May 4, 2012

DOT Docket Management System
West Building, Ground Floor, Room W12-140
1200 New Jersey Avenue, S.E.
Washington, D.C. 20590-0001

VIA ELECTRONIC FILING (http://www.regulations.gov)

Re: *Pipeline Safety: Public Comment on Leak and Valve Studies Mandated by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011*, Docket No. PHMSA–2012–0021

Dear Sir or Madam:

The Interstate Natural Gas Association of America (INGAA) submits this comment letter per the Notice of Public Comment issued in the referenced docket by the Pipeline and Hazardous Materials Safety Administration (PHMSA) on March 29, 2012, and published in the *Federal Register* on March 30, 2012 (the Notice).[1] INGAA is a non-profit trade association that represents the interstate natural gas transmission pipeline industry. INGAA's members represent approximately two-thirds of the pipelines and over 65 percent of the mileage comprising the U.S. natural gas transmission pipeline system. The interest of INGAA's members in the matters addressed in the Notice is self-evident.

Section 4 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act)[2] directs the U.S. Comptroller General to conduct a study "on the ability of transportation pipeline facility operators to respond to a . . . [natural] gas release from a pipeline segment located in a high consequence area."[3] The Notice solicits public comment on the scope of the section 4 incident response study.[4]

The title of Section 4 refers to valves and the caption of this docket refers to a valve study, but emergency response involves far more. The comments presented herein describe INGAA's view on emergency response and effective incident management. In addition, INGAA identifies particular topics that should be addressed in the Section 4 study.

Introduction

The first step in determining the scope of the incident response study is to define the policy framework the paper will address. For incident management, and indeed for many of the other topics PHMSA will be addressing under the 2011 Pipeline Safety Act, the proper policy

---

1 77 Fed. Reg. 19414.

2 Pub.L.No. 112-90 (2012).

3 *Id*. § 4 (adding 49 U.S.C. § 60102(n)(2)).

4 The Notice also solicits public comment on the scope of a separate PHMSA-sponsored study, required by a different section of the 2011 Pipeline Safety Act, concerning leak detection systems. INGAA is addressing the leak detection study in a separate filing.

framework is performance-based regulation. As INGAA noted in response to PHMSA's advance notice of proposed rulemaking on natural gas pipeline safety,[5] performance-based regulation is superior to prescriptive regulation, particularly for incident management, because performance-based regulation encourages safety-enhancing innovation and speed its deployment.[6] Incident mitigation is currently subject to performance-based regulation and should remain so.

With performance-based regulation setting the framework, the study should assess incident management to determine which procedures and tools (1) provide the most effective response to a gas release from a pipeline segment located in a High Consequence Area (HCA) and (2) enable an affected pipeline to be shut down swiftly. Each stage of the incident management process, from planning through training and education to incident avoidance and mitigation, should be parsed out and analyzed. Each step should be evaluated to minimize the time it takes to isolate and evacuate a pipeline after a catastrophic event.

Once one adopts a performance-based perspective, one can see that while valve selection and spacing are important, public safety requires a comprehensive, integrated and more detailed review of incident response. Performance-based Incident Mitigation Management (IMM), a concept INGAA introduced in its ANPRM comments,[7] focuses not only on using valves, but also on planning, coordination, communication and other tools. IMM is the appropriate approach to improving incident response, reducing incident duration and, especially, minimizing adverse impacts. The study should cover all the aspects of incident mitigation, management and response, including how operators:

- Detect failures
- Place and operate valves
- Evacuate natural gas from pipeline segments
- Determine their priorities in coordination efforts with emergency responders
- Mitigate an incident's immediate consequences
- Mitigate an incident's broader impact on other customers' supply

Each of these steps presents opportunity for time savings. Since rapid recognition and response are essential elements of incident management, and automation can be part of an effective response, INGAA members have committed to having personnel on scene within one hour to coordinate with first responders and isolate failures. Where personnel cannot respond promptly, valve spacing, selection and operation are all important, but they only address one aspect of mitigating the consequences of an incident.

To achieve the comprehensive response this issue deserves, incident mitigation is best handled by creating and implementing plans and procedures that are built upon the same risk management principles and performance objectives that underlie operators' baseline assessment

---

[5] *Safety of Gas Transmission Pipelines*, 76 Fed. Reg. 53,086 (ANPRM).

