Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
Advance Notice of Proposed Rulemaking

Safety of Gas Transmission Pipelines

Docket No. PHMSA-2011-0023

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Interstate Natural Gas Association of America

Topic-by-Topic Comments

January 20, 2012

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Response to Advance Notice of Proposed Rulemaking on Safety of Gas Transmission Pipelines

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Executive Summary

The advance notice of proposed rulemaking in this docket asks 120 questions, most with multiple sub-parts, spanning a wide array of topics related to natural gas pipeline safety. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, signed into law earlier this month, creates new statutory requirements in areas such as integrity management, verification of maximum allowable operating pressure, improvements to damage prevention efforts, and the continuation of efforts in pipeline safety research and development. These two initiatives — one regulatory, one legislative — are rooted in a common, central question: What is the best way to enhance and assure the safety of the nation's pipelines?

For America's interstate natural gas pipelines, no question is more important.

The Interstate Natural Gas Association of America (INGAA) represents approximately two-thirds of the pipelines and over 65 percent of the mileage comprising the US natural gas transmission pipeline system. INGAA's 27 members operate approximately 200,000 miles of interstate transmission pipelines, deliver one-quarter of the nation's energy and serve as an indispensible link between natural gas producers and consumers.

Pipeline safety has improved consistently over the decades through the application, continuous refinement and evolution of consensus standards, technology, law and regulation. Yet no safety incident is acceptable, and INGAA and its members recognize that more can be done to improve the safety of natural gas transmission pipelines and to regain public confidence in the safety of our pipeline infrastructure.

Last March, INGAA's board of directors adopted five aspirational, guiding principles, anchored by the goal of zero pipeline incidents:

INGAA's Guiding Principles for Pipeline Safety

1. *Our goal is zero incidents — a perfect record of safety and reliability for the national pipeline system. We will work every day toward this goal.*
2. *We are committed to safety culture as a critical dimension to continuously improve our industry's performance.*
3. *We will be relentless in our pursuit of improving by learning from the past and anticipating the future.*
4. *We are committed to applying integrity management principles on a system-wide basis.*
5. *We will engage our stakeholders — from the local community to the national level—so they understand and can participate in reducing risk.*

With its goal and founding principles established, INGAA's members developed a plan to put its aspirations into action. Starting with two principles already familiar to the pipeline safety community —integrity management and continuous improvement — a task force of top pipeline executives developed an action plan that INGAA's board of directors formally adopted last July.

The Integrity Management – Continuous Improvement (IMCI) action plan consists of nine commitments:

INGAA's IMCI Action Plan Commitments

1. *Apply risk management beyond high consequence areas to other places where people live.*
2. *Raise and harmonize the standards for corrosion anomaly management.*
3. *Demonstrate "fitness for service" of pre-regulation (or pre-1970) pipelines.*
4. *Shorten pipeline isolation and response time to one hour in populated areas.*
5. *Improve integrity management communication and transparency of performance.*
6. *Implement the Pipelines and Informed Planning Alliance guidance.*
7. *Evaluate, refine and improve threat assessment and mitigation.*
8. *Implement management systems across INGAA members.*
9. *Provide forums for engaging stakeholders and emergency officials.*

The IMCI action plan forms the foundation for INGAA's general responses and specific answers to the questions posed in the advance notice of proposed rulemaking (ANPRM).

Current regulations require operators to identify pipeline segments in populated areas (known in the regulations as High Consequence Areas or HCAs) and to perform baseline assessments of all such segments by December 2012. Consistent with the IMCI action plan, INGAA's members are committed to going beyond these requirements, applying integrity management principles throughout their transmission systems under a phased schedule that gives priority to protecting people who live, work or otherwise congregate near gas transmission facilities. Under INGAA's schedule, pipelines would extend integrity management principles outside HCAs so that approximately 90 percent of the people living near pipelines would be covered by 2020, and 100 percent would be covered by 2030.

INGAA members commit to mitigating corrosion anomalies, both inside and outside of HCAs, in accordance with objective, technical criteria developed by consensus within the corrosion engineering community. Following these standards raises the level of corrosion protection both in quality and in timeliness of repair.

INGAA members also commit to improving the identification, evaluation and mitigation of dents, pitting corrosion and selective seam corrosion by developing and using criteria comparable to those for corrosion anomalies.

INGAA members have developed a detailed protocol for assessing the fitness for service of transmission pipes that were installed before the first set of federal safety regulations took effect. As the protocol indicates, pipes deemed high-priority will undergo pressure reduction, strength testing or replacement.

Avoiding incidents is the top priority, but the importance of incident response — both planning and execution — is self-evident. INGAA members have committed that, in the event of an incident, the affected pipe will be isolated within one hour of notification. Valve spacing and the use of remotely controlled and automated valves are important considerations. Still, public safety requires a broader review of incident responses and consequences. The appropriate approach to improving incident response, reducing incident duration and minimizing adverse impacts is performance-based Incident Mitigation Management, a concept explored at length in the response to topic H, using valves and other tools.

The IMCI action plan provides solid proposals addressing many of the subjects in the ANPRM, and INGAA's members are united in their resolve to implement the action plan even if a rulemaking to address these issues is delayed. Implementing the action plan now improves pipeline safety immediately, while providing practical lessons learned that will benefit all parties — INGAA members, PHMSA and other stakeholders — when PHMSA turns to adopting new pipeline safety regulations.

At several points in the ANPRM, PHMSA asks whether it should be taking a more prescriptive approach to pipeline safety regulation, either by imposing more prescriptive standards than currently exist or by imposing prescriptive standards in areas currently subject to more open-ended, performance-based regulation. As PHMSA develops new regulations, it should consider INGAA's IMCI action plan as an effective model for assuring pipeline safety through performance-based regulation (or through a hybrid of performance-based regulation and a limited set of prescribed regulatory standards). Performance-based regulation fosters innovation by allowing operators to incorporate technological advances quickly. Performance-based regulation also supports proactive and multidimensional planning, operations and accountability, consistent with today's business practices. Finally, performance-based regulation has an established track record of success, as illustrated by several federal agencies' highly regarded regulatory programs and documented through industry studies.

INGAA and its members are committed to being thought leaders in natural gas pipeline safety, and that role demands being transparent in our thinking and soliciting feedback and information from the other members of the pipeline safety community. Months before the filing deadline, INGAA filed policy-level comments in this docket "to inform other stakeholders of INGAA's positions and to provide a focal point for stakeholder feedback." INGAA and its members spent last November and December meeting with stakeholders, discussing the IMCI proposals, exchanging information and views, and enhancing the process for implementing the IMCI plan to reflect what was heard.

Transparency and outreach remain core elements of IMCI implementation. The week before these comments were filed, INGAA conducted a webinar to review the IMCI plan and solicit stakeholders' views. Public notice of the webinar was filed in this docket and invitations were presented directly to several stakeholder groups. Filing these comments is one step in INGAA's ongoing, dynamic process of IMCI consultation, feedback, and refinement.

The IMCI action plan is comprehensive and bold; it will entail significant costs; and cost recovery is an issue that will need to be addressed. Still, INGAA and its members are confident that the IMCI action plan provides the right path toward enhancing pipeline safety and assuring public confidence in what already is the country's safest mode of transporting energy.

Overview

The Interstate Natural Gas Association of America (INGAA) is the national trade association for the interstate natural gas pipeline industry. INGAA represents approximately two-thirds of the pipelines and over 65 percent of the mileage comprising the US natural gas transmission pipeline system. INGAA's 26 members operate approximately 200,000 miles of interstate transmission pipelines, deliver one-quarter of the nation's energy and serve as an indispensible link between natural gas producers and consumers.

These comments respond to an Advance Notice of Proposed Rulemaking (ANPRM) that the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) issued on August 18, 2011.[1] The ANPRM contains some introductory and preamble language, but its core is a set of 120 questions, many with multiple subparts, covering 15 areas of pipeline safety. The goal is to build on successes to date, with PHMSA using the responses to these questions to chart a path forward that improves the natural gas pipeline safety regulations (49 CFR Part 192 or, as used in these comments, Part 192), and particularly the integrity management concepts and requirements contained in Part 192, Subpart O, to ensure public safety and enhance pipeline system integrity.

INGAA appreciates the objectives motivating the ANPRM. To the interstate natural gas pipeline industry, no safety incident is acceptable. INGAA members' goal is zero incidents, and they have committed to pursuing that goal vigorously. Their roadmap is INGAA's Integrity Management – Continuous Improvement (IMCI) action plan, and that plan guides all of the answers that follow.

The comments are grouped by topic,[2] each discussion opening with general remarks, followed by answers to the questions posed in the ANPRM. The general remarks often describe how the topic is addressed in the IMCI action plan, which was designed so it could be used as a model for future PHMSA regulations.

Consistent with responding to an advance notice of proposed rulemaking, these comments suggest central policy concepts. For example, INGAA advocates PHMSA adoption of performance-based regulations or a hybrid of performance-based regulations and a relatively small number of prescribed standards. As INGAA described in the "policy-level" comments it filed in this docket last November, performance-based regulations foster innovation, reflect modern business practices and enjoy a proven track record of success in gas pipeline safety and other safety-critical areas. For natural gas transmission pipeline safety, the path forward lies in supplementing the existing performance-based regulations, rather than adding prescriptive revisions that could limit or restrict the ability of operators to demonstrate compliance.

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1 The ANPRM was published in the August 25, 2011, issue of the Federal Register. *Safety of Gas Transmission Pipelines*, 76 Fed. Reg. 53,086.

2 The comments cover 14 of the 15 ANPRM topics. INGAA did not comment on the fifteenth topic, gathering, because gathering is not part of the interstate natural gas transmission system.

INGAA's IMCI initiative, combined with the existing performance-based regulatory framework, should set the stage for PHMSA's further analysis of the regulatory improvements contemplated by the ANPRM.

For each topic, the general remarks are followed by answers to the questions posed in the ANPRM. Text boxes restate the questions. In some cases it was appropriate to combine several questions together and provide one answer for all of them. In these cases the combined questions are placed in a single text box, with the questions separated by a horizontal line. When a question has multiple subparts (as is often the case) subparts are grouped within the text box to follow the flow of the response as closely as possible.

Each topic ends with a asking the commenter to calculate the costs, quantify the societal and safety benefits, and assess the environmental and small business impact of any suggested regulatory changes. While INGAA appreciates that these questions would need to be answered as part of any proposed rule, this response offers regulatory concepts and models, not proposed regulations,[3] so the requested analyses would be premature. For many of the ANPRM topics, particularly those addressed in the IMCI action plan, the general responses (and, where appropriate, the responses to individual questions) discuss costs, benefits and environmental factors.[4]

The responses were written with the non-technical reader in mind. Still, INGAA appreciates that a number of the answers (and a number of the questions) contain technical terms and acronyms common to the pipeline safety community. INGAA staff stands ready to help with any questions concerning this document. Inquiries should be directed to Dan Regan (telephone: 202-216-5908; e-mail dregan@ingaa.org).

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[3] There are three exceptions. In the responses to questions C.5, G.5 and G.7, INGAA recommends PHMSA incorporate existing consensus standards into Part 192 by reference.

[4] INGAA's members are committed to implementing the IMCI action plan immediately. One of the many benefits of voluntarily implementing the plan now will be the collection of empirical safety and integrity management data for use in future policymaking. A more complete empirical basis gives all parties better tools for assessing where regulations are needed and what requirements should be adopted.

Topic-by-Topic Comments

Topic A – Modifying the Definition of HCA

The existing definition of high consequence area (HCA) appropriately captures the goal of integrity management: protecting people on a risk-prioritized basis. INGAA and its members have long embraced this goal and continue to pursue it vigorously. Since the inception of the Integrity Management Program in 2002, INGAA members have invested over 3 billion dollars to improve the integrity management of their pipelines in HCAs and adjacent areas. Going forward, INGAA's members are committed to protecting people through INGAA's Integrity Management – Continuous Improvement (IMCI) action plan, which will extend integrity management principles progressively, by population, across the entire interstate natural gas transmission pipeline system.

Based on the integrity management principle of continuous improvement, INGAA's IMCI action plan commits members first to extend some degree of integrity management to approximately 90 percent of people who live, work or otherwise congregate near pipelines (that is, within the pipelines' Potential Impact Radius, or PIR) by 2012. By 2020, INGAA operators will perform full integrity management on pipelines covering 90 percent of the PIR population. At a minimum, all ASME/ANSI B31.8S requirements will be applied, including mitigating corrosion anomalies and applying integrity management principles. Continuing to areas of less population density, INGAA members plan to apply integrity management principles to pipelines covering 100 percent of the PIR population by 2030.

The IMCI action plan's framework of voluntary commitments, summarized below, will apply integrity management principles to INGAA members' entire natural gas transmission system, phasing in this expansion based on protecting people. PHMSA should use this framework, rather than redefining HCAs, to expand the application of integrity management principles to natural gas transmission pipelines.

INGAA IMCI Action Plan: Expansion of Integrity Management

- **90 Percent of Population — Integrity Management Principles by 2012**
  - By the end of 2012, INGAA members will have applied some degree of integrity management on pipelines covering roughly 90 percent of the population living within the PIR.
    - Pipe inside an HCA will be subject to the processes required in 49 CFR Part192, Subpart O
    - Integrity management for pipe outside an HCA will range from full Subpart O, to either full ASME/ANSI B31.8S (the consensus standard) or a focus on the most significant threats (e.g., Stress Corrosion Cracking (SCC) or corrosion).
  - To cover 90 percent of population within the PIR, INGAA members will apply integrity management principles to roughly 60 percent of their total pipeline mileage.

- **90 Percent of Population — Complete ASME/ANSI B31.8S by 2020**
    - By 2020, INGAA operators will perform integrity management on pipelines covering 90 percent of the population living within the PIR.
    - At a minimum, all ASME/ANSI B31.8S requirements will be applied, including mitigating corrosion anomalies and applying integrity management principles.
- **100 Percent of Population — Integrity Management Principles by 2030**
    - By 2030, INGAA's goal is to apply integrity management principles to pipelines covering 100 percent of the population living within the PIR.
        - The integrity management principles applied to the increment between 90 percent and 100 percent of the population will range from ASME/ANSI B31.8S to new pipeline assessment technology employing integrity management principles.
        - To cover 100 percent of population within the PIR, INGAA members will apply integrity management principles to roughly 80 percent of their total pipeline mileage.
- **Remaining 20 Percent of On-Shore Pipeline Miles with No Population**
    - The remaining 20 percent of on-shore pipeline miles with no population within the PIR pose a low risk to the public. In addition, this mileage poses significant technical challenges due to a number of factors, e.g., small diameter pipelines, multi-diameter pipelines, pipelines lines with low flow rate, complex geometry, and single-source feeds to customers (necessitating complete service disruptions). INGAA's members are committed to applying improved integrity management principles to these pipelines after 2030.

The phasing strategy employed in the INGAA commitment is based on the risk profiles of the segments not addressed under the present program and the anticipated availability of technology and processes in the future. To help meet this aggressive goal, INGAA is engaging the research community and technology providers to develop new inspection and assessment tools (platforms as well as sensors) that can reliably address hard-to-assess areas. This effort is consistent with Recommendation P-11-32 from the National Transportation Safety Board's San Bruno investigation report, which asks INGAA and the American Gas Association to report on the development and introduction of innovative in-line inspection (ILI) platforms, including a timeline for implementation of the advanced platforms. INGAA has begun developing a road map for the requisite ILI research and development.

Question A.1

Should PHMSA revise the existing criteria for identifying HCAs to expand the miles of pipeline included in HCAs?

If so, what amendments to the criteria should PHMSA consider (e.g., increasing the number of buildings intended for human occupancy in Method2)?

Have improvements in assessment technology during the past few years led to changes in the cost of assessing pipelines?

Given that most non-HCA mileage is already subjected to in-line inspection (ILI) does the contemplated expansion of HCAs represent any additional cost for conducting integrity assessments?

If so, what are those costs? How would amendments to the current criteria impact state and local governments and other entities?

The existing HCA identification criteria are adequate and appropriate to their primary focus, the protection of life and property, and they should be retained. This is particularly true in the case of interstate natural gas transmission operators, which predominantly use Method 2, known as the Potential Impact Radius (PIR) or “C-FER Circle” or PIR method, to identify HCAs. Method 2 uses well-reasoned and vetted identification criteria that properly focus additional critical integrity management activities on the areas of highest potential consequence.

The present HCA definition has already provided a “kick start” to applying integrity management principles outside of HCAs. A recent INGAA survey confirms that when the baseline assessments under the current Integrity Management Program[5] are completed (December 2012), more than 64 percent of total INGAA natural gas transmission mileage will have been assessed utilizing integrity management principles even though just over 4 percent of the mileage is located within HCAs. Of the total population identified within the PIR of the INGAA interstate transmission network, approximately 90 percent is within the PIR of the lines inspected during the baseline IMP integrity management period. This demonstrates that the integrity management programs currently in place, which cover both HCAs as currently defined and associated “over-testing” (defined as the non-HCA mileage inspected and remediated in conjunction with integrity management inspections of HCAs) capture the main areas of population, consequence, and risk.

Expanding the HCA criteria would affect hundreds of state and local governmental entities and each of them would have to determine the resulting impact and cost. For example, expanding the current HCA criteria likely would result in additional state and local integrity management programs for identification, certification and compliance auditing. The costs of these added “pipeline categorization” programs would be borne by state and local authorities, as well as pipeline operators, and the added programs will yield little if any improvement in public safety

[5] 40 C.F.R. Part 192, Subpart O.

because integrity management practices already will be implemented in these areas under the INGAA proposal.

An accurate impact assessment of expanding the definition of HCAs cannot be made absent a specific proposal. If a redefined HCA results in the same activities envisioned by the IMCI initiatives, the expected difference in costs would be minimal. However, if the redefined HCA is significantly different, then the difference in costs could be large and disproportionate to the safety benefit resulting from the IMCI action plan.

Question A.2

Should the HCA definition be revised so that all Class 3 and 4 locations are subject to the IM requirements?

What has experience shown concerning the HCA mileage identified through present methods (e.g., number of HCA miles relative to system mileage or mileage in Class 3 and 4 locations)?

Should the width used for determining class location for pipelines over 24 inches in diameter that operate above 1000 psig be increased?

How many miles of HCA covered segments are Class 1, 2, 3, and 4?

How many miles of Class 2, 3, and 4 pipe do operators have that are not within HCAs?

Changing the HCA definition to subject Class 3 and 4 locations to IM requirements is simply unnecessary. Subpart O already allows for the option of utilizing Class 3 and 4 locations and identified sites for HCA determination. Ten years ago, when Subpart O was being developed, many recognized that a number of operators had the data and analytical systems to identify potential population impact areas far more precisely than could be determined through the class location process. The use of class location designations as a surrogate was continued in Subpart O because some operators' data and systems were not amenable to the greater precision afforded by the "C-FER circle" or PIR concepts in Method 2.

Most of the people living near pipelines already outside of HCAs are benefitting from assessments operators conducted under IM programs that use HCAs determined through the PIR methodology. In fact, the bulk of Class 3 and 4 locations (approximately 90 percent) are being assessed already. Arbitrarily designating all pipes in Class 3 and 4 areas as HCAs, even laterals operating at low pressure, for example, would run counter to the principles underlying IM and the Subpart O regulations, and likely would result in the inclusion of smaller diameter laterals that operate at lower stress levels, have relatively small PIRs and represent significantly less risk. Forcing such pipelines into a mandatory program with prescriptive requirements likely would be very expensive, with little if any risk reduction or safety improvement.

Changing the class location width for pipes over 24 inches in diameter operating at pressures over 1,000 psig would contravene the goals of integrity management and should not be adopted. Increasing the class location width would divert effort and resources to places where little additional public safety value can be gained. The Integrity Management Program, which was envisioned as an improved way of managing risk in high consequence areas, provided a substitute for the vintage class location system. In the recently signed pipeline safety reauthorization act, Congress recognized the overlap between the vintage class system and HCAs, and asked PHMSA for a review of the benefit of maintaining these interrelated systems.[6] Determining HCAs using the PIR tool more accurately reflects a pipe's consequence area. Such a change would require significant class location pipe replacement, which would come with associated cost, service disruption, and landowner and neighborhood disruption and inconvenience, all to replace pipe which, in the majority of cases, has been assessed and evaluated already per the operator's IM program. Other safety measures, such as public awareness and damage prevention programs, liaison with emergency responders, and PIPA implementation are being utilized outside of the PIR.

The data tabulated below show natural gas transmission pipeline miles by class location and HCA status from a recent INGAA survey covering approximately 64 percent of total transmission mileage.

	Total Miles	HCA Miles	Non-HCA Miles
Total System	124,389	5,134	119,255
Class 1	103,761	475	103,286
Class 2	11,853	535	11,318
Class 3	8,746	4100	4,646
Class 4	30	24	5

Question A.3

Of the 19,004 miles of pipe that are identified as being within an HCA, how many miles are in Class 1 or 2 locations?

Results of a recent INGAA survey covering just over 5,000 miles of HCA mileage are tabulated in response to question A.2. This data sample represents approximately 64 percent of INGAA member mileage and is indicative of the nationwide diversity of pipeline systems. Of this mileage, less than 20 percent of HCA miles are in Class 1 and 2.

[6] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub.L. 112-90 § 5(a)(2).

Question A.4

Do existing criteria capture any HCAs that, based on risk, do not provide a substantial benefit for inclusion as an HCA? If so, what are those criteria? Should PHMSA amend the existing criteria in any way which could better focus the identification of an HCA based on risk while minimizing costs? If so, how? Would it be more beneficial to include more miles of pipeline under existing HCA IM procedures, or, to focus more intense safety measures on the highest risk, highest consequence areas or something else? If so, why?

As discussed at length in response to question A.1, the current HCA criteria, when applying Method 2 utilizing the PIR, are appropriate to meet the Integrity Management Program's primary goal of protecting people, property and the environment. The current criteria were carefully developed and reviewed with the goal and purpose of identifying actual areas of potentially high consequence; they already encompass the vast bulk of the population; and nothing to date indicates that the current criteria are too broad or too narrow. The existing HCA criteria do not need to be changed or expanded. However, when an operator is defining HCAs utilizing Method 1, which includes Class 3 and 4 areas, that assessment of small diameter, low pressure pipelines in these areas may not be providing a substantial risk reduction benefit.

The focus of IM should be on population. The value of a possible expansion of IM activities therefore is measured by the number of additional people within the PIR that would become covered by IM principles. Protecting people lies at the heart of INGAA's IMCI initiative.

INGAA's IMCI initiative would improve the IM programs that already have benefitted approximately 90 percent of the population living within the PIR, and would employ IM principles system-wide, with expansion prioritized by population, to cover 100 percent of the PIR population by 2030). As detailed in the general response to this topic, PHMSA should use INGAA proposed framework for expanding IM beyond HCAs.

Question A.5

In determining whether areas surrounding pipeline right-of-ways meet the HCA criteria as set forth in part 192, is the potential impact radius sufficient to protect the public in the event of a gas pipeline leak or rupture?

Are there ways that PHMSA can improve the process of right-of-ways HCA criteria determinations?

PIR provides an indication of the amount of energy in the form of radiated heat that can be released if natural gas from a pipeline rupture ignites at the time of the rupture. Methods employing PIR identify areas of potentially serious consequence, which is where the focus of pipeline safety measures have been and should remain. The PIR concept is not intended to address leaks, which are addressed by other aspects of operators' integrity management and operations and maintenance programs, such as leak surveys and patrols. Public safety outside of the PIR is being addressed successfully through other initiatives, such as public awareness, emergency response, damage prevention, and PIPA implementation.

As stated previously, the current criteria for determining HCAs are technically valid, fully implemented and understood. No changes are suggested or needed.

Question A.6

Some pipelines are located in right-of-ways also used, or paralleling those, for electric transmission lines serving sizable communities. Should HCA criteria be revised to capture such critical infrastructure that is potentially at risk from a pipeline incident?

HCA criteria should not be revised to include electric transmission lines because the public safety risk is extremely low. There have been very few instances where a pipeline incident has disrupted electric transmission service and those instances are dwarfed by the other causes of power outages.

Question A.7

What, if any, input and/or oversight should the general public and/or local communities provide in the identification of HCAs?

If commenters believe that the public or local communities should provide input and/or oversight, how should PHMSA gather information and interface with these entities?

If commenters believe that the public or local communities should provide input and/or oversight, what type of information should be provided and should it be voluntary to do so?

If commenters believe that the public or local communities should provide input, what would be the burden entailed in providing provide this information?

Should state and local governments be involved in the HCA identification and oversight process?

If commenters believe that state and local governments be involved in the HCA identification and oversight process what would the nature of this involvement be?

Public and community involvement already is addressed effectively through PHMSA regulations requiring operators to consult with local emergency officials. These officials have the expertise to represent the public and the state and local governments meaningfully, and the current regulations therefore should not be disturbed.

Input from the public and local governments also is encouraged through the rulemaking process, advisory committee meetings, submitting questions directly to PHMSA, contacting PHMSA Community Assistance and Technical Services staff, and communicating to members of the National Association of Pipeline Safety Representatives.

Question A.8

Should PHMSA develop additional safety measures, including those similar to IM, for areas outside of HCAs? If so, what would they be? If so, what should the assessment schedule for non-HCAs be?

