2005 GOVERNMENT/INDUSTRY PIPELINE R&D FORUM

Road Map to Address Inspection, Repair and Leak Detection Issues

The following table outlines 2004-2005 funding from Pipeline Research Council International, Inc. (PRCI) for their Corrosion and Inspection (C&I) Technical Committee. As indicated, the currently identified needs for R&D within the six program areas presented require financial support greater than the available resources. The table also provides the basis for a "road map" of R&D issues that are presented in this document. The road map outlined herein is substantially similar to the current working programs within the C&I committee, and are presented in no particular order or prioritization of research needs. The intent of this document is to overview current activities and identifies future needs related to the specific goals of inspection (e.g., what information is to be collected and why), repair, and leak detection technologies.

Program Areas	**2004 Program**	**2005 Projection**	**2005 Allocation**	**GAP**
Inspect for Mechanical Damage	$289	$600	$400	$200
Condition Assessment Tools for Non-Piggable Pipelines	$1,220	$555	$401	$154
External Corrosion Prevention, Mitigation and Monitoring	$720	$855	$325	$330
Prioritize and Manage Internal Corrosion Monitoring and Mitigation	$601	$1,000	$50	$950
Optimize Integrity Assessment Intervals	$226	$300	$300	0
Manage SCC	$280	$735	0	$735
TOTALS	**$3,336**	**$4,045**	**$1,476**	**$2,369**

The overall process applied by the C&I committee in the advancement of technologies towards development of the desired research outcomes (deliverables) includes:

- Review of current and potential technologies to focus PRCI research on the best available, most promising techniques,
- Ranking of the technologies based on probability of success and their importance to the end user, and
- Design of a research development and deployment plan that achieves key milestones for the work to enable the transfer of the tools to industry for implementation within the necessary time constraints.

This same strategy has been applied in the identification of project work conducted under each of its programs and overview in the remaining sections of this document.

Condition Assessment Tools for Non-Piggable Pipelines

What conditions prevent existing technology from being employed in a pipeline system?

Program Description:
This program is focused on the development of tools that will provide metal loss information for non-piggable pipelines from three different perspectives: inside the pipe, directly over the pipeline on the ground surface and indirectly along the pipeline for those shielded pipe locations.

Background:
Although natural gas transmission and distribution piping is most heavily affected by excavation damage, corrosion is the second largest cause of identified failures for these systems. While property damages related to corrosion vary from year to year for both liquid and gas lines, since 1992, 19 fatalities, 57 injuries and nearly $218 million in costs for clean up and repair have been sustained by the industry from corrosion defects. Historically, corrosion-related failures have been attributed to an inability to effectively collect, interpret and act on findings from integrity investigations.

In-line inspection (ILI) and hydrotesting are typically used to provide information about an in-service pipeline's condition. ILI tools can provide information for integrity assessments regarding wall loss and geometric deformities. They require launching and receiving facilities to be able to be utilized while the line is in service. Older pipelines may contain other obstructions to the passage of these devices such as frequent diameter changes or vintage connections. Hydrotesting provides strictly information on the pressure-containing capacity of the pipe, but in some cases, it may not be practical to take a pipeline out of service to perform a hydrotest, and disposal of hydrotest waters may be cumbersome and costly. For those pipelines that cannot be inspected with conventional ILI tools or subjected to pressure strength testing, termed non-piggable pipelines, an alternate method for gathering information about the pipeline's condition is required.

To ensure that tools meeting each of the specific inspection needs are available for use by pipeline operators in their current and future assessments, direct assessment (DA) technologies for both internal and external corrosion must be thoroughly assessed and validated to provide proper guidance, novel techniques for internal inspection of currently non-piggable lines either on or off-line (e.g., alternative designs for crawler platforms and long-range ultrasonics) must be developed, and techniques for above ground and in-the-ditch corrosion detection and measurement must be enhanced.

A review of the program's objectives and deliverables by the C&I Committee in January of 2004 resulted in the development of more focused research objectives. After more than two years of direct assessment (DA) work resulting in the development of guidelines and NACE standards for DA, the focus of 2005 program work was redirected to the development of commercial tools to be used for the inspection of non-piggable pipelines.

Objectives:

- Develop an above ground metal loss inspection tool.

- Develop an ILI metal loss tool for non-piggable pipelines.
- Develop an indirect metal loss inspection tool for shielded pipelines.