[6] Topic-by-Topic Comments, 55-60, Appx. 1, Dkt. No. PHMSA-2011-0023 (INGAA, filed Jan. 20, 2012).

[7] *Id*.

plans and several other elements of their integrity management programs. Risk-based IMM provides a comprehensive approach to incident mitigation, and INGAA urges PHMSA to consider risk-based IMM as a model for future regulations. Just as PHMSA required a baseline assessment plan in the original integrity management rule, PHMSA should now direct operators to conduct an IMM review.

The Stages of Incident Response

As shown in Figure 1, incident response involves concurrent and overlapping actions by three involved parties: the pipeline company, emergency responders and the public. The pipeline company's responsibilities are shown in the blue boxes. The emergency responders' responsibilities are shown in the purple boxes. Although the public does not have responsibilities in the sense that emergency responders' are responsible for managing the incident scene, it is still important to recognize that the public's ability to recognize a hazard rapidly and evacuate to safety can mitigate or eliminate the consequences of the accident. A comprehensive incident response model recognizes the public's role, and Figure 1 notes the public's activities in aqua.

The incident response study should investigate the roles and responsibilities of all three parties. While each party's efforts are distinct and separate, they are highly dependent on each other for success.

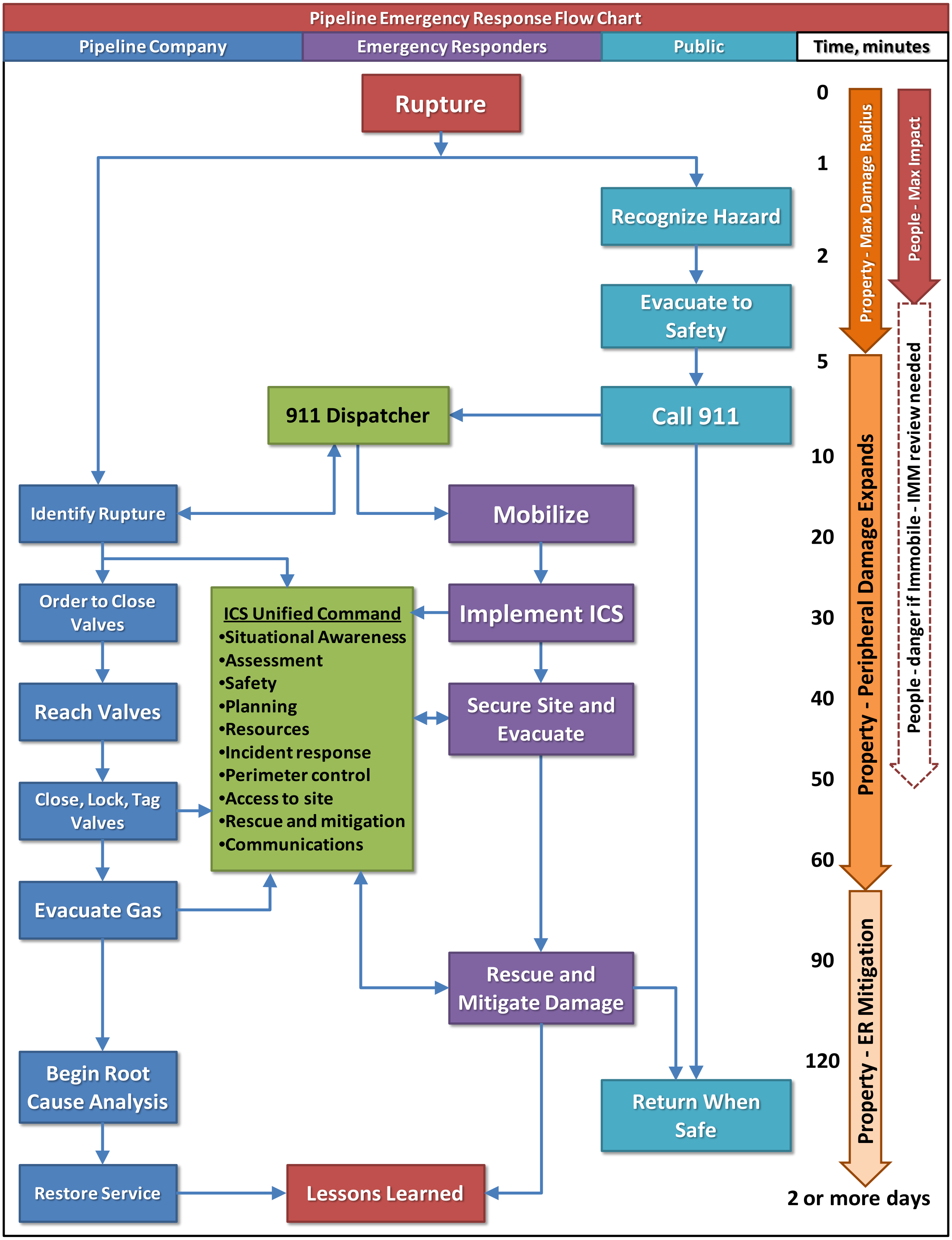


Figure 1 - Pipeline Emergency Response

The most critical aspect of mitigating the seriousness of the consequences of an accident depends on whether and how citizens have been educated to recognize a pipeline accident and to evacuate safely. The ability of the public to call 911 or the pipeline company after reaching a safe position will assist the pipeline company in quickly identifying the location of the incident, so it can take action. How efficiently the pipeline company then responds to the incident and controls gas flow, directly impacts the emergency responder's speed in instituting the Incident Command System (ICS) and Unified Command to begin mitigating additional damage.

Finally, there are human factors that should be considered in the scope of this study beyond the response of pipeline employees to reach an accident site or the awareness of a pipeline control room of an incident occurring and then reacting decisively. Emergency responders should be knowledgeable of their environment, including the location of pipelines, and make this information known in the community. The public near the pipeline right-of way should be aware of the presence of a pipeline, the steps to take during an accident and how to translate that knowledge into action in the event that an incident occurs.

What is INGAA Trying to Achieve?

INGAA's members, as pipeline companies, work every day toward a goal of zero incidents; that is, a perfect record of safety and reliability. Consistent with this broadly-publicized goal,[8] INGAA members' primary focus is on preventive measures to prevent gas releases. Beyond these preventive measures, INGAA members recognize the importance of having those processes, identified in its commitments to safety, in place for incident mitigation.