As discussed previously, INGAA members are already applying IM principles outside HCAs and are committed to continue doing so. It is therefore unnecessary to develop specific additional safety measures for areas outside HCAs. The IM program for non-HCAs should be a risk-based decision by operators based on the principles in ASME/ANSI B31.8S. This standard, portions of which are already incorporated into Subpart O, is a comprehensive standard that properly addresses all aspects of integrity management.

Question A.9

Should operators be required to submit to PHMSA geospatial information related to the identification of HCAs?

Section 6 of the 2011 pipeline safety reauthorization act[7] requires PHMSA to include designated HCAs in the National Pipeline Mapping System (NPMS). INGAA operators support providing geospatial information related to HCAs to PHMSA through the NPMS data submission. Given the security issues associated with geospatial information on critical infrastructure, PHMSA should coordinate with both the Transportation Safety Administration and the Federal Energy Regulatory Commission regarding releases of this information.

Question A.10

Why has the number of HCA miles declined over the years?

INGAA has not conducted an extensive survey of its members on this question, but offers two general reasons why HCA mileage may show a decline. First, operators are converting from Method 1 to the more accurate Method 2. As the integrity management rule was implemented, many operators took a more readily available approach and used Method 1 because they had data on their systems' Class 3 and 4 areas. As structure data and GIS systems mature and become more fully populated with data, it becomes easier to manage the calculation of HCAs using Method 2, which INGAA believes is an improvement in the process. The move from the Method 1 to the more precise Method 2 would decrease the number of recorded HCA miles. Second, pipeline retirements or abandonments may also be a factor in a reduction in HCA mileage.

[7] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub.L. 112-90 § 6.

Question A.11

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

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Topic B –Preventive and Mitigative Measures for Pipeline Segments in HCAs

INGAA strongly agrees with the necessity of applying preventive measures to address identified threats. In addition to Incident Mitigation Management (IMM) planning (discussed under topic H), guidance is provided in Table 4 and Section 7 of ASME/ANSI B31.8S. Enhancing these standards—perhaps by adding a decision tree or flow chart—will help operators systematically apply this requirement. PHMSA also would benefit by using this guidance to implement enforcement objectives.

Excavation damage to pipelines is the most significant cause of serious pipeline incidents (those involving injuries and deaths). PHMSA can improve the prevention and mitigation of excavation damage substantially by fully implementing its state damage prevention programs. Opportunities to enhance current damage-prevention programs include expanding enforcement provisions associated with one-call programs, eliminating exemptions currently granted under some state's one-call regulations, and promoting greater consistency and standardization of state program best practices.

The US Department of Transportation (DOT) can also enhance damage prevention programs by broadening public education efforts supporting 811 and one-call programs. Even with vigorous 811 education campaigns, a significant number of pipeline incidents still occur because the excavator did not use the One Call system. DOT should promote 811 public service announcements at the national, state and local level, in a manner similar to the extremely effective seat belt campaign.

Question B.1

What practices do gas transmission pipeline operators now use to make decisions as to whether/which additional preventive and mitigative measures are to be implemented?

Are these decisions guided by any industry or consensus standards?

If so, what are those industry or consensus standards?

Operators currently employ a wide variety of preventive and mitigative (P&M) methods. Many of these processes, such as corrosion control surveys, leak surveys, patrols and signage, are documented in minimum standards appearing throughout Part 192. In addition, pipeline operators may employ Part 192 practices at greater frequency than required or follow processes and practices beyond the pipeline safety regulations. The operators use experience, risk models, and location-specific threat assessments to inform their decisions regarding the value or effectiveness of these additional mitigation measures.

These decisions are guided by consensus standards such as those published by the American Society of Mechanical Engineers, the American Petroleum Institute and NACE International (formerly The National Association of Corrosion Engineers) as well as more recent information published in research reports or trade association white papers. These consensus standards, practices and guidance continue to be updated, improved and revised by the standard-setting oversight groups that include regulatory agencies, industry, the public, the research community and other technical organizations. Examples include:

- ASME/ANSI B31.8S – Table 4
- Common Ground Alliance Best Practices
- Pipelines and Informed Planning Alliance Recommended Practices
- API-RP 1162 – Public Awareness Programs,
- API-RP 1166 – Excavation Monitoring
- NACE SP0169, other associated NACE standards
- Gas Piping Technology Committee guidance materials
- RSTRENG -A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe
- INGAA Foundation Guidelines For Evaluation and Mitigation of Expanded Pipes

Question B.2

Have any additional preventive and mitigative measures been voluntarily implemented in response to the requirements of § 192.935?

How prevalent are they?

Do pipeline operators typically implement specific measures across all HCAs in their pipeline system, or do they target measures at individual HCAs?

How many miles of HCA are afforded additional protection by each of the measures that have been implemented?

To what extent do pipeline operators implement selected measures to protect additional pipeline mileage not in HCAs?

Operators have implemented additional measures to meet the requirements of § 192.935. In addition, most operators voluntarily implement measures beyond those required for compliance. Many of these additional measures were in use prior to the promulgation of Subpart O, and were employed before the concept of HCAs was established.

Additional preventive and mitigative (P&M) measures are quite prevalent, based on the risk analysis results and choices available.

Targeted measures generally are implemented to address specific issues or threats on specific segments. These may include:

- Additional reconnaissance (after seismic events, floods, etc.)
- Concrete mats over pipelines in areas particularly susceptible to excavation damage;
- Encroachment sensors
- Remotely operated valves

Some measures, such as additional patrols and signage and enhanced public awareness, are implemented more broadly than others. Generally implemented measures may be applied much more broadly than in HCAs alone.

Member company data systems generally are not set up to track the mileage that is impacted by each specific P&M measure or the benefits resulting from it. Ultimately all HCA miles benefit from P&M measures, but because of the way they are implemented, mileage tracking would require extensive data gathering and mining. General measures, such as increased patrol frequency, impact all HCA miles. Site-specific measures, such as protection by concrete mats or specific inspections following a flood, may impact only hundreds or thousands of feet, or may be employed only at a time and place where needed.

The selection of measures to protect segments outside HCAs is highly dependent on the threat being addressed. A single P&M measure may be applied well beyond the limits of the HCA itself. Examples of activities that benefit miles of pipeline beyond HCAs include increased aerial and other patrols; investigative excavations for stress corrosion cracking, for coating damage and condition, or for corrosion damage; close interval survey; direct current voltage gradient; and rectifier inspections in lightning-affected areas.

Question B.3

Are any additional prescriptive requirements needed to improve selection and implementation decisions? If so, what are they and why?

Selection and implementation decisions based on specific circumstances, risk, experience and analysis have a sound basis and provide more safety benefit than a prescriptive approach or additional prescriptive requirements. More benefit will be derived from the regular review and update of consensus standards, such as ASME/ANSI B31.8S, which provide operators with direction and guidance on alternative P&M measures for various threats to pipeline integrity. The regular review of such standards, as required by the American National Standards Institute process, is consistent with the requirement for continuous improvement of programs.

Question B.4

What measures, if any, should operators be required explicitly to implement?

Should they apply to all HCAs, or is there some reasonable basis for tailoring explicit mandates to particular HCAs?

Should additional preventative and mitigative measures include any or all of the following: Additional line markers (line-of-sight); depth of cover surveys; close interval surveys for cathodic protection (CP) verification; coating surveys and recoating to help maintain CP current to pipe; additional right-of-way patrols; shorter ILI run intervals; additional gas quality monitoring, sampling, and inline inspection tool runs; and improved standards for marking pipelines for operator construction and maintenance and one-calls? If so, why?

Part 192 already prescriptively requires many activities that are, in fact, P&M measures. Risk-based selection of additional P&M measures is more effective than the application of additional prescriptive measures because it targets actual risks and avoids dilution of effort.

Requiring additional prescriptive measures for all HCAs is not an effective or efficient approach. Tailoring explicit mandates to particular HCAs already may be one outcome of risk-based threat assessment and response, but "tailoring" in that sense is already available and there is no benefit in requiring it.

Each of the measures specified in the last portion of this question appears in ASME/ANSI B31.8S Table 4, and together they form a suite of approaches for operators to choose from based on their effectiveness in addressing a particular risk, threat or characteristic of the line. The current process allows the operator to achieve a more efficient deployment of resources, applying the specific measures, including those listed here, where analysis shows they will be the most effective in mitigating the active threats to pipeline safety. That said, there are many locations, where some of the available measures would provide essentially no benefit, and thus be counterproductive.

Question B.5

Should requirements for additional preventive and mitigative measures be established for pipeline segments not in HCAs?

Should these requirements be the same as those for HCAs or should they be different?

Should they apply to all pipeline segments not in HCAs or only to some?

If not all, how should the pipeline segments to which new requirements apply be delineated?

INGAA members propose adopting performance-based regulations using the IMCI framework for system-wide application of integrity management principles, including preventive and mitigative measures. The IMCI framework is detailed in the general response to topic A.

Under the IMCI framework, operators would employ additional integrity management measures in pipeline segments beyond HCAs, based on affected population. Operators have been applying integrity management measures outside HCAs for some time both through in-line inspection "overtesting" (the inspection or testing of pipeline mileage beyond the limits of the HCAs) and thorough anomaly response and remediation. Such areas outside HCAs would continue to be considered for additional measures on a risk basis. The IMCI framework would expand these areas to ultimately provide these safety assurances and measures to virtually all persons affected by proximity to a pipeline.

Ultimately, the processes and mechanisms for choosing effective P&M measures should be risk-based, should consider all segments of the pipeline and should be implemented at a level appropriate for the risk.

Consistent with INGAA's comments regarding topic A and its comments to the other questions posed under this topic, all pipeline segments should be considered for additional P&M measures, with decisions being based on risk, specific threats, the segment involved and the effectiveness of particular measures.

Question B.6

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

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Topic C – Modifying Repair Criteria (Appropriate Anomaly Response)

Existing regulations address non-HCA anomalies, and many operators already treat corrosion and other anomalies found by in-line inspection (ILI) virtually uniformly whether they are inside or outside HCAs. Two sets of considerations are made following an integrity assessment. The first is anomaly **response** criteria, which are performance tools that help determine the actions that need to be taken based the results of integrity assessments. ANSI/ASME B31.8S sets out anomaly response criteria, including timing criteria for determining when to make excavations to evaluate FFS and when to continue monitoring. The second set of considerations is **repair** criteria for a pipeline to be fit for service and continue operating. The most often-used repair criteria are the assessment of corrosion deterioration; another example being dent evaluation.

INGAA members have resolved to mitigate corrosion anomalies, both inside and outside of HCAs, in accordance with the technically based criteria in ASME/ANSI B31.8S (including any future enhancements or revisions). This resolve raises the level of corrosion protection both in quality and in timeliness of repair. INGAA members have also resolved to improve the identification, evaluation and mitigation of dents, pitting corrosion, and selective seam corrosion (SSC) by developing and using criteria comparable to those for corrosion anomalies.

The ANSI/ASME B31.8S protocol produces a strong technical basis for decision-making in response to the discovery of anomalies. As ILI technology (both detection and reporting) continues to improve, the best investment of resources is to reassess, repair or replace based upon the information produced by this technology wherever reasonably possible.

- Uncertainties in ILI performance and the ANSI/ASME B31.8S protocol are being identified and quantified. INGAA members have collaborated with Pipeline Research Council International (PRCI) to commission a research report *“to refine and extend the technical bases for responding to corrosion anomalies identified primarily by ILI. These technical bases will provide the operator with guidance regarding the determination of both what anomalies require a remediation response and the timing of that response, and will include consideration of measurement, corrosion growth, and analytical (model) uncertainties.”* The report is scheduled for completion in first quarter 2012.
- Upon completion of the PRCI research report, INGAA members will work with American Society of Mechanical Engineers to refine of ASME/ANSI B31.8S to include anomaly evaluation methodologies that account for data uncertainties (including tool accuracy) by applying a consistent process or series of processes across its membership. INGAA members also will work with other consensus standard setting organizations, such as the American Petroleum Institute, on guidance for ILI application.

INGAA’s goal continues to be no failures of anomalies identified by ILI technology. Future required reassessments outside of HCAs should be risk-based utilizing present and future of ASME/ANSI B31.8S criteria.

Question C.1

Should the immediate repair criterion of FPR ≤ 1.1 be revised to require repair at a higher threshold (i.e., additional safety margin to failure)?

Should repair safety margins be the same as new construction standards?

Should class location changes, where the class location has changed from Class 1 to 2, 2 to 3, or 3 to 4 without pipe replacement have repair criteria that are more stringent than other locations?

Should there be a metal loss repair criterion that requires immediate or a specified time to repair regardless of its location (HCA and non-HCA)?

The existing **repair** criteria already exceed a 1.1 failure pressure ratio. The Part 192 immediate **response** criteria for time-dependent threats, which reflect ANSI/ASME B31.8S and are consistent with the pressure test requirements for most installed pipeline mileage, have proven effective. There have been no reported instances of incidents due to the response criteria being too lax. In fact, the data suggest the opposite. The issue is not the soundness of the criteria themselves; where concerns have arisen, they have centered on the practical effect of applying these criteria in the face of uncertainty, e.g., uncertainty associated with tool performance and modeling. INGAA is aware of these concerns and its members continue to work to understand process uncertainties, their effects, and how to manage them. However, questions about how the criteria operate in practice do not undermine the criteria themselves. A regulatory revision requiring immediate response is unnecessary.

Section 192.485(a) provides that “corroded pipe be repaired by a method that . . . permanently restores the serviceability of the pipe.” Section 192.713(a) provides a similar standard for permanent field repair of imperfections and damages: “Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be . . . repaired by a method that . . . permanently restore[s] the serviceability of the pipe.” These standards have proven adequate and additional requirements are unnecessary.

For class location changes — Class 1 to Class 2, Class 2 to Class 3, Class 3 to Class 4 — Section 192.611(a) provides repair criteria that are consistent with the design factor that applied at the time of original construction. Nothing in our incident experience suggests a need for more stringent requirements or additional prescriptive requirements.

Existing regulations cover metal loss repair response criteria based on threat (time-dependent or not) in HCAs. INGAA members use the HCA response criteria as a guideline for non-HCA pipe. Additional prescriptive requirements are unnecessary.

Question C.2

Should anomalous conditions in non-HCA pipeline segments qualify as repair conditions subject to the IM repair schedules? If so, which ones?

What projected costs and benefits would result from this requirement?

As noted in the general response to this topic, many operators already treat corrosion and other anomalies found by ILI virtually uniformly whether they are inside or outside an HCA. The repair criteria tend to be the same. Outside HCAs, the time from when an anomaly is identified or discovered to when the anomaly is excavated or investigated, may be somewhat different, but that difference takes into consideration the proximity of the anomaly to potentially-affected population. Response criteria are designed to provide adequate safety until an affected segment is reassessed or investigated.

For addressing anomalies outside HCAs, the incremental cost would be marginal, because operators already apply ASME/ANSI B31.8S response criteria whether the anomaly is inside an HCA or outside an HCA. The issue is the timing of these expenses, specifically the impracticable level of short-term expense that would be imposed on operators if they had to repair all anomalies immediately upon discovery.

Question C.3

Should PHMSA consider a risk tiering—where the conditions in the HCA areas would be addressed first, followed by the conditions in the non-HCA areas? How should PHMSA evaluate and measure risk in this context, and what risk factors should be considered?

Prescribed risk tiering by PHMSA would not be beneficial. Anomalous features that meet the response criteria should be addressed in an appropriate time frame regardless of the proximity to an HCA or to a non-HCA. The INGAA framework for expanding IM beyond HCAs is to continue integrity management activities, extending their use and the appropriate risk considerations based on potentially-affected population.

Question C.4

What should be the repair schedules for anomalous conditions discovered in non-HCA pipeline segments through the integrity assessment or information analysis?

Would a shortened repair schedule significantly reduce risk?

Should repair schedules for anomalous conditions in HCAs be the same as or different from those in non-HCAs?

The repair schedules for anomalous conditions in non-HCAs, normally referred to in the industry as response criteria, should closely mirror the criteria applied inside HCAs. Some latitude in the timing of the response for HCA immediate response conditions is likely warranted due to the length of the inspected segment. Applying these response criteria in all

60 miles of an ILI run has a different impact, both on gas deliveries to customers and the ability to respond with excavations, than applying these criteria in only the three or four miles of HCA within the 60-mile ILI run.

There have been no incidents identified that would have been prevented had the response criteria been shorter or more aggressive. Operator experience since the application of the Subpart O requirements has shown the vast majority of anomalies classified as immediate response conditions per of ASME/ANSI B31.8S, when examined, did not pose an imminent threat to the integrity or safety of the pipeline. A sizeable fraction appear to have, in fact, been likely construction or early-life features that have probably remained unchanged for years or decades and were not growing. Prescribing a shortened or more aggressive repair schedule could be counterproductive by diverting finite resources to lower-risk mitigation activities and precluding the opportunity to confirm that an anomaly is not growing. Mandating more aggressive responses than necessary does not reduce risk or improve safety. In fact, excavation activities for such anomalies may pose greater risks to personnel and the associated pipeline than the risk being mitigated. This is an area where additional analyses and comparison of approaches and results may provide an overall benefit to safety. Data are currently being collected through the IMCI initiatives to further evaluate this issue.

The response schedule should be more a function of anomaly growth or degradation rates rather than a differentiation between HCA and non-HCAs. Consistent treatment of anomalies is preferable. Such a risk-based approach should be guided both by ongoing review and incorporation of data on anomalies and their behavior, and by identification of areas where aggressive growth is expected.

Question C.5

Have ILI tool capability advances resulted in a need to update the ‘‘dent with metal loss’’ repair criteria?

Both dent characterization and corrosion characterization have improved in the past decade, allowing more precise sizing of both dents and corrosion, suggesting that updating repair criteria for dents with metal loss is appropriate. The newer geometry ILI tools are much better at discriminating and characterizing smooth vs. sharp dents. The standards applicable to “dent with metal loss” have improved as well. If data from a tool integrated with other knowledge and data on a segment can discriminate between corrosion metal loss and excavation or mechanical damage (gouging), then the corrosion metal loss anomalies associated with dents can be treated by the principle of superposition (outlined in of ASME/ANSI B31.8, Section 851.4.1(f)). Incorporating this section into Part 192 would provide an appropriate update of the “dent with metal loss” repair standard, which is an interactive threat.

Question C.6

How do operators currently treat assessment tool uncertainties when comparing assessment results to repair criteria?

Should PHMSA adopt explicit voluntary standards to account for the known accuracy of in-line inspection tools when comparing in-line inspection tool data with the repair criteria?

Should PHMSA develop voluntary assessment standards or prescribe ILI assessment standards including wall loss detection threshold depth detection, probability of detection, and sizing accuracy standards that are consistent for all ILI vendors and operators?

Should PHMSA prescribe methods for validation of ILI tool performance such as validation excavations, analysis of as-found versus as-predicted defect dimensions?

Should PHMSA prescribe appropriate assessment methods for pipeline integrity threats?

In using assessment results to set the response schedules, operators use a variety of methods to treat overall uncertainties, not necessarily just tool assessment uncertainties. The methods may include adding an incremental fraction of wall loss to tool indications, performing a statistical analysis, using tool calibration records and unity plots, proportionally or selectively decreasing the response time, or employing other statistical or deterministic methods. These have all been used by operators in guiding their responses, and all have proven generally successful in addressing anomalies before they lead to leaks or ruptures. Still, all of these uncertainty assessment methods generate “false positives” that probably will require operators to respond to some number of non-threatening anomalies. Responding to anomalies that are not growing and do not pose an immediate threat to pipeline integrity does not add to safety.

Prescriptive regulatory standards essentially stifle technological advances or creative approaches to integrating data from various sources. Such prescription would require constant adjustment as tools and sensors continue to be developed. Considerable variability among tools designed for different purposes and working in lines of significantly different diameter and wall thickness also can be expected. Issuing prescriptive regulations in the face of rapid technological change would be counterproductive.

Industry generally uses API-1163, a consensus standard, to establish accuracy and demonstrate the accuracy being achieved during a particular tool run. This does not set a prescriptive accuracy requirement, but rather helps the vendor and operator establish a required accuracy and demonstrate that it has been achieved.

Established consensus standards, such as API-1163, API-579 and ASNT ILI-PQ, already are in use widely. Such standards are continuously reviewed and periodically updated based on advances in science and technologies. Updates to these standards are overseen by subject matter experts, including academia, regulators, and industry. Current standard setting procedures provide the most appropriate way to develop and disseminate such guidance. Placing additional, competing standards in Part 192 may add confusion rather than value.

Validation of tool performance is certainly desirable, and methods for performing the validation are outlined in API-1163. Rather than prescribing a validation method and stifling technological improvement, PHMSA may wish to adopt performance-based guidance endorsing the methods noted in the question and allowing other equivalent methods.

If regulations should go forward, PHMSA should adopt performance-based measures to ensure that operators are identifying the threats and assessing them with the proper methods and technologies. The regulator does not know the details of each operator's system nearly as well as the operator does, making it almost impossible to prescriptively require specific methods. Under the current regulations, threat assessment and response is clearly an operator responsibility, and should remain so.

Question C.7

Should PHMSA adopt standards for conducting in-line inspections using ''smart pigs,'' the qualification of persons interpreting in-line inspection data, the review of ILI results including the integration of other data sources in interpreting ILI results, and/or the quality and accuracy of in-line inspection tool performance, to gain a greater level of assurance that injurious pipeline defects are discovered

Should these standards be voluntary or adopted as requirements?

ILI standards have been developed and are used by operators. PHMSA representatives have been members of most of the standards oversight and development bodies. INGAA continues to encourage the participation of PHMSA and the public in the development and review of national consensus standards. Additional information on this topic appears in the response to question C.6.

At present, the standards noted (API-1163, API-579, ASNT ILI-PQ, NACE SP-0102) are, strictly speaking, voluntary at least to some extent. If PHMSA chooses to establish requirements by adopting standards in total or in part, its review and approval process should be streamlined where possible so improvements in the standards can be adopted without delay.

Question C.8

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

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Topic D – Collecting, Validating, and Integrating Pipeline Data

A key to a well-run risk-management system is quality information about the inventory and characteristics of the pipeline. Knowledge gained during investigations of pipeline failures can help focus pipeline data collection efforts. Data collection and analysis are essential to effective risk assessment.

ASME/ANSI B31.8S emphasizes the importance of collecting and utilizing data. One of the key lessons learned from of the first 10 years of applying integrity management is the importance of collecting the right data. It also is imperative that the **right** data is integrated into an overall risk assessment. INGAA members are working collaboratively to develop tools and methods to better integrate data, not only to support risk analysis, but also to support decisions concerning the selection of post-assessment excavation sites and the prevention and mitigation measures that better manage threats to integrity.

The data integration process must demonstrate how risk analysis is being applied on an ongoing and consistent basis. It must be reviewed and monitored by executive management. INGAA believes a need exists to apply progressively more advanced engineering and critical assessments within the framework of ASME/ANSI B31.8S and its revisions. Any system should include a basis for analyzing interacting threats.

Part 192 regulations require gas transmission pipeline operators to:

- Gather and integrate existing data and information concerning their entire pipeline that could be relevant to segments in HCAs (section 192.917(b)),
- Use the data and information in a risk assessment of the covered segments (Section 192.917(c)),
- Determine whether additional preventive and mitigative measures are needed (Section 192.935), and
- Define the intervals at which IM reassessments must be performed (Section §192.939).

PHMSA's concern with collecting, validating, and integrating pipeline data correctly implies that risk analyses and their conclusions can only be as good as the information used to perform them.

Questions D.1, D.2 and D.3

What practices are now used to acquire, integrate and validate data (e.g., review of mill inspection reports, hydrostatic tests reports, pipe leaks and rupture reports) concerning pipelines? Are practices in place, such as excavations of the pipeline, to validate data?

Do operators typically collect data when the pipeline is exposed for maintenance or other reasons to validate information in their records? If discrepancies are found, are investigations conducted to determine the extent of record errors? Should these actions be required, especially for HCA segments?

Do operators try to verify data on pipe, pipe seam type, pipe mechanical and chemical properties, mill inspection reports, hydrostatic tests reports, coating type and condition, pipe leaks and ruptures, and operations and maintenance (O&M) records on a periodic basis? Are practices in place to validate data, such as excavation and in situ examinations of the pipeline? If so, what are these practices?

Questions D.1, D.2 and D.3 are best answered together.

Valid data and its effective integration have always been key ingredients to managing pipeline safety and implementing integrity management, which is why data validation and integration are addressed extensively in Part 192 and standards such as ASME/ANSI B31.8S. Consensus manufacturing and construction standards have relied on defined specifications, standardized processes, statistical sampling and chain of custody methods to assure quality control.

Transmission pipeline operators have used records management systems for acquiring and validating data for project work conducted on the pipeline system, including maintenance and integrity work, since their systems were initially constructed. From the 1920s and 1930s there have been consensus standards in place covering line pipe and appurtenances to provide guidance to operators' individual procedures or specifications that define how line pipe and appurtenances (such as valves and fittings) are manufactured. These are complementary to the standards, procedures, specifications, and ultimately regulations that cover not only manufacture but installation, operation and maintenance as well. These specifications and procedures, including their data validation and documentation requirements, form a "quality management system" of the type referenced in topic M. For specifics on how manufacturer and operator specifications and procedures, including records management procedures, work together as a quality management system, please refer to the response to question M.1.

