BEFORE THE
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
UNITED STATES DEPARTMENT OF TRANSPORTATION
WASHINGTON, D.C.

Pipeline Safety: Public Workshop on the Integrity Verification Process	Docket PHMSA-2013-0119

COMMENTS OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA ON THE PHMSA DRAFT INTEGRITY VERIFICATION PROCESS

Contents

Executive Summary

The Interstate Natural Gas Association of America (INGAA) is a trade organization that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America.

INGAA is comprised of 25 members, representing the vast majority of the interstate natural gas transmission pipeline companies in the U.S. and comparable companies in Canada. INGAA's members operate approximately 200,000 miles of pipelines, and serve as an indispensable link between natural gas producers and consumers.

While the safety performance of natural gas transmission pipelines has been improving steadily for decades, it is the goal of INGAA to continually improve. Appendix A depicts the present safety performance and provides a foundation to base further actions.

INGAA has a strong commitment to pipeline safety, and its members have publicly stated a goal of zero natural gas transmission pipeline incidents. This closely aligns with goals of both the Pipeline Safety and Hazardous Materials Safety Administration (PHMSA), as the federal pipeline safety regulator, and the expectations of the public. INGAA's members have articulated a set of specific commitments[1] to achieve that safety goal, a component of which is called "Fitness for Service for Reconfirming Maximum Allowable Operating Pressure,"[2] while continuing to transport natural gas reliably to their customers.

In late June, PHMSA issued a one-page flow chart reflecting its draft Integrity Verification Process (IVP) for natural gas transmission pipelines. The chart was published with no supporting technical documents.

PHMSA hosted a public meeting on August 7 to provide an overview of the draft process and seek input from stakeholders. PHMSA also presented the draft to the technical advisory committees on August 9, and it allowed members of the committees to provide input and perspectives. INGAA appreciates these and other opportunities to learn more about the rationale for the proposed process that is depicted in the flow chart.

Still, in writing these comments, INGAA had no comprehensive proposal on which to opine. As such, it will base its comments herein on its interpretation of the flow chart, open meetings and discussions with PHMSA staff.

Using this basis, INGAA believes the draft PHMSA IVP incorporates certain aspects of INGAA's Fitness for Service (FFS) process for reconfirming maximum allowable operating pressure

[1] Appendix B: Summary of INGAA Commitments
[2] The term "reconfirmation" is used as it is in the Pipeline Safety Act 2011, Section 23(a)(1)(A) to denote that operators will be reconfirming MAOPs that were confirmed in the early 1970s under 49 C.F.R. § 192.607.

(MAOP) and INGAA's Integrity Management Continuing Improvement (IMCI) initiative, which extends and improves integrity management beyond current High Consequence Areas (HCAs).

INGAA, following a two-year effort, developed the FSS process to reconfirm the MAOP of a pipeline as originally installed. The foundation of FFS is a proven, engineering-based set of processes used consistently for several decades by the energy and process manufacturing industries (refining, petrochemical, electric power, food, beverage, chemical, pharmaceutical, consumer packaged goods, and biotechnology, etc.) and now embodied in ASME B31.8 and B31.8S. INGAA utilizes FFS in this context as a one-time process for reconfirming MAOP.

INGAA's IMCI process is superior to PHMSA's proposal because it will permit operators and the regulator to prioritize work on highest-risk segments and minimize customer service interruptions, while still providing a comparable level of safety. The IMCI process does this by clearly separating MAOP reconfirmation from extending Integrity Management (IM). In contrast, PHMSA's process, as INGAA appreciates it, seems counterproductive because it requires work of increasingly diminishing value and frustrates prioritizing work on segments at greatest risk.

Based on its interpretations, INGAA offers the following high-level comments on PHMSA's IVP proposal:

1. MAOP verification and IM should not be combined into a single process.

PHMSA's apparent decision to combine MAOP verification and IM into a single process is troubling. Combining these two processes would create unnecessary complexity and would undermine both PHMSA's and the industry's ability to prioritize MAOP verification and IM work appropriately.

There are two primary reasons that IM and IVP should be addressed separately. Doing so would:

- **Enable appropriate prioritization.**
  INGAA does not believe that combining MAOP verification and IM in a single process will facilitate prioritizing pipeline safety work in a manner in which the highest priority projects in each category are addressed first. Instead, combining the two work streams into a single process may result in muddled prioritization and counterproductive tradeoffs. Addressing a threat such as external corrosion may require an operator to conduct an assessment (for INGAA members, typically using an in-line inspection (ILI) tool) sooner than a test for material strength would be conducted for MAOP reconfirmation. As a result, an operator would be unable to prioritize work on highest-risk segments. INGAA's IMCI commitments, in contrast, allow for such prioritization, while ensuring a comparable level of safety and minimizing customer service interruptions.

  Also, the IVP Engineering Critical Analysis option uses measures that are pertinent solely to IM, such as a Close Interval Survey (CIS) or an interference survey. Prioritization of those surveys may, and likely will, be different than material strength testing for MAOP reconfirmation.

Finally, the initial, or baseline, phase of the gas transmission sector's integrity management work in (HCAs) was completed on December 17, 2012. Prioritization of work on segments in HCAs is now done based on completion of the baseline. Work to be done for HCA segments that are untested or that lack records to reconfirm the established MAOP may need to be done using different criteria for establishing priority.

- **Lead to process simplification.**
  Reconfirmation of MAOP is a one-time process. By contrast, IM is an ongoing process for the life of the pipeline. Reconfirmation of a segment MAOP can be accomplished absent complete records. In fact, that is the basis of INGAA's approach, and it is the approach being used by the California Public Utilities Commission (CPUC) in that state.

  Based on INGAA's review of the IVP flow chart, it would appear that PHMSA frequently will need to make case-specific determinations about the required work to address particular elements in IVP for individual pipelines or even individual pipeline segments. For example, where validated, traceable material documentation is lacking or missing, IVP would require a case-specific approach to testing pipe properties. This has the potential to overwhelm PHMSA's already limited resources, and result in delays that would frustrate all parties concerned. Further, this process would be less transparent to pipeline safety stakeholders and has the potential to produce inconsistent and unpredictable results.

  Finally, MAOP reconfirmation work and IM require different activities. Conducting both with the same priority, at the same time, will make access to the segment more challenging and likely will cause more extended service outages, which may affect consumers. For all of these reasons, INGAA believes that separating IM from MAOP verification will greatly reduce the likelihood of these undesirable results.

2. INGAA fully supports extending and improving IM.

INGAA fully supports extending IM. The concept of Medium Consequence Areas (MCAs), which was unveiled in the IVP flow chart, appears consistent with INGAA's commitment to prioritize extending the application of IM principles to protect all people along the pipeline. As currently expressed in IVP, however, the designation of MCAs appears to rely on a combination of class location and application of the Potential Impact Radius (PIR) analysis. An approach relying solely on PIR would result in superior risk prioritization and allocation of resources.

INGAA recognizes that there are two dimensions to build upon the success of the baseline IM program:

1. Extending IM - Increasing pipeline mileage covered by IM; and

2. Improving IM - Determining what additional practices should be added to IM and establishing a risk-based analysis of where they should be added (e.g., applying IM principles to 90 percent of the population by 2012, and applying IM as defined by ASME B31.8S to 90 percent of the population by 2020).

PHMSA needs additional time to develop the specifics for extending and improving IM in order to craft a well-reasoned plan. INGAA supports PHMSA's stated intent to hold a public meeting to review the lessons learned from the first decade under the natural gas transmission IM rules and to formulate approaches for extending IM.

Pursuant to the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pipeline Safety Act of 2011), the Secretary is required to report to the Congress on whether to extend IM beyond HCAs within two years of enactment.[3] Absent a determination by the Secretary that a risk or imminent hazard exists, that law limits the ability to issue final rules extending IM until one year after completing the report to Congress or three years after enactment. Given this direction from Congress, it is premature to propose extending and improving IM as part of IVP.

PHMSA, in its IVP, identified it wanted a better understanding of the material properties of pipe. INGAA's members fully appreciate the importance of understanding what pipe is in the ground. One aspect of improving integrity management is ensuring that material records are available for use in risk assessment, assessment planning, anomaly evaluation and response, and selection of prevention and mitigation measures. Every time the pipe is exposed during an excavation for operations and maintenance or integrity-related activities, it provides another opportunity to confirm the material properties of the pipe when needed. These excavations, as part of IM, provide a sounds basis for confirming material properties and pipe condition. As a result, a better understanding of material properties should be part of PHMSA's effort to improve IM.

3. A single pressure test during a pipeline's life is an adequate basis for reconfirming an MAOP.

A single pressure test at 1.25 times MAOP during a pipeline's life adequately establishes strength for purposes of establishing a valid MAOP. This pressure test establishes a safety margin between the test pressure and the operating pressure (that is maintained for the life of the pipeline). This single test is adequate for establishing MAOP because the operator uses ongoing operation, maintenance, and integrity management activities to manage the condition of the pipeline. When the condition of the pipeline is found to have deteriorated, it is evaluated using proven methods to ensure safe continued operation, or repaired or replaced to ensure the safety margin is restored. Therefore, there is no demonstrated reason that pressure tests should be run on a recurring basis for MAOP reconfirmation.

[3] Appendix C: Selected Requirements in the Pipeline Safety Act

In cases where a pipeline has been pressure tested, but not to the level of 1.25xMAOP, that original test should be augmented with other testing and engineering analysis to confirm an appropriate safety margin, thereby reconfirming the MAOP.

4. FFS should be used as the basis for addressing previously untested pipelines and pipelines lacking adequate records.

Previously untested pipelines or those lacking adequate records to support a segment's MAOP can be addressed using an FFS process to establish the MAOP as originally installed. FFS is the pipeline's ability to operate in a manner that ensures the safety of the people that live and work nearby and protects the environment while allowing operators to dependably transport natural gas. FFS is based on established consensus standards, many of which PHMSA has incorporated into its regulations. Use of FFS is consistent with the Pipeline Safety Act of 2011, allowing for the use of hydrostatic testing and, alternatively, technology such ILI. In this context, INGAA utilizes FFS as a one-time process for reconfirming MAOP.

5. INGAA members will work with PHMSA to demonstrate use of ILI in lieu of hydrostatic testing.

INGAA members are working with the American Gas Association, ILI providers and research organizations such as the Pipeline Research Council International and the Gas Technology Institute to commercialize ILI for use in lieu of hydrostatic testing for reconfirming MAOP.

Unlike a hydrostatic test, which is simply pass-fail, ILI reveals information about the condition of the pipe, including sub-critical anomalies. It is in the mutual interest of operators and PHMSA to demonstrate the effectiveness of ILI to better understand risk and manage it.

6. Application of FFS has the desired effect of deleting provisions of the grandfather clause that cause concern to stakeholders.

Following the San Bruno pipeline investigation, the National Transportation Safety Board (NTSB) recommended that PHMSA delete the "grandfather clause" and require a hydrostatic test.[4] INGAA proposes that PHMSA amend 49 C.F.R. § 192.619 to add a provision requiring pipelines to evaluate the fitness for service of previously untested pipelines. This would have the effect of removing the aspects of the grandfather clause that concerned NTSB, Congress and other stakeholders by ensuring that pre-1970 pipelines in HCAs, and Class 3 and 4 areas are tested for material strength.

[4] Appendix D: The National Transportation Safety Board's (NTSB) Recommendations Resulting from the Pacific Gas & Electric Company Incident in San Bruno, CA

7. PHMSA currently lacks a credible basis for establishing a cost-benefit analysis of IVP.

INGAA members have searched aggressively and diligently for records establishing the MAOPs for their pipelines. INGAA members reported the mileage of pipelines that are missing records in Part Q of PHMSA's annual report. INGAA members also reported the mileage of previously untested pipelines in Part R of the annual report.

Regrettably, the instructions for completing the annual report were inconsistent with the approach outlined in the IVP. In basic terms, the annual report guidance permitted an "either-or" verification proposition, while the IVP, in Diamonds 2-5, took an "and" approach, requiring four layers of records before the records for a pipeline were deemed acceptable. In addition, the annual report does not collect data that would permit PHMSA to analyze affected MCA mileage. More detail on PHMSA's conflicting actions is in Appendix E.

If PHMSA proceeds to issue a rule that incorporates the IVP, as proposed, it cannot rely on data from the annual report as the basis for its cost-benefit analysis of that rule. This is because the annual report data would grossly understate the pipeline mileage that would need to be tested pursuant to the IVP. Further, section 23(d)(3) of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pipeline Safety Act of 2011) requires the Secretary to consult with the chairman of the Federal Energy Regulatory Commission and state regulators to establish timeframes for the completion of testing that take into account potential consequences to public safety and the environment and that minimize cost and service disruptions. Again, the annual report data could not be the basis for the analysis in connection with this consultation because it would grossly understate the mileage for which testing may be required and, therefore, grossly understate potential costs and service disruptions.

8. Limit the scope of reconfirming MAOP.

During the August 7 public meeting, PHMSA stated that it intended to limit the scope of IVP to mainline pipe and associated valves and fittings. In other discussions, however, PHMSA has been more ambiguous with respect to the intended scope of IVP. INGAA believes PHMSA should clarify that IVP will be limited to mainline pipe and associated valves and fittings on the basis that other facilities and small appurtenances pose significantly lower risk to the public due to their proximity and design.

Background

A shared goal of zero

INGAA has stated consistently that the goal of the association and its membership is zero natural gas transmission pipeline incidents. This principle closely aligns with both PHMSA's goal as a federal regulatory agency and the expectations of the public. INGAA has articulated a vision on how to achieve that safety goal—its FFS program and other initiatives—while reliably transporting natural gas to its customers. INGAA's vision builds upon a firm foundation of pipeline regulations and an industry commitment to continued safety improvement. INGAA now seeks to augment and improve upon past processes that have contributed to achieving many safety goals. Since the development of the first federal pipeline safety regulations in 1970 and continuing through the implementation of the formalized Integrity Management Program, PHMSA and the industry cooperatively have developed programs and regulations to improve the safety of the public near natural gas transmission pipelines.

Recognition of recent pipeline incidents

Unfortunately, some tragic pipeline incidents still occur, affirming the need to reassess processes and practices used to manage the safety and integrity of the transmission system. One of the latest incidents was the tragic rupture and fire in San Bruno, California in 2010 that resulted in eight fatalities. This event spurred regulators, federal investigators, lawmakers and the industry to re-evaluate pipeline safety programs and work toward avoiding similar events in the future.

INGAA Commitments (IMCI)

For its part, INGAA initiated a set of activities to review the processes that natural gas system operators use to manage the integrity of their pipelines. This extensive effort was called the Integrity Management Continuous Improvement (IMCI) initiative. The focus of this effort was to affect changes to INGAA members' practices and processes to further improve pipeline integrity and consequence management. This two-year IMCI effort was informed by experience implementing the formalized integrity management programs, lessons learned from recent pipeline incidents, and input solicited from stakeholders, including pipeline safety advocates, regulators and others. The IMCI efforts resulted in the INGAA board of directors adopting pipeline safety commitments, which were anchored by a goal of zero pipeline incidents.

PHMSA embarked on initiatives to address concerns raised by NTSB's investigation of the San Bruno incident. It also prepared for regulatory action based on direction from Congress and advice from NTSB. Concurrently, Congress reassessed the roles and responsibilities of PHMSA and provided specific action items for the regulator in the Pipeline Safety Act of 2011.

PHMSA Integrity Verification Process (IVP)

PHMSA proposed a draft process entitled, the Integrity Verification Process (IVP), on June 28, 2013 to address many of the recommendations and mandates outlined by the NTSB and

Congress. The proposal has generated many discussions between PHMSA and stakeholders. PHMSA held a public meeting on August 7 to provide an overview of the draft process and seek input from stakeholders. PHMSA also presented the draft process to the technical advisory committees on August 9 and allowed members to provide input and perspectives. Still PHMSA has not yet provided any written material providing guidance for how pipeline operators would implement IVP.

INGAA, following a two-year effort, developed the FSS process to reconfirm the MAOP of a pipeline as originally installed. FFS is a proven, engineering-based set of processes used consistently for several decades by the energy and process manufacturing industries (food, beverage, chemical, pharmaceutical, consumer packaged goods, and biotechnology, etc.) and now embodied in ASME B31.8 and B31.8S.

Additional Technical Input Requested by PHMSA

During the August 7 public meeting, PHMSA requested input on specific technical requirements. PHMSA pointed out that certain aspects of the IVP were under development and staff requested input. INGAA seeks to answer questions posed by PHMSA during the public meeting in the sections below. The technical input provided below draws upon work by INGAA over the past 2.5 years. INGAA continues to advocate that its FFS process for reconfirming MAOP provides additional details lacking in the proposed PHMSA IVP.

How does a strength test relate to a pressure test?

The strength test, sometimes referred to as a "proof test," is the initial portion of a pressure test that is conducted at a desired pressure level, and often held for a specific period of time, to establish or provide "proof" of the strength of the pipe. Pressure tests conducted after the pipe is installed typically include a "leak test." This portion of the test, as the name denotes, is used to detect or confirm a leak. Leaks are indicated by a pipeline pressure drop. The drop in pressure may be gradual if the leak is small. By contrast, if a test failure in the pipe results in a rupture, the pressure will fall rapidly. Water leaking from the pipeline during a failed test will be found near the pipe perforation.

How is the duration of a pressure test determined?

The duration of the "proof" portion of the pressure test typically is the time required for the pressure to stabilize in the test section. The duration is a function of the test section's length, elevation changes on the section of pipeline and temperature. Typically, the segment to be tested is stabilized within 30 minutes to an hour of the test's start. In a report prepared for GRI in 2001, Robert Eiber and Brian Leis stated,

> Strength re-tests of pipelines should be conducted using high pressures (90-110% SMYS) and held for 30 minutes at maximum pressure. The pressure should then be decreased to 90% of the test pressure and held for as long as necessary

> for a leak check. This will eliminate defect growth during the leak check and minimize growth during the pressure test.[5]

In a paper at IPC in 2004, Brian Leis stated that,

> It is emphasized that a one-hour-long hold at maximum pressure remains a viable upper bound for typical ductile line pipe. As this hold time also leads to ductile tearing along the tips of the larger defects remaining in the pipeline, care must be taken to select the hydrotest parameters consistent with the purpose of the test and the properties of the line pipe body and seam.[6]

When a pipeline is tested at a manufacturing mill, a pipe joint (typically 40 feet in length) is tested for approximately ten seconds. This is the time needed to stabilize the pressure within the pipe joint. Pipe with a sufficiently large flaw in the pipe body or with a long seam that does not have sufficient strength will fail during the test pressure. The higher the test pressure, the smaller the flaw size required to fail a test. As soon as the pressure stabilizes at the desired level, the strength is established or the pipe fails. Therefore, the short duration mill test is as effective as a field pressure test for the purpose of establishing fitness for service for the long seam and pipe body.

A field-pressure test on multiple miles of installed pipe takes a longer period to stabilize. As stated above, the time required to stabilize a long-field test segment, while a function of the segment length, typically is 30-60 minutes.

Pressure Testing Level and Spike Testing

Why is a 1.25xMAOP pressure test sufficient for validating MAOP?

From an engineering standpoint, a pressure test of 1.25 times the MAOP establishes an adequate safety margin above the maximum operating pressure. Lower test pressures also may be acceptable under certain conditions, but the 1.25xMAOP test level has been shown effective in virtually all studies, and it has been accepted by safety and regulatory authorities as adequate under all conditions. The 2010 edition of ASME B31.8 requires a pressure test to 1.25 times MAOP in Class 1 and 2 locations.[7] This level of testing also matches the ASME B31.4 requirements for hazardous liquid pipelines.

Why shouldn't pressure tests for MAOP verification be repeated multiple times?

The current language in 49 C.F.R. § 192.619(a) imposes four criteria that potentially limit the MAOP. One of those four criteria is the highest operating pressure experienced in the five

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[5] Eiber, Robert and Brian Leis, "Review of Pressure Retesting for Gas Transmission Pipelines," Battelle Memorial Institute, GRI-01/0083, Feb 2001. SMYS is the specified minimum yield strength.

[6] Leis, Brian, "Hydrotest Protocol for Applications Involving Lower Toughness Steels," IPC04-0665, ASME IPC Calgary, Sept 2004.

[7] American Society of Mechanical Engineers, B31.8, 841.3.2, Table 841.3.2-1, Test Requirements for Steel Pipelines and Mains to Operate at Hoop Stresses of 30% or More SMYS.

years immediately preceding July 1, 1970, unless the line was tested after July 1, 1965. This highest operating pressure criterion also is the basis for the stand-alone grandfather clause in section 192.619(c). The basic strength properties of steel pipe – yield strength, tensile strength, elongation, strain hardening, etc. – do not change with time. Therefore, INGAA sees no basis for limiting allowable tests to only those conducted after July 1, 1965.

A pressure test for which essential parameters can be determined should be regarded as a valid and compelling test, regardless of whether it was conducted in June or July of 1965, or at any other time. It is the test parameters, not the test date, that should be considered here for the establishment of MAOP.

Still, the validity of earlier tests for MAOP establishment or confirmation does not necessarily mean that no further tests are required. An additional test or periodic testing may be required to assure the continued integrity of the segment. Such additional tests, however, are managed within the operator's integrity management program and, while important, should not be subject to an inquiry about MAOP verification. They should be considered separately.

