

Distribution Integrity Management For LPG Operators

Michael Flock, Coler & Colantonio, Inc.

On December 4, 2009 the Final Rule for Distribution Integrity Management (DIMP) was published in the federal register by Pipeline and Hazardous Materials Safety Administration (PHMSA). The regulations are the result of passage of the “Pipeline Safety Improvement Act of 2002” and the “PIPES Act of 2006”. Industry was introduced to Integrity Management regulations with Transmission IM regulations passed in 2004 for high pressure pipelines. The DIMP regulations are for gas distribution companies with a scaled down set of rules for small operators of propane systems and master meter systems.

The final rule created Subpart P of CFR 49, Part 192 “Gas Distribution Pipeline Integrity Management IM” and made revisions to 192.383 “Excess Flow Valve Installation”.

What You Need to Know

- DIMP will be enforced by State regulatory authorities.
- A Small LPG Operator is defined as an operator of a LPG distribution pipeline that serves fewer than 100 customers from a single source. §192.1001
- Operators must develop and implement a Distribution Integrity Management Program by August 2, 2011. §192.1005
- Excess flow valves are required on all new and replacement services to single family residences after February 2, 2010, if the service operates at 10 psig or greater throughout the year. Read §192.383 for additional conditions.
- Failure of compression couplings must be reported to PHMSA and State regulatory enforcement agencies. §192.1009
- The integrity program must have a written plan addressing six specific elements, at a minimum. §192.0015
 - 1) System Knowledge
 - 2) Threat identification
 - 3) Risk assessment and ranking
 - 4) Identify and implement measures to mitigate risk
 - 5) Measure performance, monitor results and evaluate effectiveness
 - 6) Periodic evaluation and improvement
- The operator must maintain IM records for 10 years.

DIMP Program/Plan Elements

A DIMP Program is the overall approach by an operator to ensure the integrity of its distribution system.

The DIMP Plan is the written explanation of the mechanisms or procedures the operator will use to implement its DIMP Program.

Knowledge of the System

Operators will need a database or written list of the facilities and pipes in their jurisdictional distribution systems. The database should include information about the pipe material and location. Additional information that can be included is: pipe coating material, pipe joint type, operating pressure, year of installation, leak history, corrosion history, one-call mark-out history, third party damage history, etc. The database will be the basis for the risk assessment element.

Operators who do not have complete knowledge of their system will be allowed to start their DIMP program with the knowledge they currently have, but their written plan must include provision for increasing their knowledge base in the future through normal activities conducted on the pipeline.

Identify Threats

As identified in the regulations, the primary threats to a distribution pipeline are:

- a. Corrosion
- b. Natural forces
- c. Excavation damage
- d. Other outside forces
- e. Material and weld failure
- f. Equipment malfunction
- g. Inappropriate operation
- h. Other

Evaluate and Prioritize Risk

Operators will need to develop a risk model incorporating the identified threats for each pipe.

Risk is defined as the product of the likelihood of a problem occurring and the consequence that could be caused by the problem if it occurs.

A risk model should produce a relative risk ranking for all facilities in the distribution system.

Most operators are simplifying risk assessment by grouping their facilities by similar characteristics such as: material, geographic region, operating system, etc. Risk assessment is then made based on the facility groups.

Identify and Implement Measures to Address Risk

The operator's program must address risk mitigation. Risk mitigation may include review and evaluation of damage prevention programs, leak management programs, accelerating various maintenance programs. Mitigation should be applied based on the risk assessment (highest risk group = highest priority).

Measure Performance, Monitor Results, and Evaluate Effectiveness

The operator's program must address measuring performance by monitoring the number of leaks eliminated or repaired on the distribution system, and the leak causes.

Periodic Evaluation and Improvement

The operator's program must address periodic review of the written plan content, and review of the program's effectiveness. The maximum re-evaluation period is 5 years. The operator must consider the results of performance monitoring in these evaluations.