Scope / Projects (2004 – current):

1. Evaluation of Holiday Detection Survey Methods or Techniques
2. Remote Corrosion Detection and Sizing in Nearby Inaccessible Areas Using EMAT's
3. ECDA Inspections & Excavations
4. Magnetic Telescope for Noninvasive Inspection of Buried Gas Transmission Lines and Distribution Mains from the Earth's Surface
5. Physical Performance and Inspection Objectives for Novel Techniques to Inspect Currently Non Pigable Pipelines
6. Evaluation & Comparison of Soil Resistivity Measurement Techniques
7. Guidelines for Implementing the External Corrosion Direct Assessment (ECDA) Process
8. Proposal to Develop a Robust Methodology for DA Based on Structural Reliability Assessment
9. ECDA Validation & Soils Model (Develop Improved ECDA Validation Data Sets)
10. Evaluate the Performance of NoPig

Deliverables:

The tools identified in the above discussed objectives are to be available for commercialization following two years (2005 and 2006) of research or earlier and they shall meet the minimum requirements identified below:

- A tool that will accurately detect metal loss from above ground for those pipelines where service cannot be interrupted.
- A tool that will accurately detect metal loss from inside the pipeline for those pipelines where tool passage is possible, and
- A tool that will accurately detect metal loss on shielded sections of pipeline that is not accessible by the above ground survey tool and for those pipelines where a tool cannot be inserted into the pipeline.

Discussion on Sensor Technology:

Inspection for cased pipes – da questionable, guided wave needs work, need other technologies to inspect inside casings

Perhaps da for cased pipes, similar to sccda
Prci has current study

Liquid unpiggable pipelines issues: short runs that don't have launch/receive facilities, but overwhelming majority are piggable; current research says robots are all capable of being launched through hot tap – can go into relatively inexpensive, and can go up and back and do the inspection that you can't do with pig – these new gen tools; very extensive program with DoT/doe looking at unpiggable technologies – all are next generation of self powererd, high dexterity, operational obstablces are reduced:

Critical research needs
Platform
Sensor few gaps here
Operation of robots – generic needs, regardless of which platform is commercialized

1) power – need improved techniques; on-board batteries are not sufficient, in-flow generation, fuel cells, etc to generate power through flow – this is limiting issues, only so much on-board power, only go so far
2) communications – wireless is great in short term (3-5k feet), maybe 2 miles with FO tether – need to look at ways to communicate with robot, but communication is not essential, communication is good for real-time assessment of pipe

Find sensors that are lower power, lighter or new ways that indicate new direction.

For SCC – if line in service that was exposed, some type of external device that could detect and estimate depth of SCC; for internal pigs, determine extent of scc and pig developments for smaller diameter pipe

transition from above ground to underground

Al Crouch:
Robots, etc: for new approaches, integrated approach – develop platform with sensors in integrated fashion; examine power and ramifications, etc. – ability to drive vertical, drag, friction, bends,

Cased pipe: what are specific conditions? Corrosion defects, shorted carrier pipe/casing – this should be precursor to pipe failing, DA – shorts/clear shorts, how much metal was lost before mitigation

Pipe size: distribution requested inspection for 1-inch lines. Should we be expanding our reach down to those smaller pipe sizes. Usually this size is to find blockage or debris.

Al Tietsma:
RFERC – reduced power requirements
MFL – PII working on reduced power reqs, but is concern
Continue to look for new techs – if you do not have to go into the pipeline at all, better off, and presumably this could be used to inspect under coatings

EWI
How do you inspect pipelines that have been repair internally (patches) down the road?

Looking for flaws in non-metallic pipe not just metallic pipe – doe has started some research, but regulations will not come soon or any non-metallic pipe inspections

Development of UT techniques for polymers

Above ground metal loss – NoPig: reasonable breakthroughs were made, can be used as a screening tool to find locations that may have issues

GE – gap in knowledge relative to performance expectations of tools – suppliers need to understand resolutions, etc will be lesser

Unpiggable lines have had no inspection since initiating service – there are residuals and contaminants that can cause pipe wall contamination; some techs are dependent on clean pipes; for liquids, cleaning is routine. Nothing to date to determine if pipe needs to be cleaned prior to inspection for non-piggables. Sensors for dirty pipes?

If we have two different levels of performance measurements, original and inspection, what other things can we gain from that? Is there a level of measurement performance that can be assessed? Verification of inspection technologies – need improved feedback loop? How do we take advantage of more precise measurements?

API 1163: Standard to ensure communication between service provides and operators. Should be published shortly.

No reason why sensors couldn't be transported unto pipelines using "pig on a stick", technologies for downhole industry

Acoustic Emission – examining as welds cooling, many cracks forming, many papers inspecting carbon fibers

Explorer: deep corrosion, 80% for ½-inch diameter, large shallow 20% 3-inch diameter, nothing smaller through wall that 20%. This is not unreasonable (al tietsma), but edge effects. Should have similar resolution as to high res mfl.

