially using the services of a competent NDE SME (see separate EE).

Brittle fracture is another potential failure mode that deserves careful consideration with regard to heavy wall equipment used in HT/HP equipment (see separate EE). Controlled heating and cooling procedures during startup and shutdown are highly advisable for heavy wall equipment to avoid the potential for brittle fracture, especially if any embrittlement phenomena have been experienced. Heavy wall equipment should never be pneumatically pressure tested unless there is no other reasonable alternative, and then only when a competent C/M engineer has been involved to assess the potential for brittle fracture and the appropriate risk assessment and contingency planning has been done.

Do you have detailed inspection plans for the potential damage mechanisms your HT/HP equipment could experience? Were they formulated using the input from experienced C/M and NDE SMEs?

References

1. API RP 934-A *Materials and Fabrication of 2 1/4Cr-1Mo, 2 1/4Cr-1Mo-1/4V, 3Cr-1Mo, and 3Cr-1Mo-1/4V Steel Heavy Wall Pressure Vessels for High-temperature, High-pressure Hydrogen Service*, Second Edition, May, 2008, plus addendums A and B, American Petroleum Institute, Washington, D.C. (3rd ed. Pending)
2. API TR 934-B, *Technical Report: Fabrication Considerations for Vanadium-Modified Cr-Mo Steel Heavy Wall Pressure Vessels*, 1st Edition April, 2011, American Petroleum Institute, Washington, D.C.
3. API RP 934-C, *Materials and Fabrication of 1-1/4 Cr-1/2 Mo steel Heavy Wall Pressure Vessels for High Pressure Hydrogen Service Operating at or Below 825 Degrees F (441 Degrees C)*, 1st Edition, May 2008, American Petroleum Institute, Washington, D.C. (2nd ed. Pending)
4. API TR 934-D, *Technical Report: Materials and Fabrication of 1-1/4 Cr-1/2 Mo and 1 Cr-1/2 Mo Steel Pressure Vessels*, 1st edition, September 2010, American Petroleum Institute, Washington, D.C.

Heat Exchanger Tubular Inspection

Like all of the EE summaries, this one discussing heat exchanger (HX) tubular inspection is a very brief overview of a very large subject matter which includes: different types of NDE techniques for HX tubular in-service inspections, some of the various advantages and limitations with these methods, HX tubular inspection planning, data analysis needs, a consequence rating method for scheduling inspection and bundle renewals, tubular cleaning methods, in-process inspection QA/QC required, and tubular inspection technician qualifications. Each of these issues need to be carefully planned for a successful application of bundle inspection and are covered in more detail in an article previously published in Inspectioneering Journal⁽¹⁾.

There are numerous methods of bundle inspection techniques available on the commercial market, including IRIS, ECT, MFL, remote visual and laser inspection. Before selecting the right technique for any particular bundle inspection job, the user must first know how he/she is going to use the data, what defects the technique must find, the extent of inspection planned (i.e. sample size⁽²⁾), and how clean the tubes will be. Some techniques are more accurate than others; some are faster; some require less extensive cleaning; some can only evaluate thickness of tubulars while others can find cracks and other flaws; some are meant more for screening evaluation; while others can produce accurate data for corrosion rate and remaining life calculations; some require higher technician skill levels; some require a couplant while others do not; some are only good for ferromagnetic materials; some for non-ferromagnetic materials and some can handle both. This list of advantages and disadvantages of each method is long and needs to be evaluated by the end user prior to selecting the technique that will most likely meet their needs; and the user needs to be wary of the vendor who only knows the advantages of the techniques which they market and none of the disadvantages.

Leaks from heat exchanger bundles are not infrequently the cause of reliability problems during scheduled process unit runs. If we are lucky, the leak has only economic consequences and some assets have to be shut down to fix the unexpected tubular leaks. If we are unlucky, the leak causes an environmental problem in your effluent system or a safety problem when hazardous substances leak into the adjacent fluids. One way to plan your bundle inspections, if you are not yet doing RBI on your bundles, is to classify all your bundles into a simple system of A-B-C, where: 'A' bundles must have maximum assurance against on-line leakage due to safety, environmental, or large economic consequences that could occur; 'B' class bundles are those that have varying degrees of economic consequences, should an unexpected leak occur; and 'C' class bundles are those that have minimal or no consequences should an unexpected leak occur. With this simple system in place, you can schedule your bundle inspections and preventive maintenance on bundles to provide better assurance that higher risk bundles will receive more attention than lower risk bundles. More conservative tubular renewal thickness levels can be established that will provide for a greater margin for error on higher risk bundles and lower renewal thicknesses for lower risk bundles in typical lower pressure process services (e.g. 0.035-0.045 inches for A class bundles; 0.020-0.30 inches for B class bundles; and 0.010-0.015 for C class bundles). More accurate methods of measuring tubular wall thicknesses can also be applied to higher risk bundles.

One of the critical success factors for obtaining high quality HX tubular inspections is to have qualified technicians using the best available (calibrated) NDE equipment. A performance demonstration program is an effective way to ensure that NDE technicians will be able to provide you with reliable results. In a performance test, the technician should be able to: 1) demonstrate proficiency with the specific NDE equipment that will be used on-site; 2) demonstrate proficiency in detecting, characterizing and sizing known defects/flaws in a test bundle; and 3) demonstrate proficiency in accurately reporting the findings in the test bundle. In addition, QA/QC of vendors providing inspection services using qualified technicians is necessary to ensure delivery of high quality work. The QA/QC should include reviewing vendor's procedures (including procedure updates), verifying compliance to training and qualification requirements, examining equipment maintenance and calibration records, and auditing field work as necessary.

In summary, getting superior results from HX tubular inspections is only possible if there is a combination of several key factors, including: doing the appropriate amount of quality inspection planning, selecting the most appropriate inspection method depending upon how the user will use the data, making sure the selected company and technician are suitably qualified and experienced to do the job, ensuring

that the tubulars are adequately cleaned for the inspection methods to be performed, doing adequate QC during the inspection, and doing the right type of data analysis to evaluate the condition of the tubulars to determine the remaining life of the bundle.

Are you doing all the right planning for your HX tubular inspections, such that you are confident that you are getting reliable data on which to forecast the necessary bundle renewal dates?

References

1. [Heat Exchanger Tubular Inspection](#), Inspectioneering Journal, July/Aug, 2008, John T. Reynolds and David Wang.
2. Proceedings of the PVP2006-icpvt-11 Conference, *Extreme Value Analysis of Heat Exchanger Tube Inspection Data*, W. David Wang, Shell Global Solutions, Inc.

Fired Heater Monitoring and Inspection

Fired heaters are often major contributors to reliability problems in hydrocarbon process facilities if they do not receive focused attention from fired heater SMEs and operators. Fired heaters are subjected to some different degradation mechanisms than pressure vessels and piping due to the combination of heat and the various chemical characteristics of process fluids in heater coils. Alloys designed to counteract specific corrosion mechanisms often exhibit other sensitivities requiring specialized inspection techniques and operating controls. As such, inspectors and engineers involved in fired heater inspection and maintenance should be trained, knowledgeable and experienced on these unique heater degradation, inspection and maintenance issues.

Process variables associated with integrity operating windows (see separate EE on IOWs) must be monitored for abnormal trends and exceedances. This data in conjunction with on-line visual, thermocouple, and infrared monitoring/mapping are especially valuable in the determination of excessive heat flux, tubular sag/strain, localized or accelerated corrosion, coke deposition, creep and other degradation mechanisms associated with the various tubular alloys⁽¹⁻²⁾. This type of information is essential in creating fired heater integrity and inspection plans. As such, an effective fired heater reliability program to monitor and control flame patterns, tube temperatures, hot spots, etc. is important to preventing premature failures of fired heater tubes. The latest edition of API RP 573⁽²⁾ contains a wealth of information on fired heater design and the necessary inspection, maintenance, on-stream monitoring and control for maximum reliability. All people involved in the inspection and maintenance of fired heaters should have ready access to this valuable information-packed standard.

When a fired heater is down for inspection and maintenance, inspectors and engineers, knowledgeable in potential deterioration mechanisms for tubulars, structural members, and refractory, need to specify and implement an effective inspection, data analysis, and maintenance effort in accordance with API RP 573(2) for each fired heater that will be opened for inspection. This effort will identify potential causes of deterioration and predict remaining life of each fired heater coil in the radiant and convection sections. Fired heater inspection and maintenance is a specialized body of knowledge that needs to be imparted to those involved, in order to avoid unexpected reliability hits when a fired heater comes off line in the middle of an operating run. And do not assume that fired heater tube failures are simply reliability problems; many higher-pressure hydroprocess fired heater tube ruptures have resulted in injuries and fatalities.

Hot spots are not an infrequent occurrence in fired heaters and refractory lined equipment associated with fired heaters, and as such, it is important that operating sites know how to monitor and evaluate hot spots. A few years back, a refinery suffered a fatality when a hot spot on a charge heater led to a tube rupture on a high pressure furnace coil. As it turns out, the site knew about the hot spot, but misdiagnosed it as glowing scale on the tube. Another heater not too long ago suffered a blow out and fire on a refractory lined effluent transfer line on a steam-methane reformer heater. The refractory had failed, leading to the hot spot and eventual line rupture because it went undetected. An effective infrared thermography inspection program combined with effective tube skin thermocouples are vital to detect and measure tube skin temperatures and hot spots. Temperature sensitive paint can also serve as a warning sign when refractory failure has occurred on the inside diameter for lined equipment. Once detected, it is very important that experienced, knowledgeable engineers and inspectors be involved in evaluating and monitoring the hot spot to ensure that blow-out conditions do not develop. Equipment can operate reliably for long periods of time with adequate, temporary, hot spot mitigation measures in place; but only if they are properly designed and implemented.

Do all of your critical fired heater coils have a reliable structural integrity analysis and remnant life prediction so that you will not be surprised by predictable failures that could have been avoided with scheduled inspection and maintenance? Do you have effective tube skin thermocouples, infrared monitoring, hot spot monitoring and evaluation procedures in place to make sure you do not suffer a surprise rupture of equipment from tubular overheating or hot spots? Are you effectively applying the wealth of knowledge on fired heater inspection, maintenance, on-stream monitoring and control contained in the latest edition of API RP 573?

References

1. API RP 571, Damage Mechanisms Affecting Fixed Equipment in the Refining Industry, Second Edition, April, 2011, American Petroleum Institute, Washington, D.C.
2. API RP 573, Inspection of Fired Boilers and Heaters, 3rd edition, October 2013, American Petroleum Institute, Washington D.C.

Atmospheric Storage Tank (AST) Inspection

Inspection of ASTs is another one of our foundational EEs with two excellent standards that provide roles and recommendations for AST inspection and repair: API 653⁽¹⁾ and API RP 575⁽²⁾. Hence, the contents of those two documents will not be summarized herein. All people involved in the inspection and repair of ASTs should have ready access to both standards. All inspectors who are involved in the inspection and repair of ASTs should be certified by the API as Authorized AST Inspectors, by passing the certification examination and meeting the experience requirements as provided in API 653. As with fired heaters, other refractory lined equipment, coatings and PRDs, inspection of ASTs involves a specialized body of knowledge that is best performed by those knowledgeable and experienced in AST subject matter.

One of the highest environmental priorities for owner-operators is to ensure that their tanks are not leaking and thereby exposing the site to potential ground water or surface water pollution. It typically costs a lot of money to remove a storage tank from service because of decontamination and cleaning expenses, let alone the potential impact on operating costs of not having the tank available. It is not uncommon for the AST inspection and maintenance budget for a large operating site to be equal to the maintenance budget for all other equipment in the plant. Therefore, it behooves each owner-operator to do the best job possible of inspecting and maintaining the tank bottom so that the tank can be returned to service with confidence that it will function reliably for the longest possible interval before the next required inspection. It does not make much sense to spend hundreds of thousands of dollars to take a tank out of service for maintenance, only to go cheap on the inspection part of the work process, thereby risking a shorter duration before the next time the AST must again be removed from service. Currently, one of the most effective ways I know of inspecting tank bottoms that can be taken out of service, is to do a “100%” MFE inspection with ultrasonic scanning type follow up of indications above the MFE threshold setting, utilizing MFE technicians and equipment that have been performance-tested on known tank bottom flaws and defects. The inspection should also include a hand-scan MFE examination of the critical zone next to the tank wall and next to all lap patch welds in the floor. And do not forget the sump area. There is nothing more embarrassing for inspection groups than to put a tank back in service after spending huge sums of money to clean, inspect and repair it, and then have it leak within weeks or months of being returned to service. Your career can only stand just so many of those snafus.

While tank bottom inspection is 99% about protecting the environment from leakage, there are a few cases of catastrophic tank failure that have resulted in safety problems as well as inspection safety issues. Inspecting tank roofs, or for that matter, any activity on the top of a cone roof tank, including gauging and vent maintenance, has significant safety issues associated with it and must be done with the utmost caution. When I started my career over 46 years ago, one of the first things I learned in the inspection group was to be very cautious about walking on tank roofs because they may be too thin (from internal condensate corrosion) to hold my weight. I was told to walk the seams and the roof supports. Not too long ago a man walking on top of a tank in a gulf coast refinery fell through the thin roof to his death, when he stepped off the boards that were provided for his safety. Tank roofs typically only start out with a thickness of 0.125 to 0.187 inches. It does not take too long for condensing vapors on the underside of tank roofs to cause that metal to become very thin, let alone what happens to the structural members holding up the roof plates. Other people have been asphyxiated by toxic substances (e.g. H₂S) coming through gauge hatches and vents on the roof.

Few people in our business have not seen the results of a severely wrinkled or collapsed AST, when a vacuum was pulled on the tank in-service. These are ugly, embarrassing, costly incidents that are easily preventable with simple AST vent maintenance. Some cases that come to my mind include tanks that collapsed because of birds or mud daubers building nests inside the vent, a painter who covered the vent with a plastic sheet and forgot to remove it before product was withdrawn from the tank, a vent that was undersized for an abnormal pump out rate, and a vent that plugged when asphalt vapors condensed on the outlet screen. AST vent devices need regular inspection and testing by competent, trained individuals, as well as careful attention during and after maintenance painting. Clearly this preventative activity is less expensive than demolishing and rebuilding a collapsed tank.

Do you use the best available commercial technology for inspecting your tank bottoms to provide maximum assurance that you have found any thin areas or cracks that might cause an unexpected leak during

the next run; and do you know if your MFE technicians are truly qualified to do the work with the best equipment available? Does everyone in your group know the dangers associated with inspection and other activities on tank roofs? Do you have routine inspection and testing of your AST vents, at a frequency that will adequately control your risk of tank collapse from plugged vents?

References

1. API 653 Standard, *Tank Inspection, Repair, Alteration and Reconstruction*, American Petroleum Institute, Washington D.C., 4th edition, November, 2013.
2. API RP 575, *Inspection of Atmospheric and Low Pressure Storage Tanks*, American Petroleum Institute, Washington D.C., 2nd edition, April, 2005.

Buried Process Piping/Vessels

Most operating sites have buried piping; a few have buried pressure vessels; and many have buried canned pumps. Obviously a lot of buried piping is in utility service (e.g. cooling water, fire water, etc.), and should be inspected as necessary for plant reliability reasons. But the focus of this EE is on that equipment and piping that is in process service, especially those in API class 1 service which would produce an immediate process safety threat if a leak were to occur (e.g. LPG service). For those that have buried process piping systems, it is a good idea to make sure that all such buried piping be shown on plot plan drawings and have documented inspection plans in accordance with section 9 of API 570⁽¹⁾ and 574⁽²⁾.

Several NDE techniques are now available and continue to be developed to help owner/operators conduct inspections without substantial excavation, including: magnetic flux leakage (MFL), ultrasonics (UT), optical video, laser, eddy current (ET) and other electromagnetic techniques. The buried piping to be evaluated needs to be free from internal restrictions that would cause the NDE device to stick within the interior of the line. The degree and number of bends in a line may restrict the application of some technologies. However, technologies capable of negotiating unlimited short radius bends are now available. Launching of some inspection pig designs may be as simple as separating a flange, inserting the pig by hand, reassembly of the flange and reinstating regular product flow. Other systems may require the line to have facilities for launching and recovering the inspection pigs or have an access that allows the addition of temporary launching/receiving capabilities. There are also self-propelled in-line inspection (ILI) tools, or free swimming NDE tools, now available that only require one point of access and can perform the wall loss examinations with or without product/fluid in the line. These tools use either ultrasonic or electromagnetic inspection methods to detect and size both ID and OD defects, and do not require typical launching and receiving line modifications; however, the use of an umbilical may restricts their inspection range.

In the early years of refining and petrochemical manufacturing, some LPG bullets were buried to keep them from heating up on hot summer days. Unfortunately that practice rendered these buried vessels relatively inaccessible for inspection, except internally. Even if such vessels were properly prepared, properly coated, buried with the proper backfill, and effectively cathodically protected (see separate EE), the coating may still break down after decades of service and render the buried vessels susceptible to external soil corrosion. In which case, the owner-operator is faced with excavating the vessels for inspection or inspecting them with specialized NDE from the inside of the vessel looking for external metal loss. There are several screening methods commercially available to do that, including low frequency eddy current, MFL, and EMAT. These screening methods will help the inspector determine if there are some corroded areas on the external surface, but may not provide accurate enough data for corrosion rate and remaining life calculations. For greater data accuracy, the inspector could use ultrasonic scanning techniques, A, B, or C. In any case, because of the localized nature of soil corrosion after coating breakdown, the inspector should consider scanning as close to 100% of the surface as possible.

Back in the late 80s, I remember the news story on the gulf coast about a large fire caused when a welder bumped up against a pipe that was emerging from an underground section of the line. The pipe broke in half and the light hydrocarbon immediately ignited due to the welding activity. Soon after the incident, the API 570 task group included inspection of soil-to-air interfaces (SAI) in the code and many operating sites embarked on a special emphasis program to inspect these SAIs on buried piping systems; finding a number of lines with significant corrosion and severe thinning at the interface. This area on a pipe (6-12 inches above and below the soil line) is usually not benefited by cathodic protection (if it is present), and is exposed to some of the most aggressive soil and atmospheric corrosive conditions out there. The accelerated localized corrosion at the interface is due to oxygen concentration cells and alternate wet-dry conditions, plus coatings and wrappings that are often damaged and/or deteriorated at the interface.

Another buried equipment issue involves buried canned pumps; especially those which are in LPG service. Some are buried in a concrete cylinder, while others are buried in direct contact with the soil. After a major LPG fire at a refinery in Texas, the need for excavating and inspecting these cans that are exposed to soil corrosion is getting more attention.

Do you have all of your buried process piping documented and adequately inspected? Do you have buried

vessels or canned pumps that need inspection for corrosion on the soil side? Are your soil-to-air interfaces routinely inspected, especially in higher risk services like API 570 Class 1 piping, and do you maintain your coatings and wrappings at the SAI?

References

1. API 570, *Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems*, 3rd Edition, American Petroleum Institute, Washington, D.C., November, 2009, (4th edition in ballot stage as of 1Q/14).
2. API RP 574 *Inspection Practices for Piping System Components*, American Petroleum Institute, Washington D.C., 3rd edition, November, 2009, (4th edition in ballot stage as of 1Q/14).

Cathodic Protection (CP)

For those sites with underground piping and vessels, as well as above ground atmospheric storage tanks and wharf/dock facilities, there will almost always be a need for some sort of CP. And just as with materials selection and coating/linings issues, this is typically the purview of a C/M SME with special training and experience with CP design, installation, and maintenance. CP is one of the many “pay-me-now or pay-me-later” aspects of FEMI programs, and generally the “pay-me-later” aspect is many times more expensive than proper installation and maintenance of CP systems over the long term. Replacing underground piping and tank bottoms are expensive propositions, let alone the safety and environmental consequences of potential leaks.

Equipment typically corrodes when it is in contact with the soil (see API RP 571⁽¹⁾, article 4.3.9). If you design, install, monitor, and maintain CP systems, you can achieve long-term, cost-effective preservation of buried equipment, piping, tank bottoms, and wharf structures. But it takes a rigorous management system to ensure that effective CP is maintained throughout the life of the equipment being protected. Sometimes there are mistakes made in CP design, stray currents creep in, insufficient current reaches all spots on the protected item, anode beds are not maintained, the rectifiers are not monitored and maintained, structure-to-soil potential measurements are not taken in the right place, or no one group has specific responsibility for maintaining effectiveness of the entire system. I have even seen the rectifiers turned off for maintenance activities and no one notices for many months that they were turned off. Many times short-term cost cutting results in loss of system maintenance, thereby sacrificing the large long-term value of the asset for small short-term budget gains.

Few things in our operating plants are more expensive than the inspection and maintenance of tank bottoms. Effective CP systems can virtually halt bottom-side corrosion of tanks and permit us to extend tank inspection intervals out to the maximum time allowable by API 653⁽²⁾; thereby allowing us to achieve the lowest total life cycle costs for storage tanks. API RP 651⁽³⁾ Section 11 has excellent guidance on operating and maintaining an effective CP system, including annual surveys of CP effectiveness, bi-monthly rectifier checks, CP preventative maintenance, and checks of the effectiveness of isolating devices. And if your site is one of those with buried light hydrocarbon (LHC) pressure vessels, you should pay particular attention to your CP system on those vessels. That might be your worst “out-of-sight, out-of-mind” FEMI issue. A soil side leak in one of those LHC vessels might be close to the top of your FEMI risk list at the site. Also, do not forget any buried canned pumps for light hydrocarbon service if they are in contact with the soil.

There are a number of professional CP system companies in the commercial market that provide CP maintenance and assessment services, and most smart operating sites that do not have CP expertise or resources in-house avail themselves of those services to make sure their CP systems are operating properly.

Does your site inspect and maintain your CP systems adequately to ensure that they are effectively protecting all of your equipment in contact with the soil and your wharf structures in order to achieve the lowest life cycle costs of your equipment?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, 2nd Edition, American Petroleum Institute, Washington, D.C., April, 2011.
2. API RP 653, *Tank Inspection, Repair, Alteration, and Reconstruction*, 4th Edition, American Petroleum Institute, Washington, D.C., April, 2009, plus addendums.
3. API RP 651, *Cathodic Protection of Aboveground Petroleum Storage Tanks*, 3rd Edition, American Petroleum Institute, Washington, D.C., January, 2007.

Inspection of Pressure Relief Devices

Inspection of PRDs is one of the foundational issues in our FEMI business. Fortunately we have a detailed guidance document for the inspection, testing and maintenance of PRDs in API RP 576(1), which is now under revision with an anticipated publication date sometime in 2015. Additionally, both API 510 & 570 each contain a section that covers the requirements for PRD testing and inspection. Both require a PRD QA manual with designated sections that must be covered in the QA manual. Plus, each code provides for necessary minimum inspection intervals, which are basically five years for typical process services and ten years for clean (nonfouling) and noncorrosive services. However, both codes allow for longer intervals if you use a valid RBI analysis or if you have documented experience indicating that longer intervals are acceptable (i.e. condition-based intervals). For example, if you have been regularly inspecting a PRV in normal process service at 5 year intervals for the last 15 years, including pre-popping the PRV before each test, and thereby have documented evidence that the PRV is popping within the set pressure tolerance range and neither the inlet or outlet are excessively fouled, then it may be reasonable to increase the interval slightly to see if the situation remains acceptable. I know of several operating sites that have been doing this successfully for many years and have gradually increased their average inspection interval up into the 8-9 year range. But to do that takes exceptional due diligence to ensure pre-popping is completed correctly according to a documented procedure, and that documented inspection results and maintenance records can support a gradual increase in test intervals. In my opinion, management of PRD inspection and testing is best done by one competent, skilled person at each operating site.

As mentioned above, one of the most important aspects of PRV servicing is the need to pre-pop all PRVs prior to servicing (before the PRV is completely cleaned or dismantled). The results of the pre-pop test are vital to scheduling the valve for its next inspection. Regardless of whether you use time-based inspection intervals, condition-based inspection intervals, or the RBI intervals, the inspector needs to know the results of this pre-popping test in order to do an effective job of setting the next inspection interval. Without those results, the inspector is just “flying blind” when it comes to adjusting the inspection interval or even maintaining it as before. Previously, some sites avoided pre-popping uncleaned PRV's with the reasoning that the valves had to be thoroughly cleaned to avoid personnel exposure to toxic or harmful fluids like HF or sulfuric acid. That excuse has been weakened by the introduction of new testing equipment that some PRV service companies are using that allows them to pull on site to perform pre-popping of “dirty” PRVs in a safe manner.

Proper handling of PRDs is also very important when it comes to the reliability and operability of PRDs. It does little good to have certified, highly competent shop procedures for servicing and setting of PRDs, if the device is going to be handled like a heavy hunk of pig iron between the shop and the installation point. Surely, that is not news to anyone at this stage, but it is still an area where QA/QC and enlightenment of all those who handle or transport PRDs, is too often lacking. I have seen PRDs laying in the mud waiting for pick up after being removed for servicing. I have seen them piled in a topsy-turvy mode on pallets after servicing to be returned to the operating site. I have seen them tossed in the back of a pick-up to transport them from where they were received to the field for installation. While you and I may know about the importance of the issue, many truck drivers, fitters, and craftsmen do not appreciate that a PRD is actually a delicate “instrument” and that less than gentle handling and transport conditions could likely lead to malfunction in service. If they really knew and appreciated what could happen to them and their associates when a PRD fails to function properly, I think they would be much more careful. It is up to us to make sure that there are rigorous, documented work practices in place for handling and transporting PRD's and that everyone in the PRD handling chain of command understands them and complies with those procedures. One of the interesting advantages of in-service, in-position PRD testing and setting is that it virtually eliminates the damage caused by rough handling and transport. But of course, there are some limitations and disadvantages to in-service PRD testing too, but that is a subject for a different EE.

Do you have a documented requirement for pre-popping all PRDs before they are serviced and diligently recording the results so that they will be useful to the person who is responsible for scheduling the next inspection interval? Do all the appropriate personnel at your site know the importance of careful, proper handling and transport of PRDs so that “your last line of defense” can operate correctly when called upon to protect equipment and people?

References

1. API RP 576, *Inspection of Pressure Relief Devices*, 2nd edition, November 2009, American Petroleum Institute, Washington D.C. (3rd edition in balloting stage).

Pressure Relief Device Auditing

Few pieces of equipment in a hydrocarbon process plant are more important than pressure relieving devices (PRDs), especially when they need to perform exactly as designed under emergency overpressure scenarios. As such, it is important that we periodically audit the installations of these devices to provide some assurance that they are installed, operated, and maintained in the manner in which they were intended. API RP 576⁽¹⁾ has a list of all of the issues (14) that are important to check during visual on-stream inspections (audits) of relief devices. A good time to conduct these visual on-stream inspections is soon after a turnaround where a number of PRDs have been serviced and reinstalled.