Is a pressure reduction an option for MAOP reconfirmation?

A target pressure reduction of 20% of the current MAOP has the effect of making the current pressure equivalent to a test of 1.25 times the reduced MAOP. Because the lower pressure would build in a safety margin, such a reduction should be sufficient to reconfirm the MAOP. An operator choosing this option should be able to bring other data and analyses to bear in determining whether the pressure reduction should perhaps be greater or less than 20%. Such data or analysis might include operating history, test history, failure history or ILI results that may be indicative of the strength of the pipe.

How should spike testing be used?

In the investigation report of the incident on PG&E's system in San Bruno, NTSB recommended use of a spike test for previously untested pipelines. A spike test is one of the tools to be considered in planning for and conducting a hydrostatic test. Spike testing is the best means of testing a pipeline with environmental cracking, such as stress corrosion cracking, that has developed while in service.

However, a pressure test to 1.25xMAOP is adequate to address the strength of a pipeline for establishing or validating an MAOP. Pipelines, at the time of installation, generally do not include cracks. However, should an operator need to conduct a pressure test on a line previously untested or lacking records to validate MAOP, it is possible that including a spike test could be useful if the line has been identified as requiring an SCC (stress corrosion cracking) assessment. In this case, the pressure test would serve a dual purpose of validating MAOP while providing an SCC assessment. We note, however, that an SCC assessment would occur under an operator's IM plan and, therefore, should not be prescribed for all MAOP verifications.

A spike test may be of value for some in-service pipelines, specifically where metallurgical fatigue is of concern. An example would be on a line that undergoes significant pressure cycling. Gas pipelines typically do not undergo significant pressure cycling and their fatigue lives can be hundreds of years in duration. PRCI sponsored a study of fatigue behavior on in-service gas pipelines conducted by Kiefner and Associates in 2006. That study confirmed that gas pipelines, absent significant pressure cycling, have long fatigue lives.[8]

The type of test and the pressure-testing level determine the fatigue life and the length of time until the next test. This is referred to as a "retest interval." A spike test to levels over 100% of SMYS establishes a longer fatigue life and retest interval than a test to 1.25xMAOP (which is equivalent to a 90% SMYS test in a Class 1 area operating at 72% of SMYS). A test to 90% SMYS can provide a sufficiently long retest interval for a typical natural gas pipeline.

Even so, fatigue must be considered for a pipeline. The 2006 PRCI study provided guidance for operators to define the operating regime in which an in-depth evaluation of fatigue should be considered. This is embodied within ASME B31.8S and is an essential part of managing the ongoing integrity of a pipeline system.

How should long-seam types in early vintage line pipe be addressed for previously untested pipe and those lacking records?

The INGAA FFS process applies special diligence if the segment contains pipe that has a weld-seam type that has experienced known integrity issues. These seam types include low-frequency electric resistance welds (LFERW), direct-current electric resistance welds (DC-ERW), electric fusion or flash welds, furnace butt-welds and lap welds.

What is an appropriate basis for prioritizing MAOP reconfirmation?

INGAA's risk-based FSS process draws upon the approach developed for previously untested hazardous liquid pipelines in the 1990s. Those specific regulatory requirements are found at 49 C.F.R. § 195.303. The liquids pipeline regulation based its risk-based approach on close proximity to population. In addition, the approach allowed for the use of ILI assessments in lieu of a pressure test. INGAA recommends a similar approach for natural gas transmission pipeline systems.

Can ILI be used in lieu of pressure testing for MAOP reconfirmation?

ILI is nearly commercially viable for MAOP reconfirmation. It will likely require two distinct types of sensors as well as improvements in analytical techniques, both of which require additional demonstration, and ultimately acceptance by PHMSA and state regulators.

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[8] Kiefner, J.F. and M.J. Rosenfeld, Basics of Metal Fatigue in Natural Gas Pipelines – A Primer for Gas Pipeline Operators, Pipeline Research Council International, Inc., Catalog No. L52270, June 2006.

ILI could be used to identify defects that would just survive a hydrostatic test. The reason for using the hydrostatic test as the comparison is that it represents a standard for our regulators and knowledgeable members of the public. While pressure testing can be used for MAOP reconfirmation, it is simply a pass-fail test. It does not provide detailed information about the pipeline; it simply confirms its strength.

In some cases, ILI may be superior to pressure testing. For example, identification of long-seam weld anomalies requires use of transverse-oriented magnetic flux leakage (MFL) technology on an ILI tool. Axially and transverse-oriented sensors have been shown to provide additional data to supplement MFL technology for seam-weld assessments. Alternatively, ultrasonic technology (UT) can be used; however, there has been limited application of UT technologies for seam-weld assessment on natural gas transmission pipelines. The transverse-oriented technology is available only in selected diameters. UT requires use of a liquid couplant, making its applicability limited.

An added benefit of employing ILI is that it can detect anomalies smaller than the large anomalies that would result in a failed pressure test. HCAs and class locations serve as the means to help calculate risk by prioritizing probability of consequences; ILI, meanwhile, is used to prioritize the probability of failure.

INGAA members are working with the American Gas Association, ILI providers and research organizations, such as the Pipeline Research Council International and the Gas Technology Institute, to improve the identification and characterization of long-seam anomalies that could pose a threat to integrity by taking advantage of multiple technologies. It is anticipated that the technologies and their analysis processes will continue to improve during the timeframe in which HCAs are being addressed and operators begin to apply integrity management techniques to pipelines located in Class 3 and 4 areas.

What is an appropriate threshold level for low-stress pipelines?

PHMSA proposed 20% SMYS as the low-stress threshold in the IVP but has not provided support in the docket as of the submittal of these comments. There are many years of precedence with the low-stress threshold being established at 30% SMYS, including PHMSA’s own regulations. PHMSA established 30% SMYS as a low-stress threshold for integrity assessments in the gas integrity management regulations at 49 CFR § 192.941(a). In addition, the level of 30% SMYS is generally accepted to be the “low-stress” boundary between leaks and ruptures for likely pipeline defects.

Moreover, ASME B31.8, in 841.3.2 establishes the threshold at 30% SMYS. The basis of this approach is that preventing ruptures represents a much higher consequence priority than preventing leaks on transmission pipelines. Leaks are important and addressed through a variety of ongoing activities along the pipeline rights-of-way by operators, including leaks surveys, patrols and maintenance work on the pipeline system.

In applying the 30% SMYS low-stress threshold, INGAA members recognize that the threshold presumes an understanding of the minimum level of toughness and the knowledge of pipe diameter, wall thickness and other metallurgical properties, such as the grade of pipe. Operators are encouraged to evaluate whether adjustments should be made to the 30% low-stress threshold level for the pipe segment being evaluated.

Should there be a date before which pressure tests cannot be used?

No. Pressure tests have been used extensively as part of a Quality Management System to validate pipeline material and construction standards. They are also used to validate pipeline integrity. Appendix F describes in detail the processes that have been used in the past to ensure quality.

The current language in 49 C.F.R. § 192.619(a) imposes four criteria that potentially limit the MAOP. One of those four criteria is the highest operating pressure experienced in the five years immediately preceding July 1, 1970, unless the line was tested after July 1, 1965. This highest operating pressure criterion also is the basis for the stand-alone grandfather clause in section 192.619(c). If section 619 is modified to require material strength testing of previously untested pipelines, thereby removing use of the highest operating pressure experienced in the five years immediately preceding July 1, 1970, then it would be reasonable to remove the corresponding restriction from 619(a) as well, along with the limitation on test dates.

The basic strength properties of steel pipe – yield strength, tensile strength, elongation, strain hardening, etc. – do not change with time. Therefore, INGAA sees no basis for limiting allowable tests to only those conducted after July 1, 1965. A pressure test whose essential parameters can be determined should be regarded as a valid and compelling test regardless of whether it was conducted in June or July of 1965, or in 1960 or at any other time. The test parameters, not the test date, should be considered here for the establishment of MAOP. INGAA also emphasizes that recognition of the validity of earlier tests for MAOP establishment or confirmation does not necessarily mean that no further tests are required. An additional test or periodic testing may be required to assure the continued integrity of the segment. Such additional tests, however, are managed within the operator's integrity management program and, while important, are not the subject of this inquiry and should be considered separately.

Appendix A: Documenting Natural Gas Transmission System Improvements in Public Safety Performance

INGAA analyzed the average number of leaks per mile in onshore natural gas transmission pipelines by cause since 1984, based on information pipelines submit annually to PHMSA, as illustrated in the chart below.[1] The data encompasses reportable leaks from all PHMSA-regulated transmission pipelines in service at the time of filing the annual report, which notably includes both pre-regulation and post-regulation pipe. These particular leak statistics have been reported in a fashion that permits statistical analysis by cause of the leak since reporting year 1984[2]. INGAA categorized the number of reported leaks into three causes to analyze general causes of pipeline leaks, and measure improvements in safety performance:

- External and Internal Corrosion
- Material and Construction Damage, and
- Outside Force Damage.

INGAA normalized the annual report data to illustrate the number of leaks per thousand miles of natural gas transmission pipeline in service during each reporting year. Accordingly, this chart is illustrative of the average number of leaks along any one thousand miles of natural gas transmission pipeline in the United Stated during a reporting year.

Why choose leaks as a safety performance metric?

INGAA member companies are committed to zero pipeline incidents, and recognize the importance of preventing incidents on natural gas pipelines. Nonetheless, analyzing the reduction in the number of ruptures per year is a statistically inappropriate way to measure the industry's safety management system since very few incidents occur each year. Rather, analyzing the number of leaks on natural gas transmission pipelines is a better predictor of future performance. Leaks, as reported annually to PHMSA, are a superset of unplanned gas releases, which include other smaller gas releases that may not be reportable incidents and ruptures.

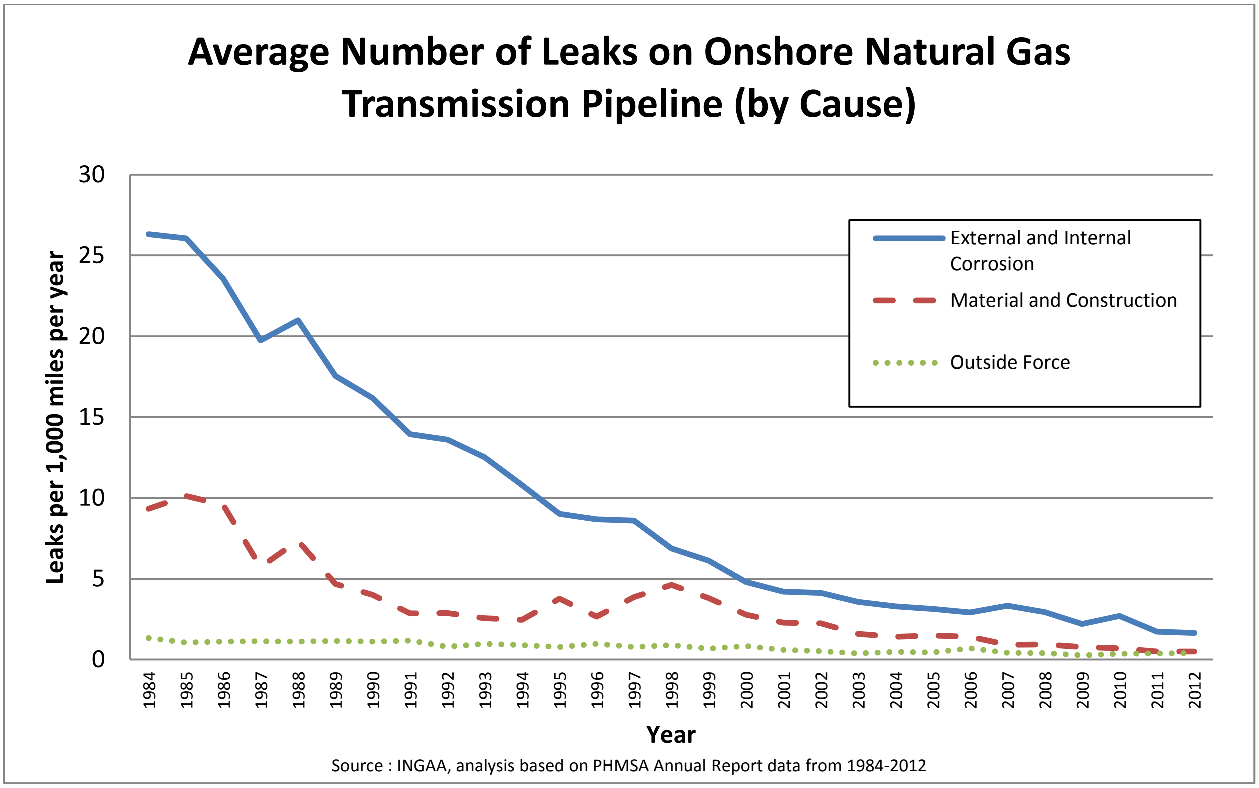
Further, unlike Department of Transportation reportable incidents,[3] the PHMSA annual reports require pipelines to report all known leaks regardless of volume, damage cost or personal injury threshold levels. Moreover, as noted above, pipelines have been reporting leaks by source consistently since 1984, which provides a good starting point for data analysis to determine a

[1] Transmission pipelines, as defined by 49 C.F.R. § 192.6, must report comprehensive pipeline safety data to PHMSA annually.

[2] INGAA started its analysis with reporting year 1984 since this was the first year that the annual report required that pipelines break down leak by cause. While INGAA broke down casues intow three categories for purposes of this analysis, PHMSA requires pipelines to report annually leak data in greater granularity.

[3] 49 C.F.R. § 191.5.

long-term trend. Accordingly, since pipelines report all known leaks to PHMSA in their annual reports, leak data provides the best data to determine whether an industry's safety management system is achieving its goal.



What are the performance metrics that are depicted?

To demonstrate the performance of natural gas transmission companies in managing safety, INGAA categorized the sources of pipeline leaks into three causes. INGAA used annual report data to move all reported leaks into one of the following three categories.

1. **Material and Construction Anomalies** - Leaks attributed to material and construction anomalies typically result from flaws in the manufacturing and construction processes. This cause is classified as being "stable" for properly constructed natural gas transmission pipeline system unless acted upon by an outside interactive force. (The pipeline does not get worse with age unless acted on by an outside force, such as backhoe damage, a flood, or a hurricane.) Pipelines use Quality Management System (QMS) procedures during construction to minimize the formation of these flaws. QMS also include detailed Quality Assurance/Quality Control (QA/QC) processes, which are applied during the design of the pipeline, material specification, manufacturing, construction of the pipeline, and the final hydrostatic test.

2. **External and Internal Corrosion** - Leaks attributed to external and internal corrosion result from the loss of steel due to the time-related action of external or internal

corrosion. These causes are classified as being "time dependent" and always have been the focus of pipeline corrosion-control programs under a pipeline's umbrella safety management system. Corrosion is a major focus of a pipeline's Integrity Management Program (IMP), which call for periodic inspections of pipelines that have entered service. External corrosion-control programs historically have relied on coating, cathodic protection, interference surveys, and close interval surveys to manage external corrosion. Internal corrosion-control programs rely on gas quality monitoring, insertion coupons and additives. The advent of in-line inspection (ILI) and continual improvement of its effectiveness have enabled operators to identify and repair anomalies before they become leaks. This has resulted in continuing to improved pipeline safety performance. IMPs developed in the early 2000s took full effect in 2004 and helped reduce leaks due to corrosion. IMPs built upon corrosion-control programs and formalized risk-assessment processes by applying greater rigor in using ILI and pressure testing and adding an additional tool—direct assessment—for un-piggable pipelines.

3. **Outside Force Damage -** Leaks attributed to outside force damage result from an external force being applied to the pipeline that was greater than that anticipated in the original design. Damage may include excavation damage, weather-related events, such as hurricanes, flooding, lightning, ground movement, and vandalism. These types of leaks are time independent, largely outside the control of the operator and, therefore, often are difficult to predict when and how they will occur. Nonetheless, pipeline operators attempt to minimize outside force damage by increasing education and emphasis on excavation damage prevention by adopting Common Ground Alliance (CGA) best practices, and increasing surveillance of the pipeline route, including ground patrols. Also, with regard to outside-force damage caused by ground movement and weather-related events, pipelines use ILI to identify damage.

What do these performance metrics show?

Material and Construction

Natural gas transmission operators significantly and continuously have improved the management of leaks caused by material and construction anomalies from the period of 1984 through 2012.

External and Internal Corrosion

Natural gas transmission operators significantly and continuously have improved the management of leaks caused by internal and external corrosion anomalies during the period 1984 through 2012.

Corrosion, whether external or internal, has been well-documented to cause time-based deterioration in steel pipelines. Pipelines utilize corrosion-control processes, such as installing cathodic protection beds and pipeline coating, to prevent corrosion on the pipeline. Companies also use technology to detect and mitigate corrosion before it results in a leak. If this threat is not managed correctly, one would expect to see the leak rate rising as the infrastructure ages. The average age of the natural gas transmission infrastructure in 2001 was 35 years old. The average age of the infrastructure in 2012 is now 41 years old. Yet, as the chart shows, despite the fact that the average age of the infrastructure is rising, the corrosion-leak rate has not and, to the contrary, has declined significantly.

The corrosion-leak rate has declined significantly due to improvements in safety-management systems employed by operating pipelines (both those installed before 1970 and those installed after 1970) during this time period (1984 through 2012). New technology and processes—such as the widespread use of improved cathodic protection monitoring systems, updated coating systems, improved construction QA/QC processes, ILI, pressure testing and direct assessment processes—have contributed to this improved performance.

Outside Forces

Leaks due to outside forces have remained relatively constant and low for the period reviewed.

As mentioned earlier, outside-force events are not easily predicted since they are not within the control of the pipeline. As a result, pipelines must work with cooperating stakeholders to improve performance. The primary component of outside force damage to the underground and above-ground pipeline infrastructure is caused by excavators or vehicle operators. The main tools to prevent outside-force leaks are increased surveillance of activity around the pipeline and the improvement of underground excavation-damage-prevention systems. The second major component of this category is leaks caused by natural events, such as floods, tornados, earthquakes, hurricanes and land movement.

Leaks caused by outside forces, which traditionally had a lower frequency rate than leaks caused by material and construction and corrosion, have not seen the same sort of risk reduction as the other two major causes. INGAA attributes this to the fact that pipeline operators have more control over leaks caused by material and construction and external and internal corrosion than leaks caused by outside forces.

What conclusions can be drawn from these results?

- Natural gas transmission pipeline operators have improved their safety performance even as the pipeline network ages and expands.
- When pipeline operators are solely responsible for managing pipeline safety for predictable causes, safety-management systems and programs focused on those threats have resulted in significant reductions in the leak rate, yielding public safety improvement.
- When pipeline operators have a shared responsibility with outside stakeholders for managing pipeline safety, or it is difficult to predict when a natural disaster will occur which will result in a pipeline leak, it has been harder for pipeline operators to achieve comparable levels of safety performance improvements.

Appendix B: Summary of INGAA Commitments

In December 2010, INGAA's board of directors established a board-level task force to signal its commitment to improving the industry's safety performance and restoring public confidence in natural gas pipelines. In March 2011, INGAA members formally adopted a set of Guiding Principles for pipeline safety, which included a primary goal of zero incidents– a perfect record of safety and reliability for the nation's onshore natural gas transmission pipelines. In July 2011, INGAA members agreed to a multi-facetted action plan to achieve this aggressive safety goal. The commitments resulting from this action plan are provided below (items in bold are directly relevant to PHMSA's proposed IVP process):

Demonstrate Fitness for Service on Pre-Regulation Pipelines

INGAA members commit to a systematic validation of records and maximum allowable operating pressure (MAOP) for their pipelines in highly populated areas that pre-date federal regulation. The process will address National Transportation Safety Board (NTSB) recommendations issued in the wake of the San Bruno, California, pipeline accident to evaluate and ensure the safety of member pipelines.

- Reference:
    - White Paper: *Definition and Application of Fitness for Service to Gas Pipelines*, dated May 31, 2012
        - Docket ID: PHMSA-2013-0119-0005
    - *Fitness for Service: Defined and Explained*, dated April 2012
        - Docket ID: PHMSA-2013-0119-0006
    - Summary: *Resident Manufacturing and Construction Threats,* dated January 7, 2013
        - Docket ID: PHMSA-2013-0119-0008

Extend and Improve Risk Management

INGAA members commit to apply integrity management principles – currently required only for the six percent of natural gas transmission pipeline located within highly populated areas – to the entire transmission system operated by INGAA members. This expansion will be focused on population within the Potential Impact Radius (PIR) along the pipeline. INGAA members will expand the program to 90 percent of the population within the PIR by 2020, and 100 percent by 2030.

- Reference
    - Summary: INGAA Members Commitment for Expanding Integrity Management Principles Beyond High Consequence Areas (HCAs)
        - Docket ID: PHMSA-2013-0119-0004

Raise the Standards for Corrosion Anomaly Management

INGAA members commit to managing all corrosion anomalies found during inspection—both inside and outside of HCAs—in accordance with technically based consensus standards and to refine the direction on application of assessment technology.