As these systems have become more robust and sophisticated, moving from widely scattered paper-based systems to the storage and registry of large amounts of electronic information, they are increasingly used for integrating this data. Improved data integration not only facilitates overlaying various data aspects and attributes, but also enhances the assessment of data consistency and the identification of data discrepancies for resolution. Such systems also facilitate the availability of information and data to the people who need it for assessment and decision making on remediation. INGAA is currently working on guidelines for operators to use to determine whether the appropriate systems are in use and whether they are being employed appropriately for maximum effectiveness.

Operators design the data storage indexing and analysis portions of their records management systems to satisfy ongoing needs. As analytic or regulatory requirements change, these systems have to be redesigned. For example, the amount of information needed for reference and analysis has changed considerably from what was needed three decades ago, so operators had to reorganize their record keeping systems completely.

In January 2011, PHMSA issued Safety Bulletin (ADB-11-01) directing operators to ensure their pipeline records are traceable, verifiable and complete. Since then, INGAA members have made a concerted effort to reorganize, validate and index historical records, such as mill inspection reports and hydrostatic pressure test records. Transmission operators are undertaking a physical review of historical records, and the results are being used to document and verify the pipe attribute data used in operator data systems, geographical information systems (GIS) and integrity management programs. These efforts have received significant support within the IMCI structure, including a workshop on various methodologies and techniques.

Extensive data reviews by INGAA members have shown that most of the pipeline data required to calculate maximum allowable operating pressure and perform threat assessments is available in various forms. However, some pipe properties and elements can be verified only through direct or indirect examination, while certain data elements cannot be evaluated or may be difficult to positively determine through nondestructive inspection. Examples of data elements that may not be easily independently verified with nondestructive methods include actual pipe grade, seam type (in some instances), year of installation, and mechanical and chemical properties.

Operators perform excavation to validate inspections indicated by in-line inspection or direct assessment to make repairs and to facilitate line crossings. Regulations and operators' practices and procedures require that whenever a pipeline segment is exposed the operator must document the segment's coating and condition. In addition to recording these basic observations, operators also take advantage of excavations to verify other pipeline attributes such as diameter, wall thickness and, when possible, seam type. While this verification practice is not formalized, this data can be compared with available records to identify discrepancies and address them.

As shown in the figure on the next page, for the two-year period 2009-2010, INGAA companies conducted more than 25,000 excavations, exposing more than 250 miles of pipe.[8] Many companies have robust processes that use GIS coordinates to capture excavation and pipe inspection data for records validation.

8 The average length of an excavation was 54 feet.

Pipeline Excavations* *(2009 - 2010)*

**The INGAA members reporting this data represent 179,169 miles of transmission pipeline*

INGAA members are establishing improved practices to revalidate pipeline attributes where data from traditional records reviews are insufficient or if observations or inspections provide information that is contrary or unknown with present record systems. These new practices, which integrate traditional records with planned pipeline excavations and internal pipeline inspection results, can result in a very high level of comprehensive confidence of the engineering characteristics of a pipeline segment. These practices are likely to be used more often in the near future as the individual technologies and integration is improved.

Further opportunities for records validation arise when a pipe segment is removed or replaced. Operators examine removed pipe to determine its mechanical properties, including seam properties, chemical compositions and microstructures. The results of this examination are compared with the operator's database, and if there are inconsistencies the operator performs additional work, including records searches and evaluations as well as physical confirmation through excavation, inspection and testing, to resolve them.

There are limited, if any, proven technologies for determining the mechanical properties of a transmission pipe during an *in situ* examination. Steel hardness, which can be measured in the field, correlates approximately with ultimate tensile strength. There is not a proven and generally available method for determining yield strength on an in-service pipeline, but there is a micro-ball technology that can be used to get an approximate value for yield strength that has been demonstrated in laboratory conditions on specially-prepared surfaces. Portable X-Ray fluorescence can be used to measure the approximate concentrations of certain chemical elements, such as manganese and columbium, but this is an indicator only. It may be used in a screening process to identify significant deviations from the chemistries reported on mill test reports, but cannot absolutely confirm those reports. There are no known methods for *in situ* determination of Charpy toughnesses, shear areas, or weld properties.

Question D.4

Should PHMSA make current requirements more prescriptive so operators will strengthen their collection and validation practices necessary to implement significantly improved data integration and risk assessment practices?

PHMSA advisory bulletin ADB 11-01 calls for operators to validate pipe records. With this guidance, combined with existing Subpart O requirements and ASME/ANSI B31.8 standards, there is no need for further prescriptive requirements. Current Subpart O and ASME/ANSI B31.8 requirements and guidance already accomplish this. This is particularly true because the existing inspection protocol requires auditors to review the adequacy of an operator's data verification and integration practices. Especially where strength testing already has proven the integrity of the pipeline materials and construction, and where time dependent threats already are being addressed adequately in an on-going manner, increased data verification requirements will yield little if any improvement in pipeline safety. INGAA believes that the current, performance-oriented work regarding improved management systems for integrating validated data and disseminating them subsequent decision making affords a better opportunity and route to improve pipeline safety and integrity than do additional prescriptive elements.

Records verification regulations that require additional excavations and field assessments could easily impose worksite hazards that would outweigh the pipeline safety benefits. Additional data verification requirements could have a negative environmental impact if more pipeline segments have to be "blown down" and removed for mechanical and chemical analysis.

Not all data gaps represent a material risk to pipeline safety, and data often can be verified, and gaps can be addressed, through other compensating measures. If regulatory changes are to be made, the most cost effective approach would be to adopt a reasonable process for making conservative assumptions where records gaps exist or where data cannot be verified.

Question D.5

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements?*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

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Topic E – Risk Models and Their Application

Risk management is a process of identifying risks and applying management systems to control them. Good, performance-oriented, risk management systems evolve as new information is gathered and understood. Prescriptive management systems are task oriented and therefore do not adjust easily to new information or knowledge. As detailed in Appendix 1, prescriptive systems are easier to audit, but not as effective as performance-based systems. Continuing the performance-based regulatory approach, exemplified by Part 192, Subpart O, is critically important to improving pipeline safety. Enhanced performance is dependent on improved technology and processes. Prescriptive requirements inhibit innovation, and could thwart safety improvements.

The pipeline integrity management programs in place today are similar to the Process Safety Management System that the Occupational Safety and Health Administration requires of many facilities and the Safety Management System used by the Federal Aviation Administration. (At the National Transportation Safety Board hearing on the San Bruno incident, board members called IMP "the pipeline industry's SMS.") These and other regulatory approaches to complex, high-risk industrial operations are highly regarded and have achieved demonstrable success.

Question E.1

Should PHMSA either strengthen requirements on the functions risk models must perform or mandate use of a particular risk model for pipeline risk analyses?

If so, how and which model?

For over ten years, the current regulations, with the incorporation of ASME/ANSI B31.8S, have served the industry and the regulators well in managing the system integrity of natural gas transmission systems. These regulations and standards incorporate set general requirements for risk modeling processes and elements, including:

- Establishing risk objectives and approach
- Obtaining data supporting a threat evaluation
- Integrating threat data
- Periodic reassessment
- Consequence analysis considerations
- Risk model performance characteristics and evaluation of the risk assessment
- Validation of the process
- Continuous improvement

Within the general requirements, operators and users have been allowed to tailor their models to the specifics of their systems.

The current approach is also consistent with the National Technology Transfer and Advancement Act of 1995 because the current program is based upon a body of recognized consensus standards. ASME/ANSI B31.8S, including the provisions governing risk modeling, is an American National Standards Institute (ANSI) approved standard. To obtain ANSI approval, the B31.8 standards setting committee must contain a cross-section of affected users and the standard must be updated periodically. The B31.8 committee meets three times per year to consider recommendations for correction or improvement, with updated editions published about every third year. Anyone can attend these working meetings in person – they are announced on the ASME webpage. Anyone can also submit an inquiry or make a recommendation for a change in the standard. PHMSA representatives participate in this process, as do several INGAA members and other technical experts.

The current approach, prescribing the elements of risk evaluation, assessment and response process but not specific details on process application, is also consistent with and similar to the Federal Aviation Administration's Safety Management System (SMS) and of the Occupational Safety and Health Administration's Process Safety Management System (PSM). These and more regulatory approaches to complex high-risk industrial operations are highly regarded with demonstrable success. With some enhancement to the current performance-based approach, PHMSA can accrue the additional benefits that the public and operators need.

Not all threats apply, or apply to the same degree, to each specific pipeline segment; nor can all threats and hazard scenarios be anticipated in a generic risk model. A prescribed set of data elements can result in misleading results if some of the data are not available or if required data elements become superseded by data with greater predictive value. Also, a prescribed model can quickly become out-of-date as new experience, technology and feedback become available. Prescriptive modeling regulations conflict with ASME/ANSI B31.8S, which specifies that risk models must allow for continuous learning and improvement and must reflect the current conditions affecting risk along the pipeline system. As opposed to adding prescriptive requirements or expanding those in place, the timely incorporation by reference of updates to ASME/ANSI B31.8S standards would allow operators to incorporate advances in modeling sooner.

Question E.2

It is PHMSA's understanding that existing risk models used by pipeline operators generally evaluate the relative risk of different segments of the operator's pipeline. PHMSA is seeking comment on whether or not that is an accurate understanding.

Are relative index models sufficiently robust to support the decisions now required by the regulation (e.g., evaluation of candidate preventive and mitigative measures, and evaluation of interacting threats)?

PHMSA's understanding is correct. Many gas transmission operators use relative risk as the centerpiece of their risk assessment to prioritize integrity assessments and work, to evaluate interacting threats, and to evaluate prevention and mitigation measures.

INGAA's members are improving the way risk assessments are approached and applied. INGAA established a work group of operating company and industry experts to develop and apply improved risk assessment methodologies. The work group is considering an array of risk assessment approaches, including not only enhancements to relative risk models, but also more robust approaches such as probabilistic risk assessment. While ASME/ANSI B31.8S, Section 5, provides an effective framework for risk assessment, there is a recognized need to clarify and enhance the language based on recent experience and recently published international standards.

INGAA members have also recognized that the way existing risk assessment models address interacting threats can be improved. The INGAA Foundation, Inc., has commissioned the Gas Technology Institute to perform a study examining this issue. The study, "Understanding Threat Interactions for Risk Analysis," is scheduled for completion in the first half of 2013.

As noted in response to question E.1, INGAA members regularly review ASME/ANSI B31.8S to see if the standard can be adjusted or improved as new information and technology become available. Operators also review their risk models continually to see if they can be refined to better represent the risks along their systems and the factors that create, increase or decrease those risks. Continual review and refinement helps demonstrate and quantify how specific protective or preventive measures can mitigate or compensate for a range of threats. Consistent with continual review and refinement, operators also look at the structures within various models to find improvements in the differential relationships and associations within the different risk assessment methodologies.

INGAA members have recognized that the stand alone modeling approaches defined in ASME/ANSI B31.8S, (relative, scenario, probabilistic and subject-matter expert-based), do not need to stand alone and in fact can be effective when used to complement each other in the decision-making preparation processes. For example, operators are using scenarios when performing threat reviews and when identifying potential hazards in performing relative risk assessment. Similarly, most risk assessments will benefit from the input of subject matter experts, regardless of the risk assessment methodology employed.

Question E.3

How, if at all, are existing models used to inform executive management of existing risks?

Risk management modeling is used to monitor and describe changes in risk, both overall and specific to individual pipeline segments if needed. The results of these models are shared with executive management to report progress and trends in risk reduction and to bring focus to risk-related decisions concerning resource allocation.

The essence of risk communication to executive management appears in ASME/ANSI B31.8S, Section 10.3 (Internal Communications):

Operator management and other appropriate operator personnel must understand and support the integrity management program. This should be accomplished through the development and implementation of an internal communications aspect of the plan. Performance measures reviewed on a periodic basis and resulting adjustments to the integrity management program should also be part of the internal communications plan.

Question E.4

Can existing risk models be used to understand major contributors to segment risk and support decisions regarding how to manage these contributors? If so, how?

Yes, existing risk models can and do provide an understanding of major contributors to segment risk and support decisions regarding how to manage these contributors. This is done by:

- Assessing pipeline segment threats and their relative magnitude.
- Incorporating assessment results that provide additional information on integrity performance and describe what is actually happening on the pipe.
- Supporting decisions on alternative threat prevention measures by integrating data and information about the pipe and evaluating the appropriate prevention, mitigation or repair measures. In this regard, pipeline operators have historically invested heavily in pipeline integrity through the implementation of pipeline maintenance activities. While these practices existed before the advent of formal, risk-based, pipeline IM programs, such programs have enhanced and optimized pipeline maintenance practices.
- Performing sensitivity analyses to determine which factors most and least affect the outcome of the risk analysis. These sensitivity analyses can be used to both improve the risk model and to help prioritize allocation of resources.

Question E.5

How can risk models currently used by pipeline operators be improved to assure usefulness for these purposes?

Continuous improvement of the risk management processes, including the models used, is a program requirement. Below are some of the ways in which this is addressed or may be further enhanced:

- Continue to incorporate findings from assessments into the data foundations of these models. INGAA members are reviewing the language of ASME/ANSI B31.8S for clarity and completeness and in particular the inter-relationships of the chapters on risk analysis, integrity assessment, responses, and the integrity plan. Suggestions will be forwarded to American Society of Mechanical Engineers.
- Continue to improve and refine the models and algorithms to the specific characteristics of the pipeline system and down to a localized scenario if required.

- Continue to integrate and incorporate available data which is relevant to the pipeline system
- Incorporate information gained through expanding integrity management beyond HCAs as detailed in the general response to topic A.
- Foster continuous improvement by engaging in ongoing formal dialogue, facilitated through INGAA groups, that is focused on sharing experience and improving processes.
- Consider and incorporate as appropriate the results of the GTI study noted in response to question E.2.
- Suggest consistent risk assessment model performance measures that will show that all threats are addressed, that will allow change comparisons across the pipeline system, and that will assist internal and external auditors in their evaluations.

Operators must also remain aware of and be responsive to unexpected or unexplained results that differ significantly from expected performance. In such cases, both the model and the data must be evaluated in an effort to reconcile the unexpected result and determine to what extent this reconciliation impacts risk evaluation elsewhere on the system.

Question E.6

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

• The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.
• The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
• The potential impacts on small businesses of modifying the existing regulatory requirements.
• The potential environmental impacts of modifying the existing regulatory requirements?

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

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Topic F – Applying Knowledge Gained through the IMP Program and Beyond

The Integrity Management Program[9] has improved pipeline safety by increasing knowledge and understanding. INGAA members independently apply knowledge gained during assessments and remediation of pipelines in HCAs to the remainder of their systems. This not only improves pipeline system integrity: it is also is good business. INGAA has committed to a more rigorous and structured approach to manage knowledge gained, through the Integrity Management Program and beyond, and to share those results with others.

Question F.1

What practices do operators use to comply with § 192.917(e)(5)?

When corrosion on a covered segment could adversely affect its integrity, as specified in Section 192.933, operators evaluate and remediate, as necessary, the subject pipeline segment. Utilizing the pipeline database as well as field knowledge, operators then review other pipeline segments (both inside and outside HCAs) that may have similar material coating and environmental characteristics, and then evaluate and remediate as necessary as required by Section 192.917(e)(5). Operators also use information obtained through assessments and evaluations to update, as warranted, their operating and maintenance procedures and risk assessment methodology as part of their continuous improvement processes. The practices used by operators include system and corrosion monitoring data such as pipe and coating data from the geographic information system or other pipeline database, annual corrosion test point survey data, close interval survey data, direct or alternating current voltage gradient data, in-line inspection (ILI) data, and excavation observations. This data is used to locate and evaluate anomalies that are judged to require a response and possible remediation. This evaluation is done irrespective of the HCA status at the location of the anomaly.

Question F.2

How many times has a review of other portions of a pipeline in accordance with § 192.917(e)(5) resulted in investigation and/or repair of pipeline segments other than the location on which corrosion requiring repair was initially identified?

INGAA is not tracking this data and is not aware of other surveys assessing this information.

[9] See generally 49 C.F.R. Part 192, Subpart O.

Question F.3

Do pipeline operators assure that their risk assessments are updated as additional knowledge is gained, including results of IM assessments? If so, how?

How is data integration used and how often is it updated?

Is data integration used on alignment maps and layered in such a way that technical reviews can identify integrity-related problems and threat interactions?

How often should aerial photography and patrol information be updated for IM assessments?

If the commenter proposes a time period for updating, what is the basis for this recommendation?

Pipeline operators assure that their risk assessments are updated as additional knowledge is gained. Experience and information gained from a variety of sources, including GIS data, corrosion data, assessment data/results, work management activities, SCADA, encroachments, analysis of leaks and failures, etc., are utilized to update risk assessments and models. Particular attention is given to updating risk assessments in cases where an occurrence on the system differs significantly from what the operator believed could be reasonably expected.

The data elements required by the threat identification and risk assessment process are aligned using a common spatial reference system that allows the data to be associated with a position on the pipeline. Data integration is periodically reviewed and updated. Update frequency varies from operator to operator. It may be on a set schedule, such as annually, or may be whenever new and significant data become available, such as following receipt of ILI data. New critical information is prioritized for any needed immediate actions.

Some operators use data integration on alignment maps or pipeline schematics, and technical reviews are performed to identify integrity-related problems and threat interactions. Tabular compilations also may be used for determining integrity issues and identifying threat interactions. These and other methods of data integration can be used effectively to identify pipeline integrity problems and threat interactions.

New information related to population changes near pipelines is gained from a number of sources including scheduled patrols, aerial photography, observations during routine operations, and planned reconnaissance surveys. Information gained from these sources should be incorporated into integrity programs on an annual basis. Other information regarding construction, crossings, earth movement, leakage, flooding or washouts, etc., may be obtained during regularly scheduled or condition-directed patrols. Such information is integrated and acted upon based on its nature and severity.

The annual update aligns with the annual pipeline risk assessment frequency that PHMSA outlined in FAQ-234: "Operators should re-evaluate risk annually. This should include consideration of any new information identified during the annual review of high consequence areas, results of assessments conducted during the year, and any changes to the pipeline system or its operations. Operators should use the results of the updated risk analysis to modify their baseline assessment plans and other IM actions, as appropriate."

Question F.4

Should the regulations specify a maximum period in which pipeline risk assessments must be reviewed and validated as current and accurate? If so, why?

While a maximum period for risk review and update is not contained in Part 192, FAQ-234 suggests this should be performed annually. This is practical and sufficient to address changes to risk that may impact operators' programs.

Question F.5

Are there any additional requirements PHMSA should consider to assure that knowledge gained through IM programs is appropriately applied to improve safety of pipeline systems?

Existing regulations require operators to improve their integrity management programs continually to reflect new knowledge and experience. Additional requirements are unnecessary. Prescriptive requirements can quickly become out-of-date as technology and knowledge improve and may cause critical resources to be diverted into activities producing little or no safety benefit.

Question F.6

What do operators require for data integration to improve the safety of pipeline systems in HCAs?

What is needed for data integration into pipeline knowledge databases?

Do operators include a robust database that includes: Pipe diameter, wall thickness, grade, and seam type; pipe coating; girth weld coating; maximum operating pressure(MOP); HCAs; hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; ILI surveys including high resolution—magnetic flux leakage (HR–MFL), HRgeometry/caliper tools; close interval surveys; depth of cover surveys; rectifier readings; test point survey readings; alternating current/direct current (AC/DC) interference surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; SCC excavations and findings; and pipe exposures from encroachments?

Experience and information gained from a variety of sources, including GIS data, corrosion data, ILI data/results, work management activities, SCADA, encroachments, leaks etc., are utilized in data integration. Operators have made major investments in database applications to meet changing organizational and/or regulatory requirements and to manage increasing volumes of data effectively.

Tools generally are available for integrating data into pipeline knowledge databases. For integration purposes, the database must contain adequate metadata elements such that dates, if important, and location and length attributes are maintained. Currently available systems are adequate for the input, storage, alignment, analysis and display of these data.

Operators use robust databases that include the elements mentioned, where applicable. However, the term "robust database" should be used carefully, since this could be construed that all applicable data should be maintained in a common database or other venue which does not meet the particular needs of the operator. The very nature of performance-based programs permits many different approaches to solving similar issues.

Tools and processes for data validation, storage, integration dissemination used are governed by management systems that serve to both assure quality and integrity and to inform organization management. INGAA has an active IMCI team addressing improvement in these processes and management systems.

Question F.7

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements?*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

Topic G – Selection and Use of Assessment Methods

An operator develops an assessment process model by balancing one or more reliable inspection methods, each based upon anticipated threats, with available technology and the physical limitations of the pipeline. Information generated from the model is integrated with information previously generated from current analysis techniques. A great advantage of the integrity management structure, as opposed to a prescriptive regulatory regime, is the creation of an environment conducive to technological development, innovation and improved knowledge. INGAA and its members have continued to work with technology providers and researchers to improve the integrity management assessment capabilities of its members. Further, INGAA members are sharing their experience with applying these new and improved assessment methods to specific threats. These types of gains can continue through performance-based regulation, while enabling some prescriptive oversight of the processes.

Question G.1

Have any anomalies been identified that require repair through various assessment methods (e.g., number of immediate and total repairs per mile resulting from ILI assessments, pressure tests, or direct assessments)?

INGAA members have used all three assessment methods, and all three have identified anomalies that required repair. The vast majority of these identifications have been made by in-line inspection (ILI), which is consistent with the relative use of ILI compared to the other two methods.

Question G.2

Should the regulations require assessment using ILI whenever possible, since that method appears to provide the most information about pipeline conditions?

Should restrictions on the use of assessment technologies other than ILI be strengthened?

If so, in what respect?

Should PHMSA prescribe or develop voluntary ILI tool types for conducting integrity assessments for specific threats such as corrosion metal loss, dents and other mechanical damage, Longitudinal seam quality, SCC, or other attributes?

While ILI is a powerful tool in collecting data on many types of defects, and ILI is widely used in its various forms, but it also has its limitations. Strength testing and direct assessment (DA) provide information that ILI does not. Because of the wide range of circumstances and risks that may be applicable to any specific pipeline segment, the operator must be able to choose the method or methods best suited to evaluate the identified or presumed threats to the pipeline. Presupposing threats and prescribing the inspection technology or methodology would be less effective in reducing risk overall because it removes this flexibility.

For example, crack detection ILI is one of the three tools that can be used for stress corrosion cracking (SCC) integrity management, alongside strength testing and SCC DA. Operators may use one, two or all three of these tools for threat management depending on their operational experience of SCC and the attributes of their pipeline system.

ILI for SCC in gas pipelines is considerably more challenging than it is in liquids pipelines, although technology and techniques for assessment continue to advance in gas pipelines. In recent years Joint Industry Project (JIP) members have conducted over 40 individual pipeline inspections using crack-detection ILI. These inspections have shown that the detection of crack-like anomalies using ILI technology still is evolving and improving, with particular emphasis being paid to detection reliability and the sizing accuracy (depth and axial length). The challenges being addressed in crack detection are similar for SCC and for certain types of seam weld anomalies, such as hook cracks. Additional information regarding SCC management is available in INGAA's responses to the various questions in topic I.

Crack detection ILI can provide some information that is not available from strength testing or SCC DA, and, in some instances, it has been used successfully as the primary tool for SCC threat management, but this is not a universal situation. Therefore, it would be premature to require the use of ILI, to restrict the use of strength testing and SCC DA, or to promulgate regulations that establish a preference for ILI ahead of strength testing or SCC DA when addressing SCC in gas pipelines.

Question G.3

Direct assessment is not a valid method to use where there are pipe properties or other essential data gaps.

How do operators decide whether their knowledge of pipeline characteristics and their confidence in that knowledge is adequate to allow the use of direct assessment?

The existing requirements for the pre-assessment stage of DA specify the required data for this method to be feasible. Operators incorporated these requirements in their procedures, and these procedures are part of integrity audits. PHMSA's regulations incorporate NACE Standard Practices by reference, and PHMSA's audit protocols ensure that operators are addressing the issue of missing or suspect data for DA.

The primary decision criterion for operators choosing DA instead of one of the other methods is the likelihood of other threats to which DA may not be sensitive. In such a case, another method, either alone or in conjunction with DA, should be used.

As to how operators decide when they are confident that their knowledge of their systems is adequate to allow DA, the same question could be posed about any of the four assessment techniques. DA does not provide the same type of information as either ILI or strength testing. Data about the pipe properties, and, in fact, much data about the pipeline is irrelevant to a DA inspection. For example, external corrosion direct assessment (ECDA) does not attempt to provide data about the pipe itself, or its condition. Rather, it provides information about the condition of the coating and the cathodic protection system, giving an indication of where external corrosion may have occurred or may occur in the future.

Question G.4

How many miles of gas transmission pipeline have been modified to accommodate ILI inspection tools?

Should PHMSA consider additional requirements to expand such modifications? If so, how should these requirements be structured?

The IMCI action plan framework, outlined in the general response to topic A, provides for additional assessments and sets out a method for operators to determine which pipelines to modify for ILI inspection and when to do so. PHMSA should adopt the IMCI framework as a basis for performance-based regulations instead of adopting prescriptive requirements.

Since 2002, more than 30,000 miles of natural gas transmission pipelines have been modified to accommodate ILI tools. By 2010, for the INGAA members' miles surveyed, the total mileage that can accommodate ILI tools had increased from 62,000 to 109,000. This increase includes both new pipelines and those modified since 2002, which constitutes almost two-thirds of the total surveyed pipeline mileage.