These in-service visual inspections include such things as: checking to see that vents on bellows sealed valves and the vents on discharge stacks are open and clear. You might be surprised to know how often someone or something has plugged the vents and drains, especially if they do not understand their vital function. I know of two people who received painful burns when a relief valve discharged and blew out scalding water, which had collected in the stack of the PRD, down upon the persons below it. Other important aspects to be checked include: proper PRD installation, proper set pressure on the tag, vent piping properly supported to avoid overstressing the valve nozzles, associated block valves sealed-open, etc. This work is not much fun and sometimes not given the right priority, but it is a very important form of “preventive inspection” for our most important pieces of equipment. You might be surprised how often auditors find non-compliance issues with installed PRDs. Additionally, a visual inspection of each PRD installation should follow any lifting/operation of a PRD to check for leakage, vibration, etc.

It is not uncommon for safety systems (relief devices, nozzles under relief devices, vent lines, dump lines, etc.) to be heat traced when there is a potential for plugging from a product condensing and solidifying, which could render the safety system ineffective. Unfortunately, we periodically find that these heat tracing systems are not functioning properly or have been shut off, and if we are lucky, we did not find it because a relief device failed to open. This is another one of those issues that easily “falls through the cracks” if we do not have effective procedures, training, discipline, and audits in place to assure ourselves that the PRD heat tracing is still functioning as intended.

Do you audit your installed PRDs at frequent enough intervals to be reasonably assured that your risk of PRD malfunction or blockage has not increased?

References

1. API RP 576, *Pressure Relieving Devices*, 3rd edition, November 2009, American Petroleum Institute, Washington D.C. (4th edition in balloting stage as of 2014)

Hydrostatic Overpressures

From time-to-time we hear about equipment being over-pressured by hydrostatic forces. The higher risk overpressures sometimes result in major events, such as the one that occurred at a west coast refinery some time back, when a pressure seal bonnet valve with split wedge seating went “hydrostatic,” resulting in a major explosion and fire. These types of valves need to have bonnet cavity pressure relief, and are especially sensitive to leak seal pumping of the packing cavities. Another such valve in a gulf coast refinery failed catastrophically in steam service because it was mounted in a vertical line; so condensate filled the bonnet cavity and ruptured the valve when it was tightly closed off. I have also seen the results of pipelines that blew a gasket when they were blocked in, full of liquid hydrocarbon, and then heated up in the sun. This can be disastrous when it occurs over navigable waters or other sensitive environments. Another scenario that I have seen with hydrostatic overpressures involved using positive displacement (PD) pumps to clear a plugged line. In this particular case, it resulted in a blown gasket and sprayed hydrocarbon, which fortunately did not ignite.

Clearly there needs to be engineering or physical constraints on all “temporary” uses of PD pumps in order to clear plugged lines, as well as a competent MOC assessment. I am also aware of incidents caused by hydrostatic pressures generated by leak-seal pumping of temporary repairs, wire-wrapped flange joints and other “boxes” (see separate EE). In one case in a gulf coast plant, repumping a boxed cavity resulted in line separation from the hydrostatic pressures involved with repumping, and the subsequent formation of a light hydrocarbon cloud. Again, fortunately in that case it did not ignite. But hydrocarbon clouds too often do find ignition sources, and when they do, the damage is never minor.

Do all stakeholders at your site understand the potential threat of hydrostatic overpressures and does your MOC procedure specifically address the need for engineering and physical constraints on work processes that could result in hydrostatic overpressures? Are you keeping track of and periodically servicing or replacing TRV's that are meant to protect piping from hydrostatic overpressure?

Special Emphasis Inspection Programs (SEIP)

SEIPs are the inspection programs that are created to intensively focus resources on a new FEMI issue or a prior inspection issue that was inadequately resourced (i.e. catch-up programs). Usually they are born from some major PSM event or economic loss, or perhaps a risk evaluation resulting from some other site in the industry experiencing a significant event due to a FEMI failure.

Sometimes the need for SEIPs are discovered during periodic FEMI reviews by second or third party SMEs that come on site for a week or more to review all aspects of the necessary FEMI management systems (see separate EE). Some examples of SEIP issues include:

- PMI,
- CUI/CUF,
- Deadlegs (D/L) inspections,
- Buried piping and Soil-to-Air Interface (SAI) inspections,
- Injection and mix points inspections,
- SBP program,
- Critical check valves (CCVs),
- External piping inspections,
- RBI implementation,
- Piperack Inspections,
- Wet hydrogen sulfide cracking inspections,
- HTHA inspections,
- Low silicon carbon steels in sulfidation service,
- Catching up on tank inspections,
- Implementation of a new Inspection Data Management System (IDMS), etc.

Those are just some examples and most of them are addressed in separate EEs. SEIPs can cover almost any of the 101 EEs of FEMI where an operating site has discovered that it may be vulnerable to a large loss or process safety event stemming from any particular FEMI issue.

Depending upon the size of the operating site or the magnitude of the task, these SEIPs are usually best implemented on a separate project basis with focused resources, rather than just piled on top of the “normal” workload for each inspector who may already be over-loaded. The latter seldom works well because the “normal” workload usually takes precedence over SEIP work, which then drags out for long periods of time or is ineffectively implemented. If a site is serious about an SEIP issue, then it should be separately resourced and handled with its own budget, own staffing, and project implementation plan to be completed by a specified target date; and then effectively melded into the run-and-maintain inspection operations after completion of the SEIP project.

As such, SEIPs typically need to be forecasted up to a year in advance in order to plan for funding in the following budget cycle, unless of course the issue has significant urgency and management is willing to force-fit it into the existing year’s budget. In my experience, I have found that it normally takes someone with project engineering skills to manage the SEIP in order to bring it to completion from the planning phase all the way through to hand-over to the existing run-and-maintain FEMI group. Without those project skills, the SEIP may drag out forever, become an economic albatross, or worse. A good example of this is trying to implement a RBI program by just piling it on top of an existing inspector’s workload. I have seen many false starts with RBI because a site tried to implement it without a SEIP.

Does your site still have FEMI issues that would be best implemented or improved by the focus and resources involved in a separate SEIP? Have you forecasted your SEIP needs for the following budget cycle?

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Advanced NDE Techniques

The development of advanced NDE techniques/tools is one of the reasons the inspection trade has taken significant steps forward in the last couple decades; and the advancements appear to be accelerating. One of the many ways to keep up with advancing NDE technology is to attend the semi-annual NDE task group meetings at the Spring and Fall API Refining and Equipment Standards Meetings. In fact, that T/G is planning to document many of the advanced NDE techniques in a new API RP 586(1). Work on the document is just getting underway, so it may take a few years before anything is published. I anticipate that sections will be published piecemeal so as not to delay the usefulness of the document for owner-users until all of the current advanced NDE methods are recorded; and when that happens, I suspect the RP will be well in excess of 100 pages. In the meantime, below is a partial list of one-liners describing some of the advanced NDE technology in use or being developed for the petroleum and petrochemical industry.

On one end of the advanced NDE spectrum are techniques/tools that are in widespread use and generally available; while on the other end of that spectrum, others are still being developed or showing some promise, but have seen very little use so far. Some will only detect damage, while others can characterize the damage and provide its size. Some are screening techniques for finding areas of possible damage and “roughly sizing” it, while others can provide highly accurate data detailing the extent of damage. Some advanced NDE techniques combine an assembly of probes using multiple sensors/transducers. Most of the widely used, standard NDE techniques are not in this list of advanced techniques (e.g. PT, MT, EC, RT, etc.). Some of these techniques have been available for decades, while others are still being developed. A few of them include:

- **Acoustic Emission (AET)** – A technique for detecting transient elastic waves in a material undergoing localized cracking or corrosion.
- **Automated Ultrasonic Backscatter Technique (AUBT)** – A collection of ultrasonic techniques for detecting HTHA in equipment that is documented in API RP 941.
- **Computer Aided Radiography (CAR)** – Computer based image processing tools for enhancement and manipulation of RTR images to improve resolution and focus on areas of interest in a digital radiograph.
- **Eddy Current Array (ECA)** – A technique that drives multiple eddy current coils placed together in the same probe assembly for flaw detection and sizing of surface cracks.
- **Infrared Thermography (IR)** – A nonintrusive, noncontact system for mapping thermal patterns on the surface of an object using infrared detectors.
- **In-Line Inspection (ILI)** – The inspection of pipe and pipelines using “smart pigs” (both tethered and non-tethered) that use primarily UT/MFL for detection and sizing of damage.
- **Internal Rotating Inspection System (IRIS)** – An ultrasonic technique for detecting and sizing corrosion in pipe and tubing using an internally inserted probe that generates sound waves.
- **Laser Scanning of Coke Drums** – A profilometry technique for creating a profile of in-service coke drum deformation sometimes combined with other advanced NDE techniques such as video and ultrasonics.
- **Long Range Ultrasonic Testing (LRUT)** – a technique that uses low frequency guided wave ultrasonics (GWUT) for detection of internal and/or external corrosion (CUI) in pipe and tubing.
- **Magnetic Flux Leakage (MFL)** – a technique that is used to detect corrosion in steel piping and storage tanks whereby a magnetic detector that is placed between the poles of the magnet detect a leakage field where corrosion is present.
- **Meandering Winding Magnetometer Array (MWMA)** – A relatively new technique for detecting and characterizing corrosion and cracking using multiple inductive sensors.
- **Phased Array Ultrasonic Technique (PAUT)** – a set of UT probes made up of multiple small elements each of which is pulsed individually with computer-calculated timing which can be used to inspect more complex geometries that are difficult and much slower to inspect with single probes.
- **Pulsed Eddy Current (PEC)** – A technique for measuring wall thicknesses on insulated equipment without having to remove the insulation and jacketing.
- **Real Time Radiography (RTR)** – A radiographic technique that produces an almost immediate electronic digital image of the item being inspected/ radiated rather than on film.
- **Remote Field Eddy Current (RFEC)** – An electromagnetic technique for finding defects in piping and tubing using an internally inserted probe that generates a magnetic field.
- **Remote Visual Inspection (RVI)** – refers to methods of enhanced visual examination means of visual aids including video borescopes, push cameras, pan/tilt/zoom cameras and robotic crawlers.

When you have an unusual or difficult inspection issue that may require advanced NDE techniques, the services of a capable, qualified NDE SME (see separate EE) are highly advisable and generally cost effective. Many of these more advanced NDE techniques are somewhat “black box” technologies, not easily or readily understood by plant engineers and inspectors whose primary inspection and FEMI duties are much broader-based than just advanced NDE. NDE SMEs can help determine which technique(s) to use, when to use multiple techniques, what the real advantages and limitations of each technique are, which NDE service companies and technicians are best qualified to do the work, which NDE service companies have the best equipment, and if the NDE procedures that are offered are applicable or appropriate for the specialized NDE work.

Are you making cost effective use of advanced NDE to solve difficult or unusual inspection problems that otherwise might result in equipment failure and a process safety incident?

References

1. API RP 586, *NDE Methods for Equipment Damage Mechanisms*, 1st edition in preparation, American Petroleum Institute (in preparation).

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API 510 and 653 clearly permit non-invasive inspections to be substituted for scheduled internal inspections. And, of course, API 570 is almost completely based on NII. Some sites are implementing OSI/NII for PV's and using them to good advantage where permitted by code to reduce the number of scheduled internal inspections. But a number of sites are not, under the mistaken notion that API 510 actually requires internal inspections at a set frequency. Such is not the case.

Those sites that are not taking full advantage NII for PV's where allowed by code may be missing out on significant cost advantages attributed to NII, as well as taking on the additional safety risk associated with confined space entry where it is not warranted. Additionally there are some risks with just cleaning out and opening up equipment that is better suited for NII; risks such as exposure to water contamination, risks of not being completely leak-tight when being re-streamed, potential damage to coatings and linings, etc. Two other good reasons for doing NII, are the advance planning knowledge it supplies for turnaround planning and when we do NII in lieu of turnaround vessel entry, we reduce turnaround work load. Since turnarounds are one of the most expensive and inefficient activities in our industry (second only to rebuilding a unit after a fire), anything we can do to improve and eliminate turnaround work with NII, will help the cause.

Of course there are potential pitfalls associated with using OSI/NII, and many of those can be avoided by accessing the knowledge and input of a qualified NDE specialist when planning OSI. Then there's the old notion that internal inspections are always better because "you never know what you might find" and "there's always the chance of finding a surprise". In my opinion those perspectives are as out-dated as rotary phones. If you have a rigorous process of MOC⁽¹⁾ for PEI issues and all the right IOW's⁽¹⁻²⁾ per the API 510 & 570 Codes in place with good communications with operations and process engineering, then you should have little or no need to go "witch hunting" for surprises by making internal inspections where they are not warranted. Now, with all that said, being able to use NII inspections in place of invasive inspections to maximum advantage takes a robust, comprehensive FEMI program to be in place with all the aspects covered in the 101 EEs, as well as all the API Codes and Standards.

The numerous advancements in NDE techniques for NII these days provide the means for making high quality, effective NII inspections (where allowed by the API 510 Code) without the additional cost and safety disadvantages associated with internal inspections. But it takes a knowledgeable Inspection/NDE engineer/inspector working with a corrosion engineer/specialist and competent NDE service providers to specify and implement the right combination of OSI/NII techniques to get the job done right. I'm aware of plenty of examples where lack of knowledge and competency in NII resulted in wasted money and inappropriate methods of NII being applied by just listening to some NDE service providers that were more interested in selling services than in providing cost-effective, value-added NII to the owner-user. The old saying of "Buyer Beware" really applies to NII inspections. There are a lot of NDE/NII methods and techniques available, with various advantages and limitations, and probably only one (or very few) combinations of methods and techniques that are best suited to any particular vessel in any particular service. Too often, NDE service providers are only willing to talk about the "advantages" of the services that they provide. You should always seek out those NDE service providers who are candid about the advantages and limitations of their NDE methods and techniques.

Hence, I always advise owner-users who are planning to expand their use of NII, to make sure they have knowledgeable competent corrosion specialists and NDE engineers/specialists involved in establishing those OSI/NII plans, let alone doing business with reputable, competent NDE service providers.

Is your site taking full advantage of the cost and safety benefits of doing carefully planned and executed OSI/NII in lieu of internal inspections where allowed by code?

References

1. [Management of Change and Integrity Operating Windows for PEI](#), John T. Reynolds, Inspectioneering Journal, March/April 2010.
2. API RP 584 *Integrity Operating Windows*, 1st edition, American Petroleum Institute, Washington, D.C., May, 2014.

NDE Subject Matter Experts

When a site is dealing with potential localized corrosion mechanisms or environmentally induced cracking mechanisms, it is necessary to understand where to look for those kinds of damage mechanisms and how to look for them. Where to look is the job of the C/M SME (see separate EE) and should be recorded in the CCD or RBI documents for each process unit. But how to look for each different type of damage mechanism (i.e. what NDE tools and techniques are best suited for each situation), is the job of a knowledgeable NDE SME. This is especially true when dealing with the many different kinds of advanced NDE techniques that are being developed at an increasingly fast rate these days. I am aware of several major multi-million dollar asset losses and significant process safety incidents that occurred when inspectors were using standard spot DUTT gauging hoping to find localized corrosion, and in at least one case, monitoring a line every 12 inches before a rupture occurred between CMLs. It pays big safety and economic dividends to use the right NDE technique for the job. There are now a variety of scanning and longer range NDE tools commercially available that can help us find localized corrosion and defects before they find us.

So when you have an unusual inspection issue that may require advanced on-stream inspection (OSI) NDE techniques, the services of a capable, qualified NDE SME are usually advisable and cost effective. Many of these more advanced NDE techniques are somewhat “black box” technologies, not easily or readily understood by plant engineers and inspectors whose primary inspection and FEMI duties are much broader-based than just advanced NDE (see separate EE), which is a FEMI discipline in and of itself. NDE SMEs can help you with determining what technique(s) to use, when to use multiple techniques, sorting out the real advantages and limitations of each technique, which NDE service companies and technicians are best qualified to do the work, which NDE service companies have the best equipment, and if the NDE procedures that are offered are applicable or even appropriate for the specialized NDE work.

I have seen operating sites waste a lot of time and money purchasing unnecessary and inappropriate advanced NDE services from NDE companies because they did not really know what they needed. NDE SMEs can help you avoid that expensive trap; let alone help you avoid receiving NDE results that may provide you with overly conservative results, causing you to repair or replace equipment/piping that really did not need to be repaired or replaced, or worse yet, provide you with a false sense of security that there is no real problem when indeed there may be. Additionally, during the field application of advanced NDE techniques, NDE SMEs can help to monitor the work for effectiveness and efficiency, as well as to troubleshoot problems that may arise. In my experience, some of the most valuable contributions of the NDE SME come about because they can interpret the raw data that is collected by the NDE technicians, thereby helping to determine if the NDE summary report and recommendations that you receive from a vendor are in fact valid.

So where do you find NDE SMEs? Sometimes inspectors with a strong NDE background can provide the right guidance, but many API certified inspectors do not have that kind of background unless they have been specially trained or perhaps were an advanced NDE technician before becoming a certified API inspector. Some larger operating companies have NDE SMEs on staff, but of course, most do not. Many NDE services companies have them on staff, but this is sometimes a “buyer-beware” situation, as some vendor NDE specialists only seem to know the advantages of the techniques that they market, when what you really need is to know the advantages and limitations of each advanced NDE technique you may be considering. But other advanced NDE service companies have very knowledgeable, very helpful NDE SMEs on staff that will level with you and give you very sound NDE advice. I have known both kinds. There are also a few contract NDE SMEs who are independent consultants, and I know a number of them too. Another good source of advanced NDE information is the many articles on the subject that appear every year in Inspectioneering Journal.

Do you access and utilize the services of qualified NDE SMEs when you need them to help you avoid the potential pitfalls of applying “black box” advanced NDE technology that you may not completely understand?

Piping and Equipment in Cyclic Service

Fatigue failures of piping and equipment in cyclic service, especially in small bore piping (SBP), can lead to reliability and process safety incidents with sudden unexpected failures. Cyclic service refers to service conditions that may produce fatigue damage due to cyclic loading from pressure, thermal, or other mechanical loads (that are not induced by pressure). Other cyclic loads associated with vibration may arise from sources such as impact, turbulent flow vortices, slug flow conditions, resonance in compressors, and wind. Fortunately you will usually have some warning that equipment or piping is in cyclic service and therefore have a chance to do something to prevent fatigue failures. If operators and others who are around operating equipment (especially machinery) on a daily basis will report vibrating piping or unsupported, overhung weight on branch connections and SBP to inspection or engineering personnel, appropriate engineering analysis and mitigation can be implemented before failure.

Evidence of significant line movements that could have resulted from liquid hammer, liquid slugging in vapor lines, or abnormal thermal expansion should be reported. At locations where vibrating piping systems are restrained to resist dynamic pipe stresses (such as at shoes, anchors, guides, struts, dampeners, hangers), periodic MT or PT should be considered to check for the onset of fatigue cracking. But generally, fatigue failures have to be prevented, as it is a fool's paradise to try inspecting for cracks before they propagate to failure. It is a rare day when a fatigue crack is found before it results in a through-wall crack or worse yet, pipe separation, because a large amount of fatigue life is taken up in crack initiation rather than crack propagation to failure. Early in the life of a plant, or after a plant change of some sort, it is not unusual to experience vibration that could lead to fatigue cracking. That is the time to do something about it. No one should treat vibrating piping as common place, as it may merely take days to crack or break; on the other hand it may take years. Regardless, the consequence of failure will be the same. Threaded connections associated with rotating equipment may be especially prone to fatigue damage and should be periodically assessed and considered for possible renewal with a thicker wall and/or changed to welded components. Vessels in cyclic service such as coke drums and PSA vessels are well known to be susceptible to fatigue damage and typically require special design and construction features to minimize the potential for fatigue cracking. A few engineering and inspection service companies specialize in inspection and stress analysis associated with code drum thermal fatigue.

I recall a chemical plant that had a full line separation on a two-inch pipe, which released 20,000 pounds of light hydrocarbon in just minutes. They were really lucky; no ignition, that time. Another plant was not so lucky, as they had immediate ignition when a 4-inch nozzle cracked and fell off a column in service. It only had a valve and a blind flange attached to it. These two cases involved austenitic stainless steel, which seems to be even more susceptible to fatigue failures than steel and its low alloys. Nearly every plant has experienced fatigue failures for a variety of reasons, especially in association with rotating equipment. The latest areas to receive increased attention are mixing points where two or more streams of different temperatures meet, causing localized thermal fatigue (see separate EE on mixing points). Bodies of valves that are exposed to significant temperature cycling (for example, catalytic reforming unit regeneration and steam cleaning) should be examined periodically for thermal fatigue cracking. In addition, a large number of piping failures occur at pipe-to-pipe welded branch connections. The reason being that branch connections are often subject to higher-than-normal stresses caused by excessive structural loadings from unsupported valves or piping, vibration, thermal expansion, or other configurations. The result is concentrated tri-axial stresses at the joint that can cause fatigue cracking or other types of failures at the branch connection. Where joints are susceptible to such failures, a forged piping Tee fitting typically offers better reliability because it removes the weld from the point of highest stress concentration. Weld-o-lets can also provide better reliability if they are properly welded to the main pipe using manufacturer's recommendations for full penetration welds.

Are the operators and other field personnel in your plant sensitive to cyclic service and vibration problems in piping systems (especially branch connections) and do they know how it can affect them personally, if cyclic conditions are allowed to lead to fatigue cracking?

References

API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, Second Edition, American Petroleum Institute, Washington, D.C., April, 2011.

Pipe Rack Inspections

At some sites, pipe rack inspections are treated with a lower priority than the piping within the boundary of a process unit. Sometimes pipe racks are not even assigned to a particular inspector, so they tend to “*fall between the cracks*”. This can lead to undetected corrosion, both on the ID and OD of piping in pipe racks. I have witnessed significant plant emergencies when a small leak of a hazardous substance started in a pipe rack, causing evacuations, unscheduled shutdowns and production losses, as well as the risk of a process safety incident. One particular problem that occurs all too frequently is a leak caused by OD corrosion where a pipe rests directly on a support member, causing the contact area to become an area of significant pitting corrosion. This pitting can be hard to find because it is relatively inaccessible, not clearly visible, and sometimes overlooked in external inspections. Pipe contact corrosion can be minimized by the installation of half-rounds or inverted angle beams on the pipe rack cross beam to convert line contact supports to point contacts, thus minimizing the area where moist deposits can collect and cause external corrosion, as well as make the pipe contact area more inspectable.

Another problem in pipe racks is leaking or blowout of plugs that were installed where high point bleeders were positioned during construction. Over time, the threads on these plugs corrode and the plug loosens, and then leak or blows out if some unsuspecting soul steps on it. Often these plugs are completely hidden by insulation. Almost all the piping degradation issues that can befall process unit piping are also potential problems in pipe racks.

Pipe rack piping can experience a variety of transient loads from time to time, including thermal growth, thermal shock, slug flow, hammer shocks, pressure spikes, vibration, etc. Inspection and operating personnel should be aware of these issues and sensitive to the locations they are most likely to occur. Clearly, to the extent possible, piping designers need to take these transient loads into consideration where they can be anticipated. Moreover, inspectors and other field observers need to watch for signs that these loads have occurred, so that piping can be properly examined for damage and potentially modified to withstand such loads that may not have been anticipated in the original design. There are a variety of small software packages that can assist in analyzing the stresses imposed by such transient loads, and if need be, we can always resort to finite element analysis (FEA) for a higher level of stress analysis. In my time, I have witnessed the results of a few systems that suffered hammer shocking (often referred to as water hammer in water containing systems). It can and does result in pipe rupture, cracking, and denting as the piping bounces off other stationary objects in the vicinity; so it is important that field personnel report incidents of hammer shocking so that the necessary preventative steps can be applied. Unexpected thermal growth can also wreck havoc with piping systems by causing them to bow and deform as they expand and shrink from temperature changes not anticipated in the original design. Sometimes, pipe shoes “fall off” pipe supports after unanticipated thermal growth, then they cause a shrinkage restriction when the pipe cools, by hanging-up on the pipe support that they previously rested upon.

Pipe supports are often constructed with open-ended pipes (dummy legs) that attach to an elbow and rest on a pipe rack. That situation can trap contaminated water which, over long periods of time, corrodes at rates of 5-10 mils per year (0.005-0.010 inches per year), and results in pipe penetration from the external surface. I know of at least four of these cases in the last couple of decades, each of which resulted in a significant reliability impact. Now that you are aware of it, you can prevent those failures by ensuring that water cannot be trapped in these dummy legs. Make sure they are properly sloped or have holes at strategic locations in order to drain out any moisture that may collect. If they are vertical dummy legs, supporting pipe from a surface, make sure there is a drain hole in the bottom of the dummy leg. These are easy preventative measures that can save significant reliability hits down the road. The 4th edition of API RP 574⁽ⁱ⁾ will have more extensive coverage of this issue when it is published. And make sure that you occasionally inspect horizontal dummy legs for CUPS. For those of you have not yet experienced CUPS, it is an aggressive, localized corrosion that occurs under pigeon droppings, and is especially prevalent in dummy legs that are just the right size for bird nests.

Do you have an effective pipe rack inspection program, with specific pipe rack responsibilities designated, so that your pipe racks are not a threat to the reliability and integrity of your operating site? Do your operators and maintenance personnel know the potential effects of transient piping loads, so that they can help avoid such circumstances and report the early warning signs of them? Does your external piping inspection program include looking for and eliminating water traps in piping dummy legs?

References

1. API RP 574 *Inspection Practices for Piping System Components*, American Petroleum Institute, Washington D.C., 3rd edition, November, 2009, (4th edition in ballot stage as of 1Q/14).

Maintenance Preparation and Access for Inspection

In the olden days, there used to be a tug-of-war between maintenance and inspection groups on how much maintenance preparation was needed to adequately prepare for inspections. Many operating sites now have a written (and somewhat unwritten) best practice for cooperation between the two groups on this issue. One such best practice is to have a documented file for each piece of equipment listing what type of maintenance preparation is needed for each type of inspection (internal, external, on-stream) for each individual piece of equipment, which details all of the necessary maintenance preparation steps. That file is then opened and updated, as necessary, for each scheduled inspection and kept in perpetuity in order to avoid “reinventing the wheel” for every turnaround. Such files contain the necessary information for staging, removal of internals and obstructions, manway openings, insulation removal, surface cleaning, and all other maintenance prep instructions.