To meet these objectives, rapid recognition and response to pipeline incidents are essential. In meeting these objectives, operators should have maximum flexibility to choose the most appropriate incident mitigation tools for the circumstances in which they operate. Further, operators should have maximum flexibility to prioritize the deployment of incident mitigation measures so they are put in place first where the consequences of a failure are greatest. For example, pipeline companies should give special consideration to the needs of "hard to evacuate" sites by planning in advance for the measures needed to protect these populations in the event of a pipeline emergency.

INGAA's Response Time Commitment

INGAA agrees with the spirit of NTSB's recommendation to reduce damage through prompt valve closure and pipeline isolation. The INGAA commitment is to achieve a one-hour response in populated areas from notification of the rupture to valve segment isolation for pipelines greater than 12 inches in diameter. INGAA proposes to utilize a risk-based approach on 12-inch and smaller diameter lines based on the HCA definition criteria.

[8] In March 2011, INGAA's board of directors adopted five "Guiding Principles for Pipeline Safety." The first guiding principle is: "Our goal is zero incidents — a perfect record of safety and reliability for the national pipeline system. We will work every day toward this goal." The Guiding Principles can be accessed on INGAA's web site at http://www.ingaa.org/File.aspx?id=13189.

INGAA is conducting a member survey to collect data on the use of automation and power actuators and the need for additional technology to achieve the desired response time, in accordance with the chart below. INGAA will analyze and evaluate the data to inform the discussion of IMM. Several major INGAA members are far along in this kind of analysis and in many cases, moving to some form of automation, such members are likely to automate hundreds of valves.

			INGAA members are filling in the number of valves below.					
				Change Needed		**Status Quo Acceptable**		
Populated Area	**Diameter**	**Response Time** [2]	**Already Automated** [3]	**Will Need Automation** [3]	**Will Only Need Actuator** [4]	**Have Actuator** [4]	**Manually Operated** [5]	**Total**
Class 3, 4 and HCAs [1]	Greater than 12”	One hour						
	12” and under	Risk analysis based on IMM		For later IMM review	For later IMM review			
Class 1 and 2	All diameters	Current Practices		Current Practices	Current Practices			
Total	All diameters	**NA**						

[1] Valves bracket the HCA or the HCA is contained within this area.
[2] Response time is from notification of the incident to valve closed.
[3] Automation means either automatic shut-in valve (ASV) or remote control valve (RCV), including powered actuator.
[4] Powered actuator but no automation (local push button). Note that adding an actuator may be all that is needed to achieve a one-hour response.
[5] Manual means no powered actuator or automation.

