**65-407 PUBLIC UTILITIES COMMISSION**

**Chapter 420: SAFETY STANDARDS FOR NATURAL GAS AND LIQUEFIED NATURAL GAS FACILITY OPERATORS**

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**§ 1 General Provisions**

A. **Scope**

This rule applies to all operators of gas utilities defined in 35-A M.R.S. §102(8) "Gas utility," all operators of gas pipelines as defined in 49 C.F.R. Part 192 except liquid propane gas distribution systems, and all natural gas pipeline utilities as defined in 35-A M.R.S. §102(10) "Natural Gas Pipeline utility"; provided that this rule does not apply to interstate natural gas pipeline facilities or interstate pipeline transportation.

B. **Applicable Codes**

1. The minimum standards for operation of natural gas and liquefied natural gas pipeline facilities are established by adoption of the following federal regulations, including amendments thereto:

a. The provisions of Parts 191, 192, and 193 of Title 49 of the Code of Federal Regulations (C.F.R.), including all amendments and revisions thereto, govern the design, fabrication, installation, inspection, reporting, testing, and the safety aspects of operation and maintenance of gas transmission and distribution systems, including gas pipelines, gas compressor stations, gas metering and regulating stations, gas mains, and service lines.

b. Title 49 C.F.R. Part 190, "Pipeline Safety Programs and Rulemaking Procedures," and Part 198, "Regulations for Grants to Aid State Pipeline Safety Programs," including all amendments and revisions thereto, govern certain enforcement, one-call system, and other matters for the MPUC's pipeline safety program, in concert with the provisions of this Chapter.

c. The provisions of 49 C.F.R. Part 199, including all amendments and revisions, which incorporate 49 C.F.R. Part 40 by reference, govern the drug testing inspection of operators of natural gas facilities.

2. Where Chapter 420 and Chapter 895 (Underground Facility Damage Prevention Requirements) establish more stringent requirements or requirements in addition to the federal pipeline safety regulations adopted pursuant to Section 1(B)(1)(a), (b) and (c) of this Chapter, the requirements set forth in Chapter 420 or Chapter 895 will apply.

3. Where this Chapter refers to "violations of this Chapter" or uses similar language, this means violations of Chapter 420 and the portions of Title 49 C.F.R. Parts 40, 190, 191, 192, 193, 198, and 199 incorporated above.

**§ 2 Definitions**

A. **Building.** "Building" means any structure that is regularly or periodically occupied by people.

B. **Chapter 130** "Chapter 130" means Chapter 130 of the rules of the MPUC, 65-407 C.M.R. ch. 130.

C. **Chapter 140.** "Chapter 140" means Chapter 140 of the rules of the MPUC, 65-407 C.M.R. ch. 140.

D. **Chapter 895.** "Chapter 895" means Chapter 895 of the rules of the MPUC, 65-407 C.M.R. ch. 895.

E. **Consolidated Rock.** "Consolidated rock" means rock that is firm and coherent, solidified, or cemented, such as granite, gneiss, limestone, shale, or sandstone that has not been decomposed by weathering.

F. **Critical Valve.** "Critical valve" means any valve whose use may be necessary for the safe operation of a distribution system.

G. **DIMP.** "DIMP" means an operator's Distribution Integrity Management Program written plan required as part of 49 C.F.R., Subpart P.

H. **Enclosure.** "Enclosure" means a protective structure that protects its contents from intrusion and/or weather.

I. **Gas.** "Gas" means natural gas, flammable gas, or gas which is toxic or corrosive including mixtures of propane and air when introduced to natural gas transmission and distribution systems, but not distribution systems dedicated exclusively to liquefied propane gas.

J. **Gas Safety Staff.** "Gas Safety Staff" means the MPUC Director of Consumer Assistance and Safety, the MPUC Gas Safety Manager, MPUC Pipeline Safety Inspectors, and any MPUC Staff Attorney or Utility Analyst assigned by the MPUC to regularly support the MPUC's pipeline safety program.

K. **Global Positioning System (GPS).** "Global positioning system" or "GPS" means a satellite navigation system used to determine the ground position of an object.

L **Independent Proctor.** "Independent Proctor" means a representative of an outside testing or qualifying organization or agency administering a given test, or, if testing is not administered by an outside organization or agency, a supervisor, manager, or consultant directly employed by the operator.

M. **Leakage Survey.** "Leakage Survey" means a survey of gas facilities employing industry accepted testing equipment and effective procedures, including atmospheric tests in available openings and bar holes to locate leaks in gas systems.

N. **Leak Progression Map.** "Leak Progression Map" means a map of the transmission and distribution system of the operator, drawn to a suitable scale, upon which there is indicated in a suitable code the leaks found to exist in the system during an indicated reporting period.

O. **Main.** "Main" means a distribution line that serves as a common source of supply for one or more service lines.

P. **MAOP.** "MAOP" means Maximum Allowable Operating Pressure pursuant to 49 C.F.R. §192.619.

Q. **Master Meter System.** "Master Meter System" means a pipeline system for distributing gas within a definable area, such as, but not limited to, a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system to supply gas using equipment operated by the ultimate consumer who either purchases the gas directly through a meter or by other means, such as by rents.

R. **MPUC.** "MPUC" means the Maine Public Utilities Commission.

S. **NFPA.** "NFPA" means the National Fire Protection Association, and any number following "NFPA" (e.g., "NFPA 54") refers to the applicable code or standard published by the NFPA.

T. **Operator.** "Operator” means a person who operates gas pipeline facilities on his or her own behalf, or as an agent designated by the owner. Operator includes all operators of gas utilities defined as a "Gas Utility" in 35-A M.R.S. §102(8), all operators of gas pipelines as defined in 49 C.F.R. Part 192 except liquid propane gas distribution systems, and all operators of natural gas pipeline utilities as defined as "Natural Gas Pipeline Utility" in 35-A M.R.S. §102(10).

U. **Pipeline System.** "Pipeline system" means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

V. **PHMSA.** "PHMSA" means U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration.

W. **Pipe Appurtenance.** "Pipe Appurtenance" means any instrument or equipment permanently affixed to a natural gas transmission line, main, or service line. Pipe appurtenances include, but are not limited to, valves, tees, and couplings.

X. **Prosecutorial Staff**. "Prosecutorial Staff" means MPUC Staff assigned as advocates in an enforcement proceeding under this Chapter. Prosecutorial Staff are parties to an enforcement proceeding under this Chapter and are not "advisory staff" as that term is used in Title 35-A of the Maine Revised Statutes and Chapter 110 of the MPUC's Rules.