Expectations are often unrealistic in understanding fundamentals of technologies as a function of materials types, etc. Easy to fill this gap if you fill from fundamental level.

Need to always consider adding calipers – information tools for smaller diameter pipes.

What can you nominally expected from an inspection – across all companies. What is POD?

Inspect for Metal Loss Corrosion

What tools, or simple in-house test methods need to be developed to characterize potential internal corrosion sites? What technologies will form the basis for corrosion growth rate predictions, which are required to address proper re-inspection intervals and gas quality decisions?

Nanotechnologies, microbes, etc. – should examine work in other industries to determine if non-engineering solutions that could be applied to these problems.

Program Description:
The primary issues to be investigated in this program include locating areas of coating failure caused by shielding or disbondment, identifying locations on wet gas, dry gas, and liquid pipeline systems where internal corrosion conditions could be present.

Background:
The key to mitigation, monitoring, and ultimately, the management of corrosion risk is the ability to reliably target areas of potential corrosion. Once the areas have been identified, reliable monitoring tools and mitigation techniques provide the information necessary to determine risk and make maintenance decisions. Internal corrosion in dry gas lines is non-uniform; it occurs at relatively few locations with the remaining system being less affected. Internal corrosion in wet gas systems is governed by the compositions of the water and gas, and the presence of bacteria. Similar mechanisms describe liquid pipelines. Identification of the mechanism of corrosion and the ability to accurately monitor growth are key elements in determining optimal mitigation treatments.

To ensure a safe, reliable pipeline system where internal corrosion may be present, improved methods of finding and characterizing imperfections without excavation are needed. The proposed program will focus on developing technologies and methods to assist pipeline operators in identifying locations on wet gas and dry gas systems where internal corrosion conditions could be present. The technology and methods will assist operators in targeting their monitoring and mitigation activities.

Cathodic Protection (CP) Shielding is a major contributor to the premature failure of pipelines and piping systems. Currently, the only reliable way to locate pipe that has suffered corrosion damage from cathodic protection shielding is through the use of in-line inspection tools. There is not a reliable above ground technique that can, with any degree of accuracy, locate corrosion damage caused by shielding. Consequently, this may be a limiting factor in the application of External Corrosion Direct Assessment (ECDA) on those pipelines or piping systems that cannot be internally inspected.

Objectives:

- Develop techniques and methods to identify locations along a pipeline that are susceptible to internal corrosion.
- Improve non-intrusive monitoring and internal corrosion rate prediction methodologies.
- Enhance Internal Corrosion Direct Assessment (ICDA) protocols.
- Develop probabilistic techniques for internal corrosion data processing to rank and prioritize susceptible locations.
- Reduce maintenance costs of existing pipelines and capital costs of new pipelines though improved corrosion prevention and control systems, standardization of corrosion control programs, and the development of methods to share standards, procedures, materials specifications and test methods.

- Ensure a safe reliable pipeline system by providing improved corrosion control systems, reducing maintenance expenses, and identifying improved methods of finding and characterizing imperfections without excavation.

Scope / Projects (2004 – current):

1. Internal Corrosion in Dry Gas Pipelines During Upsets
2. Differentiation of Corrosion Mechanisms by Morphological Feature Characterization - Experimental Approach
3. Differentiation of Corrosion Mechanism by Morphological Feature Characterization
4. Determine Inhibitory and/or Corrosive Properties of Condensate
5. Dry Gas ICDA Validation and Wet Gas ICDA Development
6. Guidelines/Quality Standards for Transportation of Gas Containing Mixed Corrosive Constituents
7. Effects of Solids and Biofilms on Dewpoint and Corrosion in Pipelines
8. Standard MIC Bench Test
9. Drip Corrosion Mitigation
10. ICDA for Liquid Hydrocarbons
11. Corrosion Prevention of Pipeline Drips
12. Mitigation of MIC using CP Including Under Disbonded Coating
13. Coupons for Disbonded Coating
14. Impressed Anode Cable & Connection Failure - Replacement Deep Anodes
15. Gap Analysis of Location Techniques for CP Shielding
16. External Corrosion Probability Assessment for Carrier Pipes Inside Casings
17. Evaluation of Aboveground Techniques for Coating Condition Assessment

Deliverables:

- ICDA methodology for dry gas and validation
- ICDA methodology for wet gas and validation
- Reliable non-intrusive monitoring tool(s)
- Guidelines/quality standards for transportation of gas containing mixed corrosive constituents.
- ICDA methodology for liquid pipelines and validation
- IC Rate Predictor for reinspection intervals and gas quality decisions.
- Enhanced capability to size and characterize metal loss anomalies.
- Evaluation of existing technologies and new techniques to locate, evaluate, and mitigate disbonded coating.