Adequate surface cleaning is a vital and sometimes over-looked element of maintenance preparation for internal inspection and exchanger tube NDE (see separate EE). This issue sometimes suffers from the “hands off” syndrome, whereby inspection depends upon someone else to take care of it, be it the maintenance organization or the cleaning contractor. When that happens, the result can be inadequate cleaning, which then leads to inadequate inspections, which can then be followed by embarrassing and costly surprise equipment failures. Inadequate cleaning can easily mask pitting, thinning, and cracking that would otherwise be apparent to the competent inspector. It is essential that equipment cleanings are prescribed and planned in detail, including the type, extent, and quality of surface cleaning applicable to each individual inspection job. That means inspectors who will be planning the necessary surface cleaning need to have a solid understanding of the potential degradation mechanisms in each piece of equipment to be inspected, where they are likely to occur, and the inspection history of each piece of equipment (see separate EE on Corrosion Control Documents). Knowledgeable corrosion and NDE SME’s can enlighten inspectors on these issues.

There are many different kinds of cleaning procedures, too many to cover in this short EE; so it is important that each operating site keep appropriate records of which ones do and do not work well for the various types of surface cleaning challenges that are encountered. Do not forget to make sure that special attention is given to the cleaning needs of things like storage tank sumps, exchanger tubes (especially in cooling water service), column shell surfaces at or below the liquid level on each tray, gasket surfaces that might be corroded or scored, and for equipment subject to stress corrosion cracking, e.g. wet hydrogen sulfide, chloride cracking, etc. where white metal blasting and/or flapper wheel grinding may be necessary. There are a multitude of situations that may require different types of cleaning procedures and varying degrees of cleaning in order to adequately prepare surfaces for inspection.

From time to time, I hear of a FEMI incident that initiated at a location on a piping system or pressure vessel that was relatively inaccessible for inspection. Overhead lines of fractionation towers are notorious for this issue, but so is piping in pipe racks. This situation is made worse when there is a process dew point occurring in the overhead line or there is some sort of water wash, chemical injection, or mix point involved (see separate EE). A substantial vapor cloud explosion and fire at two different refineries occurred not too long ago because of a pipe rupture at a relatively inaccessible spot in a tower overhead line. Others have experienced significant production interruptions because of leaks on overhead lines of fractionation columns. Inspections at inaccessible locations on piping can be relatively costly, but those inspections are not nearly as expensive as rebuilding hydrocarbon process units after a major fire. Several companies now offer these inspections by using knowledgeable experienced mountain climbers tied off securely with ropes to access otherwise inaccessible locations, and at a fraction of the cost of scaffolding. So the economic excuse for not making necessary inspections has been reduced. Having been a mountain climber at an earlier stage in my life, I am a big fan of rope access techniques for inspection of relatively inaccessible locations. But you do have to make sure that your rope access technicians are fully qualified in the NDE that they are expected to accomplish while hanging on the end of their ropes.

Are you vulnerable to FEMI incidents because you avoid making necessary inspections at relatively inaccessible locations on equipment and piping? Do you maintain a file on the necessary types of cleaning and maintenance access necessary for each type of inspection on each type of equipment?

Pressure and Tightness Testing

Correctly applied pressure and/or tightness testing is fundamental to any FEMI program and is one of the useful methods of validating the integrity of equipment that has undergone repairs or maintenance activities. However it takes some understanding and experience to know how and when to conduct leak or pressure tests, which vary from low pressure gas tests to verify leak free bolted or threaded joints, all the way up to full code specified tests to validate pressure integrity. Low pressure leak tightness tests certainly serve the important purpose of ensuring that all flanged and threaded joints “broken apart” during maintenance activities have been restored to leak tightness prior to reintroducing process fluids. Hydrostatic pressure testing serves the useful purpose of validating that welding activities not only produced a leak free condition, but also can withstand some level of stress above that anticipated during normal operation. Section 5.8 of both API 510⁽¹⁾ and 570⁽²⁾ contains important requirements and guidance on issues concerning pressure testing of vessels and piping; and ASME PCC-2 Article 5.1⁽³⁾ has some excellent guidance on conducting pressure and tightness testing.

In the past I have observed people mistakenly believe that a pressure test is a reasonable substitute for more thorough inspections, which is not true. Regulations, for instance, that require periodic pressure testing of some piping systems, serve little more purpose than validating that the piping is leak free at that moment in time. It tells you nothing about the future, like an effective inspection could do. Most of us know that a deep pit can withstand a lot of pressure during a test, with only a few thousandths of an inch of remaining metal thickness before complete penetration occurs; and even a thin film coating can mask a pin-hole leak in a weld during a pressure test. Corrosion leaks can occur within hours or days after pressure tests. Hence, though pressure tests serve a useful purpose, we need to understand their application and usefulness as part of an overall inspection and QA/QC system, and not just as a substitute for more meaningful inspections, except in lower risk situations. Other companies use full code specified pressure tests simply as a way to finish off routine inspection activities, even though no maintenance or welding repairs were performed; a practice that I have never completely understood.

Hydrotesting is a common activity in our industry, and for good reason; but it should never become so commonplace that routine hydrotesting work causes the people involved to let down their guard. Pressure testing is not risk free and can be quite hazardous if all the right precautions and procedures are not followed, especially in the case of pneumatic or hydro-pneumatic pressure testing. I am aware of incidents where inspectors were severely bruised when a hydraulic hose flew off the pump and started whipping around, uncontrollably. I am also aware of an incident where an inspector was cut on the neck, when a high pressure flange started to leak at 2500#. In another case, an inspector was injured when a flange gasket blew out and a piece of the gasket struck him in the head. The ASME Code requires that we make it a practice of backing off from the highest pressure of the test, and make sure that the system is stabilized before letting anyone into the roped off area. Great care is needed when applying pneumatic and hydro-pneumatic tests in order to avoid any potential for brittle fracture because of the stored energy in such tests⁽³⁾. All of the above described incidents highlight the fact that there is sufficient energy involved with hydrotesting to injure people.

The API and ASME in-service inspection codes permit the substitution of NDE in lieu of pressure testing after repairs or alterations, where a pressure test is not practical or necessary. The big question in such cases then is when can NDE be substituted for a pressure test and what NDE should be included⁽⁴⁾. Of course, there is no way to answer that question completely in a short EE such as this, but the first point that deserves to be emphasized is that we should not give in too easily on the need for a pressure test. Clearly there are cases where pressure tests are not advisable or practical, including refractory lined vessels, vessels and large piping that are not structurally designed to hold the full weight of water, equipment where water contamination could be hazardous, and various other cases. However, there are “other” cases where project engineers are simply trying to save a little time or effort on their project. In those “other” cases, we should apply risk analysis to help determine the pros and cons of substituting NDE for pressure tests. The downside of not pressure testing is that we lose the opportunity for a “brute force” type stressing and leak testing of the repair or modification. Having seen repairs and alterations fail their final pressure testing, I remain convinced of its value. However, when we do substitute NDE for pressure tests, I usually specify some root pass and cap pass surface NDE, along with angle beam UT of the most critical, through thickness welds. So far, I have never had a weld that had adequate NDE performed in lieu of a

pressure test, fail in service. Obviously, for critical welds, appropriate use of NDE is advisable, even when a final pressure test is part of the plan. ASME PCC-2 Article 5.2⁽⁴⁾ has some excellent guidance on substituting NDE for pressure and tightness testing which should be understood and applied whenever such substitutions are contemplated.

Water quality problems with hydrotest water have caused more than a few pipe failures soon after piping is placed into service, especially with stainless steel piping. I have seen several cases where piping was pressure tested with water of questionable quality, in spite of our efforts to specify clean, low chloride water. It takes a lot of follow through to make sure that the clean, high quality water that you specified is actually used. There are lots of folks who do not understand or appreciate the need to avoid using fire water, process water, ordinary available water, etc. In one recent example, we discovered a significant amount of MIC on type 304 austenitic stainless steel piping during a process unit start up. The piping had been pressure tested with contaminated water several months earlier, but within that short period of time between pressure testing and putting the pipe in service, MIC had completely penetrated the piping. In another case, chloride contaminated water was used to test stainless steel piping. Though the pipe was drained after testing, it was not dried, so wherever there was a small pool of chloride contaminated water, it evaporated down to high chloride water and pitted rapidly through the thickness of the pipe. In both cases, the delays to inspect the piping and replace the pitted sections were expensive and embarrassing for those involved.

Do you fully understand the value of the various types of pressure and tightness tests, and are you using them to your best advantage when you need them? Does everyone involved in pressure and tightness testing know and appreciate the safety hazards involved in such tests? Do you make sure that all the appropriate NDE is applied whenever a pressure test is waived after repairs and alterations, and do you make sure that the reasons for waiving the pressure test are valid and the risks associated with not pressure testing are acceptable? Do you have a QA/QC program for hydrotest water quality that will prevent expensive delays for pipe replacement during plant start up?

References

1. API 510, *Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration*, Third Edition, American Petroleum Institute, Washington, D.C., June, 2006 (10th edition approved and publication pending, 1Q/14).
2. API 570, *Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems*, Third Edition, American Petroleum Institute, Washington, D.C., November, 2009 (4th edition in ballot stage).
3. ASME Post Construction Committee (PCC-2) *Repair of Pressure Equipment and Piping*, Article 5.1 *Pressure and Tightness Testing of Piping and Equipment*, American Society of Mechanical Engineers, NYC, NY, April, 2011.
4. ASME Post Construction Committee (PCC-2) *Repair of Pressure Equipment and Piping*, Article 5.2 *Nondestructive Examination in Lieu of Pressure Testing for Repairs and Alterations*, American Society of Mechanical Engineers, NYC, NY, April, 2011.

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Material Verification and Positive Material Identification

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An effective PMI and material verification program for new and existing alloy piping systems is another top priority for FEMI. In the early 90's, a US Gulf Coast Refinery suffered a major fire and three fatalities that were traced to one rogue carbon steel fitting that had been placed in a spare 5 Cr-1/2Mo piping system in a coker unit. The fitting lasted 30 years in intermittent service before it ruptured and resulted in that catastrophic incident. Time and time again, owner/users have reported process safety incidents related to the failure of a rogue component of a piping system that was not the same as that specified/installed for the rest of the piping system. API RP 578⁽¹⁾ is an excellent document for instituting an effective PMI program for new installations, maintenance materials, and for checking materials in existing systems, in-service, that may have rogue materials in place. PMI surveys of new plants, performed by owner/users looking for off-spec material, routinely report finding between 1 and 3% incorrect materials being located, with some reporting non-conformances up into the double digits after some maintenance turnarounds have occurred on existing process units. Bolt-on items after maintenance activities seem to account for most material errors in turnarounds. PMI issues account for one of the leading causes of significant breaches of containment and FEMI process safety incidents in our industry.

Material verification/PMI is another of the QA/QC management systems that is essential to making sure that spare parts, replacement equipment/piping, and other materials that were specified in procurement documents are purchased from qualified fabricators and suppliers (QF&S) (see separate EE), and that the quality of all items is in accordance with your procurement documents. In my experience, if you do not have a rigorous management system and enforcement thereof involved in receiving QC clearly specified in your internal work practices, items critical to process safety are going to be received without enough attention as to whether or not they meet specified requirements. On more complex engineered items, those receiving work practices may require the involvement of engineering and/or inspection personnel. PMI should be required for some alloy products that are vital to FEMI, but at a minimum, verification of material stamping and associated paperwork (e.g. MTRs) by receiving personnel should always be required for alloy components. Color coding on some alloy products applied by receiving personnel is useful for keeping different alloys separate from one another⁽²⁾. More advanced FEMI practices will be risk-based and have multiple points of PMI on critical items to make sure there has been no mix up between manufacturing and installation in the field (e.g. PMI during shop fabrication, during receiving, after transport to the installation site, and finally after installation in the field).

Does your site have documented rigorous procedures and work practices for receiving materials and spare parts; such that you have assurance that the items specified were actually received and that everything was in complete accordance with the procurement documents? Are you using API RP 578 effectively to identify rogue materials that might cause unexpected failures in your FEMI program, for both new and existing equipment? Can you sleep comfortably knowing that process safety incidents due to PMI failures are not going to occur at your site?

References

1. API RP 578, *Material Verification for New and Existing Alloy Piping Systems*, 2nd edition, March, 2010, American Petroleum Institute, Washington D.C.
2. PFI ES 22, *Recommended Practice for Color Coding of Piping Materials*, Pipe Fabrication Institute, January, 1995.

Qualified Suppliers and Fabricators (QSF) List

There is an old adage in our business that goes like this: “The bitter taste from poor quality lasts much longer than the sweetness of low bid.” Each company and/or operating site should maintain an up-to-date list of qualified and approved suppliers and fabricators for fixed equipment; and a work process should be in place to ensure that non-qualified “low bidders” cannot creep into the procurement process. If this work process is not managed diligently, personnel turnover and those folks inclined primarily toward “low bidders”, no matter what their qualifications, will cause inferior quality goods and services to infiltrate your operating site. Moreover, you could pay dearly someday from a process safety event due to the inferior products or services of an unqualified low bidder. I have seen that happen more often than I would like to tell you. The issue of having a QSF list is closely related to the fraudulent and counterfeit materials issue discussed in an entirely separate EE.

The process to keep a QSF list up-to-date should include how QSFs can be added to and removed from the list⁽¹⁾. Some shops might be entered onto the list for a probationary period until they have proven themselves capable to your satisfaction. Other shops may be put on probationary status after some poor performance. Quality reports recorded on each supplier after equipment has been delivered are very useful for keeping such a list up to date. Grading supplier/vendors (S/V) on the basis of risk may also be very useful. For instance, on the basis of 1-5, a supplier that has delivered high quality high pressure/high temperature hydroprocess alloy vessels on time and with minimum source inspection overview, might be rated a “1” supplier; while a supplier of “pots and pans” that has to be watched over carefully in order to deliver the equipment on time and on spec might be rated in the “4-5” range.

Effective source inspection for each piece of equipment from a QSF vendor should begin with a risk based assessment of the materials and/or equipment to be procured for a project⁽²⁾ (see separate EE on supplier/vendor source inspection). These risk based assessments are completed in order to identify the level of effort for source inspection activities during the fabrication phase of a project at the vendor facility. Equipment identified as critical equipment will receive more intensive source inspection, while equipment identified as less critical will receive less intensive source inspection, and thereby rely more on the vendor quality program. The risk assessment process takes into account the probability of failure (POF) of equipment to perform as specified, as well as the potential consequences of failure (COF) to perform in service (e.g. safety, environmental and/or business impact). The ultimate risk associated for each equipment item is then a combination of the POF and COF assessments. Typically, these risk based assessments identify equipment risks using the following types of risk issues:

- Safety or environmental issues that could occur because of equipment failure to meet specification or failure while in service (e.g. a high pressure/temperature hydroprocess vessel);
- Equipment complexity; the more complex the equipment, the higher level of source inspection that may be required (e.g. a major articulated column/vessel with a lot of internals);
- Knowledge of supplier history and capability to deliver equipment meeting specifications on time (i.e. newer supplier with relatively unknown history or capabilities may need closer scrutiny);
- Potential schedule impact from delivery delays or project construction impact from issues discovered after delivery (i.e. costly, long delivery items may require higher level of source inspection);
- Equipment design maturity level (i.e. prototype, unusual or one-of-a-kind type equipment may require higher level of source inspection);
- Lessons learned from previous projects (i.e. the supplier has had problems in the past meeting specifications on time);
- Potential economic impact on the project from supplier failure to deliver equipment meeting specifications on time.

The risk assessment provides information helpful in specifying the level of effort necessary for source inspection of each supplier facility commensurate with the specified risk level. Typical levels of source inspection effort at the supplier facility commensurate with risk levels may include:

- No source inspection (lowest risk for equipment failure to meet specifications; rely solely on S/V quality).
- Final source inspection (final acceptance) just prior to shipment (lower to medium risk material or equipment; rely primarily on S/V quality with minimum source inspection).

- Intermediate source inspection (medium to medium high risk equipment; mixture of reliance on S/V quality with some source inspection activities at the more critical hold points). The number of shop visits may go up or down based on the performance level of the S/V.
- Advanced source inspection (higher risk equipment; significant amount of source inspection e.g. weekly to provide higher level of quality assurance). The number of shop visits may go up or down based on the performance level of the S/V.
- Resident source inspection (highest risk equipment; full time shop inspector(s) assigned, possibly even on all shifts).

One thing to look for (certainly not the only thing) is appropriate certification for quality management systems that certain suppliers have passed and kept-up-to-date. Included in those certifications may be ISO 9000 certification, National Board “R Stamp” certification for repair organizations, “VR Stamp” certification for relief devices, appropriate ASME stamps for fabricators, better business bureau membership in good standing, as well as several other appropriate certifications. Having these memberships and certifications does, of course, not provide any guarantee of your receiving a good quality product or service, but it is a good place to start when searching for qualified suppliers and fabricators. Passing such certifications takes extra effort and typically shows a commitment to quality management.

Is your QSF list kept up-to-date and enforced for all purchasers of pressure equipment and inspection/maintenance services, and do you know if your suppliers have passed some sort of recognized quality assurance and/or quality management process? Do you risk assess your equipment purchases to determine how much shop surveillance will be required during fabrication?

References

1. *Guide for Source Inspection and Quality Surveillance of Fixed Equipment*, API Individual Certification Program Publication, American Petroleum Institute, September, 2013.
2. [The Role of Life Cycle Management in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, Jan/Feb, 2011.

Fraudulent and Counterfeit (F/C) Materials

In our globalized economy, many operating sites are seeing an increasing amount of fraudulently marketed and counterfeit materials of construction coming from low-cost suppliers in countries without the same level of commitment to product integrity and QA/QC that the western world is used to. Some examples include: counterfeit bolts (which can cause severe injury and fatalities when they fail), counterfeit flanges, counterfeit pipe and pipe fittings, plate, forgings, and structural materials that do not meet properties stated on the MTR, counterfeit valves and porous valve castings from low-cost foundries, and counterfeit ASTM stampings. That is not to say that you cannot acquire adequate quality materials from foreign suppliers, especially from highly industrialized countries; it just means you need to be more alert and on guard when low-cost suppliers from “emerging market countries” creep into your supply chain. A report on this issue from the Construction Industry Institute (CII)⁽¹⁾ indicated that from 1990-1995, world trade expanded by 47%, but at the same time counterfeiting expanded by 150% and has continued to grow since that time.

One of the best ways to avoid receiving F/C materials is to have “pre-qualified” supplier lists (see separate EE) for not only engineered and fabricated equipment, but also for suppliers of raw materials and commodity items (e.g. bolts, castings, forgings, plate, pipe and valves) for your fixed equipment, especially when they come into your operating sites during a major construction project. Some other ways to potentially avoid receiving F/C materials from low-cost suppliers include: paying greater attention to specifying non-engineered products more carefully, increasing source inspection efforts (see separate EE), including additional third party source inspection and unannounced inspections, greater attention to receiving QA/QC, verifying that MTR’s are received and are not fraudulent, performing third party testing of material properties to verify that they meet the specifications on the MTR, increasing use of sound PMI practices and technologies, and verifying the presence of ASTM stampings (though even those are also being counterfeited). Probably the most effective deterrent comes from holding your primary domestic suppliers responsible for avoiding F/C creeping into their supply chain. You may not be able to afford to duplicate a fail-safe QA/QC system at each manufacturing plant to avoid all F/C materials, but there are many steps that can be taken to decrease the risk of receiving them. Dealing with ISO 9000 certified (or equivalent) suppliers can help avoid receiving F/C materials, though it certainly provides no guarantee, especially if there is a breakdown in the supply chain between the manufacturer and receipt at your operating sites.

Do you have adequate controls and checks in place at your site(s) in order to avoid receiving and installing fraudulent and counterfeit materials of construction?

References

1. *Product Integrity Concerns in Low Cost Sourcing Countries: Counterfeiting within the Construction Industry*, CII Research Summary 264-1, July, 2010.

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I've always been a big believer in the old adage: “You don’t get what you expect; you get what you inspect”, especially when it comes to engineered pressure equipment being fabricated by supplier/vendors (S/V). It’s one of the foundational essential elements of PEIM. That’s not to say that there aren’t some high quality S/Vs out there that will meet our requirements with minimal overview (see follow-on PEIM element). A certain amount of shop surveillance is usually needed to assure oneself that requirements are met and that the specified level of quality for equipment and piping is actually delivered. The amount of shop inspection will generally vary, depending upon a number of issues, including the complexity of the fabrication, the risk associated with equipment failure, criticality of delivery schedule and the quality of the shop, but it’s only with very low risk equipment that **no** shop inspection may be appropriate.

Certain critical hold points for inspection, NDE, PMI, etc. should be specified on some higher risk equipment. My experience with leaving all shop inspections to the designated authorized shop inspector (AI) has not been very satisfactory. Many owner-operators use the services of trusted, reputable, capable inspection contractors for some shop inspections, but I’m still a promoter of having owner-operator inspectors doing some shop inspections if for nothing else to keep them “tuned up” in the important skills associated with monitoring equipment during fabrication. Even in reputable, higher quality shops, there is a tendency for equipment that will be inspected by reputable third party inspectors, as well as owner-user inspectors, to receive more attention to quality than equipment where the shop knows that the purchaser does not intend to do any shop inspection.

A new API Individual Certification Program (ICP) is now being offered to certify inspectors who perform quality assurance (QA) surveillance and inspection activities on new materials and equipment for the energy and chemical (E&C) industry⁽¹⁾. It has been developed by the API with the assistance of numerous, experienced subject matter experts (SMEs) involved in source inspection activities. Passing an examination to demonstrate the individual’s knowledge of important quality assurance and shop surveillance activities associated with equipment fabrication will be one of the basic requirements of this ICP. A study guide is available from the API to assist the inspector candidate in preparing for the exam⁽²⁾. The program will be applicable to all segments of the E&C industry including upstream (e.g. exploration and production), mid-stream (e.g. pipelines and distribution), and downstream (refining and chemical manufacturing). The initial offering is focused solely on entry level source inspectors of fixed equipment, while future offerings may include other types of equipment and possibly advanced specialty inspection. I expect that this new API ICP will receive widespread acceptance from owner-operators, inspection contractors, and EPC companies as a way to verify that shop inspectors have the minimal amount of knowledge and skill to get the job done satisfactorily. This new certification program is in no way expected to diminish the responsibility of the fabricators, manufacturers, and suppliers to the E&C industry to continue to supply the specified quality materials and equipment; but rather to provide an enhanced method of having those that purchase such equipment and materials gain higher assurance that what they specified will actually be received.

Do you specify and conduct sufficient shop inspections in order to rest assured that the vital aspects of your equipment specifications are, in fact, delivered; or do you allow your competitors to receive the higher quality attention from your shops because they inspect what they order?

References

1. [A New API Inspector Certification Program for Source Inspectors](#), John T. Reynolds, et al, *Inspectioneering Journal*, Jan/Feb, 2013.
2. *Guide for Source Inspection and Quality Surveillance of Fixed Equipment*, API Individual Certification Program Publication, American Petroleum Institute, September, 2013.

FEMI QA/QC Programs

There are four primary aspects of quality assurance/quality control (QA/QC) work processes for the equipment required in the petroleum and petrochemical industry. Each of these four QA/QC aspects are necessary to provide assurance that equipment will be fit for the service for which it is intended, and therefore perform reliably and safely in-service. But first let's be clear on what is the difference between QA and QC. According to API 510, the definitions are: Quality Assurance (QA): All planned, systematic, and preventative actions specified to determine if materials, equipment, or services will meet specified requirements so that equipment will perform satisfactorily in-service; Quality Control (QC): Those physical activities that are conducted to check conformance with specifications in accordance with the quality assurance plan. Hence, QA is the total program and QC is the individual activities specified in the program to provide QA (e.g. inspection, testing, NDE, measurements, etc.).

The four primary QA/QC aspects for equipment in our industry include:

1. QA/QC for design;
2. QA/QC for source inspection/surveillance;
3. QA/QC for construction and installation in the field; and
4. QA/QC for in-service inspection/maintenance of operating plants.

QA/QC for the design of equipment is generally provided by the engineering organizations of the petroleum and petrochemical companies, as well as the engineering, procurement, and construction (EPC) companies that serve the industry. In large part, the necessary QA/QC for the design of materials and equipment for the industry is provided by knowledgeable, competent, and experienced engineers, inspectors and technicians rigorously applying company and industry standards and best practices from Standards Development Organizations (SDOs) such as ASME, API, ASTM, NACE, PIP and other national and international SDOs.

The second step in the QA/QC work process is source inspection/surveillance (see separate EE). Once again, the quality assurance for this step in the work process is most often provided by the engineering organizations of the petroleum and petrochemical companies, as well as the EPC companies and third party inspection companies/organizations that serve the industry. There is now an API Source Inspector Certification Program for inspectors providing this service.

The third step in the QA/QC work process is for assembly of new equipment (construction QA/QC) into a functioning plant/facility that will supply petroleum and petrochemical products for consumers. In this step the inspector's primary responsibility is to provide assurance that the many thousands of individual pieces of materials and equipment that were satisfactorily procured and delivered to the plant site are properly assembled into a facility to produce the intended products. Those materials and equipment include such things as vessels, piping, tanks, heat exchangers, instrumentation, pumps, compressors, valves, electrical gear and hundreds of other pieces of equipment necessary for plant construction, though the focus of this EE is on fixed equipment. This step in the QA/QC work process also involves knowledgeable, competent, experienced engineers and inspectors to complete the job properly so that the plant will operate reliably and safely. Some examples of certifications/qualifications that are useful in this step of the QA/QC work process for the petroleum and petrochemical industry include: ASME BPVC qualified welders, AWS Certified Welding Inspectors (CWI/CAWI), and the new program by the ASME through its PCC-1 standard for training and qualification of bolted joint assemblers.

The final step in the QA/QC work process is inspecting and maintaining all of the equipment while it is in service. The API has a long history (25+ years) of certifying inspectors who have passed an examination and have the requisite experience to show that they possess the basic knowledge to perform in-service inspection (ISI) and maintenance QA/QC for pressure vessels, piping and storage tanks. Those programs include:

1. The API ICP for Authorized Pressure Vessel Inspectors (API 510);
2. The API ICP for Authorized Pressure Piping Inspectors (API 570); and
3. The API ICP for Authorized Pressure Storage Tank Inspectors (API 653)

Some of the basic QA/QC functions for ISI that are an integral part of a plant inspector's job include:

- Maintenance repairs/replacement QA/QC (see separate EE)
- Welding QA/QC (see separate EE)
- Valve maintenance and CCV QA/QC (see separate EE)
- PWHT QA/QC (see separate EE)
- Coatings/linings QA/QC (see separate EE)
- Non-metallic materials QA/QC (see separate EE)
- Bolting & Gasketing QA/QC (see separate EE)
- NDE QA/QC (see separate EE)
- Receiving & PMI QA/QC (see separate EE)
- Pressure testing QA/QC (see separate EE)

While QA/QC is a large and important aspect of ISI, clearly there is much more to the ISI job than just QA/QC. However, I have visited several plants where certified inspectors are relegated to little more than QA/QC functions while engineers and other FEMI personnel are tasked with conducting many of the other inspector duties outlined in the three API Codes/ Standards named above. Those plants may be missing out on the capabilities of a well-rounded competent ISI inspector.