Shorten Pipeline Isolation and Response Time to One Hour

INGAA members commit to developing processes and technology to enhance the protection of people and property located adjacent to a pipeline, including setting a response-time goal of one hour from incident recognition to the start of valve-closure procedures in highly populated areas and improving communication with responders prior to and during an incident.

Improve Integrity Management Communication and Data

INGAA members commit to improving data collection and analysis, converting this data into meaningful industry information and communicating it to stakeholders.

Implement the Pipelines and Informed Planning Alliance (PIPA) Guidance

INGAA members commit to building an active coalition of INGAA member representatives to implement PIPA recommended practices and identifying selected locations for application of PIPA recommended practices. Members also commit to collaborating with PIPA stakeholders to increase awareness and adoption of PIPA recommended best practices.

Evaluate, Refine and Improve Threat Assessment and Mitigation

INGAA members commit to enhancing threat assessment by completing a comprehensive review of consensus threat and mitigation standards, and conducting critical, in-depth reviews of significant threats and root-cause analysis of incidents.

Foster a Culture of Continuous Improvement

INGAA members commit to raise the standard for use of management systems across the gas transmission industry to ensure better control of pipeline integrity and system reliability and provide guidance in practices and indicators to be used.

Engage Pubic Officials and Emergency Responders

INGAA members commit to finding new and innovative ways to inform and engage stakeholders, including emergency responders, public officials, consumer and safety advocates and members of the public living in the vicinity of pipelines.

Appendix C: Selected Requirements in the Pipeline Safety Act

The President signed the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 in January of 2012 (PLSA 2011). Section 23 of the PLSA 2011 first required operators to conduct a verification of their records in Class 3 and 4 and Class 1 and 2 HCAs by July 2012, and report to the Secretary on segments for which records were insufficient to confirm the MAOP by July 2013.

Section 23 of the PLSA 2011 also required the Secretary to promulgate regulations for conducting tests to confirm the material strength of previously untested pipelines in HCAs operating greater than 30% of the specified minimum yield strength (SMYS). This section provided for alternative methods including in-line inspection.

The Integrity Verification Process (IVP) as drafted has several components that are related to the **H.R.2845 -- Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.**

Expanding beyond high consequence areas

The first major concept identified in the IVP diagram is the **Moderate Consequence Areas (MCA).** This appears to be the same subject addressed in PLSA 2011 Section 5.

SEC. 5. INTEGRITY MANAGEMENT.

(a) Evaluation- Not later than 18 months after the date of enactment of this Act, the Secretary of Transportation shall evaluate--

(1) whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas; and

(2) with respect to gas transmission pipeline facilities, whether applying integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

(b) Factors- In conducting the evaluation under subsection (a), the Secretary shall consider, at a minimum, the following:

(1) The continuing priority to enhance protections for public safety.

(2) The continuing importance of reducing risk in high-consequence areas.

(3) The incremental costs of applying integrity management standards to pipelines outside of high-consequence areas where operators are already conducting assessments beyond what is required under chapter 601 of title 49, United States Code.

(4) The need to undertake integrity management assessments and

repairs in a manner that is achievable and sustainable, and that does not disrupt pipeline service.

(5) The options for phasing in the extension of integrity management requirements beyond high-consequence areas, including the most effective and efficient options for decreasing risks to an increasing number of people living or working in proximity to pipeline facilities.

(6) The appropriateness of applying repair criteria, such as pressure reductions and special requirements for scheduling remediation, to areas that are not high-consequence areas.

(c) Report- Not later than 2 years after the date of enactment of this Act, the Secretary shall submit to the Committee on Transportation and Infrastructure and the Committee on Energy and Commerce of the House of Representatives and the Committee on Commerce, Science, and Transportation of the Senate a report, based on the evaluation conducted under subsection (a), containing the Secretary's analysis and findings regarding--

(1) expansion of integrity management requirements, or elements thereof, beyond high-consequence areas; and

(2) with respect to gas transmission pipeline facilities, whether applying the integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

(d) Data Reporting- The Secretary shall collect any relevant data necessary to complete the evaluation required by subsection (a).

INGAA comments that the Act refers to a Report to Congress that PHMSA must provide regarding extending integrity management. The Act then discusses a review period by Congress after receipt of the report.

(f) Rulemaking Requirements-

(1) REVIEW PERIOD DEFINED- In this subsection, the term `review period' means the period beginning on the date of enactment of this Act and ending on the earlier of--

(A) the date that is 1 year after the date of completion of the report under subsection (c); or

(B) the date that is 3 years after the date of enactment of this Act.

(2) CONGRESSIONAL AUTHORITY- In order to provide Congress the necessary time to review the results of the report required by subsection (c) and implement appropriate recommendations, the Secretary shall not, during the review period, issue final regulations described in paragraph (3)(B).

(3) STANDARDS-

(A) FINDINGS- As soon as practicable following the review period, the Secretary shall issue final regulations described in subparagraph (B), if the Secretary finds, in the report required under subsection (c), that--

(i) integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas; and

(ii) with respect to gas transmission pipeline facilities, applying integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

(B) REGULATIONS- Regulations issued by the Secretary under subparagraph (A), if any, shall--

(i) expand integrity management system requirements, or elements thereof, beyond high-consequence areas; and

(ii) remove redundant class location requirements for gas transmission pipeline facilities that are regulated under an integrity management program adopted and implemented under section 60109(c)(2) of title 49, United States Code.

(4) SAVINGS CLAUSE-

(A) IN GENERAL- Notwithstanding any other provision of this subsection, the Secretary, during the review period, may issue final regulations described in paragraph (3)(B), if the Secretary determines that a condition that poses a risk to public safety, property, or the environment is present or an imminent hazard exists and that the regulations will address the risk or hazard.

(B) IMMINENT HAZARD DEFINED- In subparagraph (A), the term `imminent hazard' means the existence of a condition related to pipelines or pipeline operations that presents a substantial likelihood that death, serious illness, severe personal injury, or substantial endangerment to health, property, or the environment may occur.

INGAA comments that the Act states that PHMSA may act before the report is due if PHMSA determines that there is an imminent hazard. INGAA asserts that there is no such imminent hazard and, therefore, there is no need for PHMSA to act before it issues the report.

Verification of MAOP

INGAA comments that the second major concept addressed in the IVP process that was addressed in PLSA 2011 is the **verification** of MAOP. This terminology is distinct and different from the wording in the former regulations, 49 C.F.R. §§ 192.607 and 192.619, which uses the word **determined**.

SEC. 23. MAXIMUM ALLOWABLE OPERATING PRESSURE.

(a) In General- Chapter 601, as amended by this Act, is further amended by adding at the end the following:

Sec. 60139. Maximum allowable operating pressure

(a) Verification of Records-

(1) IN GENERAL- The Secretary of Transportation shall require each owner or operator of a pipeline facility to conduct, not later than 6 months after the date of enactment of this section, a verification of the records of the owner or operator relating to the interstate and intrastate gas transmission pipelines of the owner or operator in class 3 and class 4 locations and class 1 and class 2 high-consequence areas.

(2) PURPOSE- The purpose of the verification shall be to ensure that the records accurately reflect the physical and operational characteristics of the pipelines described in paragraph (1) and confirm the established maximum allowable operating pressure of the pipelines.

(3) ELEMENTS- The verification process under this subsection shall include such elements as the Secretary considers appropriate.

(b) Reporting-

(1) DOCUMENTATION OF CERTAIN PIPELINES- Not later than 18 months after the date of enactment of this section, each owner or operator of a pipeline facility shall identify and submit to the Secretary documentation relating to each pipeline segment of the owner or operator described in subsection (a)(1) for which the records of the owner or operator are insufficient to confirm the established maximum allowable operating pressure of the segment.

INGAA comments that the regulation below, which was eliminated in 1996, refers to the former 49 C.F.R. § 192.607. The regulation provided a requirement for how pipelines should determine MAOP under Office of Pipeline Safety regulations.

*a) Before April 15, 1971, each operator shall complete a **study to determine** for each segment of pipeline with a maximum allowable operating pressure that will produce a hoop stress that is more than 40 percent of SMYS-*

1. The present class location of all such pipeline in its system; and

2. Whether the hoop stress is corresponding to the maximum allowable operating pressure for each segment of pipeline is commensurate with the present class location.

*b) Each segment of the pipeline that has been **determined** under paragraph (a) of this section to have an established maximum allowable operating pressure producing a hoop stress **that is not commensurate with the class location of the segment of pipeline and that is found to be in satisfactory condition, must have the maximum allowable pressure confirmed or revised in accordance***

> ***with 49 C.F.R. § 192.611.*** *The confirmation or revision must be completed not later than December 31, 1974.*
>
> *c)Each operator required to confirm or revise an established maximum allowable operating pressure under paragraph (b) of this section shall, not later than December 31, 1971, prepare a comprehensive plan, including a schedule for carrying out the confirmations or revisions. The comprehensive plan must also provide for confirmations or revisions* ***determined*** *to be necessary under 49 C.F.R. § 192.609, to the extent that they are caused by changes in class locations taking place before July 1, 1973.*

INGAA comments that listed below are the applicable sections in the present regulation, 49 C.F.R. § 192.619, utilizing the word **determined**.

> §192.619 Maximum allowable operating pressure: Steel or plastic pipelines.
>
> *(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure* ***determined*** *under paragraph (c) or (d) of this section, or the lowest of the following:*

INGAA comments that Congress then proceeded further in Section 23 to discussed new testing regulations.

> *(d) Testing Regulations-*
>
> *(1) IN GENERAL- Not later than 18 months after the date of enactment of this section, the Secretary shall issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of specified minimum yield strength.*
>
> *(2) CONSIDERATIONS- In developing the regulations, the Secretary shall consider safety testing methodologies, including, at a minimum--*
>
> *(A) pressure testing; and*
>
> *(B) other alternative methods, including in-line inspections, determined by the Secretary to be of equal or greater effectiveness.*
>
> *(3) COMPLETION OF TESTING- The Secretary, in consultation with the Chairman of the Federal Energy Regulatory Commission and State regulators, as appropriate, shall establish timeframes for the completion of such testing that take into account potential consequences to public safety and the environment and that minimize costs and service disruptions*

INGAA comments that Congress stipulated that PHMSA should **confirm** the material strength of **previously untested pipelines** located in **HCAs** that **operate greater the 30% SMYS.**

Appendix D: The National Transportation Safety Board's (NTSB) Recommendations Resulting from the Pacific Gas & Electric Company Incident in San Bruno, CA

The NTSB, the federal agency responsible for investigating transportation-related incidents, made an initial set of recommendations to PG&E and the regulatory bodies regarding the September 9, 2010 PG&E incident in San Bruno, CA. These initial, and later modified, recommendations were issued on January 3, 2011 to PG&E, the Department of Transportation, PHMSA, the California Public Utility Commission (CPUC) and industry trade associations.[1]

Subsequently, PHMSA and the CPUC separately took administrative and investigative actions regarding the tragic incident.

On June 8, 2011, in its final investigative report, the NTSB made new recommendations to PG&E, the Department of Transportation, PHMSA, the CPUC and industry trade associations.

INGAA is commenting below on select recommendations to demonstrate where the NTSB recommendation was meant to apply to PG&E only, and not intended to extend to the entire transmission pipeline industry, and where the draft IVP extends beyond the NTSB recommendation. INGAA also identifies below where and how INGAA's Fitness for Service (FFS) proposal meets NTSB's goals of verifying MAOP and/or extending IM. INGAA has bolded certain language within the recommendations for emphasis.

New NTSB Recommendations to the Pipeline and Hazardous Materials Safety Administration (PHMSA)

NTSB Recommendation P-11-14

The NTSB issued the following recommendation to PHMSA:

> Amend Title 49 Code of Federal Regulations 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.

[1] NTSB conducted an investigation of the "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire" that occurred in San Bruno, California on September 9, 2010. http://www.ntsb.gov/doclib/reports/2011/PAR1101.pdf The specific recommendations by NTSB are summarized at http://www.ntsb.gov/investigations/summary/PAR1201.html.

INGAA comments that the NTSB asserted that the grandfathered PG&E pipe had not seen a test pressure above the MAOP. The NTSB stated in its accident report three reasons why the grandfather clause should be repealed.

- The pipe in the San Bruno accident would have failed a higher pressure test that was not required of pipelines that had been grandfathered.
- Present PHMSA regulations allow over pressuring a pipeline up to 1.1 times MAOP in an emergency.
- Immediate repair condition criteria utilized in IMP allow continued operation using a 1.1 times MAOP factor.

INGAA asserts that the INGAA-AGA proposal to amend 49 C.F.R. § 192.619 to add a provision requiring pipelines to evaluate the fitness of service of previously untested pipelines would have the effect of removing the aspects of the grandfather clause that concerned NTSB by ensuring that pre-1970 pipelines in HCAs, and Class 3 and 4 areas are tested for material strength. The recommendation also was directed only at PG&E.

Further, INGAA recommends that PHMSA address the IM issues raised by NTSB as part of its review of the IMP.

NTSB Recommendation P-11-15

The NTSB issued the following recommendation to PHMSA:

> Amend Title 49 C.F.R. Part 192 of the Federal pipeline safety regulations so that **manufacturing- and construction-related defects can only be considered stable** if a gas pipeline has been subjected to a **post construction hydrostatic pressure test of at least 1.25 times** the maximum allowable operating pressure.

INGAA's FFS methodology is designed to address NTSB's recommendation above.

New NTSB Recommendation to the Pacific Gas and Electric Company (PG&E)

NTSB Recommendation P-11-29

The NTSB issued the following recommendation to PG&E:

> Assess every aspect of your integrity management program, paying particular attention to the areas identified in this investigation, and implement a revised program that includes, at a minimum, (1) a revised risk model to reflect the Pacific Gas and Electric Company's actual recent experience data on leaks, failures, and incidents; (2) consideration of all defect and leak data for the life of each pipeline, including its construction, in risk analysis for similar or related segments to ensure that all applicable threats are adequately addressed; (3) a

> revised risk analysis methodology to ensure that assessment methods are selected for each pipeline segment that address all applicable integrity threats, with particular emphasis on design/material and construction threats; and (4) an improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment.

INGAA comments that this NTSB recommendation applied to PG&E only and that the NTSB did not recommend that this process apply to all transmission pipelines. Nonetheless, INGAA supports extending and improving IM. INGAA believes, however, that PHMSA needs additional time to develop a plan for doing so.

Modified NTSB Recommendation to the CPUC

Following its initial investigation, National Transportation Safety Board made the following modifications to its previously issued safety recommendations.

NTSB Recommendation P-10-6

The NTSB issued the following recommendation to the CPUC:

> Develop an implementation schedule for the requirements of Safety Recommendation P-10-2 (Urgent) to Pacific Gas and Electric Company (PG&E) and ensure, through adequate oversight, that PG&E has aggressively and diligently searched documents and records relating to pipeline system components, such as pipe segments, valves, fittings, and weld seams, for PG&E natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing as outlined in Safety Recommendation P-10-2 (Urgent) to PG&E. These records should be **traceable, verifiable, and complete**; should meet your regulatory intent and requirements; and should have been considered in **determining** maximum allowable operating pressures for PG&E pipelines. (P-10-5) (Urgent)
>
> If such a document and records search cannot be satisfactorily completed, provide oversight to any spike and hydrostatic tests that Pacific Gas and Electric Company is required to perform according to Safety Recommendation P-10-4. (Urgent)

INGAA comments that this NTSB recommendation is to the CPUC only, with a focus on PG&E. The NTSB recommends that CPUC oversee the PG&E records search and analysis. Moreover, this was the first time the term "**traceable, verifiable and complete**" was used by NTSB regarding transmission pipelines. It appears that PHMSA adopted this language in their advisory notices. For MAOP, the NTSB also utilized the term "**determining**" in its

recommendation to PG&E, which was the requirement applicable under 49 C.F.R. § §192.611 and 192.619 , and the former regulation, 49 C.F.R. §192.607.
By contrast, the Pipeline Safety Act of 2011 used the term, "re-confirm" MAOP. PHMSA should reassess its methodology in IVP adopting the concept of "re-confirming" MAOP.

Modified NTSB Recommendations to the Pacific Gas and Electric Company

NTSB Recommendation P-10-2

The NTSB issued the following recommendation to PG&E:

> Aggressively and diligently search for all as-built drawings, alignment sheets, and specifications, and all design, construction, inspection, testing, maintenance, and other related records, including those records in locations controlled by personnel or firms other than Pacific Gas and Electric Company, relating to pipeline system components, such as pipe segments, valves, fittings, and weld seams for Pacific Gas and Electric Company natural gas transmission lines **in class 3 and class 4 locations and class 1 and class 2 high consequence areas** that **have not had a maximum allowable operating pressure established through prior hydrostatic testing.** These records should be **traceable, verifiable, and complete**. (Urgent)

INGAA comments that this NTSB recommendation is to PG&E only on its records search and analysis. This recommendation also utilized the terminology "**traceable, verifiable and complete.**" It only included all pipe in the referenced locations that **did not have a hydrostatic pressure test to establish an MAOP**. The initial process to determine an MAOP for pre-regulation pipe is defined in 49 C.F.R. § 192.607,[2] but this recommendation did not state that the pipeline had to have specific records for 49 C.F.R. § 192.619 (a) (1), as is presented in the draft IVP. The NTSB recommendation did not state that the hydrostatic pressure test used by PG&E to establish its MAOP was the lowest of the 49 C.F.R. § 192.619 (a) (1) through (a) (3), as is presented in the draft IVP.

NTSB Recommendation P-10-3

The NTSB issued the following recommendation to PG&E:

> Use the **traceable, verifiable, and complete records** located by implementation of Safety Recommendation P-10-2 (Urgent) to **determine** the valid maximum allowable operating pressure, based on **the weakest section of the pipeline or component** to ensure safe operation, of Pacific Gas and Electric Company natural gas transmission lines **in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable**

[2] This regulation was subsequently removed.

> **operating pressure established through prior hydrostatic testing.** (Urgent)

INGAA comments that this NTSB recommendation is to PG&E only and describes how the traceable, verifiable and complete records should be used to determine the weakest section of a pipeline or component in the referenced locations only in sections that **did not have the MAOP established by hydrostatic pressure test**. It did not refer to a particular minimum hydrostatic test pressure that a pipeline had to conduct in order to exclude the pipe from this analysis, as required by the draft IVP.

NTSB Recommendation P-10-4

The NTSB issued the following recommendation to PG&E:

> If you are unable to comply with Safety Recommendations P-10-2 (Urgent) and P-10-3 (Urgent) to accurately determine the maximum allowable operating pressure of Pacific Gas and Electric Company natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing, **determine the maximum allowable operating pressure with a spike test followed by a hydrostatic pressure test**.

INGAA comments that this NTSB recommendation is to PG&E only and recommends how PG&E should address pipeline segments and components only in sections that do not have the MAOP established through a prior hydrostatic pressure test. It did not refer to a particular minimum test pressure or a spike test process, as is presented in the draft IVP.

Appendix E: PHMSA Administrative Activities

PHMSA issued an Advisory Bulletin regarding MAOP confirmation and records verification utilizing traceable, verifiable, and complete (TVC) acceptance criteria on January 10, 2011 (ADB-11-01).[1]

The INGAA board embraced these recommendations and undertook an initiative to address the recommendations. The board codified the Guiding Principles, and, later in 2011, embraced a series of commitments, including those related to pipe lacking records to support an MAOP and testing of previously untested pipeline using demonstrated Fitness for Service (FFS) methods.

On May 7, 2012, PHMSA issued a second Advisory Bulletin to provide additional detail regarding its interpretation of TVC records (ADB-12-06).[2] Pipeline operators have since focused significant efforts in identifying records used to establish the original MAOP, essentially a "reconfirmation" of work conducted in the early 1970s under 49 C.F.R. §§ 192.607, 192.619.

PHMSA issued a notice on January 10, 2011 seeking comment on changes to the annual report to address data needed to address Section 23 of the Pipeline Safety Act of 2011. INGAA met with PHMSA on several occasions and submitted comments on May 7, 2012. PHMSA issued an additional notice regarding the annual report changes also noting that the submission date would be moved back to June 15, 2013. In submitting data in the annual report, operators would meet the requirement of Section 23 of the PLSA 2011, requiring reporting on those segments lacking records to support the MAOP.

The results of the extensive records verification efforts undertaken by INGAA members were reported by operators in Part Q of the annual report submitted on June 15. In general, the results show that MAOP confirmation records do exist for the majority of pipeline mileage using the instructions provided in the annual report.

Regrettably, the instructions for completing the annual report were inconsistent with the approach outlined in the IVP. In basic terms, the annual report guidance permitted an "either-or" verification proposition, while the IVP, in Diamonds 1-6, took an "and" approach, requiring four layers of records before the records for a pipeline were deemed acceptable. In addition, the annual report does not collect data that would permit PHMSA to analyze affected MCA mileage.

If PHMSA proceeds to issue a rule that incorporates the IVP, as proposed, it cannot rely on data from the annual report as the basis for its cost-benefit analysis of that rule. This is because the

[1] Jan 10,2011 Advisory Bulletin 11-01

[2] May 7, 2012 Advisory Bulletin 12-06

annual report data would grossly understate the pipeline mileage that would need to be tested pursuant to the IVP

Appendix F: Historical Construction and Material Integrity Validation Requirements and MAOP Determination Requirements

High-pressure natural gas transmission pipelines use conservative engineering design criteria and redundant inspections and tests during the pipe's manufacture and construction to validate the pipeline's pressure-holding capability.