Inspect for Stress Corrosion Cracking (SCC)

What tools are available to accurately size SCC cracks in the ditch? What research is required to validate SCCDA?

SCC in dents.

Program Description:

The purpose of this program is to develop techniques to effectively manage SCC susceptible locations through the investigation of new methodologies for detecting SCC through in-line inspection (ILI), development of methods for prioritizing the susceptibility of pipelines to SCC, and determination of the factors leading to SCC. Results of the research will provide for a reduction in the cost and an increase of the effectiveness of hydrostatic retesting and in-line inspection (ILI) for managing high-pH and near-neutral-pH SCC. (These pH measures refer to surrounding soil chemistry.)

Background:

The supplement to ASME B31.8 on Managing System Integrity of Gas Pipelines, as well as the recently implemented Pipeline Safety Act, recognizes three methods of integrity assessment: in-line inspection (ILI), pressure testing, or direct assessment. The only ILI technique that has been able to adequately find, identify, and size stress-corrosion cracks is liquid-coupled ultrasonics, which requires that the pipe be filled with a liquid, a procedure that is far too expensive to be practical. Hydrostatic retesting has been demonstrated to be effective, but it also is expensive, and the cost effectiveness could be increased significantly if optimum intervals for retesting could be developed and customized for different areas of the pipeline where the probabilities of SCC are different. There currently is no protocol for SCC direct assessment. Therefore, there are a number of opportunities to increase the effectiveness and reduce the cost of ensuring the integrity of pipelines that have experienced or are thought to be susceptible to SCC. The purpose of this research program is to develop techniques to do so.

The proposed research will enable operators to determine where SCC exists (susceptibility assessment) and how to find it (detection). To address the susceptibility question, studies should result in an improved understanding of the role of environmental and geological parameters, coating deterioration and operating conditions on the likelihood of SCC and SCC growth rates. To minimize the cost of managing SCC, identifying the geographical areas for maintenance activities and determining optimum frequencies for inspection and maintenance can be developed, and methods predicting where "significant" SCC, as opposed to insignificant SCC can be developed.

Objectives:

- Determination of the physical requirements for SCC crack coalescence and accelerated deterioration.
- To advance detection technology to provide new tools capable of identifying the properties of a pipe that change due to the presence of a colony of stress-corrosion cracks; measuring these property changes will provide a first step in identifying a novel ILI technique without the shortcomings of current techniques.
- Further technologies in the use of MFL signals to detect coating adherence, and for the determination of stress as detected by a novel manipulation of MFL ILI signals.
- Develop an improved understanding of the role of environmental parameters on the likelihood of SCC and SCC growth rates. Current soils models are somewhat useful, but their reliability is limited and they are not transferable from one region to another.

A more fundamental understanding of the relationships among environmental parameters in the field and SCC behavior is needed.

- Determine the role of operating conditions on SCC growth rates. For minimizing the probability of SCC, for prioritizing areas for maintenance activities and for determining optimum frequencies for inspection and maintenance, it is important to understand how operating conditions such as pressure fluctuations affect SCC behavior. It is well established that some pressure fluctuations can be harmful, but the relative importance of various amplitudes and frequencies has not been established.
- Develop a method to predict where "significant" SCC, as opposed to insignificant SCC, will occur.
- Develop a path forward for developing commercial tools based upon the identified technology. This may involve some direct or indirect support of a tool vendor.
- Work with NACE to develop a protocol for SCC direct assessment.

Scope / Projects (2004 – current):

1. Near-Neutral pH SCC: Dormancy and Re-Initiation of Stress Corrosion Cracks
2. SCC Sample Management
3. Stress-Corrosion-Cracking Gap Analysis
4. SCC Consulting Services
5. Guided Wave Sizing and Discrimination for SCC Magnetostriction ILI Inspection
6. Determination of Factors that Transform Shallow Cracks to Significant SCC
7. Initiation of SCC in Pipeline Steel
8. Improving EMAT ILI for Grading SCC GRI 02-0164
9. Effects of Bicarbonate, Chloride, & Sulfate on Low pH SCC
10. Improvement in Performance in the Mark III Elastic Wave
11. Phased Array Wheel Probe for In-Line Inspection - Stage 1
12. Role of CO2, Chlorides & Sulfates in Pitting Corrosion/SCC, and Relationship
13. Circumferential MFL inspection of SCC
14. Improved Soils Model for SCC
15. Model for Coating Deterioration as a Precursor for SCC
16. Disbonded Tape EMAT on MFL
17. Field Trials for EMAT
18. MAPS for SCC
19. Effect of Soil Constituents on Near Neutral pH SCC Propagation
20. Inhibitive Effect of Organics on Near-neutral pH SCC

