June 30, 2023

The Honorable Patrick Leeman,
Division Counsel
Massachusetts Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

RE: Additional comments regarding D.P.U. 22-100

Dear Mr. Leeman:

The Northeast Gas Association (NGA)[1] and the undersigned Massachusetts based natural gas Distribution Company Members respectfully submit the following comments regarding the Department of Public Utilities (the Department) proceeding to amend 220 CMR

[1] NGA is a regional trade association that focuses on education and training, technology research and development, operations, planning, and increasing public awareness of natural gas in the Northeast U.S. NGA represents natural gas distribution companies, transmission companies, liquefied natural gas suppliers and associate member companies. Its operating member companies provide natural gas service to over 13 million customers in 9 states (CT, ME, MA, NH, NJ, NY, PA, RI, VT). Massachusetts Distribution Company members include The Berkshire Gas Company; Eversource Gas Company of Massachusetts and NSTAR Gas Company each d/b/a Eversource Energy; Holyoke Gas and Electric Department; Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty; Middleborough Gas and Electric Department; Boston Gas Company d/b/a National Grid; Fitchburg Gas and Electric Light Company d/b/a Unitil; Wakefield Municipal Gas and Light Department; and Westfield Gas and Electric Light Department. These MA Distribution Company Members are collectively referred to as *Operators* in these comments. Likewise, the term NGA refers to the collective NGA membership of MA Distribution Company Members and contractors which support these Operators.

100.00 and 220 CMR 101.00. The NGA membership, inclusive of Operators and their Contractors, appreciate the opportunity to offer these additional comments regarding this rulemaking and respectfully requests that the Department adopt these recommended changes to the Proposed Regulations.

NGA submitted initial comments on January 12, 2023, and participated in the public hearing on February 1, 2023, as well as both technical sessions held by the Department on March 23, 2023, and April 27, 2023. These additional comments include many of the key points discussed during the two technical sessions, reinforce points made in initial comments, and provide recommendations that meet the intent of the regulations from a pipeline safety perspective. They are aligned with the provisions of the *2021 Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy*[2] (Climate Act), the Dynamic Risk Report *Statewide Assessment of Gas Pipeline Safety: Commonwealth of Massachusetts*[3] (Dynamic Risk Report), and the National Transportation Safety Board (NTSB) accident report *Overpressurization of Natural Gas Distribution System, Explosions, and Fires in Merrimack Valley, Massachusetts September 13, 2018*[4]. NGA membership is committed to working with the Department to align Massachusetts regulations with state law, federal safety standards, and the recommendations of the above referenced reports with the ultimate goal of enhancing pipeline safety and gas system reliability.

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2 Massachusetts Session Law – Acts of 2021 Chapter 8, https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8

3 Dynamic Risk Assessment Systems, Inc. Final Report, Statewide Assessment of Gas Pipeline Safety: Commonwealth of Massachusetts, January 29, 2020, Document number 19DPUGAMY4

4 National Transportation Safety Board Accident Report, Overpressurization of Natural Gas Distribution System, Explosions, and Fires in Merrimack Valley, Massachusetts September 13, 2018, NTSB/PAR-19/02 PB2019-101365

General Comments:

Timeframe and Cost for Implementation and Compliance

The scope of work required to meet the desired outcome of the proposed regulations is significant. These comments highlight implementation timeframes that are of concern and suggest practical alternatives that, for example, incorporate risk-based prioritization schedules such that the highest degree of pipeline safety value is realized as quickly as possible. Timeframes to implement certain aspects of this regulation are very much dependent on a multitude of factors, which are explained in detail below.

The availability of qualified personnel, be they field personnel from the represented workforce, contractor personnel who conduct various construction or maintenance activities, or engineering personnel, including licensed professional engineers, will have a direct and profound impact on the ability of Operators to execute the work required by the proposed regulations. Expanding the workforce to enable Operators to execute the proposed work activities will take extensive time to recruit, hire, onboard, train, and qualify individuals as required by role. The scale of skilled and qualified individuals needed does not exist today in the market within the State. Additionally, the need to review and amend the associated labor union agreements and contractor agreements would add to the time it would take to realize the workforce needed for the proposed regulations.

Secondly, the impact of current facility design requirements, including the review done by a licensed professional engineer, as required by 220 CMR 105, has extended the timeframe needed to fully design much of the construction work required by the proposed regulations.

Additionally, the current efforts required for facility siting, as well as municipal and state-level permitting, further increase the timeframe needed to execute this construction work. Furthermore, the global supply chain challenges have had a major impact on the ability of Operators to procure the needed equipment and materials easily and speedily, particularly for specialty gas equipment, like regulators, that again increases the timeframe needed for the work required by the proposed regulations.

Thirdly, there are limitations that exist for each operator to execute the needed construction work within shortened timeframes due to seasonal constraints that ensure reliable service to customers. For example, the proposed regulations require Operators to conduct work at nearly all regulator stations across the State, which in many cases requires taking these critical supply points out of service. To manage their gas distribution system safely and reliably, an Operator needs to properly coordinate any potential supply interruptions and limit these activities to the warmer months of the construction season, typically from April to November each year. Extra caution should be taken to ensure that the regulations do not introduce undue additional risks by nature of the short timeframes proposed.

Finally, these timeframes are also highly dependent on the cooperation of municipalities to ensure timely work; municipal markouts, traffic control, police details, and permit reviews among other tasks will all be necessary for NGA members to implement system changes stemming from these proposed regulations.

We (NGA) emphasize these points as the safe and effective execution of a work plan to comply with these requirements requires reasonable implementation timeframes and operational flexibility, as each operator is impacted to varying degrees. In all likelihood, there will be common initiatives that could be undertaken in a collaborative format (such as recommended risk-based studies) and there will also be numerous initiatives that are company-specific. While NGA members are committed to collaborating on certain studies and initiatives to allow for transparent implementation and efficient enforcement, timelines to implement company-specific components will vary depending on the scale of the company and their current status/progress towards achieving the desired end state. We also note that the recoverable costs required to comply with this regulation will include both capital investments as well as incremental operation, maintenance, and associated contractor costs to continue on-going operations in compliance with revised regulations.

Additional Comments on Proposed Regulations:

NGA respectfully submits the following comments for consideration on behalf of its Massachusetts Distribution Company Members and Contractors. Additionally, NGA supports comments submitted by individual Distribution Company Members ("Members").

220 CMR 101.04: Notice of Proposed Construction

Proposed Regulation:

(1) Notice of proposed construction shall be filed with the Department at least 14 days prior to the start of any of the following projects:

(a) All new pipeline installation projects of 1,000 feet or more in length.

(b) All new pipeline installation projects where the pipeline will have an MAOP of 125 psig or more.

(c) All Uprating projects.

(2) If no construction projects in a calendar year meet the requirements of 220 CMR 101.04(1) then no less than three projects irrespective of length or MAOP shall be reported to the Department, provided that at least three projects are undertaken.

Discussion – Length of Projects Requiring Notice of Proposed Construction, 220 CMR 101.04:

NGA members understand the importance of filing the Notice of Proposed Construction with the Department. Given the numerous pipeline installation projects that exceed 1,000 feet in length, NGA respectfully suggests that an appropriate metric for this notification under subsection (a) would be 2,500 ft. versus 1,000 ft. This will minimize administrative costs of filing notification for projects which would provide only marginal pipeline safety value. Additionally, we recommend that the term "new" used in subsections (a) and (b) be struck to clarify that this requirement includes new construction as well as pipeline replacement projects. Finally, we recommend that subsection (b) be amended to require notice of proposed construction on projects where the pipeline will have an MAOP of greater than 200 psig to align with the delineation made in 220 CMR 109.

Recommendation: Revise 101.04 Notice of Proposed Construction as follows:

(1) Notice of proposed construction shall be filed with the Department at least 14 days prior to the start of any of the following projects:

(a) All ~~new~~ pipeline installation projects of ~~1,000~~ 2,500 feet or more in length.

(b) All ~~new~~ pipeline installation projects where the pipeline will have an MAOP of ~~125~~ greater than-200 psig~~ or more~~

(c) All Uprating projects.

(2) If no construction projects in a calendar year meet the requirements of 220 CMR 101.04(1) then no less than three projects irrespective of length or MAOP shall be reported to the Department, provided that at least three projects are undertaken.

220 CMR 101.06(2): Overpressure Protection

Proposed Regulation:

(2) Overpressure Protection.

(a) Operators shall take steps to protect their distribution systems from overpressure events. In addition to complying with 49 CFR Part 192, operators shall implement the following additional requirements within two years of the effective date of 220 CMR 101.00, operators shall:

1. Install one of the following:

a. a "slam shut" device in the station including in applications where there is only worker-monitor pressure control, or

b. a third regulator;

c. a full-capacity relief valve immediately downstream of the station only where a slam shut or third-regulator are not practicable.

