U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

August 16, 2024

The Honorable Maria Cantwell
Chair
Committee on Commerce, Science, and Transportation
United States Senate
Washington, DC 20510

Dear Chair Cantwell:

Enclosed please find the report, titled "Review of Best Available Technologies or Practices and Pipeline Facility Designs for Preventing or Minimizing Natural Gas Releases During Planned Operations and Maintenance," in fulfillment of the requirement outlined in Section 114(d) of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020. Section 114(d) directed the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) to conduct a review of current and new technologies, practices, and pipeline facility designs that may be used to reduce or eliminate releases of natural gas into the atmosphere during planned pipeline operations and maintenance activities.

I hope this information is helpful. Should you require further information or assistance, please feel free to call me, or have your staff contact Damon Hill, Deputy Director of Governmental, International, and Public Affairs, by phone at 202-366-4424 or by e-mail at damon.hill@dot.gov.

A similar response has been sent to the Ranking Member of the Senate Committee on Commerce, Science, and Transportation; the Chairman and Ranking Member of the House Committee on Transportation and Infrastructure; and the Chair and Ranking Member of the House Committee on Energy and Commerce.

Sincerely,

Tristan H. Brown

Tristan H. Brown
Deputy Administrator

Enclosure

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

August 16, 2024

The Honorable Ted Cruz
Ranking Member
Committee on Commerce, Science, and Transportation
United States Senate
Washington, DC 20510

Dear Ranking Member Cruz:

Enclosed please find the report, titled "Review of Best Available Technologies or Practices and Pipeline Facility Designs for Preventing or Minimizing Natural Gas Releases During Planned Operations and Maintenance," in fulfillment of the requirement outlined in Section 114(d) of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020. Section 114(d) directed the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) to conduct a review of current and new technologies, practices, and pipeline facility designs that may be used to reduce or eliminate releases of natural gas into the atmosphere during planned pipeline operations and maintenance activities.

I hope this information is helpful. Should you require further information or assistance, please feel free to call me, or have your staff contact Damon Hill, Deputy Director of Governmental, International, and Public Affairs, by phone at 202-366-4424 or by e-mail at damon.hill@dot.gov.

A similar response has been sent to the Chair of the Senate Committee on Commerce, Science, and Transportation; the Chairman and the Ranking Member of the House Committee on Transportation and Infrastructure; and the Chair and Ranking Member of the House Committee on Energy and Commerce.

Sincerely,

Tristan H. Brown

Tristan H. Brown
Deputy Administrator

Enclosure

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

August 16, 2024

The Honorable Cathy McMorris Rodgers
Chair
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Dear Chair Rodgers:

Enclosed please find the report, titled "Review of Best Available Technologies or Practices and Pipeline Facility Designs for Preventing or Minimizing Natural Gas Releases During Planned Operations and Maintenance," in fulfillment of the requirement outlined in Section 114(d) of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020. Section 114(d) directed the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) to conduct a review of current and new technologies, practices, and pipeline facility designs that may be used to reduce or eliminate releases of natural gas into the atmosphere during planned pipeline operations and maintenance activities.

I hope this information is helpful. Should you require further information or assistance, please feel free to call me, or have your staff contact Damon Hill, Deputy Director of Governmental, International, and Public Affairs, by phone at 202-366-4424 or by e-mail at damon.hill@dot.gov.

A similar response has been sent to the Ranking Member of the House Committee on Energy and Commerce; the Chair and Ranking Member of the Senate Committee on Commerce, Science, and Transportation; and the Chairman and Ranking Member of the House Committee on Transportation and Infrastructure.

Sincerely,

Tristan H. Brown

Tristan H. Brown
Deputy Administrator

Enclosure

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

August 16, 2024

The Honorable Frank Pallone, Jr.
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Dear Ranking Member Pallone:

Enclosed please find the report, titled "Review of Best Available Technologies or Practices and Pipeline Facility Designs for Preventing or Minimizing Natural Gas Releases During Planned Operations and Maintenance," in fulfillment of the requirement outlined in Section 114(d) of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020. Section 114(d) directed the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) to conduct a review of current and new technologies, practices, and pipeline facility designs that may be used to reduce or eliminate releases of natural gas into the atmosphere during planned pipeline operations and maintenance activities.

I hope this information is helpful. Should you require further information or assistance, please feel free to call me, or have your staff contact Damon Hill, Deputy Director of Governmental, International, and Public Affairs, by phone at 202-366-4424 or by e-mail at damon.hill@dot.gov.

A similar response has been sent to the Chair of the House Committee on Energy and Commerce; the Chair and Ranking Member of the Senate Committee on Commerce, Science, and Transportation; and the Chairman and Ranking Member of the House Committee on Transportation and Infrastructure.

Sincerely,

Tristan H. Brown

Tristan H. Brown
Deputy Administrator

Enclosure

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

August 16, 2024

The Honorable Sam Graves
Chairman
Committee on Transportation and Infrastructure
U.S. House of Representatives
Washington, DC 20515

Dear Chairman Graves:

Enclosed please find the report, titled "Review of Best Available Technologies or Practices and Pipeline Facility Designs for Preventing or Minimizing Natural Gas Releases During Planned Operations and Maintenance," in fulfillment of the requirement outlined in Section 114(d) of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020. Section 114(d) directed the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) to conduct a review of current and new technologies, practices, and pipeline facility designs that may be used to reduce or eliminate releases of natural gas into the atmosphere during planned pipeline operations and maintenance activities.

I hope this information is helpful. Should you require further information or assistance, please feel free to call me, or have your staff contact Damon Hill, Deputy Director of Governmental, International, and Public Affairs, by phone at 202-366-4424 or by e-mail at damon.hill@dot.gov.

A similar response has been sent to the Ranking Member of the House Committee on Transportation and Infrastructure; the Chair and Ranking Member of the Senate Committee on Commerce, Science, and Transportation; and the Chair and Ranking Member of the House Committee on Energy and Commerce.

Sincerely,

Tristan H. Brown

Tristan H. Brown
Deputy Administrator

Enclosure

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

August 16, 2024

The Honorable Rick Larsen
Ranking Member
Committee on Transportation and Infrastructure
U.S. House of Representatives
Washington, DC 20515

Dear Ranking Member Larsen:

Enclosed please find the report, titled "Review of Best Available Technologies or Practices and Pipeline Facility Designs for Preventing or Minimizing Natural Gas Releases During Planned Operations and Maintenance," in fulfillment of the requirement outlined in Section 114(d) of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020. Section 114(d) directed the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) to conduct a review of current and new technologies, practices, and pipeline facility designs that may be used to reduce or eliminate releases of natural gas into the atmosphere during planned pipeline operations and maintenance activities.

I hope this information is helpful. Should you require further information or assistance, please feel free to call me, or have your staff contact Damon Hill, Deputy Director of Governmental, International, and Public Affairs, by phone at 202-366-4424 or by e-mail at damon.hill@dot.gov.

A similar response has been sent to the Chairman of the House Committee on Transportation and Infrastructure; the Chair and Ranking Member of the Senate Committee on Commerce, Science, and Transportation; and the Chair and Ranking Member of the House Committee on Energy and Commerce.

Sincerely,

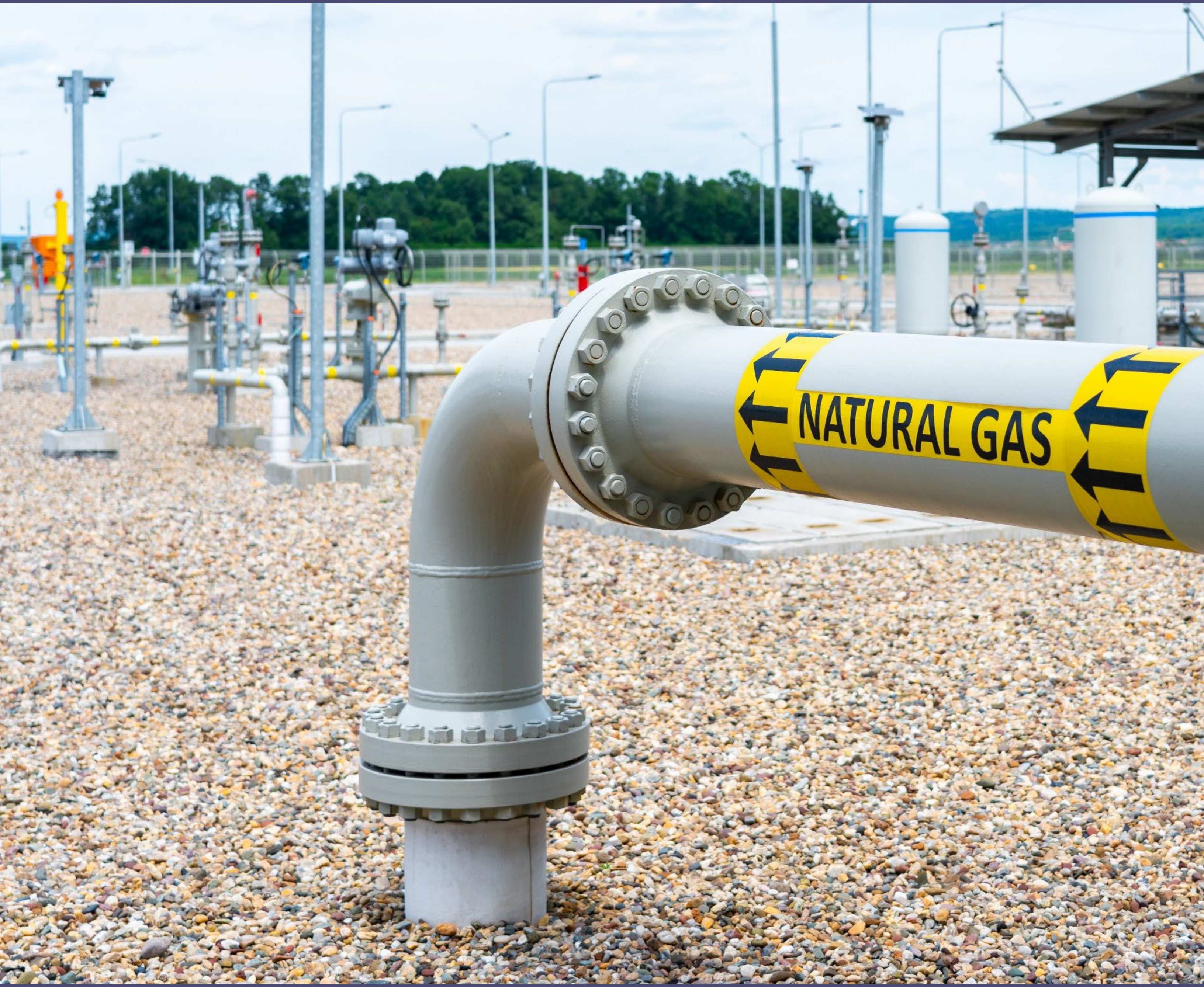
Tristan H. Brown

Tristan H. Brown
Deputy Administrator

Enclosure

U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration



Report to Congress
Review of Best Available Technologies or Practices and Pipeline Facility Designs for Preventing or Minimizing Natural Gas Releases During Planned Operations and Maintenance

Table of Contents

List of Tables

List of Figures

Photo Credit: Cover photo from Adobe Stock Images contributor SDF-QWE – stock.adobe.com AdobeStock_868100782

1 Executive Summary

In Section 114(d) of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020),[1] Congress directed the U.S. Department of Transportation (DOT) to review the best available technologies (BATs) or practices and pipeline facility designs for preventing or minimizing the release of natural gas[2] during planned repairs, replacements, or maintenance activities, as well as the best available technologies or practices for preventing or minimizing the release of natural gas when the operator intentionally vents or releases natural gas. The Pipeline and Hazardous Materials Safety Administration (PHMSA) prepared this report as it is the federal agency responsible for pipeline safety within DOT.[3] The review of the BATs, practices, and pipeline designs will aid in how best to reduce methane emissions from pipelines and pipeline facilities without compromising safety. While this report mainly presents methane reduction technology and practices, one should not conclude that safety takes second place to methane reduction. Overall, PHMSA believes both safety and methane reduction go hand in hand, but in areas where there may be safety impacts to certain methane reduction technologies or practices, it is noted in this report, accordingly.

Table 1 provides an overview of natural gas facility emissions by sector.[4, 5]

Table 1: Overview of 2021 Natural Gas Facility Emissions by Sector

Source	Net Methane Emissions (KT)	Net Methane Emissions (Bcf)
Exploration	7	0.5
Production (excluding gathering)	1,811	115.4
Gathering	1,548	98.6
Processing Plants	510	32.5
Transmission and Storage (excluding LNG)	1,572	100.1
LNG	18	1.2
Distribution	548	34.9
Data for 2021 from the 2023 Greenhouse Gas Inventory (U.S. GHGI)		

(Courtesy of U.S. Environmental Protection Agency (EPA))

[1] https://www.congress.gov/bill/116th-congress/house-bill/133/text/pl?overview=closed
[2] Throughout this document, the usage of natural gas or gas has the same meaning, as a gaseous mixture consisting mainly of methane. In addition, for purposes of this document, the terms gas release and gas emissions have the same meaning.
[3] *See* 49 CFR § 1.97.
[4] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021. Annex 3.6-1. (U.S. GHGI).
[5] Annex 3.6 of the 2023 U.S. GHGI is available for download in a spreadsheet format at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg.

PHMSA's mission is to protect people and the environment by advancing the safe transportation of energy and other hazardous materials that are essential to our daily lives. PHMSA has regulatory authority over the following natural gas pipelines and pipeline facilities:

- Transmission pipelines
- Distribution pipelines
- Underground natural gas storage (UNGS)
- Liquefied natural gas (LNG)
- Regulated gas gathering pipelines

Based on a search of available information, PHMSA outlines in this report technologies, practices, and facility designs to provide the greatest degree of natural gas emission reduction from planned activities without compromising public safety and the environment.[6] Specifically, PHMSA reviewed the following:[7]

- Pipeline facility designs that, without compromising pipeline safety, mitigate the need to intentionally vent natural gas (Section 4).
- The BATs or practices to prevent or minimize, without compromising pipeline safety, the release of natural gas during scheduled repairs, replacements, or maintenance activities (Section 5).
- The BATs or practices to prevent or minimize, without compromising pipeline safety, the release of natural gas when the operator intentionally vents or releases natural gas, including blowdowns (Section 6).

In preparing this report, PHMSA reviewed available literature and materials, and engaged with subject matter experts on natural gas emission controls. The review also included the BATs and practices outlined by the Environmental Protection Agency's (EPA) Natural Gas STAR Program (Section 2).[8] The information presented in this report represents the available knowledge of BATs at the time of publication but may not be all-inclusive due to ongoing research, development, and advancement in leak detection and quantification technologies.

PHMSA primarily focused on reviewing the best existing and emerging technologies, practices, and pipeline facility designs to eliminate or reduce natural gas emissions across the natural gas gathering, transmission, and distribution sectors—regulated under 49 Code of Federal Regulations (CFR) Part 192. Although a detailed review of technologies for UNGS and LNG

---

[6] Fugitive emissions were not included in the scope of this report as the act mandate focused on planned activities.

[7] These categories were identified in the PIPES Act of 2020, Sections 114(d)(1)(A)(iii), (i), and (ii), respectively. The sections were reordered in the report as typically design of a facility would occur before maintenance or venting activities, although all three do integrate.

[8] EPA, "Recommended Technologies to Reduce Methane Emissions." Available at https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions.

were not conducted, some of the technologies described in this report could be applicable to portions of UNGS and LNG facilities as well and are identified accordingly.

PHMSA is currently impartial regarding specific technologies used to meet Federal pipeline safety regulations and therefore does not endorse or promote any specific technology, practice, or facility design presented in this report.