Deliverables:

- A site-selection model for prioritizing pipe segments for SCC maintenance based upon geological and environmental features, pipe and coating characteristics, operating history, failure history, retest history, and inspection history.
- Specification and validation of ILI technology that successfully locate and size SCC.
- Methods to determine optimum frequencies for inspection and maintenance actions.

Inspect for Mechanical Damage

How can we improve ILI technology (MFL, US) to detect stress, cracks at dents? How can damage severity assessment methods be based on ILI output?

Program Description:
The major thrust of research performed in this program is to develop improved methods for locating pipeline mechanical damage imperfections caused by third-party sources that ensure the reliability of detection and define the threshold for the biggest missed imperfection not detected. As part of this work, methods to assess/prevent delayed pipeline failures due to mechanical damage of pipelines that have been inspected using in-line tools will be identified. Of course prevention is the key to prevention of mechanical damage but is not covered in this program area.

Background:
Although gas transmission pipelines are buried in well maintained utility right-of-ways and marked with warning signs, they are sometimes damaged by construction equipment, encroaching vehicles not owned by the pipeline company, or other third-party sources. The resulting damage, referred to as third-party or mechanical damage, is the major cause of damage to natural gas transmission pipelines. The Department of Transportation (DOT) Office of Pipeline Safety incident statistics indicate that from 1994 to 2004, approximately 32% of all hazardous accidents involving onshore transmission pipelines were caused by third-party sources resulting in mechanical damage of the pipe. The 252 third-party damage incidents occurring during this period resulted in 9 deaths, 38 injuries, and costs totaling $91 million, or an average of $360,000 per incident. Four percent of the incidents are due to the delayed effects of mechanical damage (e.g., subsequent failure following the growth of cracks produced at the damage site), and have generated the most public exposure.

Because a single incident can be devastating in terms of fatalities, injuries and costs, new technologies to detect, size and analyze mechanical damage regions are needed to assure the long-term integrity, safety and security of the nation's natural gas pipeline network. This program focuses on the detection and sizing of mechanical damage defects through ILI technologies and the assessment of the severity of defects to assist operators in their prioritization of repair/mitigation activities.

Objectives:

- Ensure the inspection technology provides adequate physical parameters to assess the remaining strength of the pipeline.
- Characterize existing capabilities for mechanical damage measurement techniques by providing methods to remove false positives and decrease false negatives, identifying improved ILI technologies for detecting long seam ERW defects, and develop capabilities to distinguish mechanical damage from corrosion in MFL signals.
- Develop new technology for mechanical damage detection by investigating alternate methods for ILI and characterization of the use of MFL signals induced by localized stresses.

Scope / Projects (2004 – current):

1. Improving In-line Inspection for Mechanical Damage in Natural Gas Pipelines
2. Better Understanding of Mechanical Damage in Pipelines
3. Enhanced Assessment Criteria for Mechanical Damaged Pipes
4. Circumferential Magnetic Flux Leakage
5. Gas Coupled Ultrasonic ILI
6. Better Understanding of Mechanical Damage in Pipelines
7. Mechanical Damage Inspection Using MFL Technology
8. Gas-Coupled UT Inspection
9. Non-Linear Harmonic Based Mechanical Damage Severity for Delayed Failures in Pipelines
10. Mechanical Damage Effects on MFL Signals – Modeling and Experimental Studies

Deliverables:

- Improved efficient of hardware to allow for the collection of comprehensive datasets within a single ILI run, thereby eliminating multiple runs.
- Guidance manual describing ILI hardware and methods to accurately measure pipeline defects.
- Development of Gas Coupled UT technology for crack type defect measurement.
- Benchmark data describing accuracy of various ILI technologies.
- Commercialized tools for accurately locating and sizing mechanical damage defects.
- Engineering models and advanced analytical methods to assess damage severity for delayed failure in pipelines.

Optimize Integrity and Repair Assessment Intervals

What are the issues in determining corrosion or crack growth rates? What can be done to set scientifically sound intervals for repair of anomalies found as a result of a smart pig inspection?