Do all of your FEMI personnel understand the difference between QA and QC and do you have rigorous, documented QA/QC programs for each important QA/QC aspects of ISI?

Valve Quality Problems

Valve quality problems seem to arise more frequently these days. Problems with casting quality are particularly prevalent, with more valve manufacturers turning toward foundries from low-cost suppliers in developing countries without the same level of focus on product integrity and without the QA/QC systems or standards that the western world is used to. Hence it is becoming increasingly necessary to make sure that you are doing business with only highly reputable suppliers who can fend off these problems for us, and that we have some sort of in-house receiving inspection and testing for critical valves to make sure that valves are received in accordance with their specification. What is a critical valve? Well, all companies need to define that for themselves, but in my mind, it is a valve that might create a substantial process safety incident if it were to fail to function properly in service. Some companies are going as far as to add foundries to their approved supplier lists, so that valve suppliers may only use castings from reputable foundries with proven QA/QC management systems. In my opinion, a good way to avoid valve quality problems is to hold your valve suppliers fully accountable for the quality of the valves they supply. Also, see the separate EE on fraudulent and counterfeit materials, as valves are particularly susceptible to such issues.

Another problem that has impacted operating sites has been receiving stainless steel gate valves destined for high temperature service which contain fluorocarbon type packing or gaskets, in spite of the fact that specifications clearly called for high temperature packing and gasketing materials. When undetected, this type of low temperature, chemical service packing, softens and extrudes out of the valve, causing substantial leakage problems soon after start up in hot services. These are just two examples of numerous valve quality deficiencies that seem to be plaguing the industry. There are plenty more.

Inspection of valves that have been placed in service should be in accordance with API 570⁽¹⁾ and when appropriate, API 598⁽²⁾. Check valves that are critical to process safety and reliability should also be inspected at appropriate maintenance opportunities to ensure that the flapper is free to move and not excessively worn in order to provide assurance that they will operate properly in order to stop a flow reversal. The flapper stop should also be checked to ensure that it is not worn or damaged (see API 570 section 5.10). A good way to find out which check valves are “critical” at your operating site is to ask the PHA team which ones must always operate properly in order to prevent a process safety incident.

It is also important to assure yourself that the shaft design of critical check valves is of a type that will prevent stem blow out if pins or keys fail. I remember a large chemical plant fire that was caused when an inadequately designed check valve shaft blew out after a small pin failed, leaving a 3.75-inch hole in the body of the valve through which the 300 psig process unit depressured. Most API 600 valves are constructed so that stem failure will not result in blow out of the stem from the body of the valve; and that is one of many good reasons to purchase valves built to proven industry standards by reputable valve suppliers.

Are your valve QA/QC management systems and approved suppliers lists effectively preventing you from receiving and installing substandard valves? Have all your check valves that are critical to preventing a process safety incident been identified and do they all receive the appropriate inspection and maintenance at scheduled intervals? Might you have some check valves or butterfly valves in service with non-blow out proof stems, which could be ejected from the valve after some type of stem failure?

References

1. API 570, *Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems*, 3rd Edition, American Petroleum Institute, Washington, D.C., November, 2009, (4th edition in ballot stage as of 2Q/14).
1. API 598, *Valve Inspection and Testing*, 9th Edition, American Petroleum Institute, Washington, D.C., September, 2009.

Welding QA/QC Programs

By and large, welding QA/QC is one of the fundamental FEMI work processes that is being performed well at most operating sites. The primary fault that I find in welding QA/QC programs is simply occasional lapses of those responsible in following documented and effective welding QA/QC procedures and work processes. A management system needs to be in place that will ensure that only qualified welders utilizing qualified procedures are allowed to weld on any pressurized equipment, including storage tanks and piping. Within North America and many locations in the world, the ASME Boiler and Pressure Vessel Code, Section IX⁽¹⁾ requirements, as referenced by the three API Codes/Standards for pressurized equipment (API 510/570/653), are widely used for such purposes. Another important aspect of welding QA/QC is the need to keep welder log sheets to help ensure that welder qualifications stay current. It also avoids the time-consuming and unnecessary process of having to retest welders on WPSs that they were previously qualified to use. The most effective welding QA/QC programs set a minimum amount of radiographic examination for every welder and track weld reject rates to ensure that rework is kept to a minimum. The best programs I am aware of stay routinely below a 1% weld reject rate. Equipment failures very often initiate at welds for a variety of reasons, including weld defects, inadequate heat treatment, excessive hardnesses, lack of preheat, poor weld repairs, etc. An effective welding QA/QC program will prevent those failures.

The 2nd edition of API RP 577, *Welding Inspection and Metallurgy*, which was recently released, is an excellent reference for welding quality assurance and a wealth of basic knowledge for the hydrocarbon process inspector and engineer on many types of welding issues faced by the in-service inspector⁽²⁾. Be sure you have access to the latest edition. Additionally, API offers a supplemental certification program based on API RP 577 which is worthwhile for plant inspectors who are not already AWS certified welding inspectors (CWI). API RP 582⁽³⁾ is another useful standard which covers a variety of unique welding issues useful to the plant inspector and engineer not covered elsewhere, including such issues as tube-to-tubesheet welding, dissimilar metal welding, backing materials, weld overlays, peening, stud welding, temporary attachments, duplex SS welding, single pass welds, and a number of other useful welding processes and issues including excellent advice on the limitations of fusion welding. Dissimilar metal welds (DMW) are one of my greatest welding concerns. I have read a number of case histories, some of them with catastrophic results, where DMWs cracked and failed in-service. My advice is to just not do it in high risk services unless you have no other reasonable alternative. And if you are going to use DMWs, make sure you have a competent welding SME involved and use carefully designed, proven welding procedures with the utmost QA/QC to ensure a satisfactory weld.

Hot tapping equipment and piping in-service is a fairly common procedure in our industry, sometimes too common, because hot tapping is not always a low risk activity. Hot taps occasionally do “go bad”, and hence it behooves us to hot tap in-service lines only when there is no other reasonable alternative. Hot tap coupons occasionally fall off of the cutter, taper plugs for line-block hot taps occasionally blow out, block valves occasionally do not seal when the cutting machine is backed out, and welders occasionally “blow through” the line being hot tapped. Well trained, experienced hot tap personnel, following qualified welding safety procedures in accordance with API RP 2201, are the minimum for any such activity⁽⁴⁾. In addition, there should be risk assessment discussions and contingency planning in case something should happen during the hot tapping process and an emergency should arise. The risk analysis should include an assessment of the likely consequences of a release during any portion of the hot tap process. Additionally, there are a number of process services that should not be hot tapped at all and several others that may be hot tapped or welded on, only with carefully thought out procedures, and input from materials and welding SMEs.

Do you use only qualified welders and qualified procedures for welding on all pressurized process equipment, and do you know what your weld reject rates are? Are you using only the latest editions of the referenced welding standards? Do your hot tap and in-service welding procedures contain all of the necessary precautions and planning requirements to minimize the potential for a hazardous incident occurring during the work process?

References

1. ASME BPVC, Section IX, *Qualification Standard for Welding and Brazing Procedures*, et al, American Society of Mechanical Engineers, NYC, NY
2. API RP 577, *Welding Inspection and Metallurgy*, Second Edition, December, 2013, American Petroleum Institute, Washington, D.C.
3. API RP 582, *Supplementary Welding Guidelines for the Oil, Gas and Chemical Industry*, Second Edition, December, 2009, American Petroleum Institute, Washington, D.C. (third edition planned for December, 2014.
4. API RP 2201, *Safe Hot Tapping Practices in the Petroleum and Petrochemical Industries*, Fifth Edition, July, 2003, American Petroleum Institute, Washington, D.C.

Repairs/Replacements

It is important that each operating site have equally stringent QA/QC requirements for maintenance repairs and replacements as it has for new construction in fabrication shops (see separate EE). In fact, it may even be more important because QA/QC is sometimes a bit more difficult to achieve in a field maintenance environment than it is in a shop environment. Those maintenance quality assurances include:

- Design - making sure that company standards for design requirements are met by everyone involved in repairs/modifications to equipment,
- Welding - making sure that all repair and alteration welds are made only by qualified welders using an approved procedure who have kept their welding certifications up to date (see separate EE),
- Coatings and Linings - making sure that the right coatings and linings are specified for the service and that installation by qualified applicators follows stringent QA/QC requirements, since installation/application techniques for coatings and linings are the main reason coatings/linings generally fail; this includes polymeric, metallic and non-metallic linings like refractory (see separate EE's),
- Bolting and Gasketing - making sure that the right bolting and gaskets are specified and actually installed properly by qualified fitters in accordance with manufacturers requirements, as well as ASME PCC-1 (see separate EE),
- PMI at the point of installation - especially where higher risk alloy materials are being utilized (see separate EE),
- Nondestructive Examination - making sure that all the right type and amount of NDE is specified and carried out in accordance with approved procedures by qualified NDE technicians (see separate EE),
- Pressure testing, especially where through-wall repairs have been conducted - deciding whether to apply a strength test or just a leak test or no test at all (see separate EE),
- Record Keeping - making sure that all PEI records are kept up to date in accordance with site requirements for PEI records, as well as API Codes and OSHA process safety information requirements (see separate EE).

One of the primary functions of a qualified ISI inspector in our operating facilities is to carefully specify the repair and testing procedures that are needed to restore equipment to serviceable condition after flaws and/or defects are detected and reported. There are a variety of methods to restore pressure equipment integrity, both permanently and temporarily (see separate EE). Such repair and testing procedures should be detailed, and whenever appropriate, be accompanied by sketches/drawings to guide maintenance personnel in making the right repair in a quality manner. I am a proponent of involving maintenance personnel in the appropriate QC activities after the repair is complete. Some sites with advanced QA/QC programs have qualified, trained maintenance personnel conducting liquid penetrant exams, calling in the radiographer, witnessing the hydrotest, and other QC activities, while the inspection group still maintains the overall QA function. This is clearly a healthy part of total quality management.

Fortunately, our industry codes API 510 and 570 both recognize that in addition to permanent repairs, properly designed and conducted temporary and on-stream repairs are often adequate and safe for restoring equipment integrity for shorter periods of time (see separate EE). ASME Post Construction Committee (PCC) is continuing to document a variety of temporary and permanent types of repairs that have long been used safely and satisfactorily in the industry(1). That standard covers a large variety of repair techniques, describing each, listing some limitations, fabrication and design issues, and covering examination and testing that should be conducted after the repair has been completed. This standard is another real step forward in enhancing our body of knowledge of recognized and generally accepted good engineering practices (RAGAGEP). Additionally, another ASME standard provides an executive summary of over 150 codes and standards applicable to equipment design, fabrication, repair and testing(2).

Watch out for that replacement-in-kind (RIK) trap. Just because OSHA and your MOC procedure do not apply to RIKs, does not mean some competent person(s) can neglect assessing why something failed (if it did fail) and whether or not some type of redesign or material change may be appropriate. Site incident investigation procedures may be needed to assess the cause of the RIK. Also, watch out for those repairs made by OEMs during fabrication that you may not know about and that might eventually lead to failure. I have read a number of failure analyses that tracked an eventual equipment failure back to a shop welding repair that was conducted on a component before the item was even shipped. You never know what

goes on during the graveyard shift in a shop. I am a proponent of building requirements into your new construction standards that any shop welding repairs have to have prior approval by the purchaser and be clearly documented, especially on unique or high risk equipment.

Does your operating site have stringent QA/QC requirements and all of the necessary work processes for maintenance repairs and replacements? Are you thoroughly documenting repair procedures and following up on every recommended pressure equipment repair to make sure it occurred just as you specified and expected? Are you using the latest editions of API and ASME standards for conducting repairs and replacements?

References

1. ASME PCC-2 2011, *Repair of Pressure Equipment and Piping*, The American Society for Mechanical Engineering, New York, Third Edition, 2011 (4th edition pending).
2. ASME PTB-2-2009, *Guide to Life Cycle Management of Pressure Equipment Integrity*. The American Society for Mechanical Engineering, New York, First Edition, 2009

Temporary Repairs

An effective QA/QC program must be in place to ensure that temporary repairs are authorized and completed only by qualified personnel, using approved methods and procedures, so that the risk of an incident is not increased by faulty or inadequate repairs. Back in the old days when maintenance cowboys (no offense to real cowboys) ran rampant over inspection and engineering with the old “just get ‘er done” attitude, some repairs were done without adequate MOC, QA/QC, and design. Thankfully in most operating facilities (though not all) that attitude has been vanquished and now temporary repairs are performed with the utmost care and attention by knowledgeable, competent personnel. But we cannot let our guard down, as there are still a few folks that are prone to bypass procedures that guard against conducting midnight repairs without getting the right people involved.

There are a variety of adequate methods to restore FEMI temporarily by using standardized and properly specified temporary repairs. Such repair and testing procedures should be detailed, and whenever appropriate, be accompanied by sketches/drawings to guide maintenance personnel in making the right repair in a quality manner. Fortunately, our industry codes API 510 and 570 both recognize that in addition to permanent repairs, properly designed and conducted temporary and on-stream repairs are often adequate and safe for restoring equipment integrity when time or circumstances may not allow a totally permanent repair/replacement to be conducted. The 3rd edition of API 570 defines temporary repairs as “Repairs made to piping systems in order to restore sufficient integrity to continue safe operation until permanent repairs can be scheduled and accomplished within a time period acceptable to the inspector or piping engineer.” API 570 goes on to state “Temporary repairs should be removed and replaced with a suitable permanent repair at the next available maintenance opportunity. Temporary repairs may remain in place for a longer period of time only if approved and documented by the piping engineer”. One issue to note is that a proposal is now being considered for the 4th edition of API 570 that will clarify that temporary repairs are only those that affect FEMI and not those leak seal injection fittings that are installed for controlling fugitive emissions for LDAR purposes.

ASME Post Construction Committee (PCC) is continuing to document a variety of temporary and permanent types of repairs that have long been used safely and satisfactorily in the industry⁽¹⁾. That standard (ASME PCC-2) does not classify any of the numerous repair procedures that it covers as either temporary or permanent, but rather leaves that up to the owner/user and ISI codes to decide what may be temporary and what is a permanent repair.

Clearly there is an important role for both MOC and FFS analysis (see separate EEs) when it comes to conducting temporary repairs. I am a believer in having inspection keep an evergreen list of all temporary repairs such as clamps, boxes, wire wrapping, composite wraps, sleeves, etc. Such lists will facilitate tracking until temporary repairs are removed and replaced and will allow scheduled follow-up monitoring in-service.

Although there are caveats, limitations and precautions to be considered for all types of temporary repairs, one type deserves special mention. Boxing and/or wire wrapping of flange leaks as a temporary repair has long been a safe and successful practice in our industry for stopping flange leaks in some services. However, this should not be done without the oversight of knowledgeable pressure equipment or materials/corrosion SME's. One significant incident occurred at a refinery when a channel head blew off from a steam generator because of bolt failure. It seems the channel head flange, which was leaking, was sealed by wire wrapping. In so doing, the small amount of caustic in the steam condensate concentrated on the now enclosed bolting, causing caustic stress corrosion cracking of the higher tensile bolts. After a number of them failed, the remaining bolts could not carry the pressure load, and failed simultaneously, resulting in a vapor cloud that ignited. Sometimes a contributing factor to such situations occurs when sealant that is injected in the boxing assembly puts so much hydraulic pressure on the flange bolts that they overload. There are several other compounds that can and have caused bolt failure by stress corrosion cracking, including wet H₂S containing streams.

Do you have an effective work process in place for temporary repairs using RAGAGEP that will avoid unscheduled outages from the failures of inappropriate repairs? Are you always cautious about what might happen to bolted joints when leak-sealing devices cause them to be exposed to fluids normally contained within the pressure equipment?

References

1. ASME PCC-2 2011, *Repair of Pressure Equipment and Piping*, The American Society for Mechanical Engineering, New York, Third Edition, 2011 (4th edition pending).

Bolting and Gasketing

The problem of flange leaks is as old as our industry, yet I continue to be amazed at how many stories I continue to hear about unsolved and repeated flange leak problems. Flange leaks are particularly common in hydroprocess facilities, as higher pressure hydrogen containing systems are more difficult to seal than other petrochemical process streams. However, there is a large body of knowledge available to help solve flange leak problems. Most can be solved with rigorous site bolting and gasketing procedures, attention to flange surface quality, attention to important design aspects, gasket selection, hydraulic torquing, and various bolt-tensioning devices for higher pressure services. Additionally, ASME Standard, PCC-1⁽¹⁾, is an excellent reference on the subject. Following the guidance in this document and various other publications can substantially reduce flange leaks in piping, exchangers, and reactors. The latest edition of ASME PCC-1 now contains an appendix that outlines an excellent process for training and qualification of bolted joint assemblers (i.e. pipe fitters), and a number of training suppliers are ramping up to provide that training and qualification.

Additionally, those sites that have rigorous bolt tightness QA/QC procedures after major maintenance turnarounds, but before start up, to check the quality of the bolt assembly process and to leak test any flange joint that was broken apart during maintenance have reduced their joint leakage problems to a bare minimum. There are many ways to leak test bolted joints; one work process that I have found effective involves taping the flanges to enclose the gasket gap, punching a pin-hole in the tape, pressuring the system with a few pounds of nitrogen, and bubble leak testing the pin-hole to detect any flange leaks prior to restart.

Another very basic FEMI issue for bolted joint QA/QC involves selecting and properly installing the right gaskets during each flange make-up. This is another one of those issues that takes procedures, training and discipline in order to get it right, every time. Sloppy gasket installation practices are a common cause for joint leakage or gasket blow-out after startup. Periodically I hear about tragic accidents when the management system for this issue breaks down. Not too long ago, there was a tragic accident when a new hydrocracker was being brought on line. An improper gasket was installed and blew out during unit pressurization. And not long before that, a spiral wound gasket at another refinery blew out, causing a major fire. In this case the high temperature gasket had a carbon steel inner ring that suffered from creep. Just recently, another operating site suffered a gasket blow-out, which resulted in a light hydrocarbon vapor cloud that thankfully did not find an ignition source. Failure analysis indicated that the gasket installed was not adequate for the temperature of service, and it gradually degraded over a period of years before it blew out. I also know of two other gasket blow-out incidents when stainless steel valves were installed in high temperature services with low temperature PTFE construction materials (See the separate EE on valve quality problems). To put it simply, my file of joint leakage and gasket blow-out problems from inadequate bolting and gasketing procedures is huge.

Do you still have repeated problems with flange leaks that could be solved by adherence to proper flange bolting standards, QA/QC procedures, practices and testing? How effective is the selection and control over gasket installation in your plant? Are your pipe fitters trained and qualified using the process outlined in ASME PCC-1?

References

1. ASME PCC-1, *Guidelines for Pressure Boundary Bolted Joint Assembly*, 2nd edition, American Society of Mechanical Engineers, NYC, NY.

Preventive Maintenance for Fixed Equipment

Mechanical Integrity

Preventive Maintenance (PM) is something more typically thought of in association with machinery, instrumentation, analyzers, and electrical equipment, as opposed to fixed equipment and piping. And that is probably because those PM functions (testing, lubricating, monitoring, adjusting, etc.) are programmed into our MMS's that process all of the maintenance work orders for an operating site on some set frequency. However, a well run refinery or process plant will also be doing a significant amount of FEMI PM in order to prevent degradation and possible process safety incidents. The FEMI PM activities that I have in mind are not included in the routine scheduled inspection activities, but rather are actual maintenance activities. Some of those FEMI PM activities include such things as:

- Maintenance of insulation systems to prevent water ingress and CUI including recaulking and maintaining jackets/coverings, maintaining surface coatings under insulation including those coatings applied to prevent ECSCC;
- Maintaining SAI coatings to prevent soil-to-air interface corrosion on buried piping;
- Removal of unneeded D/Ls in order to prevent leaks from D/L corrosion;
- Improving contact points in piperacks in order to minimize piping contact point external corrosion by installing half rounds on top of the structural support;
- Replacing and/or coating corroded bolts/nuts in flange assemblies, anchor bolting, and structural members before the bolts fail and cause integrity issues;
- Maintenance of CP systems in order that they will continue to function as designed to prevent minimize corrosion of buried equipment/piping, tank bottoms and wharf structures;
- Scheduled maintenance of CCVs per API 570 to provide increased assurance that CCVs will function as designed in order to prevent process safety incidents;
- Scheduled servicing of PRVs and PVVs in order to provide increased assurance that these devices will function as designed in order to prevent process safety incidents;
- Drilling holes in dummy legs and atmospheric PRV horns in order to make sure that moisture does not collect in the devices and cause degradation;
- Seal welding of threaded connections in SBP using proper procedures to minimize the chances of cracking and leakage;
- Pulling subsurface canned pumps to repair external coatings;
- Clamping and composite wrapping of thinning piping before it is necessary to restore integrity in order to provide an extra margin of safety and service life per the procedures outlined in ASME PCC-2;
- Repainting external surfaces of fixed equipment in the “rust bloom” stage instead of waiting until major surface cleaning and preparation are necessary.

How many more FEMI PM activities can you think of?

Some of these PM activities can be scheduled in your MSS. However, anytime inspectors or FEMI engineers write maintenance work orders to prevent degradation before it is actually necessary to restore integrity (e.g. before reaching Tmin), this can also be considered PM.

Does your operating site have sufficient FEMI PM activities periodically scheduled and/or completed to avoid unnecessary degradation or process releases and potential FEMI incidents?

Effective Inspection Record Keeping Systems

Effective inspection record keeping systems are fundamental to an effective FEMI program⁽¹⁾. Yet, often inadequate record keeping is at the root of equipment failures and reliability problems. Effective record keeping is not much fun and it rarely gets much notice; that is of course, until there is a major incident when inadequate records are found to be a major contributing factor. Every year, some operating plants suffer large FEMI incidents when equipment and piping components fail/rupture, resulting in explosions, fires, reliability impacts, etc. Inadequate record keeping practices are very often found to be a primary reason why the failure occurred, and a thorough review of the inspection records after such failures often reveals that more detailed inspections, repairs or replacements should have been scheduled prior to equipment failure.

Inspection record keeping is perhaps one of the most mundane of the necessary FEMI management systems. Unfortunately, it is also one that can be very ineffective, inefficient and burdensome if not done well, and as such, can take a huge toll on the entire FEMI management process. Hence, I place a very high value on proper FEMI record keeping and data analysis (see separate EE), not only for efficiency and effectiveness reasons, but also for legal reasons. As we all know, regulators and courts of law take a very dim view of poor FEMI record keeping.

Clearly, computerized record keeping (IDMS) is nearly a necessity when it comes to keeping track of all of the data and information essential to achieving excellence in FEMI (see separate EE on IDMS). But having a good quality, capable IDMS software program is just the beginning. Inspection record keeping goes well beyond just the IDMS software program and includes original construction records, engineering reports, failure analyses, NDE reports, baseline readings, isometric drawings, data analysis, and all of the important aspects of the comprehensive progressive inspection records mentioned in API 510, 570, 572 and 574. Good quality records are such a vital aspect of any FEMI program, that regular internal audits should be conducted of each inspector's records by those knowledgeable and experienced in effective records systems in order to determine if and where deficiencies exist and make recommendations for improvement. As nearly everyone knows by now, IDMS's do not function well with questionable, inaccurate and inadequate data; and such data can subsequently take a huge toll on inspection productivity, let alone the possibility that the garbage-in garbage-out (GIGO) syndrome can also result in breaches of containment. And while this issue mostly affects the progressive inspection history files, do not overlook the need for good quality design and construction files, as well as repair, alteration and rerating files.

The operating sites that do the best job of FEMI record keeping have a detailed, documented FEMI record keeping practice to which everyone is required to adhere. Such a document describes in detail what "good records are" and lets all FEMI inspectors and engineers know exactly what is expected of them in order to maintain thorough, comprehensive FEMI records.

How good is the quality of FEMI records at your operating site? Does your site keep high quality inspection records so that you, and anyone else, can properly assess the integrity and reliability of your equipment and schedule future inspections and/or repairs/replacements on the basis of useful, comprehensive, factual information?

References

1. [The Role of Record-Keeping and Data Management in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, Jan/Feb, 2012.

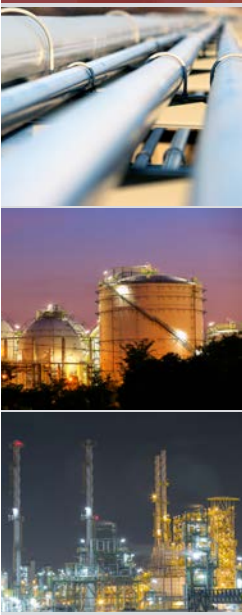
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Computerized record keeping is a necessity at most operating sites when it comes to keeping track of all of the data and information vital to achieving FEMI excellence⁽¹⁾. As nearly everyone knows by now, IDMSs do not function well when questionable, inaccurate, and inadequate equipment and inspection data is plugged in, which can subsequently take a huge toll on inspection productivity, let alone the possibility that the “garbage-in garbage-out” (GIGO) syndrome can result in breaches of containment. And while this issue mostly affects the in-service inspection history files, we should not overlook the need for high quality design and construction files in your IDMS, as well as repair, alteration, replacement and rerating files. IDMSs are usually a combination of paper and electronic records, but hopefully in this day and age no one is still struggling with only paper record systems.

The best computer-based IDMSs will not only have the capacity to store all of the necessary inspection data in a secure and easily retrievable manner, but it will make calculations for corrosion rates, inspection scheduling and remaining service lives, and will also allow you to sort and query the data in a wide variety of manners useful for understanding trends and evaluating FEMI issues. Additionally, the best IDMSs will have a number of valuable standard and user-defined report formats that are helpful for inspection, engineering, operations, turnaround planning, and routine maintenance personnel in understanding and utilizing the inspection data and information. The best IDMS’s can also be linked to the maintenance management system (MMS) in use at the site so that inspection schedules and recommendations from the IDMS can be electronically transferred to the MMS to generate and track work orders without having to manually transfer information from one system to the other. Other features available in the superior IDMS’s allow for:

- Tracking inspection recommendations to completion;
- Allowing storage of digital photos and radiographs within each equipment item folder,
- Tracking the results of special emphasis inspection programs such as those for CUI, PMI, deadlegs, injection points, piperacks, buried piping, etc.;
- Linking to equipment IOWs and MOCs associated with FEMI;
- Tracking temporary repairs and temporary installations; and
- Linking to externally supplied reports such as:
 - advanced NDE inspections,
 - construction design data/information and QA/QC results,
 - corrosion control documents (CCDs),
 - failure analysis reports,
 - engineering drawings,
 - equipment and piping isometric drawings with CML mapping,
 - FEMI incident investigations, and
 - engineering analyses (e.g. FFS reports, etc.).

