

PIPELINE ASSESSMENT & ANOMALY REPORTING

- A PIPELINE RIGHT TO KNOW ISSUE

Richard B. Kuprewicz
President, Accufacts Inc.

For WA State Citizens Committee on Pipeline Safety 12/4/08 Meeting

Major Observations on Integrity Management (IM)

- ◎ PHMSA has found wide variation in gas transmission operators' interpretation of how to meet the requirements of pipeline safety regulations in assessing, evaluating, and remediating corrosion anomalies
 - Emphasized by recent failures
- ◎ This presentation is based on discussions related to
 - 10/22/08 PHMSA Workshop on Anomaly Assessment and Repair (<http://primis.phmsa.dot.gov/meeting/Mtg55.mtg>)
 - PST 11/21-22/08 New Orleans Conference discussions
- ◎ Today Mostly Focus on Gas Transmission
 - Recent failures / repairs and the above variations underscore shortcomings in consensus standards – specifically application of ASME B31.8S, Figure 4

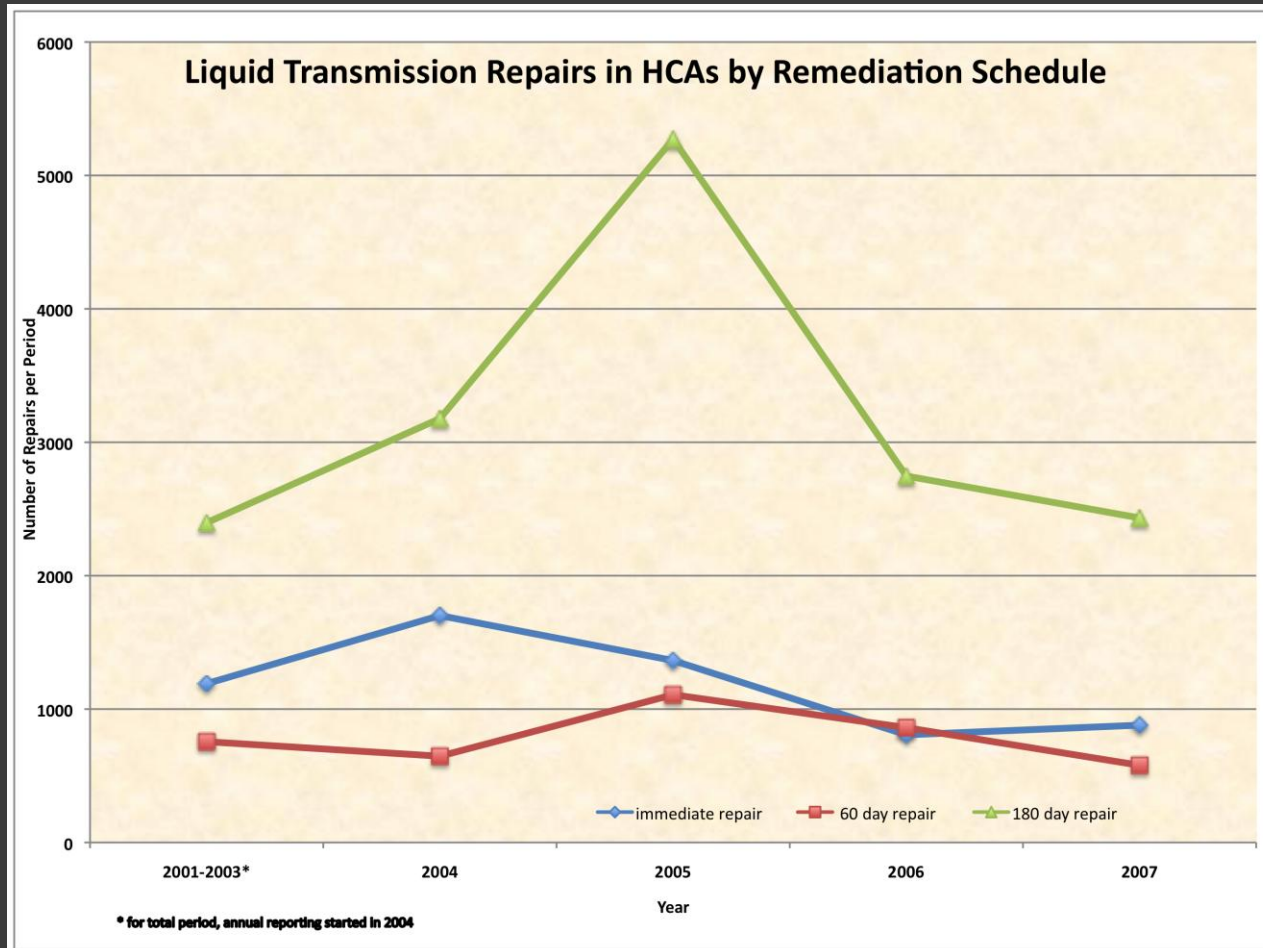
Background on Federal IM Regulations

- Liquid Integrity Management (49CFR195.452)
 - Phased (via Large / Small Operator) Regulation on 5/29/2001 & 2/15/2002
 - 7 year Baseline Assessment
 - Large operator 50% by 9/30/2004, all by 3/31/08
 - Small operator 50% by 8/16/2005, all by 2/17/2009
 - 5 year maximum reassessment interval
 - HCA determined by “could affect”
 - Captures ~ 43% of liquid transmission pipeline mileage or ~ 73,000 miles
