Last updated: September 2015

Integrity Management

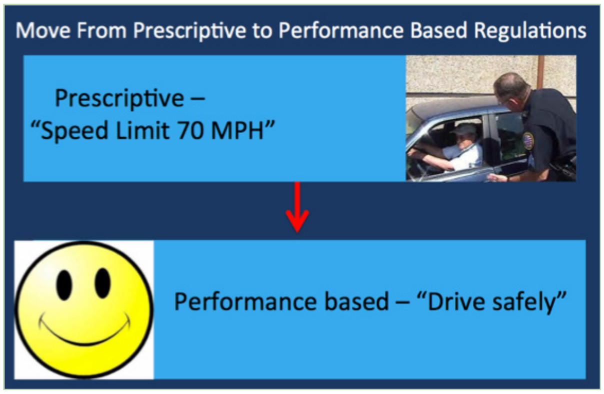
Background

Integrity management (IM) refers to a system of risk analysis and mitigation that for the first time required pipeline operators of hazardous liquid and gas transmission pipelines to identify all risks to certain of their pipeline segments, physically inspect on an ongoing basis certain sections of their pipelines, and mitigate those identified risks factors. These inspections have led to the repair of thousands of problems on pipelines. The covered sections of hazardous liquid pipelines (~44% of total mileage) are required to be re-inspected every 5 years. The covered sections of gas transmission pipelines (~7% of total mileage) are required to be re-inspected every 7 years. While less than half of all hazardous liquid pipelines, and less than 10% of all gas transmission pipelines are required to be inspected under the IM regulations it should be noted that due to the layout of the pipelines and the covered areas, significantly more miles of pipeline are inspected than required, and that a few operators have started using aspects of IM on their entire systems. For hazardous liquid pipelines this inspection system started in 2001, for natural gas transmission pipelines it began in 2004, and for gas distribution systems implementation began in August 2011.

From prescriptive rules to a performance-based risk-management approach to regulating pipelines

With the introduction of integrity management rules, PHMSA increased the pace of the shift from prescriptive regulations toward performance based risk management regulations. While PHMSA still has some regulations that are prescriptive in nature, in the integrity management rules, the regulatory concept allows operators a high degree of flexibility to adapt their programs and plans to fit their particular circumstances. While some believe this allows companies to focus on the most applicable and cost effective safety efforts, others argue that the regulations allow entirely too much flexibility and that their language inhibits enforcement. Good performance-based risk management systems also require reliable, accurate, unbiased data to be collected, maintained, readily available and easily interpreted to determine whether outcomes of the system are adequate. After the NTSB report on the PG&E failure in San Bruno called into question whether PHMSA and the states are obtaining data on "meaningful metrics" to be able to judge the outcomes of integrity management, everyone from INGAA to PHMSA to the DOT Inspector General to the California Assembly began having conversations about meaningful metrics: what they might be, whether data is being collected on any of them, and to what extent those data are reliable. That continues to be an ongoing issue.

Meanwhile, an example to help you understand the difference between prescriptive regulations and performance based ones, both aimed at safer roads:



Under a prescriptive regulatory system, like a speed limit, it's pretty easy to tell if a motorist violated the rule, and enforcement can follow, even if the motorist was driving safely at 76 miles an hour. A performance based system: "drive safely" is much more subjective, making enforcement more difficult, yet arguably, because it encompasses much more than one aspect of safe driving – speed – it *could* result in safer roads.

Integrity Management

Integrity Management, or "IM", as it is frequently called, refers to a set of assessments and continuing data integration obligations that apply to transmission pipeline operators within a certain subset of the nation's pipeline system: those operating in locations where a failure would have high consequences. For distribution pipeline operators, whose lines are predominantly in populated areas, the required integrity management programs apply to the entire systems. The basic principles of IM are the same for distribution pipelines as well as transmission pipelines, but a good deal of the language below is pulled from the gas and liquid transmission IM rules as you will see by the reference to High Consequence Areas (HCAs) which do not exist for distribution pipelines. An important distinction between liquid and gas transmission line IM is that the rules apply to gas line segments that are *in* HCAs; for liquid lines, they apply anywhere a failure *could affect* an HCA, meaning they would still apply to a segment outside an HCA if a hazardous liquid would flow into an HCA from a failure.