Valves include mainline blocks, crossovers, laterals, receipts, deliveries, interconnects and other valves needed to isolate the section of the incident.

Do not count a valve more than once. For example if a valve is within or bracketing an HCA, count it in the HCA row, but not in Class 1 and 2.
As another example, if a valve needs to be automated and also needs a powered actuator, please count it only in the column “Will Need Automation”.

For 12-inch and smaller lines in Class 3, 4 and HCAs, companies may not have completed an IMM study. If so, then assume no new automation or actuators for now. The IMM review will follow.

It is critically important to prepare and train control room personnel to know when to shut down a portion of the system. For example, have controllers been prepared to make the critical decision to shut down? Do controllers feel empowered and supported by senior management and understand in advance the impacts of shutdown throughout the pipeline system? Have these impacts been reviewed with management so that all scenarios are anticipated and the shutdown decision requires little inter-organizational coordination during an event? The process of preparing, practicing, and building situational awareness is important to saving critical time in identifying and mobilizing a response.

The study should consider if there are realistic ways to improve technology to indicate a rupture faster than a pressure drop and debugging some of the issues in evolving technology. Determining who should initiate the 911 call, and what the public should be instructed to do when calling the local authorities, the operator, or both, are critical to shaving time off mobilizing an effective response. The study should consider how to encourage the public to identify and report a rupture to 911 and the pipeline company. In addition, the Section 4 study should address the extent to which operator's controllers are prepared with regional 911 structures and call numbers.

Why the Study Should Focus on IMM

IMM is a performance-based approach to mitigation. Prevention of an incident is the primary focus. However, in the event that an incident occurs, response becomes critical. IMM should evolve from risk analysis and be part of integrity management and emergency response planning. The purpose is to identify where along the pipeline a failure in a populated area, and possibly a secondary fire, would have the most catastrophic consequences to public sector and to take action to improve incident response, reduce incident duration and consequently reduce the impact of the incident. Pipelines should review, for example, how operators detect failures, how they locate and operate valves, how they evacuate natural gas from pipeline segments, and how they determine priorities in their coordination efforts with emergency responders. Key considerations include:

- Improving mitigation performance, minimizing incident impact and reducing the duration of an incident
- Prioritizing deployment of mitigation measures, applied first where consequences of failure are greatest and where there are special population requirements, or special site considerations like critical infrastructure, extraordinary population density, building construction and fire breaks
- Identifying comprehensive actions to improve incident response, in consultation with emergency responders, on a worst first basis
- Planning focuses on populated areas: HCAs and Class 3 and 4 on pipelines with diameter greater than 12 inches, and HCAs and Class 3 and 4 on pipelines with diameter 12 inches or less based on risk analysis outcome

The following actions are a sampling of processes that are important for this study to consider throughout the mitigation planning process.

1. Pre-Incident Planning

- Where operators are using automatic shut-in valves (ASVs)/remote control valves (RCVs), operate with crossovers closed, automate the crossovers if warranted, or operate with crossovers open, incident response planning should address operation in this mode

- Develop an overarching IMM plan based on risk analysis, and prioritize the consequences in populated areas at highest risk from secondary fires due to a range of site specific factors in consultation with emergency responders (e.g. high population density, building construction type, location of critical infrastructure and fire breaks). Identify difficult to evacuate sites and work with emergency responders and local officials on ways to support those facilities, train their response teams, or suggest ways they can harden their facilities
- Train on National Incident Command System and exercise with responders and other officials
- Integrate loss of service into overall IMM risk analysis

2. Identifying Rupture

- Define how SCADA processes can be used to identify a rupture and evaluate the value of adding pressure sensors and monitoring protocols
- Develop a policy on calling 911 when preliminary information appears to identify a potential rupture, including a review of procedures and train gas controllers on who they should call and in what order
- Develop a policy educating residents on who they should call and when to evacuate
- Educate customers on the consequences if services are curtailed

3. Ordering Valve Closure

- Define authority to close valves based on available information and work to overcome inertia/bias against closing valves
- Build situational awareness of system impacts in advance through training and coaching