Y. **Service Line.** "Service Line" means the distribution line that transports gas from a common source of supply, such as a main, to an individual customer meter or to multiple customer meters as defined in 49 C.F.R. §192.3. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is furthest downstream, or at the connection to customer piping if there is no meter.

Z. **Underground Obstruction.** "Underground obstruction" means one or more sub-surface structures, including other utility infrastructure, that would require the lowering of the natural gas facility to a depth greater than 48" to obtain separation distances required by this Chapter. Consolidated rock is not an underground obstruction.

**§ 3 Participation in Underground Utility Damage Prevention Program**

A. **Natural Gas and LNG Operator Participation**

Operators in Maine must:

1. Comply with Chapter 895;

2. Maintain membership in a notification center that utilizes and promotes the 811 "one-call" notification system;

3. Promote the use of 811 and "Ok-to-Dig" notification processes for use by excavators; and

4. Report to the MPUC in accordance with Chapter 895 any damage to its underground facilities or a damage prevention incident utilizing an MPUC Underground Facility Incident Report Form.

B. **Pipeline Facility Locator Training and Qualification**

Operators must maintain documentation that each person utilized to locate the operator's underground pipeline facilities is properly trained and qualified. Such documentation must indicate the latest date the person completed or demonstrated:

1. The necessary knowledge and skills needed to use industry best practices developed by the Common Ground Alliance for locating and marking pipelines or other recognized industry authority;

2. Knowledge of state and local underground damage prevention regulations; and

3. Qualification in accordance with 49 C.F.R. Part 192, Subpart N.

C. **Notation of Facilities on System Maps Using GPS Coordinates**

1. Operators must provide GPS coordinate identifiers, referenced to the North American Datum of 1983, for the location of all facilities installed after January 1, 2012.

2. Operators must record coordinates for existing facilities whenever an underground facility is exposed.

3. Operators must obtain GPS location data for new facilities for critical valves, at intersections with service lines, main or other gas facilities, at any point of directional change and at intervals along a pipeline sufficient to achieve geospatial accuracy.

D. **Location of Underground Facilities Where Trenchless Technology Is Used**

As part of its Damage Prevention Program adopted pursuant to 49 C.F.R. §192.614, operators must maintain and follow written procedures for protecting existing underground facilities during directional drilling and other trenchless technology installation techniques. Use of trenchless technology has inherent risks and regardless of the protection method chosen by an operator, operators have an obligation to not damage or interfere with other underground utility facilities.

1**. Underground Electric Facilities.** When operators are installing natural gas facilities using directional drilling and other trenchless technology installation techniques, the operators' written procedures must require use of the exposed facility method described in Section 3(D)(2)(a) of this Chapter.

**2. Sewer Facilities.** When operators are installing natural gas facilities using directional drilling and other trenchless technology installation techniques, the operators' written procedures must require at least one of the following methods for positively locating underground sewer facilities (or two methods if using the relative elevation method for sewer service laterals and gravity sewer mains):

a. Exposed facility method. Operators must pothole and expose the underground facility at the gas crossing; the drill head, punch head, or plow must be visible in the pothole. The operator must document the distance between the punch head, drill head, or plow and the underground facility at all addresses/locations where this method was used. The exposed facility method is the only acceptable positive location method when using a punch, unless the punch head is equipped with a sonde.

b. Map and record method. Operators may use maps and records of sewer service laterals and mains to demonstrate that no conflict between the gas pipeline and the sewer service lateral or sewer main is possible. For example, if the gas service enters the front of a structure and a sewer service lateral exits the back of the same structure, the two utilities will not cross. The operator must document the criteria by which the lack of conflict was established and all addresses/locations where this method was used.

c. Sonde method. Operators may determine sewer service lateral and sewer main location and depth by a sonde transmitter at the crossed location. If operators use this method, the punch head or drill head must be equipped with a sonde and must be at least three feet from the sewer service lateral or sewer main. Operators must calibrate the sonde according to the manufacturer's specifications and at least as frequently as indicated by the manufacturer's specifications. Operators must document the sewer service lateral or sewer main depth and the punch head, drill head, or plow depth at each crossed location along with all addresses/locations where this method was used.

d. Relative elevation method (sewer service laterals only). Operators may determine the highest elevation of an individual sewer service lateral by entering the structure and verifying the sewer drain’s elevation as it leaves the structure. The punch head or drill head must be equipped with a sonde, and the punch, drill, or plow must at all times be at least three feet above the highest sewer service lateral elevation. Operators must maintain the three-foot separation across the entire width of the property. Operators must calibrate the sonde according to the manufacturer's specifications and at least as frequently as indicated by the manufacturer's specifications. Operators must document the highest sewer service lateral elevation relative to the punch head, drill head, or plow elevation along with all addresses/locations where the operator used the relative elevation method. Operators must not use this method if the distance from the proposed crossing to the closest adjacent sewer manhole exceeds 200 feet.

e. Televising method. Operators may televise individual sewer service laterals and sewer mains after the gas pipe has been installed. Operators may not introduce gas into the new pipeline until the sewer service lateral or sewer main has been televised. Operators must document with an electronic, visual record of the televising along with a written report. Operators must correlate the sewer lateral connection (wye) location with the street address in a written report. Use of this method does not alleviate the operator’s responsibility to obtain all practically obtainable information regarding the location of sewer service laterals and sewer mains prior to installation of a gas pipeline (e.g., maps, drawings, diagrams, or other records). Use of this method does not alter or supersede the requirements in this Chapter and in Chapter 895 regarding the separation of utility facilities.

**3. Other Underground Facilities.** For underground facilities other than electric or sewer, operators' written procedures must utilize the guidance material provided by the Gas Piping Technology Committee (GPTC) detailed in Guidance Material Appendix G-192-6, or other recognized industry standards.

4. When directional drilling and other trenchless technology installation techniques are conducted by third party excavators, operators' written procedures must require mandatory monitoring of these excavations when an operator is notified and the operator determines that the proximity of the proposed excavation could affect the integrity of the gas facility. Operators must train their operating personnel, including locators and others who monitor directional drilling and other trenchless technology installation activities, in the specific requirements and hazards associated with those activities.

5. Operators installing natural gas facilities using directional drilling and other trenchless technology installation techniques must implement a message, as part of their public awareness programs, to reach all stakeholders who may be involved in the clearing of obstructed sewer facilities. This stakeholder group must include, but is not limited to: residents, building owners, property management companies, municipal sewer operators, plumbing contractors, and equipment rental companies. Operators must implement the message prior to the introduction of natural gas to any facilities installed by trenchless technologies. The message must include the dangers associated with the cross boring of gas facilities through existing sewer and other utility facilities.