- Gas Transmission Integrity Management
 - PSIA of 2002
 - 10 year Baseline Assessment
 - 50% inspected by 12/17/2007, 100% by 12/17/2012
 - 7 year reassessments
 - PHMSA Regulation in 2003 (49CFR192 subpart O)
 - Maximum Reassessment Interval ranging from 7 to 20 yrs based on stress levels
 - HCA determined essentially by C-fer empirical correlation sweep
 - Captures about 7% of gas transmission pipeline mileage or ~ 19,000 miles
- GAO recommending change in reassessment intervals
 - Based on “risk factors, technical data, and engineering analysis”
 - Accufacts advises to be careful don’t take great leap “backward”

Current IM Approach

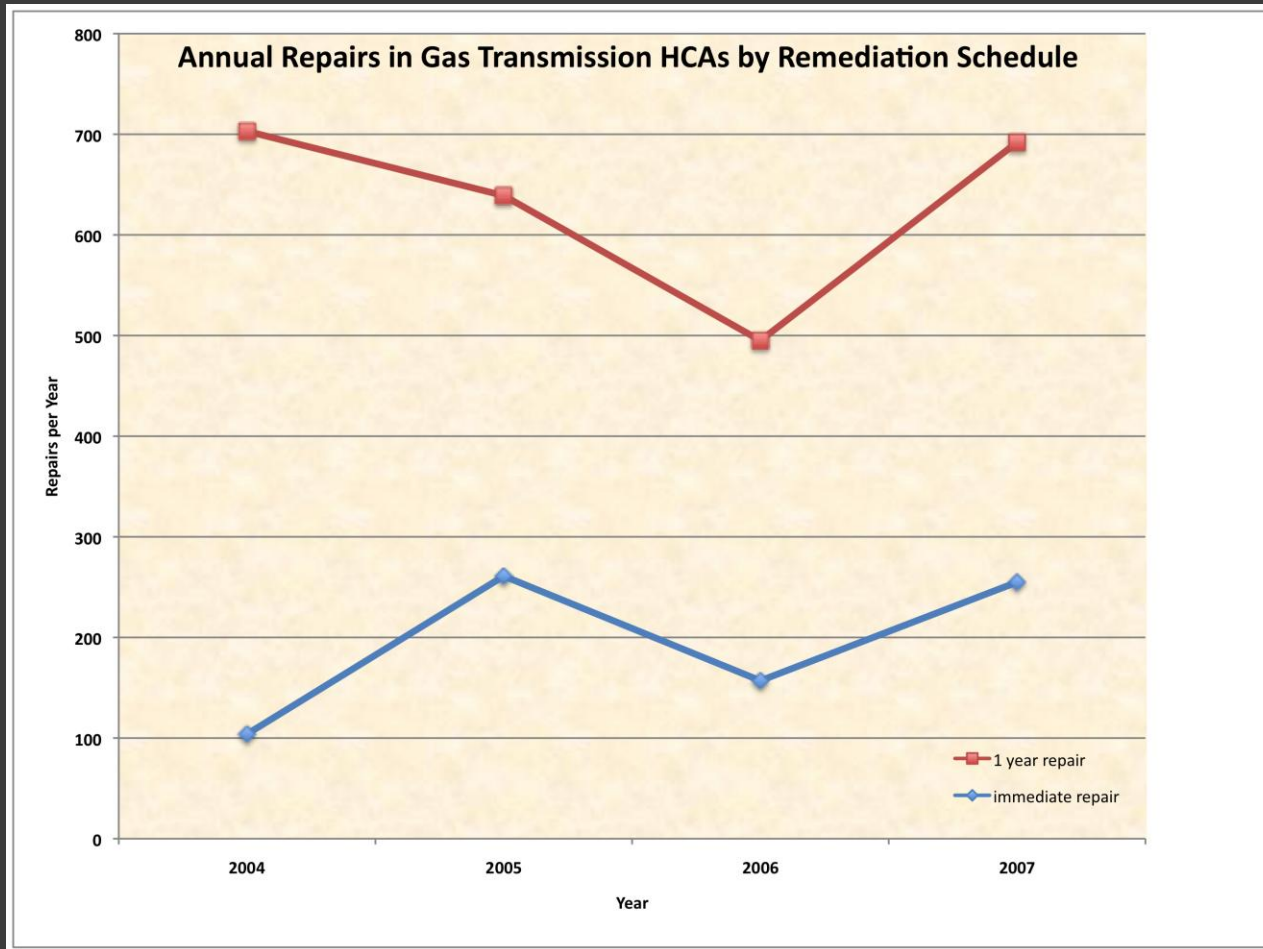
- U.S. regulations lead the world in area of Integrity Management (IM)
 - Some areas build off technology developed in other countries
 - U.S. approach is “Model One” - first of its kind
 - U.S. has more transmission mileage than other top fifteen countries combined!
- Since inception of IM rule through 2007 - Tens of thousands of repairs have occurred on U.S. pipelines
 - Liquid Pipelines ~ 26,000 repairs in HCAs, another ~ 59,000 outside HCAs
 - Gas Transmission ~ 2,500 repairs in HCAs, non HCA repairs not required to be reported
 - Caution that the past repair record does not predict future pipeline corrosion risks