Additionally, the more advanced systems will be electronically connected (linked to or integrated with) Risk-Based Inspection (RBI) software programs to allow inspection data to be assessed for probability of failure (POF) as well as consequence of failure (COF) in order to properly schedule risk-based inspections.

Does your site enjoy the efficiency and effectiveness benefits of a comprehensive, yet easy to use, IDMS, which stores all of your narrative and digital FEMI related data and information? And is it linked or integrated with your site’s MMS, RBI software, and process and engineering data storage systems?

References

1. [The Role of Record-Keeping and Data Management in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, Jan/Feb, 2012.

Thickness Measurements for Corrosion Rate Calculations

Accurate thickness measurements for corrosion rate calculations are fundamental to FEMI, yet it is a subject that is often considered so mundane that it does not receive the appropriate amount of attention. When that happens, the quality of thickness data can vary all over the map. Without accurate data for corrosion rate calculations, much time and money is lost on rework and inspections that are conducted more frequently than necessary, let alone the potential for equipment and piping failing prematurely due to the inaccurate data. An effective FEMI program needs to have appropriate NDE thickness measuring procedures in place to ensure that data will be accurate and reasonably reproducible for corrosion rate calculations.

In my experience, appropriate digital ultrasonic thickness testing (DUTT) procedures with a trained DUTT technician can yield reproducibility routinely within ± 0.010 " and profile radiographic (PRT) thickness data within $\sim 6\%$. Some round robin tests that I am familiar with indicated that a lack of adequate procedures and training would yield ultrasonic accuracy variability, routinely of 3-4 times these numbers. And these tests included long-experienced inspectors and DUTT technicians. Hence, it is my belief that inspectors/DUTT technicians (company and contract) doing DUTT and PRT thickness measurements need detailed training and procedures in order to provide truly high quality data. And that does not mean simply making sure they are ASNT Level I or II qualified, unless the technicians have been specifically trained and qualified on DUTT. It means that they receive training covering the 8-9 variables that can affect DUTT data quality, including: calibration issues, cleaning, couplant issues, temperature monitoring and correction factors, hot measurement issues, doubling, minimum diameters of piping, effect of placement and rocking the transducer on curved surfaces, taking three readings in each examination point and averaging them, when to use A-scan equipment, dealing with coatings, and gauging through CML marking stickers. For a lot more information on DUTT, I recommend you read section 5.7.1 of API 570⁽¹⁾ and section 10.2 of API RP 574⁽²⁾, both of which are currently being updated for their 4th editions.

Now that said, I recognize that not all thickness measurements need to have the accuracy necessary for corrosion rate calculations. And as such, there are alternative methods to DUTT that can suffice under various circumstances including profile radiography, long range UT, guided wave UT, pulsed eddy current, and even the old fashion caliper method. But users of these techniques must recognize that some of these techniques are just screen techniques and understand their limitations in producing accurate UT thickness data.

Do you know if your thickness data accuracy is routinely good enough to allow your inspection data management system (IDMS) to function as well as it can, providing you with accurate corrosion rates, inspection schedules, and projected remaining service life for equipment that is subject to metal loss?

References

1. API 570, *Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems*, 3rd Edition, American Petroleum Institute, Washington, D.C., November, 2009, (4th edition in ballot stage as of 1Q/14).
2. API RP 574 *Inspection Practices for Piping System Components*, American Petroleum Institute, Washington D.C., 3rd edition, November, 2009, (4th edition in ballot stage as of 1Q/14).

Minimum Required Piping Thickness

One of the more critical pieces of information for analyzing inspection data in your Inspection Data Management System (IDMS) is the minimum required piping thickness. Here is where the so-called “retirement thickness” enters the picture. In order to calculate the remaining life of equipment and piping, as well as schedule the next inspection, the user needs to enter a credible minimum required thickness, which goes by various names such as “retirement thickness,” “structural minimum thickness,” “minimum alert thickness,” “arbitrary minimum thickness,” “minimum practical thickness” and other names. Because there was such a wide range of so-called “minimum thicknesses” in use in the industry (along with a lot of confusion about what really is the minimum required thickness), it took the API Subcommittee on Inspection a significant amount of time to come with a reasonably conservative compromise approach that all users could agree upon and that could then be standardized as a recognized and generally accepted good engineering practice (RAGAGEP) for the industry. That has now happened.

My preferred approach to this issue is to use the new Table 6, Section 11.1.5 in the latest edition of API RP 574⁽¹⁾, and enter an appropriate minimum alert thickness into your IDMS. This minimum alert thickness then tells the inspector that the piping is getting closer to the retirement/renewal point so he/she needs to start paying closer attention to it and making a plan for renewal at an appropriate time in the future. Along with the minimum alert thickness, the user then has two additional possible approaches to enter a minimum required thickness, which is the thickness which indicates that some action is now necessary. The first approach is to enter the default structural minimum thickness into your IDMS if available, which is also included in Table 6 of API RP 574. The other approach, which can be done separately or in addition to the prior, is to perform a fitness-for-service calculation to find an absolute minimum thickness that can be entered into your IDMS⁽³⁾. Of course, the site always has the option of simply renewing/repairing the piping anywhere between the minimum alert thickness and the true minimum thickness.

One mistake that some sites make is that they formulate simple hoop stress calculations without any allowance for structural loads and enter that value for minimum thickness as the so-called “retirement thickness.” That, of course, is a fairly risky practice since that is the theoretical minimum thickness to hold the internal pressure, unless the calculation incorporates the design safety margin included in the allowable stress tables of the piping construction code (e.g. ASME B31.3). On the other end of that spectrum are the sites that use a minimum thickness consisting of nominal piping thickness minus design corrosion allowance. Such a very conservative approach to minimum thickness may result in sites replacing piping that actually has a lot of service life left. In my API assessments of inspection practices, I have found several sites on both ends of this spectrum and too few sites aware of the latest standardized practice in API RP 574.

Is your site now using the latest RAGAGEP practice recorded in API RP 574 for minimum alert thickness and minimum required thickness for piping?

References

1. API RP 574 *Inspection Practices for Piping System Components*, Washington D.C., 3rd edition, November, 2009, American Petroleum Institute, (4th edition in ballot stage).
2. API Standard 579-1/ASME FFS-1, *Fitness for Service*, 2nd edition, June, 2007, American Petroleum Institute, Washington D.C. (3rd edition pending) .
3. [The Role of Record-keeping and Data Management in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, January/February, 2012.

Corrosion Rate Calculations

To accomplish adequate corrosion data calculations, each operating site needs to create corrosion circuits and CML's in order to trend thickness data over time (see separate EE's). There are several types of corrosion rates commonly calculated in the better IDMS's to determine when future inspections should be scheduled⁽¹⁾:

- CML short corrosion rate – the corrosion rate determined from the previous thickness inspection to the current measured thickness.
- CML long corrosion rate – the corrosion rate determined from the first thickness measurement (baseline thickness) and the current measured thickness.
- Linear regression CML long corrosion rate – the “best-fit” rate, is more of a statistical approach which uses all of the past thickness measurements and the current thickness measurement for a specific CML. The IDMS should provide the user with a calculated correlation coefficient, which can be used to determine if any of the thickness measurements are statistical outliers.
- Circuit average short corrosion rate – the average of CML short rates for all of the CMLs measure during the current inspection (this rate can be applied to even those CMLs that were not measured during the current thickness inspection).
- Circuit average long corrosion rate – the average of CML long rates for all of the CMLs measure during the current inspection (this rate can also be applied to even those CMLs that were not measured during the current thickness inspection).
- User-defined circuit corrosion rate – the user should be able to define a rate to be used when the potential for a higher corrosion rate exists than those previously measured or a system is relatively new and an actual corrosion rate has not yet been determined.
- Historical corrosion rate – the IDMS should be able to manage CMLs that have been renewed. For example, a single carbon steel pipe spool in a longer piping circuit is renewed because of corrosion under insulation, but the whole circuit is still being monitored for trendable internal corrosion. If the user cannot identify that that specific spool was replaced, the tool would measure the new thicknesses as growth and the IDMS would flag the new measurements as data errors. The historical rate concept allows the user to flag each CML on the spool that is replaced and utilize the historical corrosion rate for those points in determining the remaining life and next inspection due date for each CML.

One more useful feature of an IDMS calculator is having a built-in temperature compensator for thickness readings conducted above a temperature that is “too hot to touch”. Such a compensator will adjust the calculations for variations in ultrasonic readings caused by fluctuating surface temperatures. Those temperature measurements of course need to be recorded by the data gatherer when he/she is taking thickness measurements.

Does your IDMS complete all of the necessary and useful calculations required to appropriately schedule future inspections and plan out when repairs and/or replacements may be needed?

References

1. [The Role of Record-keeping and Data Management in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, January/February, 2012.

Inspection Data Analysis

After the inspection planning, inspection data gathering, and data entry into the IDMS comes the really important part – analyzing the data to see what it is telling you(1). All inspection data should be recorded in the IDMS on a timely basis, for corrosion rate calculations, remaining life calculations, and inspection interval forecasting. This activity is the foundation of effective inspection programs. Timely data entry and analysis is especially important during turnarounds, so that there will be no surprises after process unit restart during the ensuing operational run (i.e. no surprise due dates coming due before the next scheduled turnaround). Nothing is quite as detrimental to the career of an inspector or inspection engineer, as not reacting appropriately to data and information that was known to exist before the unit came back on stream or before equipment failure occurred. Inspection data analysis includes looking for and reacting appropriately to:

- Changes in corrosion rate trends;
- Changes in long and/or short corrosion rates;
- Anomalies in the data;
- Growths in thickness readings;
- Overdue inspections;
- Very short intervals left for remaining life (or even overdue for retirement); and
- Unexpected changes.

It does no good to take “tons of data” and then let it sit idle in the IDMS (or worse yet in a box in your office) without the attention it deserves. Inspectors have many duties, but none are more important than analyzing their inspection data and acting upon it appropriately.

One of the biggest traps that inspectors can fall into with regard to data analysis is what I call “feeding the beast”. That is when inspectors pour tons of thickness and other data into their IDMS and then they do not assess what it means or what it is trying to tell them because they are too busy gathering more data and performing other tasks. Very often the data tells a tale of something changing that deserves closer attention (i.e. the data needs to be verified to see if it shows a real change or inspection plans need to be adjusted for what the new data is telling them). I have been involved in numerous FEMI incident investigations over the last 46 years, and I can distinctly remember at least three serious FEMI incidents, each with multiple fatalities, where the data actually showed that something was changing and needed to be investigated further. I can also remember many more such FEMI incidents where equipment leaks and ruptures occurred with large reliability impacts, but fortunately with no fatalities. In such incidents, inspectors were just caught up in “feeding the beast”, and no one spotted the changes the data was indicating; eventually leading to pipes rupturing or equipment failing. The result in each case was a huge multi-million dollar loss for the operating plant, and in some cases lives were tragically lost. No inspector ever wants that to happen in their area of responsibility. Imagine for a moment that you are in court and on the witness stand. The plaintiff’s attorney asks you, “Mr. Inspector, why did you not act on the data in your own records showing that this pipe was getting too thin to safely operate?”

Though I do understand how the “feeding the beast” syndrome happens, there is simply no good excuse for it. As we all know, inspectors gather tons of data which shows that everything is as to be expected (i.e. no change in corrosion rates, no change in damage, nothing significantly new, etc). As a result, they can sometimes get overly comfortable in their routine and a bit sloppy, and become more and more distracted by other duties or less important requests for their attention, especially since data analysis is not the most interesting or exciting part of the job. Do not fall into this pattern! Appreciate the potential hazards that can result from a “missed clue” and be scrupulous in your data analysis.

Has anyone at your site ever gotten caught up in the “feeding the beast” syndrome? Do you know what your FEMI data is telling you? Are you doing the best job possible of analyzing your inspection data and acting upon it accordingly? Do you perform data entry and analysis during the turnaround, to gain assurance that some equipment will not come due for unexpected inspections (or worse yet, replacement or repair) during the next scheduled unit run?

References

1. [The Role of Record-Keeping and Data Management in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, Jan/Feb, 2012.

Inspection Recommendation Tracking

A systematic and effective procedure needs to be in place to ensure that inspection recommendations for repairs and other mitigation are followed up and completed, or otherwise handled in an agreed upon manner. These tracking systems are usually more effective when they are built into inspection and maintenance management systems, and cannot be deleted unless agreed upon by the author of the recommendation (i.e. the inspector). I am aware of one refinery that suffered a substantial loss when a thin pipe ruptured because the inspector thought the pipe had been renewed at the last turnaround as he had requested, so he updated his records to reflect the replacement. However, due to miscommunications during the previous turnaround, it had not been replaced. There are many other examples of inspection recommendations that were deleted or delayed until such time that a FEMI incident was allowed to occur. An effective inspection recommendation tracking system could significantly reduce the chances of such events.

Ideally these inspection recommendations would be entered directly into the IDMS (see separate EE) and treated as “one-time” or non-recurring inspection schedules. Then the IDMS should generate a notification that would be electronically or manually transferred to the site MMS, where a maintenance work order would be generated to schedule the work. At those sites where there is the benefit of such an electronic interface between the IDMS and MMS, the IDMS notification (i.e. inspection recommendation) should be considered the legal repository (master file) for these recommendations and the resulting MMS notifications or work orders should be considered as simply the follow-on maintenance planning schedules (i.e. no person should be able to modify or delete an inspection recommendation or its associated priority and schedule from the IDMS without having full security rights in the IDMS to do so). That way the inspector is the only one who can modify, delete, or close out an inspection recommendation that has been sent to the MMS for maintenance scheduling. That is the level of software security that I prefer for such critical issues as FEMI repair recommendations.

Inspection repair recommendations that, for a valid reason, cannot be completed by their scheduled due date can be deferred for a specific period of time, if appropriate, by a documented and approved change in date of required completion by the appropriate person with the necessary authority. The deferral of the due date needs to be documented in the inspection records and receive approval from the appropriate FEMI personnel, including the unit inspector and/or the inspection supervisor. In this manner, inspection recommendations that have not been completed by the original due date would not be considered overdue for completion. The same work process can be used to modify the content of the original recommendation. A work process that recognizes this system will be included in the 10th edition of API 510⁽¹⁾ (see separate EE on Overdue Inspection Recommendations).

Do you have an effective, secure management system in place to track all of your FEMI inspection and repair recommendations through to completion or other satisfactory conclusion, even if it is not contained in your IDMS?

References

1. API 510 *Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair and Alteration*, 9th edition, June 2006 (10th edition approved with publication pending).

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This is clearly an EE that is vital to FEMI continuous improvement. Once a leak or failure has been reported using the leak and failure reporting process, it is necessary to do a credible job of investigating so that the direct, contributing and root causes can all be understood and learned from. In fact, the management process for FEMI investigations is so important that the API Subcommittee on Inspection (SCI) has published a recommended practice API RP 585⁽ⁱ⁾ on the subject matter. It is specifically targeted at incidents and near misses that involve or could have involved loss of containment from fixed equipment. It provides three levels for doing FEMI incident investigations, which will range from a simple, quick investigation up to a detailed root cause analysis (RCA). The three levels of FEMI incident investigations in API RP 585 are described as:

1. Level 1 – a simple one or two person investigation on low consequence FEMI incidents and near misses that can be done in a fairly short period of time. Level 1 uses the evidence and the judgment and experience of a knowledgeable investigator to determine the causes and recommend solutions.
2. Level 2 – is a more thorough investigation of medium consequence FEMI incidents and near misses that normally involves a small team and takes a bit more time to gather and analyze evidence and determine causes more accurately. The team generally uses casual factor or logic tree analysis to determine the causes e.g. Five Whys.
3. Level 3 – a more detailed investigation of high consequence FEMI incidents that involves a team typically led by a trained/experienced root cause investigator. Level 3 investigations involve the gathering of much more evidence and conducting in-depth analysis and may take several weeks or months to complete. Level 3 uses a structured RCA methodology to determine all three types of causes (direct, contributing and root).

Which level of investigation you select will depend upon the seriousness of the consequence of the incident or near miss and the need to truly understand the detailed root and/or contributing causes in order to avoid future incidents. Near misses are an important part of the investigation process, since understanding and reacting to near misses can prevent some actual FEMI incidents from occurring. In the new API RP 585, a PEI near miss is defined as: The discovery of significantly more equipment degradation than expected or the discovery of process operating conditions outside of acceptable material degradation limits that did NOT result in a loss of containment or structural stability, but corrective action is needed to prevent the progression to a FEMI failure. In my numerous assessments of operating sites, I find that companies are generally improving in their ability to investigate actual FEMI incidents, but are significantly lacking in their identification and investigation of FEMI near-misses.

After you have reported and documented a FEMI failure, and an investigation has been conducted to determine the cause, it is then vital to develop solutions and corrective actions to ensure that the probability of it happening again is reduced to an acceptably low level. In Level 1 & 2 investigations, solution development and recommending corrective actions is part of the investigation. In level 3 type RCA investigations, solution development and recommended corrective actions may be a separate follow-on activity. Sometimes there will be several possible solutions requiring different levels of resources to implement. When that is the case, risk analysis is often beneficial to help determine the most cost-effective solution i.e. the solution that will in fact address the root and contributing causes at the lowest reasonable cost. For lower level investigations of lower consequence incidents or near misses, the solution may be relatively simple and can be implemented with few resources or involve some retraining or just changing a procedure. In more serious cases, solutions may require an engineering project of some magnitude.

Once the most appropriate corrective actions are selected, it will be necessary to devise a timeline for implementation to assure that corrective actions are in fact implemented in a timely manner to prevent future such incidents. Additionally it is useful for someone to be responsible to conduct “look backs” at an appropriate interval in order to determine if the corrective actions did in fact work out as expected and are being sustained in order to prevent future FEMI incidents.

Something to think about: If our industry did as good of a job investigating and implementing corrective actions of FEMI failures as the NTSB and airline industry does for their accidents, we would probably reduce FEMI incidents by 99+%.

Does your site do a good job investigating, understanding and correcting every FEMI failure and near miss, especially those caused by damage mechanisms listed in API RP 571, in order to reduce operating risks and avoid future FEMI incidents?

References

1. API RP 585 *Pressure Equipment Integrity Incident Investigation*, 1st edition, American Petroleum Institute, Washington, D.C., May, 2014.

Failure Analysis and Corporate Failure Memory

This EE is closely related to the EE on Leak and Failure Investigation. Unless it is clearly obvious to the trained eye and experienced FEMI specialist, laboratory failure analysis (FA) of the component that led to the loss of containment is normally vital to FEMI investigations. In most cases, Level 2 and 3 investigations detailed in the newly published API RP 585 standard should require appropriate components to have a formal laboratory FA. Failure analysis will typically involve some form of metallurgical investigation of the failed component, but could also be an analysis on non-metallic components and entail chemical analysis of deposits that might be helpful in identifying corrosion deposits, corrosive fluids or fouling materials.

Sometimes it will be obvious from the outset which component failed and caused the loss of containment. But in bigger incidents because of the ensuing destruction and multiple equipment and piping failures due to the fire and explosion, it will not be so obvious which component failed first and which components may have failed due to the initial loss of containment and the consequence of the release (sometimes called knock-on or collateral damage effects). In the later case, multiple samples may need to be shipped from the site to the laboratory for analysis, not only to determine the physical cause of the initial loss of containment, but also to determine which pieces of equipment may have failed as a result of the consequences that followed the initial failure.

Preparing the samples for shipment, handling the samples and shipping them needs to be sufficiently detailed with appropriate QA/QC to ensure that they arrive at the laboratory in the same condition that they were found at the site. Care to avoid potential handling and shipping damage will help to avoid erroneous or lack of conclusions during the failure analysis due to damage that did not actually occur during or prior to the incident. Shipping and handling protocol may need to specify type of packaging, type of crating, protection from the environment, need for desiccant, etc.

But even before investigators begin to define the protocol for FA work, they must decide where to send the samples for analysis. FA for FEMI investigations should be performed by organizations competent, qualified and experienced in refinery and chemical plant failure mechanisms. Some large companies in the petrochemical industry have their own in-house FA laboratories with competent, experienced personnel whom they can trust to provide them with quality, factual FA results. Companies that do not have that in-house resource, should determine which contract engineering/metallurgical firms have appropriate skills, equipment and experience in refinery and chemical plant failure analysis that they can rely upon, preferably before they actually need that service. There are many companies in business doing FA that do not have much experience with API RP 571 type damage mechanisms and therefore cannot be relied upon to do a credible failure analysis for refining and chemical plants. FA conducted for building collapses, automobile and airplane accidents, bridge collapses, etc. is very different than the FA that needs to be conducted to find the cause of an API RP 571 type damage mechanism. This is clearly a “buyer beware” situation.

The next major step in the FA part of a FEMI incident investigation is to assemble, document and agree upon the various required steps in the laboratory failure analysis that are needed to support the FEMI incident investigation analysis. The objective of this FA protocol is to perform metallurgical/material inspection, examination and testing of the selected physical evidence items in an effort to identify failure modes and contributing damage mechanisms that caused the FEMI incident, i.e. determine the immediate physical cause for the loss of containment e.g. chloride cracking, HTHA, stress rupture, temper embrittlement or any of the other 65+ damage mechanisms summarized in API RP 571. Fifteen of those steps that should be considered for inclusion in the laboratory FA are listed in a previous article in *Inspection Engineering Journal*⁽²⁾.

Good corporate memory and effective IT systems, to retain and communicate past experiences about FEMI failures, are needed in order to communicate lessons learned (and often re-learned) from previous failures and incidents. Without these systems, we are liable to have repeat failures within our own operating sites. It never ceases to amaze me how few failures and industry incidents are caused by new problems or previously unknown causes of deterioration. I see a lot of failure analysis reports and hear about a lot of incidents within our industry, but I can honestly say that rarely do I hear about one that has not happened numerous times before or was unpredictable by knowledgeable materials, corrosion or FEMI engineers.

This situation reminds me of a quote I once heard which goes something like this, “If only we knew what we already know”.

Does your site have a quality process for determining when component failure analysis is needed, how it is to be conducted and have a short list of reliable engineering service firms that can do a credible FA job? Do you have effective IT systems that collect and make readily available to all stakeholders, the the causes, solutions and lessons learned from past equipment failures in your company?

References

1. API RP 585, *Pressure Equipment Integrity Incident Investigation*, First Edition, American Petroleum Institute, Washington, D.C., May, 2014.
2. [The Role of Continuous Improvement in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, *Inspectioneering Journal*, July/Aug, 2012.

FEMI Leak, Failure, and Near Miss Reporting and Tracking

In order to make continuous improvement in FEMI programs, we must report and track all our FEMI leaks, failures, and near misses if we want to understand and eliminate the causes that could result in future leaks and failures⁽¹⁾. For purposes of this EE, a FEMI leak is defined as a release of hazardous substances or any other fluid from fixed equipment that could result in process safety or reliability issue. As such, FEMI leaks do not include small (almost undetectable) wisps of vapors or gases such as fugitive emissions and VOCs from packing or gasketed joints that are only detected with sensitive instrument monitoring. Leaks can vary in size from a small observable gasket leak or a small unobservable CUI leak under insulation, up to a catastrophic pipe or vessel rupture. Not all leaks are failures. A gasket leak or valve packing leak can often be stopped by proper bolt tightening or other mitigative steps. A failure, on the other hand, involves the loss of mechanical integrity, as well as loss of containment, often because of one of the damage mechanisms enumerated in API RP 571.

FEMI near misses are equally important to report and track, as it is often just dumb luck that it did not lead to an actual breach of containment and possible process safety event. For purposes of this EE, a FEMI near miss is defined as finding a “surprise” condition that required some immediate or unplanned activity like a clamp, a process unit slow down or shut down, or valving off a piece of equipment in order to take unplanned corrective actions. For example, FEMI near misses include surprise near leaks found during a turnaround, piping sections thinned below or close to minimum required thicknesses that required clamping, and/or finding cracks that have not yet led to full penetration. There is just as much to learn from near leaks as there is from actual leaks and failures, and all too often sites do not pay enough attention to recording, tracking, and investigating near leaks.

Hence, it is important that we track and record all FEMI leaks, failures, and near misses in order to improve our FEMI performance. The better Inspection Data Management Systems (IDMS) will have that reporting feature built-in with various types of leak and failure reporting and tracking options. If that is not the case with your IDMS, then simple spreadsheets or other software systems can suffice. The combination of leaks and failures is just one of the many metrics which should be measured and tracked in quality FEMI programs.

The natural follow-up to leak, failure, and near miss reporting and tracking is to investigate each one so that we can understand each occurrence and take the necessary corrective action for each (see separate EE’s on (1) Leak and Failure Investigation (2) Failure Analysis and Corporate Failure Memory, and (3) Learning from FEMI Incidents. All three of these EE’s are closely related to this one and all important to continuous improvement of our FEMI programs.)

Do you track and report to your management and other interested stakeholders all the appropriate FEMI leaks, failures, and near misses involving pressure equipment at your operating site?

References

1. [The Role of Continuous Improvement in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, July/August, 2012.

Management Leadership for FEMI

Management leadership for FEMI is vital to the success of the entire FEMI program and is linked inextricably to all of the other 101 EEs. Without it, the FEMI group will be continually “pushing on a rope” to get necessary FEMI programs in place. Management leadership for FEMI includes such issues as:

- Supplying the necessary FEMI resources,
- Supplying the necessary FEMI staffing (owner-user and contract),
- Conducting the necessary FEMI training and requiring certifications,
- Planning for competency improvement of the FEMI staff,
- Delineating the necessary roles and responsibilities for FEMI,
- Having a process to transfer FEMI knowledge to others that need to know,
- Instilling a shared ownership of assets (SOA) attitude in all those involved in FEMI, and
- Establishing multi-functional teams to coordinate FEMI issues.

Each of the above issues is covered in a separate EE and related inextricably to the entire set of 101 EEs for FEMI, so those issues will not be covered in this EE. Rather a couple more important issues will be addressed.