Through 2012, INGAA members expect to assess pipelines, primarily through ILI, covering roughly 90 percent of the PIR population. This is equivalent to roughly 60% of total pipeline miles. By 2030, INGAA's goal is to assess pipelines covering 100% of the PIR population. This is equivalent to roughly 80 percent of the total pipeline miles. The remaining 20 percent of pipeline miles with no population in the PIR pose a low risk to the public. In addition, this mileage poses a significant technical challenge due to a number of factors (e.g., small-diameter lines; multi-diameter lines; and lines with low flow rates, complex geometry, or that serve as a single source feed to customers). Under the IMCI action plan's proposed framework, integrity management principles would be applied to these lines after 2030.

Before changing its regulations, PHMSA should provide data on what incidents have occurred and, by extension, what incidents would likely be or have been prevented by instituting new rules. Requiring ILI modifications in areas of low risk or for threats that ILI cannot accurately assess will not necessarily result in greater safety and may divert resources from areas where a greater risk reduction is possible.

Question G.5

What standards are used to conduct ILI assessments? Should these standards be incorporated by reference into the regulations? Should they be voluntary?

Operators use established national consensus standards, such as API-1163, API-579 and ASNT ILI-PQ to conduct ILI assessments. Such standards are continuously reviewed and periodically updated based on advances in science and technology. These updates are subject to a rigorous standards development process which is overseen by subject matter experts. This is the most appropriate way to develop and disseminate such guidance. For further information on guidance on use of various ILI methods, see the response to question C.6.

PHMSA should adopt performance-based language that references the standards noted above while allowing other equivalent methods. A performance-based approach would set a requirement and provide guidance but would not limit the use of or stifle advances in technology.

Question G.6

What standards are used to conduct ICDA and SCCDA assessments?

Should these standards be incorporated into the regulations?

If the commenter believes they should be incorporated into the regulations, why?

What, if any, remediation, hydrostatic test or replacement standards should be incorporated into the regulations to address internal corrosion and SCC?

The primary standard used to conduct Internal Corrosion Direct Assessment (ICDA) is NACE SP0206-2006. NACE SP0204-2008 provides a considerable body of knowledge and guidance concerning the conduct of SCC DA. Another major source is the Canadian Energy Pipeline Association Recommended Practice on SCC. The practical application of this guidance is illustrated in ASME STP-PT-011. SCC DA is discussed in more detail in Question G.7. ASME/ANSI B31.8S provides excellent guidance for other aspects of SCC integrity management, and it is incorporated into the regulations by reference. Recently, it was revised to include near-neutral pH SCC as well as high-pH SCC. It has been thoroughly vetted through ASME. PHMSA should adopt the 2010 Edition of ASME/ANSI B31.8S to incorporate this SCC guidance into the regulations. The existing NACE technical committee report *External Stress Corrosion Cracking of Underground Pipelines* (NACE International Publication 35103), addresses the roles of materials, environment (soils), coatings, stress, and cathodic protection and temperature in the initiation and growth of SCC. It also addresses SCC prevention, detection, and mitigation, but this report was published in 2003, and more current information is now available. This report could be updated and converted into a standard, and this could be performed expeditiously if the need arose.

The authority and direction for PHMSA to adopt such standards is provided by the National Technology Transfer and Advancement Act of 1995, which directs regulatory agencies to adopt consensus standards, where available and applicable, rather than recreate them. Such standards typically meet the American National Standards Institute (ANSI) requirements for representation and expertise on the body that creates them. The rationale for such adoption is that such standards represent the collected knowledge and experience of experts in the relevant subject. The governing ANSI requirements for these standards call for an adequate representation of a cross-section of interested parties, development by consensus, and resolution of dissenting opinions. Multiple levels of review, balloting and approval are needed to approve and publish a standard. INGAA supports the recent legislative mandate that such incorporated standards be available for public viewing.

The 2004 Edition of ASME/ANSI B31.8S, parts of which are incorporated into Part 192, provides guidance for a practicable IM program for internal corrosion, including repair methods. Hydrostatic pressure testing or pipe replacement for internal corrosion should be the operator's decision based on the severity of internal corrosion identified. Prescriptive requirements for hydrostatic pressure testing for pipelines identified with the internal corrosion should be avoided as introduction of water into a pipeline susceptible to internal corrosion may increase the threat.

The 2010 edition of ASME/ANSI B31.8S includes specific guidance for hydrostatic pressure testing in the event SCC is identified on a pipeline. As noted above, PHMSA should adopt the 2010 Edition of ASME/ANSI B31.8S to incorporate this SCC guidance into the regulations. ASME/ANSI B31.8S includes guidance for hydrostatic pressure retest intervals dependent on the severity of SCC identified and the results of previous hydrostatic pressure tests. An operator can implement this guidance, or an equivalent alternative, to develop a long-term integrity plan for SCC. Replacement of the pipe or reduction in operating pressure should be a decision made by the operator if the operator determines a long-term integrity plan is impracticable for the existing segment.

Question G.7

Does NACE SP0204–2008 (formerly RP0204), ''Stress Corrosion Cracking Direct Assessment Methodology'' address the full lifecycle concerns associated with SCC?

The NACE SP0204-2008 Standard is a standard for DA of SCC. It is one of three acceptable methods of assessing a pipeline segment for SCC, the other two being hydrostatic pressure testing and ILI. NACE SP0204-2008 does not address certain technical aspects relative to the full life cycle of concerns of SCC, such as the formation or nucleation of cracks or guidance on the calculations to assess the severity of cracks that may be found and measured. It does, however, address the factors found to be common in SCC, including surface and coating condition, environment, CP effects and the need to make an assessment of cracking severity and impact once it is found.

The NACE SP0204-2008 methodology for applying DA to SCC is appropriate for assessing for the threat of SCC. Additional guidance is available in ASME/ANSI B31.8S, as described in the response to G.6 above. These two standards are based on a significant body of both historical and recent work performed to understand and manage SCC. Taken together, they address the full lifecycle concerns associated with SCC, including detection, characterization, remediation, reassessment, and prevention and mitigation.

Hydrostatic pressure testing and ILI are discussed in NACE SP0204-2008 as integrity management options where significant SCC is found by means of SCC DA. As stated above, ASME/ANSI B31.8S addresses hydrostatic pressure testing and ILI as primary assessment techniques as well. CEPA's recommended practice on SCC also provides more detailed discussions on hydrostatic pressure testing and ILI.

Question G.8

Are there statistics available on the extent to which the application of NACE SP0204–2008, or other standards, have affected the number of SCC indications operators have detected and remediated on their pipelines?

Industry-wide statistics regarding the use and outcomes from using NACE SP0204-2008 have not been collected. However, the SCC JIP Phases I and II include a review of operating experience for over 160,000 miles of North American gas transmission pipelines, from the first recorded SCC failures in the mid-1960s to December 2010.[10]

During that time, almost 90 in-service ruptures and leaks due to high pH and near-neutral pH SCC have been experienced by the JIP members. Some statistics regarding Canadian experience of SCC were published by the National Energy Board in papers at the International Pipeline Conferences in Calgary, IPC 2008 and IPC 2010. The general trends are the result of increasingly effective application of SCC threat management – from the early restrictions on compressor discharge temperatures and application of effective coating and cathodic protection systems, to the regular use of hydrostatic pressure re-testing and more recently the use of SCC DA and crack detection ILI.

The understanding documented in NACE SP0204-2008, CEPA and other guidance documents underpins and reinforces the steps that have been taken towards successful SCC threat management. The results and trends also point out the need for operators to be able to use a multifaceted approach tailored to their specific conditions and circumstances.

Question G.9

Should a one-time pressure test be required to address manufacturing and construction defects?

A one-time pressure test, a strength test that can effectively address manufacturing and construction defects when properly conducted, has been a requirement for new pipelines for at least 40 years, since the promulgation of the first federal pipeline safety regulations. Pipelines older than this may also have had an effective strength test, even though that test may not have met all of the Subpart J requirements.

With respect to older pipelines the decision to test or not should be made on a case-by-case basis using the INGAA Fitness for Service protocol, discussed in more detail in topic N and filed

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[10] SCC JIP Phases I and II were multi-party joint industry projects initiated to develop technical rationales on issues related to integrity management of SCC in HCAs. Operators and leading industry experts, consultants and researchers participated in this effort. Phase I established criteria for severity ranking and retest strategies. Phase II has continued to build on the Phase I base, with additional emphasis on determining the equivalence of electro-magnetic acoustic transducer (EMAT) ILI with strength testing.

earlier in policy-level comments. INGAA maintains that this protocol is technically sound, exceeds the requirements of the recently-enacted legislation and is designed to be consistent with the intent of the NTSB recommendation on this subject. INGAA recommends the use of this protocol in the development of any regulations pursuant to that legislation

Question G.10

Have operators conducted quality audits of direct assessments to determine the effectiveness of direct assessment in identifying pipeline defects?

Operators are required to continually review the effectiveness of their programs and methods and to make adjustments or choose other methods when it is found that a particular method is not performing as expected and required. For DA in particular, continual review is an ongoing and integral part of the process, with a number of verification excavations required even in the absence of indications requiring them. Further, there is a built-in quality assurance verification in the DA process, requiring additional work if unexpected results are obtained. Specifically, if corrosion is found worse than predicted, the operator must evaluate whether using DA is even feasible. Re-prioritization is required when corrosion is found that is worse than predicted by the indirect measurements. Also, the objectives of the post inspection steps are to define the re-inspection interval and assess the overall effectiveness of the DA process. Some operators may undertake internal or third-party audits of their DA assessment.

The question broadly refers to “identifying pipeline defects.” As noted above, the DA process includes evaluation and assessment of the process itself – it is self-correcting. It is, however, inappropriate and unrealistic to criticize DA for not “identifying pipeline defects.” DA has a limited scope and applicability. For example, ECDA is intended to find areas of missing or damaged coating, which may or may not coincide with corrosion or excavation damage to the pipeline. DA does not assess the pipe itself or identify the damage. It is rather an indicator of where conditions for such damage might exist and their extent. In that regard, it may be viewed as a leading indicator of such potential damage, as opposed to the lagging indication provided by strength testing and ILI. DA methods have performed well within this scope. They are not effective when used outside their scope and applicability.

Question G.11

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

Topic H – Valve Spacing and Remotely or Automatically Controlled Valves

Several questions in Topic H contemplate prescriptive regulatory requirements governing the types of valves to be installed, where they are to be installed, when they are to be installed and how far apart they are to be installed from each other. Instead of issuing additional prescriptive regulations or expanding the prescriptive regulations already in place, PHMSA should increase its use of performance-based regulation. In its policy-level comments on the ANPRM, INGAA detailed the benefits of performance-based regulation: quick incorporation of technological change, flexibility consistent with best business practices, alignment with multidimensional problem solving and proven success in the field. INGAA's policy level remarks are included in these comments as Appendix 1, and INGAA urges PHMSA to embrace performance-based regulation throughout Part 192 and particularly with regard to valve spacing and technology.

Valve spacing, selection and operation are all important but they only address one aspect of mitigating the consequences of an incident. To achieve the comprehensive response this issue deserves, incident mitigation is best handled through the creation and implementation of Incident Mitigation Management (IMM) plans that are built on the risk management principles and performance objectives that underlie operators' baseline assessment plans and other elements of their IM programs. IMM plans, as detailed below, provide a comprehensive approach to incident mitigation, and INGAA urges PHMSA to consider IMM as a model for future regulations. Just as PHMSA required a baseline assessment plan in the original IM rule, INGAA believes PHMSA should now direct operators to conduct an IMM review.

The IMM plans would use information from previous risk assessments to help drive decisions for targeting mitigation improvements. These decisions would include various components of incident management, including methods for detecting ruptures; decision criteria for activating mainline isolation valves; standards governing the placement, automation and remote operation of valves; procedures for quickly evacuating the gas from affected segments to make them safe for responders; and procedures that strive to expand operators' coordination efforts with emergency responders. IMM is consistent with INGAA's commitment to shorten pipeline isolation and response time to one hour in populated areas, and, being performance-based, IMM will produce a far better public safety outcome than prescriptive valve placement requirements.

Costs and benefits would be factored into each operator's IMM plan.[11] There are an estimated 25,000 mainline transmission block valves that are manually operated. If these valves require automation the cost would be $2.5 billion. If 3,000 new, automated valves were installed based on new class location changes the cost would be $1.7 billion. Automating existing valves and installing new valves could cost a total of $4.2 billion. The total property damage for significant gas transmission incidents in the past 20 years is $1.4 billion (reference – PHMSA Stakeholder Communication Website). Since most damage occurs in the first minutes of an incident and valve operation affects only the duration of the incident, the potential savings is a fraction of the $1.4 billion over 20 years.

The cost-benefit from broadly mandating valve automation and new valve installation is poor. There is a far greater return by investing in IM programs and pipeline failure prevention. Where automating an existing valve or installation a remote or automatic valve would be beneficial, the operator's IMM plan would show it. Expenditures would thus occur in highly populated areas, where they are needed, rather than broadly where they are not beneficial.

Operators would integrate IMM plans with existing IM and risk management plans, with all of them designed both to identify and rank risk and to design appropriate prevention and mitigation efforts. IMM plans would also incorporate the portions of operators' public awareness plans addressing outreach and communication with various emergency responders. IMM plans would set out approaches that, in the unlikely event of a failure, would maximize the mitigation of consequences. Each plan would contain an implementation priority, so its substantive provisions would be implemented first where consequences of a failure are greatest. While the initial effort would focus on pipeline in HCAs, operators would strive to consult with emergency responders to see if any priorities should be adjusted.

IMM plans would include:

- Criteria governing the operator's decisions on types and locations of automatic and/or remote valves, including crossover operation
- The location of any connecting distribution lines and the potential for back flow
- Standards for operating looped lines or other take offs as common or separate and the effect on identifying a rupture

[11] Question H.8 asks for a consideration of costs and benefits, albeit in the context of proposed regulations. The cost-benefit considerations that go into creating an IMM plan are analogous. Question H.8 also asks for an assessment of the environmental and small business impact of any regulations the commenter proposes. In the context of IMM plans, these impacts are small. The environmental effect of adopting IMM guidance and regulations would be small because the environmental effects of incidents are small. In the case of a rupture with fire, the closure of valves affects the amount of carbon dioxide released to the atmosphere. In the case of a rupture without fire, the closure of valves affects the amount of natural gas released to the atmosphere. Since ruptures are rare, both of these have a comparatively small impact on the environment. Small businesses would not be uniquely affected by performance-based IMM guidelines and regulations. In the long term all businesses, large and small, all communities and customers of the gas industry, and, most importantly, those who live near pipelines benefit by the well justified expenditures that will come from a performance based rule.

- Standards for preparing gas controllers to act on valve closure, including decision support
- Plans for responding to specific locations, including after-the-fact evaluation of response times
- Priorities for determining the need and timing for automation
- The design philosophy for how a type of operator is chosen (manual, automatic control or remote control)
- Procedures for evacuating gas and rendering locations safe for responders, including the use of blow-off valves
- An analysis of component and system reliability and an overall hazard assessment that considers potential nuisance failures of automated valves, including consideration of the relative consequences of a delayed closure vs. an unintended, inappropriate closure
- A planned, coordinated communication process with emergency responders
- A training process for improving the situational awareness of gas controllers
- A process for consulting with local 911 districts on notification procedures
- An approach to increasing the awareness of first responders to pipeline location, product, diameter; the location of valves, boxes and vaults; the approximate time to isolate; and any other factors determined to be of interest at the local level
- A plan for training, tabletop and full-scale emergency exercises with responders, as appropriate and as responders are willing and able, planned on a risk-tiered basis

Question H.1

Are the spacing requirements for sectionalizing block valves in § 192.179 adequate? If not, why not and what should be the maximum or minimum separation distance? When class locations change as a result of population increases, should additional block valves be required to meet the new class location requirements? Should a more stringent minimum spacing of either remotely or automatically controlled valves be required between compressor stations? Under what conditions should block valves be remotely or automatically controlled?

Should there be a limit on the maximum time required for an operator's maintenance crews to reach a block valve site if it is not a remotely or automatically controlled valve?

What projected costs and benefits would result from a requirement for increased placement of block valves?

The various issues covered in Question H.1, including changes in population, the installation of additional valves and upgrading existing valves to include automatic or remote control, would all be addressed in the IMM plans INGAA described in its general response to this topic. For the reasons INGAA discussed in it general remarks on this topic and in Appendix 1,[12] PHMSA should

[12] Another advantage of performance-based regulation is its emphasis on looking forward. In contrast, INGAA members report that Section 192.179 is being applied retroactively to pipe replacements, particularly those associated with class location changes. Retroactive application is inappropriate, as PHMSA acknowledges when it asks, in Question H.3, whether Section 192.179 should be amended to explicitly apply to class location changes occurring after the pipeline is designed and installed.

adopt performance-based IMM guidelines and issue regulations requiring operators to develop IMM plans, including valve operations, to meet the guidelines.

An operator's valve operations would be determined by data accumulated during its IMM risk assessment. Such data include population density, proximity of critical infrastructure, seismic areas or areas of soil instability, the presence of any facilities that would pose unique evacuation challenges, and the presence of any facilities or structures that would compound the consequences of a pipeline failure, such as an oil products tank farm. At the same time, the risk assessment would recognize that valve spacing has only a limited impact on reducing the overall duration of an incident. The risk assessment would also recognize that valve closure is only one component of IMM. In fact, valve spacing is only one factor affecting incident mitigation and emergency response, as shown in the figure on the next page. As part of their IMM plan, operators would review the entire incident management process to best improve public safety.

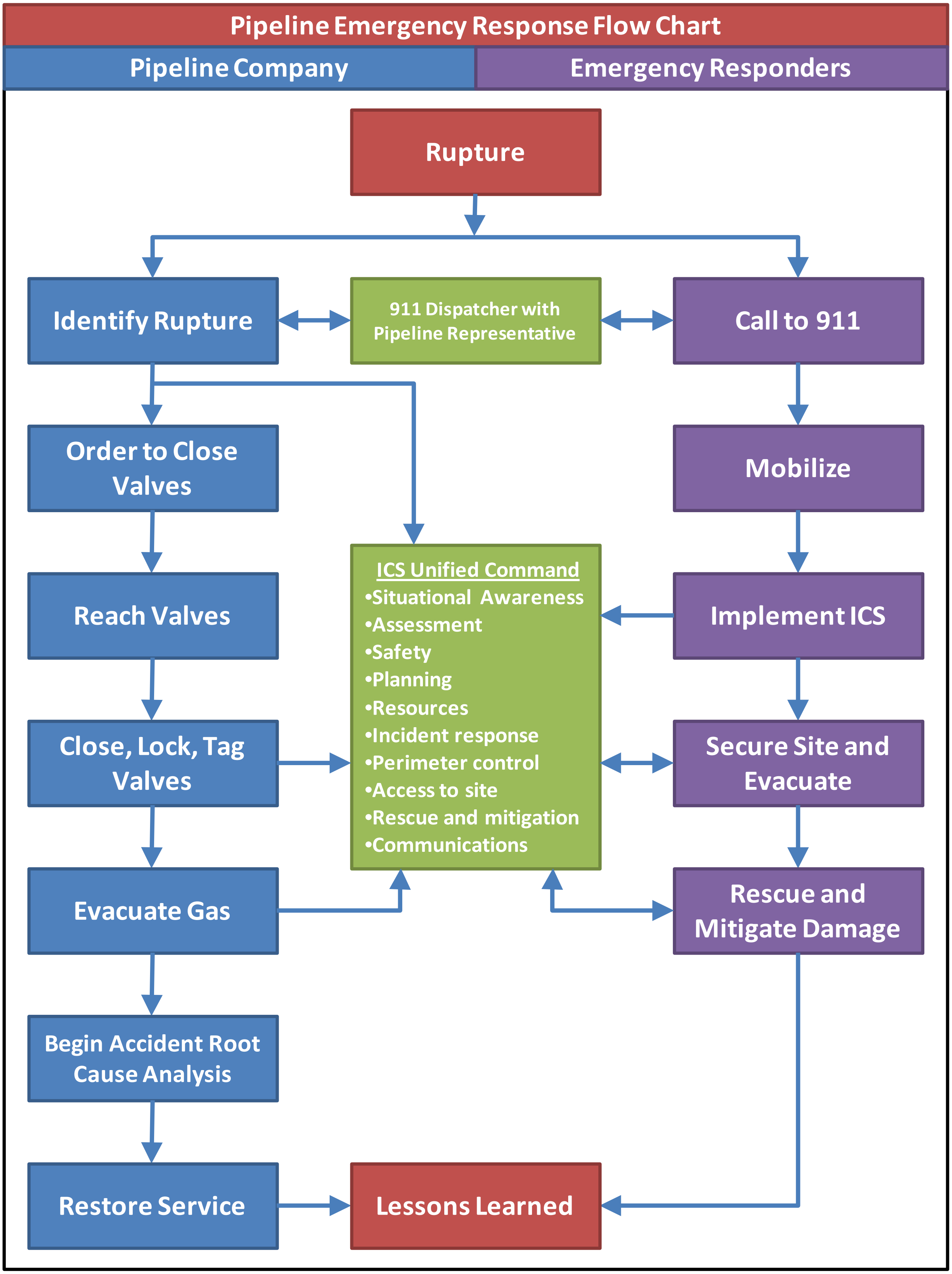
With regard to the maximum time for an operator's maintenance crew to reach a block valve, Section 192.620 requires alternative MAOP pipelines to be able to close a valve within one hour after the need to do so has been determined. One hour is a reasonable, practicable standard that operators should be required to meet for valves that would isolate pipelines in HCA's.

As to the projected costs and benefits of requiring more block valves, automating an existing valve costs approximately $80,000 to $120,000. Installing a new, automated valve costs between $300,000 and $700,000. For valves that would isolate pipelines in high population areas, automation may provide some benefit by reducing the potential for secondary fires and related property damage; however, several studies (listed immediately below) of the impacts of valve placement and time to closure have concluded that neither the placement, spacing or time to closure of valves is particularly effective in reducing risk to people near the pipeline. The most effective way to protect the public is by prevention: in other words, by avoiding a failure in the first place.

Relevant Valve Studies and Reports

- *Remote and Automatic Main Line Valve Technology Assessment*, C. R. Sparks et al., GRI/95-0101, July 1995
- *Design Rationale for Valve Spacing, Structure Count, and Corridor Width*, R. J. Eiber and W. B. McGehee, PRCI Catalog No. L41034e, May 1997
- *Cost-Benefit Study of Remote Controlled Main Line Valves*, C. R. Sparks et al., GRI-98/0076, May 1998
- *Development of the B31.8 Code and Federal Pipeline Safety Regulations: Implications for Today's Natural Gas Pipeline System*, T. M. Shires et al., GRI-98/0367.1, December 1998
- *Remotely Controlled Valves on Interstate Natural Gas Pipelines*, U.S. Department of Transportation, Research and Special Programs Administration, September 1999
- *Valve Spacing Basis for Gas Transmission Pipelines*, R. J. Eiber, et al., PRCI Catalog No. L51817e, January 2000

- *White Paper on Equivalent Safety for Alternative Valve Spacing*, Process Performance Improvement Consultants, LLC for INGAA Pipeline Safety Committee, July 2005
- *Scoping Study on the Safety Impact of Valve Spacing in Natural Gas Pipelines*, C. D. Sulfredge, Oak Ridge National Laboratory, ORNL/TM-2006/579, May 2007
- *Automatic Shut-off Valves (ASV) And Remote Control Valves (RCV) on Natural Gas Transmission Pipelines*, AGA Distribution and Transmission Engineering Committee, AGA White Paper , March 2011
- *Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing*, R. J. Eiber and Kiefner and Associates, ASME Standards Technology, LLC, ASME STP-PT-046, September 2011


Pipeline Emergency Response Flow Chart
Pipeline Company
Emergency Responders
Rupture
Identify Rupture
911 Dispatcher with Pipeline Representative
Call to 911
Order to Close Valves
Mobilize
ICS Unified Command
•Situational Awareness
•Assessment
•Safety
•Planning
•Resources
•Incident response
•Perimeter control
•Access to site
•Rescue and mitigation
•Communications
Reach Valves
Implement ICS
Close, Lock, Tag Valves
Secure Site and Evacuate
Evacuate Gas
Rescue and Mitigate Damage
Begin Accident Root Cause Analysis
Restore Service
Lessons Learned

Question H.2

Should factors other than class location be considered in specifying required valve spacing?

Section 192.179 already provides appropriate minimum standards for valve placement during the design of a pipeline project. During the design phase, operators may conclude as part of their IMM planning that additional valves are warranted for operational needs or for additional property damage mitigation. In reaching its conclusion, the operator will consider factors such as population density, proximity of critical infrastructure, seismic areas or areas of soil instability, the presence of any facilities that would pose unique evacuation challenges, and the presence of any facilities or structures that would compound the consequences of a pipeline failure, such as an oil products tank farm. For land use planning when considering new facilities or structures that may be in proximity to pipelines, the Pipelines and Informed Planning Alliance provides guidance and approaches for communities and pipeline operators to reduce interferences and to coordinate efforts to maintain public safety while meeting public needs.

Question H.3

Should the regulations be revised to require explicitly that new valves must be installed in the event of a class location change to meet the spacing requirements of § 192.179?

What would be the costs and benefits associated with such a change?