For both liquid and gas transmission lines, the IM rules apply in areas identified as "high consequence areas" or HCAs, although the definition is different for each type of line. For gas lines, HCAs are defined by the population and building density near the pipeline. See 49 CFR 192.903. For liquid lines, HCAs are defined to include urban areas or other populated areas identified by the Census Bureau, commercially navigable waterways (which PHMSA interpretation limits to areas of current shallow and deep draft freight traffic, excluding areas used by fishing and pleasure craft and is perhaps a much narrower interpretation than intended in the statute) and "unusually sensitive areas" as defined in 49 CFR 195.6. Operators are required to identify where their lines run through HCAs, but at least at the present, the public does not have current access to learn the extent of mapped HCAs, the methods that were chosen to determine them, or the factual basis for their determination. There is also no way for the public to challenge the designations. The 2011 pipeline safety reauthorization bill requires that HCAs be made part of the National Pipeline Mapping System, but since HCA locations are already in a non-public part of the NPMS, it's not yet clear if the bill will result in any additional public access to HCA designations.

PHMSA describes the purposes of the transmission IM rules as follows:

- *To perform integrity assessments of pipelines in locations where a pipeline failure could have significant adverse consequences (referred to as High Consequence Areas or HCAs).*
- *To improve operator management, analytical, and operational processes to manage pipeline integrity.*

- *To increase government's role in the oversight of operator integrity management programs and activities.*
- *To improve public confidence in pipeline safety.*

What do the Integrity Management rules require? Elements of an IM plan

From PHMSA's briefing on integrity management:

An integrity management program is a set of safety management, analytical, operations, and maintenance processes that are implemented in an integrated and rigorous manner to assure operators provide protection for HCAs. While the rules provide some flexibility for an operator to develop a program best suited for its pipeline system(s) and operations, there are certain required features – called "program elements" – which each integrity management program must have. The core integrity management program elements include:

- *Identifying all locations where a pipeline failure might impact an HCA.*
- *Developing a risk-based plan (known as the Baseline Assessment Plan) to conduct integrity assessments on those portions of the pipeline. Integrity assessments are performed by in-line inspection (also referred to as "smart pigging"), hydrostatic pressure testing, direct assessment or other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe.*
- *Integrating the assessment results with other relevant information to improve the understanding of the pipe's condition.*
- *Repairing pipeline defects identified through the integrated analysis of the assessment results.*
- *Conducting a risk analysis to identify the most significant pipeline threats in segments that can affect HCAs. Examples of pipeline threats include corrosion, excavation-induced damage, material defects, and operator errors.*
- *Identifying additional measures to address the most significant pipeline threats. These measures include actions to prevent and mitigate releases that go beyond repairing the defects discovered through integrity assessment.*
- *Regularly evaluating all information about the pipeline and its location-specific integrity threats to determine when future assessments should be performed and what methods should be selected to conduct those assessments.*
- *Periodically evaluating the effectiveness of the integrity management program and identifying improvements to enhance the level of protection.*

The Baseline Assessment Plan must identify the specific integrity assessment method(s) for each segment that can affect an HCA. These methods must be based on the identification of the most significant integrity threats for the specific segment. The Plan

For specific Information on the differing Integrity Management Programs click the links below:

Integrity Management for Hazardous Liquid lines http://primis.phmsa.dot.gov/iim/index.htm

Integrity Management for Natural Gas Transmission pipelines: http://primis.phmsa.dot.gov/gasimp/index.htm

Integrity management for natural gas distribution pipelines:

http://primis.phmsa.dot.gov/dimp/

must also include a schedule indicating when the assessments of each segment will be performed. The schedule must be risk-based, meaning that higher-risk segments are scheduled before lower-risk segments. Operators must document the technical basis for the assessment methods they select and the risk analysis performed to establish the schedule.

Implementation: What's the Status?

There are undoubtedly examples of companies where IM is well thought out, well managed and well-implemented. Unfortunately, the 2010 PG&E explosion in San Bruno will stand for a long time as an example of how IM can fail as a safety program when the company's program is inadequate and regulators fail to identify its inadequacies. PG&E lacked sufficient records on which to base its threat identification and operating pressures because it failed to maintain records showing the kinds of pipe or quality of welds. It chose an assessment method ("direct assessment") only valid for use when corrosion is correctly identified as the biggest threat to a segment. And it chose not to use a hydrotest (a pressure test using water in the pipe) on that section of its pipeline. The direct assessment inspections of PG&E failed to identify the pipeline's shortcomings, in part because of the way the inspections were designed. As the NTSB pointed out, the inspections need to verify the truth of the operators' records, not just blindly trust them.