Distribution Integrity Management Regulations Issued or Revised by PHMSA December 4, 2009

§ 192.383 Excess flow valve installation. (a) Definitions. As used in this section:

Replaced service line means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence.

(b) *Installation required.* An excess flow valve (EFV) installation must comply with the performance standards in §192.381. The operator must install an EFV on any new or replaced service line serving a single-family residence after February 12, 2010, unless one or more of the following conditions is present:

- (1) The service line does not operate at a pressure of 10 psig or greater throughout the year;
- (2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence;
- (3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or
- (4) An EFV meeting performance standards in §192.381 is not commercially available to the operator.

(c) *Reporting.* Each operator must, on an annual basis, report the number of EFVs installed pursuant to this section as part of the annual report required by §191.11.

[Amdt. 192–113, 74 FR 63934, Dec. 4, 2009, as amended at 75 FR 5244, Feb. 2, 2010]

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

Source: 74 FR 63934, Dec. 4, 2009, unless otherwise noted.

§ 192.1001 What definitions apply to this subpart?

The following definitions apply to this subpart:

Excavation Damage means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

Hazardous Leak means a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

Integrity Management Plan or *IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart.

Integrity Management Program or *IM Program* means an overall approach by an operator to ensure the integrity of its gas distribution system.

Small LPG Operator means an operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

§ 192.1003 What do the regulations in this subpart cover?

General. This subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator or a small LPG operator, must follow the requirements in §§192.1005–192.1013 of this subpart. A master meter operator or small LPG operator of a gas distribution pipeline must follow the requirements in §192.1015 of this subpart.

§ 192.1005 What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart?

No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in §192.1007.

§ 192.1007 What are the required elements of an integrity management plan?

A written integrity management plan must contain procedures for developing and implementing the following elements:

(a) *Knowledge.* An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(1) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

- (2) Consider the information gained from past design, operations, and maintenance.
 - (3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).
 - (4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.
 - (5) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.
- (b) *Identify threats.* The operator must consider the following categories of threats to each gas distribution pipeline: Corrosion, natural forces, excavation damage, other outside force damage, material, weld or joint failure (including compression coupling), equipment failure, incorrect operation, and other concerns that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.
- (c) *Evaluate and rank risk.* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.
- (d) *Identify and implement measures to address risks.* Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).
- (e) *Measure performance, monitor results, and evaluate effectiveness.*
- (1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:
 - (i) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(iv) Total number of leaks either eliminated or repaired, categorized by cause;

(v) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material; and

(vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

(f) *Periodic Evaluation and Improvement.* An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(g) *Report results.* Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by §191.11. An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

§ 192.1009 What must an operator report when compression couplings fail?

Each operator must report, on an annual basis, information related to failure of compression couplings, excluding those that result only in non-hazardous leaks, as part of the annual report required by §191.11 beginning with the report submitted March 15, 2011. This information must include, at a minimum, location of the failure in the system, nominal pipe size, material type, nature of failure including any contribution of local pipeline environment, coupling manufacturer, lot number and date of manufacture, and other information that can be found in markings on the failed coupling. An operator also must report this information to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

§ 192.1011 What records must an operator keep?

An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.

§ 192.1013 When may an operator deviate from required periodic inspections under this part?

(a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart.

(b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency. The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

(c) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

§ 192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?

(a) *General.* No later than August 2, 2011 the operator of a master meter system or a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph (b) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

(b) *Elements.* A written integrity management plan must address, at a minimum, the following elements:

(1) *Knowledge.* The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

(2) *Identify threats.* The operator must consider, at minimum, the following categories of threats (existing and potential): Corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.

(3) *Rank risks.* The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.

(4) *Identify and implement measures to mitigate risks.* The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.

(5) *Measure performance, monitor results, and evaluate effectiveness.* The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.

(6) *Periodic evaluation and improvement.* The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(c) *Records.* The operator must maintain, for a period of at least 10 years, the following records:

(1) A written IM plan in accordance with this section, including superseded IM plans;

(2) Documents supporting threat identification; and

(3) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.