As noted above, Section 192.179 should not be made to apply retroactively to class location changes. An operator's IMM planning considers additional risk factors and mitigation actions that may be needed. Valves are considered along with other preventive and mitigative measures to determine effective and practicable responses to class changes. The studies cited in response to question H.1 have indicated that, due to the compressibility of natural gas, valve spacing has limited impact in reducing the overall duration.

Under a performance based rule, each operator would evaluate the costs and benefits of adding valves when a class location changes. Due to the high cost ($300,000 to $700,000 per new valve) compared to other less costly measures to speed incident response (improved detection, decision making, automating existing valves and use of blow down valves), the other measures are likely to provide the desired mitigation benefits at a lower cost. Of course, the same analysis will, in some instances, prompt the operator to install a new valve.

Question H.4

Should the regulations require addition of valves to existing pipelines under conditions other than a change in class location?

Under a performance-based approach to IMM planning, operators would determine valve placement based on factors such as population density, proximity of critical infrastructure, seismic areas or areas of soil instability, the presence of any facilities that would pose unique evacuation challenges, and the presence of any facilities or structures that would compound the consequences of a pipeline failure, such as an oil products tank farm. Adding valves is not the only path to incident mitigation, and often there are alternatives that are superior. Regulations that prescribe additional valves and preclude other, better alternatives are needlessly counterproductive. As noted in the response to question H.3, the studies cited in response to question H.1 have indicated that, due to the compressibility of natural gas, valve spacing has limited impact in reducing the overall duration.

Question H.5

What percentage of current sectionalizing block valves are remotely operable? What percentage operate automatically in the event of a significant pressure reduction?

INGAA estimates that 40 to 50 percent of existing mainline block valves in HCAs are remotely operable or operate automatically in the event of a significant pressure reduction. The percentage decreases to less than 20 percent in sparsely populated areas. Within the 40 to 50 percent, the more common design is remote operation, which is favored because they are less subject to nuisance closures. There are also some cases where local automation is preferred. Under a performance-based approach, the criteria for deciding between remote control valves and automatic control vales should be part of the operator's IMM plan.

Question H.6

Should PHMSA consider a requirement for all sectionalizing block valves to be capable of being controlled remotely?

Operators should have the discretion to consider all the alternatives available to them in achieving the goal of prompt evacuation of gas depending on the IMM plan. No one solution should be chosen in advance of comprehensive risk assessment and risk control decisions being completed by the operator.

Question H.7

Should PHMSA strengthen existing requirements by adding prescriptive decision criteria for operator evaluation of additional valves, remote closure, and/or valve automation? Should PHMSA set specific guidelines for valve locations in or around HCAs? If so, what should they be?

PHMSA should work with stakeholders to develop and agree upon IMM guidance, identifying the factors operators must consider in completing an IMM plan, IMM regulations, in identifying the criteria for evaluating these plans once they are completed. Prescribing new or additional decision criteria is inappropriate for the reasons discussed in the general response to this topic and in Appendix 1.

Question H.8

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

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Topic I – Corrosion Control and SCC

Corrosion is one of the most significant time-based deterioration mechanisms on steel transmission pipelines; corrosion control is an intricate process to manage it. Our response covers two items: corrosion control under Part 192, Subpart I; and stress corrosion cracking (SCC).

General Remarks: Corrosion Control

INGAA members have had good success managing corrosion anomalies within HCAs through ILI inspection and direct assessment. INGAA members commit to mitigating corrosion anomalies, both inside and beyond HCAs, consistent with ASME/ANSI B31.8S. This commitment raises the level of protection, both in quality and in timeliness of repair, in areas outside HCAs.

Enhanced external corrosion management methods, such as close interval surveys and post-construction coating surveys, have proven effective in helping identify and mitigate certain corrosion damage conditions. That said, these methods can be redundant or inferior when combined with other assessment techniques. Enhanced external corrosion management methods, such as close interval surveys and post-construction coating surveys, should not be required singularly and arbitrarily by new prescriptive regulation. Rather, these methods should continue to be used by operators on a threat-specific basis, as is currently practiced under performance-based regulations and consensus-based IM programs.

Common principles for applying and using close interval surveys are addressed in consensus standard NACE SP0207: Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines. Operators should continue to use this standard. As part of a continuing commitment to improve corrosion control, the INGAA Foundation recently completed guidance on field applied coatings to be used in orienting and training coating inspectors and applicators. In addition, a compilation of best practices of field applied coatings was also developed by the INGAA Foundation. The titles are:

- Pipeline Construction, Fabrication, and Testing – Training Guidance for Construction Workers and Inspectors for Welding and Coating
- Best Practices of Field Applied Coatings

General Remarks: Stress Corrosion Cracking

SCC occurs in isolated areas under specific operating conditions. INGAA members have been involved closely with SCC threat-management processes since the first SCC failure on a pipeline was identified. The following describes just some of the focus INGAA members have placed on SCC management:

- Ten members of INGAA formed a Joint Industry Project (JIP) in 2006 to review historical experience and evaluate ways for improving current standards and guidance. The JIP met for two years, documenting incident experience, developing methods for selecting excavations for SCC direct assessment (DA) and reviewing experience with hydrostatic pressure testing, DA, and emerging ILI technologies such as the electro-magnetic acoustic transducer (EMAT). The JIP developed a method for conducting a spike strength test for SCC and the basis for defining the appropriate reassessment interval for hydrostatic pressure testing. Finally, the JIP developed specific guidance on near-neutral SCC, as the original version of ASME/ANSI B31.8 did not explicitly address near neutral conditions. The JIP has made a number of recommendations to the B31.8 Committee for inclusion into B31.8S.

- API 1110, a recommended practice that can be applied to both natural gas and hazardous liquid pipelines, was revised in 2009 to provide specific detail on conducting spike strength testing. The revision addressed test level and duration, as well as leak checking. ASME/ANSI B31.8S was revised in 2010 to address near-neutral SCC. In addition, there were other clarifications made to ensure consistent application of the process.
- A second JIP was formed in 2010 to analyze and evaluate recent SCC experience, including incidents, hydrostatic pressure testing experience and the use of ILI. Protocols have been developed for analyzing and evaluating ILI data and data from excavations. These protocols serve as a basis for operator's procedures. In addition, the JIP compared SCC fitness for service methods with other methods (for other types of cracks), providing operators with guidance on their application.
- INGAA operators have also engaged in the following:
  - Supporting ILI vendors, both individually and via the EMAT User Group, to achieve improved accuracy and reliability for SCC detection and severity assessment.
  - Most INGAA members support projects aimed at SCC prevention, detection, assessment and mitigation through their membership in PRCI.
- Some INGAA members also have in-house research projects aimed at delivering specific improvements in SCC management. The information gained from these projects is generally shared with other operators through the various joint-industry forums.

INGAA members are fully committed to all the activities associated with delivering continuous improvements in SCC management performance. PHMSA should incorporate the new SCC-management provisions in ASME/ANSI B31.8S as the basis for identifying and mitigating SCC.

Also, PHMSA should be responsive to further enhancements. Current standards have improved the management of SCC conditions in natural gas transmission pipelines; but zero is INGAA's target. More research work needs to be done.

INGAA members are committed to enhance consensus standards to prevent in-service failures due to SCC. Evergreen standards such as ASME/ANSI B31.8S, NACE RP 0402-2004 and API 1110 are updated continually with current research from PRCI, PHMSA, JIPs and individual company research. INGAA members are committed to continuing to lead these R&D efforts and to getting the results promptly incorporated into consensus standards.

Questions: Existing Standards

Question I.1

Should PHMSA revise subpart I to provide additional specificity to requirements that are now presented in general terms, as described above? If so, which sections should be revised? What standards exist from which to draw more specific requirements?

Operators have already developed programs to address the requirements of Subpart I, with specific requirements based on the particular operative corrosion threats. The regulations and standards are often not more specific because of the wide ranges of activities that have proven effective and the wide ranges of pipe, coating, cathodic protection (CP), environmental, interference and other conditions that exist. A requirement for test stations every half-mile, for example, may be insufficient in some urban areas and overly stringent in some rural areas. PHMSA and others have acknowledged the effectiveness of performance-based elements of the current programs. Adding prescription and specificity to these already established programs would be disruptive for operators; would shift the focus of the current programs from results and performance to completing certain activities; and, more importantly, would not be expected to provide a discernable improvement in safety.

Question I.2

Should PHMSA prescribe additional requirements for postconstruction surveys for coating damage or to determine the adequacy of CP?

If so, what factors should be addressed (e.g., pipeline operating temperatures, coating types, etc.)?

Post-construction surveys can identify coating damage associated with first- or second-party damage, but is rarely associated with external corrosion or SCC of either type if effective CP is applied. These surveys are unable to identify shielding coating, the primary mechanism for near-neutral pH SCC and a frequent factor for external corrosion. Post-construction close-interval potential surveys would need to be performed after CP systems are in service and the pipeline is polarized. Sufficient time must be allowed for CP systems to be energized, for them to be adjusted as needed, for soil compaction and settling to occur, and for full polarization to develop.

Question I.3

Should PHMSA require periodic interference current surveys?

If so, to which pipelines should this requirement apply and what acceptance criteria should be used?

Advice for conducting interference current surveys on newly-constructed pipelines is provided in PHMSA Advisory Bulletin ADB-03-06, *Corrosion Threat to Newly Constructed Gas Transmission and Hazardous Liquid Pipelines*. Practices for monitoring interference currents are presented in NACE SP0169 Section 9, “Control of Interference Currents”. Operators have long been aware of the issues associated with interference currents and typically consider them as part of their overall CP program. Before developing proposed requirements, acceptance criteria or other regulatory provisions, PHMSA should discuss this topic with operators in much more detail than can be provided in the answer to this single question.

Question I.4

Should PHMSA require additional measures to prevent internal corrosion in gas transmission pipelines? If so, what measures should be required?

The likelihood, assessment, mitigation and prevention of internal corrosion — are already addressed in Subparts I and O. With the amount of pipeline mileage tested in conjunction with assessing segments covered by Subpart O, and with the expansion of integrity management principles to virtually all of the transmission system, additional measures are unnecessary. Operators understand that enforcement of gas quality standards is an important — perhaps the most important — factor in preventing internal corrosion, along with the control or elimination of free liquids that can act as electrolytes. In addition, when necessary, operators inject corrosion inhibitors.

Question I.5

Should PHMSA prescribe practices or standards that address prevention, detection, assessment, and remediation of SCC on gas transmission pipeline systems?

Should PHMSA require additional surveys or shorter IM survey internals based upon the pipeline operating temperatures and coating types?

Operator experience indicates that the occurrence of SCC varies from pipeline to pipeline depending on system attributes, installation and operational practices. Standards and guidance can best accommodate this variability by prescribing a framework of processes and decision-making that can tailor threat management to the requirements of each pipeline. For example, specific coating types are often linked to occurrence of SCC, but the installation dates and prevailing application practices are also key factors that vary from pipeline to pipeline.

PHMSA should avoid prescriptive standards for the prevention, detection, assessment and remediation of SCC on gas transmission systems. Given the complex and variable nature of the factors contributing to the formation and growth of SCC, performance-based standards allowing operator's maximum flexibility to develop and apply situational techniques for detecting, assessing and remediating this threat will ensure the state of the art for managing these types of anomalies continues to progress.

Pipe coating type and operating temperatures are not sufficient in themselves to identify the risk of SCC. A set of criteria inclusive enough to capture all pipe potentially susceptible to SCC would be overly conservative, implicating virtually all pipe, and would not allow operators to differentiate the threat on their systems based on the unique combination of these criteria and experience.

ASME/ANSI B31.8S adequately covers prevention, detection, assessments, and remediation of SCC on gas pipeline systems. Experience-based refinements to specific aspects of the assessment process could be beneficial, but further regulation is not considered necessary. IM survey intervals should be determined based on what is found in previous assessments and on the technique employed; it would not be useful to set specific intervals in advance.

The pipeline industry has conducted numerous studies relative to various aspects of SCC, its causes, prevention and remediation. A recent JIP was conducted to review and assimilate the collected knowledge of these studies as well as those cited by PHMSA above. The report of that JIP, ASME publication STP-PT-011, *Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas* (October 31, 2008), contains additional guidance to operators regarding identification, inspection, evaluation and remediation protocols.

Question I.6

Does the NACE SP0204–2008 (formerly RP0204) Standard ''Stress Corrosion Cracking Direct Assessment Methodology'' address the full lifecycle concerns associated with SCC?

Should PHMSA consider this, or any other standards to govern the SCC assessment and remediation procedures?

Do these standards vary significantly from existing practices associated with SCC assessments?

NACE SP0204-2008 is a standard for DA of stress-corrosion cracking (SCCDA). SCCDA is one of three acceptable methods of assessing a pipeline segment for SCC, the other two being hydrostatic pressure testing and ILI. NACE SP0204-2008 does not address and is not intended to address all aspects relative to the full life cycle of concerns of SCC, e.g., the formation or nucleation of cracks or guidance on the calculations to assess the severity of cracks that may be found and measured. NACE SP0204-2008 does, however, address the factors found to be common in SCC, including surface and coating condition, environment, CP effects and the need to make an assessment of cracking severity and impact once SCC is found. Hydrostatic pressure testing and ILI are discussed in NACE SP0204-2008 as options for further addressing SCC after it has been found by means of SCCDA.

A significant body of work provides information and guidance on managing the assessment and remediation of SCC, including:

- ASME/ANSI B31.8S
- Numerous SCC-related reports published by PRCI and listed in their catalog at www.prci.org
- NACE International Publication 35103, "External Stress Corrosion Cracking of Underground Pipelines,"
- NACE SP0204-2008
- Reports from the JIPs on SCC (SCC JIP I and II),
- ASME STP-TP-011

- CEPA recommended practice
- Part 192, Subpart O.

A few of these documents, notably the NACE SCCDA standard, NACE Publication 35103, ASME/ANSI B31.8S and STP-TP-011, and the CEPA recommended practice, taken together, address the full life cycle of SCC, including the roles of materials, environment (soils), coatings, stress, and CP and temperature in the initiation and growth of SCC. They also address SCC detection, characterization, remediation, reassessment and prevention and mitigation, including strategies for hydrostatic pressure testing.

Many INGAA members have participated in the studies and development of the standards noted. The existing practices associated with SCC assessments are based upon and quite consistent with this body of work.

Question I.7

Are there statistics available on the extent to which the application of the NACE Standard, or other standards, have affected the number of SCC indications operators have detected on their pipelines and the number of SCC-related pipeline failures? Are statistics available that identify the number of SCC occurrences that have been discovered at locations that meet the screening criteria in the NACE standard and at locations that do not meet the screening criteria?

Statistics are available (see ASME STP-PT-011) showing that the number of SCC–related pipeline failures per year is generally decreasing. But those statistics cannot be directly related to the specific application of any particular standard. A recent survey of the North American gas pipeline industry indicated that 80 to 90 percent of the in-service SCC failures met the screening criteria in ASME/ANSI B31.8S, which are the same as the NACE criteria; as did over 95 percent of the hydrostatic pressure test failures and about 85 percent of the stress-corrosion cracks exceeding 10 percent through-wall depth found during excavations. During Phase II of the JIP on SCC management, additional data was collected up to the end of 2010. The same trends are apparent.

Question I.8

If new standards were to be developed for SCC, what key issues should they address? Should they be voluntary?

The covered topics for any integrity threat should include detection, assessment, mitigation, periodic reassessment, and evaluation of effectiveness. The studies and documents referenced in response to Question I.6, including ASME/ANSI B31.8S, the research reports and the JIP results and recommendations, provide the basis for a diligent, practicable approach to SCC management. INGAA supports the development of voluntary standards for use by operators as applicable.

Question I.9

Does the definition of corrosive gas need to clarify that other constituents of a gas stream (e.g., water, carbon dioxide, sulfur and hydrogen sulfide) could make the gas stream corrosive? If so, why does it need to be clarified?

Existing performance-based regulations are appropriate to address the threat of internal corrosion, as the operator is responsible for determining when corrosive conditions could exist on its system. Prescriptive limits for potentially corrosive constituents in a gas stream, such as those found in Section 192.620, would not be as effective in reducing the threat of internal corrosion. Such arbitrary limits are not based on science, as temperature, pressure and the presence of an electrolyte (i.e., free water) are not considered.

Question I.10

Should PHMSA prescribe for HCAs and non-HCAs external corrosion control survey timing intervals for close interval surveys that are used to determine the effectiveness of CP?

Public safety would be best served by identifying a risk-based approach that allows operators to determine the appropriate frequency for performing close interval surveys (CIS). To aid that process, operators have additional data that provides information relative to the effectiveness of cathodic protection (CP), including annual survey results and trends, bi-monthly rectifier readings and inspections, and ILI results. Prescriptive regulations requiring CIS on lines that are not at risk (such as new lines) or at an arbitrary interval would take resources away from lines that are higher risk.

Question I.11

Should PHMSA prescribe for HCAs and non-HCAs corrosion control measures with clearly defined conditions and appropriate mitigation efforts? If so, why?

INGAA does not believe it is feasible to develop prescriptive measures that identify necessary and sufficient monitoring and mitigation efforts in all environments.

Questions: Existing Industry Practices

Question I.12

Are there statistics available on the extent to which gas transmission pipeline operators apply the CEPA practices?

There are no statistics available to our knowledge, but most major operators in North America have adopted threat management practices closely aligned with Canadian Energy Pipeline Association (CEPA) guidance, ASME STP-PT-011 and ASME/ANSI B31.8S. Even within CEPA, we understand that its members do not uniformly implement the RP in its entirety. Some statistics regarding Canadian experience of SCC were published by the National Energy Board (NEB) in papers at the International Pipeline Conferences in Calgary, IPC2008 and IPC2010. The development of threat management practices commenced soon after the first SCC failures in the mid-1960s, and current IM documentation incorporates much of the early practice.

Question I.13

Are there statistics available that compare the number of SCC indications detected and SCC-related failures between operators applying the CEPA practices and those applying other SCC standards or practices?

We are not aware of any industry statistics that directly correlate the application of the CEPA practices to the rate of detection of SCC or the failure frequency associated with SCC. At various industry forums the NEB has noted the effectiveness of this document in managing SCC within Canada. The analysis of experience in the SCC JIP I (ASME STP-PT-011) and JIP II shows that applying the practices considered in that work, including ASME/ANSI B31.8S, SCC-DA and the CEPA recommendations, has led to a significant reduction in in-service failures on natural gas transmission pipelines. We encourage PHMSA to consult with the NEB regarding this issue.

Question I.14

Do the CEPA practices address the full lifecycle concerns associated with SCC? If not, which are not addressed?

The CEPA PR addresses the full life cycle of near-neutral-pH SCC. Many of the management techniques are common to high pH SCC, but the two are not identical. Written as a recommended practice, it is envisioned that operators would selectively apply elements of the document as warranted by their specific circumstances based on sound engineering judgment. This approach acknowledges that certain operators with extensive experience regarding SCC will incorporate proprietary research or technologies in their assessments.

Question I.15

Are there additional industry practices that address SCC?

Much of the focus above is on the management of SCC in older pipelines. Significant guidance on the management of both high pH and near-neutral pH SCC is provided in the standards and other materials and reports noted earlier.

In Europe there are no specific industrial practices that address SCC on natural gas pipelines. In Australia, Appendix G of AS 2885 addresses SCC in a manner similar to that in ASME/ANSI B31.8S.

It should not be forgotten that, for new pipelines, good installation and operational practices (such as good coating application and CP system control) have minimized the threat of SCC. The adoption of such practices is probably is largely responsible for the absence of SCC failures in lines installed in North America since 1980.

Questions: The Effectiveness of SCC Detection Tools and Methods

Question I.16

Are there statistics available on the extent to which various tools and methods can accurately and reliably detect and determine the severity of SCC?

The measurement of ILI crack detection tool performance is an ongoing research activity, both within JIP Phase II and within the Pipeline Research Council International, which is actively supported by the tool vendors and the pipeline operators. Several issues regarding the acquisition and interpretation of information need to be standardized by the practitioners before a clear picture can emerge. The implications of tool tolerance on predicted failure pressure are being studied In the JIP Phase II.

Question I.17

Are tools or methods available to detect accurately and reliably the severity of SCC when it is associated with longitudinal pipe seams?

Natural gas transmission pipelines face a continuing challenge to develop ILI tools that reliably detect and accurately assess the severity of SCC associated with longitudinal pipe seams. There are currently no commercially available tools that have completely demonstrated these abilities. In contrast, some ILI technologies applicable to liquid can accurately detect SCC and determine its severity to a reasonable extent. The tool technologies applicable to liquid service will typically identify the cracks, but have difficulty in determining the severity.

The detection and interpretation of a crack is more difficult when close to a longitudinal pipe seam, and is even harder when also close to a girth weld. Due to the conservative interpretation, cracking features reported in proximity to the longitudinal pipe seams are typically false positive calls causing unnecessary expenditures. Operators continue to urge vendors to develop tools that obtain more information on the attributes of cracking features so they can be characterized more accurately.

Question I.18

Should PHMSA require that operators perform a critical analysis of all factors that influence SCC to determine if SCC is a credible threat for each pipeline segment? If so, why? What experience-based indications have proven reliable in determining whether SCC could be present?

Operators are currently required to perform an analysis to determine the relative likelihood of SCC in each of their pipelines in HCAs, using methods based on the NACE, CEPA and ASME guidance. Most operators apply the same methodologies to the balance of their systems. As has already been said, the current ASME criteria capture 80-90 percent of the in-service failure experience, and hence focus initial attention on the lines with highest likelihood of SCC.

Operator experience (JIP I and II) indicates that the most effective approach is to address the pipelines with highest relative likelihood first, and to address lower-likelihood lines based on the information and experience gained from working with the higher likelihood lines.

Question I.19

Should PHMSA require an integrity assessment using methods capable of detecting SCC whenever a credible threat of SCC is identified?

Subpart O currently requires operators to assess for identified threats. If SCC is an identified threat in a covered segment, the segment must by assessed by a method or methods capable of detecting SCC. In the context of a covered segment where SCC is an identified threat, a credible threat is taken to mean a measure of SCC similar to the "significant" SCC designation used in the previous version of the CEPA SCC RP. In the case of an identified or credible threat, the operator would have to actively manage the threat per its IM program as set out in Subpart O and ASME/ANSI B31.8S. Active threat management could include assessment techniques capable of detecting SCC, but detection should not be narrowly interpreted to preclude hydrostatic pressure testing, which does not "detect" or identify the population of SCC on a pipeline but rather removes any crack which is of a critical size at the test pressure.

Question I.20

Should PHMSA require a periodic analysis of the effectiveness of operator corrosion management programs, which integrates information about CP, coating anomalies, in-line inspection data, corrosion coupon data, corrosion inhibitor usage, analysis of corrosion products, environmental and soil data, and any other pertinent information related to corrosion management?

Should PHMSA require that operators periodically submit corrosion management performance metric data?

Subpart O currently requires operators to keep records, measure program effectiveness, continually evaluate and assess systems, integrate relevant data and demonstrate continuous improvement. These requirements apply to many aspects of pipeline safety, including the corrosion management program. The effective management of external and internal corrosion and SCC typically requires the integration and analysis of multiple disparate datasets. However, the value and usefulness of a particular dataset varies depending upon the type of corrosion or SCC, the assessment techniques employed (ILI, DA or hydrostatic pressure testing) and the data those techniques are able to provide. DA is essentially predicated on data integration. ILI data integration would largely revolve around the integration of multiple ILI datasets, excavation, crossing, interference and encroachment data, and could also utilize environmental data depending on the circumstances. The requirement for robust data integration is already clearly prescribed and understood.

Although Subpart O applies specifically to covered segments, operators generally apply the same programs, procedures and criteria system-wide. Many metrics bearing on the effectiveness of the corrosion control program are required to be collected by operators, as shown in ASME/ANSI B31.8S Tables 8, 9 and 10. Operators do not have to submit this information to PHMSA, but the information is subject to inspection, confirmation and evaluation by PHMSA during audits.

Question I.21

Are any further actions needed to address corrosion issues?

The fact that corrosion issues continue to exist indicates that further actions are necessary. Continued study and evaluations to determine the root causes of the issues, documentation of findings and communication of results through industry forums and workshops, rather than increasing prescriptive requirements, is the most likely course of action to produce further reduction and mitigation of this threat.

Question I.22

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

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Topic J – Pipe Manufactured Using Longitudinal Weld Seams

The first federal pipeline safety regulations were established in 1970. Gas transmission pipelines had existed for many years prior to this, some as early as 1920. By 1970, many of these pre-regulation pipelines had operated safely for years. The processes for making the seam welds in pipe have evolved over the decades. Some of the early seam welding processes, such as low frequency electric resistance welding, direct current electric resistance welding, flash welding, furnace butt welding, hammer welding and lap welding, had largely been phased out by the early 1970s.

All pipelines installed after 1971 ("post-regulation pipe") will have been tested to at least 1.1 times MAOP, so the question relates to pipelines installed before the regulations came into effect ("pre-regulation pipe"). For pre-regulation pipe, the objective should not be testing *per se*, but establishing that the pipe is fit for service. Fitness for service (FFS), which is described in Appendix 2 should be established using the FFS protocol detailed in INGAA's general response to Topic N.

Question J.1

Should all pipelines that have not been pressure tested at or above 1.1 times MAOP or class location test criteria (§§ 192.505, 192.619 and 192.620), be required to be pressure tested in accordance with the present regulations?