6. Operators' written procedures regarding the use of trenchless technology must be reviewed annually and modified as necessary to be consistent with industry best practices.

**§ 4 Emergency Procedures**

A. **Emergency Notification**

Operators must provide prompt telephone notification to the MPUC's Gas Safety Manager (or a Gas Pipeline Safety Inspector if the Gas Safety Manager is not immediately available) if an emergency exists for which prompt MPUC or Gas Safety Staff action is likely to be needed, if such notice is otherwise required by MPUC Rules, if an incident attracts significant interest from other government agencies or from the media, or if specifically requested by a member of the Gas Safety Staff.

B. **Requirements for Responding to Reports of Leaks or Gas Odor**

A first responder employed or contracted by an operator must possess training, experience, and knowledge in emergency response, leak classification and investigation, and be qualified in accordance with 49 C.F.R. Part 192, Subpart N.

Operators must maintain emergency response records and report in accordance with Section 7(E) of this Chapter.

**§ 5 Installation and Maintenance Standards**

A. **Interruptions of Service**

1. Operators must use all practicable means to avoid interruptions to service, including maintaining appropriate levels of maintenance and planning for unexpected events.

2. Should interruptions occur, operators must reestablish service within the shortest time practicable consistent with safety.

3. Operators must keep a record of all interruptions to service involving twenty or more customers that include the following:

a. The date and time of interruption;

b. The approximate number of customers affected;

c. The date and time of service restoration;

d. The cause of such interruption when known; and

e. A description of steps taken to prevent its recurrence.

4. Operators must report to the MPUC unintended service interruptions pursuant to Section 5(A)(3) of this Chapter occurring within a calendar month by the 15th of the following month.

5. When an operator interrupts service to perform work on lines or equipment, such work must be done at a time causing minimum inconvenience to customers consistent with the circumstances.

6. If practicable, operators must notify, three days in advance of scheduled work on lines or equipment that requires an interruption to service, all commercial, institutional or other customers that can reasonably be expected to be seriously affected.

**B**. **Operator Qualification (OQ) Program for New Construction**

Operators must include all pertinent tasks related to new construction as covered tasks in their OQ Program.

**C**. **Installation and Maintenance of Meters, Pressure Regulators and Service Piping**

**1.** **Location of Meters.** Operators must install meters in either of the following locations:

a. Outside the building at a location selected by the operator; or

b. When an outside location is not feasible, inside the building, preferably in a dry, well-ventilated place not subject to excessive heat, and as near as possible to the point of entrance of the pipe supplying service to the building.

**2.** **Master Meters.** Operators must not utilize master meter systems unless all service lines to the buildings served are operated and maintained by an operator in accordance with this Chapter.

**3.** **Protection of Meters and Distribution System Facilities from Damage from Motorized Vehicles or Equipment.** Operators must provide adequate protective barriers for gas meters, regulators, and aboveground pipeline facilities located in areas subject to vehicular damage on each side exposed to vehicular traffic. Operators that have above-ground piping and appurtenances at commercial and industrial premises must consider the potential for damage to the gas facilities from equipment used in the operation and maintenance of that facility and provide adequate protection.

**4.** **Protection of Meters and Distribution System Facilities from Snow and Ice Damage.** Operators must protect regulators, meters, and other equipment installed in the piping system must from the forces anticipated as a result of accumulated snow or falling snow and/or ice.

**5.** **Accessibility and Location of Pressure Regulators at Meters or Service Piping.** Pressure regulators installed by operators at meters or on service piping locations must conform to the following requirements:

a. Pressure regulators must be accessible for inspection, testing and adjustment.

b. Pressure regulators must be installed with a screened vent pointed down, or under a protective cover that will prevent blockage of the screened vent by rain, snow, ice or debris.

c. Vents on pressure regulator~~s~~ installed after July 1, 2011 with over-pressure protection that vent gas to atmosphere must be at least three feet horizontally, or eight feet vertically, away from any existing building opening above the vent, and at least five feet away from any existing source of ignition (e.g., electrical meters, openings into direct-vent (sealed combustion system) appliances, or mechanical ventilation air intakes). Pressure regulators that utilize over-pressure shutoff (OPSO) technology or otherwise effectively eliminate venting gas to atmosphere need not abide by the above distance restrictions.

d. Operators must not direct-bury new regulators. All existing buried regulators must be rated by their manufacturer for the application for which they are used and must be vented above grade.

**6.** **Observation of Unsafe Condition of Customer Facilities**

a. When visiting a customer's premises for any technical service, such as atmospheric corrosion inspections of facilities or connecting or reconnecting a customer service, operators must also observe visible customer piping for atmospheric corrosion or other potential safety issues.

b. All operators must include in their O&M Procedures a "Red Tag" hazardous equipment procedure for suspending service to a customer when a hazardous condition is discovered that makes the continued delivery of gas unsafe.

c. Operators' Public Awareness Plans must include notification to customers that their piping must be in compliance with NFPA 54 and maintained to prevent atmospheric corrosion.

**D**. **Installation and Maintenance of Mains and Service Lines**

**1.** **Installation of Plastic Pipe, Warning Tape, and Tracer Wire.** To facilitate location of buried plastic pipe, when plastic pipe is installed or replaced, operators must use the following location methods:

a. An electrically conductive tracer wire must be installed with new or replaced plastic pipe, including plastic pipe that is inserted into existing buried cast iron pipe as a means of pipe replacement. Tracer wire must not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited when trenchless technology, including pipe insertion, is used. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated 12-gauge copper wire or by other means.

b. Continuous gas pipeline warning tape must be installed approximately one foot below finish grade. The warning tape must be yellow, indicate the presence of a gas line, and at least six inches wide. No warning tape is required when pipe is installed by trenchless technology, including pipe insertion.

**2.** **Plastic Pipe Joining and Design**

a. Each person that joins plastic pipe must be qualified to do so for each joining method at intervals not exceeding 15 months, but at least once each calendar year.

b. Each completed joint, regardless of joint type, must be inspected by a person qualified to perform the inspection, and the joint, pipe, or fitting must be marked with the initials or other identifier unique to the individuals who both made and inspected the joint. This person cannot be the person that performed the joining method that is subject to inspection.

c. Design of plastic pipe must be in accordance with the design factor specified in 49 C.F.R. §192.121.