PHMSA has provided data for integrity management performance measures for each type of pipeline, which can be found through the links above. As we've discussed earlier, there are several discussions occurring around the issue raised by the NTSB – what meaningful metrics should operators and regulators and the public be using to judge the performance of integrity management systems? The data on this page reflect the nature of those discussions, and are still in flux as of October 2015. If you rely on the incident-based performance data on these pages, make sure you confirm that data by reviewing incident reports. (More about incident metrics follows.)

PHMSA has also provided progress reports for each type of pipeline on how many miles have been assessed using various methods, and how many repairs have resulted from those assessments. Those assessment reports can be found on the PHMSA website, also under the "Performance Measures" tab on the left, but through a link in the text on that page.

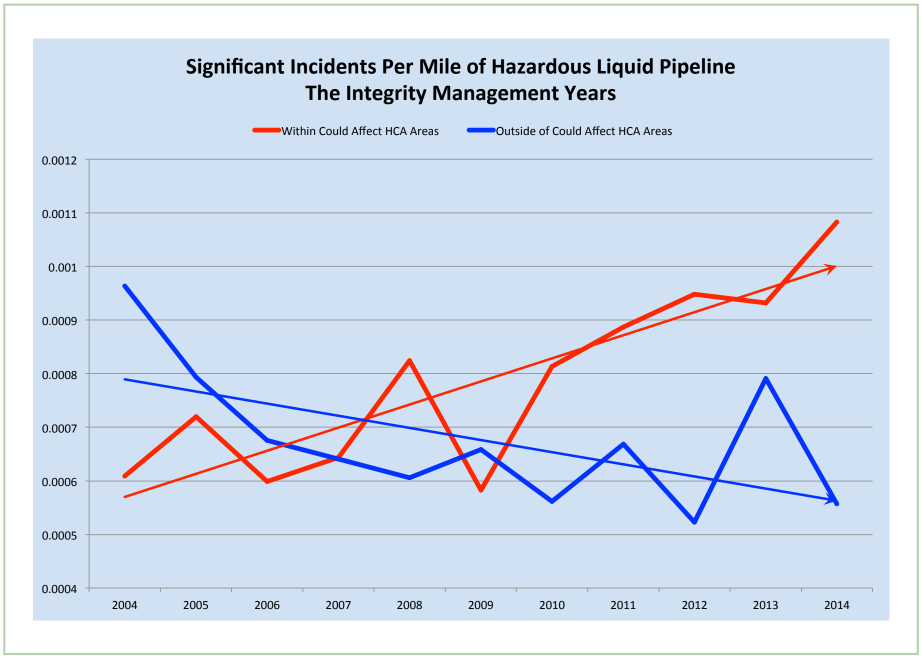
The gas transmission link is here: **http://opsweb.phmsa.dot.gov/primis_pdm/gt_imp_assess_nat_sum.asp**

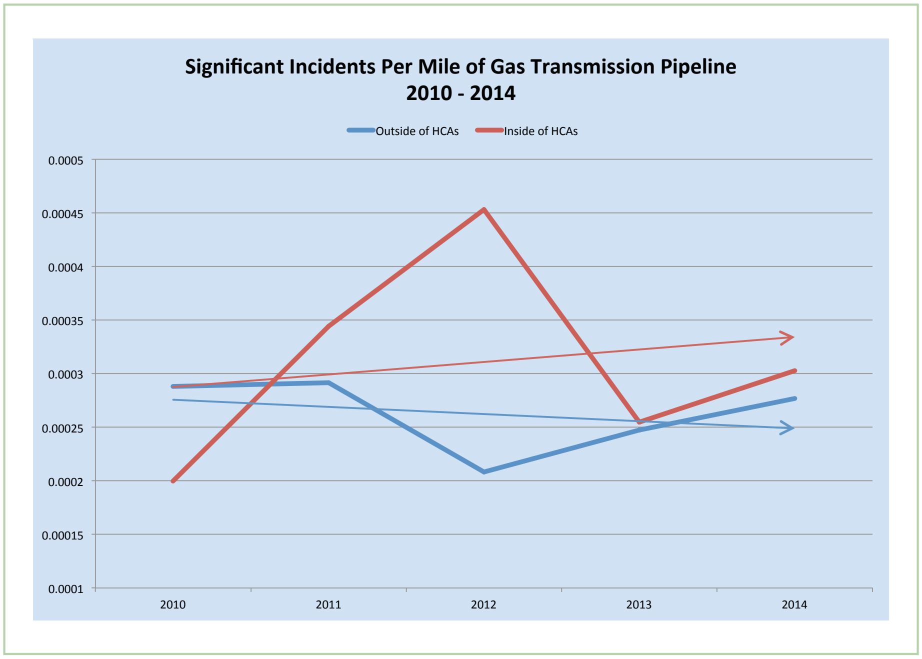
And the Hazardous Liquid link is here: **http://opsweb.phmsa.dot.gov/primis_pdm/hl_imp_perf_nat_sum.asp**