4. Reaching Valves and Closing, Locking and Tagging Them

- Develop plans to achieve a response time goal of one-hour from incident recognition to isolation of pipeline segments located in populated areas
- Where automation is needed, develop and implement a plan

5. Evacuating Gas

- Study pipeline system and develop a plan for improving gas evacuation speed
- Review regulations and need for blow down valves, and review and identify where such valves are located
- Incorporate lessons learned back into IMM plan

The incident response study should also examine the frequency and consequences of instances where automated valves close falsely. For example, many gas customers are very sensitive to the consequences of shutting off supply, particularly to critical facilities like hospitals, nursing homes and power plants, and the time, labor and disruptive effects on the public and their safety in cold or hot weather. Unfortunately, there are a number of instances where false closures of automated valves located near the market areas have triggered service losses, including New York City, Chicago, and recently around Santa Fe.

The Cost of Automating and Installing Valves

The cost of automating valves is a significant consideration in IMM, and it should be a significant element of the incident response study. For example, in many cases where pipeline companies are performing an analysis of the consequence factors along their pipelines, they are making decisions to automate valves or to improve the reaction time to close the valve.

Presentations at the PHMSA workshop provided differing cost estimates of automating valves. INGAA offers its own costs estimates to respond to the workshop presentations and to provide guideposts for the incident response study.

Pipeline valve operators typically fall into four categories:

- Manual Valve - operated by a person on site using a hand wheel or specialty wrench
- Power Assisted Valve - operated by a person on site typically using a valve actuator powered by gas pressure, hydraulics or electric motor
- Automatic Shut-in Valve (ASV) - operated by a specifically designed control system, with no human intervention, if local operating conditions exceed programmed limits, utilizing a power-assisted valve actuator
- Remote Control Valve (RCV) - operated by a person communicating with the valve control equipment from a remote location, utilizing a power-assisted valve actuator

Different valve operating methods may be combined, such as an RCV that has programmed automatic shut-in limits, and onsite operation by either a power-assisted valve or a manual value, such as a hand wheel. Sometimes an operator retrofit is not possible and, if so, the operator must cut out the old valve and replace it with an entire new valve set.

A summary table of high end and low end cost estimates for automating and installing valves on pipelines of various sizes is provided below. The figures represent a reasonable minimum and maximum cost estimate; however, occasionally, sites may include a combination of technical issues and urban density conditions that could double the cost, e.g., a valve site in a vault beneath a roadway. Given that operators will have hundreds of valve sites to automate, it is very likely that some individual cases will exceed estimated “high case” costs for INGAA member companies. Specific elements within the table are discussed in the subsections that follow.

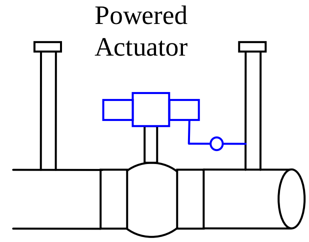
INGAA Experience (In Dollars)						
Automating an Existing Valve						
	12" Valve		**30" Valve**		**42" Valve**	
Item	**Low Case**	**High Case**	**Low Case**	**High Case**	**Low Case**	**High Case**
Actuator	-	30,000	-	80,000	-	120,000
ASV System (no bottle)	30,000	-	30,000	-	30,000	-
RCV Adder	-	100,000	-	100,000	-	100,000
Alternate Power	-	25,000	-	25,000	-	25,000
Reserve Gas Bottle	-	5,000	-	10,000	-	15,000
Building	-	15,000	-	15,000	-	15,000
Total	**30,000**	**175,000**	**30,000**	**230,000**	**30,000**	**275,000**
Installing a New Valve						
	12" Valve		**30" Valve**		**42" Valve**	
Item	**Low Case**	**High Case**	**Low Case**	**High Case**	**Low Case**	**High Case**
Install new valve	150,000	170,000	400,000	420,000	650,000	670,000
Actuator	-	30,000	-	80,000	-	120,000
ASV System	30,000	-	30,000	-	30,000	-
RCV Adder	-	100,000	-	100,000	-	100,000
Alternate Power	-	25,000	-	25,000	-	25,000
Reserve Gas Bottle	-	5,000	-	10,000	-	15,000
Building	-	15,000	-	15,000	-	15,000
Total with new valve	**180,000**	**345,000**	**430,000**	**650,000**	**680,000**	**945,000**

For comparative purposes, members of the American Gas Association (AGA) operate transmission systems in more highly populated locations and their estimates reflect the high population density and associated costs of working in congested urban environments with smaller diameter pipelines.