**3.** **Minimum Cover and Separation Standards for Mains and Service Lines**

a. **Mains in Public Right-of-Ways.** New or replaced mains located in public rights-of-way must be installed with at least 24 inches of cover above the shallowest pipe appurtenance, except where an obstruction, from other utilities or underground structures, prevents that installation depth or when pipe is inserted into existing pipe. This provision does not supersede any minimum cover depth requirements of an authority having permitting jurisdiction over the facilities being installed.

b. **Service Lines.** Service lines must be installed with at least 24 inches of cover above the shallowest appurtenance attached to the service line. Cover may be reduced to 18 inches above the shallowest appurtenance attached to the service line for the connection to a prefabricated riser.

c. **Separation from Underground Obstructions**

1. Where there is interference with underground obstructions, the operator must lay the main or service at a clearance distance of not less than 12 inches away from such obstructions unless the operator provides adequate shielding to protect the gas pipeline and the other facilities.

2. Operators must avoid where possible any interfering structure which provides a space in which an explosive atmosphere might accumulate in the event of a leak and must give preference to crossing over rather than under such structures.

d. **Shallow Installations due to Underground Obstructions.** When an operator has installed a main or service with less than 24 inches of cover, the operator must protect the main or service with shielding that conforms with gas industry standards both in respect to material and manner of installation. This provision does not supersede any minimum cover depth requirements of an authority having permitting jurisdiction over the facilities being installed.

**4. Material Tracking**

1. Operators must utilize a Geospatial Information System (GIS), or other comparable method to accurately track the location, by GPS coordinates, of all materials utilized for the installation and maintenance of mains and service lines that are permanently affixed to or installed with the mains or service lines.
2. The materials to be tracked by the operator include but are not limited to: pipe, valves, fittings, steel pipeline girth welds, and any other appurtenances.
3. The information tracked by the operator must include but is not limited to: material description; manufacturer; date of manufacture; batch, lot, and/or heat numbers; maximum design pressure and/or minimum yield strength; and identification of the individual(s) who made any plastic pipe joints and/or steel welds.

**E.** **Accessibility and Operability of Pipeline System Valves**

**1.** **Pipeline Valves**

Each pipeline valve installed on a main must be in an accessible location and the operator must mark and maintain the pipeline valve's GPS coordinates and triangulation on a pipeline system drawing. Operators must ensure that current maps are easily accessible to operating personnel.

**2.** **Distribution Line Valves**

a. Operators must maintain each valve installed on a main that has been designated by the operator as a critical valve to be readily accessible to facilitate its operation.

b. Each valve installed on a main that has been designated by the operator as a critical valve must be inspected and partially operated at least once each calendar year at intervals not to exceed 15 months. Operators must take prompt remedial action to correct any critical valve found inoperable, unless the operator designates an alternative critical valve.

c. Operators must inspect and partially operate each valve installed on a main that is not a critical valve at least once every five calendar years at intervals not to exceed 66 months. Operators must take remedial action to correct any non-critical valve found inoperable, or document on valve records and maps that the valve is inoperable.

d. Operators must inspect and partially operate each valve installed on a service line where there is not a valve at the service riser or where it is not practical to access the service riser valve in an emergency at least once every five calendar years at intervals not to exceed 66 months.

e. Operators may designate any valve that the operator does not intend to utilize (e.g., a valve installed on a main to facilitate construction) as a "non-operational valve." In so designating, the operator must document the valve as a non-operational valve on valve records and maps. Non-operational valves so designated and documented by an operator are not subject to the inspection, operation, or remediation requirements of this Section.

f. Operators that do not have an MPUC-approved isolation zone plan must install sufficient distribution valves on mains to isolate looped portions of a pipeline system and minimize outages to no more than 500 customers but no more than the number that the operator has sufficient technical resources, including mutual aid, to relight within eight hours. The relight interval begins immediately upon restoration of sufficient system function to support reconnection of service load.

e. If an operator installs a valve in a buried box or enclosure, the operator must install the box or enclosure to avoid transmitting external loads to the main and service line(s).

**3.** **Valve Boxes.** Operators must maintain all valve boxes associated with critical valves so as to avoid being paved over or filled with debris that prevents access to the valve or degrades valve operability.

**4.** **Valves at Regulator Stations**

a. Each regulator station controlling flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit operation of the valve during an emergency that might preclude access to the station.

b. All regulator stations constructed after July 1, 2011, must have exterior shutoff valves or a sectionalizing valve installed on all lines entering and leaving regulator stations for use in an emergency to stop gas flow. Such valves must be installed at a readily accessible location where they can be operated in an emergency.

c. Exterior shutoff valves, for stations installed after July 1, 2011, must be located a minimum of 40 feet from the regulator station if inlet pressure to the station is 100 psig or less. Valves must be located a minimum of 100 feet from the regulator station if inlet pressure is more than 100 psig. The above minimum separation distances do not apply to stations where achieving the minimum separation distances is not practicable and where an automated fire-valve is installed at the inlet to the station.

d. A check valve may be used in lieu of an exterior shutoff valve on downstream piping if located a minimum of 40 feet from the regulator station.

e. The exterior shutoff valve may be a sectionalizing valve.

**§ 6 Operation Standards**

**A.** **Operator Qualification (OQ) Program Requirements**

Operators must include mechanisms and processes to achieve the following requirements in its OQ Program’s written plan:

1. All of the operator’s personnel and the employees of the operator's contractors who may be joining plastic pipe, by any method, or inspecting plastic pipe joints must be qualified (a) directly by an employee of the operator who is fully trained and qualified; or (b) if an operator utilizes an agency to qualify its personnel, all such qualifications must be by the same agency through which the operator has adopted their OQ Program written plan. Any individual(s) conducting inspections or qualification testing must be qualified to join plastic pipe by all methods and have a minimum of two years of experience making all joints they are inspecting or for which they are qualifying others;

2. Documentation that all qualified personnel (employees and contractors) have received training, for all tasks at which they are qualified, prior to being tested for qualification. Operators must retain this documentation for as long as the individual is performing the covered task, and for five years thereafter;

3. Documentation indicating that personnel (employees and contractors), qualified for any task by written testing, were tested for those tasks by an independent proctor and that all tests were corrected by the test proctor or by a computerized or online test administrating organization or agency. Operators must retain this documentation for as long as the individual is performing the covered task, and for five years thereafter. If written testing is conducted through a computerized or on-line test administered by the Northeast Gas Association or similar organization or agency, then the operator must ensure that the test proctor has been qualified by the administrator of the test;

4. Documentation indicating that personnel (employees and contractors), qualified for any task by hands-on testing, were tested individually for those tasks by an independent proctor and that all tests were corrected by the test proctor. Operators must retain this documentation for as long as the individual is performing the covered task, and for five years thereafter;

5. If task testing is computer based, procedures and documentation ensuring that the stated individual is the one actually taking the test(s) and that the individual is receiving no assistance from others during the testing. Operators must retain this documentation for as long as the individual is performing the covered task, and for five years thereafter;

6. For tasks other than joining plastic pipe, the operator must perform analysis to verify that the domains and elements of all tasks performed by contractor personnel, qualified by an OQ Program other than the operator's, equate to the tasks as described in the operator's OQ Program. Operators must retain documentation of this analysis for as long as the contractor personnel are performing covered tasks, and for five years thereafter;

7. If the domains and elements of a contractor's task do not equate to those contained in the operator's OQ Program or if contractor personnel are lacking qualification for necessary tasks, the affected personnel must be qualified by the operator or the same agency through which the operator has adopted their OQ Program written plan; and

8. Prior to the start of each construction season, the operator must provide the Gas Safety Staff with the necessary usernames and/or passwords to access any on-line databases used for the tracking of qualifications of the operator's employees and contractors.