Is IM working?

Integrity Management is more than "Pig and Dig." It means assessing the threats to a section of pipeline, preventing failures, mitigating potential consequences, and integrating data about that section from all operational activities back into the threat assessment. Somewhere along the way, that system is not working properly, because even though many anomalies have been found and repaired as a result of the required inspections and repairs, the number of incidents in areas covered by integrity management has actually risen in the years since IM became the law.

Significant Incidents on both hazardous liquid lines and gas transmission lines have gone up in high consequence areas, or in the case of hazardous liquids, in those areas where a failure could affect an HCA.





As of this writing, no one has offered a good explanation for why incidents are increasing on these lines that are getting better attention and assessments than other pipelines. The trend is disturbing. It is important, in the context of working to identify meaningful metrics for pipeline safety, that information like this not be buried in the deluge of pipeline industry PR about its safety record.

What repairs need to be made, and how soon after the operator discovers them?

Both the liquid and gas IM rules establish categories of integrity problems with pipelines, and for each anomaly discovered, the operator must determine how serious a problem it is and put it on a repair/remediation schedule accordingly. The categories differ slightly: for gas, they are immediate, one year and monitored; for liquids they are immediate, 60 day and 180 day. *[As of this writing, PHMSA has proposed a new rule for hazardous liquids that would reduce these to an immediate and a 270 day category.]* In general, operators must evaluate and remediate an anomaly within the relevant time. What do those timeframes mean? Well, firstly, they don't begin until after the repair condition is "discovered." That means, for liquid lines, "*The date after an internal inspection run when an operator has adequate information about a defect, anomaly, or other pipeline feature to determine the need for repair. Depending on the circumstances, adequate information may be available when the preliminary report is completed, following an analytical evaluation that integrates information from other sources, following excavation, or following receipt of the final internal inspection report. In no case, can the date of discovery be later than the date of the final report.*" PHMSA website, **here**. That PHMSA glossary also describes what qualify as immediate, 60- and 180- day repairs for liquid lines. Unlike most other IM regulations, these include very specific prescriptive descriptions of dents, cracks and gouges, their depths and locations and the resulting category of repair conditions they must be placed in. The descriptions of immediate, one year, and monitored repair conditions for gas pipelines are similar, although we are unable to give many specifics because this is another area where PHMSA has incorporated industry-developed standards by reference, and without purchasing those standards, you would not be able to read the details provided. See **49 CFR 192.933**.

Opportunities for Improvement

The NTSB report for the Enbridge spill in Marshall, MI and the PG&E explosion in San Bruno, CA each provide additional fodder for discussions about improving integrity management throughout the national pipeline system. Those reports and their accompanying recommendations can be found here: **http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1201.pdf** and here: **http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf**. NTSB also completed a study in 2015 that highlights shortcomings of the gas transmission integrity management system, focusing on three major incidents in that occurred in HCAs within five years. NTSB states, "there is no evidence that the overall occurrence of gas transmission pipeline incidents in HCA pipelines has declined." The study with its 28 recommendations for improvement can be found here: **http://www.ntsb.gov/safety/safety-studies/Pages/SS1501.aspx**.

While there are clearly opportunities to improve the implementation of IM, the basic theory of risk assessment, inspection, verification, program changes, and re-inspection that should lead to continuous improvement of pipeline safety seems sound. The initial years of IM have led to the discovery and repair of thousands of pipelines problems before failures occurred. For that reason the Pipeline Safety Trust made expansion of the IM program to include all miles of pipelines its highest priority during the 2011 Congressional reauthorization of the national pipeline safety program. We feel that people in rural areas and that many other types of environmentally sensitive areas deserve these same protections. We also believe that gathering lines that are the same size and operate at the same pressures as transmission pipelines should also fall under the IM program.