Congress also directed PHMSA to recommend a timeline for updating the pipeline safety regulations, as the Secretary of Transportation (Secretary) determines to be appropriate, to address the matters related to BATs, practices, and pipeline facility designs. PHMSA has issued, is implementing, or has proposed five rules that may reduce methane emissions. The rules include the Gas Gathering, Valve Installation and Minimum Rupture Detection Standards, Gas Transmission Safety, the proposed Gas Pipeline Leak Detection and Repair, and the proposed Safety of Gas Distribution Pipelines. PHMSA believes the recently issued and ongoing rulemakings are sufficient to address the matters related to best available technologies, practices, and pipeline facility designs that are covered in this report. PHMSA will continue to evaluate impacts of these rules, along with lessons learned from other directives in Section 114 of the PIPES Act of 2020—such as inspections of operator plans and procedures to minimize releases of natural gas from pipeline facilities, and any outputs from the Comptroller General (also known as Government Accountability Office (GAO)) study required by Section 114(c)—and consider the potential for future rulemakings or other PHMSA actions to address methane emissions reduction.

Section 114(b) contained a self-executing mandate requiring operators to update their inspection and maintenance plans to address eliminating hazardous leaks and minimizing releases of natural gas (including intentional venting during normal operations) from their pipeline facilities and for PHMSA and states to inspect those plans through Section 114(a). Leading into the inspections in 2022, PHMSA issued an advisory bulletin (ADB-2021-01) on June 10, 2021[9] to remind operators of the congressional mandate to revise their plans to address the replacement or remediation of pipeline facilities that are known to leak based on their material, design, or past operating and maintenance history. The statute required pipeline operators to complete these updates by December 27, 2021. The inspections of operators' plans by PHMSA and state inspectors generally found that operators had complied with PIPES Act of 2020 requirements for updating their operation and maintenance plans. The GAO report directed by Section 114 (c), issued on June 3, 2024[10], reached the same conclusion. PHMSA attributed these satisfactory results to existing programs, operator initiatives, and other efforts.

PHMSA would like to thank the following organizations for reviewing these 114(d) reports and providing valuable feedback:

---

[9] See https://www.phmsa.dot.gov/regulations/federal-register-documents/2021-12155

[10] See GAO-24-106881, "Gas Pipelines: Oversight of Operators' Plans to Minimize Methane Emissions" https://www.gao.gov/products/gao-24-106881?utm_campaign=usgao_email&utm_content=topic_naturalresources&utm_medium=email&utm_source=govdelivery

- Canada Energy Regulator
- U.S. Environmental Protection Agency
- Pipeline Safety Trust
- Pipeline Research Council International

Their review does not imply endorsement of this final report.

2 Introduction

In Section 114(d) of the PIPES Act of 2020, the Secretary was directed to do the following:

(1) Report of the Secretary: Not later than 18 months after the date of enactment of this Act, the Secretary shall submit to the Committee on Commerce, Science, and Transportation of the Senate, and the Committees on Transportation and Infrastructure and Energy and Commerce of the House of Representatives, a report—

(A) Discussing:

(i) the best available technologies or practices to prevent or minimize, without compromising pipeline safety, the release of natural gas when making planned repairs, replacements, or maintenance to a pipeline facility;

(ii) the best available technologies or practices to prevent or minimize, without compromising pipeline safety, the release of natural gas when the operator intentionally vents or releases natural gas, including blowdowns; and

(iii) pipeline facility designs that, without compromising pipeline safety, mitigate the need to intentionally vent natural gas; and

(B) Recommending a timeline for updating pipeline safety regulations, as the Secretary determines to be appropriate, to address the matters described in subparagraph (A).[11]

(2) Rulemaking: Not later than 180 days after the date on which the Secretary submits the report under this subsection, the Secretary shall update pipeline safety regulations that the Secretary has determined are necessary to protect the environment without compromising pipeline safety.

[11] PHMSA has a rulemaking in progress to address gas pipeline leak detection and repair mandates in Section 113 of the PIPES Act of 2020 and related issues (2137-AF51). PHMSA will consider initiating an additional rule based on the findings of this report and outcomes of the Section 113 rulemaking and others identified in this report. The status of PIPES Act of 2020 related rulemakings is available on PHMSA's website at https://www.phmsa.dot.gov/legislative-mandates/pipes-act-web-chart.

Figure 1 shows the areas to which DOT and EPA regulatory coverage would apply for natural gas emissions.[12] The EPA has regulations addressing emissions from natural gas facilities in the production and processing sectors as well as natural gas storage facilities associated with the natural gas transmission sector. The EPA and DOT share responsibility for regulating releases of natural gas from compressor stations. Lastly, DOT provides oversight for some gathering pipelines, transmission pipelines, distribution pipelines, and UNGS and LNG plants to protect public safety and the environment.

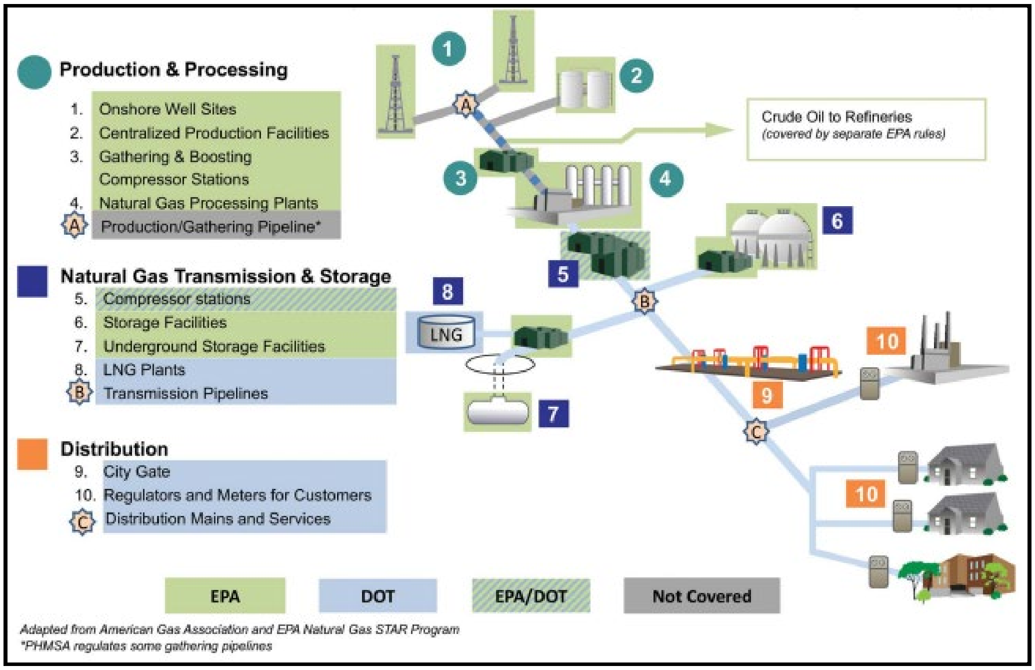


Figure 1: Current/Potential Regulatory Authorities Over Natural Gas Emissions From the Oil and Gas Supply Chain (From the U.S. Methane Emissions Reduction Plan)

Since 1993, the EPA has collaborated with companies with U.S. oil and gas operations to reduce greenhouse gas (GHG) emissions through its voluntary Natural Gas STAR Program.[13] This program provides a framework for partner companies to implement methane reducing technologies and practices and document the companies' voluntary emission reduction activities.

In this report, PHMSA focused primarily on reviewing the best existing and emerging technologies, practices, and pipeline facility designs to eliminate or reduce gas emissions across the gathering, transmission, and distribution sectors. However, some of the technologies described in this report could be applicable to portions of UNGS and LNG sectors as well. Applicable technologies are described further in Table 2.

[12] The White House Office of Domestic Climate Policy, "U.S. Methane Emissions Reduction Action Plan," November 2021. Retrieved from https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf.
[13] https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions

Table 2 summarizes each BAT or practice and facility design by pipeline sector described in this report. Each has the potential to enhance pipeline safety and reduce natural gas emissions.

The paragraph numbers in the first column refer to the report sections where each titled topic is discussed in greater detail.

Table 2: BATs or Practices and Facility Designs by Sector

Paragraph No.	Title	Sector
4.1.1.1	Electrically Driven Compressors	Transmission, Gathering
4.1.1.2	Compressor Station Blowdown Systems	Transmission, Gathering
4.1.2	Centrifugal Compressor Wet Seal Degassing Recovery System	Transmission, Gathering
4.1.3	Integrating Emergency Shutdown (ESD) Systems with Supervisory Control and Data Acquisition (SCADA) Systems	Transmission, Gathering, UNGS, LNG
4.2.1	Increased Use of Excess Flow Valves (EFVs) on New or Renewed High-Pressure Service Lines	Distribution
4.2.2	Replacement of Relief Valves and Seal Pots with Dual Regulators, Monitor Regulators, or Automatic Shutoff Valve Designs	Distribution
4.2.3	Replacement of Bleed-by Controllers with No-Bleed Controllers	Distribution
4.2.4	Replacement of Service Line Regulators Using Internal Relief With Automatic Pressure Shutoff Valves	Distribution
5.1.1.1	Replacing Centrifugal Compressor Wet Seals with Dry Seals	Transmission, Gathering
5.1.1.2	Replacement of Rod Packing Seals in Reciprocating Compressors	Transmission, Gathering
5.1.1.3	Replacement of Pneumatic Controllers (PCs)	Transmission, Gathering
5.1.1.4	Automated Air/Fuel Ratio (AFR) Control Systems	Transmission, Gathering
5.1.1.5	Glycol Dehydrators	Transmission, Gathering
5.1.1.6	Replacing Gas Starters with Air or Electric Starters	Transmission, Gathering
5.1.1.7	Vapor Recovery from Pigging Operations for Gas Transmission and Gathering Systems	Transmission, Gathering
5.1.2.1	No-Blow or Gas-Free Equipment for Pipeline Work	Distribution
5.1.2.2	Elimination of Jumping for All Distribution System Operating Pressures	Distribution
5.1.2.3	Shutting Off High-Pressure System Valves When Performing Emergency Work	Distribution
5.1.2.4	Cast-Iron (CI) Mechanically Joined Pipe	Distribution
5.1.2.5	Pipeline Repair, Renewal, Rehabilitation, or Replacement Programs	Distribution
5.1.2.6	Residential Gas/Methane Detectors	Distribution
5.2.1.1	Directed Inspection and Maintenance (DI&M) Programs	Transmission, Gathering, UNGS, Distribution
5.2.1.2	Compressor Shutdown Operating Practices	Transmission, Gathering
5.2.1.2.5	Increased Isolation Valve Maintenance	Transmission, Gathering
5.2.1.3	Pipeline Drawdown Techniques to Lower Gas Line Pressure Before Maintenance	Transmission, Gathering
5.2.2	Distribution Sector—Ventless Stop-Off Procedures for High-Pressure and Polyethylene Mains	Distribution

6.1.1.1	Pressure Relief Valve Inspection and Repair Programs	Transmission, Gathering, Distribution
6.1.1.2	Capture Purged Gas from Pipeline Facilities Using Drawdown Compressors	Transmission, Gathering, Distribution
6.1.2.1	Pipeline Purging	Transmission, Gathering
6.1.2.2	Hot Tapping for Service Line Connections or Tie-Ins	Transmission, Gathering
6.1.3	Distribution Sector—Capture Purged Gas-Air Mixture from Customer Fuel Gas Piping	Distribution
6.2.1	Emergency Shutdown (ESD) Systems and Practices	Transmission, Gathering, UNGS, LNG
6.2.2	Integrity Management Programs (IMPs)	Transmission, Gathering, UNGS

2.1 Report Overview and Scope

This report includes perspectives on new, improved, and innovative technologies to help reduce or eliminate natural gas emissions primarily associated with planned activities, including venting. Additionally, regulations and standards published by other agencies—such as the EPA—to promote innovative technologies for reducing or eliminating gas emissions were reviewed and considered.

Natural gas emissions can be broken up into two general categories:

- Fugitive emissions, which are unintentional leaks from equipment such as pipelines, flanges, valves, or other equipment.
- Vented emissions, which are intentional or planned releases attributable to equipment design or operational/maintenance procedures, such as pneumatic device bleeds, blowdowns, incomplete combustion, equipment venting, or reliefs.

Venting is the release of natural gas into the atmosphere resulting from a process or activity, including those that are planned for operations and maintenance (O&M) activities. Pipeline system venting occurs during normal operations, maintenance activities (i.e., isolation of a specific pipeline segment), or emergency shut down of a system.

Vented gas is the gas not burned by a designated flare[14] and is released into the atmosphere. The activities that may result in venting include, but are not limited to, the following:

- Equipment venting from packing rods, seals, dehydrators, and pneumatic devices, as well as valve components;
- Planned depressurization or clearing of gas pipeline facilities for maintenance or repairs;
- Piping used during the insertion or removal of an in-line inspection device; and
- Unplanned depressurization of gas pipelines due to system issues or emergencies.

Section 3 outlines PHMSA's mission and the applicability of each identified BAT or practice to gathering, transmission, and distribution pipelines. Sections 4 through 6 provide descriptions of each BAT or practice and facility design—including the emission sources being addressed, design or implementation strategy, benefits and limitations, and safety and feasibility impacts.

Appendix A provides additional BATs specific to the UNGS and LNG sectors.

[14] In 40 CFR § 98.238, EPA defines *flare* as "a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery." While flaring may require additional equipment and release GHGs, "burning gas [via flaring] rather than releasing it into the atmosphere significantly reduces the climate change impacts of vented emissions by converting methane gas to carbon dioxide and water via combustion. Under favorable conditions a well-designed and maintained flare stack can combust gas with almost 100% efficiency, however, leaks and unlit or incomplete flaring (due to poor maintenance, design, or operation practices) can reduce the methane reduction efficiency on a field-level basis to approximately 90%," per PHMSA rulemaking, "Pipeline Safety: Gas Pipeline Leak Detection and Repair," May 18, 2023. Available at https://www.federalregister.gov/documents/2023/05/18/2023-09918/pipeline-safety-gas-pipeline-leak-detection-and-repair.

Appendix B contains a list of acronyms and abbreviations used in this report.

3 PHMSA Mission

PHMSA's mission is to protect people and the environment by advancing the safe transportation of energy and other hazardous materials that are essential to our daily lives. The Agency establishes national policy, sets and enforces standards, educates, and conducts research to prevent incidents. PHMSA also prepares the public and first responders to reduce consequences if an incident does occur.[15]

PHMSA administers a national regulatory safety program to ensure the safe, reliable, and environmentally sound design and operation of pipeline facilities that includes more than 3.3 million miles of gas pipelines in the United States. This program requires that pipeline operators design, construct, operate, and maintain pipeline facilities in compliance with federal pipeline safety regulations found in 49 CFR Parts 190 through 199.[16]

PHMSA has issued or proposed the following rulemakings that may help reduce releases of natural gas:

- **Gas Gathering Pipeline Safety Rule (Final Rule).**[17] This rule imposed new requirements on some previously unregulated natural gas gathering pipelines—including new safety requirements for a portion of these lines—that will result in reduced GHG emissions associated with leaks and incidents.
- **Valve Installation and Minimum Rupture Detection Standards Rule (Final Rule).**[18] This rule accomplishes the following, each of which will reduce emissions resulting from both incidents and maintenance and repair activities:
    - Requires operators of newly constructed and entirely replaced large-diameter pipelines to install rupture mitigation valves or alternative equivalent technologies.
    - Establishes minimum performance standards for the operation of such valves.
    - Addresses requirements for the maintenance and inspection of rupture mitigation valves.
    - Requires improved response times for gas transmission pipeline ruptures.