Two key processes have been put in place to assure the quality of the installed pipeline to match or exceed the design pressure:

1. **Manufacturing specifications for pipeline material.**
   While there are many different specifications for manufactured material installed in pipelines (e.g. pipe, valves and fittings) the predominant material used is line pipe. Natural transmission gas pipelines predominantly use American Petroleum Institute-specified line pipe.

2. **Post-construction strength tests to higher levels than the pipeline will operate.**
   The predominant standard for post-construction strength testing was ASA B31.1, which eventually was renamed ASME B31.8. The pressure test level used and duration of the test changed through the decades.

American Petroleum Institute (API) Line Pipe Specifications

Since 1928, the API has produced a set of specifications that pipeline operators could use to validate the quality of manufactured steel pipe purchased for use in high-pressure transmission pipelines. These specifications, plus a pipeline operator's own requirements, form the basis for the Quality Assurance (QA) requirements for the manufacture of high-quality steel pipe for natural gas transmission pipelines. The API standards include specifications for material composition and strength and specify QA tests throughout the manufacturing process. The API pipe manufacturing specifications, which have been periodically updated to reflect changes in technology and processes, are incorporated by reference in the PHMSA pipeline safety regulations. Pipe segments (joints) rejected by tests conducted at the pipe mill are not used by the purchaser for pipeline construction. Accordingly, the purchaser of the material can be assured of the quality of the final pipeline segments they receive.

Examples of QA requirements throughout the decades are shown in Tables 1 and 2 and include strength tests, consisting both of hydrostatic pressure tests and tensile tests of samples of the pipe material. As illustrated in the tables, even before federal regulation in 1970, pipelines were subject to numerous and extensive quality specifications.

Table 1: Pipe Mill Pressure Testing and Tensile Testing Requirements Vintage API 5L Editions

Edition	Effective Date of Standard	Hydrostatic Pressure Test as a % of SMYS	Time Duration of Hydrostatic Pressure Test (sec)	Rate of Tensile Tests (test per joints)
1	Jan 1 1928	60	5	2 of 200
2	Jan 1 1929	60	5	2 of 200
3	Jan 1 1930	60	5	2 of 200
	sup February 1931	60	5	2 of 200
4	July 1 1931	80	5	1 of 100
	Sup July 1 1932	80	5	1 of 100
5	January 1 1934	80	5	1 of 100
6	August 1 1935	80	5	1 of 100
	Sup 3 Sept 1938	80	5	1 of 100
	Sup 6 Sept 1939	80	5	1 of 100
7	April 1 1940	80	5	1 of 100
	Sup No 2	80	5	1 of 100
8	May 1 1942	80	5	1 of 100
	sup 1 War Measures	80	5	1 of 100
9	August 1 1944	80	> 5 allowed	1 of 100
10	August 1 1945	80	> 5 allowed	1 of 100
	Sup July 1 1946	80	> 5 allowed	1 of 100
11 to 14th	March 1 1955	80	10	1 of 100
15	March 1 1956	80	10	1 of 100
16	April 1 1957	80	10	1 of 100
17	March 1 1959	80	10	1 of 100
18	February 1 1960	80	10	1 of 100
	sup January 1961	80	10	1 of 100
19	March 1962	80	10	1 of 100
20	March 1963	80	10	1 of 100
21	March 1965	80	10	1 of 100
22	March 1967	80	10	1 of 100
23	March 1968	80	10	1 of 100
24	April 1969	80	10	1 of 100
25	April 1970	80	10	1 of 100
26	April 1971	80	10	1 of 100
27	April 1973	80	10	1 of 100
	Sup to 27th	80	10	1 of 100
28	March 1975	80	10	1 of 100
29	March 1977	80	10	1 of 100
30	March 1978	80	10	1 of 100
31	March1980	80	10	1 of 100
32	March 1982	80	10	1 of 100

Table 2: Pipe Mill Pressure Testing and Tensile Testing Requirements Vintage API 5LX Editions

Edition	Effective Date of Standard	Hydrostatic Pressure Test as a % of SMYS	Time Duration of Hydrostatic Pressure Test (sec)	Rate of Tensile Tests (test per joints)
1	February 1948	85%	5	2 of 100
2	May 1949	85%	> 5 allowed	2 of 100
	sup December 1949	85%	> 5 allowed	2 of 100
3	March 1951	85%	> 5 allowed	2 of 100
	sup January 1952	85%	> 5 allowed	2 of 100
4	March 1953	85%	> 5 allowed	2 of 100
	sup February 1954	85%	> 5 allowed	2 of 100
5	November 1954	85%	10	2 of 100
6	February 1956	90%	10	2 of 100
7	April 1957	90%	10	2 of 100
8	March 1958	90%	10	2 of 100
	sup March 1959	90%	10	2 of 100
9	March 1960	90%	10	2 of 100
	sup January 1961	90%	10	2 of 100
10	March 1962	90%	10	2 of 100
	sup July 1962	90%	10	2 of 100
11	March 1963	90%	10	2 of 100
	sup March 1964	90%	10	2 of 100
12	March 1965	90%	10	2 of 100
13	March 1966	90%	10	2 of 100
14	March 1967	90%	10	2 of 100
15	March 1968	90%	10	2 of 100
16	April 1969	90%	10	2 of 100
17	April 1970	90%	10	2 of 100
18	April 1971	90%	10	2 of 100
	sup April 1972	90%	10	2 of 100
19	March 1973	90%	10	2 of 100
20	March 1975	90%	10	2 of 100
	sup March 1976	90%	10	2 of 100
21	March 1977	90%	10	2 of 100
22	March 1978	90%	10	2 of 100
23	March 1980	90%	10	2 of 100
	sup March 1981	90%	10	2 of 100
24	March 1982	90%	10	2 of 100
API 5L collected	back to 5L for 5LX, 5LS, & 5LU			
33	March 1983	90%	10	2 of 100
34 to 41	March 1984 to 95	90%	10	2 of 100
39	June 1991	90%	10	2 of 100

Design, Construction and Testing Standards were defined in ASME B31.8 and its predecessors

High-pressure natural gas transmission pipelines built before adoption of the ASA B31.1 engineering standard, utilized engineering specifications, processes and procedures that were developed by individual pipeline companies based on previous practices in other industries that utilized pressured piping (ASME Pressure Pipe Code B31) as a model.

As additional pipelines were built, these processes and practices were shared among pipeline operators. In order to promote common pipeline safety standards, an effort under the American Society of Mechanical Engineers (ASME), and through the American Standards Association (ASA/ANSI), was formed to develop a specific section for natural gas pipelines. The following excerpt from the testimony to the Federal Power Commission (FPC) documents the adoption and maturation of the standard.

> Safety Record Is the Product of Continuous Effort and Surveillance
> The gas pipelines' safety record results from a continuous effort to establish and abide by a code for the safe design, construction and operation of natural gas pipelines. In March 1926, Project B3l to write a code for all types of piping systems was undertaken. The first tentative standard was published in 1935; a revision to this standard was undertaken in 1937. This revision provided greater uniformity between sections of the code and resulted in the 1942 American Standard Code for Pressure Piping. Supplements to the 1942 code appeared in 1944 and 1947.
>
> By 1950, the tremendous expansion of the gas pipeline industry made it apparent that a separate document was required for gas piping. In November 1951, the B3l Committee authorized a separate publication of a gas piping code and designated it as Section 8. The first publication of Section 8 was made in 1952, consisting of material in the previous Section 2 combined with fabricating and comparable details from Sections 6 and 7.
>
> A new Section 8 Committee was organized in 1952. This committee numbered seventy-two individuals who represented not only gas pipeline and distribution companies but manufacturers of materials, government agencies, research organizations, the National Board of Fire Underwriters, engineering consultants and national organizations such as the American Petroleum Institute, the American Society of Mechanical Engineers and the American Society of Civil Engineers. After one and one-half years of concentrated effort, a draft of cod$ was approved by the committee in August of 1954 and by the' B31 Committee in October 1954. This Code was submitted by the American Gas Association to its member companies and overwhelmingly approved by 150 companies out of 154 who voted.

The full Section 8 Committee has met once a year since the initial publication of the Code in 1955 and has kept the Code current and abreast of the times based on new materials, new techniques and new information. Revised editions were published in 1958 and 1963.

The Code's acceptability as a proper standard is evidenced by its adoption by twenty-four state regulatory commissions*. Other state commissions presently have under consideration the adoption of the Code as a standard.

The interstate natural gas transmission pipelines that were regulated by the Federal Power Commission (the FPC is the precursor to the Federal Energy Regulatory Commission) utilized these ASA standards for the design, construction, operation and maintenance processes. On June 30, 1966 the FPC issued Order 324 to prescribing the maximum safe operating pressure for new pipelines built under the Commission's jurisdiction. In that order, the FPC stipulated that the determination should follow the ASA methodology in order to get prompt approval and significant justification was needed to vary from that methodology.

In the 1966, the FPC published a report for Congress titled "Safety of Interstate Natural Gas Pipelines," a review of the state requirements for the regulation of natural gas pipelines was documented in a table and 26 had adopted ASA B31.8 . Congress recognized the value and recommended to the Office of Pipeline Safety (OPS), the precursor to the present PHMSA, adopt the 1968 Edition of ASME B31.8 as the interim pipeline safety standards. In 1970, OPS rewrote sections of the interim Federal pipeline safety standards and established the present Part 192.

Criteria for the design pressure of natural gas transmission pipelines under ASME B31.8 was based on the internal design pressure and conservative factors added for population density around the pipeline, outside force interaction and corrosion protection.

Design Pressure and MAOP Criteria Based on Material Strength and Population Density

Initially, the design-pressure criteria of ASME B31.1 was based on the population density near the pipeline at the time of construction; with Division 1 being roughly equivalent to today's Class 3 and 4 and Division 2 being equivalent to Class 1 and 2. The Barlow formula supplanted the ASME pressure vessel code design for Division 1 locations in 1942 ASA Edition of B31.1 and has been standardized as the design formula of steel pipelines since then. The Barlow formula utilizes the specified minimum yield strength (SMYS) based on the material purchased by the pipeline operator as referenced in the API pipe specifications (5L).

The concept of Maximum Allowable Operating Pressure (MAOP) was introduced in the first published edition in 1942. At the issuance of the ASA B31.8 (1955 Edition), these two location distinctions used for design were further subdivided into four class locations that are roughly equivalent to the present PHMSA class-location descriptions. An important distinction from the present ASME code and the regulations is that these were simply design requirements. O&M practices were not adjusted for future population density changes, and there were exclusions for pipeline segments with design pressures at low-stress levels (<40%SMYS). In addition to these changes, there was an increasing requirement for a pressure test differential at the commissioning of the pipeline, as shown in Table 3.

Table 3: Onshore Natural Gas Transmission Pipeline Pressure Testing Requirements of Vintage ASA/ASME B31.8 Editions

Current class designations	ASA B31.1 -1942 Description of population density at time of construction	ASA B31.1 - 1951 pressure test description	ASA B31.1.8-1955 pressure test description operating over 30% SMYS	AS B31.8-1958 Pressure test description operating over 30% SMYS	AS B31.8-1963 Pressure test description operating over 30% SMYS	USAS B31.8-1968 Pressure test description operating over 30% SMYS	Present pressure test description Subpart J [192.505]; [192.619 (2) (i)]; [192.611]
Class 1	Division 2	Maximum Service Pressure +50psi	1.1xMOP with water, gas or air	1.1xMOP with water, gas or air	1.1xMOP with water, gas or air except tie-ins	1.1xMOP with water, gas or air except tie-ins	Installed before Nov. 12, 1970 Test pressure is 1.1 * MAOP for 8 hours Installed after Nov. 11,1970 Test pressure is 1.1 * MAOP for 8 hours
Class 2	Division 2	Maximum Service Pressure +50psi	1.25xMOP with water or air	1.25xMOP with water or air	1.25xMOP with water or air except tie-ins	1.25xMOP with water or air except tie-ins	Installed before Nov. 12, 1970 Test pressure is 1.25 * MAOP for 8 hours Installed after Nov. 11,1970 Test pressure is 1.25 * MAOP for 8 hours Upgraded pipeline is previously tested pressure of MAOP /.8 for 8 hours
Class 3	Division 1	1.5 times Maximum Service Pressure	1.40xMOP with water	1.40xMOP with water	1.40xMOP with water except tie ins. 1.1xMOP with air if below 32 deg.at pipe depth or no water available. 1.2xMOP with air if MOP<50% SMYS and longitudinal joint factor is 1.	1.40xMOP with water except tie ins. 1.1xMOP with air if below 32 deg. at pipe depth or no water available. 1.2xMOP with air if MOP<50% SMYS and longitudinal joint factor is 1.	Installed before Nov. 12, 1970 Test pressure is 1.4 * MAOP for 8 hours Installed after Nov. 11,1970 Test pressure is 1.5 * MAOP for 8 hours Upgraded pipeline is previously tested pressure of MAOP/.667 for 8 hours
Class 4	Division 1	1.5 times Maximum Service Pressure	1.40xMOP with water	1.40xMOP with water	1.40xMOP with water except tie ins. 1.1xMOP with air if below 32 deg. at pipe depth or no water available. 1.2xMOP with air if MOP<50% SMYS and longitudinal joint factor is 1	1.40xMOP with water except tie ins. 1.1xMOP with air if below 32 deg. at pipe depth or no water available. 1.2xMOP with air if MOP<40% SMYS and longitudinal joint factor is 1	Installed before Nov. 12, 1970 Test pressure is 1.4 * MAOP for 8 hours Installed after Nov. 11,1970 Test pressure is 1.5 * MAOP for 8 hours Upgraded pipeline is previously tested pressure of MAOP/.5555 for 8 hours

An important change to the ASA B31.8 occurred in 1968 when that edition of the code dictated that pipeline companies should survey for population density changes along operating pipelines and adjust the operating pipeline safety factor calculations accordingly. At the time, there were not a set timeline for the class-location identification or making pipe line segments commensurate with the new safety factors. The anticipation of this change and subsequent adoption of the B31.8 code by the Office of Pipeline Safety as an interim safety standard, created a significant amount of replacement, retesting and rerating of pipeline segments among INGAA membership as shown in Table 4.

Table 4: Summary of Replacement and Testing Mileage as a result of 1968 ASA B31.8

	1967 (miles)	1968 (miles)	1969 (miles)	1970 (miles)
Retesting Existing Pipelines	2,660	2,538	3,855	1,812
Replacing	342	289	413	201

(18 INGAA companies reporting [April 1971])

OPS proposed the initial Part 192 pipeline safety regulations[1] in 1970 under the direction of Congress, which clearly stated that design, material and construction practices only be applied to pipelines built after the promulgation of the regulations[2]. Operation, inspection and maintenance requirements under the regulations would cover all pipelines in service.

OPS proposed a change to the class-location definition under Docket OPS-3D in 1970, requiring a re-designation of pipeline class locations established under the ASA 1968 B31.8 Edition and adopted in the subsequent interim PHMSA regulations.

Concurrently, OPS initiated a rulemaking under Docket OPS-3E that established the requirement to establish the MAOP of pipeline segments in service. The original OPS NOPR established a strict design-based process for future pipelines as envisioned by Congress, but left no solution for a significant amount of pipe that was already operating safely at that time. After significant public debate and a risk assessment by PHMSA, the present 49 C.F.R. § 192.619 was adopted.

49 C.F.R. § 192.619 in conjunction with new 49 C.F.R. § 192.607 allowed a transition time for pipeline segments that were deemed to not be commensurate with the new class-location requirements to either be replaced, tested or the MAOP established at a lower level than the design pressure. Pipeline segments that were deemed lower risk (MAOP<40% SMYS, Class 1 segments and pipelines with a design pressure that was commensurate with the new class location definition) were excluded from any of this activity. The regulations required that pipeline segments that were not commensurate to pass through the new design-based criteria under the 49 C.F.R. § 192.619 (a) sections.

[1] OPS-3 Transportation of Natural and Other Gas by Pipeline; Minimum Safety Standards; June 12, 1970
[2] INGAA Comments to OPS-3E docket (April 1971)

There was a lot of conjecture on the ability of the pipeline companies to conduct all this activity in the time provided, as the final rule 49 C.F.R. § 192.607 demanded a two-step deadline. As a result, future hearings[3] were established to review these schedule deadlines after the level of effort was determined under application of the new class-location definitions and MAOP determination requirements. INGAA presented testimony of the estimated activity as shown in Table 5.

Table 5: Comments by INGAA on Pipe Replacement Estimates Due To Class Location Changes

Pipe Replacement Estimates Due To Class Location Changes		
Segments	Mileage	
1,274	754	
Retesting Estimates Due to Class Location Changes		
Segments	Mileage	
966	4,045	
Pipe Replacement and Retest Estimates Due to Multiple Occupancy		
Multiple Locations	Replacement Mileage	Retest Mileage
846	158	293

49 C.F.R. § 192.607 was then modified under a subsequent rulemaking[4] to require the process to be completed by 1974. 49 C.F.R. § 192.607 was removed from the regulation in 1996 since the time for the applicability in the initial determination of MAOPs had long since passed.

Interaction of the Regulatory Process after the Adoption of 49 C.F.R. § 192.6, .607, .611, and .619

The original regulations included 49 C.F.R. § 192.607, which required operators to determine the class location of their pipelines and to review the design factors for their pipe to determine if they were commensurate with the requirements of 49 C.F.R. § 192.111 (Class 1 – 0.72; Class 2 – 0.60; Class 3 – 0.50; Class 4 – 0.40). This review was limited to pipe with a MAOP that produced a hoop stress more than 40% SMYS, and was to be completed by April 15, 1971. If the design factor was commensurate, no further action was required. If the design factor was not commensurate, the operator was required to follow the requirements in 49 C.F.R. § 192.611. Presumably, this study was only required for "grandfathered" pipelines, since any MAOP based on 49 C.F.R. § 192.619(a) (1-3) would have had a design factor commensurate with the regulations and would have been pressure tested.

Operators were required to complete confirmation or revision of the MAOP of at least 50% of their systems by January 1, 1972 and the remainder by January 1, 1973. Later rulemaking extended this deadline to December 31, 1974. Since all action required by 49 C.F.R. § 192.607

[3] OPS – 3E Public Hearings

[4] Amendment 192-5; Docket No. OPS-11

was to be completed by January 1, 1974, it became irrelevant after that date. It was removed from Part 192 in 1996.

Operators conducted the required evaluation and the required pipe replacement or pressure testing. A substantial amount of pipe replacements, hydrostatic testing and MAOP reductions occurred as a result of the requirements of 49 C.F.R. § 192.607. Many operators prepared a comprehensive study to document the work performed to meet these requirements.

49 C.F.R. § 192.611

If design factors were commensurate at the time of the study required by 49 C.F.R. § 192.607, no further action was required. This provision allowed non-tested pipe in all class locations, provided that the design factors were commensurate with the class location.

If the design factors were not commensurate with the design factor required for the class location in 1970-1974, and the pipe had been hydrostatically tested, the following limitations applied:

1. The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

2. If the pipe had not been tested, operators could test the pipe to meet the requirements of 49 C.F.R. § 192.611 within the limits noted in #1, above. As a result, operators tested a substantial amount of pipe in the early 1970s.

3. If the design factor exceeded the limitations in #1 above, the pipe would have to be replaced or the MAOP derated. As a result, operators replaced a substantial amount of pipe in the early 1970s.

49 C.F.R. § 192.619

The MAOP requirements in the 1970 regulations were very similar to those in effect today. Operators could establish their MAOP under 49 C.F.R. § 192.619(a) (1-4) (design, pressure test, highest pressure) or under 49 C.F.R. § 192.619(c), the "grandfather" clause.

Conclusions

As a result of the historical industry actions:

- The pipeline industry recognized the need and hence developed consensus engineering standards to improve the safety of natural gas transmission pipelines.

- The API specifications always have required that line pipe be subject to pressure tests and material strength sampling to assure quality at the pipe mill.
- Pipelines built under ASA/ASME B31.8 standards were subject to various levels of pressure tests at the time of construction. Pipeline built within populated areas required a greater pressure test level.

As a result of historical actions by state regulators and the FPC:

- ASA/ASME B31.8 standards and API line pipe standards were incorporated into various state and FPC regulations.

As a result of the historical actions taken by OPS/PHMSA:

- PHMSA addressed MAOP determination in a series of rulemakings when the federal pipeline safety regulations were initiated (in the 1970s) and made risk-informed decisions regarding the transition from standards-based implementation to regulatory oversight.
- Over a period of time, PHMSA permitted pipeline companies time to replace, retest and rerate pipeline systems to comply with the federal regulatory mandate.
- Class 1 locations were not (and are still not) addressed in 49 C.F.R. § 192.611, so no action was required if the pipe was not commensurate with Class 1 design factors. Accordingly, pipelines in Class 1 locations are allowed to have a grandfathered MAOP above 72% SMYS under 49 C.F.R. § 192.619(c).
- All pipe in Class 2, 3 and 4 locations must be commensurate with the design factor relevant for that class or be compliant with 49 C.F.R. § 192.611.
- Pipe with a design factor commensurate with its relevant class location did not have to be pressure tested in 1971-1973 pursuant to Subpart J. Barring any changes to the class location, the pipeline segment can continue to operate without a pressure test.