2. Install and employ telemetered pressure recordings at Pressure Limiting and Regulating Stations in order to signal failures immediately to operators at control centers. The telemetering pressure gauge shall be installed at the outlet of each Pressure Regulating Station;

3. Completely and accurately locate, map, and document the location of all control (i.e., sensing) lines within the system. The control line mapping shall include, but not be limited to, the line size, depth, length, material and distance of each line from reference points;

4. Ensure that all underground control lines not contained within the safety of a Pressure Regulating Station vault or pit are plated to protect from possible damage. The location, depth and size of the plates shall be mapped and documented as specified in 220 CMR 101.06(2)(a)(3);

5. Ensure that all aboveground control lines are secured by the installation of a fence or protective enclosure.

6. Ensure that all overpressure protection is set below MAOP of the downstream system, with the exception of the devices mandated by 220 CMR 101.06(2)(a)(1) which may be set at MAOP;

7. Establish procedures requiring the isolation of overpressure protection devices if MAOP could be exceeded during maintenance or testing;

8. Ensure that all steel control lines are cathodically protected in compliance with 49 CFR 192.463;

9. Maintain a list of critical valves and Pressure Limiting and Regulating Station isolations. The list shall be readily available for all personnel that would need to operate these valves. The list shall contain the number of turns needed to operate each valve and the direction the valve must be rotated to close it;

10. Establish a procedure for checking the operability of critical valves in the operator's system. The procedure shall require that critical valves be checked once every calendar year at intervals not exceeding 15 months;

11. Visually inspect and document Pressure Limiting and Regulating Stations four times per year at intervals not to exceed four months. This inspection is to verify the physical condition of all equipment and structures;

12. Review and verify that no section of the distribution system is operating above 90% of its maximum capacity. Operators shall contact the Division if any section is found to exceed 90% of its maximum capacity; and

13. Establish or update procedures to require that personnel immediately respond to the location of any overpressure protection (OPP) activation.

(b) All maintenance activities on Pressure Limiting and Regulating Stations shall include the following:

1. Any underground control lines undergoing maintenance shall be relocated to the safety of a Pressure Regulating Station vault or pit. If the relocation of the control lines is not possible, the operator shall repair or replace the leaking segment of a control line and ensure that all control lines are plated as specified by 220 CMR 101.06(2)(a)(4).

2. If any major maintenance (i.e., valve replacement) is to take place, the Pressure Regulating Station is to be updated to comply with 220 CMR 101.06(2)(a)(4).

(c) All future construction activities for new Pressure Limiting and Regulating Stations shall comply with all existing guidelines and shall:

1. Be designed in a worker-monitor style;

2. Include a third level of overpressure protection such as a "slam shut" or additional monitor regulator;

3. Include a filter installed upstream of each individual pressure limiting or regulating pipe run;

4. Be designed and installed with a redundant parallel regulator piping run;

5. Have all control lines contained within the Pressure Limiting or Regulating Station vault or pit;

6. Include a flooding indicator that alerts in the operator's control centers;

7. Include a gas sensor that monitors for general leaks that alerts in the operator's control centers; and

8. Include a telemetering pressure gauge installed at the outlet of each regulating station.

Discussion – Risk Based Prioritization and Implementation Timelines, 220 CMR 101.06(2)(a):

NGA supports the intent of adopting a layers-of-protection approach to prevent overpressure events. We offer considerations and recommendations that achieve the same pipeline safety objectives of the proposed regulations while affording Operators greater flexibility to achieve the desired outcomes given the vast differences in the scale, scope, and asset base of each Operator. The recommendations that follow are aligned with the recommendations within the Dynamic Risk Report and the NTSB report. We note that the Climate Act does not address specific aspects of overpressure protection.

In the proposal, Operators will be required to take steps to implement additional safeguards to protect their distribution systems from overpressure events, including installation of a "slam shut" device, third regulator, or a full-capacity relief valve as well as pressure monitoring telemetry. In some cases, implementation of these measures will require a major investment in the regulator station. The siting and design process for a regulator station is typically one year, followed by an additional 12 to 18 months for procurement, fabrication, and installation. As noted in the general comments section, these timeframes are very much dependent on many factors including availability of qualified personnel, labor union agreements, contractor agreements, availability of engineering personnel and licensed professional engineers, facility design and siting requirements, permitting, procurement, and limitations on construction timeframes due to weather constraints as well as cooperation from municipal agencies where the work will be performed. In aggregate, there are in excess of 900 regulator stations in the Commonwealth of Massachusetts. The number of regulator station assets of each Operator varies significantly from single digits to more than 500. Given these cycle times and vast differences between Operators, there is a need for each Operator to assess and prioritize overpressure protection activities such that the highest degree of pipeline safety value is achieved as expeditiously as possible.

As an alternative, NGA proposes an approach that includes an engineering asset assessment and risk ranking of regulator station facilities requiring investments including an assessment of existing Gas System Enhancement Program (GSEP) plans, to the extent that GSEP plans impact the regulator station assessment. We also propose that this risk assessment be prioritized to first focus on regulator stations that feed low-pressure distribution systems and other stations with inlet pressures above 125 psig since intermediate or high-pressure distribution systems already incorporate an additional layer of protection in the service regulator that provides overpressure protection to each customer, thereby protecting customer owned piping and utilization equipment. NGA notes that PHMSA issued Advisory Bulletin ADB-2020-02, dated Sept 29, 2020 "to remind owners of *low-pressure* (emphasis added) natural gas distribution systems of the possibility of a failure of overpressure protection devices" and requiring Operators to account for the possibility of overpressure events in the design and operation of their systems under a Distribution Integrity Management Plan (DIMP). The risk associated with low-pressure distribution systems is also noted in both the NTSB Report and the Dynamic Risk Report. Given the risk associated with low-pressure systems, NGA recommends that 220 CMR 101.06(2)(a)(1) be limited to regulator stations which feed low-pressure distribution systems. This approach will optimize the pipeline safety value of overpressure protection upgrades.

Under this risk-based proposal, Operators would be required to complete the risk ranking evaluations and develop a regulator station investment plan within one year of rule change adoption and complete work required by the investment plan in accordance with Department approved, company-specific risk-based plans following completion of the proposed engineering assessment risk ranking.

Further, if the facility is scheduled for retirement/replacement as part of an existing capital improvement program, such as GSEP, it is recommended that retirements/investments associated with these facilities should be considered, and where feasible would proceed in accordance with prior scheduled plans and will be identified within the overall risk-based project plan. This would align capital plans and avoid new investments in facilities that may be retired shortly thereafter. This approach affords each Operator the appropriate timeframe to perform assessments, develop approved facility specific designs, acquire necessary materials, secure construction permits and acquire trained and qualified resources to ensure successful installations while meeting the safety intent of the proposed rule. NGA emphasizes the complexity of these critical assets and the importance of establishing appropriate and reasonable timeframes to execute these projects safely and efficiently. For most operators, the timeframe to complete the proposed requisite work would be approximately 10 years. For the largest Operators, the timeframe to complete the proposed requisite work may exceed 30 years given the number of stations, the associated cost and the complexity of the work, including the ability to plan and coordinate with other necessary work and to coordinate with our communities to obtain permits. For these reasons, NGA recommends that each Operator work with the Department in establishing appropriate timeframes based on the Operator's engineering and risk assessment, volume of work and associated cost, and ability to design, permit and safely perform the work necessary to comply with the requirements.

Discussion – Telemetry and Implementation Timeframe, 220 CMR 101.06(2)(a)(2):

Similar to the discussion above, installation of telemetry is a complex undertaking requiring siting, engineering design, coordination and installation of power and communications, procurement, as well as competent instrumentation and SCADA personnel. These efforts are best coordinated with each Operator's risk-based regulator station investment program and performed in concert with regulator station upgrades. We also note that the increased frequency of regulator station inspections, as required under 220 CMR 101.06(2)(a)(11), helps mitigate risk until telemetry can be installed.

Discussion – Protection of Control Lines and Implementation Timeframe, 220 CMR 101.06(2)(a)(3) and (4):

Regarding the term "control lines" and the use of plates to protect control lines, as required under 220 CMR 101.06(2)(a)(3) and (4), NGA recommends that the language of the proposed regulation be amended to more clearly identify that these requirements shall be applied to those control lines[5] where a damage would result in a potential overpressure event, commonly referred to as *sensing lines*. As such, NGA recommends use of the term *sensing line* versus *control line*.