Probably one of the highest priority issues for the FEMI group is that there is “real” management leadership for “real” FEMI needs, and that the line of authority for inspection passes up through Engineering Groups to senior plant management. I believe it is vital that inspection groups not report directly to those responsible for day-to-day operations and maintenance activities in order to avoid the inevitable conflict of interest between short-term production and budget needs and the needs of preserving and protecting fixed equipment assets over the long haul. That said, I am also aware of situations where the FEMI groups can report directly to a Maintenance/FEMI Manager where the plant manager clearly holds that manager accountable for both functions and not just for meeting maintenance goals. I also believe that FEMI groups need to make sure that their programs and recommendations are, in fact, cost effective over the long haul, and do not have an arbitrary sense of “my way or the highway.” Inspection needs to have effective, close working relationships with maintenance and operating groups, so that we are not working in our silos, without consideration for the needs of other functions. Of equal importance to reporting relationships is the leadership provided by senior management for the long-term preservation of fixed equipment assets. And I am not talking about passive support, but rather, active, out-front, “walk the FEMI talk” leadership for maintaining FEMI, support that is well understood by operations, maintenance, engineering, and inspection groups. Without it, achieving excellence in FEMI will be very difficult.

There is often a large difference in management support and leadership of the FEMI function, from those that pay little attention to it, to those that provide real leadership for the FEMI function at all levels in the organization and actually “walk the FEMI talk”. Clearly if you are going to achieve real excellence in FEMI, you will need real management leadership for the FEMI function.

What is “real management leadership” for FEMI? Those are the managers all the way up to the site manager who take seriously all aspects of the 101 EEs, and who hold their direct reports in operations, engineering and maintenance accountable for FEMI excellence. They are ones who come around asking whether there are any FEMI issues that need their attention, whether you need any additional resources to implement the agreed upon FEMI plan, and ask what they can do to help you accomplish the plan. They know that FEMI is a very big and important part of overall process safety management. They are the ones that truly believe that success in other plant responsibilities makes them feel good, but success in FEMI allows them to sleep well at night. In that manner, they differentiate themselves from those managers that are “supportive” of FEMI, give it lip service, but are not providing real FEMI leadership. True FEMI leaders understand that in order for their site to be successful with their business plan, they must achieve excellence in FEMI and not simply compliance, which may only provide mediocre FEMI.

But the knowledge and understanding of managers will generally only come from an effort by site FEMI SMEs to enlighten them, to communicate often, to keep them informed on the FEMI issues, plans and progress. And that knowledge and understanding does not come by what I call “assmosis”, which is the act of managers sitting on your reports until they absorb all the information in them. It only comes by

proactive efforts on the part of FEMI SME's to enlighten management about all vital aspects of FEMI.

Another essential aspect of FEMI management leadership is FEMI management system (MS) reviews. If your management is truly providing the leadership that they should for maintaining and advancing FEMI, then they should be requesting and receiving the opportunity to have selected FEMI personnel periodically come in for a face-to-face (FTF) meeting to discuss FEMI issues, goals, plans and progress. In my mind, annually is an inadequate frequency, semi-annually is a minimum, and quarterly is better depending upon the urgency of some FEMI issues. In between the FTF FEMI MS review meetings, management should also be requesting and receiving concise, written executive summaries of the status of key FEMI issues.

How well informed is your management on the issues that could cause threats to FEMI and potentially result in process safety incidents and/or loss of production? Does your FEMI group have the proper line of authority to senior management and do your senior managers “walk the FEMI talk”? Do you have FTF FEMI MS reviews with senior site management?

References

1. [Management Leadership and Support for PEI&R](#), John T. Reynolds, Inspectioneering Journal, Jan/Feb 2010.

Learning from FEMI Incidents

One of most valuable work processes that any FEMI group can have in place is a process for learning from incidents (LFI), be they incidents at your site, within your company, or within the industry. Thank goodness the major FEMI events in our industry are few and far between, but they still do happen. And with hundreds of refineries and process facilities around the world, it seems to me that a major FEMI incident occurs somewhere around 10 times per year. If you work for a company that has a LFI process in place, you probably benefit by seeing such reports on a regular basis. If your company/site does not have such a work process, then there are still ways for you to benefit from the LFI work process. The truly major events receive considerable media coverage as well as OSHA/CSB investigations in the United States, so we all get a chance to learn from them. Networking (see separate EE) is also an excellent way to find out about FEMI incidents in the industry. Inspectioneering Journal frequently publishes information on past incidents, and you can also find similar stories in their weekly e-newsletter, [The Inspectioneering Turnaround](#). Additionally, the API hosts an Operating Practices Symposium (open only to owner-users) twice per year at the Downstream Standards Meeting, where numerous presentations are made on FEMI incidents.

One reference indicates that 90-95% of process safety incidents are avoidable and that 80-85% are repeated in the industry⁽¹⁾. I think that both of those numbers are low from a FEMI perspective, as my 46 years of FEMI experience in the industry indicates to me that about 99% of FEMI incidents are avoidable and that over 95% are repeated. When I page through API RP 571, I can think of numerous FEMI failures for nearly every one of the 67 damage mechanisms covered⁽²⁾. I also have well over a hundred FEMI LFI reports in my personal files, many of which are repeats. Hence, it is my somewhat biased opinion that if operating sites would rigorously apply the entire contents of our API FEMI codes and standards, as well as the information contained in each of the 101 EEs, that we could cut the number of FEMI incidents in the process industries by a prodigious percentage.

In the words of the immortal Martin Luther King, “*I have a dream*”. My dream is that someday a major SDO like the API or CCPS will create a LFI searchable database of anonymous FEMI incidents that all operating sites could access to quickly and easily learn from the plethora of FEMI incidents that have occurred and continue to occur.

One last specific LFI issue has to do with the installation of pollution control equipment. It seems that not a year goes by when I do not hear of one or two explosions/fires/incidents associated with the installation of pollution control equipment to eliminate or control vapor emissions. Several carbon canisters designed to control emissions from storage tanks have exploded. At one company, efforts to seal the top of an API separator resulted in an explosion due to a volatile mixture contacting a non-explosion proof device. At another site, a detonation occurred in an electrostatic precipitator, which shut down a FCCU for well over a month. The list goes on and on. While we surely must obey environmental laws and improve our carbon foot print, we must not create process safety hazards/incidents in the name of making environmental improvements. In this case, the industry was slow to learn from these incidents.

How well does your operating site learn from past FEMI incidents in the industry? Does your company keep an easily searchable database of such incidents?

References

1. *Safety Management: A Comprehensive Approach to Developing a Sustainable System*, Boca Raton, FL, CRC Press, 2012.
2. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, Second Edition, American Petroleum Institute, Washington, D.C., April, 2011.

FEMI Networking

FEMI networks (both intra- and inter-company) are vital to the efficiency and effectiveness of the discipline⁽¹⁾. Collaborative FEMI networks are one of the best ways I know of to share and capture FEMI knowledge/best practices for all to use and apply. Within companies (intra-company), FEMI networks can document and share multiple best practices for use at all company sites. The efficiency of intra-company FEMI networks is enormous when you consider the cost and resources that would need to be consumed if all operating sites within a company had to solve their own FEMI problems and create their own best practices/standards. Within the industry (inter-company), networks at SDOs such as API, ASME, and NACE create industry codes, standards and recommended practices by combining the knowledge of FEMI SMEs from the entire industry (See separate EE on codes and standards). In addition to the value of documents created by such networks, the regular sharing of information and trouble-shooting inquires between members of networks within their FEMI communities often results in “quick wins” that would not be possible by one person working without input from other FEMI SMEs. Networks are also the best way to learn from incidents (see separate EE) that occur outside the boundaries of any one operating site. Plus there is a cost efficiency of shared resources (e.g. one site may have a welding SME; another site may have a refractory SME; another site may have a coatings/linings SME; another site may have a corrosion/materials SME, another site may have an NDE SME; etc.), all of which could participate in the same FEMI network. Another soft benefit of FEMI networks is that for a few hours per month or quarter, it allows individual contributors to escape from the daily grind and focus on the big picture of FEMI issues, thus enhancing his/her overall knowledge base and contribution to the business.

One of the fallouts from industry downsizing, cost pressures, and mergers is that fewer knowledgeable people are available to participate on industry standardization committees (networks) to the point that we are now reaching a participation crisis point in some of our technical societies. When we do not participate and our industry standards committees begin to become dominated by manufacturers, suppliers, regulators, and other industries, we end up with standards that do not adequately represent the interests of the process and production industry. Each time an oil or chemical company merged with another, the industry FEMI network lost the participation of another member. On many ASTM committees, our industry has little or no representation, which has led to domination by manufacturers and others that do not have our interests in mind. As a result, we get specifications that meet the needs and desires of manufacturers and not users. One good example of that are steel flange specifications that allow carbon contents to be so high, that they are virtually un-weldable under normal circumstances. At the API, where we have many standards committees under the umbrella of the Committee on Refinery Equipment (CRE), progress on the development and revision of many of our standards has been significantly slowed by inadequate owner-user participation. Since we all benefit by having high quality, reasonable, cost-effective FEMI standards (RAGAGEP) to guide us, all of our companies lose out by not supporting these industry standards committees (i.e. networks).

Does your company create and support FEMI networks? Does your company depend upon high quality industry codes/standards, and if so, does your company support your participation on these standards committees?

References

1. *Process Safety Management – Leveraging Network and Communities of Practice for Continuous Improvement*, Lutchman, Evans, Maharaj, and Sharma, CRC Press, June, 2013.
2. [The Role of Industry Codes and Standards in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, July/Aug, 2011.



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If we are going to be assured that all aspects of our FEMI programs are functioning efficiently and effectively, it is vital that we periodically assess (review in detail) each of the 101 essential elements to determine the health of the entire FEMI program. Such an AIM Review should be conducted by experienced, knowledgeable FEMI SMEs. They can come from other sites in the same company or from engineering service companies that have such SMEs on staff. Some large operating companies have created these types of FEMI reviews in-house and conduct them periodically at each of their operating sites. Additionally, some engineering support companies have created a protocol for AIM reviews of operating sites. Following the big plant incident in Texas City in 2005, API and AFPM have created a program called the Process Safety Site Assessment Program (PSSAP), which includes a FEMI protocol, among other key process safety protocols such as MOC, facility siting, operating procedures, etc. Each PSSAP conducted at an operating site includes two FEMI SMEs on each team to assess the strengths and make observations (e.g. opportunities for improvement) of operating site FEMI programs. The FEMI protocol was put assembled by numerous FEMI SMEs from operating sites and includes the majority of the 101 EEs of PEIM. I have participated in most of the PSSAPs conducted to date and can attest to the value of the final report in helping operating sites identify their opportunities for improvement of FEMI issues.

Whether you conduct such FEMI AIM reviews with your own people or hire a third party to conduct them for you, here is a bit of advice. Make sure they are conducted by FEMI SMEs with long experience in the oil and petrochemical industry. In conducting such reviews, I have had the opportunity to read numerous other AIM review reports that have been previously conducted at operating sites and found most of them that were conducted by so-called “process safety specialists” i.e. non-FEMI SMEs, were not worth the paper they were written on. Knowledgeable and experienced FEMI personnel (SMEs) are crucial to the process because they know how to interpret an answer when they hear it and ask the right follow-on questions and know when an answer does “not seem quite right”; whereas a trained auditor who is not a FEMI SME will only be able to ask the question on the script and record the answers, without really understanding where and how to “deep dive” into an issue or when to explore an issue a bit further to get “all the pertinent information”. As such, nearly all the AIM technical reviews that I have read that were not conducted by FEMI SMEs contain little value in helping the operating sites may real improvements in their FEMI programs.

Conducting FEMI/AIM reviews is one of the most important elements for making continuous improvements in FEMI programs at operating sites. These FEMI technical reviews are what used to be called “audits”; but unfortunately the word “auditing” has recently become associated with more negative connotations like someone with stereotyped IRS characteristics coming into your facility and “beating you about the head and shoulders” because you are doing things “wrong”. Additionally, audits also have the connotation of looking primarily for “compliance”, whereas AIM technical reviews are primarily focused on looking for ways to improve performance. Over my 46 years of experience with technical reviews, I have witnessed great strides in improved performance by operating sites that have implemented effective internal, second party and third party AIM reviews.

By way of explanation, internal audits are those that are conducted by people at the same site on their own FEMI procedures and practices (sometimes called first party reviews). Second party reviews would be those conducted by people from the same company, but from different sites or from company headquarters. Whereas third party FEMI reviews would be those conducted by an independent company or outside consultants. Whoever conducts them, it’s crucial that such PEI&R audits are conducted by very knowledgeable and experienced FEMI SMEs following an objective structured process with a protocol of specific questions and issues to be explored and reviewed.

Does your site conduct periodic internal FEMI reviews, as well as receive the benefits of second and third party FEMI reviews in an effort to find ways to improve upon your FEMI management systems and their implementation?

References

1. [Measuring the Effectiveness of the Pressure Equipment Integrity Management Process](#), John Reynolds, Inspectioneering Journal, Sept/Oct & Nov/Dec, 1998.
2. [The Role of Continuous Improvement in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John Reynolds, Inspectioneering Journal, July/Aug, 2012.

FEMI Key Performance Indicators (KPIs)/Metrics

It has been said that “you can’t improve what you don’t measure.” There is some truth to that, though I also know that competent, knowledgeable FEMI SMEs can make lots of improvements to FEMI methods and processes without KPIs. At the same time, it is important to measure and track some FEMI KPIs. The key to success with KPIs is to choose the proper metrics to measure and make sure the chosen metrics produce useful information that can lead to improvements. Too often we have FEMI metrics because someone in management says we have to have them, so we create them to keep management happy, even though many of our metrics end up being a waste of time and resources. I am a big fan of measuring the cost of FEMI programs, as well as the cost of failures because of inadequate FEMI programs, and then comparing the two metrics. One without the other can lead to misleading directives from management. Unfortunately, we have no good way of credibly measuring the cost of all of the FEMI incidents that are avoided because of a lack of excellence in FEMI (i.e. you cannot prove a negative). If we did, management would probably swamp us with resources to improve our FEMI programs.

Another FEMI metric that I like is FEMI “saves,” which counts the number of unexpected finds made by inspection groups that end up avoiding lost production opportunities (LPO) (i.e. shutdowns and slow-downs), as well as avoiding potential process safety incidents. For example, an inspector performing routine profile radiography or UT scanning on a hydroprocess REAC header finds a 4 inch spot of highly localized corrosion from ammonium bisulfide salts that would have ruptured the header if gone undetected much longer. Or another inspector finds HTHA cracking on a carbon steel flange weld by using AUBT pursuant to the API warning that the carbon steel curve in API RP 941 may no longer be valid for all cases. Or another inspector finds highly localized CUI on the bottom of a column that is near penetration and could have dumped the column had the CUI gone to full penetration. All sites have dozens of examples of these “near-miss” finds. If we track them and attempt to put a value on the LPO and other consequential costs of a potential incident, we can continue to show management the value of our FEMI programs.

Also important is that the data needed to satisfy the metrics has to be readily available and easily tracked in some software system. The time for manual data collection has passed. If you cannot collect the necessary data for your FEMI metric with the click of a few buttons, then create the software and/or databases to do it for you before you issue the metric. Moreover, be careful with what you measure. Some metrics can end up working against you when it comes to the quality of results. For instance, if you have a metric for the number of units with RBI implemented, you could end up satisfying the metric while doing a poor job of implementing RBI just to show progress in your RBI program. The metric needs to read something more like, “the number of process units with RBI fully implemented” (meaning the implementation meets a detailed specification on what it means to have a quality RBI program actually “fully implemented”). I have seen too many FEMI metrics that became the goal in themselves (i.e. “make the quarterly metrics look good”), rather than the quality of the FEMI issue that was being measured. Do not fall into that trap.

Of course it is important to evaluate our metrics and react to what they are telling us by setting goals for such things as reducing leaks in buried piping, improving our NDE productivity, improving our cooling water treatment to extend bundle service lives, increasing the amount of non-invasive inspections where appropriate, reducing the number of CUI leaks, completing the number of process units with an intensive review of IOWs, reducing leaks at pipe support points, reducing the number of overdue inspections on storage tanks, etc.

Anyone creating and sustaining FEMI metrics/KPIs should be fully apprised of and coordinate with the site implementation program for meeting the requirements and recommended practices of API RP 754(1).

Do you have an effective set of FEMI metrics that are recorded and tracked from which you set goals for making improvements in FEMI?

References

1. API RP 754, *Process Safety Performance Indicators for the Petroleum and Petrochemical Industry*, 1st edition, April 2010, American Petroleum Institute, Washington D.C.

Overdue Equipment and Inspection Recommendations

There should be a policy in place and enforced by management at each operating site of not allowing equipment and repair recommendations to become overdue for inspection and handling. Such a practice goes a long way toward increasing the credibility of the inspection efforts at each operating site, as well sending the message that FEMI is just as important as other plant priorities. Of course, in order to get to that point, inspection scheduling, data quality, data analysis, and record keeping (see separate EEs) have to be of sufficient quality and credibility, that ignoring inspection schedules actually increases risk, as well as putting the operating site in violation of codes and standards and potential jurisdictional regulations.

At the same time, fixed equipment and inspection recommendations that, for some valid reason, cannot be inspected or completed by their due dates can sometimes be deferred by using a valid risk-based deferral process. My experience indicates that a structured risk assessment for potential deferrals of scheduled inspections is far better than the old ways that involved either (1) someone in inspection drawing an arbitrary “line in the sand” and saying “Absolutely no deferrals”, or 2) someone else in the organization just making arbitrary decisions (without inspection involvement or approval) that a scheduled inspection or inspection recommendation will simply be allowed to become overdue without understanding the risks associated with such arbitrary “hand waiving” of the due dates. In my experience, the work process for deferring equipment inspections and/or inspection repair recommendations should be rigorous, well documented, risk-based and not be so simple and easy that the site ends up with such a long list of deferrals that the process becomes nearly equivalent to just letting equipment and/or inspection recommendations become overdue. A best practice for such deferrals is to require the approval of a site senior manager before equipment or inspection recommendations are allowed to be deferred. That level of approval will usually keep the process from being abused.

Such a deferral process is currently in effect at many operating sites and has now been approved by the API Inspection Subcommittee and will be part of the next editions for API 510⁽¹⁾ and 570⁽²⁾. The following is some quoted material from the approved 10th edition (publication pending) of API 510. Definitions:

- “*Overdue inspections*: Inspections for in-service vessels that are still in operation, that have not been performed by their due dates documented in the inspection plan, which have not been deferred by a documented deferral process.”
- “*Overdue inspection recommendations*: Recommendations for repair or other mechanical integrity purposes for vessels that are still in operation that have not been completed by their documented due dates, which have not been deferred by a documented deferral process.”

In the body of the 10th edition of the API 510 Code, the deferral process is addressed this way: [Quote]

“Inspection tasks for equipment and PRDs (not set by RBI) that cannot be performed by their due date can be risk-assessed and deferred for a specific period of time, where appropriate. A deferral procedure shall be in place that defines a risk-based deferral process, including a corrective action plan and deferral date, plus necessary approvals, if inspection of a piece of pressure equipment is to be deferred beyond the established interval. That procedure should include: (1) concurrence with the appropriate pressure equipment personnel including the inspector and appropriate owner/user management representative, (2) any required operating controls needed to make the extended run, (3) need for appropriate non-intrusive inspection with NDE, if any, as needed to justify the temporary extension, and (4) proper documentation of the deferral in the equipment records.

Notwithstanding the above, an inspection or PRD servicing interval may be deferred by the Inspector, without other approvals, based on a satisfactory review of the equipment history and appropriate risk-analysis, when the period of time for which the item is to be deferred does not exceed 10 percent of the inspection/servicing interval or six months, whichever is less.

For equipment with risk based inspection intervals, the existing risk assessment should be updated to determine the change in risk that may exist by not doing the originally planned inspection. A similar approval process used for equipment with non-RBI intervals should be used to document the change in risk levels.

Deferrals need to be completed and documented before the equipment is operated past the scheduled inspection

due date; and owner/user management apprised of the increased risk (if any) of temporarily operating past the scheduled inspection due date. Pressure equipment operated beyond the inspection due date without a documented and approved deferral is not permitted by this code. The deferral of scheduled inspections should be the occasional exception not a frequent occurrence.” [End quote]

With regard to deferrals of inspection repair recommendations, the body of the API 510 Code deferral process is addressed this way: [Quote]

“Inspection repair recommendations that cannot be completed by their due date can be deferred for a specific period of time, if appropriate, by a documented change in date of required completion. The deferral of the due date shall be documented in the inspection records and have the concurrence with the appropriate pressure equipment inspection personnel including the inspector and the inspection supervisor. Inspection recommendations that have not been completed by the required due date without a documented and approved change of date are not permitted by this code and are considered overdue for completion. The deferral of inspection recommendations should be the occasional exception not a frequent occurrence. Equipment must remain within the limits of the minimum required thickness as determined in this Code or by other engineering evaluation during the period of deferral.” [End quote]

And finally with regard to reviewing and potentially changing of inspection repair recommendations, the body of the API 510 Code addresses the issue this way: [Quote]

“Inspector recommendations can be changed or deleted after review by pressure vessel engineer or inspection supervision. If that is the case, inspection records shall record the reasoning, date of change/deletion and name of person who did the review.” [End quote]

Do you keep your management informed of equipment that is overdue for inspection? Does your plant management practice a strict “no overdue” equipment policy? Does your site have a structured deferral process for equipment and/or inspection recommendations that may become overdue that is at least as good as the new sections that will be in the 10th edition of API 510?

References

1. API 510 Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair and Alteration, 9th edition, June 2006 (10th edition approved and publication pending).
2. API 570 Piping Inspection Code: In-Service Inspection, Rating, Repair and Alteration of Piping Systems, 3rd edition, November 2009 (4th edition in balloting as of 2/Q/2014).

FEMI Resources and Staffing

Clearly, without adequate resources being budgeted to the FEMI function by site management, the necessary run-and-maintain FEMI work may not be adequately covered and little progress toward improvement and achieving FEMI excellence can be made. An annual work process at each operating site needs to be in place to adequately plan for the necessary FEMI resources for the following annual cycle. I actually prefer to have both a detailed annual plan and a five year forecasted line-item plan for FEMI budgets, which are updated each year in preparation for next year’s budget request.

The FEMI function needs to be heavily involved in the FEMI budget planning process. Do not assume that those who “hold the bag of gold” will take care of your FEMI needs⁽ⁱ⁾. Be proactive in the budgeting process by planning for your routine run-and-maintain FEMI needs, as well as the resources that will be needed to make improvements in the FEMI program and to implement special emphasis programs (see separate EE) the following year. Then those budget needs should be passed along to those responsible for the various budgets that support FEMI activities, such as: the MI manager who is responsible for the FEMI staff and FEMI contractors, the maintenance manager who is responsible for all the costs associated with maintenance support functions such as scaffolding, opening, and cleaning equipment for inspection, and the turnaround manager who is responsible for all the costs associated with implementing a turnaround where so much vital FEMI work gets done. Then there is a little salesmanship associated with each budget submittal, which entails letting the responsible manager know why each budget line item is needed and what might happen to FEMI if it is not adequately funded (i.e. the downside of deleting the item from the budget).

In order to be truly effective at monitoring and/or mitigating all 101 FEMI EEs, each hydrocarbon and petrochemical processing facility needs to have adequate FEMI staff. In a previous litigation, a refining company lost a court case where inadequate inspection staffing was a key issue. In that case, an overhead receiver vessel thinned below its retirement thickness and ruptured, causing a large explosion and fire that severely injured three workers. The plaintiffs introduced evidence that other local refineries had significantly greater inspection staffing, when compared to the refinery in this court case.

I do not know the magic formula for determining the proper amount of inspection staffing. FEMI staffing numbers largely depend upon where a particular operating site is on the ladder of FEMI excellence. Those sites that do not have all of the 101 EEs of FEMI in place will likely need more FEMI resources in the short term in order to build the proper foundation for FEMI excellence. Those resources will probably include funding for specific catch-up activities, as well as inspectors and engineers to carry on the existing programs and improve upon those that need more attention. Operating sites with more corrosive, higher risk process units may need more FEMI resources, particularly if aging equipment has not been adequately maintained in the past. To augment in-house staffing, some capable, qualified, experienced contract resources may be necessary for a period of time (see separate EE). Those few operating sites left with relatively non-corrosive, lower risk process fluids may need fewer FEMI resources. One good way to determine whether you may need more resources to improve your FEMI program is for your site to sign up for the Process Safety Site Assessment Program (PSSAP), administered by the API in conjunction with AFPM. A FEMI assessment protocol is a primary focus of the PSSAP.

Are you sufficiently involved in the FEMI resource budgeting process and does your management provide the necessary resources to complete the planned FEMI activities and agreed upon improvement goals each year? Have you outlined all of the resources that will be needed to build your foundation of FEMI excellence, and have you put together a justification memo for management action? Are all of the FEMI slots filled in your target organization?

References

1. [How to Improve Your Fixed Equipment Mechanical Integrity Program by Managing Your Manager\(s\)](#), John Reynolds, Inspectioneering Journal, July/Aug 2013.

Inspection Service Contracting

Nearly all sites are dependent upon the services of third party contractors for additional inspectors and NDE technicians. Some operating sites will have a core group assisting their FEMI department over the longer term, taking data and conducting routine inspections to supplement their resource limited staff; while other sites will bring in contract inspection services for peak loading for project work, special emphasis inspection programs and turnaround staffing. Most sites do both. A best practice is to have documented requirements and expectations for all contract staff and a documented work practice indicating how the entire inspection service contracting process is to be handled.

Why is this important? I have seen sites where these documented work practices and requirements worked well to obtain and receive the inspection services needed. I have also seen other cases where inspection contractors were summarily dismissed toward the end of a TAR for cost control reasons, and the site later realized they had little documentation of all of the inspections and QA/QC that were supposedly completed by inspection service contractors during the TAR. Imagine having to deal with that situation when planning the next inspections. Outside of the usual safety training and company policy information that all contractors have to receive, some of the best practices for inspection service contracting work practices that I have seen contain topics like:

- The need for CVs for key inspection personnel detailing work experience, training, and required qualifications and certifications,
- The type and amount of orientation to site FEMI practices and procedures that contract inspection service personnel will need to be exposed to prior to any field work,
- The inspection histories and plans that contract inspectors will need to review prior conducting inspections,
- OJT and orientation, if necessary, prior to starting work,
- Report writing and submitting requirements, timing and what needs to be submitted to whom before leaving the site,
- Who will be responsible for ensuring that all requirements are met prior to contract service personnel being released from the site, and
- What all is included in a complete contract inspection job.