AGA Experience: Cost Factors per Installation (In Dollars)		
Cost Item	Low End	High End
Materials - valve, actuators, controls, etc.	10,000	250,000
Need for a new/replaced valve – basic construction	75,000	300,000
Need for a new/replaced valve – complex construction	200,000	750,000
Pipeline outage/customer service continuity	50,000	600,000
Power and communications availability	10,000	250,000
Permitting, land, environmental constraints	10,000	250,000
Site improvement/restoration	5,000	200,000

Listed below are typical variables that can affect the cost of valve automation shown in the table above. These breakdowns help illustrate the relative size of the various expenditures and why there is a wide variance of costs based on the use and application of the technology.

1. Replacing or Installed Actuators on Gear-Operated Valves



Valves on larger diameter pipelines may require hundreds of turns using a hand gear wheel, so a power-assisted valve actuator can be installed. Such an actuator is also necessary for closing automated valves; however, not all existing actuators are compatible for automated service.

For example, some actuators cannot be automated and must be replaced when automation is required. Some actuators rely upon high gas pressure power-assist to function properly and thus require a supplemental pressurized gas bottle to operate reliably during a nearby incident that could draw down (bleed away) the gas pressure available for power-assist.

In the pictures below are some examples of actuators installed on gas transmission pipelines.


Ball Valve - Direct Gas Actuator


Gate Valve - Gas Motor Actuator

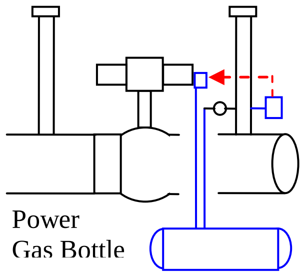

Gate Valve - Linear Actuator

Examples of the all-in average cost for installing or replacing a valve actuator on an existing mainline valve are:

On 12” Pipeline	$30,000
On 30” Pipeline	$80,000
On 42” Pipeline	$120,000

2. Retrofitting ASVs

The simplest ASV system adds mechanical devices (to sense pressure), signal tubing, a trip system to engage a power-assisted valve actuator, and possibly an enclosure to house the equipment. For retrofitting an existing valve, a pressurized bottle may also be required for some types of valve actuators to supplement power gas in the event of low pipeline pressure due to a failure.



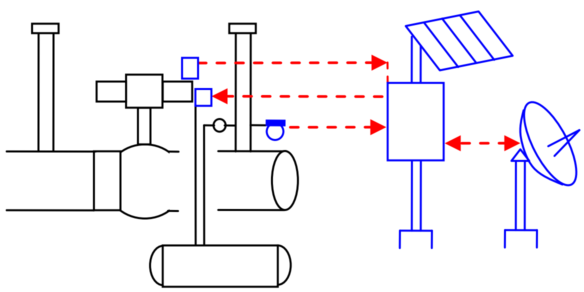
ASV retrofit of an existing valve would require specialized knowledge, so it might be done using a manufacturer representative traveling with a small work crew to assist with piping, tubing, mounting, pressure testing, calibration, and gas bottle installation. A person experienced in operating equipment in natural gas service would also be needed for venting, purging, and commissioning. A ballpark cost for a very basic ASV retrofit (assuming the valve and actuator are compatible with ASV) is about $40,000, although bottle size and cost could vary depending upon pipeline diameter and actuator type.

Based on quotes from a major actuator manufacturer, the cost of materials alone associated with a new actuator are:

	Ball Valve Actuator	**Gate Valve Actuator**
On 12” Pipeline:	$34,000	$52,500
On 30” Pipeline:	$43,500	$66,500
On 42” Pipeline:	$50,000	$76,000

3. Retrofitting RCVs

An RCV system typically adds a computer, a solar panel for power, and a battery and charger for back-up power. Electronics include devices to monitor pipeline pressure, detect valve position, send alarms, and activate valve closure. RCVs may have additional devices for enhanced monitoring.