Regarding the mapping and protection of sensing lines, as required under 220 CMR 101.06(2)(a)(3) and (4), NGA recommends a ten year implementation timeframe given the number of regulator stations and the process required to accurately map and protect these assets. We also note the limitation of qualified resources to complete this work given the scope of 220 CMR 101.06(a)(2) in its entirety. The increased frequency of regulator station inspections, as required under 220 CMR 101.06(2)(a)(11), helps mitigate risk of damage to a sensing line. Furthermore, NGA recommends that the additional required asset data (e.g., the line size, depth, length, material, distance of each line from reference points) be required only for those sensing lines where the location is not currently documented. This will allow for the prioritization of resources to achieve the greatest degree of pipeline safety value.

Additionally, the language of the proposed regulation should account for similar approaches to protect sensing lines from damage, such as the use of concrete caps or alternative protective measures, rather than limit the method of protection to only plating. Furthermore, NGA recommends that this requirement to protect sensing lines be required for all sensing lines extending beyond five feet from the exterior of the vault structure. Sensing lines within five feet of the vault are inherently protected by the vault structure itself given the proximity to the sizable and visible vault structure. Additionally, access is required to maintain valves that are adjacent to

[5] The broader term *control lines* typically includes *loading lines*, used to supply upstream pressure to regulators to enable standard operations.

the vault. This access may be impeded by the use of protective plates.

The Dynamic Risk Report identified the utilization of pre-fabricated vaults as a best practice. The regulator station design noted in this best practice incorporates a static sense line header adjacent to the vault, which eliminates the need for sensing lines to extend beyond five feet from the vault structure. This practice is being utilized by most Operators in the State.

Discussion – Regulator and Overpressure Protection Setpoints, 220 CMR 101.06(2)(a)(6):

The addition of a third level of protection or secondary overpressure protection equipment requires careful consideration of the setpoint of each device to ensure proper operation and avoid pressure control anomalies such as control instability, regulator hunting, "fighting" for control between two pressure regulators, and inadvertent tripping/activation of slam-shut or relief devices. These devices are already in use by several Operators and the Operators offer the following insight based on operating experience. The critical elements to ensure proper pressure control is to keep setpoints sufficiently apart such that the normal pressure fluctuation from the controlling device does not impact the other devices and to ensure proper placement of sensing lines in an area of laminar flow. The addition of another level of overpressure protection will limit the ability to achieve adequate setpoint separation of each device. Some of the devices already in use by Operators require a minimum differential between device setpoints (e.g., 5" W.C. or greater). As such, NGA recommends that the setpoint requirements of 49 CFR 192.201(a) be incorporated into 220 CMR 101.06(2)(a)(6). This approach will ensure the setpoint of the controlling regulator is set below MAOP for normal operations while allowing appropriate flexibility for the setpoint of each overpressure protection device based on the MAOP of the downstream distribution system and the requirements stipulated in 49 CFR 192.201(a). This approach is also supported by PHMSA Interpretation Response #PI-19-0019.

Discussion – Maintain a List of Critical Valves, 220 CMR 101.06(2)(a)(9):

NGA recognizes the safety value in maintaining a list of critical valves associated with pressure regulating stations. Valve information, such as the number of turns required to operate the valve, is captured for all new valves, and exists for most legacy valves. There are some legacy valves, however, where the number of turns may not be known and cannot be obtained due to the critical nature of the valve/regulator station and impact on system operations if fully operated. Likewise, normally closed valves cannot be routinely operated. This information could be ascertained if/when the regulator station is replaced or shut down for significant maintenance.

Discussion – Regulator Station Capacity, 220 CMR 101.06(2)(a)(12):

During the technical session on April 27, 2023, DPU Staff clarified that the intent of 220 CMR 101.06(2)(a)(12) is to verify that no *regulator station* operates above 90% of its maximum capacity. NGA agrees and reflects this change in the recommendations below. We also note that this determination of regulator station capacity may be accomplished by either direct measurement or hydraulic modeling.

Discussion – Regulator Station Maintenance, 220 CMR 101.06(2)(b):

Regarding 220 CMR 101.06(2)(b), NGA respectfully requests that timely performance of necessary maintenance not be contingent on facility upgrades as proposed in 220 CMR 101.06(2)(b)(1) and (2). Major maintenance, such as the replacement of regulator station components, often requires engineering design, approvals, procurement, and project planning and therefore cannot be performed immediately. This requirement would limit an Operator's ability to perform necessary maintenance or simple like-for-like component replacement in a timely manner. Delays in required maintenance or replacement may introduce unnecessary risk and impede the normal operation of these critical assets. Alternatively, NGA proposes that the conditions noted in this section be addressed in due course as specified and in accordance with the timelines outlined in our recommendations for 220 CMR 101.06(2)(a). Additionally, and as noted previously, the location of the sensing lines is critical to achieving proper and stable pressure control. For most applications, the proposed requirements to install sensing lines inside the vault may result in pressure control anomalies.

Discussion – Secondary Overpressure Protection, 220 CMR 101.06(2)(c)(1) and (2):

During the technical session on April 27, 2023, DPU Staff clarified that the intent of 220 CMR 101.06(2)(c)(2) is with regard to a *second* level of overpressure protection. In addition, DPU Staff clarified that the term *monitor* was intended to include both wide-open monitor and working monitor configurations. NGA agrees with both clarifications and reflects these changes in the recommendations below.

Discussion – Filters or Strainers, 220 CMR 101.06(2)(c)(3):

Regarding 220 CMR 101.06(2)(c)(3), NGA requests that the use of a *strainer* or filter be included in the regulation as acceptable alternatives. Strainers are commonly used upstream of pressure control devices to reduce the risk of dust or debris impacting the performance of equipment.

Discussion – Redundancy, 220 CMR 101.06(2)(c)(4):

Regarding 220 CMR 101.06(2)(c)(4), NGA recommends that this requirement be amended to more broadly ensure adequate redundancy to protect against a single failure versus the current focus on redundancy of each regulator run. This accommodates station designs where parallel runs may be required to run simultaneously to meet peak demand.

Discussion – Sense Line Location, 220 CMR 101.06(2)(c)(5):

As previously noted, placement of sensing lines is critical to proper performance of pressure regulating equipment. Best practice and manufacturer guidance recommends placement of sensing lines sufficiently downstream of the pressure regulators (typically 10 or more pipe diameters downstream of the regulator) on a section of pipe that is not subject to flow turbulence or pressure fluctuations. Locating sensing lines within the confines of the pressure regulator station typically conflicts with these design standards and/or would require the vault structure to be so large that it could not be practically sited. NGA recommends the use of a static sense line header for new pressure regulator station designs which achieve desired pressure control requirements and minimize the length of sensing lines outside of the vault to approximately five feet or less. The use of plates or other sense line protective measures where there is no header or where sensing lines are greater than 5 feet from the vault mitigates risk for existing regulator stations. This design approach was included in the prefabricated regulator vault design best practice recommended in the Dynamic Risk Report and is already being utilized for new regulator station designs by most Operators. This design approach is reflected in our recommendations for 220 CMR 101.06(2)(c)(5).

Discussion – Electronic Sensors in Vaults and Location of Telemetry, 220 CMR 101.06(2)(c)(6), (7), and (8):

With regard to 220 CMR 101.06(2)(c)(6) and (7), experience has shown that the installation of electronic devices in areas prone to water intrusion and high moisture, such as regulator vaults, results in failures of equipment and/or frequent maintenance. In most cases, the equipment is not designed for this harsh environment. Accordingly, NGA recommends terminating regulator vent lines above grade such that pressure control is not impacted by water intrusion into the vault or flooding. This provides for a higher degree of safety as this additional level of protection is not subject to response times as would be required with a response to a flood indicator alarm. Regarding a gas sensor alarm, NGA agrees with the clarification provided by the Department during the April 27, 2023, technical session that the intent of 220 CMR

101.06(2)(c)(7) is to require gas detectors in above grade regulator stations located in buildings. We also note that the more frequent regulator inspections required under 220 CMR 101.06(2)(a)(11) mitigates the risk of leaks at regulator stations.

With regard to 220 CMR 101.06(2)(c)(8), NGA recommends that a telemetering pressure gauge be installed *in close proximity* to the outlet of each regulating station. Telemetry has unique siting requirements in that power and communications must both be available. This is not always possible at the regulator station itself. Telemetry may be placed nearby within the same distribution system and will still achieve the same goal of immediate notification of a pressure anomaly.

Recommendations: Revise 220 CMR 101.06 (2) Overpressure Protection as follows:

(2) Overpressure Protection. (MFS Standards§§ 192.195, 192.201, 192.741).