Any pipe in Class 2, 3 or 4 locations that is not commensurate with the design factor for the current (2013) class, and is not compliant with 49 C.F.R. § 192.611, is out of compliance under current regulations. This is true for pre-regulation and post-regulation pipe.

BEFORE THE
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
UNITED STATES DEPARTMENT OF TRANSPORTATION
WASHINGTON, D.C.

Pipeline Safety: Public Workshop on the Integrity Verification Process	Docket PHMSA-2013-0119

ADDITIONAL COMMENTS OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA ON THE PHMSA DRAFT INTEGRITY VERIFICATION PROCESS

October 7, 2013

Table of Contents

Executive Summary

The Interstate Natural Gas Association of America (INGAA), a trade organization that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America, welcomes the opportunity to submit additional comments on the Pipeline & Hazardous Materials Safety Administration's (PHMSA) Integrity Verification Process (IVP).

INGAA members have reviewed PHMSA's second draft IVP, posted September 11, and agree with many of PHMSA's changes. INGAA members commend PHMSA for addressing key points made in the public workshop on August 7 and at the Advisory Committee Meeting on August 9. Specifically, INGAA members commend PHMSA for recognizing:

- Maximum Allowable Operating Pressure (MAOP) can be reconfirmed by having a test of material strength to 1.25xMAOP,
- MAOP reconfirmation and Integrity Management (IM) need to be managed as separate processes,
- Records and, in particular, material records are critical for IM,
- Alternate methods need to be developed and approved for determining specificed minimum yield strength (SMYS),[1] and
- The benefits of high consequence area (HCA) and moderate consequence area (MCA) designations in lieu of the less accurate class location process.

The comments submitted herein are meant to supplement INGAA's September 9 filing.[2] In these supplemental comments, INGAA:

1. Provides its own version of an IVP flow chart and a supporting narrative describing the core differences between INGAA's proposal and PHMSA's document,
2. Proposes regulatory text at 49 C.F.R. § 192.619(e) to address "grandfathered" pipelines,
3. Clarifies what records are needed for MAOP reconfirmation,
4. Clarifies PHMSA's early-1970s MAOP confirmation process, including records requirements, and
5. Provides a conceptual view for extending and improving Integrity Management.

INGAA provides its alternate IVP flow chart and supporting narrative for consideration.

INGAA submits a flow chart (see page 8) that addresses the key elements of PHMSA's second draft IVP, while improving it by providing additional detail and

[1] 49 C.F.R. § 192.3, specified minimum yield strength
[2] PHMSA 2013-0119-0042 (INGAA Comments filed September 9, 2013).

clarity and a proposed implementation timeline. For example, INGAA details the use of prior strength tests (INGAA IVP Steps 5 and 6) and how PHMSA's engineering critical analysis (ECA) can be applied (INGAA IVP Step 10).

Page one of INGAA's flow chart focuses on two types of pipelines where IVP is applicable:

1. Pipeline segments lacking records to support MAOP reconfirmation, and
2. Previously untested pipelines.

INGAA compares PHMSA's second draft IVP and INGAA's IVP flow chart on page 7. To further illustrate the differences, INGAA provides a high-level comparison in the following table:

Table 1: High-Level Comparison between INGAA's Draft IVP and PHMSA's 2nd Draft IVP

	PHMSA's IVP Box #	PHMSA's Draft Approach	Industry's IVP Box #	Industry Approach
Screening Criteria	1	20% SMYS threshold	4	30% SMYS threshold; consistent with existing 49 C.F.R. § 192.941 and multiple requirements in ASME B31.8
	3+4	"Legacy" and "modern" – classification only determines minimum test and circumstances where spike test is required	Page 2	"Legacy" pipe issues monitored and addressed in IM, which may include a spike test
	3+4	Includes review of manufacturing and construction (M&C) related failures	Page 2	Included in IM improvements
	3+4	Subjects grandfathered pipelines to PHMSA's boxes 5-10 regardless of prior pressure test	5	Requires material strength test on grandfathered pipelines subject to priortizations in boxes 1-4
	3+4	Requires minimum pressure test level commensurate with class	5	Allows use of prior pressure tests to 1.25xMAOP for pipelines installed before federal regualtions became effective, which is widely accepted as level to establish adequate safety margin for MAOP, and has the same requirement as PHMSA for pipelines installed after the Federal regulations became effective
"Actions"	8+10	Requires spike test for all legacy pipe; spike test only required on modern when a history of M&C failures	8	Requires spike test when needed in IM
	9	De-rate commensurate with class	9	De-rate pipeline by 20%; an established method for providing an effective safety margin and is used by PHMSA
	6	"ECA" option	7+10	Provides specificity for using ILI in lieu of pressure test, when demonstrably proven to be an 1.25xMAOP alternative test of material strength, as an "ECA" option
	11	Material verification process	Page 2	Records needed for ILI anomaly response will be required in boxes 7+10

INGAA also provides a separate conceptual flow chart for IM (see page 18) that captures and organizes the commitments made by INGAA members to extend and improve IM.[3] As INGAA stated in its previous comments, its members firmly believe

[3] INGAA's commitments are substantive improvements that grew largely out of the work conducted by INGAA members under the Integrity Management Continuous Improvement (IMCI) Initiative in 2011 and 2012. Many of these commitments were undertaken in response to concerns raised and opportunities

that reconfirming the MAOP of pipelines is a one-time process, while IM is an ongoing process. As such, MAOP reconfirmation and IM should be handled as separate processes in PHMSA regulation.

In addition to its conceptual flow chart on IM, INGAA proposes a phased approach for implementation of IM improvements.

INGAA believes extending and improving IM warrants further public discussion. INGAA understands that PHMSA plans to hold a workshop to discuss experience and lessons learned during the first ten years of 49 C.F.R. § 192 Subpart O, as well as potential improvements to IM. INGAA members support such a public forum and commit to sharing experiences and lessons learned. INGAA members request the opportunity to refine its flow chart and provide additional information to PHMSA on IM expansion over the next 90 days.

INGAA members support inclusion of a new provision in 49 C.F.R. § 192.619 to address grandfathered pipe.

INGAA members support the concept asserted by the American Gas Association (AGA) that PHMSA add a provision to 49 C.F.R. § 192.619 to address grandfathered pipeline segments. This is consistent with INGAA's original comments requesting that PHMSA develop an approach for "grandfathered" pipelines that addresses stakeholders' concerns by ensuring that pre-regulation pipelines in HCAs are tested for material strength, and that pre-regulation pipelines in MCAs are evaluated and, where appropriate, undergo testing. Therefore, INGAA proposes a new subsection (e) of Section 192.619, which provides specific performance-based language for PHMSA's consideration. INGAA's proposal (see page 13) adds specificity to AGA's language by providing details on engineering critical analyses using in-line inspection (ILI) for MAOP reconfirmation, and recommends a review of the MAOP reconfirmation schedule after additional information is available to assess the impact on customers consistent with the Pipeline Safety Regulatory Certainty and Job Creation Act of 2011 (PLSA 2011), Section 23(d)(3) – Completion of Testing, which describes consultation among the FERC, PHMSA and state regulators.

INGAA clarifies what records are needed for MAOP reconfirmation.

There are very distinct differences between what records are needed for MAOP reconfirmation and IM activities (see Table 2 below). Therefore, the processes should remain separate.

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foreseen by PHMSA management and staff. *See* PHMSA 2013-0119-0042 (INGAA Comments filed September 9, 2013).

Table 2: Records Uses

	Records Required for MAOP Reconfirmation	Records Required for Integrity Management
Determine operating stress level (%SMYS)	Diameter, wall thickness, SMYS and long seam to ensure that correct stress level	
Determine existence of susceptible seam types	Susceptible seam type existence must be validated to determine how the screening criteria are applied	
Determine prior strength test to 1.25xMAOP	Field test documentation	Not applicable
Determine prior strength test to 1.1xMAOP	Records of field test or mill test report (80% SMYS)	
Evaluate anomalies with ILI processes	Diameter, wall thickness, SMYS for ILI Alternative	Diameter, wall thickness, SMYS for ILI

INGAA provides additional background on historical MAOP record requirements

INGAA understands and appreciates PHMSA's goal of verifying MAOP determination records. However, INGAA members are concerned that the agency is retroactively imposing recordkeeping requirements. In PHMSA's first draft IVP chart dated July 9, and in FAQs #13-16, the agency proposes that an operator must have four sets of records in order to properly verify MAOP. Even though PHMSA revised its flow chart on September 10, the notes portion still indicates a similar requirement.

As PHMSA is aware, many transmission pipelines predate the federal pipeline safety regulations. When these pipelines were constructed, most operators chose to follow the design, construction, operations, and maintenance standards that were in effect at the time. For example, if a pipeline was constructed in 1955, an operator could use Section 845.22 of the American Standards Association (ASA) B31.1.8-1955 to establish MAOP. In 1968, the Department of Transportation adopted the American Society of Mechanical Engineers (ASME) Standard B31.8 (1968) as the interim pipeline safety regulation and used the ASME's MAOP definition. None of these standards had explicit recordkeeping requirements for MAOP determination. There was no federal recordkeeping requirement because 49 C.F.R. Part 192 did not exist. Likewise, when the Department of Transportation introduced 49 C.F.R. Part 192 in 1970, the MAOP regulations (§ 192.619) did not require operators to maintain records supporting each of the four methods to verify MAOP. Rather, most operators only retained the appropriate record to support the § 192.619(a)(1)-(4) method they chose. Most operators with pre-regulation pipe that verified their MAOP under § 192.619(c) kept proof of their actual operating pressure for the five years preceding 1970. Finally, the agency did not require retention of four separate records when it directed operators to confirm its MAOP under 49 C.F.R § 192.607.[4]

[4] Section 192.607 required operators to reconfirm MAOP to ensure it was commensurate with the new class location definition.

To date, there still is no explicit requirement in the pipeline safety regulations to maintain records for each Section 192.619(a)(1)-(4) MAOP verification method. Congress did not mandate that the agency impose recordkeeping requirements for the verification methods operators did not choose. Similarly, the National Transportation Safety Board (NTSB) did not make this specific recommendation to PHMSA. Historically, PHMSA has taken a practical approach by accepting a variety of records for MAOP reconfirmation. The agency has recognized the different types of recordkeeping approaches and record types used by manufacturers, engineering companies and operators to verify MAOP. INGAA hopes that PHMSA will consider practical approaches in choosing appropriate records for its IVP process.

Provides a conceptual view for extending and improving Integrity Management

INGAA believes some concepts that appeared in PHMSA's IVP, such as fatigue life analysis, material verification and spike testing, should be addressed in IM. As a result, INGAA also offers a separate flow chart (see INGAA IVP details on IM, page 18) to illustrate how pipelines can extend and improve IM. Many of the suggested improvements should be topics in PHMSA's planned IM 2.0 workshop.

Background

While the safety performance of natural gas transmission pipelines has been improving steadily for decades, it is the goal of INGAA's members to continually improve. INGAA's September 9 comments discussed improvements to the natural gas transmission system's safety performance.[5]

INGAA has a strong commitment to pipeline safety, and its members have publicly stated a goal of zero natural gas transmission pipeline incidents. This closely aligns with goals of both PHMSA, as the federal pipeline safety regulator, and the the public. INGAA's members have articulated a set of specific commitments[6] to achieve pipeline safety.

INGAA emphasizes key positions

INGAA members want to emphasize their comments over the last few months, including the IVP comments submitted on September 9, and statements made during the IVP Workshop, the Gas Advisory Committee Meeting, and other engagements. While it appears that PHMSA has made changes to its second draft IVP to address many of INGAA's positions, INGAA believes it is important to re-emphasize its key points:

1. MAOP verification and IM should not be combined into a single process.
2. MAOP confirmation is a one-time process that establishes a safety margin between the test pressure and the operating pressure.
3. IM is a set of ongoing activities to manage safety and integrity, including maintaining a margin of safety. INGAA fully supports extending and improving IM.
4. An ECA/Fitness for Service (FFS) process should be used as the basis for addressing previously untested pipelines and pipelines lacking adequate records to support an MAOP. An ECA-process proposed by PHMSA can work as long as it has the rigor of INGAA's proposal.
5. INGAA members will work with PHMSA to demonstrate use of an ILI process in lieu of pressure testing for eliminating material and construction anomalies that could fail independently in operating service.
6. Application of ECA/FFS has the desired effect of addressing provisions of the grandfather clause that cause concern to stakeholders.
7. PHMSA currently lacks a credible basis for establishing a cost-benefit analysis of the various versions of IVP due to lack of definition and proposals that are inconsistent with past regulatory policy.

[5] PHMSA 2013-0119-0042 (INGAA Comments filed September 9, 2013).
[6] *Id.*

Detailed Comments

In this section, INGAA discusses its five main points from the Executive Summary in detail. Specifically, INGAA provides: (1) a detailed comparison of the differences between PHMSA's second draft IVP and INGAA's flow chart; (2) proposed language to address grandfathered pipelines; (3) a summary of what type of records are needed to support MAOP reconfirmation; (4) a discussion of the historical MAOP recordkeeping requirements, and (5) a conceptual view for extending and improving IM.

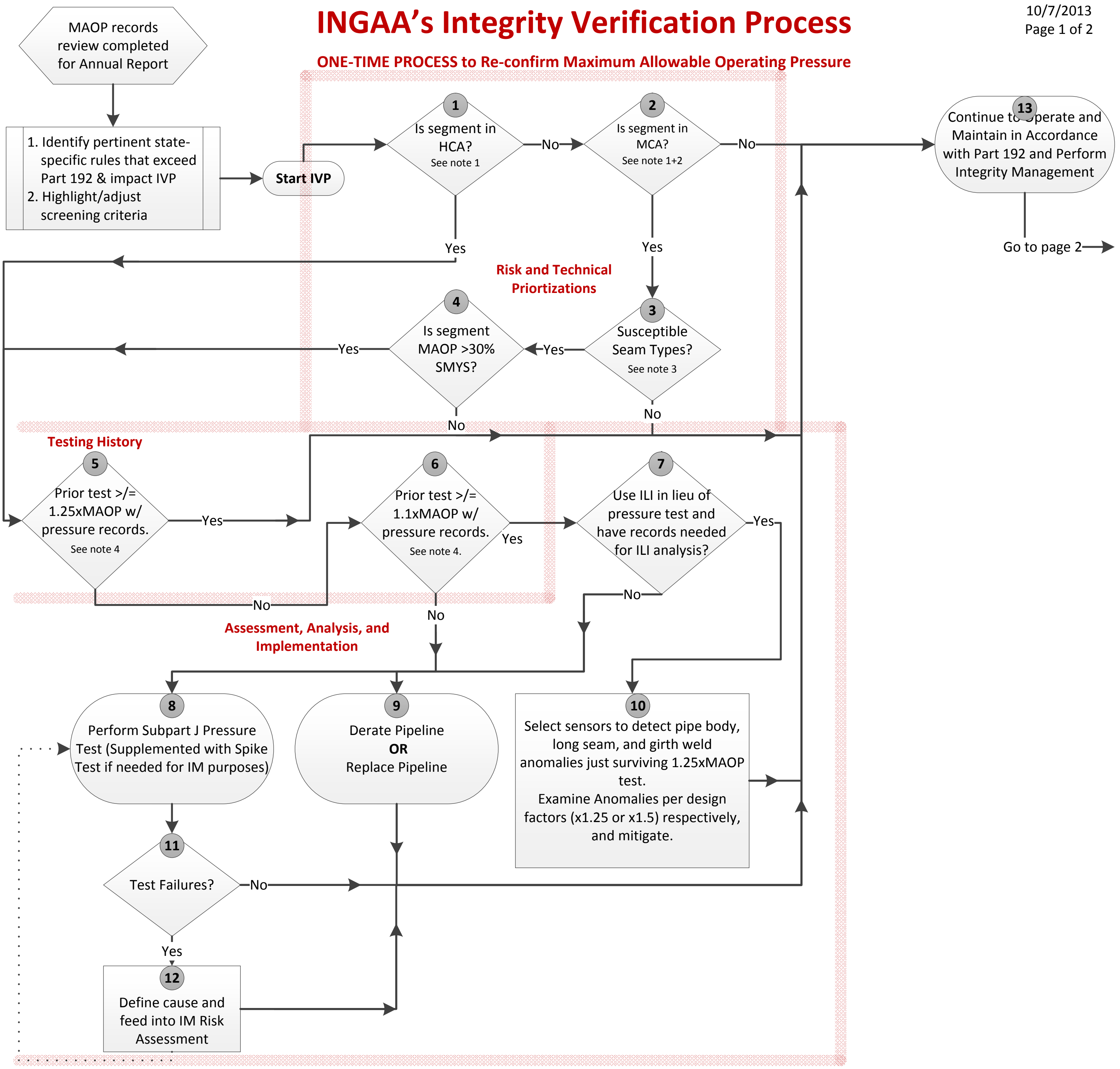
INGAA provides its IVP flow chart and narrative for consideration.

INGAA's IVP flow chart is based on its "Fitness for Service for Reconfirming Maximum Allowable Operating Pressure,"[7] which was developed as part of INGAA's IMCI Initiative. INGAA members developed a process based on long-standing engineering principles of FFS to demonstrate the material strength of a pipeline segment as it was originally installed, recognizing that material strength is the basis for MAOP. INGAA's proposed timetable for implementation is designed to address segments lacking records to support MAOP or those previously untested, while continuing to transport natural gas reliably to customers.

INGAA's IVP flow chart has been designed to emulate PHMSA's IVP flow chart. INGAA's chart is divided into two components: (1) the process for MAOP reconfirmation and (2) a diagram for extending and improving IM. INGAA envisions that all transmission pipeline segments would follow the processes outlined in this flow chart.

[7] The term "reconfirmation" is used as it is in Section 23(a)(1)(A) of the PLSA of 2011, to denote that operators will be reconfirming MAOPs that were already confirmed in the early 1970s under 49 C.F.R. § 192.607.

Figure 1: INGAA IVP (Page 1)



PROPOSED DEADLINES			
Mileage	HCA	50%	Date (Final Regulation) + 4 yrs
		100%	Date (Final Regulation) + 8 yrs
	MCA	50%	Date (Final Regulation) + 13 yrs
		100%	Date (Final Regulation) + 18 yrs

Notes:

Note 1: See table titled "proposed deadlines." For intrastate natural gas transmission pipelines actual timing to be implemented by order of state utility commissions.

Note 2: ***Moderate Consequence Area*** (MCA): INGAA supports the concept of MCAs to address population within the PIR.

Note 3: ***Susceptible Seam Types*** mean LFERW, SSAW, Flash Weld (AO Smith), or pipe w/ joint factor < 1 (e.g., lap welded pipe) regardless of date of manufacture with known history of long seam issues.

Non-susceptible Seam Types mean DSAW, HF-ERW, and Seamless

Note 4: For the purposes of MAOP re-confirmation there is no limitation on allowable hydrostatic test dates (pre-65 tests acceptable) or test durations. Mill tests acceptable for use in box 6 screening.

Differences still remain in screening criteria between INGAA's IVP and PHMSA's Second Draft of IVP.

PHMSA's and INGAA's IVP proposals include specific screening criteria that determine what pipeline segments may be subject to "actions," such as Subpart J pressure tests, de-rating, replacing or ILI/ECA. The following sections detail the differences in the screening criteria between the two proposals.

Table 3: High-Level Comparison of Screening Criteria

	PHMSA's IVP Box #	PHMSA's Draft Approach	Industry's IVP Box #	Industry Approach
Screening Criteria	1	20% SMYS threshold	4	30% SMYS threshold; consistent with existing 49 C.F.R. § 192.941 and multiple requirements in ASME B31.8
	3+4	"Legacy" and "modern" – classification only determines minimum test and circumstances where spike test is required	Page 2	"Legacy" pipe issues monitored and addressed in IM, which may include a spike test
	3+4	Includes review of manufacturing and construction (M&C) related failures	Page 2	Included in IM improvements
	3+4	Subjects grandfathered pipelines to PHMSA's boxes 5-10 regardless of prior pressure test	5	Requires material strength test on grandfathered pipelines subject to priortizations in boxes 1-4
	3+4	Requires minimum pressure test level commensurate with class	5	Allows use of prior pressure tests to 1.25xMAOP for pipelines installed before federal regualtions became effective, which is widely accepted as level to establish adequate safety margin for MAOP, and has the same requirement as PHMSA for pipelines installed after the Federal regulations became effective

PHMSA and INGAA use different operating stress levels, stated as percent SMYS, as screening criteria.

INGAA agrees that using operating stress level is an effective means to determine risk-based exclusions; however, the percentage level in the two proposals is different. PHMSA's approach utilizes a <20% SMYS exclusion for certain MCA Class 1 and 2 locations while INGAA's approach utilizes a <30% SMYS exclusion for all MCA locations.