---

[15] https://www.phmsa.dot.gov/about-phmsa/phmsas-mission
[16] Regulations available at https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D.
[17] PHMSA, "Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments," November 15, 2021. Retrieved from https://www.federalregister.gov/documents/2021/11/15/2021-24240/pipeline-safety-safety-of-gas-gathering-pipelines-extension-of-reporting-requirements-regulation-of.
[18] PHMSA rulemaking, "Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards," Docket PHMSA-2013-0255, published April 8, 2022, and effective October 10, 2022. Available at https://www.federalregister.gov/documents/2022/04/08/2022-07133/pipeline-safety-requirement-of-valve-installation-and-minimum-rupture-detection-standards.

- **Gas Transmission Pipelines Safety Rule (Final Rule).**[19] Some aspects of this rule, such as maximum allowable operating pressure (MAOP) reconfirmation, have already taken effect. Overall, this rule aims to reduce the frequency of leaks and ruptures on more than 300,000 miles of gas transmission lines by addressing integrity management provisions, management of change processes, gas transmission pipeline corrosion control requirements, requirements for inspections following extreme events, strengthened integrity management assessments, and repair criteria for heavily populated areas/high consequence areas (HCAs).
- **Gas Pipeline Leak Detection and Repair Rule (Notice of Proposed Rulemaking (NPRM)).**[20] Section 113 of the PIPES Act of 2020 directs the Secretary to promulgate regulations that require operators of new and existing regulated gas gathering, transmission, and distribution pipelines to conduct a leak detection and repair program to ensure gas pipeline safety and protect the environment. PHMSA expects the requirements proposed in the NPRM would reduce methane emissions from gas pipeline blowdowns and reduce emissions via the detection and repair of leaks from natural gas pipelines and thus provide both safety and environmental benefits.
- **Safety of Gas Distribution Pipelines Rule (NPRM).**[21] Title II of the PIPES Act of 2020 directs PHMSA to amend the pipeline safety regulations to improve gas distribution pipeline safety in the wake of the deadly 2018 pipeline explosions in Merrimack Valley, Massachusetts. The requirements in the proposed rule would address Sections 202 through 204 and 206 of the PIPES Act of 2020. PHMSA expects that the rulemaking will provide safety and environmental benefits—including, but not limited to, avoided methane emissions associated with a reduced risk of leaks and incidents on natural gas pipelines—due to improved gas distribution O&M and other pipeline safety practices.

In addition to the Section 114(d)(2) requirement for the Secretary to update pipeline safety regulations that the Secretary has determined are necessary to protect the environment without compromising pipeline safety, PHMSA may consider initiating an additional rulemaking, if necessary, based on the findings of this report and outcomes of the rulemakings above, particularly the Gas Pipeline Leak Detection and Repair Rule.

[19] PHMSA rulemaking, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," October 1, 2019. Available at https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf.
[20] PHMSA rulemaking, "Pipeline Safety: Gas Pipeline Leak Detection and Repair," May 18, 2023. Available at https://www.federalregister.gov/documents/2023/05/18/2023-09918/pipeline-safety-gas-pipeline-leak-detection-and-repair.
[21] PHMSA rulemaking, "Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiative," September 7, 2023. Available at https://www.federalregister.gov/documents/2023/09/07/2023-18585/pipeline-safety-safety-of-gas-distribution-pipelines-and-other-pipeline-safety-initiatives.

3.1 Gathering Pipelines

Natural gas gathering, which is a “midstream” sector between the production/processing and gas transmission sectors, includes more than 340,000 miles of pipeline and several thousand gas compressor stations.[22] **Figure 2** shows typical gathering station components.

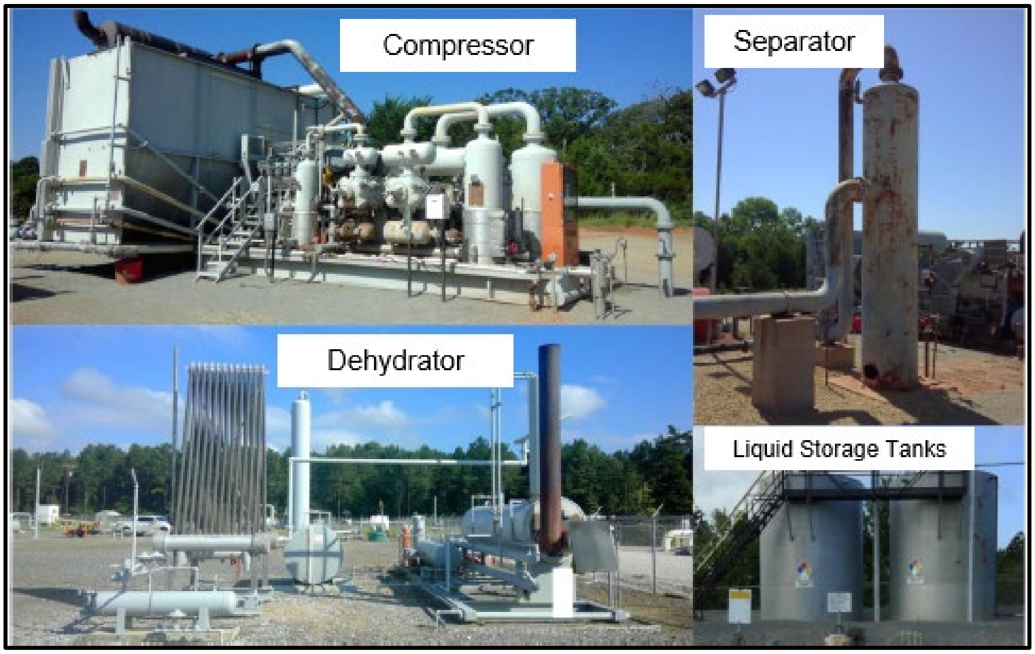


Figure 2: Typical Gathering Station Components
(Courtesy of the Energy Institute at Colorado State University)

[22] Zimmerle, D., et al., “Characterization of Methane Emissions from Gathering Compressor Stations: Final Report,” Energy Institute at Colorado State University, 2019. (p. 14). Retrieved from https://www.osti.gov/servlets/purl/1506681.

The U.S. GHGI estimated gas gathering sector methane emissions of approximately 98.6 Bcf in 2021 (**Figure 3**).[23]

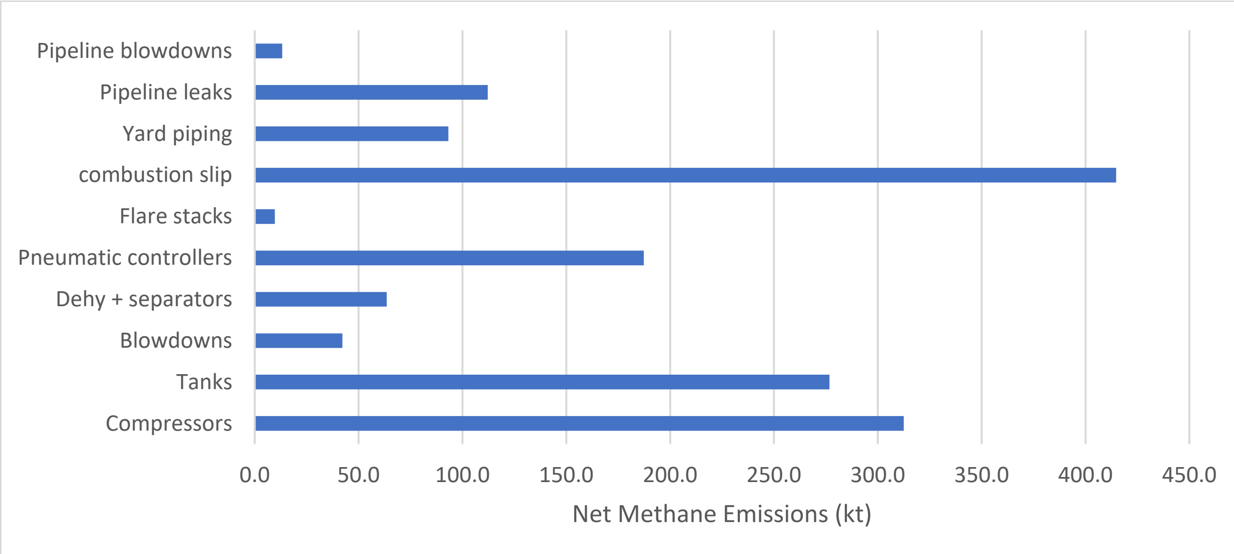


Figure 3: Reported Methane Emission Sources in the Gathering and Boosting Sector, 2021 (Data Courtesy of EPA GHGI)

3.2 Transmission Pipelines

Gas transmission pipelines transport gas from a gathering line or storage facility to a distribution center, storage facility, or large-volume customer that is not downstream from a distribution center, or transport gas within a storage field. Gas transmission occurs through a vast network of high-pressure pipelines that range from several inches to several feet in diameter. The pressure in each section of pipeline may range from 50 to 1,500 pounds per square inch (psi). This sector contains both interstate and intrastate infrastructure—including more than 2,000 compressor stations; approximately 300,000 miles of pipeline networks; metering and regulation stations; underground storage facilities; and supporting equipment.

According to the estimates in the U.S. GHGI, of the 100.1 Bcf of net methane emissions from gas transmission systems and gas storage facilities (excluding LNG) in 2021, 78.4 Bcf were associated with compressor stations[24] (**Figure 4**). The top reported emission sources were station venting and releases from reciprocating compressors.[25]

[23] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).
[24] EPA, "2011–2021 Greenhouse Gas Reporting Program Sector Profile: Petroleum and Natural Gas Systems," 2023 (p. 16). Retrieved from https://www.epa.gov/system/files/documents/2022-10/subpart_w_2021_sector_profile.pdf.
[25] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

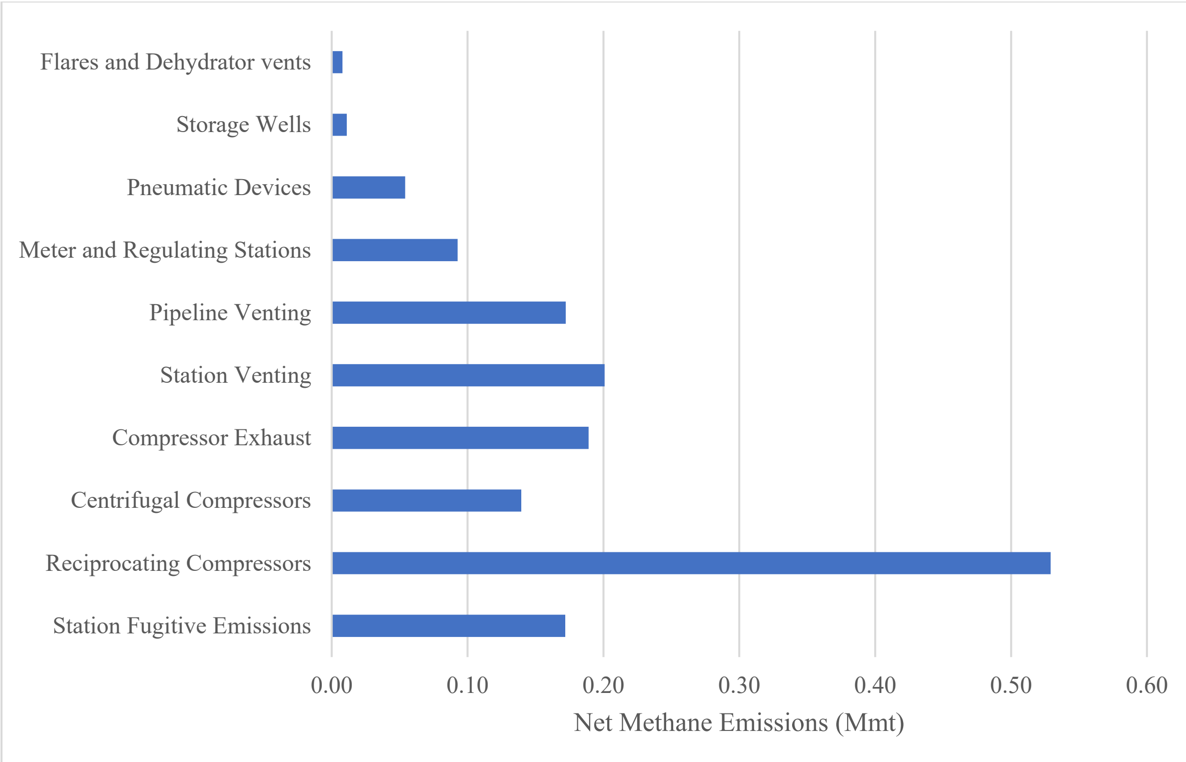


Figure 4: Net Methane Emission Sources in Transmission and Storage Sector, 2021 (Data Courtesy of EPA GHGI)

3.3 Distribution

The gas distribution sector refers to the natural gas infrastructure system downstream of the city gate, where gas is delivered from gas transmission pipelines. Distribution companies are local utilities that deliver natural gas to customers through more than 2.3 million miles of interconnected distribution pipelines. In the U.S. GHGI, the EPA estimated net methane emissions from gas distribution facilities in 2021 was approximately 34.9 Bcf.[26]

Most natural gas emissions from the distribution sector are fugitive, the sources of which include the following:

- Commercial/industrial and residential meter sets (**Figure 5**)
- Leak-prone cast iron, protected and bare-steel systems, and legacy plastic pipelines (**Figure 6**)

[26] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

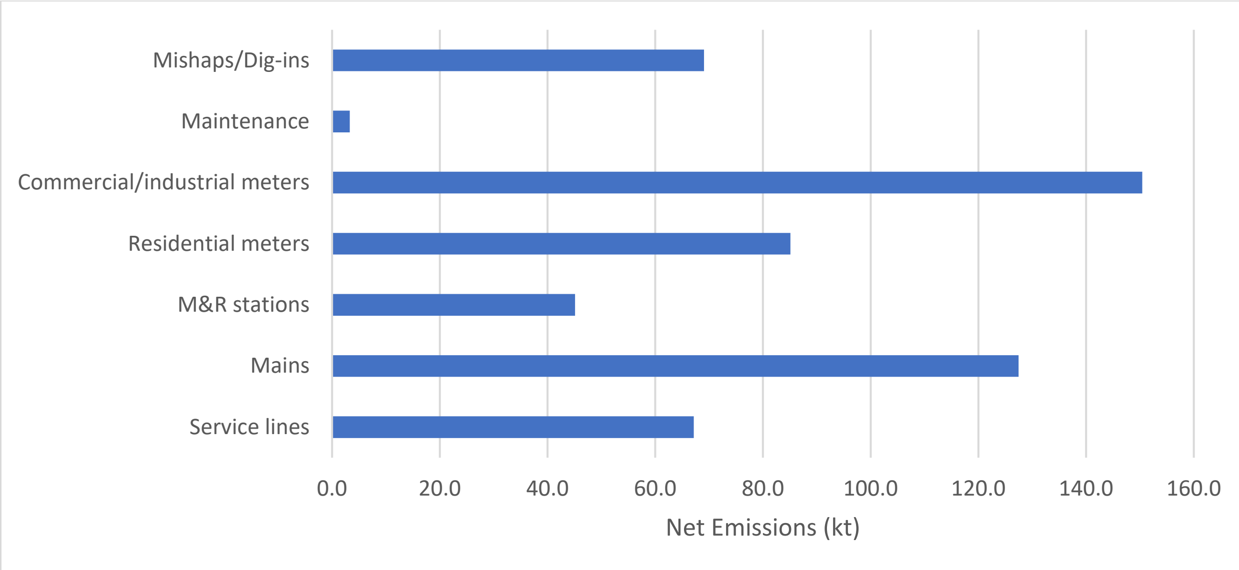


Figure 5: Reported Methane Emission Sources in the Gas Distribution Sector, 2021 (Data Courtesy of EPA GHGI)