(a) Operators shall take steps to protect their distribution systems from overpressure events. Operators shall conduct a risk analysis and risk ranking of regulator stations to prioritize investments in regulator stations to comply with this part. The risk analysis shall also consider the abandonment of regulator stations as part of the Operator's Gas System Enhancement Program (GSEP) plan (if one exists). Operators shall complete this assessment and develop a regulator station investment plan within one year of the effective date of 220 CMR 101.00. Operators shall complete facility modifications in accordance with their approved regulator station investment plan by the timelines stipulated in the plan and set forth below, unless otherwise approved by the Department. Within the regulator station investment plans, operators shall include provisions to: ~~In addition to complying with 49 CFR Part 192, operators shall implement the following additional requirements within two years of the effective date of 220 CMR 101.00 or as otherwise stipulated below, operators shall:~~

1. For regulator stations which feed low-pressure distribution systems or regulator stations with inlet pressure in excess of 125 psig, install ~~Install~~ one of the following in accordance with the regulator station investment plan timeframe:

a. a "slam shut" device in the station including in applications where there is only worker-monitor pressure control, or

b. a third regulator; or

c. a full-capacity relief valve ~~immediately~~ downstream of the station only where a slam shut or third-regulator are not practicable.

2. Within ten years of the effective date of 220 CMR 101.00, operators shall install ~~Install~~ and employ telemetered pressure recordings at Pressure Limiting and Regulating Stations in order to signal failures immediately to operators at control centers. The telemetering pressure gauge shall be installed as close as practicable to ~~at~~ the outlet of each Pressure Limiting and ~~Pressure~~ Regulating Station;

3. Within ten years of the effective date of 220 CMR 101.00, operators shall completely ~~Completely~~ and accurately locate, map, and document the location of all pressure limiting and regulating ~~control (i.e.,~~ sensing lines within the system, where the sensing line location is not already documented. The ~~control line~~ mapping shall include, but not be limited to, the line size, depth, length, material and distance of each line from reference points;

4. Within ten years of the effective date of 220 CMR 101.00, operators shall ensure ~~Ensure~~ that all underground ~~control~~ sensing lines which extend beyond 5 feet from ~~not contained within the safety of~~ a Pressure Regulating Station vault or pit are provided with additional protection to prevent damage to the pipe by external forces. ~~Plated to protect from possible damage. The location, depth and size of the plates shall be mapped and documented as specified in 220 CMR 101.06(2)(a)(3);~~

(b) Operators shall implement the following additional requirements within two years of the effective date of 220 CMR 101.00:

1~~5~~. Ensure that all aboveground ~~control~~ sensing lines for pressure limiting and pressure regulating stations are secured by the installation of a fence or protective enclosure.

2~~6~~. Ensure that all worker (i.e., controlling) regulators are ~~overpressure protection is~~ set below MAOP of the downstream system and that all overpressure protection is set as follows:~~with the exception of the devices mandated by 220 CMR 101.06(2)(a)(1) which may be set at MAOP;~~

a. For low-pressure distribution systems, overpressure protection must be set to prevent the unsafe operation of any connected and properly adjusted gas utilization equipment in accordance with 49 CFR 192.201(a)(1).

b. For pipelines other than low-pressure distribution systems, overpressure protection must be set to comply with 49 CFR 192.201(a)(2).

3~~7~~. Establish procedures requiring the isolation of overpressure protection devices if MAOP could be exceeded during maintenance or testing;

4~~8~~. Ensure that all coated steel control lines are cathodically protected in compliance with 49 CFR 192.463;

5~~9~~. Maintain a list of critical valves and Pressure Limiting and Regulating Station isolations. The list shall be readily available for all personnel that would need to operate these valves. To the extent that information is available, the ~~The~~ list shall contain the number of turns needed to operate each valve and the direction the valve must be rotated to close it;

6~~10~~. Establish a procedure for checking the operability of critical valves in the operator's system. The procedure shall require that critical valves be checked once every calendar year at intervals not exceeding 15 months;

7~~11~~. Visually inspect and document Pressure Limiting and Regulating Stations four times per year at intervals not to exceed four months. This inspection is to verify the physical condition of all equipment and structures;

8~~12~~. Review and verify that no regulator station ~~section of the distribution system~~ is operating above 90% of its maximum capacity. Operators shall contact the Division if any regulator station ~~section~~ is found to exceed 90% of its maximum capacity; and

9~~13~~. Establish or update procedures to require that personnel immediately respond to the location of any overpressure protection (OPP) activation.

(c) ~~(b)~~ All maintenance activities on Pressure Limiting and Regulating Stations shall include the following:

1. Any underground ~~control~~ sensing lines undergoing maintenance shall be mapped, documented, and ~~relocated to the safety of a Pressure Regulating Station vault or pit. If the relocation of the control lines is not possible, the operator shall repair or replace the leaking segment of a control line and ensure that all control lines are plated~~ protected as specified by 220 CMR 101.06(2)(a)~~(4)~~.

2. If any major maintenance (i.e., station reconfiguration ~~valve replacement~~) is to take place, the Pressure Regulating Station risk ranking and investment plan as defined in ~~is to be updated to comply with~~ 220 CMR 101.06(2)(a) shall be reviewed and updated.

(d) ~~(c)~~ All future construction activities for new Pressure Limiting and Regulating

Stations shall comply with all existing guidelines and shall:

1. Be designed ~~in a~~ with two regulators in series utilizing a "control" or "working" regulator and a "monitor" (wide-open or working monitor) for the first level of overpressure protection; ~~worker-monitor style;~~

2. Include a second ~~third~~ level of overpressure protection as per 49 CFR 192.201 such as a "slam shut", ~~or~~ additional monitor regulator, or a full-capacity relief valve where a "slam shut" or additional monitor regulator is not practical;

3. Include a filter or strainer installed upstream of each individual pressure limiting or regulating pipe run;

4. Be designed and installed with adequate redundancy to protect against a single failure ~~redundant parallel regulator piping run~~;

5. Be designed in a manner that limits sensing lines from extending beyond five feet from the Regulator Station vault ~~Have all control lines contained within the Pressure Limiting or Regulating Station vault or pit~~;

6. Be designed such that all regulator atmospheric vent lines terminate above grade and be rain and insect resistant ~~Include a flooding indicator that alerts in the operator's control centers;~~ and

7. For above-grade regulator stations located inside of buildings, ~~Include~~ include a gas sensor that monitors for general leaks that alerts in the operator's control centers; and

8. Include a telemetering pressure gauge installed in close proximity to ~~at~~ the outlet of each regulating station.

220 CMR 101.06 (7) Meters and Regulators.

<u>Proposed Regulation</u>:

(a) Meters and regulators shall be installed so as to protect them from anticipated or potential dangers, including but not limited to vehicles, falling ice and snow, flooding, or corrosion.

(b) Service Regulators:

1. Operators shall not install or operate a service regulator located within ten feet of a source of ignition or an air intake into a building. Utilities shall not install or operate a service regulator located within three feet from an opening

into a building or any electrical source not intrinsically safe.

a. The distance shall be measured from the vent or source of release (discharge port), not from the physical location of the meter set assembly; and

b. If the operator learns of a regulator that fails to meet the three- or ten-foot minimum distance requirement, it shall resolve the problem by extending the regulator vent to meet the requirement within 60 days of discovery.

2. All service gas regulator records shall be kept for at least ten years.

3. Each operator shall develop and implement a seven-year service regulator maintenance program. All service regulators shall be inspected during statutory meter changes every seven years, including a lock-up and run test, and maintained in accordance with manufacturers' specifications.

4. Service regulators on service lines without an excess flow valve (EFV) shall be replaced with meter replacement not to exceed seven years from installation.

<u>Discussion – Service Regulator Vent Terminations and Corrective Action Timeframes, 220 CMR 101.06(7)(b):</u>

The Climate Act, NTSB Report, and Dynamic Risk Report do not address specific aspects of the Meter and Regulator requirements proposed in 220 CMR 101.06(7).

NGA appreciates that the proposed rules regarding meter, service regulator and service regulator vent proximity are intended to provide additional clarity and specificity to ensure safety. The industry generally has recognized the need to assess variables associated with meter set placement and vent proximity, and as a result, has supported independent research through the Gas Technology Institute (GTI), now GTI Energy, to assess safety risks associated with meter set placement and clearances.[6] The study confirmed the efficacy of existing requirements, which preclude installation within three feet of an ignition source. NGA provides recommended clearance distances to service regulators, as noted below, based on the application of the risk data from the GTI Energy study to reasonably expected and practical scenarios. We also note that these recommendations align with existing New York State Code, 16 CRR-NY 255.355(b)(2), which requires the service regulator vent to have a minimum of 18 inches clearance to any opening into the building. Additionally, other regional pipeline safety regulators currently reviewing their regulations have recognized the safety value in this analysis and have proposed similar recommendations.

NGA proposes that service regulator vent ***terminations*** shall be located at least:

(1) 12 inches to the side or 18 inches above and below any building opening.
(2) three feet in any direction from any exterior defined source of ignition; and
(3) five feet in any direction from any forced air intake.