INGAA believes <30% SMYS is a more effective screening criteria because there are many years of precedence with the low-stress threshold being established at 30% SMYS, including PHMSA's own regulations. PHMSA established 30% SMYS as a low-stress threshold for integrity assessments in the gas integrity management regulations in 49 C.F.R. § 192.941(a). In addition, 30% SMYS generally is accepted to be the "low-stress" boundary between leaks and ruptures for likely pipeline defects (it also is used as a low stress threshold in multiple provisions within ASME B31.8, such as pressure testing and repairs). This is important because preventing ruptures is a much higher priority than preventing leaks on transmission pipelines. Still, INGAA recognizes preventing leaks is important and operators conduct a variety of ongoing activities to prevent leaks, including leaks surveys, patrols and maintenance work on the pipeline right-of-way.

In applying the 30% SMYS low-stress threshold, INGAA members recognize that the threshold presumes an understanding of the minimum level of toughness and knowledge of pipe diameter, wall thickness and other metallurgical properties, such as the grade of pipe. Operators are encouraged to evaluate whether adjustments should be made to the 30% low-stress threshold level for the specific pipe segment being evaluated.

PHMSA's inclusion of "legacy" and "modern" pipe classification as screening criteria in IVP is unnecessary.

PHMSA's IVP flowchart includes two new classifications of pipe segments – "legacy" and "modern" – that ultimately have minimal effect on what screening criteria is required and what corrective actions are needed. The classifications determine whether a 1.1xMAOP strength test is acceptable for Class 1 or whether 1.25xMAOP should be the minimum strength test accepted for screening pipe. INGAA's flowchart utilizes the more conservative standard (1.25xMAOP) for all pipelines, whether legacy or not, so INGAA's process is appropriately more conservative in this regard.

The other requirements affected by PHMSA's "modern" or "legacy" classification are PHMSA's Box 8 and 10 where a Subpart J pressure test is required. The differences associated with these boxes are discussed in a later section.

PHMSA's inclusion of manufacturing and construction-related failures as a screening criteria for MAOP re-confirmation is misplaced.

INGAA agrees that operators should continually evaluate pipeline segments that have a history of M&C-related failures, however, PHMSA's way of addressing them is misplaced. On PHMSA's IVP flowchart in Boxes 3 and 4, one of the screening criteria used is a "history of M&C failures." INGAA emphasizes that consideration for such failures and subsequent corrective actions are best addressed in an operator's IM programs, because IM entails a continuing consideration of manufacturing and construction-related threats.

As mentioned previously INGAA has provided proposed improvements to IM on page 17, where this issue is addressed further.

PHMSA's process broadly requires "grandfathered" pipelines be subjected to additional screening criteria regardless of a previous pressure test.

INGAA agrees that previously untested grandfathered pipelines should be subjected to the Integrity Verification Process. It is important to acknowledge that grandfathered pipelines can have a previous pressure test, including one to 1.25xMAOP, as there are instances where a grandfathered pipe was pressure tested prior to or after federal pipeline safety regulations became effective. However, PHMSA's process doesn't appear to recognize this fact, requiring further action for grandfathered pipelines with previous pressure tests. PHMSA has not provided a basis for refusing to accept previous pressure tests conducted to adequate levels to reconfirm MAOP.

INGAA's process requires all pipelines (grandfathered or not) be subjected to the same screening criteria. Doing so provides an understandable and transparent decision process. INGAA has also provided previous comments that address this difference. Please reference the sections in INGAA's comments of September 9, Appendix B: Key Points from INGAA's September 9 Comments, titled:

- Application of FFS has the desired effect of deleting the provisions of the grandfather clause that cause concern to stakeholders (page 32)
- A single pressure test during a pipeline's life is an adequate basis for reconfirming an MAOP (page 30)
- FFS should be used as the basis for addressing previously untested pipelines and pipelines lacking adequate records (page 32)

INGAA's screening criteria for a 1.25xMAOP minimum pressure test is more conservative than PHMSA's criteria.

On PHMSA's second draft IVP flowchart in Boxes 3 and 4, a pressure test commensurate with class location is used as a screening criterion. INGAA's process, on the other hand, requires a single pressure test during a pipeline's life to 1.25xMAOP. Such a pressure test adequately establishes strength for purposes of establishing a valid MAOP. This pressure test establishes a safety margin between the test pressure and the operating pressure, and is more conservative than PHMSA's criterion. Ongoing pipeline safety and integrity management requirements are then used to manage the safety margin for the life of the pipeline.

Differences still remain in required "actions" between INGAA's IVP and PHMSA's second draft IVP

As a result of applying the various screening criteria in PHMSA's and INGAA's IVP proposals, certain "actions" are required to reconfirm MAOP, such as Subpart J pressure tests, de-rating, replacing or ILI/ECA. The following sections detail the differences in the "actions" among to the two proposals.

Table 4: High-Level Comparison of Required "Actions"

	PHMSA's IVP Box #	PHMSA's Draft Approach	Industry's IVP Box #	Industry Approach
"Actions"	8+10	Requires spike test for all legacy pipe; spike test only required on modern when a history of M&C failures	8	Requires spike test when needed in IM
	9	De-rate commensurate with class	9	De-rate pipeline by 20%; an established method for providing an effective safety margin and is used by PHMSA
	6	"ECA" option	7+10	Provides specificity for using ILI in lieu of pressure test, when demonstrably proven to be an 1.25xMAOP alternative test of material strength, as an "ECA" option
	11	Material verification process	Page 2	Records needed for ILI anomaly response will be required in boxes 7+10

Spike testing is more appropriately considered in IM than in MAOP reconfirmation.

There are differences among INGAA's and PHMSA's approach to including a spike test while doing a Subpart J pressure test. PHMSA's second draft IVP Box 8 requires pressure tests, including a spike test for "modern" pipe, when a history of M&C failures exist. PHMSA's second draft IVP Box 10 also requires a spike test for all "legacy" pipe. For example, the presence of wrinkle or miter bends classifies a segment as"legacy" pipe, which requires a spike test. Such features, however, arguably yield little benefit from a spike test in reducing risk. Additionally, PHMSA has yet to provide a technical basis for requiring spike tests for all "legacy" pipe and some "modern" pipe.

INGAA agrees that spike testing may be appropriate when already performing Subpart J pressure tests for MAOP reconfirmation. Since the need for spike testing always has been identified through an operator's IM program, including spike testing by default, PHMSA's proposal to require spike testing by default for MAOP reconfirmation is misplaced.

As mentioned previously, INGAA has provided proposed improvements to IM on page 17, where this issue is addressed further.

A 20% de-rate is more appropriate than a de-rate commensurate with class location.

PHMSA's second draft IVP requires a pipeline to reduce pressure on its system commensurate with class location in Box 9 while INGAA's IVP requires a 20% de-rate. Since 1.25xMOAP is the desired safety margin, the corresponding de-rate is 20%. When considering from which pressure to de-rate, an operator should use the higher of either the previous pressure test or historical operating level. If a 1.25xMAOP pressure test is used as a screening criteria to reconfirm MAOP, a de-rate that the equivalent safety margin of a 1.25xMAOP test should be an acceptable response for pipes that require action. There is also long-standing precedent of using a single de-rating factor regardless of design factor, or class location.

PHMSA's IVP includes an ECA option

PHMSA's IVP, Box 6, provides ECA as an option as one of the "actions" that can be required for pipeline segments not excluded by the previous screening criteria. PHMSA includes a wide variety of assessment methods that can be used as required, such as "ILI Program, CIS, Coating Survey, Interference Survey Remaining Life Fatigue Analysis, etc." The activities that PHMSA proposes are tools and methods used in managing integrity, not tools applicable to reconfirming MAOP. INGAA has adopted ILI as an option in its Boxes 7 and 10 (provided it is demonstrably proven to be a 1.25xMAOP pressure test alternative). In this case, INGAA does not believe that relying on methods such as coating surveys, and some of the other assessment methods outlined by PHMSA, would be the right "action" when re-confirming an MAOP. In this case, INGAA believes options should be limited to performing a pressure test, de-rating, replacing, or running an ILI tool (i.e., using ILI in lieu of pressure testing).

PHMSA's ECA option appeared to require that using one or more of the methods enumerated above (such as CIS or a coating survey) to reconfirm MAOP would require a case-by-case consideration by PHMSA staff. Past experience with MAOP and class location special permits that entailed case-by-case reviews often lacked transparency. In addition, it is unimaginable that PHMSA will have adequate staff to address thousands of case-by-case reviews. INGAA would prefer a simple, technically sound process that assures transparency to re-confirming MAOP. Therefore, INGAA does not believe entering into a case-specific process in which operators have unique one-on-one discussions with PHMSA is a practical or transparent means to re-confirm MAOP.

PHMSA's IVP includes a separate process entitled "Material Documentation Process"

PHMSA's IVP includes a sidebar process that details a "material documentation process" that consists of "long term statistical sampling" to "establish material properties." INGAA strongly recommends that PHMSA revise the word "establish" to "confirm," as operators are not for the first time specifying material properties, rather they are confirming them. INGAA's has provided comments to clarify what records are need for IVP (refer to Table 5 on page 15) and has included similar concepts as part of INGAA's improvements to integrity management which can be found in sections below (pages 17-24). Where operators need material records, such as for response to ILI results, appropriate records will be utilized.

INGAA members support inclusion of a new subsection in 49 C.F.R. § 192.619 to address grandfathered pipe.

INGAA members support AGA's concept of adding a provision to 49 C.F.R. § 192.619 to address grandfathered pipeline segments. This is consistent with INGAA's original comments requesting that PHMSA develop an approach for grandfathered pipelines that addresses stakeholders' concerns. INGAA proposes the following regulatory text for PHMSA's consideration:

> (e) Transmission pipelines:
>
> (1) For transmission pipelines located in HCAs that have not been previously tested for material strength of 1.25xMAOP, or lack records to support the MAOP, the pipeline must be subjected to one of the following methods:
>
> (i) a pressure test consistent with the requirements of section (a)(2),
>
> (ii) an engineering critical analysis using the results of in-line inspections to identify anomalies in the pipe body, long seam and girth welds that survive an equivalent pressure test under Subpart J,
>
> (iii) a reduction in pipeline MAOP by the test pressure or highest operating pressure divided by 1.25, or,
>
> (iv) a procedure that has been approved by the Administrator.
>
> (2) For transmission pipelines located in MCAs (to be defined) with an MAOP that produces a hoop stress of greater than 30% of SMYS, that have susceptible seam types identified in 49 C.F.R. § 192.917(e)(4) with a history of failure and that have not been previously tested for material strength or lack records to support the MAOP, the pipeline must be subjected to one of the following tests:
>
> (i) a pressure test consistent with the requirements of section (a)(2),
>
> (ii) an engineering critical analysis using the results of in-line inspections to identify anomalies in the pipe body, long seam and girth welds that survive an equivalent pressure test under Subpart J;
>
> (iii) a reduction in pipeline MAOP by the test pressure or highest operating pressure divided by 1.25, or
>
> (iv) a procedure that has been approved by the Administrator.
>
> (3) Interstate operators shall prioritize segments and complete 50% of the HCA mileage by (*effective date of final regulation plus four years*), and all applicable HCA mileage identified by the effective date of this rule by

(*effective date of final regulation plus eight years*)[8]. Interstate operators shall prioritize segments and complete 50% of the MCA mileage by (*effective date of final regulation plus 13 years*), and all applicable HCA mileage identified by the effective date of this rule by (*effective date of final regulation plus 18 years*).

INGAA recommends a review of the MAOP reconfirmation schedule by PHMSA after additional information is available to assess the impact on customers.

INGAA clarifies what records are needed and under what circumstances.

There are very distinct differences between the records needed for MAOP re-confirmation and IM activities (see the table that follows). Where a decision is made to conduct a Subpart J hydrostatic test to establish an MAOP (INGAA IVP Step #8), or where a previous 1.25xMAOP strength test is used, additional records are not necessary to validate the strength test.

Table 5: Records Uses

	Records Required for MAOP Reconfirmation	Records Required for Integrity Management
Determine operating stress level (%SMYS)	Diameter, wall thickness, SMYS and long seam to ensure that correct stress level	
Determine existence of susceptible seam types	Susceptible seam type existence must be validated to determine how the screening criteria are applied	
Determine prior strength test to 1.25xMAOP	Field test documentation	Not applicable
Determine prior strength test to 1.1xMAOP	Records of field test or mill test report (80% SMYS)	
Evaluate anomalies with ILI processes	Diameter, wall thickness, SMYS for ILI Alternative	Diameter, wall thickness, SMYS for ILI

INGAA provides additional background on historical MAOP record requirements

There is no explicit regulatory requirement to maintain MAOP analysis records for pre-regulation pipe.

INGAA disagrees with PHMSA's Integrity Verification Process FAQs, specifically FAQ #13, 14, 15, and 16. PHMSA states in FAQ #13 that "Pipeline operators are required

[8] INGAA proposes that the language be revised based on application of the PLSA 2011, Section 23(d)(3), Completion of Testing - "The Secretary, in consultation with the Chairman of the Federal Energy Regulatory Commission and State regulators, as appropriate, shall establish timeframes for the completion of such testing that take into account potential consequences to public safety and the environment and that minimize costs and service disruptions."

by the Code to maintain records that were used to determine MAOP."[9] In FAQ #15, the agency elaborates that operators need records and documentation for all four sections of 192.619(a)(1)-(4).[10] An operator must be able to support and justify its MAOP, but the agency has never required a particular set of records. Rather, the agency historically has accepted a variety of documents to verify MAOP.

In 1986, in response to a question of whether the regulations require operators to have records to substantiate the pressures used to establish MAOP under section 192.619(c), the agency stated that "[t]he regulations do not require "records" and that "…a violation would have to be clearly obvious in order to be enforceable."[11] This particular interpretation listed various records that an operator could use to establish its highest pressure for the five years preceding 1970. The acceptable records included pressure recording charts, compressor station records, flow calculations from a substantiated point, dispatcher records, or sworn statements. In 1998, the agency's Training and Qualifications division published its "Determination of Maximum Allowable Operating Pressure" document, which included instructions and a form that could be used to determine MAOP.[12] The agency concluded that if operators did not have complete records, an affidavit may suffice. The agency would not have made this statement if four distinct records were required. Finally, in 2004, PHMSA issued FAQs for its Gas Integrity Management Rule. One of the questions focused on whether an operator had to provide the original source documents, such as an actual pressure test for MAOP or a mill test report for a pipeline segment. The agency responded that "[o]perators should use the best information that they have available in performing the data integration and analysis associated with integrity management…"[13] These documents demonstrate that in the past, PHMSA and its predecessor agencies did not contemplate requiring pre-regulation pipeline operators to keep four different sets of records to verify MAOP.

INGAA acknowledges that an operator must have documentation to support its MAOP, but operators should not be expected to produce supporting records for MAOP methods they did not use. PHMSA's FAQs #14, 15, and 16 state that records for all four criteria in section 192.619(a) are required by 49 C.F.R. § 192.603(b). Section 192.603(b), promulgated in 1970, requires that operators keep records "necessary to administer the procedures established under section192.605". This

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[9] PHMSA Integrity Verification Process Workshop FAQs, August 7, 2013, at 4-5.
[10] *Id.*
[11] PI 86-005, August 4, 1986, at 3 *available at* http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Interpretation%20Files/Pipeline/1986/PI86005.pdf
[12] "Determination of Maximum Allowable Operating Pressure in Natural Gas Pipelines", April 22, 1998, at 2 *available at* http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/maop_determination.pdf. The agency published a similar document in 1995.
[13] PHMSA FAQs for Gas Transmission Integrity Management, FAQ 205, December 6, 2004, *available at* http://primis.phmsa.dot.gov/gasimp/faqs.htm#top41.

particular section applies to operating, maintaining, and repairing the pipeline. It is undisputed that MAOP is an operation activity. However, there is only one enforcement case in which the agency applied section 192.603(b) to MAOP records. In that decision, the agency acknowledged that …"the regulations do not explicitly require Respondent to have records of the pressures used to establish MAOP under 192.619(c)…"[14] PHMSA enforcement decisions and interpretations support the fact that the agency has never imposed specific recordkeeping requirements for MAOP verification.

PHMSA should accept a variety of different records to verify MAOP.

INGAA urges PHMSA to allow operators to produce various documents to verify MAOP. Operators use records to demonstrate that the analysis or process occurred with a level of quality control. Operators can reconfirm their MAOP without having to produce support for all four § 192.619(a) verification methods. INGAA encourages PHMSA to engage stakeholders in a discussion about acceptable records.

Integrity Management

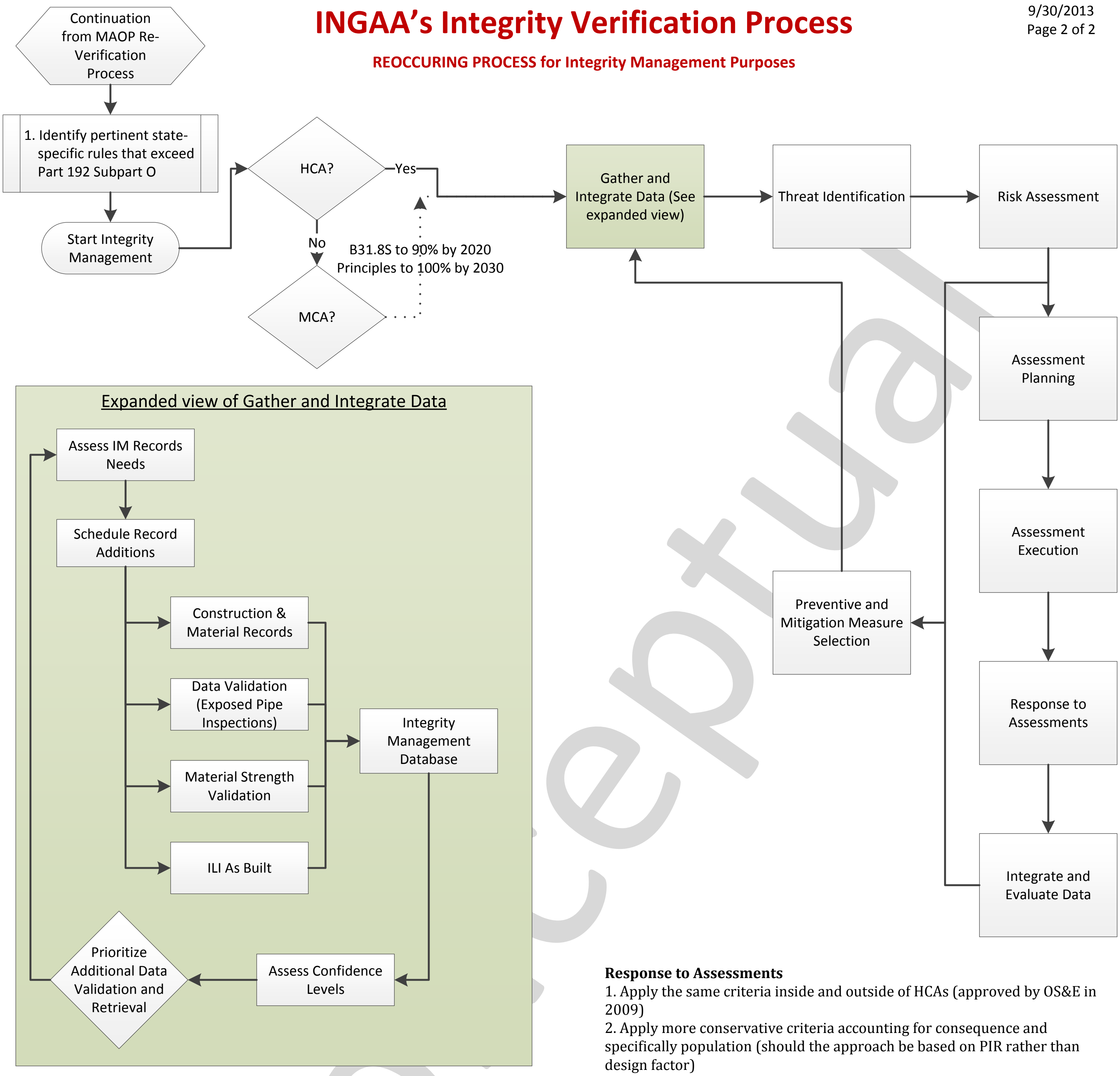
Improvements to Integrity Management

As mentioned in the executive summary, in addition to providing a flow chart on IVP, INGAA has added a separate flow chart (see INGAA IVP details on IM, page 18) to depict how it would improve and extend the coverage of the existing Integrity Management Program, which has been in place in HCAs since 2002.

INGAA members already use this flow chart to execute an overall IM program. Each box represents a step in the process of a comprehensive IM program. The flow chart's nine boxes – Gather and Integrate Data, Threat Identification, Risk Assessment, Assessment Planning and Assessment Execution, Response to Assessments, Integrate and Evaluate Data (Post Assessment), Prevention and Mitigation Measures, Management System Elements, and Lessons Learned – correspond in large part to PHMSA's subpart O requirements and to ASME B31.8S, the international consensus standard for IM.

[14] *In the Matter of West Texas Gas, Inc.,* CPF No. 4-2004-1007 (September 13, 2006).

Figure 2: INGAA IVP Page 2



Gather and Integrate Data

1. Know Your Pipe

- Diameter, Wall thicknessGrade
- Long seam (JF)

Validated thru IM assessment excavations, or through sampling program, based on quality of records and likelihood of "unknowns". Under some circumstances, may be factor-based, statistical, or yield testing [619(a)(1)(i).