**B. Quality Assurance/Quality Control (QA/QC) Program**

1. Operators must, as part of their compliance with 49 C.F.R. §192.605 *Procedural manual for operations, maintenance, and emergencies*, include procedures for evaluating the work performed by operator personnel to determine the effectiveness and adequacy of the procedures used during normal operation and maintenance tasks and to modify the procedures when deficiencies are found. Such procedures must be set out in a written QA/QC program that promotes gas system and related employee and contractor safety through monitoring of field work activities performed during the construction, installation, operation and maintenance of gas facilities. The operator must also develop a construction inspection program for new construction and facility repair work done by its employees and by contractors as part of its QA/QC program.

2. A mandatory component of operators' QA/QC Programs must be on-going audits of tasks performed with a goal to ensure compliance with the operator's written policies, practices, procedures and specifications; and with applicable codes. Record keeping accuracy and completeness verification audits are also included in this component of the QA/QC Program.

3. The QA/QC audit program must include:

a. Field Verification Audits of which a representative number are conducted after field work is completed for specific tasks.

b. Performance Audits which consist of various tasks of which a representative sample are evaluated during the actual time that the work is being performed by the employee or contractor.

c. Construction Inspections that are frequent enough to encompass most of the new facility installation and repairs that are done on the operator's system.

d. Detailed forms incorporating activity checklists prepared to cover normally performed work activities for evaluation or inspection of specified field work and construction.

4. When necessary, operators must use QA/QC audit and construction inspection findings to implement changes in procedures, training, and work practices.

5. Audits must be conducted by management personnel (e.g., supervisors, engineers) and performed on different employees/crews to ensure that all personnel are reviewed and construction work is inspected regularly.

**C**. **Scheduling Permanent Abandonment/Disconnection of Inactive Mains and Service Lines**

1. Operators must add and monitor service lines where gas is no longer being billed to a customer and which are not cathodically protected steel or plastic gas service lines equipped with an excess flow valve, according to the operators' DIMP written plans until the lines are disconnected and abandoned.

2. Operators discovering inactive bare steel (unprotected) service lines or stubs in the course of leakage surveillance, construction, maintenance or inspection of facilities must abandon or replace those lines or stubs as follows: If leaking, abandon immediately at the main; if not leaking, abandon or replace as soon as practicable but not more than six months after discovery.

3. The operator must indicate in its mapping system any main or service line that is abandoned at the time it is abandoned.

4. The operator must maintain records of any main or service line that has been abandoned.

5. If a building with an active service line is to be demolished and is not slated to be replaced the operator must abandon the service line must at the main.

**D**. **Leak Detection**

1. **Leakage Surveys and Patrols.** Operators must conduct leakage surveys and patrols according to the following:

a. Operators must conduct a risk-based leakage survey program for all gas mains with, at a minimum, the requirements as set forth in 49 C.F.R. §192.723. As part of their compliance with 49 C.F.R. §192.605, operators must provide the detail on the survey cycles. Operators' DIMP written plans must provide the justification, based on data and metrics compiled and reviewed as part of the DIMP written plan, for the selection of each survey cycle identified in the operators' operations and maintenance procedures.

b. Operators must conduct a leakage survey of all cast iron main lines at least every 30 days between December 1 and April 30.

c. Operators must conduct a leak survey at buildings used for public assembly, including schools, post offices, churches, hospitals, nursing homes, theaters, and municipal buildings each year during the period March 1 to December 1. This requirement only applies to all public assembly buildings having a gas service line. Operators must utilize risk-based parameters to identify additional service lines in places of public congregation beyond those listed above, that require a survey each year from March 1 to December 1. Operators must use existing and readily accessible data to identify these risk-based parameters which may include service size, delivery pressure, number of meters, meter size, or building occupancy

d. If, when investigating a leak, an operator determines or has determined that the perimeter of a leak area extends to a building wall, the investigation must continue into the building unless public safety or identifiable urgent circumstances prohibit entry.

e. Once public safety or identifiable urgent circumstances no longer prohibit entry, the investigation, as provided in (d) above, must continue into the building, if the leak has not yet been resolved utilizing a combustible gas indicator.

2. **Leak Detection Equipment Calibration and Maintenance**

Operators must maintain written procedures for the calibration and maintenance of leak detection equipment. These procedures must consider the type of equipment, frequency of use, manufacturer's calibration recommendations, historical performance, age of equipment, required maintenance intervals and equipment failure protocols.

Operators must review these procedures annually and modify the procedures to the degree necessary to ensure that leak detection equipment used in the field has been properly calibrated and maintained.

**E**. **Leak Classification and Repair**

The purpose of the leak grading system is to determine the degree or extent of the potential hazard resulting from gas leakage and to prescribe remedial actions. Operators must promptly respond to any notification of a gas leak or gas odor or any notification of damage to facilities by excavators or other outside sources.

Operators must ensure that leak grading is made only by those individuals who possess training, experience, and knowledge in the field of leak classification and investigation. The judgment of these individuals, based upon all pertinent information and a complete leakage investigation at the scene, must form the basis for the leak grade determination.

**1.** **Leak Response**

a. Operators must establish a leak repair priority based on their evaluation of the location and the magnitude of a leak.

b. Operators must assign a classification of leaks in accordance with this subsection;

c. Operators must immediately notify the fire department of the community involved of each Grade 1 leak found to exist in their pipeline systems.