For existing installations, upon completion of a scheduled mandated inspection, and discovery that an installation does not meet these requirements, NGA recommends that an Operator be required to complete corrective action by the next scheduled mandated inspection cycle or in accordance with an Operator defined remediation plan, which may be warranted for some Operators based on legacy practices. The above timeframe will enable Operators to assess the scope and impact of this code change and address resulting "actionable conditions."

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[6] Evaluation of Meter Set Placement and Clearances, Final Report GTI Project Number 21860, October 2017

Remediation timeframes are expected to decrease following the first inspection/remediation cycle as new installations will comply with these new requirements. In addition, NGA recommends consideration of additional risk mitigation measures in the event an installation cannot meet the installation requirements specified in 220 CMR 101.06(7)(b) such as the installation of an Over Pressure Shut Off device (OPSO), or a vent-less or vent-limited gas service regulator similar to requirements of other regional pipeline safety jurisdictions.

<u>Discussion – Risk Based Approach to Service Regulator Inspection and Maintenance, 220 CMR 101.06(7)(c) and (d)</u>:

The proposed requirements of 220 CMR 101.06(7)(c) and (d) for Meters and Regulators include additional requirements for service regulator maintenance and replacement cycles. NGA is not aware of any scientific basis or manufacturer's requirement supporting the proposed timeframes for this recommendation and, as such, recommends that Operators sponsor a risk-based engineering study to assess service regulator replacement frequency. Results of the study could be incorporated into an Operator's DIMP to ensure the operational safety of these devices. This risk-based assessment approach to establishing a frequency of replacement and maintenance is similar in principle to §192.1013 in establishing an alternate frequency of inspection under Part 192 Subpart P. Additionally, the Dynamic Risk Report questions the safety benefit of the seven-year meter change out program, which was used as the premise for establishing the proposed seven-year frequency for service regulator maintenance and/or replacement in the proposed regulation. This further supports the need to undertake a risk-based assessment to determine an appropriate inspection frequency.

NGA also notes that many Operators have made significant investments in *bypass meter bar* technology to enable meter replacement without accessing the home and inconveniencing the customer. The utilization of a bypass meter bar does not require jurisdictional and non-jurisdictional piping to be purged which avoids introducing methane emissions into the environment. This approach to minimizing methane emissions is consistent with the requirements of the PIPES Act of 2020 and the Massachusetts Climate Act. In addition, the proposed requirement to perform a lock-up and run test on a seven-year frequency negates this investment as access to the building is required to conduct this test. NGA is not opposed to performing the lock-up and run test, but the frequency of doing so should be determined through a risk assessment that also takes into account customer and environmental impacts.

Recommendations: Revise 220 CMR 101.06 (7) Meters and Regulators as follows:

(a) Meters and regulators shall be installed so as to protect them from anticipated or potential dangers, including but not limited to vehicles, falling ice and snow, flooding, or corrosion.

(b) Service Regulators:

1. Operators shall not install or operate a service regulator located within 12 inches to the side or 18 inches above and below any building opening; 3 feet in any direction from any exterior defined source of ignition; and 5 feet in any direction from any forced air intake. ~~within ten feet of a source of ignition or an air intake into a building. Utilities shall not install or operate a service regulator located within three feet from an opening into a building or any electrical source not intrinsically safe.~~

a. The distance shall be measured from the vent or source of release (discharge port), not from the physical location of the meter set assembly;

and

b. If the operator learns of a regulator that fails to meet the above ~~three- or ten-foot~~ minimum distance requirements, it shall resolve the problem by extending the regulator vent to meet the requirement, installing an Over Pressure Shut Off (OPSO) device, installing a vent-less or vent limited gas service regulator, or implementing another operator-defined mitigating measure. ~~within 60 days of discovery~~. Operators shall be required to complete corrective action by the next scheduled mandated inspection cycle or in accordance with an Operator-defined remediation plan.

2. All service gas regulator records shall be kept for at least ten years.

3. ~~Each operator~~ Operators shall complete a risk-based engineering study to assess service regulator inspection, maintenance, and replacement frequency within 2 years of adoption of this rule. Results of the study shall be incorporated into an Operator's DIMP and be used to establish a service regulator maintenance ~~develop and implement a seven-year service regulator maintenance~~ program. ~~All service regulators shall be inspected during statutory meter changes every seven years, including a lock-up and run test, and maintained in accordance with manufacturers' specifications.~~

~~4. Service regulators on service lines without an excess flow valve (EFV) shall be replaced with meter replacement not to exceed seven years from installation.~~

220 CMR 101.06 (10)(h) General Pipeline Pressure Test Requirements

Proposed Regulation:

(h) Pre-tested pipe may be used only on mains, subject to the following conditions:

1. Pre-tested pipe sections shall be no more than 12 feet in length.

Discussion – Length of Pre-Tested Pipe, 220 CMR 101.06 (10)(h):

The standard length that plastic and steel pipes are produced and delivered to Operators is approximately 40 feet. NGA therefore recommends that pre-tested pipes be permissible up to one standard length, or 40 feet in nominal length. This practical recommendation eliminates the need for segmenting a pipe length prior to pressure test and provides greater operational flexibility in responding to emergency situations that require the use of pre-tested pipe.

Recommendation: Revise 220 CMR 101.06(10)(h) General Pipeline Pressure Test Requirements as follows:

> (h) Pre-tested pipe may be used only on mains, subject to the following conditions:
>
> 1. Pre-tested pipe sections shall be no more than 40 ~~12~~ feet in nominal length.

220 CMR 101.06(15) Operating Pressures for Low-Pressure Distribution Systems

Proposed Regulation:

(15) Operating Pressures for Low-Pressure Distribution Systems.

> (a) Maximum allowable operating pressure. The MAOP of low-pressure distribution systems shall be 14 inches water column.
> (b) Minimum operating pressure. The pressure at the outlet of any customer's service meter shall not normally be less than one-half of the normal pressure at the outlet as recorded during the course of the year.

Discussion – MAOP of Low-Pressure Distribution Systems, 220 CMR 101.06(15)(a):

NGA recommends that the language be revised such that MAOP for low-pressure distribution systems *does not exceed* 14" W.C. as some Operators currently have low-pressure systems with established MAOP less than 14" W.C. (e.g., 11.5" W.C.). Clearly the intent is not to uprate these systems to establish a MAOP of 14" W.C.

<u>Discussion – Minimum Operating Pressure, 220 CMR 101.06(15)(b)</u>:

This proposed regulation does not clearly indicate the intended improvement to safety, reliability, and system integrity. While the proposed regulation is intended to apply to only low-pressure systems, it is not clear from the language. In addition, there are no clear requirements or processes for reporting pressure at the outlet of a customer's service meter at regular intervals, and so it is not clear how to quantify or validate the "normal pressure" at the meter outlet. 49 CFR 192.623(b) provides a minimum operating pressure threshold that is adequately detailed for existing system operation. NGA agrees that a more detailed minimum operating pressure regulation potentially improves system safety, reliability, and integrity; however, without a clear method for establishing and monitoring this information, it is unclear how this could be achieved. NGA recommends that the delivery pressure to the customer be no less than one-half of the standard delivery pressure (e.g., 6" or 7" W.C.), as defined by each Operator.

<u>Recommendations</u>: Revise 220 CMR 101.06 (15) Operating Pressures for Low-Pressure Distribution Systems:

(15) Operating Pressures for Low-Pressure Distribution Systems.

(a) Maximum allowable operating pressure. The MAOP of low-pressure distribution systems shall not exceed ~~be~~ 14 inches water column.

(b) Minimum operating pressure. For low-pressure service, the delivery pressure to the customer shall not normally be less than one-half of the standard delivery pressure. ~~The pressure at the outlet of any customer's service meter shall not normally be less than one-half of the normal pressure at the outlet as recorded during the course of the year.~~

220 CMR 101.06 (19) Operator Qualifications

Proposed Regulation:

> (a) By one year from effective date of 220 CMR 101.00, all operator written qualification programs (OQ) shall list all covered tasks and include specific abnormal operating conditions for each task.
>
> (b) All OQ covered tasks shall be cross-referenced with applicable construction standards or specifications or applicable operation and maintenance activities including emergency response.
>
> (c) All individuals who perform OQ covered tasks shall be qualified in all the OQ covered tasks that they perform.
>
> (d) Individuals who are responsible for inspection or supervision of those performing OQ covered tasks shall be qualified in all the OQ covered tasks for which they are responsible.

Discussion – Span-of-Control Training, 220 CMR 101.06 (19)(c):

The proposed regulation, 220 CMR 101.06(19)(c), provides that: "All individuals who perform OQ covered tasks shall be qualified in all the OQ covered tasks that they perform." Similarly, 220 CMR 101.07(3)(b) would require Operators to ensure that all personnel performing covered tasks, including contractors, are "qualified."