2. Improved Data Integration – IMCI

Threat Identification

1. Improved consideration of interactive threats
2. Clarification of "stable" and re-designation as "resident" and included consideration of "acted upon" by external forces or hoop stress.

Risk Assessment

1. Inclusion of learnings from hydrostatic test and in-service failures
2. Increased vigilance with natural hazards and particularly, ground movement.

Assessment Planning and Assessment Execution

1. Include assessment method referred to as Continued Monitoring

Response to Assessments

1. Apply the same criteria inside and outside of HCAs (approved by OS&E in 2009)
2. Apply more conservative criteria accounting for consequence and specifically population (should the approach be based on PIR rather than design factor)
3. Need 619(a)(1) data to know SMYS to calculate FPRs; use excavations to validate data

Integrate and Evaluate Data (Post Assessment)

1. Increased use of risk assessment in consideration and selection of prevention and mitigation measures

Prevention and Mitigation Measures

1. Commitment to one-hour response time
2. Development of guidance on incident mitigation management

Management System Elements

1. Development of industry-wide pipeline safety management system to build on QA/QC, MOC, PM and Communication

Lessons Learned – broaden from Incident Investigations

1. Lessons Learned Workshops – annually each Fall
2. Conduct root cause analyses

Segments having gone through IM process, i.e., having been assessed mitigated and had prevention and mitigation measures applied are no longer subject to requirements of 49 CFR 192.611.

In this section, INGAA will provide details on what it intends to do under each of the nine processes (or steps) that are part of IM to improve and extend the overall program, and thus, improve pipeline safety. PHMSA included some of the concepts mentioned below in its IVP flow charts, specifically fatigue life, spike testing and material verification. However, as INGAA has noted extensively in its comments, it believes that these concepts are best addressed separately in IM on a regular interval for the life of the pipeline (separate from reconfirmation of MAOP).

INGAA believes many of its suggestions should be topics in PHMSA's planned IM 2.0 workshop.

Gather and Integrate Data

1. **"Know Your Pipe" –** INGAA recognizes the public's and the regulators' concern following recent pipeline safety incidents in which it was discovered that a pipeline operator did not know the material properties of an affected pipeline. INGAA agrees that operators must know the properties and characteristics of the assets that they owns and operate and have the records to enable an effective IM program.

   INGAA's members have engaged in extensive records search and verification efforts since late 2010, and they have reported to PHMSA as part of the annual report the number of miles on which they have complete records and on which they do not.

   A "one size fits all" approach to material verification is inapproporiate due to the variety of circumstances where there are gaps in records and the variation in documentation used throughout the years in pipeline manufacturing and construction. One of the most effective ways of verifying, and in some cases documenting, material properties such as diameter, wall thickness, and seam type is through IM assessment excavations. Under some circumstances, such as longer segments, or segments identified as having possible unknowns based on ILI, a sampling program may be warranted. A sampling program may entail use of statistical methods. Alternatively, an operator can apply yield testing as specified in the regulations [49 C.F.R. § 619(a)(1)(i)].

   INGAA members commit to using routine IM inspections as an opportunity to learn as much as they can about their pipelines, including information about the pipeline's properties and characteristics.

2. **Improved Data Integration –** Integration of data in multiple steps is important in a well-developed IM program. At a high level, data integration involves gathering and presenting data in a manner that enables the most complete depiction of the condition of assets being evaluated. Integration can be facilitated by using spreadsheets, queries from databases and visual

alignment of data, but ultimately subject matter experts evaluate integrated data. An IMCI work group shared experiences among INGAA members on methods for integrating data and tools for visually aligning data for evaluation. Members select approaches and techniques from the meetings to improve their data integration process.

INGAA intends to continue sharing data integration experiences and work to improve the use of technology to identify threats.

Threat Identification

1. **Improved consideration of interactive threats –** Interactive threats are the coincidence of two or more threats in a pipeline segment, the result of which is more damaging than either threat alone. Most INGAA members considered the interaction of threats in the first or early version of their IM programs in HCAs. Incidents in 2010 and 2011 highlighted the opportunity to improve processes for considering interacting threats.[15] INGAA has developed information reporting proposals to further identify multiple causes for an incident so interactive threats can be better understood.

   As a result, The INGAA Foundation, Inc., joined with Operations Technology Development (OTD) to fund a program within the Gas Technology Institute (GTI) to study threat interaction and develop a software application that operators can add to their existing risk assessment models to provide a more robust analysis of threat interaction. The work is nearly complete, with operators testing the software application.

   INGAA members commit to improve upon interactivity as part of IM to better understand the threats to its pipeline.

2. **Expand consideration and management of manufacturing and construction-related threats –** Manufacturing and construction-related threats result from small imperfections in pipeline materials, whether it is line pipe steel or material in a weld. The small imperfections generally are non-injurious to the integrity of the pipeline and referred to by engineers as being "subcritical." In ASME B31.8S, these threats were referred to as being "stable, unless acted upon by external forces or the operating stress of the pipeline." Unfortunately, the part of the standard indicating the importance of being "acted upon by external forces or the operating stress of the pipeline" lost sufficient emphasis in some applications. In fact, PHMSA personnel reported hearing operators refer to the threats as "stable," which is a misnomer.

   INGAA members recognize that the term "stable" might not be apt, and consequently have agreed that a change in terminology would help place

[15] Interacting Threats to Pipeline Integrity – Defined and Explained.

emphasis on this term. INGAA members now refer to these threats as being "resident."[16] In addition, members are committed to also applying the qualifying clause, "unless acted upon by external forces or the operating stress of the pipeline."

This terminology change, which INGAA members have sought to incorporate into the consensus standards, clarifies the need for operators to ensure that manufacturing and construction-related threats on a pipeline need to be monitored closely, including applying vigilance to ILI anomalies considered "subcritical." INGAA members are committed to monitor diligently any threats, including subcritical manufacturing and construction-related anomalies.

Risk Assessment

1. **Lessons learned from pressure test and in-service failures** – INGAA members shared experiences and practices in risk assessment during its IMCI work efforts. INGAA members recognized the value of learning from pressure test failures and in-service failures and incorporating lessons learned into how pipelines assess risk. Operators shared lessons learned, including findings of root cause analyses and information about the condition of coatings, cathodic protection systems, soils and line pipe. This improved information provides operators with a more accurate risk assessment, which supports a more effective prioritization of work and selection of preventive and mitigative measures.

2. **Increased vigilance with natural hazards** – INGAA members are committed to being increasingly vigilant when dealing with natural hazards and particularly, ground movement. Incidents in 2011 and 2012 in southeastern Ohio and northeastern Kentucky, an area prone to ground movement, highlighted the need to increase vigilance.

   These ground movement incidents taught operators valuable lessons that have been shared with the rest of the pipeline industry, including the value of additional ground patrols, geotechnical evaluations and use of specialized ILI technology in targeted locations along the system.

Assessment Planning and Assessment Execution

1. **Broadening and improving use of in-line inspection** – INGAA members recognize the continuing opportunity to broaden the use of ILI to manage integrity. INGAA sponsored an ILI Summit in December 2011 to challenge ILI providers and operators to work jointly to continue to improve current

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[16] An IMCI work group developed a short paper providing this background and guidance on management of resident threats, entitled, Resident Manufacturing and Construction Threats.

applications for indentations and metal loss in the body of line pipe and broaden demonstrable capacity for long seams, girth welds and improve performance for crack-like features.[17]

An outgrowth of the ILI Summit and subsequent work conducted by orgnizations such as the PRCI and ILI providers was to pursue the concept of using ILI to "confirm"[18] material properties of line pipe has been pursued and currently the subject testing and demonstration.

2. **Develop an assessment method referred to as "condition monitoring"** – Condition monitoring is an assessment method used in Canada as an alternative assessment method on lower-risk segments. A similar approach referred to as risk-based inspection is used in refineries, chemical plants and electric power generating facilities with many miles of piping within process facilities. Essentially, condition monitoring is a formalized process for gathering and integrating data on the condition of the pipeline system and the environment that surrounds the pipe. For external corrosion, it entails the integration of data on cathodic protection, including rectifiers, test points, above ground surveys and pipe inspection reports. The method uses trend analyses and targeted excavations to track changes in performance and to confirm the condition of the segment. Operators undertake prevention and mitigative actions where trends indicate a change in performance warranting action. Operators gather data for internal corrosion and environmental-related cracking (such as stress corrosion cracking) and apply trend analyses, with targeted excavation and prevention and mitigative actions, as warranted.

   INGAA will seek PHMSA approval to use condition monitoring as an alternative to three conventional methods – pressure testing, ILI and direct assessments – for inspecting lower-risk pipeline segments.

Response to Assessments

1. **Apply more conservative anomaly response-criteria to account for consequences** –INGAA members have committed to apply more conservative criteria when judging anomalies on their systems to better take into account the potential consequences of an incident, and specifically population near a pipeline.

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[17] INGAA worked with AGA, and research organizations, including NYSEARCH, PRCI and OTD, to produce a compendium on the state of the art of ILI technology, in a report entitled, Historical and Future development of Advanced In-Line Inspection (ILI) Platforms for Natural Gas Transmission Pipelines.

[18] ILI will also be of value in identifying locations that may be discrepancies or characteristics inconsistent with records.

2. **Acknowledge that material property data are needed in anomaly response –** INGAA members recognize the need to have material properties data to evaluate properly anomalies identified by integrity assessments. Specifically, diameter, wall thickness, long seam type and SMYS must be known to calculate failure pressure ratios, the bases for response timing. INGAA members will use excavations conducted routinely as part of anomaly response to validate data, and where there are gaps in data, will excavate to determine key parameters. INGAA is investigating the capability of ILI processes to collect and categorize information about the material and construction of the pipeline. Finally INGAA is supporting methodologies to confirm the strength of pipe material for use in IM processes. This better data will help improve IM programs.

Integrate and Evaluate Data (Post Assessment)

1. **Increased use of risk assessment - prevention and mitigation measures** – INGAA members are committed to increasing the use of risk assessment to consider and select prevention and mitigation measures. Through IMCI work group efforts and in the 2012 Lessons Learned Workshop, members recognized the opportunity to apply risk assessment more broadly in selecting prevention and mitigation measures.

Prevention and Mitigation Measures

1. **Commitment to one-hour response time** – INGAA members commit to developing processes and technology to enhance the protection of people and property located adjacent to the pipeline, including setting a one-hour response time goal for incident recognition to start of valve closure procedures in highly populated areas for pipelines greater than 12" in diameter. This is a key element in INGAA's pipeline safety commitments.

2. **Development of guidance on incident mitigation management –** While INGAA's main goal is to prevent pipeline incidents, it also recognizes the importance of a robust incident mitigation plan in the event of an emergency. An IMCI work group is developing – and is now refining – guidance on incident mitigation management for members. The guidance will provide approaches to improving communication prior-to and during an incident, as well as planning for incident response. This guidance will help improve emergency response, including coordination with outside emergency responders.

Management System Elements

1. **Development of industry-wide pipeline safety management system –** INGAA members are committed to developing and implementing safety management systems to improve overall pipeline safety performance. The

objective is to build on management system elements, Quality Assurance/Quality Control, management of change, performance measurement and communication within a risk management framework, as described in ASME B31.8S, which members started using in 2003.[19]

In evaluating ways to improve IM, an IMCI work group developed guidance for members on management systems, how they have been applied in other industries, and identified key elements that members can consider to improve their existing management systems.[20]

INGAA members serve on a work group developing a pipeline safety management system standard under the auspices of the American Petroleum Institute and the American National Standards Institute (ANSI) process. ANSI has an established process that is accepted worldwide for developing standards. It is anticipated that the standard will be published in 2014.

Lessons Learned – broaden from Incident Investigations

1. **Lessons Learned Workshops** – INGAA members are committed to sharing the lessons learned from pipeline incidents. Members will meet annually to share incident experiences and lessons learned. An inaugural meeting of members was held over two days in fall of 2012. This year's workshop is scheduled for November 2013.

2. **Conduct root-cause analyses** – INGAA members are committed to conducting root-cause analysis in test failures and incidents. Many members use a tiered approach, which enables them to tailor the analysis appropriately to the nature of the event.

   Sharing lessons learned in workshops and other public forums helps operators become aware of potential threats and take actions to mitigate them.

[19] A key first step for members was to build upon the successes members had in personnel safety programs by developing a white paper on safety culture, Safety Culture Is A Core Value.
[20] The guidance is presented in a white paper, entitled, Management System: Foundation For An Effective Safety Culture.

Appendix A: Step-By-Step Guide to INGAA's IVP Flow Chart

Step #1 (Is segment in HCA?): Congress directed PHMSA to develop testing regulations to confirm the material strength of previously untested natural gas transmission pipelines located in High-Consequence Areas (HCAs) under section 23 (d) of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act).

> *(d) Testing Regulations-*
> *(1) IN GENERAL- Not later than 18 months after the date of enactment of this section, the Secretary shall issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines* ***located in high-consequence areas*** *and operating at a pressure greater than 30 percent of specified minimum yield strength.*

This particular decision point separates the transmission pipeline mileage that is located in an HCA from areas that are not. If the pipeline is located in a HCA, then the operator would drop down to Step #5. All other pipeline mileage will go to Step #2.

Step #2 (Is segment in MCA?): INGAA has committed to extend Integrity Management principles beyond HCAs. INGAA is embracing PHMSA's quest to utilize improved consequence modeling (HCA and MCA) along with enhanced IM initiatives to substitute for class location designations and their attendant procedures and processes. INGAA's commitment would encompass individual structures along the pipeline within the Potential Impact Radius (PIR). While the definition of MCA has not been decided, conceptually, INGAA members propose to use MCAs as a means to prioritize work. If the pipeline segment is not located within an MCA, then the pipeline operator may continue to operate under company procedures that include the pipeline safety standards under Part 192 and perform integrity management under Step #13. If a pipeline is located within an MCA, it should be examined in the next filter process in Step #3.

Step #3 (Susceptible Seam Type?): The group of piping that is examined under this step would include pipe located in an MCA. Historical PHMSA and industry information can be used to identify the characteristics of certain vintage design, manufacturing and quality control processes that make pipe segments susceptible to material and construction anomalies in the longitudinal weld seam that can independently fail while in operation. Particular manufacturing processes that are susceptible have already been identified and are described in 49 C.F.R. § 192.917(e)(4). It would be very useful to have a workshop to discuss the delineation of susceptible seam type to minimize confusion. If a pipeline segment is located within an MCA with a susceptible seam type, or an unknown seam type, then it should pass through to Step #4. If the pipeline segment is located within an MCA and does not have a susceptible seam type, then the pipeline mileage should continue to operate under company procedures that include the pipeline safety standards under Part 192 and perform integrity management under Step #13.

Step #4 (Is segment MAOP >30% SMYS?): Piping located in MCAs that has been identified as having a MAOP less than or equal to 30% of the Specified Minimum Yield Stress (SMYS) is not required to have a MAOP reconfirmation in this process. Still, sufficient records or alternate test methods about the pipe segment SMYS are necessary to calculate that the pipe is operating at or below 30% SMYS at its validated MAOP.

If the pipeline segment is located within an MCA and has a MAOP greater than 30% SMYS, then operator should continue to Step #5.

Step #5 (Prior test >/= 1.25XMAOP w/pressure records?): Pressure records for piping located in HCAs or MCAs with susceptible seam types operating at than 30% SMYS should be analyzed to determine that the pipeline segment has been subject to a pressure of 1.25xMAOP or greater for a sufficient period of time.[21] If the pipeline segment has an acceptable pressure record, then the pipeline operator could continue to operate under company procedures that include the pipeline safety standards under Part 192 and perform IM under Step #13. Otherwise, the pressure records should be analyzed under Step #6.

Step#6 (Prior test >/= 1.1XMAOP w/pressure records?): Piping located within HCAs or MCAs with susceptible seam types and operating greater than 30% SMYS will need to analyze pressure records to determine that the pipeline segment has been subject to a pressure of 1.1xMAOP or greater for a sufficient period of time. If a pipeline segment has an acceptable pressure record, then the operator goes to step #7. Otherwise, operators proceed to Step #8 or #9.

Step #7 (Use ILI in lieu of pressure testing and have records needed for ILI analysis?): This decision point has been established to accommodate alternate technology processes that have not yet been developed and approved for use. Piping with susceptible seam types located in HCAs or MCAs operating greater than 30% SMYS that have had a previous test of at least 1.1xMAOP would be eligible to utilize this alternate technology. The use of an ILI process would allow complete examination of the pipeline segment. The process is envisioned to provide the same or greater level of confidence as a 1.25xMAOP pressure test to identify and remove material and construction anomalies from the pipeline segment that could fail independently in operation. If the technology is developed and approved by PHMSA for the particular anomalies, then an operator could proceed to Step #10. If the technology is not developed and approved, then an operator should proceed to Steps #8 or #9.

[21] The use of the 1.25xMAOP criteria is explained in Appendix C- Additional Technical Input Requested by PHMSA.

Step #8 (Perform Subpart J Pressure test?): Pipeline segments that have gone through Step #6 and do not have an adequate pressure test, or if the alternate technology is not approved in Step #7, would have the option to have a pressure test conducted utilizing Part 192, Subpart J procedures. If there are particular pipe segment conditions in which a spike test would be desired for IM purposes, it should be incorporated into this pressure test.

Step #9 (Derate Pipeline, Repair or Replace Pipeline?): As an alternative to the pressure test in Step #8, the operator may choose to replace the pipe segment. All the current requirements of Part 192 for design and construction would be used for this step. Alternatively, the operator may choose to derate the MAOP utilizing the highest recorded pressure test or historical operating pressure to establish an equivalent pressure test level of 1.25xMAOP.

Step #10 (Select sensors?): An operator could use a yet-to-be developed methodology which matches sensor capabilities, pipe characteristics, metallurgical failure prediction processes and analysis to provide an equivalent level of confidence as a pressure test in assuring a pipe segment will not fail independently in operations due to material or construction anomalies. Any anomalies that do not meet the acceptable criteria will be replaced or repaired by approved methods. After completion of this step, the pipe segment should continue to operate under company procedures that include the minimum pipeline safety standards under Part 192 and perform IM under Step #13.

It is noted that an added benefit of utilizing the ILI in lieu of pressure testing process will be the opportunity to confirm records through excavations and additional data the ILI tool provides.

Step #11 (Test Failures?): When a pressure test is conducted under process Step #8, and a failure results, the root cause of the test failure should be assessed to determine if it is a material and construction anomaly that could fail independently while in operation or if it is the result of IM conditions. The pipeline segment should be repaired and the test should recommence until there are no failures under the 1.25x MAOP criteria level.

Step #12 (Define Cause and Feed into Risk Assessment): A pressure test, regardless of the number of failures during the test, establishes a safety factor once completed. In those instances where a pressure test failure occurs, the INGAA process specifies that the operator conduct a root cause analysis. An operator first determines if the test failure is related to material and construction issues and, if so, identifies the extent of off-specification or improperly installed materials. Operators also seek to understand what the leak or rupture indicates, as there are significantly different implications for each.

Note: INGAA recommends that PHMSA contemplate conducting a review of the IVP process perform an assessment of the IVP schedule within 18 months after the effective date of the requirement in order to assess the process and schedule impacts to customers after additional information is gathered, experience is gained and plans have been started to be implemented.. INGAA suggests that operators should report an inventory of the current classification of the pipeline mileage located in HCAs, Moderate Consequence Areas (MCAs) and outside of these areas within a time frame to be determined after the establishment of the IVP requirements. Finally, INGAA suggests that operators should provide information in their annual reports detailing the progress of reconfirming its MAOP.

Appendix B: Key Points from INGAA's September 9 Comments

Below are the key points INGAA submitted on September 9 as part of its comments to PHMSA's first IVP draft.

MAOP reconfirmation and IM should not be combined into a single process.

There are three primary reasons that IM and MAOP reconfirmation should be addressed separately:

- **MAOP reconfirmation is a one-time process; IM involves ongoing processes.**
  MAOP reconfirmation is a one-time process that involves evaluating records to support the established MAOP. If an operator lacks records to support the MAOP or owns a pipeline that was previously untested, the owner must conduct further testing, reduce the pressure, or replace the segment.

  IM entails application of ongoing, routine work on covered segments and includes processes such as:
  - gathering and integrating data,
  - identifying threats,
  - conducting risk assessment,
  - planning and executing integrity assessment,
  - responding to assessment findings, and
  - selecting preventive and mitigation.

- **Prioritization of pipeline safety work.**
  INGAA does not believe that combining MAOP verification and IM in a single process will facilitate prioritizing pipeline safety work in a manner in which the highest priority projects in each category are addressed first. Instead, combining the two work streams into a single process may result in muddled prioritization and counterproductive tradeoffs. Addressing a threat such as external corrosion may require an operator to conduct an assessment (for INGAA members, typically using an ILI tool) sooner than a test for material strength would be conducted for MAOP reconfirmation. As a result, an operator would be unable to prioritize work on its highest-risk segments. INGAA's IMCI commitments, in contrast, allow for such prioritization, while ensuring a comparable level of safety and minimizing customer service interruptions.