Historical Perspective - Liquids



From PHMSA web site <http://primis.phmsa.dot.gov/iim/index.htm>

Historical Perspective - Gas



From PHMSA web site <http://primis.phmsa.dot.gov/gasimp/PerformanceMeasures.htm>

Gas Transmission Pipelines & IM

- ⦿ Major Differences from Liquid IM rule in
 - Gas has only one specific corrosion reporting requirement
 - Not required to report anomalies in non HCAs
 - HCA definition
 - Remediation / repair schedules
 - Reassessment intervals
- ⦿ Gas industry now arguing for change in reassessment intervals
 - Currently required to report only corrosion anomalies in HCAs where calculated failure pressure ≤ 1.1 MAOP
 - Assumptions in B31.8S and corrosion rate “calls” lead to much greater risks
 - Repairs not always timely or consistent
 - There are a lot more pipeline corrosion anomalies than those reported!

ASME B31.8S Figure 4, Gas Corrosion Timing

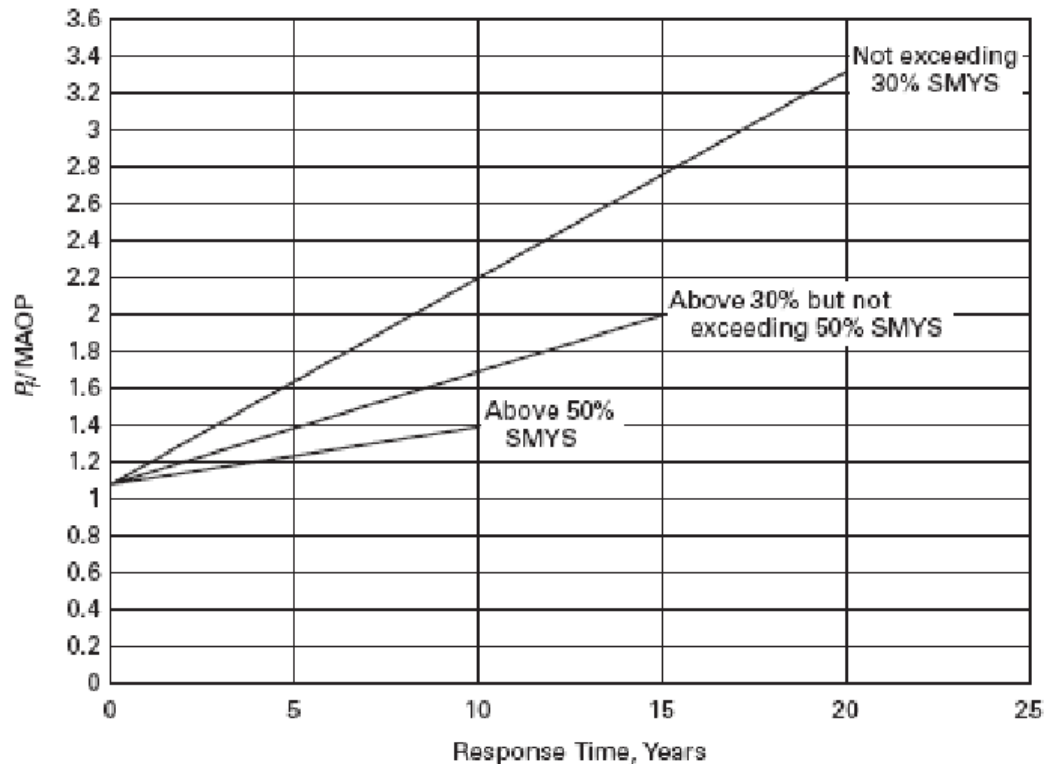


Fig. 4 Timing for Scheduled Responses: Time-Dependent Threats, Prescriptive Integrity Management Plan