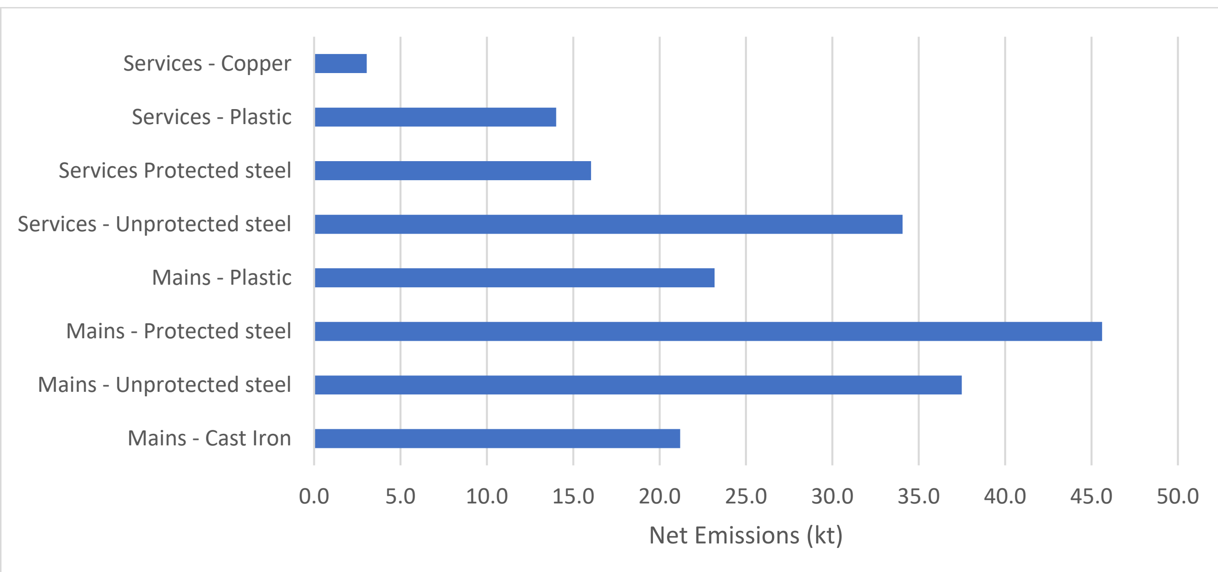


Figure 6: Reported Methane Emissions from Gas Distribution Mains and Services (excluding meters), 2021 (Data Courtesy of EPA GHGI)

While fugitive emissions are not in the scope of this study, PHMSA is implementing initiatives through Natural Gas Distribution Infrastructure Safety and Modernization Grants[27] to municipal or community owned utilities that can help with reducing emissions.

[27] More information on the grant program is available at https://www.phmsa.dot.gov/about-phmsa/working-phmsa/grants/pipeline/natural-gas-distribution-infrastructure-safety-and-modernization-grants.

4 Pipeline Facility Designs to Mitigate the Need to Intentionally Vent Gas

Designing facilities to prevent or reduce emissions before they are put into service, or modifying existing facilities can reduce natural gas leakage, improve safety, and reduce emissions. Implementing emission reduction strategies in the design phase is typically less expensive than modifying a facility after operations have begun. Individual analysis would likely be conducted at each facility location, and not necessarily be applied across all assets.

4.1 Transmission and Gathering Sectors

The following subsections identify details of equipment design developments used in the reduction or elimination of natural gas emissions during facility operation.

4.1.1 Compressor Stations

Approximately 1,700 midstream compressor stations, containing 5,000 to 7,000 total compressors, operate in the United States.[28] The design requirements for compressor stations are outlined in 49 CFR Part 192, Subpart D, Design of Pipeline Components. Compressor stations in the transmission and gathering sectors are among the largest sources of natural gas emissions from those segments. In 2023, based on data submitted through 2021, the U.S. GHGI estimated that of the 100.1 Bcf of net methane emissions from gas transmission and storage facilities, 78.4 Bcf was associated with compressor stations.[29]

Compressor station facility and equipment design and technologies can be implemented in pipeline facilities—without compromising safety—to mitigate the need to intentionally vent gas into the atmosphere. Facility design elements can incorporate natural gas emission reduction technology prior to the start-up of a new facility or during modifications to existing facilities. This subsection applies primarily to the design of new facilities.

An essential component of a natural gas transmission and gathering system is the compressor station (**Figure 7**), which is strategically located along a natural gas pipeline to support the continuous flow of natural gas. In a compressor station, gas is compressed from lower to higher pressures so that increased gas volumes can be transported through the pipeline. Through pressure drop, the higher pressure provides the energy to move the natural gas through a pipeline to its destination or delivery point.

[28] Elliott Group (Brun, K.), "The US Natural Gas Compression Infrastructure: Opportunities for Efficiency Improvements," October 2018. Retrieved from https://netl.doe.gov/sites/default/files/netl-file/Brun.pdf.

[29] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

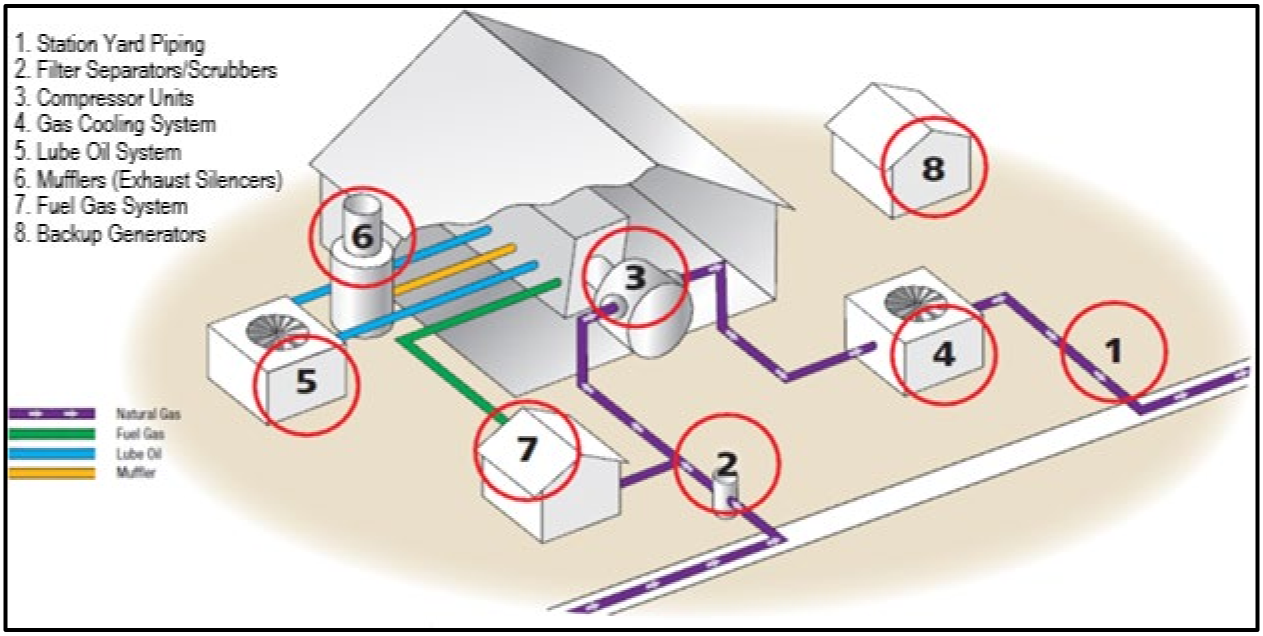


Figure 7: Compressor Station Yard Components (Courtesy of Spectra Energy)

In addition to the compressor itself, a typical compressor station includes many components including:[30]

- Drivers/engines
- Filter separators or scrubbers
- Gas coolers
- Piping, valves, flanges, supports, and foundations
- Recycle/bypass/anti-surge systems
- Auxiliary systems (air, lube oil, coolant)
- Noise control
- Air filtration and emissions equipment
- Flow metering
- Utilities (electricity, backup generators, water)
- Blowdown, excess pressure protection, and emergency shutdown systems
- Fuel gas systems
- Control systems (automated and/or manual)
- Communications systems
- Buildings for equipment and personnel
- Cathodic protection systems
- Safety and security systems
- Pressure regulation equipment
- Station lighting

[30] Science Direct, "Compression Machinery for Oil and Gas," 2019 (p. 392). Abstracts available at https://www.sciencedirect.com/book/9780128146835/compression-machinery-for-oil-and-gas.

Gas in a compressor station is gathered and compressed from either (1) multiple wells or gathering lines over a large area, or (2) a large pipeline. In the planning phase of a new compressor station, the full range of station operations and growth scenarios must be considered when designing system components. The size and number of compressors in a station varies based on pressure, volume of gas to be moved, and the distance to the next compressor station or termination point.

The following subsections describe design elements that can reduce intentionally venting natural gas from compressor stations, while being designed to meet the minimum safety standards in 49 CFR Part 192.

4.1.1.1 Electrically Driven Compressors

4.1.1.1.1 Emission Source

Natural gas facilities often use gas-driven engines to operate compressors, generators, and pumps. Natural gas emissions may result from leaks in the gas fuel lines, incomplete combustion in the engines (methane slips), or equipment involved in system maintenance or emergencies.

4.1.1.1.2 System Design Strategy/Benefits and Limitations

Replacing gas-driven compressors with electric compressors can reduce this source of emissions.[31] In an EPA case study,[32] an operator reported replacing five gas-driven reciprocating compressors (two 2,650 hp; two 4,684 hp; and one 893 hp) with four 1,750 hp electric motor driven compressors. This resulted in an annual methane emissions reduction of 32,800 Mcf.

Additionally, other operators reported average annual methane emissions reduction ranging from 40 to 16,000 Mcf by installing electric compressors.[33]

The annual fuel gas savings from replacing gas-driven engines with electric compressors are based on the compressor power output. The EPA calculated that replacing gas-driven engines with electric engines would reduce emissions annually by 2.11 Mcf/hp.[34] The U.S. GHGI estimates reciprocating compressors emitted 27.1 Bcf of methane from transmission facilities and 6.6 Bcf of methane from storage facilities.[35]

The EPA also reported that using electrically driven compressors can increase operational efficiency and reduces maintenance costs. Reduced maintenance costs would offset some incremental electricity costs, which is approximately 10 percent of the capital costs. A limitation of this technology is that it cannot be implemented without a reliable and cost-efficient electric

---

[31] The replacement of gas-driven compressors with electric compressors must consider the reliability of the electric grid and power generation facilities in the area; the capability of natural gas pipelines to deliver gas to power plants will have an effect on electric power generation.
[32] EPA Natural Gas Energy STAR, "Install Electric Compressors," PRO Fact Sheet No. 103, 2011 (p. 2). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/installelectriccompressors.pdf.
[33] Ibid.
[34] EPA Natural Gas Energy STAR, "Install Electric Compressors," (p. 1).
[35] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

power supply, which is a significant consideration because compressor stations are often located in remote areas.

4.1.1.1.3 Safety and Feasibility Impacts

No increase in compressor station safety risk is anticipated from installing electrically driven compressors; however, a backup power generation is required during power grid outages to prevent transmission system shutdown or reduction in gas volume throughput.

It should be noted that depending on the mix of the electricity's energy source, the use of electric drive compression may not reduce overall greenhouse gas emissions. Reliability may also be reduced with electrically driven compression when using off-site generated power. Reliability of the gas grid is especially important in areas where natural gas is used to provide fuel to electrical generation during peak pull periods.

One technical solution is onsite electrical power generation for electric drive compression. However, to make this efficient, surplus power can be sold to the grid.

4.1.1.2 Compressor Station Blowdown Systems

4.1.1.2.1 Emission Source

Blowdowns, an intentional gas venting activity, can be planned or unplanned. Planned events—in which outages are scheduled in advance—can include equipment or pipe replacement, facility retirement, testing, compliance-related inspections, or routine maintenance activities. Unplanned gas venting activities may be necessary due to emergency shutdowns, leaks, and ruptures.

The largest source of natural gas emissions associated with taking compressors off-line is from the blowdown or venting of gas remaining within compressors and piping. But these emissions are dwarfed by emissions from normal compressor operations.

Capturing vented gas during blowdowns can reduce emissions by adding an ejector[36] to the system in conjunction with recapturing the vented gas. The modification could result in additional emissions reduction from blowdown stacks.[37] It is believed that capture and recompression can be effective up to a point. There is a point of diminishing returns where the amount of greenhouse gases, namely carbon dioxide (CO_2), required to recompress the gas is higher than the CO_2 of the gas remaining in the system. The time required for the recompression can also be a limiting factor.

[36] Ejectors, also known as compressor blowdown vent line ejectors, are venturi nozzles that use high-pressure gas as motive fluid to draw suction on a lower-pressure gas source before discharging into a medium-pressure gas stream.
[37] EPA, "Reducing Emissions When Taking Compressors Off-Line," Lessons Learned from Natural Gas STAR Partners, October 2006. Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_compressorsoffline.pdf.

Based on estimates of venting and blowdown emissions from the U.S. GHGI, the technologies listed in section 4.1.1.2 may reduce annual blowdown emissions from stations by up to approximately 15.5 Bcf, or 27.3 Bcf if pipeline blowdowns are included (**Table 3**).[38]

Table 3: Estimated Venting/Blowdown Net Methane Emissions (Bcf), 2021

Source	Station Venting	Pipeline Venting	Total
Transmission	10.9	11.0	21.9
Storage	1.8	N/A	1.8
Gathering	2.7	0.8	3.5
Total	15.5	11.8	27.3

Another alternative is to bleed high pressure sources into lower pressure sources. For example, if a reciprocating compressor needs to be blown down to repair a compressor valve (leaky compressor valves also contribute to GHG emissions due to the loss in efficiency), the gas could be piped to a low-pressure fuel use, such as a fuel gas header. The gas could then be recompressed to remove more of the remaining gas to a lower pressure load. Doing so significantly reduces the time and energy to prevent gas loss.

There are related design issues to factor into this process, including controls to prevent over pressurization and to address situations where there is no active demand on the low-pressure load (e.g., the entire compressor station is shut down and therefore there isn't demand for a lower pressure fuel use).

Recompressing gas to minimize/avoid pipeline blowdowns is often limited by where recompression could be (temporarily) installed; the corresponding noise and air emissions (including required permits that may be required for gas driven temporary compression); and the additional time required to execute using recompression versus a blowdown.

There are also other sources related to emissions at compressor stations. For example, relief valves (which also apply to pressure regulation/meter stations) and reciprocating compressor rod venting.[39] In reviewing PHMSA reportable incidents, there are a significant number of events where a relief valve opened when it should not have. Many of those were caused by debris in the relief valve pilot, including liquids. Adding filters (with the corresponding maintenance) could significantly reduce unplanned relief valve venting. Using redundant control systems as pressure limiting devices at compressor stations could eliminate the need for relief valves at compressor stations.

[38] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

[39] Pipeline Research Council International PR-312-08206-R03 “Methods to Reduce the Greenhouse Gas Footprint from Pipeline Compressor and Pump Stations.” Retrieved from https://doi.org/10.55274/R0010042.

4.1.1.2.2 Implementation or System Design Strategy

Incorporating natural gas emission reduction strategies into compressor station designs, including vent gas capture systems and compressor blowdown vent line ejectors, can reduce or eliminate emissions from blowdowns.

a. Vent Gas Capture System

Vent gas capture systems capture gas vapors from atmospheric vents and combust them to use them as supplemental fuel for the natural gas engine. The vents on the blowdown piping are connected to the fuel system, redirecting the captured gas vapors into the compressor engine air intake to fuel the engine.

b. Compressor Blowdown Vent Line Ejectors

Natural gas emissions from compressors that have been taken offline can be reduced by installing ejectors on the compressor blowdown vent lines. The ejector is installed on vent connections between the compressor discharge and suction, routing the captured and motive gases[40] to the compressor engine suction or fuel gas system.