If not, should certain types of pipe with a pipeline operating history that has shown to be susceptible to systemic integrity issues be required to be pressure tested in accordance with the present regulations (e.g., low frequency electric resistance welded (LF–ERW), direct current electric resistance welded (DC–ERW), lap welded, electric flash welded (EFW), furnace butt welded, submerged arc welded, or other longitudinal seams)? If so, why?

The FFS protocol addresses all the specific types of pipe identified in Question J.1.

Pre-regulation pipe accounts for about 60 percent of U.S. natural gas transmission mileage. When operators installed pre-regulation-pipe, they generally used the ASME/ANSI B31.8 consensus standard and company procedures to determine the pipe's FFS, including its MAOP. Most pre-regulation pipes are performing well. Operators of these pipes have also been actively reviewing records to achieve the goals of PHMSA Advisory Bulletin ADB-11-01 and Section 23(a) of the recently enacted pipeline safety reauthorization.

For pipes susceptible to manufacturing-related seam integrity issues, INGAA's FFS protocol, which is described in Appendix 2 and the flow chart in the general response to topic N, provides a basis for establishing the FFS of pre-1970s pipe more effectively and efficiently than a prescriptive requirement to strength test all pipelines that have not been tested at or above 1.1 times MAOP. The FFS protocol rigorously focuses on material, the primary threat that differentiates these pre-regulation pipelines from pipelines designed and constructed after the regulations went into effect. This approach is consistent with the shared concern of PHMSA, the National Transportation Safety Board, INGAA and others: demonstrating that pipeline systems are fit for service.

Question J.2

Are alternative minimum test pressures (other than those specified in subpart J) appropriate, and why?

INGAA is not aware of any evidence that the existing minimum test pressures established in Subpart J and used on existing pipelines have been inappropriate or inadequate.

INGAA does believe, however, that it may be prudent to conduct additional tests or inspections to verify FFS if the strength test is conducted at a pressure of less than 1.25 times MAOP. This approach to verification is consistent with the current guidance in ASME/ANSI B31.8, which regards the strength test as a single, stand-alone test (as opposed to a part of a comprehensive FFS analysis), and provides for a minimum test pressure of 1.25 times MAOP.

It is important to recognize that strength tests analogous to those conducted per Subpart J were recognized and routinely conducted long before Subpart J took effect. Since 1928, consensus standards for line pipe have required a specified minimum test pressure during “mill tests” (strength tests for each piece of pipe released from a pipe manufacturing facility). In fact, the 1928 American Petroleum Institute standard for line pipe required strength tests at the mill for each and every joint of pipe. In 1956, the test pressure was raised to 90 percent of the SMYS, which for a pipe operating at 72 percent SMYS in Class 1, is 1.25 times MAOP. That requirement remains in place today, and many operators require test pressures somewhat above this level. This test establishes a pipe’s initial FFS with regard to manufacturing-related threats.

Based on available information, the material that failed in San Bruno would not have passed a mill or a field strength test under the prevailing standards of that time. INGAA members believe the pipes and components in their systems were manufactured to prevailing standards and INGAA members are working diligently to validate those records. Records verification is underway to achieve confidence in the integrity of pre-regulation pipelines. Absent verifiable records, INGAA members are applying the FFS protocol.

Question J.3

Can ILI be used to find seam integrity issues?

If so, what ILI technology should be used and what inspection and acceptance criteria should be applied?

Identification of seam integrity anomalies is best characterized as work in progress. ILI technology, in combination with records, can identify what seam technology was used for a particular segment, so attention can be focused on the possible issues associated with that particular type of seam. Several available technologies can be effective for inspecting natural gas pipelines:

- Circumferential or transverse magnetic flux leakage (CMFL or TFI) sensors
- Multi-axial or triaxial tools with multiple direction sensors
- Spiral-field tools with the magnetic field oriented at an angle less than 90 degrees to the pipe axis
- Electromagnetic acoustically-coupled transducer (EMAT) sensors

These sensors can identify anomalies, but additional work must be conducted to improve the probability of anomaly identification and to reduce both false negatives (anomalies not identified) and false positives (identifying an anomaly where none is present). Circumferential ultrasonic sensors offer better performance but require introducing a liquid couplant that is not normally present in natural gas pipelines.

Consistent with the significant investment that has been made to make systems piggable, and with the goal of continually improving integrity management through the collection and use of new data, INGAA has committed and begun to expand research, development and commercialization of ILI technologies.

Maximizing the use of ILI technology builds upon the extensive investment that INGAA members have made to make their systems “piggable.” The alternative, universal hydrostatic pressure testing, would result in widespread pipeline capacity constraints. Performing a hydrostatic pressure test requires completely removing the pipeline from service for up to several weeks. Universal testing thus would dramatically increase the likelihood and magnitude of transportation service disruptions (and consumer energy prices). Furthermore, with hydrostatic pressure testing costs of approximately $250,000 to $1,000,000 per mile and with approximately 179,000 miles of pre-1970 natural gas transmission pipelines in the United States, the direct cost of such testing alone could have a significant impact on consumer energy costs when included in natural gas pipeline rates. Reconfirming the maximum allowable operating pressure for grandfathered pipe is clearly an area that should be subject to a rigorous cost-benefit analysis, where less costly and less disruptive alternatives to achieve the same safety goals should be considered.

While there are benefits to testing older pipes, such as those with a known history of longitudinal weld seam issues, there are also significant costs, including potential service outages, the atmospheric venting of methane (a greenhouse gas), the generation of millions of gallons of hydrostatic test water, and the creation of hazardous work environments. Testing therefore must be targeted only to those lines for which significant safety benefit can be shown.

Question J.4

Are other technologies available that can consistently be used to reliably find and remediate seam integrity issues?

While not receiving the same attention as the ILI technologies, other non-destructive examination techniques such as magnetic particle inspection (MPI), ultrasonic inspection (UT) and dye penetrant inspection (DPI) can be applied in excavations to identify long seam anomalies when the pipe surface is exposed. Most operators have adopted a practice of routinely conducting MPI inspection on the long seam where disbanded coating is observed during maintenance and integrity-related excavations. This practice identifies injurious anomalies that can then be remediated immediately.

As more data are collected from these inspections, operators will be able to use these data to enhance their ability to characterize the nature and occurrence of existing seam issues, their ability to anticipate where seam issues might occur, and the effectiveness of their inspection methods overall. The data base will also provide a statistical basis for assessing the potential for seam integrity issues in a pipeline segment of a certain technology and vintage to occur.

Question J.5

Should additional pressure test requirements be applied to all pipelines, or only pipelines in HCAs, or only pipelines in Class 2, 3, or 4 location areas?

For pipes placed in service after the federal safety regulations took effect, the current testing requirements are adequate and should be maintained. INGAA's FFS protocol, which is described in response to questions N.3 and N.4, addresses strength test requirements for all pre-regulation pipelines regardless of HCA status or class location. This approach is consistent with the provisions of Section 23 of the recently-enacted pipeline safety act.[13] Testing and other activities should be performed on pre-regulation pipe as the protocol provides.

Question J.6

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

[13] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub.L. 112-90 § 23.

Topic K – Underground Natural Gas Storage

This portion of the ANPRM, particularly question K.7, suggests that it is (or should be) an open question whether regulatory jurisdiction over the safety of interstate natural gas storage facilities regulation rests at the federal or state level. INGAA disagrees. The federal law is clear: safety jurisdiction over federally certificated natural gas facilities, including storage facilities, rests exclusively at the federal level.

The issue is not whether PHMSA has exclusive federal safety jurisdiction over interstate natural gas storage facilities. It does.[14] The issue is how that jurisdiction should be exercised. INGAA urges PHMSA to follow a course that has already proven successful in other areas of Part 192.

First, a collaboration of interested stakeholders, including regulators, would develop consensus, risk-based standards governing the operational integrity of interstate underground natural gas storage facilities. INGAA's underground gas storage operators have achieved an admirable track record of facility integrity and safety over their decades of operating history. This strong level of performance has been accomplished through the development of and conformance to sound engineering practices that are both geographically and geologically appropriate.

The safety and integrity of the nation's underground gas storage infrastructure could be further enhanced by the development and application of a recognized industry standard that is based on the collective operating experience of INGAA's members and others and that provides all operators with flexible, performance based methods for the monitoring and assessment of storage facility operational integrity. INGAA is committed to the development of an American National Standards Institute (ANSI) certified standard for the Management of Underground Gas Storage Operational Integrity. The process would be stewarded by the American Petroleum Institute (API), with work commencing in 2012 and a targeted duration for completion of 18 – 24 months. The final result envisioned is an API "Recommended Practices" document, similar in nature to the API RP 1114 and 1115 which were developed for liquid products storage in leached caverns. A strong, performance-based federal standard would ensure that broad industry knowledge and experience is fully leveraged and maximized, that flexible, appropriate and effective methodologies for operational integrity management are achieved at a national level and that the duplication of effort and the complexity of managing multi-jurisdictional regulation are minimized.

Once the standards have been developed, PHMSA would incorporate them into Part 192 by reference. Upon incorporation, the standards would be mandatory and enforceable by PHMSA, with the Secretary of Transportation having authority, through the agreement provisions of the Pipeline Safety Act,[15] to allow state agencies to become PHMSA's agents in monitoring the

[14] The legal basis for exclusive federal jurisdiction over the safety of interstate natural gas storage facilities is detailed in Appendix 3.

[15] 49 U.S.C. § 60106(b).

federal requirements consistent with "participat[ing] in the oversight of pipeline transportation."

PHMSA is the best suited organization for the development and oversight of these regulations given their extensive experience in working with industry to develop and codify industry consensus engineering and technical standards and for their considerable knowledge and understanding of risk and integrity management principles for natural gas and hazardous liquid related infrastructure.

Question K.1

Should PHMSA develop Federal standards governing the safety of underground gas storage facilities?

If so, should they be voluntary?

If so, what portions of the facilities should be addressed in these standards?

For underground storage facilities PHMSA should adopt, as a federal safety standard, rules developed in consultation with interested stakeholders. The federal standard should recognize and address legitimate regional and geologic differences between storage fields, and they should permit storage operators to continue using regionally-appropriate monitoring and assessment methods. States with oil and gas and gas storage wells have regulations in place governing well construction, remediation, and plugging of those wells. These oil and gas well regulations take into consideration specific geologic conditions in each state and are designed to provide for public safety and to prevent waste, leakage and pollution. These regulations also are applicable to the construction, remediation, and plugging of natural gas storage wells. There are presently at least 30 states that have ongoing underground storage activity. A federal standard that acknowledges and reflects existing applicable state rules is a good-sense, efficient means of rule-making and of incorporating the regional and geologic variations into the safety rules.

Before addressing specific aspects of the federal standards developed on the basis of API guidelines and recommended practices, it is important to reach a common understanding of what is meant by "underground storage facilities" and how operators currently ensure their operational integrity. INGAA understands "underground storage facilities" to include the geologic formation, related wells, and piping to inject and remove gas. Specific to this discussion, underground storage facilities are identified as beginning at and including the wing valve at the wellhead, the wellhead components, the well bore, and the "underground container" (i.e., the geologic formation). The underground container, which is certificated and pressure-regulated by FERC, includes man-made caverns or mines in domal salt, bedded salt, or other rock, depleted oil and gas reservoirs, and gas storage reservoirs developed in aquifers. Wellhead wing valves and downstream pipeline components are already subject to Part 192; the other facilities mentioned in this paragraph are not specifically addressed.

The federal standard also should acknowledge and reflect existing regulatory frameworks that support underground storage safety. As mentioned earlier, state oil and gas well construction and operation rules provide value in that those rules inherently incorporate regional geologic variations into regulation. Other existing regulatory frameworks are highlighted in the next several paragraphs to further illustrate what INGAA would propose be considered en route to development of the federal standard governing underground storage safety.

Interstate storage operators are subject to the review and operating conditions imposed upon them by FERC. As FERC summarized in its opinion in *Dominion Transmission, Inc.*:[16]

> There are more than 200 jurisdictional underground storage fields generally operating successfully and safely without major operational problems, despite the variety of difficulties inherent in storage operations. Such concerns include, for example, gas migration and/or loss resulting from facility mechanical integrity issues arising in operation of surface and subsurface facilities…
>
> Field operators have achieved broad success through a system of sound engineering practices using appropriate monitoring and testing of storage field performance throughout the entire active operating life of each storage field. The early detection of problems such practices allow has proven effective in assuring the initiation of remedies to minimize adverse effects to the environment and the preservation of the stored natural gas.[17]

Existing federal and state certification programs and compliance inspection related to gas storage facilities are effective in regulating the maximum operating parameters and environmental protections, so there is no apparent need to produce additional standards in these subject matter areas. FERC approves maximum pressure and flow and maximum gas volume which may be contained in the storage project. Solution mining wells utilized for salt cavern construction are permitted under the Environmental Protection Agency's Underground Injection Control (UIC) Program or its authorized state program delegates.

Storage operators within INGAA have implemented effective integrity management and monitoring programs to ensure storage safety. Implementation is site-specific, with each operator applying the monitoring and assessment methods that are best suited for the particular container- or well-specific environment. Working together, these site-specific approaches form a best practices system, resulting in a high level of confidence in overall storage system integrity.

The federal safety standard built on API guidelines and recommended practices should recognize and build upon current approaches. A prescriptive, "one size fits all" approach would fail to consider the many variations in the manner in which storage wells are currently completed and the successful monitoring programs storage operators have employed over the life of these assets. Given the geographic and geologic diversity of storage facilities and the

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16 99 FERC 61,385 (2002).

17 *Id*. at pp. 62,639-40.

broad range of conditions in which they operate (pressure, capacity, depth of geologic structure, age and condition of existing assets), public safety is best served by allowing operators to continue selecting which of the accepted monitoring and assessment methods best suits each situation.

The federal standard also should cover what third parties must do when drilling through or completing a well in or adjacent to a dedicated storage formation. A storage operator's principal goal is to preserve operational integrity by monitoring and assessing the natural geologic confinement mechanisms. The potential for gas migration is minimized by ensuring that wells are completed in a mechanically competent manner, which prevents storage communication with other geologic formations. A concern to "underground container" integrity is the penetration of or encroachment into the container by third parties through drilling or well stimulation programs, which may have the effect of breaching the vertical and lateral isolation of the underground storage container.

The potential for gas migration is minimized by ensuring that wells are completed in a mechanically competent manner, which prevents storage communication with other geologic formations and fluids from leaking from or entering into the storage formation. The federal standard should provide that when third party non-storage operators propose to drill through or near storage containers, advance notice will be provided to the potentially impacted storage operator and the operator and regulator will have an opportunity to review and approve the well plans. A number of states, including Michigan, Oklahoma and Pennsylvania, have notification-review-and-approval processes that the collaborative group could draw upon in developing the federal standard. The advance of well drilling and completion technology, in particular the substantial resource development employing long-horizontal well multi-stage large-scale hydraulic fracture treatment programs, requires new approaches to regulatory oversight. INGAA's members believe the new regulatory approach is best achieved by a federal standard requiring a notification-review-and approval process.

Question K.2

What current standards exist governing safety of these facilities?

What standards are presently used for conducting casing, tubing, isolation packer, and wellbore communication and wellhead equipment integrity tests for down-hole inspection intervals?

What are the repair and abandonment standards for casings, tubing, and wellhead equipment when communication is found or integrity is compromised?

Existing Standards

Interstate and intrastate storage facilities typically are regulated by FERC or a governing state agency, respectively. FERC or the state agency may place controls on maximum flow, volume, pressure, and other operating conditions to provide for facility-level safety and integrity.

States with oil, gas and gas storage wells have regulations in place governing well construction, remediation and plugging. In the absence of federal standards, interstate gas storage operators have used these state regulations as a standard. These well regulations take into consideration specific geologic conditions in each state and are designed to provide for public safety and to prevent waste, leakage and pollution. The state well regulations are applicable to the construction, remediation and plugging of natural gas storage wells. Well site surface location and well spacing requirements are included in state regulations, and interstate storage facilities must obtain FERC approval for facility site development and temporary and permanent work space. In addition to compliance with state well construction standards, INGAA-member company gas storage operators maintain integrity monitoring and integrity testing programs for each gas storage field.

Some states (for example, Michigan, Oklahoma, Pennsylvania) have programs in place allowing for storage operator notification-review-and-approval of third-party well drilling that may encroach on storage facilities and for certain construction requirements for those wells. The response to question K.1 recommends establishing a federal standard requiring a storage operator notification-review-and-approval process for third party wells encroaching on storage containers. Establishment of this type of federal standard will promote storage container safety and integrity by ensuring that any well penetrating or encroaching on the container will be competent to prevent fluids from leaking from or entering into the storage formation.

In order to confirm the long-term containment of the underground storage container, operators establish a pressure-inventory relationship for the storage facility and monitor storage pressure against the relationship. Storage facility operators demonstrate underground storage integrity by periodic well shut in pressure tests.

A number of other operator program features contribute to storage facility safety. For example, operators install signs to identify the well, operator, location, contact number, and other information. Operators develop site security strategies and tactics based on the operator's evaluation of need. Safety training in compliance with DOT Operator Qualification, augmented by industry group certification or an operating company's additional qualification programs, ensures that operating staff are trained to carry out their duties in a safe manner. Storage operators develop and maintain general and site-specific operating plans, inspection protocols and other standard operating procedures including recognition of abnormal operating conditions, and storage well emergency response plans.

Specific to Cavern Storage

The salt cavern operators, as represented by INGAA member companies, must implement and comply with certain construction, commissioning and operating requirements as determined by either state or EPA-Regional implementation of the EPA's Underground Injection Control (UIC) Program.

Well operators must comply with permit conditions regarding siting, constructing, operating and maintaining, converting, plugging and abandoning activities. The UIC Program is overseen either by the state or by one of the EPA regional offices. State programs must meet minimum federal UIC requirements to gain primacy. EPA has delegated primacy to thirty-three states, shares responsibility in 7 states, and administers from regional offices the program in ten states. Alabama, Texas, Louisiana, Mississippi, among others, have gained primacy and have enacted the UIC Program code in their state.

Casing, Tubing, Etc.

State storage well regulations also address casing, tubing, and isolation packer pressure tests, and how an operator demonstrates the ability of the well to contain maximum authorized injection pressure. Storage well integrity verification and wellbore communication concerns are assessed using a number of methods. Operators qualify the pressure containing capacity of their existing wells by maintaining documentation that the well has safely contained maximum storage pressure in the past. The historical demonstration of integrity in existing wells is the shut-in pressure trends on those wells, along with down-hole inspections (which may include casing inspection surveys, noise, temperature, neutron, or other logs), annulus pressure monitoring, and other demonstrations performed by the storage facility operator. The operator considers the results of all such information gained from the multiple tests and inspections and determines if the storage well demonstrates integrity. Operators define the frequency of the tests at any specific well on a needs-basis determined by the well's construction, history, and the local geologic conditions, operating influences, and results of past tests. Wells demonstrating mechanical integrity in accordance with an operator's program should not be required to undergo special tests and demonstrations other than those identified in the operator's integrity monitoring and management programs.

INGAA members have implemented effective integrity management and monitoring programs to ensure storage safety. The well integrity assessment practices employed by our member companies, in particular the facility/site-specific flexible application of multiple assessment techniques, should be promoted as the means to maintain storage safety.

Secondary tubing strings set on a packer inside of cemented casing are not required in most states and are not necessary to promote or maintain well integrity and therefore should not be required in a federal minimum standard. Casing completions designed and tested to storage pressure provide fluid containment competency and are an established, mechanically competent storage well construction method. Operators have designed "casing-completion" wells to optimize flow, velocity, and pressure reduction variables, which minimizes the number of wells required. Reduced flows resulting from regulations mandating installation of secondary tubular strings would require additional well drilling, without improving safety.

Specific to Cavern Storage:

The UIC Program, through the permitting requirements, requires operators to conduct and submit for approval successful Mechanical Integrity Tests (MITs). These tests are designed to prove the ability of the cavern-wellbore-wellhead system to safely contain gas. At set time intervals after development an operating gas cavern must pass additional MITs. The requirements for periodic re-tests provide the operator and the regulator timely re-assessments of the cavern storage system integrity. Monitoring, repairing, and abandoning activities, among others, are also required under the UIC Program.

Repair and Abandonment

A repaired well is expected to meet the same state safety standards as when originally constructed. States have various safety standards for well abandonment.

INGAA members proactively use the findings of their multi-faceted IM programs to determine the need for remedial work on their storage wells. When remedial work is necessary, a number of safe, reliable techniques can be used to ensure the continued integrity. Remedial options include, but are not limited to:

- replacing or repairing wellhead equipment or defective tubulars when those defective areas can be retrieved
- installing a liner set on a packer or cemented in place
- applying casing patches internally over isolated defect areas, and
- plugging and abandoning the well when none of the other alternatives are deemed feasible.

Question K.3

What standards are used to monitor external and internal corrosion?

Storage operators use a variety of inspection methods, depending on the well's construction, geologic conditions, operational history; and other site-specific factors. Unlike pipeline inspections, most well casing cannot be recovered to verify the findings of the inspection devices. A storage operator must make integrity-related decisions based not on a single source of indirect assessment, but on a thorough knowledge of the well, its history, and indications or findings from a number of monitoring methods. When and where casing inspection tools can be used, they serve as screens or indicators. In a more robust approach, storage operators assess well casing integrity and storage safety by using a system of sound engineering practices incorporating integrity verification methods that fit the location, history, and risks specific to the well. The long-term integrity and safety record of the storage industry demonstrates that the multi-assessment approach used by INGAA members has been effective in promoting overall safety in underground storage facilities.

The storage operators within INGAA work proactively through established, credible programs, such as those provided by the Gas Technology Institute, the Pipeline Research Council International, the Solution Mining Research Institute and the US Department of Energy, to research, develop, and improve the tools used for integrity monitoring and indirect assessment. INGAA does not support prescriptive standards based on a specific casing inspection tool and the interpretative findings from any specific tool. There is no specific casing inspection tool that can be used in all storage wells.

Question K.4

What standards are used for welding, pressure testing, and design safety factors of casing and tubing including cementing and casing and casing cement integrity tests?

Like most oil and gas wells, most of the newly constructed pressurized casing strings for storage wells are constructed by connecting threaded couplings from the depth of the bottom hole to the surface. As a result, no welding is necessary or generally performed on the pressurized casing string in wells completed in aquifer or depleted reservoir storage fields. However, it is often the case in salt cavern storage that the final production string is run using welded connections. An approved welding procedure is established by the storage operator and this procedure is then qualified in much the same manner as welding procedures on a pipeline are qualified and tested. The procedure is compliant with ASTM B31.8 and Part 192, and inspection is conducted using API 1104 criteria.

Operators qualify the pressure-containing capacity of their wells by maintaining documentation that the well has safely contained maximum storage pressure in the past. Wells demonstrate integrity in ongoing storage operations in accordance with shut-in pressure trends, annulus monitoring, and other integrity monitoring coupled with gas inventory verification programs.

States with oil, gas and natural gas storage wells have regulations governing the design, construction, remediation, and plugging of those wells. The well regulations take into consideration specific geologic conditions in each state and are designed to provide for public safety and to prevent waste, leakage and pollution. These regulations include design safety factors that are specific to the use envisioned for the tubular or cement. The design factors reflect geology, well geometry, borehole and formation fluid chemistry, and other site-specific features; allowance for such variations must be reflected in the federal standard.
State storage well design and construction regulations also govern casing cementing programs. Casing cementing programs are customized for the geographic area and geologic conditions and designed to isolate storage pressure and fluid to prevent leakage out of or into the storage interval and wellbore. In accordance with state regulations, installation and cementation of multiple casing strings may be required in some cases in order to isolate and protect sensitive formations. As with other aspects of storage safety regulation, existing state programs on casing cementing should be examined for best practices when developing the federal standard.

Some state storage well regulations also contain casing cementing programs, which are designed to isolate storage pressure and fluid to prevent leakage out of or into the storage interval and wellbore. In some cases, multiple casing strings may have to be installed and cemented to isolate and protect sensitive formations. As with other aspects of storage safety regulation, existing state programs on casing cementing should be considered in developing the federal standard.

Question K.5

Should wellhead valves have emergency shutdowns both primary and secondary?

Should there be integrity and O&M intervals for key safety and CP systems?

Specific to Cavern Storage:

For natural gas salt storage cavern wells, it is a generally accepted practice by the salt storage industry (and often a state requirement) to have emergency shutdown systems (ESDs) at the well site and either on or near the wellhead. Function testing of the ESD systems is a component of industry operators' standard operating procedures.

Specific to Depleted Reservoir and Aquifer Storage:

For reservoir and aquifer storage wells, automatic-actuated or remote-actuated emergency shut-down valves, wellhead or side-gate or down-hole safety valves are not required. Operators evaluate the need for any type of safety valve by considering:

- the type of hydrocarbon, total fluid flow, and maximum flow potential
- the distances between wellheads or between wellheads and other facilities, and the availability of access for drilling and service rigs and emergency services
- the risk from and to roadways, rights of way, railways, airplanes, populated areas, and industrial or facilities
- alternative protection measures which could be afforded by barricades or distance or other measures
- the present and predicted development of the surrounding area
- the topography and regional drainage systems and the proximity to aquifers, wetlands, potable water sources
- the local climate
- the added safety risks created by installation and servicing requirements of safety valves, in particular of down-hole safety valves

Implementation of cathodic protection (CP) of well casings is subject to the operator's determination of need. Operator experience indicates installing CP on well casing is best handled as a site-specific issue, and the need for and benefits of CP must be studied by gathering and analyzing data at specific locations, even within a single field.