Based on information shared at the March 23, 2023, Technical Session, NGA understands the intent of the proposed regulations is to eliminate "span of control" (on-the-job) training and require personnel to demonstrate competency in the classroom before they are deployed in the field.

There is nothing in the Climate Act directing the Department to eliminate "span of control" (on-the-job) training and adopt a model where personnel must demonstrate competency in the classroom before they are qualified to perform work in the field. In fact, this approach conflicts with 49 CFR §192.805 (c), which allows individuals, who are not qualified, to perform a covered task if directed and observed by an individual who is qualified.

Based on information shared at the March 23 Technical session, NGA understands the proposed regulation is based, in part, on a recommendation in the Dynamic Risk Report. The Dynamic Risk Report states:

> Certifications of a certain level of knowledge are a good first step in identifying individuals qualified to perform the tasks involved in designing, operating, and maintaining gas systems. They are, however, merely a first step – a foundational minimum requirement.

Dynamic Risk Report at 62.

A narrow reading, limited to the above excerpt, suggests classroom certification/qualification testing should be a pre-requisite to allowing personnel to engage in field work. However, the Dynamic Risk Report goes on to explain that there is an opportunity to evolve Operator Qualifications "from a certification process to one that assesses an individual's qualification and competency to both understand the hazards and perform the work safely." To illustrate this point, the Dynamic Risk Report explains that "the fact that an individual has passed the rigorous test to become a Professional Engineer does not alone qualify that individual to evaluate and design gas systems or processes without additional training and experience." Thus, the key point in the Dynamic Risk Report is that training and experience in the field under real world conditions provides the basis for a stronger qualification program. NGA concurs with this point. For most tasks, training should take place in the field for personnel to fully understand the potential hazards of gas work and the importance of performing gas work in a safe manner. Additionally, because span of control training takes place in the work environment, it also includes aspects of the company's culture, climate, and normative behavior. These are organizational and field environmental aspects that other methods of training are unable to replicate.

A classroom environment cannot simulate the unpredictability of field work or the diversity of conditions and circumstances that may be encountered. For example, it is impractical to simulate a Dig Safe mark-out scenario where there are multiple underground utilities in proximity to the Operator's gas-pressurized assets. Some things simply cannot be taught in a classroom and must be learned by actually performing the task under real world conditions. Additionally, "span-of-control" training provides direct exposure to various work site conditions and abnormal operating conditions where an individual benefits from working alongside an experienced and qualified peer. For example, trainees work one-on-one with a qualified Dig Safe technician and perform numerous mark-outs in the field with a high degree of exposure to variable site conditions under the direction and observation of the qualified technician. This experience, under real-world conditions and with supervision, is necessary to properly train and qualify a locator, and provide him or her with the tools necessary to further enhance the training provided in the classroom. For these reasons, field training, prior to qualification, should remain part of a robust qualification program.

From a practical standpoint, there are numerous small Operators in the Commonwealth that do not have training centers of sufficient size with sufficient equipment to properly train and qualify personnel on all covered tasks. These small Operators utilize span-of-control training as the primary means of competency development and this approach has proven to be effective.

Requiring all training to be performed in a classroom setting prior to qualification will create an undue cost burden with no corresponding increase in pipeline safety value.

If the Department eliminates the ability of Operators to employ a “span-of-control” training approach, it will undermine the development of a skilled workforce that can perform tasks effectively, while not reducing risk. This is not consistent with the purpose of the Climate Act, which is to enhance safety on the Commonwealth’s natural gas distribution systems. Further “span-of-control” training in addition to classroom training is how most Operators demonstrate appropriate training consistent with 49 CFR 192.805(h). Accordingly, NGA urges the Department to preserve “span-of-control” training and suggests revisions to 101.06(19)(c) and 101.07(3)(b) that limit “span-of-control” training to a span-of-control ratio of no more than one qualified individual to one non-qualified individual (1:1 ratio).

Discussion – Competency of Supervisors and Inspectors, 220 CMR 101.06 (19)(d):

The proposed regulation, 220 CMR 101.06(19)(d), provides that: “Individuals who are responsible for inspection or supervision of those performing OQ covered tasks shall be qualified in all the OQ covered tasks for which they are responsible.”

As drafted, the proposed regulation is overly broad and would apply to certain tasks in which supervisors do not need to be qualified because there are other resources employed to assess adherence to quality expectations. For example, Certified Welding Inspectors are qualified to inspect welding work but are not necessarily qualified to perform the welding. Likewise, pipeline inspectors need not be operator qualified to install all coating systems, but they need to understand the proper installation process and be competent to inspect the finished product. To further this point, Operators occasionally utilize specialty contractors to perform specialty services that are not typically performed in-house such as large diameter hot taps, directional drilling, and installation of composite repair systems. The supervisor or inspector needs to understand the process and be competent to inspect the finished product but does not need to be able to operate the equipment or perform the task as is required with the operator qualification process.

The proposed regulation may also have unintended consequences. For example, the proposed regulation may preclude office-based supervisors from engaging in the general administration of programs that involve OQ-covered tasks. Further, a supervisor may be able to pass a written exam to demonstrate subject matter expertise but may not be able to complete the physical examination (e.g., tapping/stopping) due to physical limitations. However, a supervisor is no less knowledgeable and competent because he or she is unable to complete the physical requirement for qualification. To become Operator Qualified, an individual must possess the requisite knowledge, skill, and ability to perform the covered task. Contrarily, in order to be an effective supervisor, *knowledge* of the task being overseen is the essential competency to ensure the task is being performed safely and accurately rather than the skill and ability to perform the task itself.

To avoid an overly broad application of the regulation and possible unintended consequences, NGA recommends changes to the proposed regulation allowing Operators the flexibility to define competency requirements of supervisory personnel.

<u>Recommendations</u>: Revise 220 CMR 101.06 (19) Operator Qualifications as follows:

> (a) By one year from effective date of 220 CMR 101.00, all operator written qualification programs (OQ) shall list all covered tasks and include specific abnormal operating conditions for each task.
>
> (b) All OQ covered tasks shall be cross-referenced with applicable construction standards or specifications or applicable operation and maintenance activities including emergency response.
>
> (c) All individuals who perform OQ covered tasks shall be qualified in all the OQ covered tasks that they perform or, if they are not qualified to perform the OQ-covered task, shall perform such tasks under the direction and observation of an individual who is qualified with a span-of-control ratio of no more than one qualified individual to one non-qualified individual (1:1 ratio).
>
> (d) Individuals who are responsible for inspection or field supervision of those performing OQ covered tasks shall be ~~qualified~~ knowledgeable and competent in all the OQ covered tasks for which they are responsible. Operators shall define within their OQ Written Plans the knowledge and competency requirements for individuals responsible for inspecting or supervising those performing OQ covered tasks.

220 CMR 101.06 (22) MAOP

Proposed Regulation:

> (22) MAOP. MAOP shall be posted at gate and district regulator stations as well as service regulators.

Discussion – Availability of System MAOP Information, 220 CMR 101.06 (22):

NGA agrees that appropriate knowledge of MAOP is essential to ensure facilities are not inadvertently over-pressurized during routine operations. However, posting MAOP information for general public access may result in increased security risk of those facilities. Based on information shared at the April 27, 2023, Technical session, NGA understands that the intent of this code section is to ensure that operating personnel have access to MAOP information, but not the general public. NGA agrees with this intent. MAOP information is accessible through company maps, records, and/or computer systems and is typically posted within gate and regulator stations. Additionally, given the accessibility of MAOP information through maps, records, and computer systems, it is unclear if physically posting system MAOP on individual service regulators would enhance public safety.

Recommendation: Revise 220 CMR 101.06 (22) as follows:

> (22) MAOP. MAOP shall be readily available for all personnel who would need to operate or maintain ~~posted at~~ gate and district regulator stations as well as service regulators.

220 CMR 101.07(1) Oversight of Contractors

Proposed Regulation:

> (1) Contractors who wish to be eligible to receive contracts with operators to perform gas work shall be required to register annually with the Department. Contractors must provide documentation, in a manner specified by the Department, and certify:
>
> (a) That the contractor is in good standing with the Department, including, but not limited to being in compliance with:
>
> 1. all penalties; and
> 2. all consent order items.
>
> (b) That the contractor is in compliance with:
>
> 1. 49 CFR Part 192 subpart N;
> 2. 49 CFR Part 193 subpart H (if applicable); and
> 3. 49 CFR Parts 199 and 40.

> (c) The contractor shall comply with any other requirements set forth by the Department.