On the other side of the ledger is the need for contract service companies to be very clear (to the extent possible) as to what specific services they will be contracted to perform, and possibly, what services they will not be performing unless a contract change order is authorized. For example, if the contract inspection company is providing an experienced API certified inspector to be responsible for all of the inspector duties and responsibilities within a certain area of the site that are listed in the inspection codes (e.g. API 510/570/653) – that is one type of all encompassing inspection service contract. On the other hand, if the certified inspector is being hired to only perform certain tasks and report the results to an owner-user representative, that may be an entirely different type of contract that should have more limited liability. It pays to be very clear on both sides of the contracting process who is going to do what, where, when and how.

Do you have a documented management system for contracting with inspection service providers that lists all of the requirements and expectations for contract service personnel qualifications and work they will be responsible for while they are on site?

FEMI Training and Certification

One of the most important aspects of an effective FEMI program is the quality of training and skills of the FEMI inspectors. Unlike some other inspection/technical disciplines like electrical, rotating equipment, and instrumentation, most FEMI inspectors come into their jobs with little technical knowledge about FEMI issues. Some advance into the position after a successful career as an NDE technician, some come from a welding background, some were pipefitters, others were operators; whereas electrical inspectors nearly always come from having been an electrician and rotating equipment inspectors were often previously pump mechanics, etc. But 90% of what the typical FEMI inspector needs to learn, he/she has to learn on the job after becoming a FEMI inspector. This on-the-job experience is an important aspect of inspector development, but it cannot be relied upon to produce the entire body of knowledge necessary for competent process unit inspectors. There is a large body of knowledge for FEMI technical training that each inspector needs, including both classroom training and on-the-job training (OJT).

Classroom FEMI courses cover the entire range of necessary technical knowledge for inspectors, including: corrosion and materials, welding inspection, vessel and piping inspection, heat transfer equipment inspection, surface and volumetric NDE techniques, radiographic film interpretation (both profile and weld quality), in-service API inspection codes and standards, advanced NDE techniques, thickness measurement techniques, storage tank inspection, PRV servicing, etc. The list is long. Many companies have some of these courses available internally; but for those who do not, most of these subjects are covered in commercially available courses and are necessary to enhance the knowledge base of competent inspectors. Some two-year technical colleges offer programs/courses to teach a wealth of FEMI knowledge. Each classroom course should preferably be accompanied by an examination at the end in order to confirm the necessary knowledge transfer. Do not make the mistake of believing that if you send your inspectors to take exam prep courses for API 510/570/653 certifications, they will gain all the knowledge they need to become a competent inspector. Many of those courses teach the minimum knowledge required to pass the exam and become certified. Competent inspectors need significantly more FEMI technical knowledge than they could possibly receive in a one week exam prep course.

On-the-job training should be organized and systematic. The best programs will have an outline of all the field exposure to FEMI tasks that an inspector needs to have prior to becoming a stand-alone inspector. For example, there should be a list of all the tank inspection issues that a new tank inspector should experience under the mentorship of an experienced tank inspector, including such issues as internal and on-stream inspection techniques, tank bottom NDE techniques for floor plates, sumps and the critical zone, shell inspection techniques, roof inspection techniques, tank vent device inspection and servicing, roof rafter and structural support inspection, potential for pyrophoric materials being present, door sheet cutting and replacement, tank bottom linings, and a host of other tank inspection knowledge. As each OJT aspect is completed, the outline would be initialed by the mentor and trainee and placed in a training file for the new inspector. Such a systematic process and OJT outline should be in place for every kind of fixed equipment that the new inspector will be responsible for, including standard pressure vessels, weld overlayed reactors, columns, piping, relief devices, heaters/boilers, structural members, CUI/CUF, flare systems, etc.

One other vital aspect of FEMI knowledge transfer is training on all site procedures and work practices that involve FEMI. It does little good to have excellent, extensive, documented work practices and procedures if the inspectors are not trained on them, including refresher training when revisions are issued. The best way I know to do this is every time a new or revised procedure is issued, someone in the FEMI group is assigned to lead a group discussion highlighting all of the new information and refreshing everyone on the existing information. Another practice I support is having each inspector sign off that he/she read/understands the information in each FEMI procedure.

Do all the FEMI personnel at your site have the appropriate amount of training on FEMI technical knowledge and skills to function effectively in their jobs to help keep your equipment safe and reliable?

FEMI Competency Improvement

This EE is closely related to FEMI Inspector Training (see separate EE) which covers three of the most important types of inspector training (classroom training, OJT, and FEMI procedures training). Inspection competency improvement program (CIP) is a method of organizing FEMI training for inspectors, as well as inspection support engineers, in order to achieve a higher level of knowledge, skills, performance, and therefore success on the job. If your company has a CIP then you probably know what it is all about. If not, you can create a CIP for yourself in order to achieve your professional goals in FEMI. Here is an example: let's say your company recognizes three levels of FEMI competency:

1. FEMI Awareness level (or trainee/entry level) where you get introduced to a lot of basic information in most the FEMI subject matter. It feels like drinking from a fire hose.
2. FEMI Stand Alone level where you have obtained enough competency and experience to do the normal job by yourself with limited supervision.
3. FEMI Advanced level where you have the competency and experience to outperform most of your colleagues, solve more difficult FEMI issues, develop FEMI programs, teach others, and work with little or no supervision.

Each of these three levels would then be defined in much more detail regarding how much training, knowledge, experience, skills, certifications, etc. is needed to achieve each level.

The next step in the FEMI CIP is to define the entire Body of Knowledge (BOK) necessary for you to have at each level. That technical BOK might consist of FEMI subject matter such as:

- corrosion and materials (C/M),
- corrosion control methods,
- welding inspection,
- vessel and piping inspection,
- heat transfer equipment inspection,
- atmospheric storage tank (AST) inspection,
- thickness measurement techniques,
- basic surface and volumetric NDE techniques,
- advanced NDE techniques,
- radiographic film interpretation (both profile and weld quality),
- in-service API inspection codes and standards,
- risk-based inspection (RBI)
- source/shop inspection,
- PRV servicing, and
- any of the other 101 EEs.

Take C/M for example. At level 1 you would be introduced to (and be amazed by) the many different types of construction materials in use in a process plant and start learning about the 67 different types of damage mechanisms that can occur(1). At level 2, you would know all of the different construction materials in use in your process unit, as well as their advantages and limitations and which damage mechanisms each might be exposed. Then at level 3, you would have studied for and passed the API RP 571 supplemental ICP exam and have a wide knowledge base of different types of construction materials for process plants, be able to knowledgeably select alloy upgrades when an existing material is not adequate, and have a significant level of C/M knowledge as defined in API 510/570 for a Corrosion Specialist, without being a full time C/M specialist. If your plant does not have a full-time C/M SME, you would be the “go-to” person until more specialized C/M knowledge is needed.

At any one point in time as you move up the FEMI competency ladder in each of the BOK subjects, you might be at different competency levels for the various subject matter. For instance, after five years on the job as a process unit inspector, you might be at level 2 for most of the FEMI technology subjects listed above, but perhaps be at level 3 in two or more of them and perhaps only level 1 for AST inspection. As another example, if you have been an AST inspector most of your career, you might be at level 3 in AST inspection, be at level 2 in cathodic protection and tank linings/coatings, but only be at level 1 in many of the

other FEMI subjects with which you have had little experience or exposure. Likewise, an inspector with AWS CWI and API 577 certification might be at level 3 in welding inspection and be the “go-to” expert for many other inspectors and FEMI support engineers for welding issues, but with that single focus, might only be at level 1 in many of the other FEMI subjects depending upon their background and experience. So as you see, at different points in your FEMI career you can and will be at different levels in the many different subject matters in the FEMI BOK.

Effective utilization of a FEMI CIP will lead to better FEMI training, better use of FEMI skills, better forecasting of FEMI employee development needs, and a better understanding of the gaps between existing FEMI competencies and business needs.

Do you have a FEMI competency improvement plan to achieve your ambitions? At what different levels do you consider yourself to be in the FEMI BOK? Are you moving up the competency improvement ladder at a rate that satisfies your professional goals/objectives?

References

1. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, 2nd Edition, American Petroleum Institute, Washington, D.C., April, 2011.

Inspector/NDE Certifications and Performance Testing

Just as inspector training (see separate EE) is important, so too is the certification of inspectors and NDE personnel. Federal rules for process safety management within the USA *imply* the necessity of such certification, and numerous companies have been cited for lack thereof during OSHA PSM audits. The reason that inspector certification is “implied” by the OSHA regulation is that the rule clearly indicates that operating sites need to comply with applicable industry standards. And since a site cannot be in compliance with API 510/570/653 without having their inspectors certified, then the rule implies that inspectors must be certified. Within the petroleum and petrochemical industry, the API conducts an Inspector Certification Program (ICP), which has turned out over 27,000 authorized inspectors worldwide for pressure vessels, piping systems and storage tanks. About 50% of those reside in the USA and 50% in the rest of the world. These certifications not only lend third party and jurisdictional credibility to your FEMI program, but also result in higher skill levels, because of the amount of training and knowledge necessary to pass these examinations. The exams are not easy to pass without studying the materials included in the body of knowledge (BOK) specified for each exam. Typically, about 50-60% of those taking the three basic certifications exams at any one time pass them.

Additionally, the API has three Supplemental Inspector Certification Programs (SCIP) through which FEMI personnel and inspectors can display their advanced knowledge of RBI (API 580), Welding Inspection (API 577), and Material/Corrosion issues (API 577). As of this writing, there are almost 800 certified to API 580, almost 500 certified to API 571 and over 200 certified to API 577.

Likewise, NDE personnel are expected to be certified for the NDE techniques that they employ at an operating site, which in the USA typically means certification to ASNT SNT TC-1A or CP-189 standards. One of the more important aspects of QA/QC in our FEMI programs is our need to use competent, qualified NDE examiners. How do we know if the persons taking our ultrasonic angle beam measurements for critical flaw detection and sizing are capable of doing the job using the right equipment? How do we know if the technicians conducting MFL floor scans on our tank floors are providing us with quality data in order to make decisions on the need for repair or replacement of tank bottoms? How do we know if thickness measurements taken by digital ultrasonics (DUTT) or profile radiography (PRT) are accurate enough to rely on for critical decisions on how long equipment will be fit for service?

There is a good way, and it has little to do with the “hocus pocus” of an NDE company simply “waiving a wand” and telling us their technicians are qualified because they followed some national standard for NDE level 2 qualification. One way is to pass a nationally administered NDE examination like that included in ASNT CP-189. Another way has to do with performance testing in real life situations in order to determine if the NDE technician can detect and/or size defects correctly. The API now has an effective UT flaw detection and sizing performance test. I am aware of some companies that also have an effective MFL tank bottom scanning performance test and DUT and PRT thickness measurement performance testing, as well as flaw sizing performance testing. These performance tests grade the technician in “real life” situations on their ability to find and size flaws in equipment, like the ones that exist in our operating sites. This performance testing is one of the newer thrusts in our business of qualification testing and a very important effort. I am hoping that it continues, so that we eventually have effective performance tests for most of our vital NDE techniques. In the past, I have seen a lot of “bad” data submitted by so-called “qualified” level 2 examiners that, at worst, could have led to premature failures, and at best, resulted in excessive inspections because of shorter than required inspection intervals.

Of course being certified by a third party organization is not the “be all – end all” of adequate performance on the job. When an inspector or NDE technician first becomes certified, they are typically just showing that they have the knowledge to become “entry level” personnel in our industry. In some cases, operating sites still need to have their own contracting procedures, experience requirements, performance testing, etc. to provide greater assurance that the inspectors and NDE technicians that they hire are competent and capable (see separate EE).

Are your inspectors not only trained and knowledgeable, but certified by a third party, such as the API, to indicate that they have the knowledge base required to accomplish the job expected of them? Are you confident you are employing truly qualified NDE technicians that are using quality procedures and effective tools to provide you with accurate NDE data on which you can make sound equipment integrity decisions?

Shared Ownership of Assets (SOA)

One of the most important aspects of FEMI excellence is to extend the “ownership” and/or “stewardship” of fixed equipment assets beyond the boundaries of those specifically charged with inspecting and maintaining them. That means convincing operations, maintenance and engineering colleagues that they also have an important FEMI role and duties (see separate EE on roles/responsibilities). Without that extension of “ownership” to other operating site functions, it is difficult to avert many otherwise avoidable FEMI failures and process safety events. Operators are especially important to the work process of protecting the integrity of fixed equipment assets. Operators and operating specialists need to be involved in outlining and setting limits for operating variables for all fixed equipment in order to make sure the equipment is always operated in a manner that does not accelerate corrosion/damage or introduce new damage mechanisms (see separate EE on IOWs). With a work process that involves operators, you will typically find they are enthusiastic, accepting and carefully attentive to those limits, especially when they find out what risk(s) may be imposed upon them if they do not operate within the established limits. You may also experience an increase in the vital communications between operators and inspection personnel that can lead to failure prevention through attention to early warning signs.

This SOA work process also involves assembling Corrosion Control Documents (CCD), including Integrity Operating Windows (IOW) (see separate EEs). When IOWs need to be changed, the FEMI MOC work process (see separate EE) is utilized. And when these CCDs are completed, the information in them is loaded into the RBI software (see separate EE) in order to generate a risk-based inspection plan that is both effective and efficient at the same time. As you can see, the SOA work process helps to pull all of the EEs and functional disciplines together, which is key to achieving the best results from your FEMI work process. Operating sites that have their departments “working in separate silos” focused mainly on their primary business function, will never achieve excellence in FEMI, which means continued leaks and process safety events.

One more important aspect of an SOA program is what I call “OEMI team meetings.” These periodic meetings are comprised of a team of Operations / Engineering / Maintenance / Inspection (OEMI) personnel in each process area that meet for the express purpose of sharing knowledge about issues that might affect FEMI in each process unit. Examples of such issues include: long-term and short-term FEMI issues, proposed changes in hardware or process, deviations from established IOWs, new threats to FEMI, the impact of planned projects on FEMI, turnaround planning issues that involve FEMI, the top 10 FEMI concerns for each process unit, etc. To be most effective, these teams should meet periodically and separately from other teams to establish FEMI action plans and review progress in each operating area. I say “separately” because if these team meetings are conjoined with the daily operations or maintenance meetings, then too often the importance of longer-term FEMI issues gets buried in the handling of the “hot rocks” of the day that involve production efficiency. In the best SOA environments, the operating managers are so vitally interested in FEMI that they are the ones that schedule the meetings and conduct them, rather than FEMI personnel having to “push the rope uphill.”

Typically the information that comes out of these OEMI meetings is used to update process unit CCDs, RBI plans, IOWs, and to bring together the information necessary to handle MOC issues associated with fixed equipment. One of the primary purposes of these OEMI meetings is to assess the risk of any changes (administrative, process and/or equipment) that might be occurring (or anticipated) in order to understand if the risk of a breach of containment could increase. Another benefit of the OEMI team meeting is FEMI knowledge transfer (see separate EE) from the FEMI SME’s to others on the OEMI team. To repeat a theme appearing throughout the 101 EE’s: we in the FEMI profession cannot do it alone when it comes to protecting and preserving FEMI. We need the eyes, ears and brains of operations, maintenance and engineering personnel to assist us in our FEMI endeavors.

And of course, it takes real management leadership⁽¹⁾ walking the FEMI talk to each of the stakeholders to reinforce the importance of their FEMI roles. In the best of SOA environments, the operating managers come to the FEMI personnel (including the corrosion/materials specialist) and ask them for their list of the top ten FEMI concerns in their operating area, and then they take that list and pursue resolutions for each of the risks within the OEMI team.

Is there a real multi-functional effort at your plant to work together, in a shared ownership environment, to prioritize and mitigate FEMI risks? Do you have the effective involvement and attitude of “real ownership” from your operators, maintenance personnel and process engineers in preserving and protecting your fixed equipment assets?

References

1. [Management Leadership and Support for PEI](#), John T. Reynolds, Inspectioneering Journal, Jan/Feb, 2010.

FEMI Knowledge Transfer

FEMI knowledge transfer is closely related to FEMI training, but is separated in this EE because it is not oriented toward FEMI personnel. Rather, it is what FEMI personnel should be doing for all others on site who have a role in maintaining fixed equipment integrity, such as operators, process engineers, project engineers, and maintenance craft personnel (see separate EE on Shared Ownership of Assets). Since many others at the site have a role in maintaining FEMI, they need some amount of awareness knowledge of FEMI issues in order to be able to function effectively as our extra set of “eyes and ears”. Surely they will not need the same level of knowledge as inspectors, inspection engineers, or C/M SMEs, but they will need enough to know what can go wrong if a FEMI issue, for which they may have some level of responsibility, is not handled properly.

For instance, the maintenance mechanic needs to know what could happen if he/she grabs a carbon steel fitting and installs it in a 5 Cr-.5Mo alloy piping system. An operator needs to know what could happen if he/she exceeds an established operating limit (integrity operating window) for some period of time. A process engineer needs to know what might happen to corrosion rates if he/she makes a small change in process conditions to improve yield. A project engineer would need to know what will likely happen if he/she deletes the CUI coating specified to be installed under vessel insulation in order to control costs on the project. These folks are on the “front lines” of our battle to resist unexpected degradation and surprise failures, so they need to know what can go wrong if they make a mistake or see something that they should bring to our attention. I could go on and on with hundreds of examples of what FEMI knowledge about potential equipment damage mechanisms and FEMI issues that others may need to know in order to help protect the integrity of fixed equipment, but I am sure you get the idea. We cannot do the FEMI job alone.

It does little good to have highly knowledgeable engineers and inspectors, who know all about corrosion, cracking, embrittlement, and other forms of construction material degradation, if those on the front line do not have the minimum amount of information that will help the plant avoid hazardous incidents. Often, small deviations or errors in work processes do not cause immediate or obvious degradation problems, so our front line workers sometimes assume that these “small” deviations do not matter because they have no impact. It is really a joy to involve operators and maintenance workers in this type of knowledge transfer and watch their initial reactions of suspicion and resistance turn into enthusiasm and eagerness to learn, as they realize that we want to help them keep their process units safe for them as well.

And do not forget about operating, engineering, and maintenance managers and supervisors. Many of them have no idea what the full scope of our FEMI jobs entail. Some are tempted to “run and hide” when they see us coming because they may view us as “bearers of bad news” who primarily cost them money or slow the progress of their efforts. They too need to be enlightened about what happens when equipment fails and what can make it fail. Every chance I get, I speak to managers and supervisors about lessons learned from process safety incidents that are caused by FEMI failures. Insurance industry statistics continue to show that FEMI failures are still the leading cause of large losses in the industry.

Do others at your site that have a FEMI role (operators, maintenance, and engineering personnel) have all of the FEMI knowledge that they need in order to help protect equipment from unexpected or accelerated deterioration? Do your operators know what aspects of their jobs can cause equipment to degrade faster than expected, or cause other surprise failures that might lead to hazardous releases?

FEMI Roles/Responsibilities

Clearly defined FEMI roles and responsibilities is another key EE; yet to some readers it will seem so mundane that they will be tempted to skip over it completely. I have seen some very detailed, very explicit, high quality, documented role descriptions for FEMI personnel, which is as it should be. That way, everyone clearly understands everything they are responsible for. Two full pages for a well documented role description are not uncommon. I have also seen some very general, very brief role descriptions that were not worth the paper on which they were written. Some said little more than “go forth and do good in FEMI” and do whatever else the boss says to do. Others had all the good stuff that HR and the Safety Department personnel like to see in everybody’s role description, but had woefully inadequate FEMI technical content. The technical content of a good quality role description would be full of one-liners from the entire 101 EEs which would show to all interested stakeholders at the site how much territory you cover. If you do not have an in-depth role description, how does your boss or other stakeholders really know all the important FEMI tasks that you do for the site?

Every different type of FEMI job needs an explicit, detailed role description (meaning a junior inspector might have one role and a senior inspector might have a much more extensive role, including one to act as a mentor for junior inspectors). This is also true for inspection support personnel like corrosion/materials engineers, FEMI engineers, FEMI specialists, inspection supervisors, inspection managers, etc.

In the best performing organizations, everyone in the plant who has a role in keeping equipment safe (i.e. a role in maintaining FEMI) would have their FEMI responsibilities spelled out in their role descriptions. Once again, those of us with full time roles in inspection and FEMI technologies need to help the operations, maintenance, and engineering folks understand what their expected FEMI roles are and why they are important (see separate EE on Shared Ownership of Assets). Those roles should include such things as operating within the established Integrity Operating Windows (IOWs), conducting and implementing MOCs associated with FEMI, communicating process upsets, welding QC by maintenance, equipment installation and repair, receiving, project QA/QC, and dozens more specific roles. As I have said many times, those of us with full-time FEMI roles cannot accomplish FEMI alone. We need a lot of help from other operating, maintenance, and engineering personnel to operate and maintain fixed equipment in a safe and reliable manner.

As I travel around from site to site doing FEMI assessments on operating plants, I am amazed at the difference in actual roles that various managements have set up for their inspectors. It varies on one end of the spectrum from a highly technical, engineering assistant type of role of a well-trained, knowledgeable API inspector, as described throughout the API codes and standards, to the other end of the spectrum, where the “inspectors” are simply what I call “go-fers.” Go-fers make physical inspections and measurements, and then bring the data/information back to FEMI engineers who then make recommendations/decisions for repair, replacement, and/or maintenance. Some other “inspectors” are simply doing QA/QC for construction and repairs, instead of being involved in the full spectrum of inspection duties including: understanding the process environment, damage mechanisms and corrosion mitigation aspects of their assigned process unit, doing the inspection planning, risk-analysis, scheduling, interpreting NDE results, making recommendations for repairs and other improvements, reacting to process changes, doing follow up QA/QC, investigating leaks, learning from incidents, record keeping, etc.

While there are a multitude of inspector duties and responsibilities described throughout all 101 EEs, as well as in the many API codes and standards, I will single out just one to cover in this EE: field surveillance. By field surveillance I mean “walking (and climbing) around” in their assigned process units, looking for FEMI issues (using their head full of FEMI knowledge), and talking with (and enlightening) operators and maintenance workers about their FEMI concerns or what they are looking for. Since inspectors cannot be everywhere, I am a strong believer that operators and maintenance personnel should be trained to be “our extra pair of eyes and ears” in the field.

The amount of field surveillance time needed has long been a controversial issue, but even more so now with our dependence on computerized record keeping (see separate EE on IDMS) and electronic communications. Clearly inspectors cannot be totally effective if they lose contact with their equipment and with those “on the front lines” by staying glued to their computer screens. And vice versa, having inspectors

spend too much time wandering around in the process unit is not a very effective use of their professional skills and time either. I recognize that some inspectors need to be encouraged to leave their computer station and get out in the field, while others need to be encouraged to come back to their office to do more effective record keeping and data analysis. Neither extreme will result in a completely effective inspector. So some reasonable compromise is necessary. I am not sure that there is any magic formula to answer the quandary, but if pressed, I would estimate that 10-15% of each week is a reasonable minimum target for field surveillance activities, though some jobs may require more.

I also believe that field surveillance activities should be reasonably structured and purposeful. For example, scheduled API 510 or 570 external inspections are effective field surveillance activities, as well as shop visits for specific QA/QC activities on equipment being replaced or repaired. Other field surveillance activities include looking for various issues like hot spots on furnace tubes, weep holes in lined pipe and on re-pads, stains that may indicate a low level of leakage, bolting corrosion, signs of insulation disturbed by CUI, significant external corrosion, sweating lines, vibrating and poorly supported piping, and cracked fire-proofing that may indicate CUF. There are an infinite number of things that the trained FEMI eye can spot during purposeful field surveillance. How many more can you think of?

What is the quality level of FEMI role descriptions at your site and does everyone with some FEMI responsibilities have them included in their role description? Do the inspectors at your site have the right combination of field surveillance and office work to maximize their effectiveness on the job, and are their field surveillance activities structured and purposeful?

Grey Zone Equipment

“Grey zone” equipment is that equipment which sometimes falls between functional disciplines and thereby does not always have a person responsible for making sure it is designed, fabricated, inspected, and maintained in a manner that will not impact plant reliability and process safety. As a result, this type of equipment sometimes fails unexpectedly, causes an unscheduled outage, or worse, a process safety incident. Most people in the plant know who has the primary responsibility for inspection and maintenance of pressure vessels, piping, exchangers, storage tanks, relief valves, etc. That is clearly the FEMI discipline. But what about other types of equipment, such as: thermowells, level bridges, filters, control valves, pump cases, critical check valves, cathodic protection systems, cooling towers, sewers, structural steel, process hoses, plastic utility pipe, sample cylinders, full flow instrument check valves, furnace burners, stack dampers, gaskets, functionality of column internals, etc.? This is the type of equipment that sometimes falls in the grey zone (or twilight zone).

Failure of such equipment often catches management by surprise, and produces a lot of finger pointing between the functional disciplines because no one had been designated as responsible for the equipment’s integrity and reliability. I am aware of several examples of such failures, all of which were unexpected and rather costly (mostly because the failure caused an unscheduled process outage). One example involved the failure of a thermowell right after a successful TAR and startup. The thermowell had a small leak and started spraying flammable product out of the side of the tower. The FEMI discipline thought the instrument people were responsible for thermowells since it was a temperature measuring device. The instrument people thought the FEMI people were responsible for it since the thermocouple was protected by a special piece of pipe. I am also aware of a cooling tower that collapsed in the middle of a process run because there was not a clearly designated function responsible for its integrity. I will not bore you with a dozen more examples, as I am sure you get the picture.

All the foregoing equipment examples have an interface with the FEMI function. So it is imperative that we get out of our silos and make sure that someone is the designated party responsible for important aspects of each of these pieces of equipment, be it design, fabrication, quality assurance, inspection, or maintenance. And it does not always have to be the same party for each aspect of the equipment life cycle. A best practice for an operating site is to have a document that lists all process and utility equipment at the site, and then in adjacent columns, lists which functional discipline is responsible for each phase of the life cycle of equipment (e.g. design, fabrication, inspection and maintenance). In one of the operating sites where I used to work, there were over 100 different pieces of grey zone equipment that had documented roles and responsibilities for integrity maintenance, which put an end to the finger pointing that ensues when a orphaned piece of equipment fails and shuts down a process unit.

Do you know if there is process equipment at your operating site that falls into the grey zone? Is there a designated person or function responsible for each aspect of the life cycle of that equipment to make sure it does not “fall between the cracks”?

Equipment Functionality Inspections

Early on in my FEMI career, I discovered there was a considerable gap between what process engineering folks wanted from internal vessel inspections and what FEMI personnel needed to do. FEMI personnel, as all my readers know, were looking for damage and corrosion that could affect equipment integrity. But operating and process folks were more interested in those issues that could affect operability, functionality, and reliability of pressure vessels to meet the business plan. Seemingly small changes or problems with vessel/column internals, trays and distributor hardware can have a large effect on column performance, especially with some of the newer designs. Though I have also been in some columns during a TAR when we found most of the trays in the bottom and operations had no idea.

