Subcommittee on Energy
Hearing on
"The State of Pipeline Safety and Security in America"
May 1, 2019

Mrs. Christina Sames
American Gas Association

The Honorable Cathy McMorris Rodgers (R-WA)

1. I know your pipeline companies are serious about improving their safety records and incorporating lessons-learned from prior accidents.

    a. Can you provide some recent examples of lessons-learned, or recommendations made by PHMSA or NTSB that have been implemented?

    RESPONSE:

AGA works closely with its members to share information and promote the implementation of practices that have the potential to prevent similar incidents from occurring, which would appear to have same cause as those being investigated by NTSB. AGA can provide several examples from past incidents, but will limit its response to the incident which occurred on September 13, 2018, in the Merrimack Valley in Massachusetts

Following the Merrimack Valley incident, AGA and the industry took quick action based on the apparent circumstances of the incident, including the information initially shared by NTSB in its preliminary report on October 11, 2018

- Issuing a survey to its members to gather practices in place that are intended to prevent over-pressurization
- Collecting information from a variety of sources including technical publications and industry experts
- Holding a roundtable of several hundred operators and service providers to review the practices submitted
- Bringing together subject matters experts from over 30 companies to analyze the cumulative results and identify leading practices

Using this information, AGA and its members developed a white paper: *Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event*, which was issued just two and a half months after the incident. The paper identifies 63 practices which address over-pressurization across the gas delivery system, and which go beyond low pressure systems. Based on conversations with its members, AGA knows that operators are performing a gap analysis to compare their operating practices against those in the document.

Pipeline Safety Management Systems is another example of AGA members being pro-active. On May 21, AGA's Board issued a resolution for all AGA member companies to implement Pipeline Safety Management Systems or API RP1173 within the next 3 years.

To address the NTSB recommendation following the Merrimack Valley incident that operators have certain documents or plans sealed by a professional engineer prior to commencing work, AGA created a white paper *Skills and Experience for Effectively Designing Natural Gas Systems.* The purpose of this document is to provide guidance to operators on how to develop, maintain, and enhance the key technical competencies required to safely and effectively perform engineering work functions for natural gas systems. AGA's member companies are relying on this document to identify any needed changes in their procedures for approving work packages involving engineering design.

PHMSA periodically issues advisory bulletins on any items that warrant added consideration from operators. While these advisory bulletins do not represent new regulatory requirements, operators pay close attention to the information shared by PHMSA and sometimes even make enhancements to operating procedures based on the information conveyed in the bulletins.

In addition to the above, AGA holds an annual Executive Leadership Safety Summit to share lessons learned from incidents and how other industries approach safety. AGA has held approximately a dozen Safety Summits in response to a recommendation from NTSB's Christopher Hart. AGA also created the Plastic Pipe Database and the Plastic Pipe Database Committee which collects and analyzes plastic pipe failures. This was in response to an NTSB recommendation and the database currently has over 85,000 failures. Finally, AGA has worked with state commissioners on programs that allow for the quicker replacement of older pipelines. This was in response to Secretary LaHood's Call to Action and 43 states and the District of Columbia now have programs.

<u>The Honorable Tim Walberg (R-MI)</u>

1. What is the difference between manual valves, Automatic Shut-off Valves and Remote Control Valves?

    a. Can you please provide the benefits, challenges, and performance expectations associated with the installation of Automatic Shut-off Valves and Remote Control Valves on existing and new natural gas pipelines.

    RESPONSE:

There are several important differences between these three types of valves, and how they are potentially used on a transmission pipeline in a gas distribution operator's system.

Manual Valves – A valve that has a closure element that is controlled locally by operating personnel. These valves do not have powered actuators that allow for automated or remote control of natural gas flow and they require personnel to be on site to manually turn the valve to closure.

Automatic Shut-off Valves (ASV) – A valve that has a powered actuator to close the valve automatically based on data sent to the actuator from pipeline sensors. The sensors send a signal to close the valve based on predetermined criteria, generally based on pipeline operating pressure or flow rate. The ASV does not require human evaluation or interpretation of information surrounding an event to determine if the event is a legitimate pipeline issue and closes automatically based on the established criteria (e.g., the valve closes when the pressure in the line drops below a certain point).

Remote Control Valve (RCV) – A valve equipped with an actuator that allows an individual to operate (open, throttle or close) the valve based on an order (signal) from a remote location, such as a control room. The use of an RCV requires operating personnel in the remote location to review and evaluate data in their pipeline system and make a determination of whether a pipeline issue exists based on available information. This available information can be changes in the operating pressure and flow data transmitted from the pipeline, or communications from the public, emergency responders or company personnel on site. Based on the available information, if the gas controller determines that there is a problem that would require a valve operation, they may execute a command to operate the valve remotely.