Discussion – Contractor Registration Process and Definition of "Gas Work", 220 CMR 101.07(1):

The Department's proposed regulation, 220 CMR 101.07(1), would require Contractors who seek to perform "gas work" register with the Department and provide documentation to meet certification requirements, as set by the Department (D.P.U. 22-100, at 2). NGA understands the Department drafted 220 CMR 101.07 to comply with the following provision of the Climate Act:

> Contractors who wish to be eligible to receive contracts with a gas company to perform **gas work** shall be required to register with the department and provide all required documentation to meet certification requirements, as set by the department, to the department on an annual basis.

St. 2021, c. 8 § 103 (emphasis added).

The term "gas work" is not defined in the Climate Act, but the Division has proposed the following definition:

> **Any activity** covered by applicable state and federal pipeline safety standards that the Department has the authority to enforce, including but not limited to the following: 220 CMR 99.00, 220 CMR 101.00 through 115.00, and all federal pipeline safety standards as set forth in 49 CFR Part 192; federal safety standards for liquefied natural gas (LNG) as set forth in 49 CFR Part 193 (emphasis added).

The proposed definition of "gas work" is so broad that it would capture activities that are not directly related to the distribution of natural gas. For example, the current definition would require Contractors that perform fence repair and landscaping work to register annually with the Department. Consequently, the proposed definition of "gas work" would lead to results that are unreasonable and of little practical value.[7]

The Legislature could not have intended for the registration requirement to apply to Contractors of the type described above (fencing/landscaping) because that would not serve the interest of enhancing pipeline safety and reducing risk, which are the clear purposes of the statute. A reasonable construction of the statute, with due consideration of its purposes, is that the Legislature intended the Contractor registration requirement to apply only to contractors performing work on a pipeline[8] that is used directly in the distribution of natural gas or piping[9] at a Liquefied Natural Gas (LNG) facility. Accordingly, the definition of "gas work" should be amended to narrow its scope to activities that are directly related to work on the gas distribution system and that are reasonably related to the safety interest that underpins Section 103 of the Climate Act. To this end, NGA proposes the following amendment to the definition of gas work:

Gas Work. Any activity performed on a pipeline or piping at a Liquefied Natural Gas (LNG) facility covered by applicable state and federal pipeline safety standards that the Department has the authority to enforce, including but not limited to the following: 220 CMR 99.00, 220 CMR 101.00 through 115.00, and all federal pipeline safety standards as set forth in 49 CFR Part 192; federal safety standards for liquefied natural gas ~~(LNG)~~ as set forth in 49 CFR Part 193.

The Department's proposed regulation, 220 CMR 101.07(1), would require Contractors to

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[7] Worcester Regional Retirement Board v. Public Employee Retirement Administration Commission, 489 Mass. 94, 100 (2022) ("Although [the Court] afford[s] deference to an agency's interpretation of a statute that it administers, such deference does not extend to facially unreasonable constructions."); Craft Beer Guild, LLC v. Alcoholic Beverages Control Commission, 481 Mass. 506, 527 (2019) ("Although we are generous in our deference to administrative agencies in their interpretation of their own regulations . . . that deference is not unlimited."); ENGIE Gas & LNG LLC v. Department of Public Utilities, 475 Mass. 191, 197 (2016) ("We defer to the agency's interpretation insofar as it is reasonable.").

[8] 49 CFR Part 192.3 Definitions; *Pipeline* means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

[9] 49 CFR Part 193.2007 Definitions; *Piping* means pipe, tubing, hoses, fittings, valves, pumps, connections, safety devices or related components for containing the flow of hazardous fluids.

annually certify to the Department that they are in good standing and in compliance with 49 CFR Part 192 subpart N (if applicable), 49 CFR Part 193 subpart H (if applicable), and 49 CFR Parts 199 and 40. The proposed regulations are not prescriptive as to the process for registering and certifying Contractors. This is a sensible approach because best practices are likely to evolve over time, and a rigid framework would be the enemy of the flexibility that may from time to time be required. However, there are general parameters that should apply to ensure the continued safe, efficient, and reliable operation of the gas distribution system and that can be outlined in the Department's annual filing requirements:

- Documentation for certification should be filed with the Department no later than the fourth quarter each year to cover the upcoming construction season.
- The timeframe for approval of certification should be no later than 90 days from the submittal date.
- Certification should be effective until the next annual review, which is consistent with the Climate Act's language that certification be on an "annual basis."
- Contractors should remain in good standing if they are working through the enforcement process—only final determinations should impact standing.

220 CMR 101.07(2) Contractor to Inspector Ratio of 2:1

<u>Proposed Regulation</u>:

(2) Operators who utilize contractors to perform gas work shall be required to:

(a) Ensure that the contractor is registered with the Department; and

(b) Maintain a ratio of no greater than two contractor crews to every one qualified inspector within its service territory.

Discussion – Contractor to Inspector Ratio and the Definition of a Contractor Crew, 220 CMR 101.07(2):

The Department's proposed regulation, 220 CMR 101.07(2)(b) would require Operators to maintain a ratio of no greater than two "contractor crews" to every one qualified inspector. The Department notes that 220 CMR 101.07 was added in compliance with Section 103 of the Climate Act but NGA notes that there is no specific requirement in the statute for the 2:1 ratio set forth in the Proposed Regulations; *see* Climate Act St. 2021, c. 8 § 103. However, NGA acknowledges that the Dynamic Risk Report states that Operators should "[c]onsider using inspectors on a 1:1 or 1:2 ratio on job sites to provide the level of interaction between crew and inspector at a work site that adds value and enhances safe execution of the work." Dynamic Risk Report at 84.[10]

NGA agrees that a ratio of no greater than two contractor crews to every one inspector makes good sense in certain circumstances. However, the Department should not impose a fixed, one-size-fits-all crew to inspector ratio on an unqualified basis. There are certain situations where the 2:1 ratio would increase customer costs without any corresponding safety benefit. For example, performing activities such as cathodic protection readings presents a low risk of potential impact to the system and imposing the ratio in this case would not enhance the safe execution of the work. Most Operators confirm Quality Assurance on these types of tasks through their Quality Control and Quality Assurance programs.

The 2:1 crew to inspector ratio should be focused on activities that represent a higher

[10] *See also* Dynamic Risk Report at B-37 ("Add independent, engaged inspectors to achieve a ratio closer to 1:1 or 1:2 inspectors per job site."), B-76 ("Increase use of independent, engaged inspectors with goal of reaching ratio of inspector to work site closer to 1:1 or 1:2;").

potential safety risk. In order to appropriately focus the applicability of this ratio, NGA recommends that the Department add the following definition to the Proposed Regulations:

> Contractor Crew. A Contractor Crew consists of two or more individuals engaged in the installation of gas mains, gas services, or piping at an LNG or LPG plant, or regulator station.

Additionally, as discussed under 220 CMR 101.06(19)(c), inspectors must be knowledgeable of the task to ensure that the task is being performed correctly and to inspect the finished product but do not necessarily need to be formally operator qualified on a task, which requires the skill and ability to physically perform the task. As such, NGA recommends use of the term *inspector* versus *qualified inspector* in 220 CMR 101.07(2)(b).

Recommendation: Revise 220 CMR 101.07 (2) as follows:

> (2) Operators who utilize contractors to perform gas work shall be required to:
>
> (a) Ensure that the contractor is registered with the Department; and
>
> (b) Maintain a ratio of no greater than two contractor crews to every one ~~qualified~~ inspector within its service territory.

220 CMR 101.07(3) Contractor Qualifications

Proposed Regulation:

> (3) Operators who utilize contractors to perform gas work shall be required to evaluate contractor qualifications by:
>
> (a) Ensuring that all contractors follow the operator's written qualification program;

(b) Ensuring that all personnel performing covered tasks are qualified;

(c) Maintaining complete and accurate OQ training and certification records for all contractors.

(d) Reviewing and monitoring compliance with the contractor's Drug and Alcohol plan.

Discussion – Span-of-Control Training, 220 CMR 101.07(3)(b):

The proposed regulation, 220 CMR 101.07(3)(b) would require Operators to ensure that all personnel performing covered tasks, including contractors, are "qualified." Similarly, 220 CMR 101.06(c), provides that: "All individuals who perform OQ covered tasks shall be qualified in all the OQ covered tasks that they perform."

As noted previously in the comments provided under 220 CMR 101.06(c), if the Department eliminates the ability of Operators to employ a "span-of-control" training approach, it will undermine the development of a skilled workforce that can perform tasks effectively, while not reducing risk. This is not consistent with the purpose of the Climate Act, which is to enhance safety on the Commonwealth's natural gas distribution systems. Further, "span-of-control" training in addition to classroom training is how most Operators demonstrate appropriate training consistent with 49 CFR 192.805(h). Accordingly, NGA urges the Department to preserve "span-of-control" training and suggests revisions to 220 CMR 101.07(3)(b) that limit "span-of-control" training to a span-of-control ratio of no more than one qualified individual to one non-qualified individual (1:1 ratio).