Hence, we need to close that gap between what FEMI folks are looking for and what is important to process folks. There two ways to do that: either train the inspector to look for all of the process sensitive issues, or have a process engineer for the unit also involved in internal inspections to look for the issues of concern for operability and reliability. In an effort to close that gap, I have put together a checklist for the inspection of vessel and column internals that includes items like:

- Operability cleanliness, which is sometimes different from the cleanliness needed for adequate FEMI inspections;
- Tray valves and bubble caps all in place and attached properly with the correct tolerances;
- Tray valves that travel freely and are properly secured;
- Coke or other fouling material on tray valves that could affect operability;
- Tray decks reasonably level and free of bulges that might have been caused by column upsets;
- Downcomer clearances and weir height tolerance still within spec;
- Seal pans being clean and free of debris;
- Demister pads being fouled or plugged and properly secured;
- Valve tray panels tightly secured to each other and chimney trays with correct size holes;
- Feed and reflux distributors solidly supported with correctly sized slots/perforations;
- Nozzles on spray headers all in place with proper size holes;
- Instrument tap cleanliness; and
- Vortex breaker cleanliness, thinning and properly secured.

These are just a few examples of operability issues to look for with regard to the inspection of column and vessel internals, in addition to all of the usual FEMI issues. The inspection plan for the operability of internals should be prepared by an experienced unit process engineer and perhaps conducted by the same person in conjunction with the FEMI inspection.

Who does the operability inspections for your vessel internals? Is that person adequately trained and knowledgeable in the issues that can affect vessel/column performance?

Inspection Checklists

One of the best practices which I find at some operating sites when I am involved in FEMI assessments is the preponderance of inspection checklists in use where FEMI tasks are repetitive and critical to process safety. And checklists are not only handy for repetitive tasks, but also for tasks that are not done very often. Additionally, checklists are very good training tools for new inspectors and for contract inspectors who have not been on site before and are not familiar with all of the issues you expect them to address. In my experience, if you hand a checklist to a contract inspector for something you need done during a TAR, you are much more likely to receive a job thoroughly completed that meets all of your expectations. Hence, I decided to make the use of FEMI checklists one of the 101 Essential Elements of an effective FEMI program. Clearly there are far more than just a 101 FEMI issues for us to remember as we go about our daily tasks. It is more like 1001+. Even for us experienced hands, who among us can remember all of the 37 potential issues we need to be looking for every time we make an external inspection of a vessel or piping systems? Or the 26 potential issues we need to be conscious of when surveying PRVs in the field? Or the 18 different issues we want a contractor to look for and do when he or she is assigned to the bundle pad during a TAR?

I have seen some thorough checklists in use at operating sites for the following FEMI activities:

- External inspections of PVs, piping systems, ASTs,
- Internal inspections of PVs, columns, fired heaters and HXs,
- Structural inspections,
- Refractory lined equipment,
- Bolting and gasketing quality checks before start up,
- Failure investigations,
- FEMI records auditing,
- On-the-job training outlines for new inspectors,
- Shop inspections for equipment under fabrication
- CCV inspections,
- HX bundle inspections, and
- Damage mechanisms to be considered for RBI planning and PHAs.

And I imagine you may have other useful checklists. I have also seen where inspection records are improved with the use of checklists, by reminding inspectors, especially new or contract inspectors, of all of the things they should be commenting upon when filing their reports⁽¹⁾. On the other hand, there is a downside to using checklists as the report itself, which has to be carefully managed. Checklists are not a substitute for writing thorough narratives about everything an inspector has observed. Some less effective inspectors like the opportunity to just check boxes rather than writing descriptive narratives.

Is your site making good use of inspection checklists to improve inspection thoroughness and quality? Do you have checklists for OJT for new inspectors to make sure they are exposed to every facet of each type of inspection activity?

References

1. [The Role of Record-Keeping and Data Management in Achieving Excellence in Pressure Equipment Integrity and Reliability](#), John T. Reynolds, Inspectioneering Journal, Jan/Feb, 2012.

FEMI Programs for the Small Sites vs. Large Sites

Periodically I hear statements like: “We are not a large refinery or chemical plant or large company, so we don’t have the extra resources and can’t do everything that larger sites can do to maintain our FEMI program.” Unfortunately, the response to that statement is that every one of the 101 FEMI EEs needs to be assessed to see if and how applicable it is to every site, large or small⁽¹⁾. Yes, the larger sites can have an advantage of economies of scale with some SMEs on staff for the various FEMI specific issues; and small sites have to be more efficient in their use of limited resources with many people “wearing several hats”⁽²⁾. But no site can afford to ignore any of the 101 EEs that may be applicable at their site or eventually you will come to regret that you did not give it the attention it deserved. Smaller sites without FEMI SMEs on staff need to know their limitations and seek the help of contract SMEs when necessary (see separate EE on Engineering Support for FEMI). Small sites with fewer resources need to recognize when they need outside FEMI assistance. Sometimes small sites do not even have sufficient FEMI expertise to identify FEMI problems and issues. I am aware of several serious FEMI mistakes made by small sites when management and staff tried to muddle through a complex FEMI issue by themselves that they did not fully comprehend. Just because a small site has a certified API inspector(s) or mechanical engineer on staff does not mean that inspector or engineer is all-seeing, all-knowing when it comes to the various FEMI issues that crop up periodically; that is especially true if the site FEMI personnel are not networking with their counterparts at other sites within the same company and/or not networking with industry FEMI SMEs (see separate EE on networking).

Of course, if you do not have hydro-process units at your site, then the HTHA EE may not be applicable; or if you do not use FFS analysis and instead just repair every flaw found during inspection, then you do not need to pay attention to the FFS EE; and so on and so forth. If a small site has less through-put, less integrated process units, less process complexity and severity, and less corrosive feedstocks, then it may be able to avoid the depth of some FEMI procedures and work practices that larger, more complex, more corrosive operating sites need to have in place. But the only way to adequately determine which of the 101 EEs are applicable to your site, is to have a competent FEMI person(s) assess the applicability of each FEMI issue and determine what FEMI work practices and procedures are necessary and which ones are not at each site⁽¹⁾.

Do you know when your site should be seeking assistance from competent, external SMEs to assist with a specific FEMI issue before it gets “out-of-hand” and causes a PSM event?

References

1. [Measuring the Effectiveness of the Pressure Equipment Integrity Management Process](#), John T. Reynolds, Inspectioneering Journal, Sept/Oct, 1998 and Nov/Dec, 1998.
2. [Management Leadership and Support for PEI&R](#), John T. Reynolds, Inspectioneering Journal, Jan/Feb 2010.

Idle and Retired Equipment

This is an issue that can lead to major problems and unwelcomed surprises if it is not handled with sound practices and company policies. Without effective management, idle or retired equipment may find its way back into service without the inspection and monitoring that the asset needs to avoid future integrity problems. Equipment that has been retired-in-place has been determined to be an asset that is no longer needed. Therefore, it cannot be legally placed back into service without the proper accounting practices and should not be connected to any piping or valves that would easily allow it to be placed back into service (i.e. it should be blinded/blanked or air gapped). On the other hand, idle equipment is equipment/piping that needs to be preserved for future use and remains a legal asset of record and service.

Regardless of whether equipment is temporarily idled or retired-in-place, users must remember the equipment will likely deteriorate while out of service. Users should also be aware that the deterioration modes or damage rates while the equipment is idle or retired-in-place may be different, and in some cases, higher than they were while the equipment was in service. Such deterioration, if unchecked, could lead to equipment failures that have serious safety consequences or could cause collateral damage to neighboring equipment and structures. As one example, a tall column or heater stack may be retired-in-place because the cost of demolition would be too high due to congestion and the proximity to other equipment. The inspection planning for such an endeavor should consider any applicable deterioration modes to guard against structural collapse of the equipment or objects falling from the structure, such as insulation, sheathing, or external attachments. SBP has been known to corrode to failure while equipment is out of service, often as a result of CUI, and fall to the ground. Small pieces of piping, valves, etc. falling from great heights can be lethal to those below. External accoutrements on the structure, such as lightning protection or aircraft warning lights, may still need to be maintained. Such needs will likely also require inspection and maintenance of ladders and platforms. These examples mean that even equipment that is retired-in-place cannot be ignored by FEMI personnel.

Of equal importance to the inspection and maintenance of retired-in-place equipment is temporarily idled equipment that is expected to be reused in the future. There are several publications providing guidelines on how best to do that, including NACE/MTI 34⁽¹⁾. Idle equipment should be preserved in a cost-effective manner for future use. That can take many forms depending upon the type of equipment, the process, and the length of time it is expected to be idle. Corrosion under insulation is a common problem on equipment that is idled. If it has been idle for years, instead of months or weeks, it may need full insulation stripping and thorough inspection to determine if it is fit for further service. I am aware of one facility that restarted an alky plant after eight years sitting idle without any significant effort to assess CUI during the idle period, only to spring numerous leaks before it had to be shut down for a considerable amount of piping replacement. Additionally, the appropriate internal and/or external inspections may need to be conducted in order to ascertain if it is fit to re-enter service. A rigorous management of change (MOC) process (including FEMI SMEs) should be applied to any equipment (including piping) that has been idled and will be returned to service. Part of that MOC process should be checking for deadlegs that were created as a result of the idle condition, so that they can be properly monitored by the deadleg inspection program. Another important aspect of maintaining idle equipment is to ensure that any relief devices continue to be kept up with during the idle time, not only for preservation purposes, but also to protect the equipment from fire exposure and other means of overpressure while it is in the idle state.

Do you have a company policy and effective practices in place to make sure that idle equipment is not brought back into service without full knowledge, proper handling and approval of the responsible FEMI SMEs at your site (i.e. rigorous MOC process)? Likewise, does your site inspect and maintain retired-in-place equipment to the extent necessary that it does not become a safety hazard to those working around it?

References

1. NACE MTI 34 *Guidelines for the Mothballing of Process Plants*, National Association of Corrosion Engineers, Houston, TX.

Third Party and Temporary Equipment

There have been a number of incidents in our industry associated with third party owned equipment that was not receiving the same level of inspection and maintenance that owned equipment received. One example of that almost completely leveled a refinery in the Middle East, when a third party pipeline that crossed through a refinery process unit began to leak light hydrocarbons. Attempts were quickly made to find out who was responsible for the pipeline and try to get the pumps shut down. Unfortunately, within an hour and before that could be accomplished, the pipeline ruptured, creating a huge light hydrocarbon vapor cloud, which ignited and caused human deaths and substantial destruction. Another case involved an ammonia storage vessel that cracked and started leaking toxic ammonia into the environment. The third party owner was not aware of the potential for stress corrosion cracking of carbon steel in totally anhydrous ammonia service and was not inhibiting with a small percentage of water, nor inspecting the vessel for cracking. The owner of the plant was unaware of what the owner of the vessel was doing (or not doing) to ensure its integrity. Another incident occurred when a third party nitrogen storage vessel brittle fractured in-service when the nitrogen vaporizer controls failed, allowing liquid nitrogen to flow into the vessel at cryogenic temperatures. These are just a few examples of the problems operating sites can experience by having third party owned equipment on site and not knowing the risks to their own plant of some sort of catastrophic failure. Hence, one essential element of your FEMI program may be to seek the appropriate amount of knowledge about the FEMI program for third party owned equipment on your operating site.

Additionally, it has now become a more common practice to have third party companies own and operate process plants within the borders of, or directly adjacent to, your operating site. In such cases, if there are significant risks that FEMI failures in those facilities could directly impact the safety at your operating site due to “knock-on effects”, it may behoove you to find out how effective the FEMI programs are at those adjacent sites.

Likewise, another fundamental aspect of a FEMI program is to record and track any temporary piping installations to make sure they are adequate for the purpose intended, and will be removed or made more permanent at some point in time. Most sites will have an effective MOC procedure to cover this issue to ensure that the right people are involved in authorizing the use of temporary equipment/piping. It is a best practice to keep a master list of all temporary equipment on site so that a responsible person knows where the equipment/piping is located, who is responsible for operating it, what the service conditions are, when it will be removed, if it will require any interim inspection/monitoring, etc.

Do you know where all of your third party owned equipment is located at your site and whether it is receiving adequate FEMI attention? Do you have an effective cradle-to-grave MOC work process in place for temporary installations?

Pressure Equipment Regulatory Activities

It is important to know and stay engaged with your local, state, and provincial regulatory authorities that have jurisdiction over fixed equipment at your site. For the most part, good communication and strong relationships with jurisdictional authorities will pay great dividends when there is an issue where regulators control what you can and cannot do with your fixed equipment. Most regulatory authorities appreciate those companies in our industry which maintain strong, viable FEMI programs internally, in compliance with our industry C/S (RAGAGEP). The knowledge that we have these effective, credible FEMI programs, allows regulatory authorities to focus their attention elsewhere within their jurisdictions, where the needs are greater, to increase public safety.

In those few jurisdictions that have overly restrictive rules that add cost and burden, but not much value-added safety, it is also important to have good working relationships with jurisdictional authorities in order to work toward more reasonable regulations, such as adoption of the latest editions of our industry codes and standards like API 510, 570, 653, 579, and 580. Working with jurisdictional authorities can help them understand that these high quality codes and standards are developed under the auspices of ANSI, and represent a consensus of many SMEs from many companies, whose entire professional endeavors are devoted to safe, effective inspection and maintenance of fixed equipment in our industry.

A primary objective of our efforts to work with jurisdictional authorities should be to get them to update their regulations where they have adopted an out-of-date version of our C/S. I encourage FEMI professionals in those jurisdictions to band together to visit with their regulators to show them the advantage of adopting the latest versions of API C/S in lieu of being forced to apply out of date versions. Jurisdictions typically do not have the time or knowledge level to write rules that are better than those contained in API C/S, which are adopted using the rigorous ANSI standardization process. One good way to facilitate such a dialog is to encourage local jurisdictional authorities to adopt an advisory board process whereby industry FEMI representatives meet periodically with jurisdictional authorities to discuss regulatory FEMI issues. Such a work process helps to dispel the distrust and lack of respect that sometimes occurs when there is insufficient communication between the two groups. The same goes for federal regulatory authorities like OSHA. One of the real advantages of the OSHA 1910.119 regulation is that it was written (for the most part) as “performance-based” and not rule-based. As such, the OSHA regulations expect our industry to implement and sustain FEMI programs based on our own C/S (see separate EE). Those C/S are what the API SCI considers “best practices” in addition to RAGAGEP (see separate EE). With few exceptions, those companies that stay in compliance with RAGAGEP do not receive FEMI citations.

Always keep in mind that in the end, even though in some cases we may have different approaches than our jurisdictional authorities to maintaining fixed equipment integrity, our end goal is nearly always the same – continued safe operation of fixed equipment, so that no person is harmed and the environment is not significantly damaged. The industry FEMI C/S generally serve that end goal much better than FEMI regulations written by state regulators who do not have the FEMI knowledge and experience that is embodied in our C/S. Whenever you become aware that your local or state regulators are considering implementing or changing their own rules and regulations for FEMI, I encourage you to bring it to the attention of the API Subcommittee on Inspection (SCI) and to meet with your regulators to show them the value of our industry C/S that they could adopt in lieu of having to write their own rules and regulations for FEMI.

We in the API SCI are always interested in hearing from jurisdictional authorities about their concerns and issues, and we welcome their input on how to improve our RAGAGEP. Unfortunately, very few regulators come to the semi-annual API SCI meetings. Those few that do are welcomed and are excellent contributors. And I know they have gained respect for the professionalism and passion for equipment safety that industry FEMI professionals display during our consensus building process to improve our existing RAGAGEP and create new standards.

Are you engaged with your regulatory authorities on issues that are vital to your FEMI program and do you know what FEMI issues are being actively considered in your jurisdiction?

Flexible Hoses

Flexible hoses are often used to transfer hydrocarbons and other process fluids on a temporary basis to facilitate turnaround activities (clearing equipment, de-inventorying, purging, etc) and for transferring process fluids/products to rail cars and/or tanker trucks for shipment. Some sites will maintain several flexible hoses to be used as needed in multiple services. Flexible hoses come in a variety of construction materials and designs. Owner-users should have appropriate quality assurance systems in place to ensure that each type of flexible hose is compatible with the process service for which it is to be used.

Flexible hoses utilized in hydrocarbon or other chemical services should be individually identified and include appropriate service (chemical) limitations and acceptable operating conditions. Flexible hoses should be cleaned and stored appropriately (per manufacturer's instructions where available) when not in use to minimize both mechanical damage and exposure to environmental conditions and chemicals that could compromise one or more components of the hose assembly.

Flexible hoses have ruptured in service and caused process safety and environmental incidents. As such, they require an appropriate management system to provide assurance that they can operate safely. Each flexible hose (new and used) should be inspected prior to being placed into service. This inspection should include a verification of its intended service (process chemicals and temperature/pressure rating), an assessment of its overall condition (looking for mechanical damage to connections, fittings, flanges, etc.), and confirmation that the periodic inspection has been performed. Periodically, a complete inspection of the hose should be performed (I suggest annually unless a longer interval is justified by risk analysis depending upon intended service). This inspection should include the following activities:

- Ensure hose has been individually identified (ID Tag) and that the records contain appropriate design conditions and service limitations or compatibility.
- Verify diameter, length and end fittings for individual assemblies and compare with existing ID Tags and documentation.
- Verify the hose and fitting pressure ratings are within the design parameters for the hydrostatic proof pressure test (generally 1.5 times MAWP), and check the condition of the fittings (thread condition and gasket or sealing surface condition to provide a proper seal). Fittings should also be examined for mechanical damage from over tightening of the threads or over torquing of bolted assembly, causing flange face rotation. The hose-to-fitting attachment point should also be inspected for loose or damaged clamps or compression fittings.
- Perform visual inspection of hose cover for any cuts, gouges, breach, fraying or other defects where reinforcement is exposed. The hose assembly should also be inspected for excessive abrasion damage to the outer covering/jacket and for damage from heat (brittleness and/or cracking).
- Inspect for damage from excessive bending (kinking) which may produce partial crushing/flattening of the hose or crimping.
- To the extent possible, examine the internal condition of the hose, looking for signs of erosion, cracking or chemical attack/degradation of a non-metallic liner (swelling, tears, abrasion/ roughness, etc).
- Perform visual inspection of the hose tube with a boroscope or videoprobe to determine the general condition of the interior liner (looking for blisters, cracks or other defects).
- Perform tests to ensure electrical continuity between end fittings and perform electrical conductivity test on fluoropolymer & thermoplastic tube hose.
- Check for appropriate alloy (PMI) per manufacturer and equipment records. This may only be an initial inspection unless hose fittings or other components may be changed or modified.
- On-stream inspection using infrared thermography examination may help to identify damage to one or more of the hose components/layers.
- Fittings may be examined with dye penetrant, eddy current, and/or ultrasonic methods to identify cracking or other damage.
- Hydrostatic pressure test in accordance with manufacturer's recommended design specifications (limited by the lowest pressure rating of included component).
- Any other OEM recommended inspection and testing activities.

Much of the above information is being considered for inclusion in the 4th edition of API RP 574 which is currently in ballot stages.

Do you have a robust management system in place to provide assurance that your process hoses are inspected and tested at the appropriate frequency to help avoid in-service failures that could cause a process safety incident? Do you conduct a MOC when you are considering a new use for flexible hoses in process service?

References

1. API RP 574, *Inspection Practices for Piping System Components*, 3rd edition, November, 2009, American Petroleum Institute, Washington D.C. (4th edition pending).

Structural Inspections

Structural inspections may not be the highest priority or highest risk aspect of a FEMI program, but like all other EEs, structural inspections cannot be ignored. It is mighty embarrassing when pipe racks sag and fall because of a lack of structural maintenance, or when heater stacks buckle or fall for lack of maintenance of guy wires or anchor bolting. Clearly, people can be and have been injured when walkways, ladders, hand rails, and platforms deteriorate to the point that they can collapse under a person’s weight. Sadly enough, an operator died a few years back at a refinery when he fell after a guard rail gave way under his weight due to corrosion.

There are structural inspection aspects of almost every FEMI program; columns and vessel skirts, davits, tank dikes, dock structures, pipe supports, pipe dummy legs; this list goes on and on. Structural inspections are often one of those “gray zone” equipment items (see separate EE) that can fall between the cracks unless they are assigned to a specific function in the plant. And it is not as important who does it, as it is important that someone who is trained and competent in the necessary tasks does it right. It does not necessarily require a certified pressure equipment inspector, especially if the pressure equipment inspection function is not adequately staffed for extra duties like structural inspections. Wherever possible, I favor having operators and maintenance personnel performing structural inspections, but again, only if they are trained to do so and they follow a specific work process/procedure outlining how to do it properly.

Cooling water towers (CWT) are another area requiring structural inspections, but they need to be conducted by SMEs to ensure the long term structural integrity of the CWTs. CWTs operate in a fairly aggressive environment relative to the materials of construction, which can result in wood rot and steel corrosion that weakens the structure. Some newer models are especially susceptible to structural damage from the weight of biological growth, ice, and other plugging materials. Nothing is quite as embarrassing or costly as having a CWT collapse in the middle of an operating run. I am aware of four such incidents where this, in fact, has happened. CWT inspection may not be your highest priority, but like all of the other 101 essential elements, it cannot be ignored or reliability impacts will eventually occur.

Both API RP 572⁽¹⁾ and 574⁽²⁾ have specific guidance on the issues individuals performing structural inspections should look for during external inspections of pressure vessels and piping systems.

Are all of the necessary structural inspections at your site identified and assigned to competent personnel who then take ownership for making sure that they are conducted at proper intervals and that the necessary preventative maintenance activities are performed?

References

1. API RP 572, *Pressure Vessel Inspection Practices*, 3rd edition, American Petroleum Institute, Washington, D.C., November 2009 (4th edition pending) .
2. API RP 574, *Inspection Practices for Piping System Components*, 3rd edition, American Petroleum Institute, Washington, D.C., November 2009 (4th edition pending).

Utility Systems Inspection

Vessels and piping systems in utility services are specifically excluded from, but considered optional for, inspection under the API Inspection Codes and Standards; so it is basically up to each owner-user to decide how much inspection is warranted. The API standards define utility systems/vessels as those non-process vessels and piping associated with a process unit handling such fluids as steam, air, water, nitrogen, etc. However, as everyone knows, there are many jurisdictions that have specific regulations covering utility systems, especially boilers and boiler piping. In addition to complying with jurisdictional regulations for steam boilers and piping systems, API RP 573⁽¹⁾ provides guidance on fired boiler inspection, as well as process heaters.

Inspection of utility systems/vessels not covered by codes/standards/regulations should be considered on the basis of risk assessment. Typically, plant operating management should have a major say in whether or not utility pressure vessel and piping system leakage or failure might have a significant impact on process unit reliability. Then, based on that risk analysis and the use of limited FEMI resources, a joint decision could be made as to the amount and extent of inspection needed for the utility system. I have seen some operating sites on both ends of the spectrum when it comes to inspection and maintenance of utility systems. Some do not think about it at all until there is a major failure and a significant reliability impact. One example of that was a ruptured cooling water line from soil side corrosion that shut down several process units until emergency repairs could be conducted. I observed the other end of that spectrum when I came upon a plant with many TMLs on their superheated steam lines and a natural gas line with a TML every thirty feet; perhaps a bit over-the-top (OTT) as we say in the trade. A few typical utility systems that might warrant some attention in a plant FEMI program include, but are not limited to:

- condensate piping which is prone to carbonic acid corrosion⁽²⁾,
- cooling water lines which are prone to cooling water corrosion and fouling⁽²⁾,
- fire water lines, also subject to typical water side corrosion,
- any buried utility piping subject to soil side corrosion, and
- other utility systems that support emergency safety systems.

Are you giving your utility systems the proper amount of FEMI attention based on risk analysis (i.e. not too much, not too little)?

References

1. API RP 573, *Inspection of Fired Boilers and Heaters*, 3rd edition, October 2013, American Petroleum Institute, Washington D.C.
2. API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*, Second Edition, American Petroleum Institute, Washington, D.C., April, 2011.

Conclusion

That's it folks – the entire 101 Essential Elements of Pressure Equipment Integrity Management for the petroleum and petrochemical industry. Each of the EEs must be managed well in order to achieve operating excellence in fixed equipment integrity management (FEMI). Remember that operating excellence is not FEMI perfection or a waste of resources. It is simply doing all 101 EEs right, every time in accordance with the documented plans on a sustained basis in order that fixed equipment assets are available to meet the business plan. In summary, here are just a few higher level questions for you to ponder to help you determine whether your site has already achieved operating excellence in FEMI:

- Do you have all your damage mechanisms for each process unit identified and recorded in a comprehensive CCD and a risk-based inspection strategy for each piece of equipment based on your CCDs?
- Does every process unit at your site have a robust set of IOWs based on all identified damage mechanisms in accordance with API RP 584?
- Do you routinely ask your management to provide the necessary resources for your site to achieve operating excellence in all 101 EEs according to an agreed upon prioritized plan?
- Is your piping inspection program as robust as your vessel inspection program such that you are not having leaks and failures that cause unscheduled production outages?
- Are you making full use of all the valuable information and guidance in the latest editions of the API codes and recommended practices for FEMI referenced in the 101 EEs?
- Is your corrosion engineering strategy sufficient to provide proactive avoidance of damage mechanisms as opposed to simply reacting to surprises?
- Do you keep your management informed of the Top Ten FEMI risks in each process unit so they are not surprised when equipment fails/leaks unexpectedly; and do you meet with them on a frequent enough basis to keep them informed of your FEMI program progress and accomplishments?
- Are all 101 EEs addressed in a site procedure, work practice and/or management system such that everyone involved knows all the what, when, how, where, and whys needed to sustain your FEMI program over the long haul?
- Do you have a work process in effect at your site of Shared Ownership of Assets such that everyone in operations, maintenance and engineering who has a roll in FEMI does their job well in helping to prevent incidents due to FEMI failures?
- When you heard about the last big FEMI failure that caused a serious process safety event at one of your competitor's plants, did you have to put together a catch-up program to address the FEMI issue that caused the failure? Or was your FEMI program for that issue already robust?
- Do you have a comprehensive IDMS for record-keeping that is up-to-date and provides you with a searchable database that will answer all your FEMI questions about equipment history at your site?
- Are you networking with your FEMI peers in your company and in industry such that you are continuing to improve your FEMI knowledge on a regular basis?

If your answers to these questions, as well as all other summary questions in each individual EE, are a resounding YES, then **CONGRATULATIONS**. You are already there, and I'm sure you are enjoying all the benefits of having achieved operating excellence with your FEMI program.

I wish you the best in your FEMI endeavors.

John Reynolds

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