**2.** **Grade 1 Leaks**

a. A Grade 1 leak is a leak that represents an existing or probable hazard to persons or property and requires prompt action, immediate repair, or continuous action until the conditions are no longer hazardous. A Grade 1 leak includes but is not limited to:

1. Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard;

2. Escaping gas that has ignited;

3. Any indication of gas, which has migrated into or under a building, or into a conduit or tunnel;

4. Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building;

5. Any reading of 70% lower explosive limit (LEL) or greater in a confined space;

6. Any reading of 70% LEL or greater in small substructures, other than gas associated substructures, from which gas would likely migrate to the outside wall of a building; or

7. Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

b. A Grade 1 Leak requires an operator to take action immediately to eliminate the hazard and make repairs. The action may require one or more of the following:

1. Implementing an emergency plan;

2. Evacuating premises;

3. Blocking off an area;

4. Rerouting traffic;

5. Eliminating sources of ignition;

6. Venting the area by removing manhole covers, barholing, installing vent holes, or other means;

7. Stopping the flow of gas by closing valves or other means; or

8. Notifying emergency responders.

**3.** **Grade 2 Leaks**

a. A Grade 2 leak means a leak that is recognized as being non-hazardous at the time of detection but justifies scheduled repair or removal within six months or less of detection due to the probability of its future hazard.

b. Grade 2 leaks vary greatly in degree of potential hazard. Operators must establish a repair priority for all Grade 2 leaks. In determining the repair priority, Operators must consider criteria such as the following:

1. The amount and migration of gas;

2. The proximity of gas to buildings and subsurface structures;

3. The extent of pavement; and

4. Soil type and conditions, such as frost cap, moisture, and natural venting.

c. Operators must complete Priority 1 repairs within 30 days of detection of any leak:

1. With a sustained reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak;

2. With a sustained reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 Leak;

3. With a sustained reading less than 70% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard;

4. With a sustained reading between 20% LEL and 70% LEL in a confined space;

5. With a reading on a pipeline operating at 30 percent SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak;

6. With a reading of 70% LEL, or greater, in gas associated substructures; and

7. Which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

d. Operators must re-evaluate all active Grade 2 leaks at a minimum of every 30 days until the leak is repaired and cleared.

e. Operators must take action ahead of ground freezing or other adverse changes in venting conditions with respect to any leak which, under frozen or other adverse soil conditions, would likely allow gas to migrate to the outside wall of a building.

**4.** **Grade 3 Leaks**

a. A Grade 3 leak is a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

b. Operators must survey and re-evaluate each Grade 3 leak at least once every 180 days from the date of discovery, until the leak is repaired. A leak requiring re-evaluation at periodic intervals includes any reading:

1. Of less than 70% LEL in small, gas-associated substructures;

2. Under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building; and

3. Of less than 20% LEL in a confined space.

c. Operators must repair each Grade 3 leak within 24 months of its detection unless the leak is located within an approved main replacement program area in which case the operator may extend the time for repair to the scheduled replacement.

**5.** **Bare Steel Service Line Leaks**

Operators finding a leak on a bare steel service line must replace the entire service line.

**6.** **Post-Repair Inspections**

a. In the case of leak repairs other than Grade 1, the need for a follow-up inspection must be determined by qualified personnel of the operator.

b. Operators must conduct a follow-up inspection as follows:

1. The adequacy of leak repairs must be checked before backfilling;

2. The perimeter of the leak area must be checked with a combustible gas indicator (CGI) or equivalent gas detection equipment; and

3. Where there is residual gas in the ground after the repair of a Grade 1 leak, the operator must conduct a follow-up inspection as soon as practical after allowing the soil atmosphere to vent and stabilize, but in no case later than one month following the repair.

c. A leak is considered to be effectively repaired when an operator's operating personnel obtains a gas concentration reading of 0%.

d. For a repaired leak with a gas concentration reading greater than 0% at the time of repair, operators must conduct a post-repair leak inspection within 30 days after the repair to determine whether the leak has been effectively repaired. If the second post-repair inspection shows a gas concentration reading greater than 0%, operators must continue conducting post-repair leak inspections every 30 days until there is a gas concentration reading of 0%. If on cathodically protected steel or plastic pipe, three post-repair inspections have been performed and the operator is unable to obtain a gas concentration reading of 0%, then the operator must initiate a new repair. For cast iron or unprotected steel pipe, which is included in an MPUC-approved pipe replacement program, and the operator is unable to obtain gas concentration readings of 0% after the third recheck, then these leaks must be regraded and moved to active status. Additional repairs will be required utilizing the requirements established for the new leak grading. If, after the third post-repair leak inspection, an operator regrades a leak and moves it to active status, the new leak classification will be based on the highest gas reading, or other conditions found during the third inspection, that results in the most conservative leak grade, prior to venting or other activity.

e. Post-repair inspections are not required for leak repairs completed by the replacement or insertion of an entire length of pipe or service line, or for the repair of leakage caused by excavator or third-party damage, provided a complete re-evaluation of the leak area after completion of repairs verifies that no further indications of leakage exist.

f. Remedial measures such as lubrication of valves or tightening of packing nuts on valves which seal leaks are considered to be routine maintenance work and do not require a post-repair inspection.

**7.** **Upgrading.** When operators upgrade a leak to a higher grade, the time period for repair is the remaining time based on its original classification or the time allowed for repair under its new grade, whichever is less. This requirement does not apply to leaks that, at the time of discovery, the operator classified at a lower grade pending a further, more complete investigation of the leak hazard area.

**8.** **Downgrading.** Operators must not downgrade a leak unless it is repaired.

**F**. **Leak Progression Maps.** Operators must institute and maintain on a continuing basis a leak progression mapping system of their service areas in a format that conforms with the specifications of Chapter 140. Map attributes to be included for each leak must be: pipe or appurtenance material; location of leak; cause of leak; and type of joint, if joint leak. Operators must enter into the system all leaks that have occurred since January 1, 2009. Operators should enter into the system leak history information prior to January 1, 2009 if the operator can verify the accuracy of the information.

**§ 7 Documentation and Reporting Requirements**

**A.** **Filings with MPUC.**

1.All plans, specifications, procedures, and other documents filed with the MPUC which pertain to the integrity of natural gas pipelines must bear the signature and seal of a Maine-licensed Professional Engineer when required by regulations adopted by the Maine Board of Licensure for Professional Engineers that apply to filings made with State agencies.

2. A copy of any report filed with PHMSA must also be provided to the MPUC.

**B.** **Preservation of Records**

1. Except as expressly provided to the contrary, all records required by this Chapter and federal regulations must be preserved by the operator for the life of the system.

2. Operators must make such records available to the MPUC or the Gas Safety Staff upon request at the operators' Maine office.

**C.** **Participation in the Plastic Pipe Data Collection and Sharing Initiative.** Operators must participate in the Plastic Pipe Data Collection and Sharing Initiative and report each discovered incident of plastic pipe failure as prescribed in the Initiative to the MPUC Gas Safety Manager, and the American Gas Association Plastic Pipe Ad Hoc Committee.