Program Description:
The focus of this program is to provide operators with technically sound approaches for the estimation of corrosion rate growths, and therefore, reasonable means for the determination of necessary intervals for integrity assessments. The tasks considered under this program examine the effects of measurement accuracies and variabilities, probabilities of missing defects during inspections, and prior measurement histories in the formation of guidance on the proper selection of assessment and repair intervals.

Background:
The NACE ECDA and ASME B31.8 Integrity Standards require periodic integrity evaluations. The period between inspections is established from an estimate of the largest defect remaining unexcavated and the corrosion rate. Simple corrosion rate estimates generally over estimate the actual deterioration and may lead to uneconomically short intervals. Thus, operators need to establish a sound basis for estimating integrity inspection intervals for the threats of internal and external wall loss corrosion.

Integrity inspections inherently produce variable measurement uncertainties and a probability of missing defects. Integrity re-evaluation intervals require an estimate of the remaining unverified defects and the corrosion kinetics. A standard is needed for estimating corrosion rates from prior history, including inspection and bell hole records, coupons, etc., that provides greater assurance that actual corrosion rates and related uncertainties are properly estimated by methods other than a simple linear growth rate from the year of construction.

Objectives:

- Determine methods to establish inspection intervals based on internal and external corrosion rate predictions.
- Provide assessment guidelines for determining quantitative probability of failure against corrosion caused wall loss defects.
- Establish a standard method for estimating the mean, standard deviation and distribution shapes for wall loss reported by smart pigging and DA (sizing accuracy) and measure this method against API 1163.
- Establish a standard method to estimate the defect population that ILI technologies and DA can not identify or misidentify and measure this method against API 1163.
- Establish method(s) for determining corrosion rates to consider past (when did it start, actual average annual corrosion rate) and future corrosion kinetics.
- Develop methods for determining optimum integrity testing intervals for In-Line Inspections and Direct Assessment.
- Determine the risk reduction achieved from performing and integrating multiple integrity assessments, either repeated or different methods.

Scope / Projects (2004 – current):

1. Ultrasonic Measurement of Stress in Pipelines
2. Dev of Standardized Pig Testing Methodologies
3. Relate Critical Assessment Criteria to MFL Signals
4. Optimization of Inspection Intervals, Defect Repair and Mitigation of Defects on Pipelines carrying Hazardous Materials
5. Reassessment Intervals by LPR
6. Inspection Interval Assessment
7. Knowledge Visualization System
8. Inspection Intervals Using Artificial Intelligence

Deliverables:

- Methodology to establish appropriate ILI assessment intervals allow non-prescriptive frequency to ensure the highest integrity at the lowest cost.
- Methodology to establish appropriate DA assessment intervals and reduce unnecessary inspection costs
- Methodology to establish appropriate Pressure Test assessment intervals and reduce unnecessary inspection costs

Leak Detection

Is leak detection only a problem for LDCs and liquids pipelines? If so how come all the money is spent in looking in class 1 areas? Should there be less emphasis on methane/ethane and more on oil volatiles?

Program Description:

Activities related to leak detection are conducted under the Design, Construction and Operations (DC&O) Technical Committee of the PRCI focus on the development of practical and cost-effective technologies to detect minor oil leaks, and to assess the effects of human factors on controller spill and detection response. The goal of planned work is to improve detection and response capabilities for liquid pipelines, and to provide real-time notification and response to unexpected operational upsets.

Background:

Current technology cannot reliably detect and locate small leaks, whose hydraulic behaviors are similar to normal operational activity. This is because there are many uncertainties in the myriad of parametric factors (e.g., fluid properties), which determine the minimum leak sensitivity. Proposed research will quantify the input parameters and determine their relationships, thereby facilitating the optimization of CPM systems to minimize leak volumes by identifying smaller leaks and/or shortening the time-to-detect.

In addition to current limitations of measurement and monitoring technologies, human factors, such as skill and knowledge limitations, high task complexity, inaccurate system information, unclear display and controls, and inadequate written procedures can lead to poor response times and adversely affect controller spill detection and response performance, and the safety, reliability, and efficiency of pipeline monitoring and control operations. Hence, guidelines are needed that can be used by industry to identify human factors problem areas in their operations and develop continuous improvement strategies to improve the effectiveness of pipeline monitoring and control operations.

Objectives:

- Commercialize reliable remote sensing and real-time monitoring technologies that alert pipeline operators of minor leaks before they become a large problem.
- Provide improved technologies and strategies for automated and early leak detection and notification, the prevention of operator error, shorter response times, and reduced mitigation costs.