4.1.1.2.3 Benefits and Limitations

a. Vent Gas Capture System

Connecting blowdown vent lines to the fuel gas system can reduce the emissions from a blowdown vent. This option involves adding piping and valves to bleed the gas from an idle compressor into the compressor station's fuel gas system. The cost will depend on compressor size; the number of necessary fittings, valves, and piping supports; and piping size/length.

b. Compressor Blowdown Vent Line Ejectors

Installing ejectors will allow operators to:

- Recover blowdown gas that would otherwise be vented;
- Direct the recovered gas to a useful outlet, such as fuel for turbine engine operation;
- Redirect the gas to a sales line; or
- Flare the gas.

In addition to the ejector itself, capital expenditures will also include ejector block valves and piping from the blowdown vent line connections.

[40] Compression in ejector systems is realized by high-pressure gas (motive fluid) drawing suction on a lower-pressure gas source, then discharging into an intermediate-pressure gas stream. The ejector can use the discharge from an adjacent compressor (the motive fluid) to pump blowdown gas from a shut-down compressor into the suction.

4.1.1.2.4 Safety and Feasibility Impacts

The industry began developing and studying this technology in 1995; therefore, no adverse safety impact is anticipated.

The capital and electricity costs for electric motors are higher than those for gas-driven engines. Recovering gas via an ejector is cost-effective only when the recovery system has sufficient capacity to consume the gas.

4.1.2 Centrifugal Compressor Wet Seal Degassing Recovery System

The most prevalent compressor types are reciprocating (Paragraph 5.1.1.2) and centrifugal (**Figure 8**), which is any machine that draws in low-pressure natural gas and uses mechanical rotating vanes or impellers to discharge significantly higher-pressure natural gas.[41] A well-designed wet seal degassing recovery system can recover up to 99 percent of methane from the seal lubricant, thereby reducing emissions.[42]

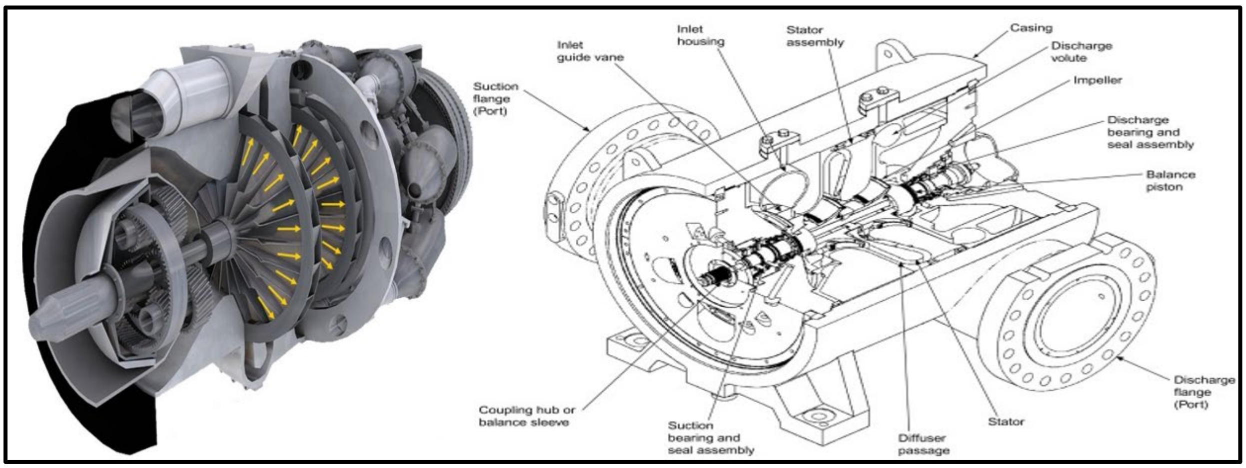


Figure 8: Centrifugal Compressor Internal Views
(Left—Courtesy of Engineering Concepts via YouTube; Right—Courtesy of Science Direct)

4.1.2.1 Emission Source

Emissions from centrifugal compressors are vented from wet seals (**Figure 9**), which use specialty oil that is circulated under high pressure to act as a barrier against compressed gas leakage. The oil absorbs methane when it contacts the gas at the compressor interface. The contaminated seal oil is purged of natural gas in a process called degassing, in which the natural gas is typically vented into the atmosphere. The seal oil is first degassed so that its viscosity and lubricity is maintained, then recirculated.

---

[41] EPA Office of Air Quality Planning and Standards (OAQPS), "Report for Oil and Natural Gas Sector Compressors, Review Panel," April 2014. Retrieved from http://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-compressors.pdf.
[42] EPA Natural Gas Energy STAR Program, "Wet Seal Degassing Recovery System for Centrifugal Compressors," 2014 (pp. 3 and 5). Retrieved from https://19january2021snapshot.epa.gov/sites/static/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf.

Studies have found variability in the methane emission volume from wet seal degassing in any one compressor. One study[43] calculated a per-compressor average methane emission rate of 63 cfm from a sample of 48 wet seal centrifugal compressors.[44] Assuming 8,000 hours of annual operation, the average annual gas emissions was 30.24 million scf per compressor.[45]

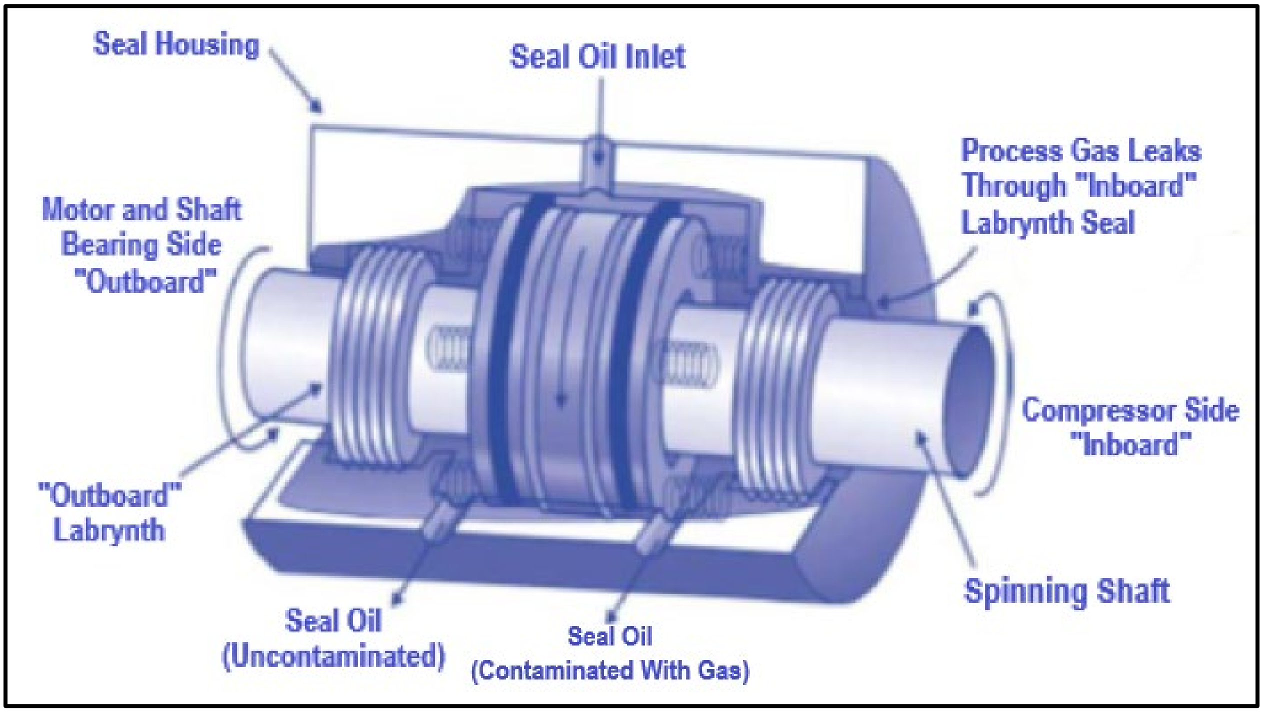


Figure 9: Centrifugal Compressor Wet Seal Schematic (Courtesy of EPA Energy STAR)

4.1.2.2 Implementation or System Design Strategy

One method for reducing natural gas emissions from centrifugal compressor seal oil degassing is separating gas from the seal oil in a small separator/disengagement vessel and routing it back into a pressurized inlet such as compressor suction or turbine gas (**Figure 10**). In this wet seal degassing recovery system, the contaminated seal oil is separated from entrained gas in a separator that operates at seal oil pressure, with gas flow controlled by a critical orifice. The entrained gas captured from the seal oil is routed to a seal oil demister for removal before being routed to a gas recovery system. Then, the seal oil flows from the bottom of the seal oil degassing separator to the atmospheric degassing separator, where the remaining minimal volume of entrained/dissolved gas is removed and vented into the atmosphere. Finally, the regenerated seal oil is recirculated back to the compressor seal oil system.

---

[43] Bylin, C., et al., "Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry," 24th World Gas Conference, October 2009 (p. 16). Retrieved from https://www.epa.gov/sites/default/files/2016-09/documents/best_paper_award.pdf.
[44] EPA Natural Gas Energy STAR Program, "Wet Seal Degassing Recovery System for Centrifugal Compressors," 2014 (p. 3). Retrieved from https://19january2021snapshot.epa.gov/sites/static/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf.
[45] Ibid.

The seal oil gas demister can be designed to receive recovered gas from multiple centrifugal compressors with wet seals. The design characteristics of this vessel will vary depending on the number of centrifugal compressors connected to the vessel.

In a typical wet seal configuration, the seal oil enters through the inlet (top) (**Figures 9** and **10**) and provides a barrier against escaping gas by forming two thin films under higher pressure between the center rotating ring and the two stationary rings.

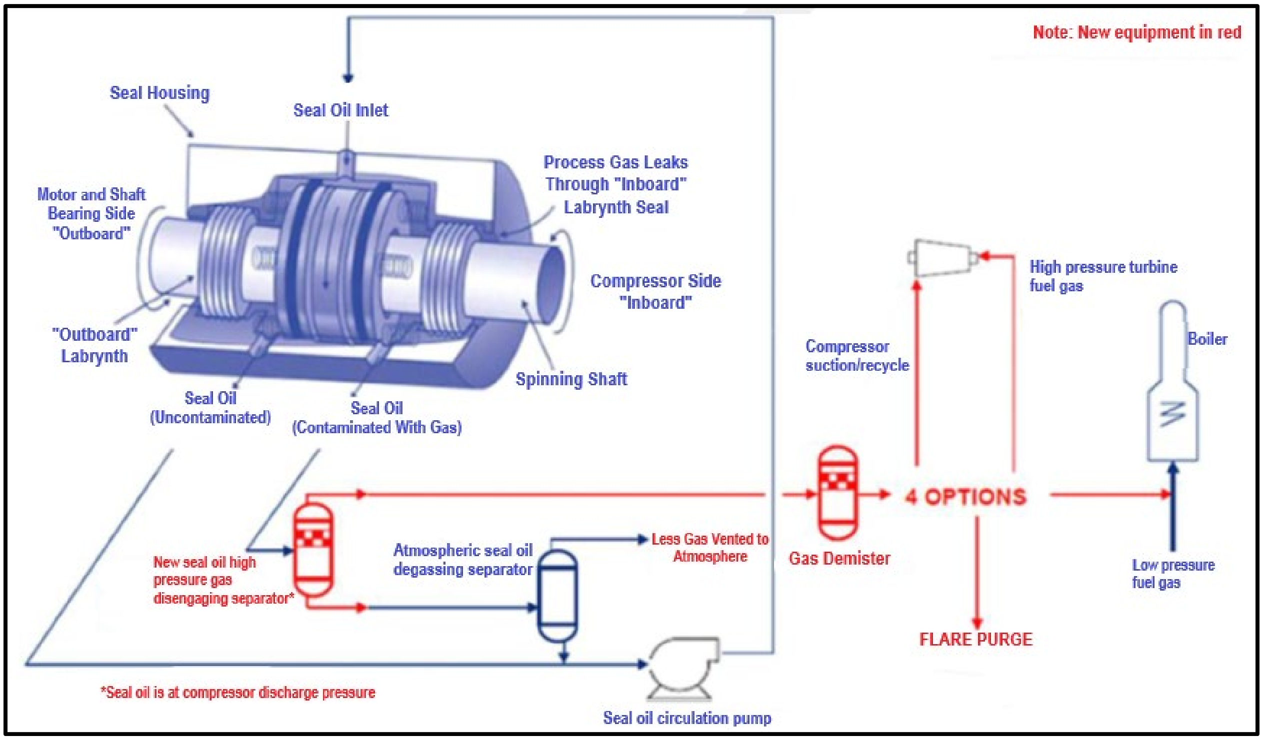


Figure 10: General Wet Seal Recovery System Process Flow (Courtesy of EPA Energy STAR)

4.1.2.3 Benefits and Limitations

The recovered gas can be used as site fuel gas or go back into the system. Operators have several options for the recovered gas, including the following:

- Using as high-pressure turbine fuel (typically requires recompression);
- Routing as low-pressure fuel (typically requires recompression); or
- Routing back to compressor engine (via combustion air intake).

Wet seal degassing recovery systems mitigate natural gas emissions with little compressor downtime. Instead of retrofitting the compressors with dry seals (Paragraph 5.1.1.1)—which may not be feasible due to operating conditions and requirements, costs, and compressor downtime—these systems can be installed at locations with wet seal centrifugal compressors. Additionally, wet seal capture systems can be integrated into the design process at new facilities containing wet seal centrifugal compressors.

The average natural gas emissions from centrifugal compressor wet seal degassing are estimated to be 63 cfm of gas per compressor; the total annual gas emissions are 30 million scf per compressor assuming 8,000 hours of operation.[46] One example of a wet seal degassing recovery system producing significant natural gas emission reduction occurred at a facility where more than 99 percent of entrained gas in the seal oil from 15 centrifugal compressors (four low pressure, nine high pressure, and two tandem) was recovered.[47] This system captured 1.6 Bcf—or 3,300 cfm—of gas over an 8,500-hour operational year.

The initial investment for a compressor wet seal degassing recovery system includes costs for the following:

- A high-pressure seal oil separator;
- New piping;
- Pressure and flow controls; and
- Labor for designing and installing the equipment.

System limitations include the following:

- Some applications, such as availability of low-pressure fuel systems, may not be available at all sites;
- The gas recovered from the low-pressure side of the compressor may require compression depending on use, or the gas may not be usable in high-pressure applications; and
- Retrofit installation requires that each compressor be shut down to tie the seal oil circulation piping into the gas disengagement vessels.

4.1.2.4 Safety and Feasibility Impacts

Because the industry began developing and reporting this technology in the early 2000s, no adverse safety impact is anticipated. Feasibility considerations include out-of-service costs, impact to flows, and future compressor upgrades. An analysis for installing a wet seal degassing recovery system should consider the capital and operational costs as well as the revenue generated by recovered gas.