Communications equipment associated with RCVs are also required to transmit signals back and forth, and may include VHF radio, satellite systems, cellular phone systems, or a modem and telephone connection. VHF is simple and low cost, but only works where there is a line-of-site between antennas. Cellular phone systems have their limitations: they may not have coverage or may not be reliable in many areas, have not proven to be very durable such that they can require frequent replacement, and can be a security risk due to easy access by anyone who has the phone number. Accordingly, radio and satellite systems are often a better fit. Satellite systems require greater power consumption, so they may cost more than a solar power system, especially in cold, northern latitudes. A lease-line for a telephone system will have a very high operating cost.

The all-in cost to retrofit an existing valve with an existing actuator for RCV function is about $100,000 plus a power gas bottle, if needed. This RCV system cost is independent of the pipeline diameter size.

In northern areas where snow and low sun angle can make solar power unreliable, the pipeline may need to add electrical service or a thermoelectric generator, at an added all-in cost of $15,000 to $30,000. A small building may need to be installed in some areas for greater security or reliability at an added all-in cost of $20,000 (metal) to $60,000 (concrete) depending upon the location, environment and available space. Sites may also require maintenance platforms, vault installations, low temperature design, etc.

Typical material costs for RCV components are:

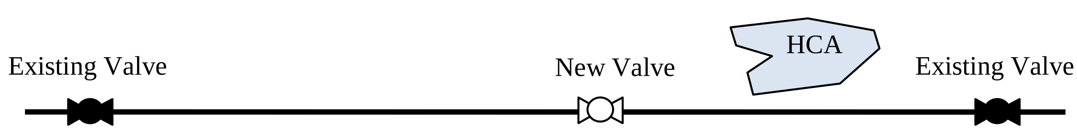
• Enclosure, relays, manifold, etc.	$ 3,000
• RTU	$ 5,200
• Battery backup	$ 5,300
• Valve retro-kit	$ 5,000
• Solar system	$ 1,700
• VSAT system	$ 2,300
• Differential pressure transmitter	$ 2,400
• **TOTAL**	**$24,900**

Costs for materials, installation, and support services can vary significantly depending upon the type of valve, type of actuator, and site specific requirements.

Once a valve site has full RCV capability, adding supplemental ASV functions typically only requires minor programming enhancements instead of installing mechanical devices.

4. Installing New Automated Valves

There may be situations where an existing valve cannot be automated because of physical restraints and must be cut out and replaced. While valves typically are spaced more closely on pipelines in these congested areas, a valve may not be located directly adjacent to an HCA populated area. Under this circumstance, the installation of an additional valve may be desired. These additional requirements add to the previous costs and impacts discussed, because it requires taking the pipe segment out of service for a period of time during the construction.



In market areas, where maintaining gas flow to customers may be limited to singular facilities, the economic cost of the loss or interruption of gas service to a customer can be very significant.

These customer costs vary based on customer demand, which, for example can be driven by weather for a local distribution company or manufacturing production schedules for an industrial plant.

Examples of the all-in average cost in 2012 dollars for installing a new manually-operated mainline valve facility are:

On 12" Pipeline: $150,000
On 30" Pipeline: $400,000
On 42" Pipeline: $650,000

In addition to the cost of the materials and the contract installation, the "all-in" cost for a project to install new valve facilities will include personnel providing various support services, which varies depending upon the project scale. These services can be about 20% to 30% of the cost of a project.

- Administrative support
- Accounting/invoicing
- Cost estimating
- Scheduling
- Budgeting
- Contracts administration
- Supervision
- Engineering
- Environmental permitting
- Land acquisition
- Drafting
- Purchasing and handling materials
- Project management
- Records
- Onsite inspection
- Operations personnel (e.g., valve commissioning, pipeline shut-in, gas venting and purging)

The basic valve installation would also include an access road, survey, leased temporary construction work space, fencing, site gravel, and vented gas cost. Environmental considerations, such as excavation permits, wetlands, archaeological survey, and protected species, will also impact the cost of basic valve installations. The above estimates assume a reasonable site acquisition cost; however, the costs associated with site acquisition could range from $5,000 in a remote area to $1,000,000 in a congested, urban area where available land is scarce. Above-ground valve sites are not popular. In fact, there even may be cases where an ASV or RCV site may need to be buried in a vault beneath a roadway, with a structural roof to support traffic loads.