Deliverables:

- Methods for locating small leaks from patrol aircraft.
- Parametric-based models to lower leak detection threshold for liquids pipelines.

GAPS:

Don't reject out of hand if can only get down to certain detection speed → always going to do foot patrols, will be out there anyway, will never completely abandon

Need to be on ground anyway, but isn't new component is that we need to see under ground?

For LDC, have option to walk – from arieal, not good for LDC since no clean line of sight, for transmission, better option since clean line of sight

LDC vs. transmission – different application for two different markets

In transmission, leak to be found is ng pilot leak, transmission operators don't really have same problem, would use if free add-on to arieal patrols

Advantages are for liquid lines since consequences are much larger on env impacts --. Ng transmission doesn't appear to have a lot of value
NG: Class 1 vs 4, may look at cost benefit approach to look for detection and encroachments, but could couple with arieal, optical may be viable from economic perspective → could be add on to existing procedures from cost benefit standpoint – not regulatory response to issues, but co specific, depends on population density

"industry accepted practices to inspect for gas leaks" – need regulatory concurrence that acceptable method during developmental phases

Will technology allow you to completely change how you operate and who you operate with?

Liquid: small leaks happen in gathering units, don't have a lot of liquid leaks across mainline in us, API/AOPL has studied issue that suggest largest leaks happen outside gathering loops, smallest inside gathering loops

Pinholes in welds, pinhole corrosion in both ng and liquid – easier to find in ng, but in liquids may not come up to surface → quicker better way to find small pinhole leaks in liquids

Nice to determine economically what they are for liquids – fly over device to detect hydrocarbons → like to determine even small leaks in cross-country that could be used with aerial device – not major gap, but nice to have

After many ILI, leaks are not issue. With all IM, this is not priority.

Most ldcs would like handheld device

Problem with LDCs has been leak pinpointing: leak migration patterns

LDCs are more regulated – have to do more frequency of inspections, also access to perform inspections

While rare, small leaks may be a problem, there are certain defects that are not currently detectable, may use leak detection to help address that problem???????????

Determining the magnitude of problem – is there good data to suggest that this is a problem

Why is DOT/OPS funding this problem? Is there a disconnect between regulatory and industry

EPA evaluation of leaks seems to indicate larger number of problems with leaks, gov't is trying to fund, industry states not much of a problem → may be an integrity issue vs. lost and unaccounted gas issue

Is the problem getting worse as the infrastructure is getting older?

AGA submitted report to regulators, etc: Unaccounted for gas – is this an issue, is this related to safety and integrity? How do you develop breakdown for unaccounted for gas? Industry is looking for respone. Public comment will be coming back from OPS.

LDCs leak a lot, but is this a risk? Concept of HCA for ng is different than for LDC. → How can we take known/suspect leak information by topography to develop better integrity management – to evaluate consequence. Process, data management, data integration issue.

Liquids – is the aging infrastructure resulting in more small leals. API study trends and showed that trend is less leaks and smaller volumes → attributed to internal inspection progam because of proactive activities.

As more and more NG is inspected, it is anticipated that fewer leaks. Flanges and valve seal improvements have improved performance and increased economy; high res mfl runs does not lead to conclusion that small undetected leaks are more prominent.

MANAGING Perception.

Differentiate line pipe leaks vs. leaks at other appurtenances for liquids.

Consider:
Difference between transmission and aging pipe, vs facilities, compressors
Canada study – leaking valves, etc. leaks that are always there
Fugitive gas laws coming – limitations coming, therefore, handheld remote systems

Technology associated with aerial patrols – something more accurate than current systems.

Computational leak model – sensitivity, repeatability, of measurement for proper modeling; liquids are much more computationally challenging

Leak detection for subsea connectors – standardized connectors – could minor or major issue depending on where it is located in the system

Leak before rupture – to consider finding small leaks before rupture

Challenges and Gaps for Mechanical Damage

Short of quantification of mechanical damage, what is it that the operators really need, near term? In melding regulations with risk tolerance, what does industry want?

Guidance is required to make life predictions, prioritization. If damage is present, fatigue, issues, etc., need qualitative guidance.

We're a long way from measuring and applying sizing parameters for precise analysis. Need qualitative guidance to help make decisions.

NLH project will provide screening, ranking tool.

Defects based on low res techniques are based on severity – low, moderate and severe. This is same as years ago.

From field, laser mapping of mech damage to develop strain profile to allow for assessment.

Not only how do you find and how do you fix in difficult areas?

If code says dent with gouge, must repair, what happens with minor dent – we don't have any tools to assess severity and determine acceptable level of minor damage. Near term issue.