4.1.3 Integrating ESD Systems with SCADA Systems

Emergency shutdown (ESD) systems (**Figure 11**), which evacuate hazardous vapors from safety-sensitive areas during compressor station emergencies and shutdowns, operate in conjunction

[46] EPA, PRO for Reducing Methane Emissions, "Wet Seal Degassing Recovery System for Centrifugal Compressors," 2014. (p. 5). Retrieved from https://19january2021snapshot.epa.gov/sites/static/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf.
[47] EPA, PRO for Reducing Methane Emissions, "Wet Seal Degassing Recovery System for Centrifugal Compressors," 2014. (p. 3).

with compressor station facilities and pipelines to incorporate shutdown levels appropriate to the hazard presented to personnel, the compressor station, and the environment. Rerouting combustible gases during ESDs not only eliminates potential hazards in the operating area but also can reduce methane emissions.[48]

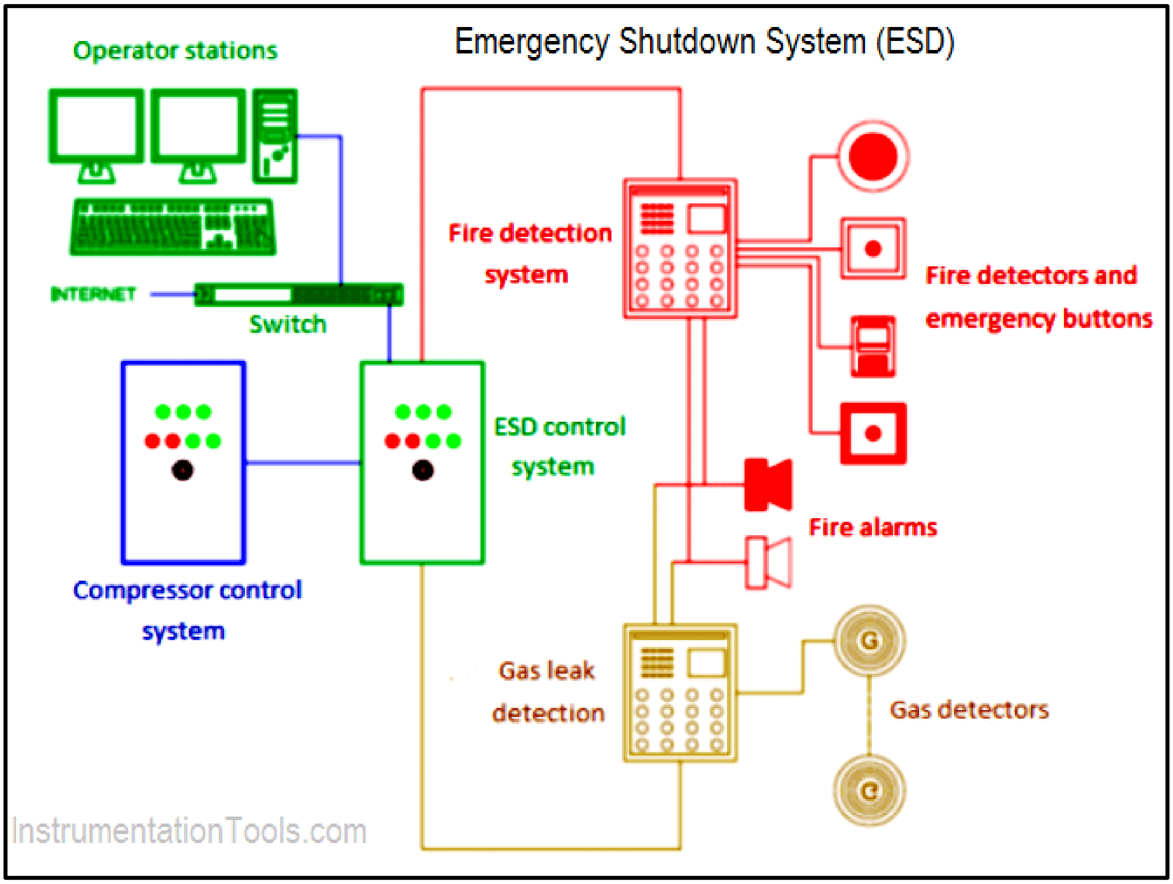


Figure 11: Example ESD Schematic (Courtesy of Instrumentation Tools)

Modern ESD systems can integrate with computer-based supervisory control and data acquisition (SCADA) systems (Paragraph 4.1.3.2) for enhanced system monitoring and control for emergencies. Integrated ESD systems can be configured to remotely monitor and control ESD valves (**Figure 12**) during system operations. ESD systems also provide valve status alerts and recommendations as well as partial stroke tests.

[48] EPA Energy STAR Program, PRO Fact Sheet No. 908, "Redesign Blowdown Systems and Alter ESD Practices," 2011. Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/redesignblowdownsystems.pdf.

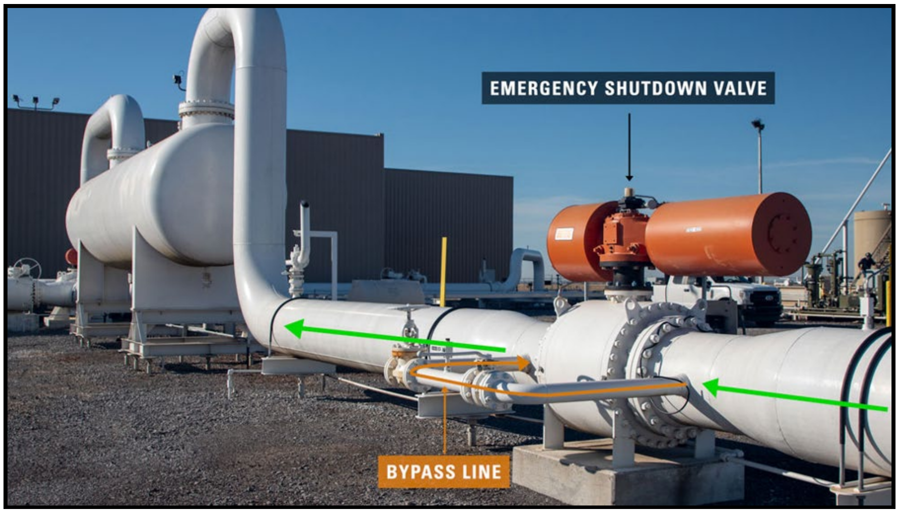


Figure 12: ESD Valve at Compressor Station (Courtesy of Kimray, Inc.)

4.1.3.1 Emission Source

Each compressor station contains an ESD system connected to a control system that can detect abnormal conditions, such as unanticipated overpressuring, pressure drop, or gas leakage. During an emergency blowdown event, the ESD can be activated onsite or from remote locations to (1) automatically stop the compressor units, and (2) isolate and vent compressor station piping gas. Some ESD systems route the vented gas to a flare stack for combustion; other systems vent the blowdown emissions into the atmosphere via a vent stack.

Based on 2019 PHMSA accident/incident data, 122 unplanned incidents with unintentional release in the transmission and gathering sectors resulted in total natural gas emissions of approximately 1.67 Bcf. Each incident had an approximate average release of 13,700 Mcf.[49]

4.1.3.2 Implementation or System Design Strategy

ESD systems can be integrated into any new or existing SCADA system to continuously monitor the compressor station and decrease the frequency of blowdown events, which in turn would result in reduced overall emissions. The use of SCADA systems to better detect large leaks and ruptures will require more pressure sensors along the pipeline and better measurement of gas inputs, outputs, usage, and losses along a pipeline segment.

SCADA systems, which typically are used for geographically expansive systems such as transmission pipelines with compressor stations at multiple sites, gather and analyze real-time data to monitor and control equipment involved with critical and time-sensitive events. Standard

[49] PHMSA, Pipeline Data and Statistics. **Table C-1** (Appendix C) provides details of the filters applied to the datafile. Data accessed July 2022 from https://www.phmsa.dot.gov/data-and-statistics/phmsa-data-and-statistics by clicking on (1) Pipeline Data and Statistics in the sidebar, (2) Pipeline Incident Flagged Files, and (3) Source Data in the sidebar, then downloading the flagged datafiles as a zip archive by clicking on PHMSA Pipeline Safety–Flagged Incidents. (The relevant data are in the gtggungs2010toPresent datafile.)

communication protocols allow equipment and instrumentation from different manufacturers to operate in the same system.

When used in transmission or gathering compressor stations, the SCADA system:

- Monitors flows, pressures, temperatures, valve opening and closure status, and compressor operational status across the entire system; and
- Can automatically manage compressor station processes.

4.1.3.3 Benefits and Limitations

Emissions savings vary by compressor station size, operating pressure, and facility. Per EPA Partner Reported Opportunities (PRO) Fact Sheet No. 908, annual methane emissions savings of 1,800 Mcf are based on a typical compressor station with eight compressors and 10, 8-inch-diameter ESD valves. The test is assumed to be conducted when the station pressure is at 500 psig.[50] Gas savings from rerouting blowdown emissions back into the system or for fuel use could justify the costs for piping and operation. However, rerouting blowdown from an ESD back into the system could have other feasibility challenges. For instance, to do so would require a significant amount of time and the installation of a recompressor, which is not always feasible in an emergency situation.

The integration of SCADA systems that operate with reliability-centered maintenance programs enables the detection of issues before blowdowns occur, and provides maintenance personnel advance notice of impending shutdowns and time to implement preventive maintenance to avoid—or reduce the frequency of—shutdowns. Predictive maintenance based on performance monitoring via SCADA can reduce intentional venting incidents, ESD frequency, and blowdown-induced downtime.

A well-designed SCADA system optimizes overall compressor station system performance via hardware and software that continuously monitor compressor station functions. Additionally, a SCADA system with real-time applications specific to operating conditions provides operators with the following:

- Accurate gas flow, volume, temperature, and pressure level measurements; and
- System detection of major leaks and pipeline breaks.

[50] EPA Energy STAR Program, PRO Fact Sheet No. 908, "Redesign Blowdown Systems and Alter ESD Practices," 2011. (p. 2). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/redesignblowdownsystems.pdf.

4.1.3.4 Safety and Feasibility Impacts

Site suitability for network-based SCADA systems may be impacted by requirements for continuous onsite and backup electric power sources as well as Internet access for web-based applications.

4.2 Distribution Sector

This section describes BATs within distribution systems and operations.

4.2.1 Increased Use of EFVs on New or Renewed High-Pressure Service Lines

Excess flow valves (EFVs) are installed on the pipeline to react quickly to a sudden rapid increase in pressure that causes the valve to close, minimizing the gas released to the atmosphere. Situations that may activate an EFV include damage to the pipeline occurring during excavation activities. **Figure 13**[51] illustrates these and other examples, along with an example of where an EFV is typically installed. **Figure 14** illustrates the design and activation of an EFV.

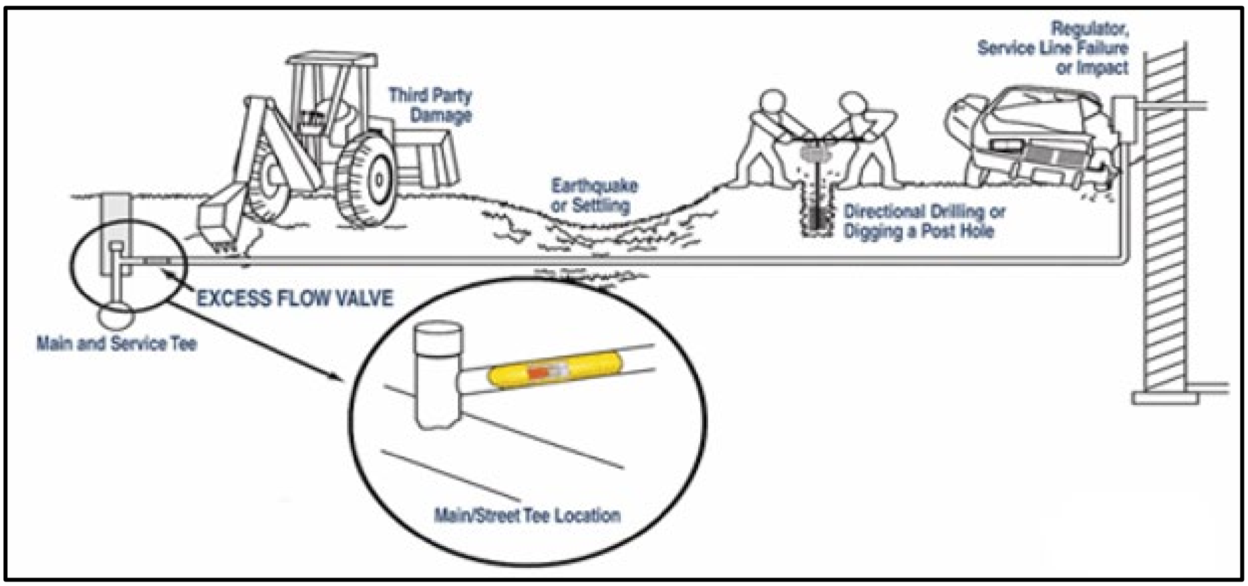


Figure 13: EFV and Service Tee in Damaged Service Line
(Courtesy of Public Service Electric and Gas (PSE&G))

[51] Public Service Electric and Gas (PSE&G) (Ragula, G.), "Installation of Excess Flow Valves Without Excavation to Prevent 3rd Party Damage," World Gas Conference, Buenos Aires, Argentina, October 5–9, 2009.

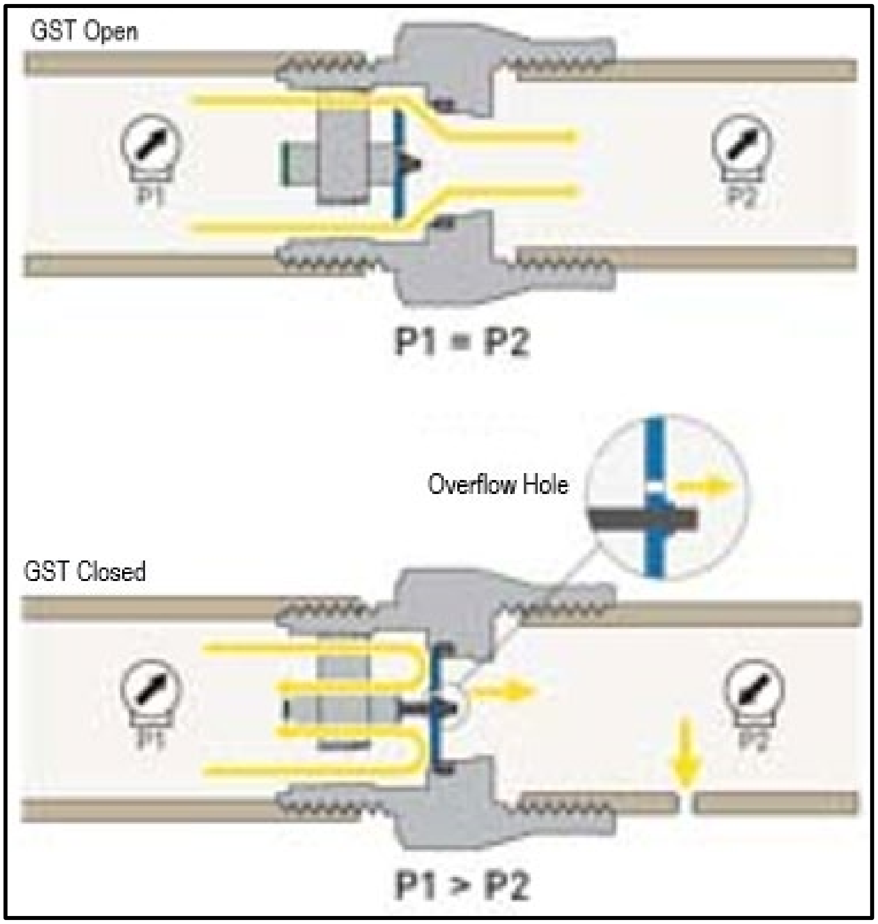


Figure 14: Triggered EFV (Courtesy of Teco Americas)

49 CFR § 192.383 requires the following:

- Mandatory installation of EFVs on new or replaced service lines to single-family residences that operate at a pressure of 10 psig or greater throughout the year; and
- The installation of EFVs on service lines, based on installed meter capacity.