A pipeline shut-down to install a valve must be carefully managed to ensure that natural gas service to homes, industry, power plants and other customers is minimally impacted by the installation of the valve, which requires taking the valve of the service. This can sometimes result in additional construction costs because of coordination with customers and the additional cost for alternative fuel supply to customers, possibly in the range of $300,000.

Leak and Rupture Detection Technologies in Use or Under Consideration

In considering the scope of this study, PHMSA's contractor should consider operators' use of the following rupture and leak detection technologies. A sensor's location can impact its ability to communicate information quickly back to the operator which can significantly improve incident mitigation by saving time in recognizing a rupture and mobilizing a response. Several of these technology systems have reached maturity and others have the potential for advancing the technology. But, in many cases, the notification (via phone to gas control) by a person along the right-of-way exceeds the performance of the technology systems identified below in confirming the release of gas, so it very important that this path of identification and notification be maintained and improved.

	Technology	Examples
Rupture	microphone - internal sound pattern	GasNet Atmos Wave Accoustic Systems Inc. WAVEGuard Ansel-Tec
	pressure - rate of pressure drop	Shafer Fcs Bettis/Emerson Biffi/tyco Cameron
	pressure - low trigger	Shafer Fcs Bettis/Emerson Biffi/Tyco Cameron
	flow rate - high trigger	Cameron GL Nobel Denton R&D
	vibration - fiber optic signal pattern	FFT Secure FoxTec expected to improve
	tracer - fiber optic signal break	FoxTec Westminster expected to improve
Leak	microphone - internal sound pattern	GasNet Atmos Wave Accoustic Systems Inc, Ansel-Tec WAVEGuard
	microphone - external sound pattern	Vista PALS, GE,
	flow rate - mass flow differential trigger	GL Nobel Denton
	vibration - fiber optic signal pattern	FFT Secure, FoxTec
	temperature - fiber optic signal pattern	FoxTec Sensornet
	gas composition - IR detection, foot, car, helicopter	Apogee Lasen Selma
	gas composition - fiber optic signal pattern	expected to improve
	gas composition - hollow tubing to gas chromatograph	Tyco Leak , expected to improve

Metrics Contemplated

The incident response study should consider how government, industry and the public would know if, and to what extent, the pipeline industry is making progress in mitigating the duration and consequences of a pipeline rupture. A properly applied, performance-based approach to mitigation is the most effective method to improve pipeline safety. Performance-based approaches work best when there are appropriate metrics that provides the needed opportunity for a review of processes in use and which will help determine what adjustments to practices and technology choices are needed. If this study concentrates more on the processes comprising risk mitigation rather than the achievement of specific prescribed parameters, the interstate pipeline industry can be more successful in reducing damage to people and property. The following metrics reflect a performance approach and indicators that are worth studying for their potential value in making decisions on recommended approaches going forward:

1. Individual Operators

Valve closure time following an emergency and summary of lessons learned including notification processes, response time and consequences.

2. Industry

- Complete the valve inventory based on INGAA response time commitment, including target and completion dates to automate necessary valves
- Compile the percentage of incidents where the INGAA one-hour response commitment was achieved
- Compile the percentage of segments where valves have been reviewed or modified in response to risk criteria
- Complete the overall design review and evaluate and document the capability of technology to detect leaks and ruptures on gas transmission pipelines
- Compile the percentage of pipeline segments in HCAs and Class 3 and 4, where IMM plans have been developed and implemented.

Conclusion

A study of pipeline operators' ability to respond to natural gas releases in a high consequence areas will, and should, involve far more than an examination of valve spacing and technology. Valve spacing, selection and operation are all important, but they only address one aspect of mitigating the consequences of an incident. The proper framework for a study of incident management is a performance-based review of all of the steps that go into incident mitigation management, including: the respective roles of the pipeline, emergency responders and the public; the numerous, individual steps that go into pipeline incident management; the impact of false closures of automated valves; the overall cost and individual cost elements associated with valve automation and installation; the current and potential impact of emerging leak and rupture detection technologies; and the identification and development of appropriate incident management metrics. All of these elements are essential to a thorough, performance-based, incident response examination consistent with the 2011 Pipeline Safety Act.

Respectfully submitted,

/s/
Dan Regan
Regulatory Attorney
Terry D. Boss
Senior Vice President of
Environment, Safety and Operations
Interstate Natural Gas Association of America
20 F Street, N.W., Suite 450
Washington, DC 20001
(202) 216-5900