Question K.6

What standards are used for emergency shutdowns, emergency shutdown stations, gas monitors, local emergency response communications, public communications, and O&M Procedures?

Generally, operators maintain emergency response procedures, including links into the Incident Command System and special provisions for loss-of-well-control (storage well emergency) incidents. Additionally operators comply with the current DOT regulations for emergency shutdowns, emergency response, or communications where associated storage pipelines and compressor station systems are regulated by DOT.

Question K.7

Does the current lack of Federal standards and preemption provisions in Federal law preclude effective regulation of underground storage facilities by States?

State safety jurisdiction extends only to intrastate storage facilities, and neither the current lack of federal standards nor the preemption provisions of federal law prevent states from regulating the **intrastate** facilities falling within their jurisdiction. In contrast, interstate natural gas storage facilities are under exclusive federal jurisdiction.[18] Uniformly applying a federal standard that permits storage operators to continue implementing established, regionally-appropriate monitoring and assessment methods would promote integrity management and the safe operation of natural gas storage facilities. Once adopted into regulations, the federal standard described in the general response and specific answers to this topic will set the minimum requirements that must be applied across all states.

Question K.8

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

INGAA recognizes the need to develop federal safety standards governing interstate natural gas storage. The standards should be developed through a collaboration involving regulators and other interested stakeholders, and INGAA is pleased to initiate this process. With specific

[18] The Secretary may not delegate the enforcement of safety standards for interstate pipeline facilities to a State authority. 49 U.S.C. § 60106(b)(1).

standards yet to be developed an assessment of costs, safety and societal benefits, small business impacts and environmental effects would be premature. The collaborative group will consider and assess these issues as they deliberate over possible federal standards.

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Topic L – Management of Change

ASME/ANSI B31.8S defines management of change as "a systematic process … to ensure that, prior to implementation, changes to pipeline system design, operations or maintenance are evaluated for their potential risk impacts, and to ensure that changes to the environment in which the pipeline operates are evaluated." Although the ANPRM indicates that Part 192 does not currently address management of change (MOC), Part 192 already incorporates the MOC concept:

- INGAA members have applied MOC for HCAs, per Section 192.911(k), since the regulations went into effect in 2004.
- Many members have applied MOC since publication of ASME/ANSI B31.8S in 2002 and even earlier, when MOC was adopted by their corporate families.
- MOC also will be implemented as part of PHMSA's control room management regulations (Section 192.631), which became effective on August 1, 2011.

Section 192.911(k) requires operators to use an MOC process and refers to ASME/ANSI B81.8S, Section 11 ("Section 11"), which is the prevailing consensus standard for MOC. In addition, section 192.909 defines how an operator can change its IM plan, and changing an IM plan requires the use of MOC procedures.

INGAA members are committed to clarifying and expanding the use of a formal "management of change" process, and to facilitating its consistent application as a key management system. INGAA believes that the full adoption of ASME/ANSI B31.8S will facilitate the widespread application of these principles. INGAA members have developed a white paper, which appears below as Appendix 4, to help clarify and expand the use of MOC.

Question L.1

Are there standards used by the pipeline industry to guide management processes including management of change?

Do standards governing the management of change process include requirements for IM procedures, O&M manuals, facility drawings, emergency response plans and procedures, and documents required to be maintained for the life of the pipeline?

The prevailing standard used in the natural gas transmission industry is Section 11, which envisions applying MOC not only to changes in the items listed in Question L.1, but also to changes in equipment, equipment configuration, systems and personnel related to integrity management.

Question L.2

Are standards used in other industries (e.g., Occupational Safety and Health Administration standards at 29 CFR 1910.119) appropriate for use in the pipeline industry?

Section 11 is based on the standards contained in OSHA's Process Safety Management (PSM) regulation, which is the regulation referenced in question L.2. OSHA worked with several industries, including the oil and gas industry, when it included MOC in 29 CFR 1910.119. OSHA developed its PSM standard to ensure that potential threats were identified properly and that steps were taken to mitigate threats and eliminate failures and unsafe acts.

Question L.3

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

Topic M – Quality Management Systems

Quality management systems (QMS) are central to the management of pipeline system assets throughout their lifecycle. As part of the IMCI initiative, INGAA formed one team to examine how management systems can be applied more broadly in verifying pipeline integrity. There was a second team formed with a more tightly focused scope on how QMS can be applied to improve pipeline construction.

The value of a management system in verifying pipeline integrity was recognized during the development of ASME/ANSI B31.8S. Four elements of a management system, quality assurance/quality control, management of change, communication and performance measurement were embodied into ASME/ANSI B31.8S, to provide a first step of integrating a management system as part of verifying pipe line integrity. These elements of the standard have already been incorporated into regulation by PHMSA.

The IMCI team working on management systems began its work by providing guidelines on improving safety culture, and improving management of change practices (filed with these comments as Appendix 4). The team began with safety culture as many INGAA members have embraced a goal of zero incidents within their personnel safety programs. Understanding how operators have designed their personnel safety programs to achieve the goal of zero was the place to begin as safety culture is one element of a broad-based management system.

The team is currently developing an overview of management systems in industries where the consequences of failure can be unacceptable, including the chemical manufacturing, petroleum refining, nuclear power, and aviation industries, as well as the medical field. In many instances, the regulators in these industries have elected to use management systems to audit and evaluate the effectiveness of safety, as well as environmental programs. Standards being reviewed include those of the Federal Aviation Administration, the Occupational Safety and Health Administration, and the Environmental Protection Agency, as well as international standards.

Implementing a quality management system (QMS) on pipeline construction projects improves material and construction quality by providing a structured approach to quality management. INGAA intends to clarify and improve its application of QMS. Through effective QMS, pipeline construction project sponsors can achieve consistent conformance to established quality standards and specifications, reducing rework and unexpected construction issues. Project sponsors, suppliers, contractors and service providers, all need to work together to embrace higher standards of quality through the application of QMS principles.

Achieving a consistent and uniform level of quality management across the pipeline construction industry is a challenge well suited for the INGAA Foundation, Inc. (Foundation), which represents pipeline operators, suppliers, contractors and service providers. INGAA formed the Foundation in 1990 to advance the use of natural gas and to facilitate the efficient construction and safe, reliable operation of the North American natural gas pipeline system.

The Foundation has proven to be an effective forum to tackle construction issues because all key industry sectors are represented. The Foundation has sponsored and will continue to sponsor workshops aimed at achieving a consistent and uniform level of quality management across the pipeline construction industry.

The Foundation also has successfully addressed similar challenges in other areas, including environmental construction requirements promulgated by the Federal Energy Regulatory Commission, project permitting and pipe quality. The Foundation will publish five white papers related to QMS in early 2012, each addressing different elements of improved construction practices. These Foundation white papers are:

- Overview of Quality Management Systems – Principles and Practices for Pipeline Construction
- Pipeline Construction, Fabrication, and Testing – Training Guidance for Construction Workers and Inspectors for Welding and Coating
- Best Practices of Field Applied Coatings
- Best Practices in Applying API 1104, Appendix A
- Standards for Procurement and Installation of Field Segmented Bends

Question M.1

What standards and practices are used within the pipeline industry to assure quality? *Do gas transmission pipeline operators have formal QMS?*

There are a large number of standards and practices used within the industry to assure quality, including those referenced in 49 CFR Section 192.7. In addition to these, there are numerous additional standards and practices used by the industry.

INGAA members do have formal QMS and more broadly, management systems for verifying pipeline integrity. As stated above in the preamble to this section, there is a desire to broaden the application of management systems in verifying pipeline integrity. In addition, operators recognize the value of integrating the procedures and specifications used by different elements of the natural gas pipeline community, e.g., manufacturers and operators, into QMSs. For example, a QMS provides lifecycle management of line pipe and appurtenances. A detailed examination this QMS reveals not only that the system assures quality, but also that the system heavily focuses on the matters explored in topic D: the collection, validation, and integration of pipeline data.

As an example, QMS for line pipe and appurtenances, such as valves and fittings, is designed to manage, validate and document the quality of these materials throughout their lifecycle. Working with the operator, the pipe manufacturer creates a specifications and procedures document that establishes key control parameters for each step in manufacturing. The manufacturer and operator work together to develop a quality assurance plan, also known as an inspection and test plan, which defines how materials will be inspected during manufacturing. These plans specify the type of testing and inspection that occur at each step, the acceptance criteria, and the documentation requirements. Pipe or appurtenances that do not meet plan specifications at any point is subject to being removed from production.

As another example, the manufacturing elements of the QMS dovetail with operators' procedures for pre-installation testing and post-installation surveying. At the pre-installation stage, operator procedures define how hydrostatic pressure tests will be conducted and specify periodic recalibration standards to ensure the hydrostatic pressure test equipment is yielding results that are valid. Post-installation procedures define how leak surveys will be conducted and set recalibration standards for leak survey instruments.

At every stage within the QMS, including pipeline maintenance and integrity work and failure investigation, manufacturer and operator procedures include data validation and documentation requirements. As test and performance data is acquired and validated, it is loaded into operators' records management systems, forming a database that manufacturers, operators and others reference on an ongoing basis to continually improve product quality and public safety.

Efforts to expand industry use of QMS continue recognizing issues that arose during the pipeline construction boom of 2007 to 2009. In 2010, The INGAA Foundation, Inc. assembled a workgroup on QMS for pipeline construction projects. Workgroup participants noted that operators have varying approaches to quality management. In general, operators rely mainly on internal practices and specifications to establish quality management objectives and requirements for pipeline construction projects. Workgroup participants also noted that internal company practices include quality assurance/quality control processes to validate the conformance of construction activities to established requirements.

Operators have in place key elements of a formal QMS, as outlined in the ISO (9001:2008 / 29001:2010) and API (Spec Q1) quality management standards. API published Spec Q2, Specification for Quality Management System Requirements for Service Supply Organizations for the Petroleum and Natural Gas Industries, in December 2011. INGAA Foundation members now have this reference standard to apply within their QMS as is relates to service providers, contractors and suppliers.

Question M.2

Should PHMSA establish requirements for QMS? If so, why? If so, should these requirements apply to all gas transmission pipelines and to the complete life cycle of a pipeline system?

INGAA recommends that PHMSA not establish requirements for QMS at this time. As described above there is a tremendous amount of work ongoing to improve quality management. PHMSA may wish to adopt consensus standards at some point in the future as this work comes more to fruition. There are overarching standards identified above such as API Spec Q1 and Q2 that could be incorporated by reference.

Question M.3

Do gas transmission pipeline operators require their construction contractors to maintain and use formal QMS?

Are contractor personnel that construct new or replacement pipelines and related facilities already required to read and understand the specifications and to participate in skills training prior to performing the work?

INGAA members apply quality management processes to various aspects of their pipeline construction projects, including having contractors conform to specified requirements. This includes the establishment of project specifications, procedures and the development and execution of related training; however, this varies from one operator to another. There is room to establish a more structured approach to QMS for operators and construction contractors, which will yield more uniform and consistent results on projects.

Question M.4

Are there any standards that exist that PHMSA could adopt or from which PHMSA could adapt concepts for QMS?

As detailed in the general response to this topic, The INGAA Foundation is planning to release several white papers related to QMS for pipeline construction projects in the near future. These papers provide excellent best practice guidance on ways to apply QMS both generally and specifically to pipeline construction projects and key activities like welding, non-destructive examination and field application of coating. Several standards, including ISO 9001:2008 (Quality Management Systems), ISO 29001:2010 (Oil and Gas) and API Spec Q1 (Oil and Gas), exist as general references for QMS.

Question M.5

What has been the impact on cost and safety in other industries in which requirements for a QMS have been mandated?

Although difficult to quantify, QMS have been demonstrated to reduce risk. For example, QMS deliver value to projects and organizations by achieving consistent conformance to established quality standards and specifications and by reducing rework and unexpected construction issues. The keys to a successful QMS are simplicity, empowerment, accountability and ease of implementation.

Question M.6

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

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Topic N – Exemption for Facilities Installed Prior to 1970

The first federal pipeline safety regulations were established in 1970. Gas transmission pipelines had existed for many years prior to this, some as early as 1920. By 1970, many of these pre-regulation pipelines had operated safely for years at pressures higher than would have been allowed under the new regulations. To preclude a required reduction in the operating pressure of these pipelines, PHMSA's predecessor included a regulation allowing pipelines to operate at the highest actual operating pressure to which they were subjected during the five years prior to July 1, 1970. Safe operation at these pressures was deemed to be evidence that operation could safely continue.

This exemption is still in Part 192, at Section 192.619(a)(3).[19]

As an appendix to its November 2, 2011, policy-level comments on the ANPRM, INGAA provided a white paper describing FFS and proposing a protocol for establishing FFS for pre-regulation pipe. The essence of the FFS protocol is detailed in a two-page flow chart, which is reproduced at the end of this general response.

The FFS protocol evaluates the findings from work on pre-regulation pipe in HCAs and then relies on a risk-based approach, focused on protecting people, to determine testing beyond HCAs. The FFS protocol is data driven. The operator must either produce adequate records verifying a pipeline's FFS or reconfirm its FFS by strength testing or utilizing an alternative technology. Following the FFS protocol would meet the requirements for establishing maximum allowable operating pressure under the flexible approach required by Section 23 of the pipeline safety reauthorization act.[20]

Implementing the FFS protocol will require time to manage customer service impacts and acquire necessary resources. It also involves setting priorities for taking actions and performing tests and inspections. Pipeline segments within HCAs that have incomplete strength test records will carry a higher priority in this regard.

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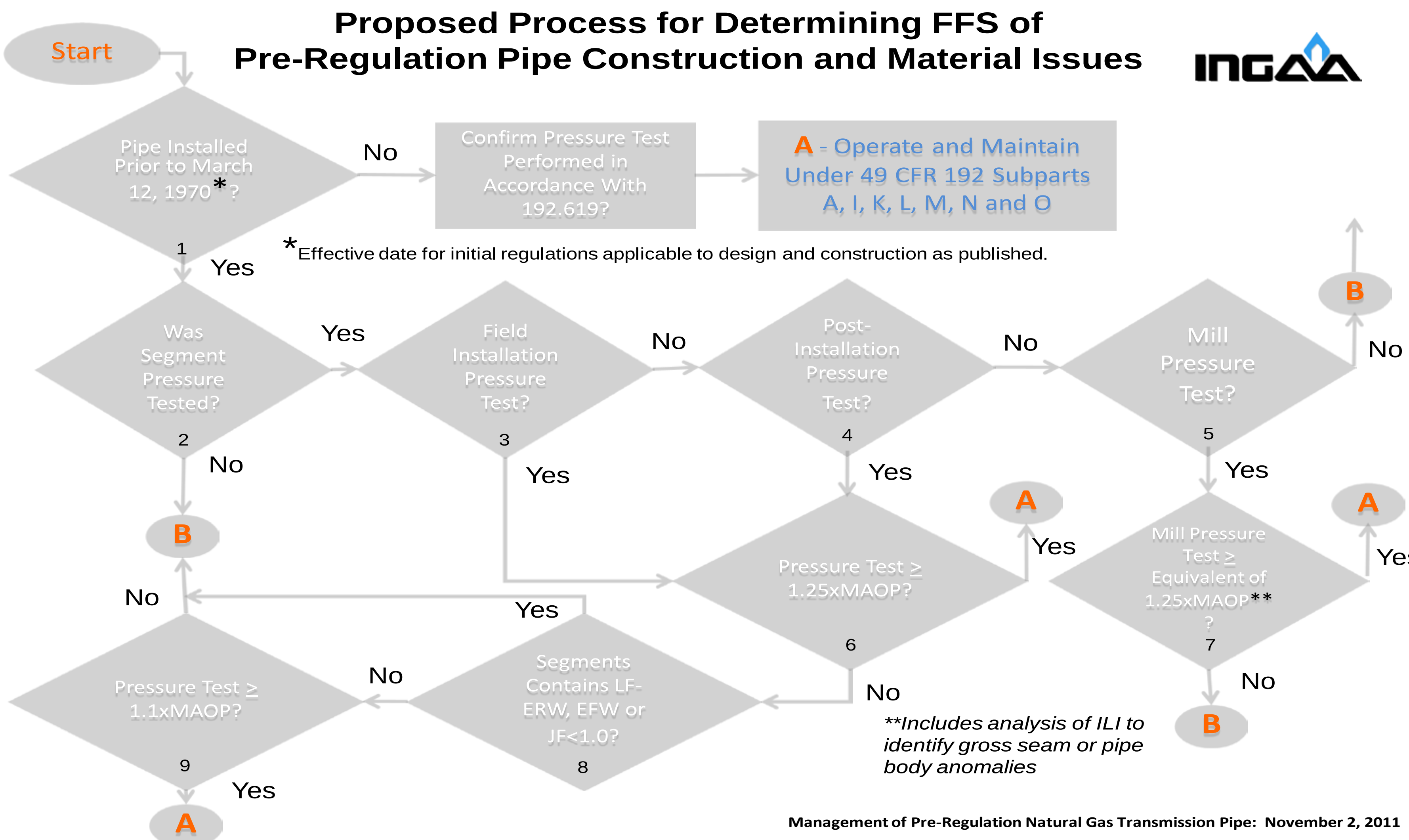
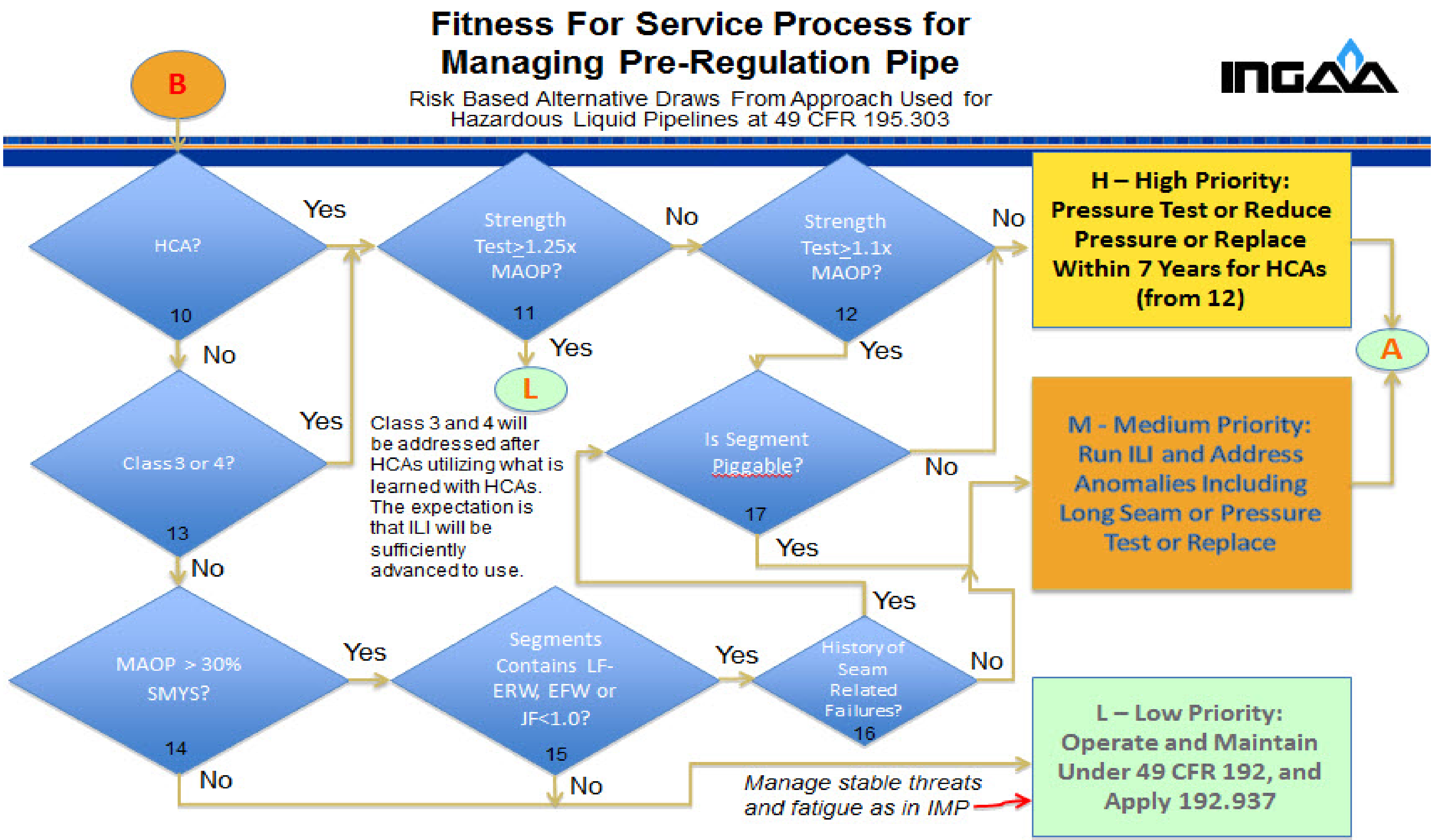
19 49 C.F.R. § 192.619(a)(3). The only amendment to Section 192.619(a)(3) was to accommodate some onshore gathering pipelines that were reclassified as transmission pipelines. The amendment allowed operators to establish the MAOP for those pipelines at the highest actual pressure experienced in the five years before the reclassification.

20 Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub.L. 112-90 § 23.


Proposed Process for Determining FFS of
Pre-Regulation Pipe Construction and Material Issues
Start
Pipe Installed Prior to March 12, 1970*?
1
No
Yes
Confirm Pressure Test Performed in Accordance With 192.619?
A - Operate and Maintain Under 49 CFR 192 Subparts A, I, K, L, M, N and O
*Effective date for initial regulations applicable to design and construction as published.
Was Segment Pressure Tested?
2
Yes
No
B
Field Installation Pressure Test?
3
No
Yes
Post-Installation Pressure Test?
4
No
Yes
Mill Pressure Test?
5
No
Yes
B
Pressure Test ≥ 1.25xMAOP?
6
Yes
No
A
Mill Pressure Test ≥ Equivalent of 1.25xMAOP**?
7
Yes
No
A
B
Segments Contains LF-ERW, EFW or JF<1.0?
8
Yes
No
Pressure Test ≥ 1.1xMAOP?
9
No
Yes
A
**Includes analysis of ILI to identify gross seam or pipe body anomalies
Management of Pre-Regulation Natural Gas Transmission Pipe: November 2, 2011



LF-ERW is low frequency electric resistance welded; EFW is electric fusion or flash welded; and JF is joint factor as defined at 49 CFR 192.113

Work In Progress: January 12, 2012 Version

Question N.1

Should PHMSA repeal provisions in part 192 that allow use of materials manufactured prior to 1970 and that do not otherwise meet all requirements in part 192?

The suitability of materials and their FFS cannot be determined solely by the manufacture date or whether it meets all current requirements in Part 192.[21] Some pre-regulation materials should not be used. Other materials, such as seamless pipe, however, may be virtually identical to modern materials and completely suitable for use. As with pipes generally, the key safety question for materials is fitness for service.

The FFS of pre-1970 material is determined by its properties, strength test history, condition, and other factors. An operator can manage the integrity of pre-1970 material over its lifecycle by implementing installation, testing, operation and maintenance procedures appropriate to the type of material and its known properties; and by using conservative assumptions when the properties of a specific material cannot be determined. PHMSA therefore should not repeal the part 192 provisions that allow operators to use materials manufactured prior to 1970 and that do not otherwise meet all part 192 requirements.

Question N.2

Should PHMSA repeal the MAOP exemption for pre-1970 pipelines?

Should pre-1970 pipelines that operate above 72% SMYS be allowed to continue to be operated at these levels without increased safety evaluations such as periodic pressure tests, in-line inspections, coating examination, CP surveys, and expanded requirements on interference currents and depth of cover maintenance?

The maximum allowable operating pressure (MAOP) exemption pre-regulation pipe should not be repealed; instead, PHMSA should allow the FFS protocol, detailed in the general response to this topic, to determine which pre-regulation pipes can continue to be operated safely and reliably.

The safety performance of grandfathered pipelines operating above 72 percent SMYS is as good as or better than overall industry performance. PHMSA references this safety performance in the preamble of the 2008 Final Rule *Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines* (Docket #PHMSA–2005–23447). As noted by PHMSA in this rulemaking, the safety record of these pipelines can be attributed to aggressive inspection and maintenance practices.

[21] On a broader note, INGAA believes PHMSA is largely correct in assuming that much of the warehoused or stocked or emergency pipe manufactured prior to 1970 has probably been used or scrapped in the ensuing 40-plus years.

To help assure their continued fitness for service, pre-regulation pipes operating above 72 percent SMYS should be subject to a comprehensive integrity management program that includes:

- A one-time strength test to 1.25 x MAOP for all pipelines in Class 3, Class 4 and HCA. Many of the "grandfathered" pipelines operating at and above 72 percent SMYS have already been strength tested to levels providing a safety margin commensurate with operation at these higher stress levels (specifically, a margin of 1.25 times MAOP). For these strength-tested lines, the incident data do not support a periodic hydrostatic pressure test requirement.
- In-line inspection and response to anomalies in accordance with ASME/ANSI B31.8S regardless of HCA status.
- Cathodic protection (CP) surveys and/or interference surveys where in-line inspection results or other data indicate corrosion is an issue. Interference surveys may also be warranted where new facilities, such as high-voltage power lines or third party pipelines, are installed in proximity to pipelines operating above 72 percent SMYS.
- Evaluation of coating condition when CP levels cannot be maintained by other means, such as adjusting rectifiers, adding ground beds or anodes, installation of linear anodes, etc.
- A comprehensive damage prevention program to prevent first-, second- and third-party damage.
- Depth of cover maintenance where a threat analysis indicates it will have a positive effect on pipeline safety.