49 CFR § 192.383 also outlines criteria for exceptions to the requirements and includes provisions for a customer's right to request an EFV.

More than one million EFVs were installed in 2020, and approximately 15.9 million EFVs were in service by the end of 2020.[52]

[52] PHMSA, Pipeline Data and Statistics. Retrieved Gas Distribution Annual Data 2010 to present .zip file in June 2022 from https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids, then used fields EFV_INSTALLED_CY and EFV_IN_SYSTEM for the numbers of EFVs installed each year and EFV systems in service at the end of the year, respectively.

4.2.1.1 Emission Source

Although the focus of this report is on planned activities, unplanned events such excavation damage contribute to natural gas releases. Similarly, if there is an issue during maintenance and repair, there can be a release or other catastrophic events in other segments of the system.

Damage to such service lines lacking EFVs can result in significant volumes of blowing gas and the increased potential of ignition from static electricity discharge until the service can be safely shut down—either by closing the valve tee at the main or squeezing off the plastic, depending on the damage location. NTSB has noted the importance of EFVs in the Merrimack Valley Accident Report.[53]

4.2.1.2 Implementation or System Design Strategy

Since the early 1980s, EFVs have been used successfully on high-pressure service lines to prevent blowing gas resulting from pipeline damage.

4.2.1.3 Benefits and Limitations

Current EFV technology enables operation at pressures lower than 10 psig. With the development of trenchless techniques, EFVs can be installed at the main connection on outside meter sets, enabling the retrofitting of existing service lines with EFVs without excavation. In 2016, PHMSA determined that expanding the use of EFVs beyond single-family residences could further reduce fatalities, injuries, lost product, and other property damage from various types of preventable incidents. Additionally, PHMSA estimated the following:[54]

> "...a total impacted community of 4,448 operators for this rule (3,119 master meter/small LPG operators who will need to comply with notification requirements and 1,329 natural gas distribution operators who will need to install valves and comply with notification requirements) and 222,114 service lines per year on average. It is expected to generate safety benefits in the form of reduced fatalities, injuries, lost product, and other property damage from certain types of preventable incidents in gas distribution pipelines. The overall benefits over a 50-year period were estimated at the annual equivalent of $5.5 million per year versus $10.6 million in compliance costs when calculated using a 7 percent discount rate. When using a 3 percent discount rate, the total benefits of the rule were estimated at $10.5 million while the costs were estimated at $12.0 million."

[53] NTSB, "Overpressurization of Natural Gas Distribution System, Explosions, and Fires in Merrimack Valley, Massachusetts September 13, 2018." Retrieved from https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1902.pdf.
[54] U.S. Federal Register, "Pipeline Safety: Expanding the Use of Excess Flow Valves in Gas Distribution Systems to Applications Other Than Single-Family Residences: A Rule by the Pipeline and Hazardous Material Safety Administration on October 14, 2006." Retrieved from https://www.federalregister.gov/documents/2016/10/14/2016-24817/pipeline-safety-expanding-the-use-of-excess-flow-valves-in-gas-distribution-systems-to-applications.

4.2.1.4 Safety and Feasibility Impacts

Although exceptions to mandatory installation of EFVs exist, these valves are widely used in the natural gas distribution sector to enhance safety by preventing or minimizing the uncontrolled release of natural gas into the environment when a service line is cut or damaged, often by third-party construction activities.

4.2.2 Replacement of Relief Valves and Seal Pots With Dual Regulators, Monitor Regulators, or Automatic Shutoff Valve Designs

To prevent accidental system overpressurization, 49 CFR § 192.195 requires that pipelines connected to a gas source for which the maximum allowable operating pressure (MAOP) could be exceeded due to pressure control or other failures be equipped with pressure-relieving or pressure-limiting devices. Additionally, 49 CFR § 192.201(c) requires the installation of relief valves or pressure-limiting devices—with the capacity to limit the maximum pressure in the main such that it does not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment—at or near each regulator station in a low-pressure distribution system. Dual monitor regulators should be designed properly so there isn't ‘wind-up’ in the monitor regulator (i.e., it can instantaneously take over control without having to move to the correct position). Monitor systems should also be designed so they are truly independent/redundant from each other. Note that this section also applies to the transmission sector.

4.2.2.1 Emission Source

Relief valves, used to protect against pipeline overpressure, help maintain a set MAOP by intentionally venting gas into the atmosphere when the pressure set point is exceeded. Relief valves generally are used in measuring stations, gate stations, and compressor stations as well as where a pipeline with a higher MAOP is connected to a pipeline with a lower MAOP via regulator. These are commonly located in remote areas, where venting gas is considered safe. Some operators use liquid-filled seal pots (**Figure 15**) that operate under a manometer principle for the same purpose, are considered legacy components that predate the 1970 implementation of 49 CFR Part 192, and are located in urban areas.

Relief valves historically have been reliable when properly set and maintained; most inadvertent gas releases into the atmosphere result from improper maintenance. Seal pots are more susceptible to inadvertent gas releases into the atmosphere due to aboveground vent post damage caused by motor vehicle accidents—the vent post transfers the force of the impact to underground piping connected to the seal pot, which is commonly joined with mechanical fittings. Additionally, the congested environments in which seal pots operate increase the risk of accidental ignition at damage sites. In addition to relief valves, some gas pipeline operators use an overpressure protection device called a liquid seal relief, which is typically water mixed with propylene glycol to prevent freezing. A liquid seal relief (1) uses a liquid-filled seal pot to contain system pressure under normal operating conditions, and (2) relieves system pressure under emergency conditions by venting gas to atmosphere through a vent post (**Figure 15**). Such devices, which operate on a simple concept, were used extensively until the mid-1950s and are still used today.

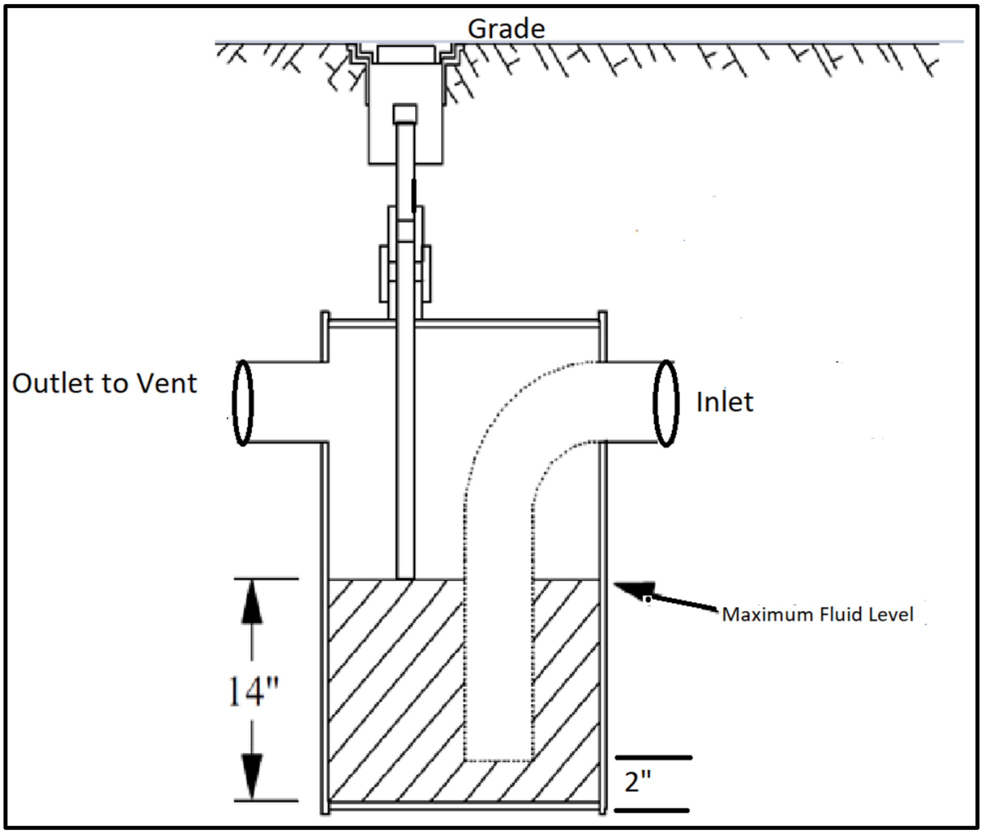


Figure 15: Typical Seal Pot Configuration Set to Relieve at 12 Inches Water Column (wc) (Courtesy of RagulaTech)

4.2.2.2 Implementation or System Design Strategy

In urban areas, most utilities now use dual (series) regulators or regulators with monitor designs to limit system pressure without venting gas. Series regulators are placed in a way where one regulates the pressure while the second monitors pressure. In any overpressure situation, the monitor regulator will prevent the overpressure of the system without the need to vent.

Automatic pressure shutoff valves, which are pressure-limiting devices that trip closed when a maximum pressure set point is reached, can also be used to limit the MAOP. Historically, these devices were used in isolated areas where gas shutoff had minimal impact to customers and the overall system, depending on system backfeeds and seasonal loads. Their overall use, however, has expanded recently with newer system designs that gas utilities are incorporating into overall system design processes.

For new or replacement construction, such pressure-limiting devices can prevent accidental system overpressurization without venting gas into the atmosphere.

4.2.2.3 Benefits and Limitations

Although pressure-limiting devices can dramatically reduce intentional and accidental venting of gas into the atmosphere, the use of automatic pressure shutoff valves may interrupt gas service to a greater number of customers, depending on the time of year, system demands, and the number of backfeeds in a looped system. An automatic pressure shutoff valve requires a manual reset by the operator.

4.2.2.4 Safety and Feasibility Impacts

No safety impact is anticipated with the use of either pressure-relieving or pressure-limiting designs because both are currently acceptable designs by code and are commonly used today.

4.2.3 Replacement of Bleed-By Controllers With No-Bleed Controllers

4.2.3.1 Emission Source

Bleed-by controllers release excess gas into the atmosphere as part of their normal design and function, the amount of which can vary depending on the specific control application; pressure cut, MAOP, and operator requirements; equipment used; and working pressures. Because higher bleeds can present a gas odor problem in nearby areas, it is often necessary to filter out the odorant in the gas by bleeding gas through vent lines piped to lengths of eight feet or higher with charcoal-filled socks installed at the outlet.

Also contributing to gas odor is the design used for some regulator stations constructed in the 1950s and 1960s that convert high-pressure gas to medium-pressure gas. In such designs, regulators release gas during normal operation through breather lines connected to vent posts.

The natural gas industry has made an effort to replace bleed-by controllers with newer, no-bleed controllers that function without venting gas into the atmosphere; however, bleed-by controllers continue to be used in isolated situations, possibly for the following reasons:

- Bleed-by design predates current regulations (grandfathered);
- May be considered a simpler solution for difficult or unusual control design parameters;
- No immediate need exists to replace controllers that are working as designed;
- The cost to retrofit pipelines may be high; and
- Operators familiar with bleed-by controllers may be uncomfortable with a design change.

Retrofitting or replacing bleed-by controllers with no-bleed controllers can reduce methane emissions in this application by 100 percent.

4.2.3.2 Implementation or System Design Strategy

Although 49 CFR § 192.203 provides requirements for the design of instrument, control, and sampling pipe as well as related components, there is no requirement for the use of no-bleed controllers.

4.2.3.3 Benefits and Limitations

The use of no-bleed controllers to the extent possible will protect the environment and the public by reducing the amount of gas released into the atmosphere and eliminate related odor issues. It should be noted that zero bleed pneumatic controllers can only be used with very low pressures and may not be suitable to replace continuous bleed pneumatic controllers in many applications.

4.2.3.4 Safety and Feasibility Impacts

When bleed-by controllers are replaced with no-bleed controllers, gas venting to the atmosphere can be eliminated without adversely impacting safety.

4.2.4 Replacement of Service Line Regulators Using Internal Relief With Automatic Pressure Shutoff Valves

To prevent unsafe overpressuring of end user appliances when a service regulator fails, 49 CFR § 192.197 requires the use of suitable protective devices for high-pressure distribution systems to customers. Various overpressure devices can be used in distribution systems; the device types being used are based upon MAOPs of 60 psig or less or greater than 60 psig, respectively.

4.2.4.1 Emission Source

Most operators use service line regulators equipped with internal pressure reliefs, which are safety mechanisms that accomplish the following:

- Prevent the overpressurization of customer owned piping serving residential gas equipment; and
- Lower the gas pressure for residential appliance usage.

This design is commonly used on meter sets that are installed either inside or outside buildings. For indoor meter sets, a properly sized pipe that extends to the outside of the building from the indoor meter set serves as a vent line to prevent venting gas inside the building. On outdoor meter sets, a vent line is unnecessary because the gas is vented directly from the service regulator diaphragm located outside.

Internal pressure reliefs, however, release gas into the atmosphere when required by the service regulator to maintain safe operating pressures for downstream customer gas utilization equipment.

Internal pressure reliefs are reliable, convenient, and require minimal maintenance. Additionally, they allow the safe operation of customer gas utilization equipment when gas is released into the atmosphere to correct excess pressure conditions.

4.2.4.2 Implementation or System Design Strategy

Automatic pressure shutoff valves, which would be used instead of internal pressure reliefs, close before a customer pipeline overpressure condition occurs and thus operate without venting gas into the atmosphere.

4.2.4.3 Benefits and Limitations

The use of automatic pressure shutoff valves will eliminate the venting of gas into the atmosphere to relieve excess pressure conditions downstream. Operators, however, must manually reset the valve; gain access to any structure requiring relighting; and relight appliances. Additionally, replacing internal pressure reliefs with automatic pressure shutoff valves may be costly; however, consideration should nonetheless be given to using an automatic pressure shutoff design in new and replacement facilities where overpressurization and venting can harm people.

4.2.4.4 Safety and Feasibility Impacts

The use of automatic pressure shutoff valves instead of internal relief valves achieves an equivalent level of safety. Additionally, any overpressure problem is immediately known when an automatic pressure shutoff valve closes. A relief valve, conversely, may operate intermittently over extended periods of time. Automatic pressure shutoff valves, however, result in a loss of gas service to customers, which may cause other safety risks, such as loss of heating during winter months; loss of service to sensitive customers, such as hospitals, schools, chemical plants, and power plants, that can take days or weeks to resolve; or risks associated with reintroduction of gas into a system and safe relighting of pilot lights in appliances once gas service is returned.

5 BATs and Practices When Performing Planned Repairs, Replacements, or Maintenance

This section focuses on identified BATs and practices that minimize or prevent the release of natural gas into the atmosphere during planned pipeline facility repairs, replacements, and maintenance. All recommendations are based on collected and analyzed data that provide a better understanding of intentional natural gas releases during such activities. The data include considerations such as failure causes, equipment and facility conditions, operator capabilities, pipeline age, and the quantity of natural gas released.

5.1 Release Prevention

5.1.1 Transmission and Gathering Sectors

The BATs and practices in this subsection can be included in the design of new facilities or as modifications to existing facilities that can be installed during planned shutdowns when feasible to limit both downtime and product loss.

5.1.1.1 Replacing Centrifugal Compressor Wet Seals with Dry Seals

This BAT, which only applies to the replacement of wet seals on centrifugal compressors, is separate from the technology described in Paragraph 4.1.2 that focuses on wet seal degassing recovery systems. For maximum operational efficiency, such seal replacements should be scheduled for a normal downtime period.