**D.** **Annual Submission of Operation Plans**

1. Operators must annually file electronically with the MPUC Gas Safety Manager current copies of the following written plans for each pipeline system operated within the State of Maine:

a. Pipeline Operating & Maintenance Plan (O&M Plan)

b. Construction Standards

c. Pipeline Emergency Plan (may be combined with O&M Plan)

d. Operator Qualification Plan

e. Damage Prevention Plan

f. Public Awareness Plan

g. Transmission and/or Distribution Integrity Management Program (when required by 49 C.F.R. Part 192)

h. Quality Assurance / Quality Control Plan

1. Control Room Management Plan

2. Operators must underline the most recent revisions to each plan.

3. Operators must make their annual filings no later than the 1st day of May or no later than two weeks prior to the start of pipeline operations by an operator of a new or newly acquired pipeline system.

4. Acceptable electronic formats for the plans may have the following file name extensions: .doc or .pdf, or other formats that are approved in advance of the filing deadline by the MPUC Gas Safety Manager.

5. Operators must designate a person or persons responsible for coordination of the plans listed above, and who will be responsible for on-going evaluation of the effectiveness of each plan and identifying changes needed due to changes in technology, code requirements, or improved procedures.

**E.** **Coordination of Written Operation & Maintenance (O&M), Emergency, and Operator Qualification (OQ) Plans.**

Operators must:

1. Annually review their O&M Plans to verify that they meet the requirements of 49 C.F.R. §192.605, and that their Emergency Plans meet the requirements of 49 C.F.R. §192.615;

2. Identify the specifications, procedures and/or any applicable manufacturer instructions that apply to the operations described in their pipeline O&M and Emergency Plans and to the identified covered tasks listed in their OQ Plans;

3. Clearly indicate within each plan the operators' specification, procedure, and/or manufacturer instructions that persons performing the operation or task must apply or follow by tabbing, footnoting, end-noting, indexing, linking or by other method(s) that will provide all required information to personnel in the field, as well as to operator managers and supervisors, and to the MPUC Gas Safety Manager.

**F.** **Logging and Analysis of Responses to Gas Odor and Leak Reports**

1. Operators must record each gas leak or odor report it receives.

2. Operators must keep and maintain a log recording the receipt and handling of each such report and the log must contain the following information:

a. Incoming date

b. Incoming time

c. Address, town and state

d. Work order number

e. Dispatcher name or employee identification number

f. Technician name or employee identification number

g. Time assigned to technician

h. Time accepted by technician

i. Time on route

j. Time arrived on site

k. Total time work order held in dispatch

l. Total travel time

m. Total response time

n. Time condition was made safe

o. Response time classification (30, 45, 60)

3. Operators must submit monthly reports of leak and gas odor calls to which they responded. The reports must include the lapsed time for each call, from receipt of the initial call to the arrival of a qualified responder, and a summary of the total calls responded to

a. Within 30 minutes;

b. Within 45 minutes;

c. Within 60 minutes; and

d. In excess of 60 minutes.

4. For any response time in excess of 60 minutes, operators must report the amount of time it took to arrive at the location of the report of a leak or gas odor, and provide a detailed written explanation for its failure to respond to the location within 60 minutes or less.

5. For each report of a gas leak or gas odor received by an operator, the operator must report to the MPUC the amount of time that lapsed time from initial notice until the leak(s) have been made safe by eliminating leaking gas.

**G.** **Monthly Leak Report**

1. Operators must provide, on or before the 20th of every month, a monthly leak report containing a description of the status of any leak on their systems along with its classification as Grade 1, 2 or 3. Operators must identify and describe the status of the leaks as follows:

a. As of the beginning of each month;

b. Those reported during the month;

c. Those repaired during the month; and

d. Those reported and awaiting repair at the end of the month.

**H.** **Odorization Records and Reporting**

1. Operators must:

a. Conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable;

b. Select sampling sites utilizing sound engineering judgment to ensure that allgas within the entire piping system contains the required odorant concentration.

2. Operators must record and retain the following information in the operators' files:

a. Odorizer location;

b. Brand name and model of the odorizer;

c. Million cubic feet (MMcf) of gas odorized during the month/quarter; and

d. Injection rate of gas odorant per MMcf, or the following:

1. Quantity of gas odorant and the beginning of the month/quarter;

2. Amount of gas odorant added during the month/quarter; and

3. Quantity of gas odorant at the end of month/quarter (indicating adjustments for new quantity received during the month/quarter)

3. Operators must provide, on or before the 20th of every month, reports to the MPUC Gas Safety Manager of the odorant level measured at the sampling sites.

**I.** **Construction Work Reporting**

Operators must send to the MPUC, by e-mail or other electronic means acceptable to the MPUC, weekly reports of scheduled construction and repair activities. Reports must be received no later than 5:00 p.m. on the Friday prior to the scheduled work and must include both the operators' and contractors' construction activities and any scheduled repair activities. Operators must break down report information by individual crews and the scheduled work must be listed by day and address, as much as practical.

**J.** **Pipeline Up-Rating Study and Notice Requirements.**

In addition to the requirements of 49 C.F.R. 192, Subpart K, operators, 30 days prior to up-rating the MAOP of any pipeline segment, must:

1. Complete a study of the pipeline segment(s) proposed for up-rating utilizing proper inspection, testing, and engineering practices that demonstrates:

a. the integrity of each affected pipeline segment and all its appurtenances, and

b. the safety of operating each affected pipeline segment after the proposed up-rating.

2. Submit the up-rating study to the MPUC.

**K.** **Drug and Alcohol Program Documentation.** When operators are required to file a copy of a Drug and Alcohol Testing Management Information System (MIS) Data Collection Form with PHMSA, operators must simultaneously submit a copy of the form to the MPUC.

**§ 8 Enforcement procedures**

**A.** **Gas Safety Staff Actions**

The Gas Safety Staff may, in their discretion and as appropriate, undertake any of the following actions.

**1.** **Reinforcement Reminder**

The Gas Safety Staff may provide a reinforcement reminder to an operator to reinforcing the operator’s knowledge of a specific requirement, previously agreed upon action, an upcoming deadline, or compliance issue. A reinforcement reminder may be oral or written, and an operator may, but need not, respond orally or in writing. Written reminders, and responses to those reminders, may be submitted via email.

**2.** **Request for Information**

The Gas Safety Staff may make a written request for information related to the construction, operation, or maintenance of an operator’s system and facilities. The operator must respond to the request within 14 calendar days or such other time as specified by the Gas Safety Staff in the request. Written requests for information, and responses to those requests, may be submitted via email.