Questions N.3 and N.4

Should PHMSA take any other actions with respect to exempt pipelines? Should pipelines that have not been pressure tested in accordance with subpart J be required to be pressure tested in accordance with present regulations?

If a pipeline has pipe with a vintage history of systemic integrity issues in areas such as longitudinal weld seams or steel quality, and has not been pressure tested at or above 1.1 times MAOP or class location test criteria (§§ 192.505, 192.619 and 192.620), should this pipeline be required to be pressure tested in accordance with present regulations?

While some pipelines are pre-regulation and others are post-regulation, no interstate gas transmission pipelines are exempt from regulation. In general, the provisions of Subparts B, C, D, E, F, G, H and J do not apply retroactively because they apply primarily to materials, design and construction activities. In contrast, the provisions of Subparts A, I, K, L, M, N and O generally apply retroactively or continuously to all transmission pipelines. Changes in a pipeline, such as class location changes, also may require the application of some of the provisions of Subparts B, C, D, E, G and J.

The issue of strength testing is discussed at length in the general response to this topic and Topic J: the key safety question is fitness for service and the way to establish fitness for service reliably and efficiently is to employ the FFS protocol.

If a segment has a history of seam-related failures and can accommodate in-line inspection (ILI), the segment can be inspected using appropriate ILI technology. However, if it cannot accommodate such inspection, or if appropriate ILI technology is not available, it must be strength tested. Operators will continue to have the option of strength testing pipelines even if they are piggable.

Question N.5

If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

A general response to this question and its counterparts in the other ANPRM topics is provided in the overview.

Appendix 1: The Benefits of Performance-Based Regulation

Overview

At several points in the ANPRM, PHMSA asks whether it should be taking a more prescriptive approach to pipeline safety regulation, either by imposing more prescriptive standards than currently exist or by imposing prescriptive standards in areas currently subject to more open-ended, performance-based regulation. INGAA strongly urges PHMSA to expand its use of performance-based regulation for several reasons:

- Performance-based regulation recognizes and incorporates technological advances more quickly, fostering safety innovation.
- Performance-based regulation supports proactive, multidimensional planning, operations and accountability, consistent with today's business practices.
- Performance-based regulation has an established track record of success as illustrated several federal agencies' highly regarded regulatory programs and documented through industry studies.

Properly applied, a performance-based regulatory approach can reap these benefits without compromising public safety.

Performance-Based Safety Regulation Is More Nimble

When it first promulgated Part 192 in 1970, PHMSA's predecessor adopted the majority of ASME/ANSI B31.8, a set of standards that a majority of the natural gas pipeline industry deemed useful in achieving a common level of safety performance in the design, construction, operation and maintenance of natural gas transmission pipelines. Although these practices were often driven by risk-based thinking, when they were assembled into ASME/ANSI B31.8 many of them were translated into minimum prescriptive standards, which continue in Part 192 today.

Experience demonstrates that prescriptive regulatory standards cannot keep up with technological advances. ASME/ANSI B31.8 has been updated a number of times to incorporate new processes and technologies. When updates have been released, PHMSA and its predecessors have worked to incorporate the ASME/ANSI B31.8 revisions into Part 192. However, Part 192 can be updated only through a rulemaking proceeding, and rulemaking proceedings are inherently lengthy. Where prescriptive regulations are employed, the lag between technological innovation and regulatory change is unavoidable, and in many cases this unavoidable lag inhibits the development and adoption of technologies and processes that may improve safety performance.

There is no lag in performance-based regulation. The regulation identifies an objective to be achieved, leaving the regulated community to determine the means for achieving it. Technological advances do not change the identified regulatory objective, so industry can adopt them immediately, without waiting for the rulemaking process to catch up. Where prescriptive standards inhibit innovation, performance-based standards foster innovation by encouraging advances that allow performance objectives to be achieved more effectively and efficiently.

Performance-Based Safety Regulation Supports Proactive, Multidimensional Risk Mitigation

Beginning in the 1990s and continuing through PHMSA's adoption of the various IMPs, policy makers have identified the need to be more proactive and innovative in managing safety, and, specifically, in risk mitigation risk. Even then, the need for something beyond the existing requirements was evident.

Prescriptive regulations emphasize conformity over creativity, prescribing detailed process requirements enforced through inspections and the prospect of remedial action. By specifying decision the criteria an operator must follow, prescriptive regulations necessarily imply that an operator's existing process for making safety decisions is inadequate. Compliance is essentially reactive and one-dimensional.

As the IMPs illustrate, performance-based regulation concentrates more on the processes comprising risk mitigation than the achievement of prescribed parameters. In response to the performance-based provisions of the integrity management regulations, operators have developed customized, multi-layered processes to identify risks and defend against them. Standing alone, each process may have gaps, but taken together, taken as a coordinated, comprehensive and integrated set, the processes merge into a strong set of protections. It is the set of actions and protections, operating as a unified system, that should deliver the greatest risk reduction when properly executed.

More can be done. Prescriptive regulations undermine the benefit of proactive and multidimensional risk assessment and remediation. Wherever possible these regulations should be replaced with performance-based standards that will allow a more complete integration of risk mitigation processes and an even greater involvement of all operator personnel. Operators have realized that IMP enhances not only safety but business performance, too. A performance-based approach keeps this momentum and helps operators be innovative and proactive.

Performance-Based Safety Regulation Works

The performance-based elements of PHMSA's integrity management regulations are similar to highly regarded risk mitigation programs at other federal agencies:

- The Process Safety Management System (PSM) adopted by the Occupational Safety and Health Administration
- The Risk Management Process (RMP) adopted by the Environmental Protection Agency
- The Safety Management System (SMS) adopted by the Federal Aviation Administration

Experience with these complex, high-risk industrial operations prompted these diverse regulators to choose risk performance-based approaches over prescriptive approaches to improve safety. The same is true for PHMSA. During the latter 1990s, PHMSA was active in promoting risk management demonstration programs, where pipelines added flexible practices and procedures on top of the prescriptive Part 192 regulations. Today's IMPs trace their origin to these demonstration programs. In fact, at the NTSB's recent San Bruno pipeline hearing, several members called IMP the pipeline industry's SMS.

Industry studies document the benefits of performance-based approaches to safety regulation. In the mid-1990s, the American Institute of Chemical Engineers surveyed 25 companies on the benefits of a systems approach to safety. Respondents were gas plants, chemical facilities and refineries, all with operations similar to pipelines and all subject to OSHA's PSM and EPA's RMP. Respondents ranged in size from small companies to those with annual revenues of up to $10 billion per site.

Half of the respondents said that even in the very early years following regulation the process developed under PSM and RMP paid for themselves. The primary benefit was avoided incidents, which translated into avoided impacts on operations; avoided environmental damage; avoided personal injuries, hospitalizations and deaths; avoided litigation; and avoided evacuations and sheltering in place. Some respondents cited a rebirth in innovative thinking as an important benefit. Additional benefits were improvements in product quality and productivity, lower insurance cost and reduced workman's compensation payments. Similar benefits will be gained by preserving IMP as a non-prescriptive regulation and allowing integrity management to expand and improve.

The Path Forward

The benefits of expanded performance-based regulation are clear. The question is how to frame the regulations to foster risk-mitigation and provide regulators a means to audit it effectively. The next generation of performance-based, integrity management regulation should focus on three areas: the adequacy of the safety management process, the adequacy of the resulting layers of protection and the adequacy of measures and processes for assuring accountability.

Adequacy of Processes

Regulations should ensure that an operator has the goals, planning, documentation and evaluation processes necessary to execute safety decisions well. PHMSA should provide more explicit criteria and guidelines documenting operators' safety decision processes. Potential areas for performance-based, process regulations include whether there is appropriate management commitment and involvement, whether an operator is using data appropriately to support risk assessment conclusions, whether there is a system in place for taking action to minimize risks and mitigate failures, and whether there is an evaluation process to determine if measures to prevent or mitigate risk are adequate.

Adequacy of the Layers of Protection

Recognizing that risk mitigation is a multi-layered process, performance-based regulation should examine whether these processes work together to deliver improved safety decisions. Using performance metrics, the regulations should place a premium on seamless process integration.

Accountability under Performance-Based Safety Regulation

There are ways to preserve the benefits of proactive thinking, encouraging innovations and flexibility in alternative options, while addressing the challenges of holding operators more accountable through the inspection and enforcement process. For example, INGAA recently adopted five guiding principles for pipeline safety. These principles act like a code of conduct, specifying industry commitments and guiding industry behavior. Having these guiding principles promotes better operating practices, good quality consultation among operators and benchmarking.

Performance-based accountability regulations would require operators to demonstrate how they adhere to these principles and the effectiveness of the resulting mitigation efforts. For example, operators could be required to measure the effectiveness of continuous improvement efforts.

Appendix 2: Definition and Application of Fitness For Service to Gas Pipelines

What Is Fitness for Service (FFS)?

FFS is the ability of a system or component, in this case a pipeline system or portion thereof, to provide continued service, within established regulations and margins for safety, until the end of some desired period of operation or scheduled inspection and reassessment. FFS is a well-accepted approach to evaluate flaws that may be injurious to integrity in equipment, including pipelines, to determine acceptability for continued operation. The FFS approach is used extensively throughout the world in transportation, energy, construction and many other industries.

FFS evaluations for pipelines rely on a detailed threat assessment, risk analysis, the selection of appropriate inspection techniques, and flaw acceptance criteria. Results from FFS evaluations provide guidance on equipment inspection intervals and shape decisions to run, alter, repair, monitor, or replace equipment.

FFS was the key criteria behind the development of the first ASME/ANSI B31.8 consensus standards. Through prescriptive recommendations, those initial standards laid out how a pipeline should be designed, constructed, operated and maintained so the pipeline could be judged fit for service. Eventually, PHMSA and its predecessors imported many of these practices into 49 CFR Part 192 as the Minimum Pipeline Safety Standards in effect today. Subsequent ASME editions modified and improved the initial standards and methods. The most recent version, ASME/ANSI B31.8S, is the latest step in improving FFS.

What Data and Information Do FFS Evaluations Rely On?

FFS evaluations employ a review of historical performance, among other things, to identify threats that have and could pose a risk to the safe operation of the facility. Technical analyses, including stress analysis and fracture mechanics, are then employed to evaluate each of the threats and the associated physical flaws (for example, locally thin areas and cracks, or damage such as dents, bulges, and distortions or conditions such as outside/dynamic loads.

Have FFS Evaluations Been Applied in Other Industries?

The methods currently used in FFS evaluations have been applied in the petroleum refining, petrochemical, nuclear, paper and steam electric power industries since the 1980s. One of the first acknowledged incident threat specific applications was actually in the pipeline industry with the development of B31G, a method for calculating the remaining strength of pipelines in areas with metal loss, first published in 1984.

In the absence of federal regulations covering analysis of complex systems, subject matter experts across of number of these industries decided to create a compendium of the methods to address a breadth of defect types in the late 1990s. The document was first published in

2000, as American Petroleum Institute (API) Recommended Practice (RP) 579. It was updated in 2007 through a joint effort between API and ASME and published as API RP 579-1/ASME FFS 1.

API RP 579-1/ASME FFS 1 provides for three levels of analysis based on the amount of available data, depth of knowledge, and the degree of conservatism desired:

- Level 1 is used for rapid evaluation, requires the least number of measurements, the few key parameters, and is quite conservative, i.e., it provides for a relatively large safety factor.

- Level 2 requires a deeper analysis and therefore more measurements to establish the actual remaining cross sectional area. It is generally less conservative than Level 1 because of the added depth of analysis and the additional knowledge and information required.

- Level 3 relies on stress analysis to provide an even more in-depth examination of metal loss. Level 3 requires an intensive quantification of measurement, loading stresses, and material properties, to meet the detailed needs of a finite element analysis.

Is Evaluating FFS Different for the Pipeline Industry?

Yes and no. The process is the same, but the setting is not. In every other industry where FFS evaluations are applied, the equipment being evaluated is generally within a fence line. This means that the environment around the equipment including piping can readily be monitored and quite often controlled.

FFS evaluations for pipelines are different in that they rely on a detailed threat assessment, risk analysis, selection of appropriate inspection techniques, and acceptance criteria for non-injurious defects.

Where other facilities subject to FFS assessment generally are accessible and geographically contained, pipelines typically are buried, traversing linearly through the countryside, passing through a variety of soil types and geological conditions while encountering flooding, storm damage and other environmental challenges. Burying minimizes some environmental threats, but burying also subjects pipelines a variety of ground movements such as subsidence, vibration effects and even damage through direct contact and disturbance from excavation work.[1]

[1] While the NTSB concluded that pipe bursting activities nearby the transmission line did not contribute to the San Bruno failure, the fact that it was the subject of significant fact gathering and analysis in their investigation provides a key lesson learned: Pipeline operators must be aware of excavation and construction work around their facilities, and of equal importance, entities planning to work around underground facilities, including pipelines, must contact One Call.

Evaluating a pipeline's FFS thus requires an operator not only to understand threats to integrity, but also to assess a pipeline environment spanning tens, hundreds and often thousands of miles.

Risk assessment is essential in prioritizing and managing preventive and mitigation measures. A complete understanding of the threats to integrity is essential including the potential contribution of the surrounding environment. Risk assessment is most effective when available data, including data specific to individual operating environments, is examined as an integrated whole. FFS evaluations use data from assessments, as well as from routine maintenance activities, often to identify areas warranting further investigation through excavation and inspection. FFS methods are used in these excavations to evaluate fitness based on a pipeline segment's actual, as-found condition.

Assessment tools and engineering methods are imperfect, so an operator will integrate the data collected during an excavation with other information (such as coating condition and as-found pipe to soil potentials) to form the analytical foundation for making decisions on preventive and mitigation measures. Finally, as part of a continuing desire to improve processes and achieve the target of zero incidents, the as-found conditions and results of evaluations are fed back into the threat assessment and risk analysis processes. Lessons learned from the findings and analyses are shared throughout the organization and, where applicable, throughout the industry.

Examples of FFS Evaluations for Metal Loss/Corrosion

The corrosion evaluation method, ASME B31G, is a Level 1 type method. It is used for rapid evaluation of a concern; it requires data for just a few key parameters; and it is quite conservative in that it provides for a relatively large safety factor. RSTRENG applied in two parameter mode is also a Level 1 method. RSTRENG applied using a metal loss profile (sometimes referred to as a "river bottom" analysis) is a Level 2 method. API RP 579-1/ASME FFS 1, which is described in detailed above, is a Level 3 method.

Pipeline operators also apply a variety of techniques to assess a pipeline segment's physical condition. ILI with high-resolution magnetic flux leakage sensors are used to identify, characterize and measure metal loss. High-resolution geometry sensors are used to identify, characterize and measure deformations in pipelines.

The FFS evaluation results in an estimate of a segment's remaining strength, which can be characterized by a predicted failure pressure ratio. Operators use the predicted failure pressure ratio, a measure of the margin above the MAOP, and the calculated pipeline strains to determine whether to excavate. Where an excavation is made to evaluate the metal loss, an indentation or both, FFS methods are then applied using actual measurements to determine a safe operating pressure. These comparative measurements are then used to improve ILI technology. Where excavation is not warranted, the operator uses the predicted failure pressure ratio to define an interval where the segment will be monitored pending the next assessment.

It is important to understand that operators do not rely simply on one measure or one tool. The corrosion control methods in ASME/ANSI B31.8, which are in large part incorporated into 49 CFR 192 Subpart I, provide for “layers of protection” from failure.

The concept of “layers of protection analyses” or LOPA was first described in the chemical industry in the mid-1990s. It was recognized as a way of demonstrating while failures are so infrequent, while assessing the rare failures both to diagnose what occurred and to identify measures to prevent recurrence. LOPA was first captured in a book entitled, Inherently Safer Chemical Processes, published by the Center for Process Safety (part of the American Institute of Chemical Engineers). LOPA approach “designs in” redundancy, so failure is prevented even if one layer of defense is weakened or lost.

FFS Applied to Environmental-Related Cracking

There are FFS methods available for evaluating environmental-related cracking, including stress corrosion cracking (SCC). SCC direct assessment (DA) prioritizes locations along the pipeline for investigative excavations. Nondestructive evaluations and measurements on the exposed pipe provide the inputs for FFS evaluations that estimate a segment’s remaining strength and predicted failure pressure ratio. As was the case with metal loss and indentations, the operator uses the results of the FFS evaluation to determine whether to excavate and, where there is a sufficient margin of safety, to define a future interval to the next assessment.

FFS Applied to Pre-Regulation Pipe

There are approximately 179,000 miles of on-shore natural gas transmission pipe installed prior to pipelines safety regulations (1970) out of a total 300,000 miles. INGAA operates approximately two-thirds of this mileage.

INGAA conducted a survey of its members in April 2011 and found that about 91 percent of the pipeline mileage located within HCAs has readily available documentation showing that the segment was strength tested after construction at least once. Outside of HCAs, the corresponding figure was about 77 percent. This particular survey result did not include strength testing of the pipe that was conducted in the pipe mills during the manufacturing process. This process will be defined in detail in the White Paper titled “Management of Pre-Regulation Natural Gas Transmission Pipe”. A process flow diagram within the paper has been developed by the INGAA membership to organize the myriad of records that can be used singularly or in unison to verify that the pipe was strength tested at one time during its lifetime to address construction and material defects. This multipath process also establishes alternative ILI processes that can be used to verify the quality of pipe utilizing developing technology and available records as a surrogate for the strength test.

Appendix 3: Exclusive Federal Safety Jurisdiction re Interstate Natural Gas Storage

The Pipeline Safety Act (PSA)[1] authorizes the Secretary of Transportation to set and enforce safety regulations for natural gas pipeline facilities. Further, the PSA specifically preempts the application of state safety standards to interstate natural gas pipeline facilities by stating that a "State authority may not adopt or continue in force safety standards for interstate pipeline facilities or interstate pipeline transportation."[2] The federal courts have consistently held that any such attempt to regulate safety for interstate pipeline facilities is preempted. For example, in *ANR Pipeline Co. v. Iowa State Commerce Commission*[3] the Eighth Circuit held that the Natural Gas Pipeline Safety Act (NGPSA)[4] expressly preempted all state regulation of safety matters for interstate pipelines. The court held that the Iowa law was preempted because (1) the NGPSA expressly preempts state regulation of safety in connection with interstate gas pipelines, (2) the legislative history of the NGPSA expresses congressional intent to prevent state regulation in this area, (3) the NGPSA leaves nothing to the states in the area of substantive safety regulation of interstate pipelines and (4) Congress occupied the entire field, leaving no room for any state regulation.[5]

It is clear that interstate storage facilities are interstate pipeline facilities that are subject to the PSA and thus exclusively regulated for safety by the Secretary of Transportation.[6] Section 60101(a)(6) of the same statutes defines "interstate gas pipeline facilities" as facilities that are used to transport natural gas and that are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). In pertinent part, section 60101(21)(A)(i) of federal pipeline safety statute defines "transporting gas" as "gathering, transmission, or distribution of gas by pipeline or the storage of gas , in interstate or foreign commerce." These definitions make clear that interstate storage facilities are subject to federal jurisdiction under the PSA and not state jurisdiction. It is settled law that interstate storage facilities transport natural gas, with the Supreme Court finding that storage is integral to moving natural gas from states where it is produced to states where it is consumed.[7] As for being subject to FERC jurisdiction, interstate natural gas storage facilities are constructed and placed in service under certificates of public convenience and necessity which FERC issues in accordance with section 7(c) of the Natural Gas

[1] 49 U.S.C. § 60101 *et seq.*

[2] 49 U.S.C. § 60104(c).

[3] 828 F. 2d 465 (8th Cir. 1987).

[4] In 1994 the PSA recodified the NGPSA and the Hazardous Liquids Pipeline Safety Act.

[5] 828 F. 2d 468-470.

[6] *Colorado Interstate Gas Co. v. Wright, et. al.*, 707 F.Supp.2d 1169 (D.Kan. 2010).

[7] *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 295 n. 1 (1988) (citing *Columbia Gas Transmission Corp. v. Exclusive Gas Storage Easement*, 776 F.2d 125, 129 (6th Cir. 1985)).

Act.[8] These FERC certificates set the metes and bounds of interstate storage facilities, authorize their operation, and require certificate holders to meet a variety of FERC requirements, including safety standards.[9] Today there are over 200 FERC-certificated storage fields operating in 24 states.[10]

8 15 USC § 717f(c).

9 *E.g.,* 18 CFR § 157.14(a)(9)(vi).

10 "Jurisdictional Storage Fields in the United States by Location (Updated November 30, 2010," (FERC 2010), available at http://www.ferc.gov/industries/gas/indus-act/storage/fields-by-location.pdf. Since this list was assembled FERC has certificated additional storage fields.

Appendix 4: Management of Change

Background

Management of change (MOC) *is a systematic process … used to ensure that, prior to implementation, changes to pipeline system design, operations or maintenance are evaluated for their potential risk impacts, and to ensure that changes to the environment in which the pipeline operates are evaluated*. This is the definition provided in the ASME Supplement for Managing System Integrity of Gas Pipelines, ASME/ANSI B31.8S. This is one of four management systems addressed within ASME/ANSI B31.8S; the other three being:

- quality control/quality assurance
- performance measurement, and
- communication.

The team that developed the original management of change section in ASME/ANSI B31.8S included personnel from the petrochemical, petroleum refining, and coal and nuclear power generation industries. Ensuring that a broad range of experience with management of change was reflected in the development for pipelines was viewed as being essential. INGAA members have applied management of change for HCAs as stipulated at 49 CFR 192.911(k) since the regulations went into effect in 2004. Many members have applied management of change since publication of ASME/ANSI B31.8S in 2002 and even before that in many instances as they had adopted management of change across integrated energy companies. Management of change will be practiced as part of Control Room Management regulations at 49 CFR 192.631 that became effective on August 15, 2011.

When Does Management of Change Apply?

Section 11 of ASME/ANSI B31.8S requires formal management of change procedures to identify and consider the impact of changes to pipeline systems and their integrity. The expectation is that procedures should be flexible enough to accommodate major and minor changes including temporary, emergency and permanent technical, physical, procedural and organizational changes to the system.

Examples of changes considered in scope include changes:

- that may affect the consequence of an incident or likelihood of an incident (e.g., land use)
- the result from integrity management program inspection (e.g., changes to a CP program or operating pressure)
- that arise from operator decisions (e.g., to increase pressure to or near MAOP, or to change load patterns from steady state to cyclical)
- that are related to the system, equipment, procedures, processes and design.

There are eight required steps as part of executing management of change process under ASME/ANSI B31.8S. The eight steps are:

- reason for change
- authority for approving changes
- analysis of implications
- acquisition of required work permits
- documentation
- communication of change to affected parties
- time limitations
- qualification of staff

When Is Management of Change Not Required?

Not all activities require MOC, for example, replacing equipment “like for like” or “like in kind,” and INGAA has developed guidance on when to apply MOC. Our members have found that answering a series of questions has been helpful in evaluating the need to apply management of change. If the answer to any of the questions below is “yes” or “possibly yes,” then the change is subject to the MOC process. If all the answers are no, management of change is not required. If in doubt, proceed with the management of change process.

- Does the replacement equipment not match the original specification or current configuration or capabilities?
- Does the work involve the addition or deletion or equipment?
- Will the logic of operating, monitoring, control or safety systems change?
- Will plot plans, process and instrumentation diagrams, physical capacity, or secondary or emergency systems change?
- As a result of this change, is it possible for operating parameters to deviate from currently established limits?
- Could the change adversely affect the environment?
- Will the work require regulatory approval of changes to existing permits, plans, or programs?
- Is the change NOT addressed through established safe work practices or approved site-specific procedures?
- Is the change to the testing, inspection or maintenance programs?
- Does the action involve new or revised procedures or deviation from safe work practices?
- Is the change the result of a change in legal, regulatory, or company policy requirements?
- Does the change involve organization or personnel qualification changes?

Summary

INGAA members strive to apply the MOC process in more and more areas. New avenues for possible MOC application include:

- Staff and management review and assessment of safety impact
- Ensuring the management of change procedures remain viable and effective
- Ensuring that changes are documented
- Ensuring that operators use change documentation for continual refinement of their understanding of their systems and possible threats to system integrity.
- Communication to any affected parties per section 11 of ASME/ANSI B31.8S
- Qualification and refresher training of personnel, particularly for equipment.
- Documentation and communication of the application of new technologies

ASME/ANSI B31.8S requires that the management of change procedures:

- Are understood by the personnel that uses them
- Include a review procedure by staff and management including assessment of safety impact
- Integrate change-based updates into the integrity management program

Properly applied, a performance-based regulatory approach to MOC can reap these benefits without compromising public safety.

- Performance-based regulation recognizes and incorporates technological advances more quickly, fostering safety innovation.
- Performance-based regulation supports proactive, multidimensional planning, operations and accountability, consistent with today's business practices.
- Performance-based regulation has an established track record of success as illustrated several federal agencies' highly regarded regulatory programs and documented through industry studies.