AGA members have been voluntarily installing ASVs and RCVs on new transmission pipeline construction for the past 5 years, where practicable and feasible, under AGA's Commitment to Enhancing Safety[1]. AGA's members have also retrofitted existing transmission lines where their analysis has shown safety benefits. AGA members recognize that the potential benefits of installing ASVs and/or RCVs include the following[2]:

- Timely interruption of the fuel source to a pipeline event allowing improved emergency response to the affected area.
- Providing a means to close valves more rapidly as compared to manually operated valves in remote or difficult to access areas.

[1] *AGA's Commitment to Enhancing Safety*, AGA's Operations Managing Committee, https://www.aga.org/sites/default/files/agas_commitment_to_enhancing_safety_-_revised_october_2015.pdf Revised October 2015.
[2] *Design Guidelines for Installation of Automatic Shut-off Valves (ASV) and Remote Control Valve (RCV) Systems in Natural Gas Transmission Pipelines*, American Gas Association Distribution and Transmission Engineering Committee, October 2012

- Closing valves more rapidly provides the opportunity for maintaining gas service to customers located outside of the affected pipe section by maintaining gas pressure to these customers.
- Reducing the economic and environmental issues associated with a large unplanned gas release.
- Providing additional system control functionality to deal with planned pipeline maintenance and shutdowns, and abnormal operating situations other than unplanned gas releases.

When utilizing ASVs and/or RCVs, there are a number of concerns that need to be taken into consideration. These include the following[2]:

- Unintended or inappropriate automated valve closure. For ASVs, this could possibly result from increased flow rates or reduced pipeline pressures during winter peak load conditions and other less frequently occurring operational variations at normal times. For RCVs, this could potentially be caused by a human decision-making error in deciding when to close an RCV. Industry experience has shown that ASVs are much more susceptible to unintended or inappropriate valve closure than RCVs.
- A valve closure, whether intended or unintended, may lead to widespread customer outages where re-establishing service could take days or weeks with the potential for human hardship and property damage in certain climate conditions.
- Susceptibility to physical and cyber security threats.
- Possibility of equipment failures causing the valve control system and the automated valve to fail to function as designed.
- Realization that not all unplanned gas releases would necessarily trigger an ASV to operate, or for an RCV, be identified by the SCADA system for a gas controller to take action.

b. What considerations must natural gas pipeline operators take into account when installing Automatic Shut-off Valves and Remote Control Valves on transmission lines that are integrated within distribution systems, and how do these vary by operator?

RESPONSE:

Every pipeline operator should begin with a clear and consistently applied set of guidelines and criteria for the utilization and installation of ASVs and/or RSVs. The 2013 GAO report on Pipeline Safety and Operator Incident Response[3] reported that "*The primary advantage of installing*

[3] *GAO Report to Congressional Committee: Pipeline Safety – Better Data and Guidance Needed to Improve*

automated valves is that operators can respond quickly to isolate the affected pipeline segment and reduce the amount of product released; however, automated valves can have disadvantages, including the potential for accidental closures—which can lead to loss of service to customers or even cause a rupture—and monetary costs. Because the advantages and disadvantages of installing an automated valve are closely related to the specifics of the valve's location, it is appropriate to decide whether to install automated valves on a case-by-case basis."

In developing these guidelines and criteria, the following factors may be considered:

- Specific physical criteria of the pipeline such as diameter, operating pressure, predicted impact radius if failure were to occur, material strength, pipe condition and material fabrication. Pipeline properties vary between pipelines and operators must take these factors into account when determining the type of valve to install and its potential benefits.
- For ASVs, the flow and pressure within the pipeline and pressure and flow fluctuations. ASVs close when they sense a drop in pressure and an increased flow of gas. For lines that have the potential for large pressure or flow fluctuations, such as many intrastate transmission lines that feed natural gas distribution systems, ASVs are not effective since they will not work as designed.
- Threats from natural forces, such as earthquakes, landslides, flooding, subsidence zones and other special geographic features.
- Valve location and accessibility to account for geographic conditions, permitting, and other constraints.
- Human impact consequence factors if the pipe were to fail, such as population density around near the pipeline and structures that may be challenging to evacuate.
- Expected time to identify and isolate an affected pipeline section and subsequently to depressurize the pipeline based on current system design.
- Capital and operating costs. For example, the cost to install a new ASV or RCV on a new transmission pipeline for fully replaced transmission pipeline typically range from $100,000 to $1,000,000 per valve. However, the cost doubles when installing a new ASV or RCV in an existing transmission pipeline
- Minimum magnitude of a pipeline event that realistically can be detected and managed through ASV or RCV operations.
- Magnitude of customer service impacts (customer loss of gas and customer restoration efforts).

Pipeline Operator Incident Response, Governmental Accountability Office, GAO-13-168, January 2013.