**3.** **Field Corrective Action**

When an evaluation or inspection of an operator's records or facilities indicates that the operator is apparently violating this Chapter, the member of the Gas Safety Staff conducting the evaluation or inspection will informally discuss the probable violation with the operator before concluding the evaluation or inspection. Any documentation or physical evidence necessary to support a future allegation of non-compliance may be obtained by the Gas Safety Staff during the inspection. At the discretion of the Gas Safety Staff, on-site corrective action may be taken by the operator of the facilities where the probable violation exists, thus correcting the violation without further action.

**4.** **Warning Letter**

Upon determining that an operator may have committed a violation of this Chapter, the Gas Safety Staff may issue a written warning notifying the operator of the probable violation and advising the operator to correct the probable violation or be subject to future enforcement action. In its warning letter, the Gas Safety Staff may describe recommended measures the operator may take to ameliorate the violation or prevent future violations. The warning letter may also include the maximum penalty to which the operator could be subject for the probable violation. The operator, in its discretion, may submit a response to a warning letter if one is not otherwise requested.

**5.** **Notice of Probable Violation**

Upon determining that a probable violation of this Chapter has occurred, the Gas Safety Staff may issue an NOPV. The NOPV may also include a proposed administrative penalty amount and describe the maximum penalty amount to which the operator could be subject for the described violations. A written response from the operator must be filed with the MPUC within 10 days of the time the operator receives the violation notice.

**B.** **Response Options Open to Operator**

Operators, in responding to an NOPV, may:

1. Submit a written plan specifying actions that the operator will take to correct the violation, a schedule for completion of each action step, and a final date of compliance. If the MPUC accepts the corrective plan submitted by the operator and the operator implements the corrective actions, the violation is resolved.

2. Request a status conference. Upon request for a status conference, a Hearing Examiner designated by the MPUC that is not a member of the Gas Safety Staff will establish a date, time, and location for the conference. The Hearing Examiner will conduct the status conference. During the conference, the Hearing Examiner will review the NOPV, and review and discuss efforts made by the operator and the Gas Safety Staff to identify corrective actions and reach a mutually acceptable resolution of the NOPV.

The operator and the Gas Safety Staff are encouraged to meet informally prior to the status conference in an effort to reach a mutually agreeable resolution of the NOPV. If this effort is successful, the parties may document the resolution of the NOPV with a consent agreement or other mutually agreed upon document.

If the operator and the Gas Safety Staff are ultimately unable to reach a mutually agreeable resolution of the NOPV, the Hearing Examiner must refer the NOPV to the MPUC for formal resolution.

**C.** **Formal MPUC Action**

1. When a Hearing Examiner refers a probable violation to the MPUC for formal resolution, the MPUC may take the following actions:

a. Issue a cease and desist order pursuant to 35-A M.R.S. §§ 4515 or 4704;

b. Commence an investigation pursuant to 35-A M.R.S. §1303.

2. Notwithstanding any other provision of this rule, the MPUC may at any time resolve an alleged violation by approving a consent agreement between the Gas Safety Staff and the operator. A consent agreement is effective only if approved by the MPUC through the issuance of an order.

3. In any formal resolution proceeding before the MPUC, the Gas Safety Staff will serve as Prosecutorial Staff and the Hearing Examiner and any other MPUC staff assigned to the proceeding will serve as Advisory Staff.

**D.** **Hazardous Facility Orders**

1. In conjunction with, in addition to, or separate from the MPUC actions described in Section 8(C) above, if the MPUC finds a pipeline facility is hazardous to life or property, it may issue an order requiring the operator to take immediate corrective action, which may include:

a. Suspended or restricted use of the facility;

b. Physical inspection;

c. Testing;

d. Repair;

e. Replacement; or

f. Other action.

2. The MPUC must give the operator written notice and an opportunity for a hearing before issuance of a hazardous facility order unless the MPUC determines there is a serious and imminent threat to life or property. If the MPUC issues the order without a prior hearing, the MPUC must give the operator written notice and an opportunity for a hearing as soon as possible after the order is issued. Any such hearing must be recorded and a member of the MPUC's legal staff that is not a member of the Gas Safety Staff will serve as Hearing Examiner.

**§ 9 Federal Regulation Waivers**

Upon application by an operator, the MPUC may grant a waiver from compliance with the federal gas pipeline safety regulations for intrastate pipeline transportation, subject to review by PHMSA.

A. The MPUC may grant waivers for particular circumstances where it is inappropriate for an operator to follow a regulation of general applicability.

B. Before granting a waiver, the MPUC must give notice and opportunity for written comments and hearing, unless the it finds that notice is impracticable, unnecessary, or not in the public interest.

C. If the MPUC finds that a requested waiver is consistent with gas pipeline safety and is otherwise justified, the waiver must be issued under appropriate terms and conditions with a statement of reasons for granting the waiver.

D. If the MPUC finds a requested waiver is inconsistent with gas pipeline safety or is otherwise unjustified, the request must be denied, and the applicant notified of the reasons for denial.

E. The MPUC must give PHMSA written notice of each waiver at least 60 days before it becomes effective. Each notice of waiver must provide the following information:

1. The name, address, and telephone number of the applicant;

2. The safety standards involved;

3. A description of the pipeline facilities involved;

4. The justification for the waiver, including the reasons why the standards are not appropriate and why the waiver is consistent with gas pipeline safety.

**§ 10 STATE REGULATION WAIVERS**

Upon the request of any person subject to this Chapter or upon its own motion, the MPUC may, for good cause and upon a finding that the requested waiver is consistent with gas pipeline safety and is otherwise justified, waive any requirement of this Chapter that is not required by federal pipeline safety regulations or state or federal statute. The waiver may not be inconsistent with the purposes of this Chapter or Title 35‑A. The MPUC, the Director of Consumer Assistance and Safety, the Gas Safety Manager, the attorney assigned to the Gas Safety Staff, or the presiding officer assigned to a proceeding related to this Chapter may grant the waiver.

STATUTORY AUTHORITY:

35-A M.R.S. §§ 111, 4508, 4515, 4516-A, and 4705-A

EFFECTIVE DATE: This rule was approved as to form and legality by the Attorney General on February 25, 2011. It was filed with the Secretary of State on February 28, 2011 and became effective on March 5, 2011 (filing 2011-59).

EFFECTIVE DATE: This rule was approved as to form and legality by the Attorney General on September 18, 2015. It was filed with the Secretary of State on September 21, 2015 and became effective on September 26, 2015 (filing 2015-171).

EFFECTIVE DATE: This rule was approved as to form and legality by the Attorney General on March 25, 2021. It was filed with the Secretary of State on March 26, 2021 and became effective on March 31, 2021 (filing 2021-066).