  Also, the PHMSA IVP Engineering Critical Analysis option uses measures that are pertinent solely to IM, such as a Close Interval Survey (CIS) or an interference survey. Prioritization of those surveys may, and likely will, be different than material strength testing for MAOP reconfirmation.

Finally, the initial, or baseline, phase of the gas transmission sector's integrity management work in HCAs was completed on December 17, 2012. Prioritization of work on segments in HCAs is now done based on completion of that baseline. Work to be done for HCA segments that are untested or that lack records to reconfirm the established MAOP may need to be done using different criteria for establishing priority.

- **Lead to process simplification.**
  Based on INGAA's review of the PHMSA's first IVP flow chart, it would appear that PHMSA frequently will need to make case-specific determinations about the required work to address particular elements in IVP for individual pipelines or even individual pipeline segments. For example, where validated, traceable material documentation is lacking or missing, IVP would require a case-specific approach to testing pipe properties. This has the potential to overwhelm PHMSA's already limited resources, and result in delays that would frustrate all parties concerned. Further, this process would be less transparent to pipeline safety stakeholders and has the potential to produce inconsistent and unpredictable results.

  Finally, MAOP reconfirmation work and IM require different activities. Conducting both with the same priority, at the same time, will make access to the segment more challenging and likely will cause more extended service outages, which may affect consumers. For all of these reasons, INGAA believes that separating IM from MAOP verification will greatly reduce the likelihood of these undesirable results.

A single pressure test during a pipeline's life is an adequate basis for reconfirming an MAOP.

A single pressure test at 1.25 x MAOP during a pipeline's life adequately establishes strength for purposes of establishing a valid MAOP. This pressure test establishes a safety margin between the test pressure and the operating pressure (that is maintained for the life of the pipeline). This single test is adequate for establishing MAOP because the operator uses ongoing operation, maintenance, and integrity management activities to manage the condition of the pipeline. When the condition of the pipeline is found to have deteriorated, it is evaluated using proven methods to ensure safe continued operation, or repaired or replaced to ensure the safety margin is restored. Therefore, there is no demonstrated reason that pressure tests should be run on a recurring basis for MAOP reconfirmation.

In cases where a pipeline has been pressure tested, but not to the level of 1.25xMAOP, that original test should be augmented in these populated areas with other testing and engineering analysis to confirm an appropriate safety margin, thereby reconfirming the MAOP.

Limit the scope of reconfirming MAOP.

During the August 7 public meeting, PHMSA stated that it intended to limit the scope of IVP to mainline pipe and associated valves and fittings. In other discussions, however, PHMSA has been more ambiguous with respect to the intended scope of IVP. INGAA believes PHMSA should clarify that IVP will be limited to mainline pipe and associated valves and fittings on the basis that other facilities and small appurtenances pose significantly lower risk to the public due to their proximity and design.

INGAA fully supports extending and improving IM.

INGAA fully supports extending IM. The concept of Medium Consequence Areas (MCAs), which was unveiled in PHMSA's first IVP flow chart, appears consistent with INGAA's commitment to extend IM principles to protect all people along the pipeline. However, the designation of MCAs in PHMSA's IVP chart appears to rely on a combination of class location and application of the Potential Impact Radius (PIR) analysis. An approach relying solely on PIR would result in superior risk prioritization and allocation of resources.

INGAA recognizes that there are two dimensions to build upon the success of the baseline IM program:

1. Extending IM - Increasing pipeline mileage covered by IM; and
2. Improving IM - Determining what additional practices should be added to IM and establishing a risk-based analysis of where they should be added (e.g., applying IM principles to 90%of the population by 2012, and applying IM as defined by ASME B31.8S to 90% of the population by 2020).

PHMSA needs additional time to develop the specifics for extending and improving IM in order to craft a well-reasoned plan. INGAA supports PHMSA's suggestion to hold a public meeting to review the lessons learned from the first decade under the natural gas transmission IM rules and to formulate approaches for extending IM.

Pursuant to the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act), the Secretary is required to report to the Congress on whether to extend IM beyond HCAs within two years of enactment. Absent a determination by the Secretary that a risk or imminent hazard exists, that law limits PHMSA's ability to issue final rules extending IM until one year after submitting the report to Congress or three years after enactment of the Act. Given this direction from Congress, it is premature to propose extending and improving IM as part of IVP.

In its IVP, PHMSA stated it wanted a better understanding of the material properties of pipe. INGAA's members fully appreciate the importance of understanding what pipe is in the ground. One aspect of improving integrity management is ensuring that material records are available for use in risk assessment, assessment planning, anomaly evaluation and response, and selection of prevention and mitigation measures. Every time the pipe is exposed during an excavation for operations and maintenance or integrity-related activities, it provides another opportunity to confirm the material properties of the pipe when needed. These excavations, as part of IM, provide a sound basis for confirming material properties and pipe condition. As a result, a better understanding of material properties should be part of PHMSA's effort to improve IM.

INGAA's Fitness for Service (FFS) could be used as the basis for addressing previously untested pipelines and pipelines lacking adequate records.

Previously untested pipelines or those lacking adequate records to support a segment's MAOP can be addressed using an FFS process to establish the MAOP as originally installed. FFS demonstrates the pipeline's ability to operate in a manner that ensures the safety of the people that live and work nearby and protects the environment while allowing operators to dependably transport natural gas. FFS is based on established consensus standards, many of which PHMSA has incorporated into its regulations. Use of FFS is consistent with the Pipeline Safety Act of 2011, allowing for the use of pressure testing and, alternatively, technology such ILI. In this context, INGAA utilizes FFS as a one-time process for reconfirming MAOP.

INGAA members will work with PHMSA to demonstrate use of ILI in lieu of pressure testing.

INGAA members are working with the American Gas Association, ILI providers and research organizations such as the Pipeline Research Council International and the Gas Technology Institute to commercialize ILI for use in lieu of pressure testing for reconfirming MAOP.

Unlike a pressure test, which is simply pass-fail, ILI reveals information about the condition of the pipe, including sub-critical anomalies. It is in the mutual interest of operators and PHMSA to demonstrate the effectiveness of ILI to better understand risk and manage it.

Application of FFS has the desired effect of deleting provisions of the grandfather clause that cause concern to stakeholders.

Following the San Bruno pipeline investigation, the National Transportation Safety Board (NTSB) recommended that PHMSA delete the "grandfather clause" and require a hydrostatic test.[22] INGAA proposes that PHMSA amend 49 C.F.R. § 192.619 to add a provision requiring pipelines to evaluate the fitness for service of previously untested pipelines. This would have the effect of removing the aspects of the grandfather clause that concerned NTSB, Congress and other stakeholders by ensuring that pre-regulation pipelines in HCAs, and Class 3 and 4 areas are tested for material strength.

[22] PHMSA 2013-0119-0042 (INGAA Comments filed September 9, 2013).

PHMSA currently lacks a credible basis for establishing a cost-benefit analysis of IVP.

If PHMSA proceeds to issue a rule that incorporates the IVP, as proposed, it cannot rely on the annual report data as the basis for its cost-benefit analysis of that rule. The annual report data would grossly understate the pipeline mileage that would need to be tested pursuant to PHMSA's IVP, as currently proposed. INGAA members reported the mileage of pipelines that are missing records in Part Q of PHMSA's annual report. INGAA members also reported the mileage of previously untested pipelines in Part R of the annual report. Regrettably, the instructions for completing the annual report were inconsistent with the approach outlined in the IVP. In basic terms, the annual report guidance permitted an "either-or" verification proposition, while the IVP (Draft 1), in Diamonds 2-5, took an "and" approach, requiring four layers of records before the records for a pipeline are deemed acceptable. In addition, the annual report did not collect data that would permit PHMSA to analyze affected MCA mileage.

Further, section 23(d)(3) of the Act requires the Secretary to consult with the chairman of the Federal Energy Regulatory Commission and state regulators to establish timeframes for the completion of testing that take into account potential consequences to public safety and the environment and that minimize cost and service disruptions. The annual report data could not be the basis for this consultation because it would grossly understate the mileage for which testing may be required and, therefore, grossly understate potential costs and service disruptions.

Appendix C: Additional Technical Input Requested by PHMSA from INGAA's Sept. 9 Comments

In its September 9 filing, INGAA provided additional details in response to PHMSA's specific questions asked during its August 7 workshop. INGAA seeks to answer these questions. The technical input provided below draws upon work by INGAA over the past 2.5 years. INGAA continues to advocate that its FFS process for reconfirming MAOP provides additional details lacking in the proposed PHMSA IVP.

How does a strength test relate to a pressure test?

The strength test, sometimes referred to as a "proof test," is the initial portion of a pressure test that is conducted at a desired pressure level, and often held for a specific period of time, to establish or provide "proof" of the strength of the pipe. Pressure tests conducted after the pipe is installed typically include a "leak test." This portion of the test, as the name denotes, is used to detect or confirm a leak. Leaks are indicated by a pipeline pressure drop. The drop in pressure may be gradual if the leak is small. By contrast, if a test failure in the pipe results in a rupture, the pressure will fall rapidly. Water leaking from the pipeline during a failed test will be found near the pipe perforation.

How is the duration of a pressure test determined?

The duration of the "proof" portion of the pressure test typically is the time required for the pressure to stabilize in the test section. The duration is a function of the test section's length, elevation changes on the section of pipeline and temperature. Typically, the segment to be tested is stabilized within 30 minutes to an hour of the test's start. In a report prepared for GRI in 2001, Robert Eiber and Brian Leis stated,

> Strength re-tests of pipelines should be conducted using high pressures (90-110% SMYS) and held for 30 minutes at maximum pressure. The pressure should then be decreased to 90% of the test pressure and held for as long as necessary for a leak check. This will eliminate defect growth during the leak check and minimize growth during the pressure test.[23]

In a paper at IPC in 2004, Brian Leis stated that,

> It is emphasized that a one-hour-long hold at maximum pressure remains a viable upper bound for typical ductile line pipe. As this hold time also leads to ductile tearing along the tips of the larger defects remaining in the pipeline, care must be taken to select the hydrotest parameters consistent with the purpose of the test and the properties of the line pipe body and seam.[24]

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[23] Eiber, Robert and Brian Leis, "Review of Pressure Retesting for Gas Transmission Pipelines," Battelle Memorial Institute, GRI-01/0083, Feb 2001. SMYS is the specified minimum yield strength.
[24] Leis, Brian, "Hydrotest Protocol for Applications Involving Lower Toughness Steels," IPC04-0665,

When a pipeline is tested at a manufacturing mill, a pipe joint (typically 40 feet in length) is tested for approximately ten seconds. This is the time needed to stabilize the pressure within the pipe joint. Pipe with a sufficiently large flaw in the pipe body or with a long seam that does not have sufficient strength will fail during the test pressure. The higher the test pressure, the smaller the flaw size required to fail a test. As soon as the pressure stabilizes at the desired level, the strength is established or the pipe fails. Therefore, the short duration mill test is as effective as a field pressure test for the purpose of establishing fitness for service for the long seam and pipe body.

A field-pressure test on multiple miles of installed pipe takes a longer period to stabilize. As stated above, the time required to stabilize a long-field test segment, while a function of the segment length, typically is 30-60 minutes.

Pressure Testing Level and Spike Testing

Why is a 1.25xMAOP pressure test sufficient for validating MAOP?

From an engineering standpoint, a pressure test of 1.25 times the MAOP establishes an adequate safety margin above the maximum operating pressure. Lower test pressures also may be acceptable under certain conditions, but the 1.25xMAOP test level has been shown effective in virtually all studies, and it has been accepted by safety and regulatory authorities as adequate under all conditions. The 2010 edition of ASME B31.8 requires a pressure test to 1.25 times MAOP in Class 1 and 2 locations.[25] This level of testing also matches the ASME B31.4 requirements for hazardous liquid pipelines.

Why shouldn't pressure tests for MAOP verification be repeated multiple times?

The current language in 49 C.F.R. § 192.619(a) imposes four criteria that potentially limit the MAOP. One of those four criteria is the highest operating pressure experienced in the five years immediately preceding July 1, 1970, unless the line was tested after July 1, 1965. This highest operating pressure criterion also is the basis for the stand-alone grandfather clause in section 192.619(c). The basic strength properties of steel pipe – yield strength, tensile strength, elongation, strain hardening, etc. – do not change with time. Therefore, INGAA sees no basis for limiting allowable tests to only those conducted after July 1, 1965.

A pressure test for which essential parameters can be determined should be regarded as a valid and compelling test, regardless of whether it was conducted in June or July of 1965, or at any other time. It is the test parameters, not the test date, that should be considered here for the establishment of MAOP.

ASME IPC Calgary, Sept 2004.

[25] American Society of Mechanical Engineers, B31.8, 841.3.2, Table 841.3.2-1, Test Requirements for Steel Pipelines and Mains to Operate at Hoop Stresses of 30% or More SMYS.

Still, the validity of earlier tests for MAOP establishment or confirmation does not necessarily mean that no further tests are required. An additional test or periodic testing may be required to assure the continued integrity of the segment. Such additional tests, however, are managed within the operator's integrity management program and, while important, should not be subject to an inquiry about MAOP verification. They should be considered separately.

Is a pressure reduction an option for MAOP reconfirmation?

A target pressure reduction of 20% of the current MAOP has the effect of making the current pressure equivalent to a test of 1.25 times the reduced MAOP. Because the lower pressure would build in a safety margin, such a reduction should be sufficient to reconfirm the MAOP. An operator choosing this option should be able to bring other data and analyses to bear in determining whether the pressure reduction should perhaps be greater or less than 20%. Such data or analysis might include operating history, test history, failure history or ILI results that may be indicative of the strength of the pipe.

How should spike testing be used?

In the investigation report of the incident on PG&E's system in San Bruno, NTSB recommended use of a spike test for previously untested pipelines. A spike test is one of the tools to be considered in planning for and conducting a pressure test. Spike testing is the best means of testing a pipeline with environmental cracking, such as stress corrosion cracking, that has developed while in service.

However, a pressure test to 1.25xMAOP is adequate to address the strength of a pipeline for establishing or validating an MAOP. Pipelines, at the time of installation, generally do not include cracks. However, should an operator need to conduct a pressure test on a line previously untested or lacking records to validate MAOP, it is possible that including a spike test could be useful if the line has been identified as requiring an SCC (stress corrosion cracking) assessment. In this case, the pressure test would serve a dual purpose of validating MAOP while providing an SCC assessment. We note, however, that an SCC assessment would occur under an operator's IM plan and, therefore, should not be prescribed for all MAOP verifications.

A spike test may be of value for some in-service pipelines, specifically where metallurgical fatigue is of concern. An example would be on a line that undergoes significant pressure cycling. Gas pipelines typically do not undergo significant pressure cycling and their fatigue lives can be hundreds of years in duration. PRCI sponsored a study of fatigue behavior on in-service gas pipelines conducted by

Kiefner and Associates in 2006. That study confirmed that gas pipelines, absent significant pressure cycling, have long fatigue lives.[26]

The type of test and the pressure-testing level determine the fatigue life and the length of time until the next test. This is referred to as a "retest interval." A spike test to levels over 100% of SMYS establishes a longer fatigue life and retest interval than a test to 1.25xMAOP (which is equivalent to a 90% SMYS test in a Class 1 area operating at 72% of SMYS). A test to 90% SMYS can provide a sufficiently long retest interval for a typical natural gas pipeline.

Even so, fatigue must be considered for a pipeline. The 2006 PRCI study provided guidance for operators to define the operating regime in which an in-depth evaluation of fatigue should be considered. This is embodied within ASME B31.8S and is an essential part of managing the ongoing integrity of a pipeline system.

How should long-seam types in early vintage line pipe be addressed for previously untested pipe and those lacking records?

The INGAA FFS process applies special diligence if the segment contains pipe that has a weld-seam type that has experienced known integrity issues. These seam types include low-frequency electric resistance welds (LFERW), direct-current electric resistance welds (DC-ERW), electric fusion or flash welds, furnace butt-welds, lap welds and cases where long seams are unknown.

What is an appropriate basis for prioritizing MAOP reconfirmation?

INGAA's risk-based FSS process draws upon the approach developed for previously untested hazardous liquid pipelines in the 1990s. Those specific regulatory requirements are found at 49 C.F.R. § 195.303. The liquids pipeline regulation based its risk-based approach on close proximity to population. In addition, the approach allowed for the use of ILI assessments in lieu of a pressure test. INGAA recommends a similar approach for natural gas transmission pipeline systems.

Can ILI be used in lieu of pressure testing for MAOP reconfirmation?

ILI is nearly commercially viable for MAOP reconfirmation. It will likely require two distinct types of sensors as well as improvements in analytical techniques, both of which require additional demonstration, and ultimately acceptance by PHMSA and state regulators.

ILI could be used to identify defects that would just survive a pressure test. The reason for using the pressure test as the comparison is that it represents a standard for our regulators and knowledgeable members of the public. While pressure

[26] Kiefner, J.F. and M.J. Rosenfeld, Basics of Metal Fatigue in Natural Gas Pipelines – A Primer for Gas Pipeline Operators, Pipeline Research Council International, Inc., Catalog No. L52270, June 2006.

testing can be used for MAOP reconfirmation, it is simply a pass-fail test. It does not provide detailed information about the pipeline; it simply confirms its strength.

In some cases, ILI may be superior to pressure testing. For example, identification of long-seam weld anomalies requires use of transverse-oriented magnetic flux leakage (MFL) technology on an ILI tool. Axially and transverse-oriented sensors have been shown to provide additional data to supplement MFL technology for seam-weld assessments. Alternatively, ultrasonic technology (UT) can be used; however, there has been limited application of UT technologies for seam-weld assessment on natural gas transmission pipelines. The transverse-oriented technology is available only in selected diameters. UT requires use of a liquid couplant, making its applicability limited.

An added benefit of employing ILI is that it can detect anomalies smaller than the large anomalies that would result in a failed pressure test. HCAs and class locations serve as the means to help calculate risk by prioritizing probability of consequences; ILI, meanwhile, is used to prioritize the probability of failure.

INGAA members are working with the American Gas Association, ILI providers and research organizations, such as the Pipeline Research Council International and the Gas Technology Institute, to improve the identification and characterization of long-seam anomalies that could pose a threat to integrity by taking advantage of multiple technologies. It is anticipated that the technologies and their analysis processes will continue to improve during the timeframe in which HCAs are being addressed and operators begin to apply integrity management techniques to pipelines located in the areas envisioned by the MCA concept.

What is an appropriate threshold level for low-stress pipelines?

PHMSA proposed 20% SMYS as the low-stress threshold in the IVP but has not provided support in the docket as of the submittal of these comments. There are many years of precedence with the low-stress threshold being established at 30% SMYS, including PHMSA's own regulations. PHMSA established 30% SMYS as a low-stress threshold for integrity assessments in the gas integrity management regulations at 49 CFR § 192.941(a). In addition, the level of 30% SMYS is generally accepted to be the "low-stress" boundary between leaks and ruptures for likely pipeline defects.

Moreover, ASME B31.8, in 841.3.2 establishes the threshold at 30% SMYS. The basis of this approach is that preventing ruptures represents a much higher consequence priority than preventing leaks on transmission pipelines. Leaks are important and addressed through a variety of ongoing activities along the pipeline rights-of-way by operators, including leaks surveys, patrols and maintenance work on the pipeline system.

In applying the 30% SMYS low-stress threshold, INGAA members recognize that the threshold presumes an understanding of the minimum level of toughness and the knowledge of pipe diameter, wall thickness and other metallurgical properties, such as the grade of pipe. Operators are encouraged to evaluate whether adjustments should be made to the 30% low-stress threshold level for the pipe segment being evaluated.

Should there be a date before which pressure tests cannot be used?

No. Pressure tests have been used extensively as part of a Quality Management System to validate pipeline material and construction standards. They are also used to validate pipeline integrity. Appendix F in INGAA's September 9 comments [27]describes in detail the processes that have been used in the past to ensure quality.

The current language in 49 C.F.R. § 192.619(a) imposes four criteria that potentially limit the MAOP. One of those four criteria is the highest operating pressure experienced in the five years immediately preceding July 1, 1970, unless the line was tested after July 1, 1965. This highest operating pressure criterion also is the basis for the stand-alone grandfather clause in section 192.619(c). If section 619 is modified to require material strength testing of previously untested pipelines, thereby removing use of the highest operating pressure experienced in the five years immediately preceding July 1, 1970, then it would be reasonable to remove the corresponding restriction from 619(a) as well, along with the limitation on test dates.

The basic strength properties of steel pipe – yield strength, tensile strength, elongation, strain hardening, etc. – do not change with time. Therefore, INGAA sees no basis for limiting allowable tests to only those conducted after July 1, 1965. A pressure test whose essential parameters can be determined should be regarded as a valid and compelling test regardless of whether it was conducted in June or July of 1965, or in 1960 or at any other time. The test parameters, not the test date, should be considered here for the establishment of MAOP. INGAA also emphasizes that recognition of the validity of earlier tests for MAOP establishment or confirmation does not necessarily mean that no further tests are required. An additional test or periodic testing may be required to assure the continued integrity of the segment. Such additional tests, however, are managed within the operator's integrity management program and, while important, are not the subject of this inquiry and should be considered separately.

[27] PHMSA 2013-0119-0042 (INGAA Comments filed September 9, 2013).