B31S includes rejection criteria since realization that very conservative. B31.4 has been approved.

Quantification is ideal, but, kinds of data that are required may not allow for it. Need to start making some discrimination and dissemination – becomes resource issue, may be permitting and cost impacts with potential to disrupt customers, etc.

Do not have any definition of cracks, significant crack or microcracks. Definitions is an issue. If you had analytical capability, you would be able to make these definitions. Need rational basis for models and definitions.

A579 can be used only when a crack is known.

Types of material. Inspection techniques are not all the same. Understand how various properties interact – do we need to do more work on the materials side as we develop inspection techniques?

When to repair:

What is the technology needed to support repair decisions?

How to you mine existing datasets to learn from it and provide practical guidance?

SCC: How to respond to data obtained from SCC-finding pig? How do you address anomalies?

Corrosion rate growth? What are gaps?

Since driven by regulations, and they are not based on technical issues, by doing these corrosion growth rates, etc. is this realistic to get us out from underneath the regulations? Research should be used to provide foundation for standards, and standards should be basis for regulations.

Over past few years, there has been an increasing willingness at OPS – if we do our homework and have compelling story backed up by data, generally acceptable. Regulatory agencies are willing to work with industry when data exists to back positions.

Will readdress interval. If corrosion rate growth will assist interval definition, this should be a priority.

Knowledge based and opposed to technology based research to change regulatory climate. Research can be done to "get out from under a regulation."

What are changes that we need? Improvements to existing technologies, or new technologies altogether to deal with problems not specifically dealt with?

Post ILI calibrations? High precision maps of what corrosion looks like. Can this be used as calibration component to regrade and entire ILI log to refocus data sets? Does this help with reinspection intervals? Integrity rehab scopes.

API Coil Tubular group:
JIP project: U of Tulsa, small diameter tubes, 100s of defects, samples from industry of gouges, bend, pressure, 3% strain, cycle – measure depth, width, aspect ratio of defects on outside surface → program that will predict loss of life in any specific defect in any specific shape → once above 0.008-inch, started losing information about what is at bottom of pit for bacteriological pits, sharp edged, rounded pits → shape started disappearing after lift-off gets beyond 0.008-inch.

How to repair
What types of repairs is industry looking at that we are possibly not addressing at this time?

Composite repairs – there seems to be a number and variety of types; need guidelines on which are better for what applications, difficult to feel confidence in selection without any type of guidance – comparable numbers for specific applications – opportunity for standards development→ ASME PCC2 supposed to address standards on composite sleeves

Since 192 changed, there have been a number of new products – need tracking database for repair types under which circumstances, etc….

Corrosion in wrinklebends?

ASTM D25, 13 and 17 – plastic pipe materials and composites, distribution side, polys – will likely begin seeing them on transmission side since not have 2-300# ratings

Could industry setup test bed demonstration to have cmte evaluate. Test beds have not been successful – vendors refuse to submit to ranking board since didn't want to engage in this type of comparative analysis. This would be beneficial, but would be difficult to make vendors comply.

Information clearing house. Who's using what and under what circumstances? What is economically viable under what circumstances? People and process part of technology.

What are real drivers? Are we interested in repairs that minimize disruption? Ease of use, cost basis, safety, etc.

Cost savings as opposed to cut-outs, etc.

State of industry report – why is only 2% repair done by composite sleeves when so many products are out there?

DOE/NETL is funding next generation composite liner study. Is there a gap in understanding what we have today? LDC vs. transmission. If the cost difference large diameter vs. small diameter?

Challenges from OPS:

Relating the technologies to IMP rule and the threats outlined within. Where are inspections focused to ensure highest probability problems are being addressed.

Regulators to handle increased volume of ILI logs from new gas IMP. Not an issue.

Validating deep water repair methods. Didn't come up in context. Prescriptive IMP sometime in the next 4 years – this could be issue.

Consistent evaluation of anomalies and tools to identify SCC.

Efficiently and systematically estimating the value of inspection for a particular application. Is this dollar or technical value?

Prediction of sites for localized corrosion and/or SCC?

Distribution –
Water intrusion. Nice to have technology to rapidly identify where water or liquid pooling exists in pipe. Could be ICDA technologies – stuff to come is for lower pressure distribution system, if it is intrusion, closest low spot is where it is going to pool, so may not be useful tool for those situations.

Automated UT: DOT/DOE be willing to advance technology for industry? This should be included in welding discussion.

Project Idea (what)	**Who**	**When**	**Where**	**How (much)**