Are the corrosion rates and assumptions used in developing the above figure appropriate?
Hint – corrosion rates are seldom linear, especially for severe wall thickness loss

The Corrosion Disconnect

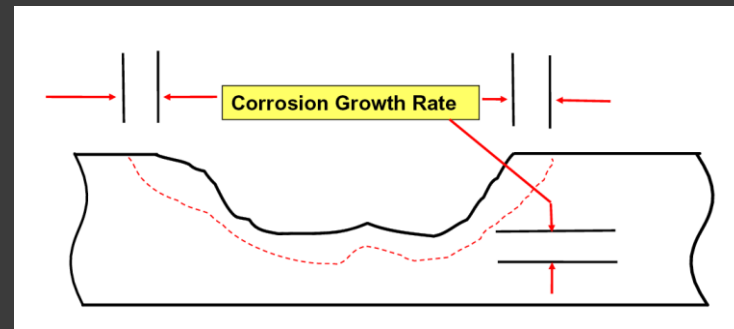
Regulation permits use of corrosion one point in time remaining strength calculation methods:

B31.G

Modified B31.G

RSTRENG

Other methods



As corrosion wall loss increases, sensitivity to corrosion rate assumptions / changes increases risks of time to failure miscall and possible failure



For reassessment, all the remaining strength methods are moot if future assumed corrosion rate wrong at site



Some corrosion depth threshold should be required which triggers additional reporting, closer attention, and possible repair

Gas IM Corrosion Risks & Common Sense

- If going to change reassessment intervals, need a depth threshold for reporting corrosion anomalies in both HCAs and nonHCAs in line with corrosion rate uncertainties
- Wall loss threshold should provide adequate safety margin for corrosion rate miscall
 - E.g., corrosion wall loss > 0.5 or 0.6 might mandate corrosion reassessment within 1 year
 - Time delayed repairs aren't at 0.8 wall loss!
 - Required repairs should also be commensurate with severity of metal loss, especially for rupture potential.

PHMSA Proposed Draft Perspective*

- Draft proposal for natural gas pipelines
- Investigation and repair criteria for non-HCAs (no special permit)

			Immediate		1 Year		Monitored	
Location	Class Location	%SMYS	FPR	Wall Loss	FPR ^L	Wall Loss	FPR	Wall Loss
Non-HCA	1	≤72%	≤1.1	≥80%	≤1.39	≥60%	>1.39	<60%
Non-HCA	2	≤60%	≤1.1	≥80%	≤1.67	≥60%	>1.67	<60%
Non-HCA	3	≤50%	≤1.1	≥80%	≤2.00	≥60%	>2.00	<60%
Non-HCA	4	≤40%	≤1.1	≥80%	≤2.50	≥60%	>2.50	<60%

L Criteria of 1.39, 1.67, 2.00 & 2.50 equate to class location factors of 0.72, 0.60, 0.50 & 0.40.

Combination of wall loss, failure pressure calculation, and class location

* From Barrett PHMSA Perspective presentation at PHMSA 10/22/08 workshop

Recommendations for Gas IM

- Support PHMSA position beyond B31.8S on corrosion data gathering and repair for reassessment interval changes
- Need to address problems / risks associated with poor corrosion rate calls
 - Special risks with higher wall loss corrosion
 - Incorporate a critical corrosion depth trigger to increase reporting to PHMSA
 - Especially important as shift to higher strength thinner wall pipeline grades
 - Add other stress loading as additional risk factor to corrosion.
- More public transparency required in IM data gathering / reporting
 - Current reporting requirement understating corrosion risks in pipelines
 - Mandate pipeline operator additional reporting of corrosion anomalies and repairs to PHMSA both in HCAs and non HCAs
 - PHMSA should report annual inspection and damage database by anomaly type (corrosion, third party, material, etc.) for both HCAs and non HCAs

Where Do We Go From Here?

- PHMSA needs public advice in reassessment process
- Definitely a public right to know issue!
- No change in reassessment interval without additional corrosion anomaly information reported to PHMSA and made public
- Any Committee Action?