Discussion – Contractor Records, 220 CMR 101.07(3)(c):

The Department's proposed regulation, 220 CMR 101.07(3)(c), would require Operators to evaluate Contractor qualifications by "maintaining complete and accurate OQ training and certification records for all contractors." As drafted, the proposed regulation can be read to require Operators to maintain a duplicate set of Contractor OQ training and certification records. If the Department applied the regulation in this manner, it would be inefficient and divert funding away from areas that should be a higher priority from the safety and risk perspective. For these reasons, the proposed regulation should be modified to make clear that Operators can comply with the regulation by implementing appropriate protocols to ensure the Contractor is maintaining its OQ training and certification records. NGA recommends changes to this section of the Proposed Regulations to clarify this point.

Recommendations: Revise 220 CMR 101.07(3) Oversight of Contractors as follows:

(3) Operators who utilize contractors to perform gas work shall be required to evaluate contractor qualifications by:

(a) Ensuring that all contractors follow the operator's written qualification program;

(b) Ensuring that all personnel performing covered tasks are qualified or, if they are not qualified, ensuring that they shall perform such tasks under the direction and observation of an individual who is qualified with a span-of-control ratio of no more than one qualified individual to one non-qualified individual (1:1 ratio);

(c) Implementing processes and protocols to ensure all Contractors utilized by the Operator are maintaining complete and accurate OQ training and certification records. ~~Maintaining complete and accurate OQ training and certification records for all contractors.~~

(d) Reviewing and monitoring compliance with the contractor's Drug and Alcohol plan.

220 CMR 101.08 Distribution Maps and Records

<u>Proposed Regulation</u>:

(1) Operators shall establish and maintain maps of the operator's service area which identify the operator's intrastate gas pipeline facilities. Each operator shall establish and follow procedures to ensure that maps and records are:

(a) Accurate, complete, and shall contain the location of all active pipes, including but not limited to mains, services, and service stubs;

(b) Updated within 30 days of the completion of construction, maintenance, or discovery of a main or service;

(c) Kept and maintained at a secure location; and

(d) Available to all operating personnel.

(2) Facilities that are under active construction or maintenance must be identified in the Operator's maps and records and be available to operating personnel.

(3) Operators shall establish a training for all construction and maintenance staff, including contractors, on its maps and records procedures.

(4) Operators shall conduct annual inspections of its maps and records to identify inaccuracies.

(5) Operators shall comply with all guidelines set by the Division regarding service quality metrics.

<u>Discussion – Timely Updates of Maps and Records, 220 CMR 101.08 (1) and (2)</u>:

The Climate Act directs the Department to "establish requirements for the maintenance, timely updating, accuracy, and security of gas company maps and records." St. 2021, c. 8 § 86.

The Climate Act does not define what "timely" means, but as noted above, the Division has proposed to define it as "within 30 days." What "timely" means should be defined based on practical considerations and in relation to the Climate Act's requirement that maps and records be annotated **accurately** and stored in a **secure** location. A 30 day window is not a sufficient amount of time to relay the required information from field personnel, perform the review and validation necessary to ensure the updates are accurate, and save them in a secure location—which may include one or more electronic repositories (i.e., GIS System, cloud-based systems). Additionally, the workload to update maps and records is seasonal, with higher volumes realized during construction season, resulting in practical workforce challenges during peak seasons. Based on the operating experience of its members, NGA recommends a 60 business day window to update maps and records because this would provide sufficient time for the review and validation cycle and would not exceed the F7100.1 federal reporting timeframes on asset documentation from the prior calendar year.

NGA further recommends that the requirements of subsections (1) and (2) of the proposed regulation be required of either maps *or* records, in a manner determined by the operator based on the type of activity and the associated system of record. For example, there are short term activities that do not need to be reflected on the Operator's maps because updates to records will provide personnel with the necessary information regarding these activities. In the case of individual service installations that are completed within a short period of time, and where the Operator's resource are in plain view from start to finish and a schedule is available to appropriate personnel, it would not add any safety benefit to immediately update maps with the locations of these activities. Finally, NGA proposes language to clarify the intent of the terms *completion of construction* and *maintenance* in 220 CMR 101.08(1)(b) and 220 CMR 101.08(2) respectively.

Discussion – Annual Inspection of Maps and Records, 220 CMR 101.08(4):

The proposed regulation, 220 CMR 101.08(4), would require Operators to conduct annual inspections of their maps and records. However, the process of inspecting maps and records is a dynamic one—requiring continuous review and verification. In the normal course of business, maps and records are subject to review and verification in real time as information is transmitted back and forth from supervisors to resources in the field.

As proposed, an annual record review would provide no incremental pipeline safety value than the current, and arguably more efficient, method of review. Accordingly, NGA recommends the proposed regulation be amended to require Operators to implement a Quality Assurance and Quality Control program to inspect and validate maps and records on a rolling basis rather than once per year.

Recommendations: Revise 220 CMR 101.08 Distribution Maps and Records as follows:

> (1) Operators shall establish and maintain maps of the operator's service area which identify the operator's intrastate gas pipeline facilities. Each operator shall establish and follow procedures to ensure that maps ~~and~~ or records are:
>
> > (a) Accurate, complete, and shall contain the location of all active pipes, including but not limited to mains, services, and service stubs;
> >
> > (b) Updated within 60 business ~~30~~ days of the completion of construction~~,~~ or maintenance (defined as purging into or out of service), or discovery of a main or service;
> >
> > (c) Kept and maintained at a secure location; and
> >
> > (d) Available to all applicable operating personnel.

(2) Facilities that are under active construction or maintenance, which alters the facility's location or size, must be identified in the Operator's maps or ~~and~~ records and be available to operating personnel.

(3) Operators shall establish ~~a~~ training for all construction and maintenance staff, including contractors, on its maps and records procedures.

(4) Operators shall implement a Quality Assurance and Quality Control program to identify and correct inaccuracies of its maps and records ~~conduct annual inspections of its maps and records to identify inaccuracies~~.

(5) Operators shall comply with all guidelines set by the Division regarding service quality metrics.

220 CMR 101.09(1) Single-Feed System

Proposed Regulation:

(1) Single-Feed System. Each operator with a single-feed distribution system (i.e., a system with one confirmed source such as a single district regulator supplying gas downstream of the regulator) shall measure the gas pressure in the system at all times over the course of the year and report the results to the Department by March 15th of each year in a format to be determined by the Department, in accordance with the following:

(a) Prior to January 1, 2025, operators may use telemetering or recording pressure gauges as may be required.

(b) As of January 1, 2025, telemetering shall be the sole method used to measure the gas pressure at all times for each single-feed distribution system.

(c) In addition to the annual report, operators shall report to the Department any abnormal pressure variations within 72 hours of discovery.

Discussion – Abnormal Pressure Variations, 220 CMR 101.09(1):

The proposed regulation adds an undefined term in 'abnormal pressure variations' that creates an ambiguous additional criterion for reporting beyond the Telephonic Incident Reporting required by proposed regulation 220 CMR 101.09(6). Additionally, pressure variation within a distribution system, particularly one that is a single-feed, is normal as the active variables involved, most notably customer gas usage, fluctuate. Proposed regulation 101.09(6), Telephonic Incident Reporting Requirements, and the criteria specified by the Department in the Telephonic Incident Notification Procedures for Operators dated November 19, 2019, already establish the two bounds where identification of an abnormal operating condition would require notification to the Department. These bounds are defined as any potential exceedance of MAOP on the distribution system, and any under-pressure scenario that results in the unsafe operation of customers' appliances and results in the loss of gas service to customers. All other pressure variations between these two bounds should be considered 'normal pressure variations' and not warrant notification to the Department. Accordingly, NGA recommends that part (c) of this regulation be struck.

Recommendations: Revise 220 CMR 101.09(1) Single-Feed System as follows:

> (1) Single-Feed System. Each operator with a single-feed distribution system (i.e., a system with one confirmed source such as a single district regulator supplying gas downstream of the regulator) shall measure the gas pressure in the system at all times over the course of the year and report the results to the Department by March 15th of each year in a format to be determined by the Department, in accordance with the following:
>
> (a) Prior to January 1, 2025, operators may use telemetering or recording pressure gauges as may be required.
>
> (b) As of January 1, 2025, telemetering shall be the sole method used to measure the gas pressure at all times for each single-feed distribution system.
>
> ~~(c) In addition to the annual report, operators shall report to the Department any abnormal pressure variations within 72 hours of discovery.~~

Conclusion

NGA appreciates the opportunity to provide these additional comments on behalf of our

Massachusetts' Distribution Company and Pipeline Contractor Members. Our goal in offering these comments is to provide practical alternatives for the Department's consideration, which meet or exceed the intended pipeline safety objectives of these regulations. Please contact us if you have any questions.

Sincerely,

Jose Costa

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