Wet seals are a significant source of gas leakage, particularly from lubricating oil that is not degassed. One Natural Gas STAR partner who installed a dry seal on an existing compressor, for example, reduced emissions by 97 percent—from 75 to 2 Mcf per day.[55]

5.1.1.1.1 Emission Source

In the natural gas transmission and storage sector, centrifugal compressors accounted for approximately 9 percent of total methane emissions (8.9 Bcf).[56]

Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the compressor casing. Beam-type compressors are the more common type and have two seals—one on each end—and "over-hung" compressors have a seal only on the inboard (motor) side. These seals use oil that circulates under high pressure between three rings around the compressor shaft and forms a barrier against compressed gas emissions (**Figures 9** and **10** earlier in the report). Compressors using wet (oil) seal technology (Paragraph 4.1.2) require a lubricant oil that traps natural gas and must be degassed appropriately.

Conversely, dry (gas) seal technology eliminates not only the need for oil lubrication associated with contacting seals but also the resulting need to address harmful emissions entrapped in the oil.

5.1.1.1.2 Implementation or System Design Strategy

An alternative to the traditional wet seal system is the mechanical dry seal system, which does not use circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic static pressure; this opposing force of high-pressure gas pumping between the rings and springs pushing the rings together creates a thin gap through which little gas can leak.

[55] EPA, "Replacing Wet Seals with Dry Seals in Centrifugal Compressors," Lessons Learned from Natural Gas STAR Partners, October 2006 (p. 1). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_wetseals.pdf.

[56] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

Most centrifugal compressors can be retrofitted with dry seal components, which in turn can reduce natural gas emissions by up to 95 percent during operations.[57] Two or more dry seals in a series, known as tandem dry seals, are most effective in reducing gas leakage.

When retrofitting centrifugal compressors to replace wet seals with dry seals, operators should consider natural gas emissions savings as well as operational costs and benefits. This should include a comprehensive inventory and technical evaluation of existing compressors that considers compressor type, age, hardware, and operating conditions.

5.1.1.1.3 Benefits and Limitations

The benefits of using dry gas seals in centrifugal compressors include the following:[58]

- Efficient minimization of gas leakage;
- Reduced wear, friction, power consumption, and O&M costs on equipment;
- No oil lubrication or the resulting need to address natural gas that becomes entrapped in the oil;
- No need for oil circulation components or treatment facilities;
- No fluid consumption; and
- Reduced leakage—dry seals have less than one percent of the leakage of a wet seal system that vents into the atmosphere.

Gas transmission centrifugal compressors equipped with wet seals emitted a total of 3.5 Bcf of methane gas according to the 2023 U.S. GHGI.[59] The annual EPA estimated volume of natural gas savings from replacing wet oil seals with dry seals in a centrifugal compressor is 45,120 Mcf.[60] These savings are based on the difference between the average vent rates of wet and dry seals (100 and 6 cfm, respectively) on a beam-type compressor with two seals operating over an 8,000-operational-hour year. Replacing a wet seal with two tandem dry seals, therefore, can reduce methane emissions by approximately 42,412.8 Mcf per year—assuming a natural gas methane content of 94 percent.[61]

[57] John Crane Company, "3 Ways We Are Working to Battle the Methane Emissions Problem," January 8, 2019. Retrieved from https://www.johncrane.com/en/resources/blog/2019/3-ways-battle-methane-emissions-problem.
[58] https://www.johncrane.com/en/products/mechanical-seals/dry-gas/aura120ns
[59] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI). The EPA does not provide a breakdown.
[60] EPA, "Replacing Wet Seals with Dry Seals in Centrifugal Compressors," Lessons Learned from Natural Gas STAR Partners, October 2006 (p. 1). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_wetseals.pdf.
[61] EPA, "Replacing Wet Seals with Dry Seals in Centrifugal Compressors," Lessons Learned from Natural Gas STAR Partners, October 2006 (p. 4).

The cost of a dry seal system will depend on compressor operating pressure, shaft size, rotation speed, and other installation-specific factors. Other costs include engineering, installation, and ancillary equipment.

5.1.1.1.4 Safety and Feasibility Impacts

Because this technology has been used by the industry, no adverse safety impact is anticipated. Dry seals are considered safer to operate than wet seals because they eliminate the need for a high-pressure oil system.

More than 80 percent of centrifugal compressors manufactured today use dry seals.[62] Replacing existing wet seals with dry seals, however, is not a straightforward solution—a comprehensive feasibility study should first be conducted.

5.1.1.2 Replacement of Rod Packing Seals in Reciprocating Compressors

Reciprocating compressors (**Figures 16** and **17**) increase the pressure of process gas by positive displacement, employing linear movement of the drive shaft. According to the U.S. GHGI, annual methane emissions from reciprocating compressors in gas transmission and storage service were approximately 33.7 Bcf in 2021.[63] In Figure 16, the arrow is pointing to an electric motor that is driving the compressor. The compressor is the large blue object. The two smaller blue items on the bottom right are motors driving pumps for lubrication and/or cooling.

[62] Borba, A., and Borges, F., "The Pros and Cons of Dry Gas Seals Installation in an Existing Synthesis Gas Compressor," Ammonia Technical Manual, 2007 (p. 128). Retrieved from http://www.webcalc.com.br/blog/compressor_dgs.pdf.
[63] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

Figure 16: Packaged Medium-Speed, Short-Stroke Compressor Unit (Courtesy of the Ariel Corporation)

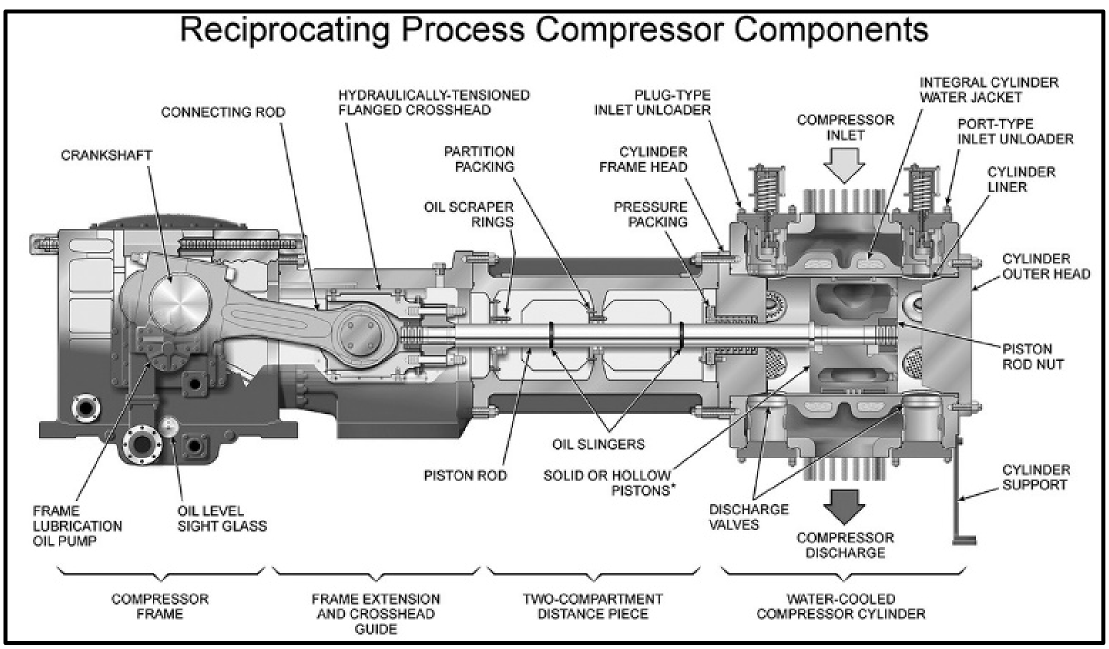


Figure 17: Reciprocating Compressor, Internal View (Courtesy of Piping Engineering)

5.1.1.2.1 Emission Source

Natural gas reciprocating compressors function as piston rods extend through the cylinder head into the compressor frame as well as move in and out of the cylinder at average speeds of up to 1,200 feet per minute at displacements (strokes) of three to eight inches. Compressor packing refers to the seal around the reciprocating rod (**Figure 18**.) The pressure packing case helps to seal around the piston rod. Pressure packing seals are designed to minimize gas leakage and route the leakage to a safe disposal or collection point; their primary purpose is to prevent natural gas leakage between a cylinder and piston rod.[64]

The packing ring design uses several sets within the packing case that comprise one to four rings in series. The rings, which often are segmented with various cut patterns, are held together by a garter spring around the outer ring diameter. The cut patterns allow the ring to maintain contact with the piston rod as it wears. The variations in the cut patterns minimize leakage by ensuring that the gaps of consecutive rings do not align.[65]

Emissions from reciprocating compressors are vented from the packing surrounding the mechanical compression components. In the transmission sector, the estimated total natural gas emissions from reciprocating compressors were 27.1 Bcf in 2021.[66]

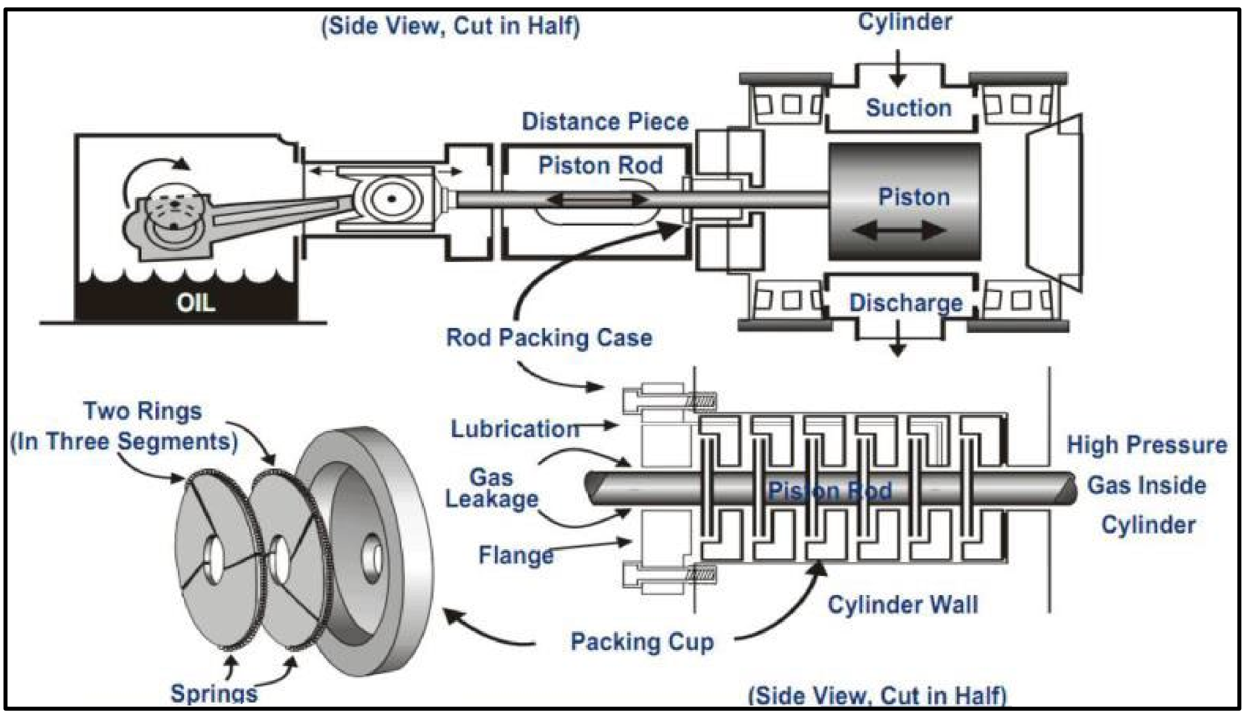


Figure 18: Typical Reciprocating Compressor Rod Packing System (Courtesy of EPA)

---

[64] Ariel Corporation (Hannon, D.), "Compressor Emissions Reduction Technology," March 1, 2018. Retrieved from https://www.arielcorp.com/company/newsroom/compressor-emissions-reduction-technology.html.
[65] Ariel Corporation (Hannon, D.), "Compressor Emissions Reduction Technology," March 1, 2018.
[66] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

Rod packing emissions typically occur around the piston rod rings as a result of slight ring movement in the cups and between the rings and shaft as the rod moves. Pressure packing rings provide a dynamic, mechanical seal around the piston rod and against the packing case cup to prevent leakage from the compressor cylinder.

5.1.1.2.2 Implementation or System Design Strategy

One recently patented rod packing system provides sealing capabilities of gapless rings in a cooled packing assembly.[67] Additionally, several manufacturers have developed rod packing seals that are designed to function as low- or zero-emission seals. The rod packing seals of inline reciprocating compressors can be retrofitted and replaced during scheduled maintenance or planned shutdowns.

5.1.1.2.3 Benefits and Limitations

The expected emission reductions from a rod packing replacement were calculated by comparing the average rod packing emissions to the average emissions from newly installed and worn-in rod packing;[68] the per-compressor annual emission reductions were estimated to be 396.5 and 1,258 Mcf for the gathering and transmission sectors, respectively.[69] Additional potential benefits of rod packing seal replacement include:

- Improved compressor reliability and efficiency;
- Extended packing operating life; and
- Reduced emissions during piston rod replacement, which may be necessary depending on rod condition.

The costs of implementing this emission mitigation strategy will vary depending on the compressor components and equipment being replaced. For example, the cost of replacing packing rings will depend on the number of compressor cylinders, the number of cups per cylinder, and the ring material.

5.1.1.2.4 Safety and Feasibility Impacts

The industry began developing and reporting this technology in the early to mid-1990s; therefore, no adverse safety impact is anticipated.

[67] https://www.cookcompression.com/en/products/rod-rings/low-emissions-rod-packing.html
[68] EPA OAQPS, "Report for Oil and Natural Gas Sector Compressors, Review Panel," April 2014. (p. 30). Retrieved from http://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-compressors.pdf.
[69] EPA OAQPS, "Report for Oil and Natural Gas Sector Compressors, Review Panel," April 2014. (Table 4-1, p. 31). Retrieved from http://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-compressors.pdf.

5.1.1.3 Replacement of Pneumatic Controllers (PCs)

Pneumatic controllers (PCs) are quite common at natural gas facilities; an estimated 90,000 to 130,000 pneumatic devices in the transmission sector[70] activate isolation valves as well as regulate gas flow and pressure at compressor stations, pipelines, and storage facilities. Gas-driven PCs are mechanical actuators operated by compressed natural gas drawn from pipelines. Automated PCs activate valves used to control processes in all sectors of the natural gas industry. Isolation or ESD valves also may be controlled and activated pneumatically.

PC devices include, but are not limited to, the following:

- Emergency response devices;
- Flow rate, liquid level, pressure, and temperature controllers;
- Positioners; and
- Transducers.

The use of instrument air-powered or electronic controllers can eliminate methane emissions on controllers for valves. According to the U.S. GHGI, in 2021, gas transmission, storage, and gathering systems released 2.9 Bcf from high bleed pneumatic controllers; 12.0 Bcf from intermittent bleed pneumatic controllers (10.0 Bcf from gathering systems); and 0.5 Bcf from storage facilities, or 15.4 Bcf in total.[71]

5.1.1.3.1 Emission Source

Many actuators in these process control systems use high-pressure natural gas because it is a continuous power source, eliminating the need for electrical power on remote sites or separate air compression and drying equipment to compress and dry ambient air. Pneumatically actuated valves normally vent natural gas into the atmosphere during operation.[72] The cumulative emissions from pneumatically actuated valves, each with a dedicated PC, are significant.

Emission sources across the natural gas supply chain include intermittent bleed controllers and existing PCs in the transmission, storage, and distribution sectors. The reported 2021 emissions in the U.S. GHGI from pneumatic devices in the transmission sector were approximately 2.3 Bcf.[73]

---

[70] EPA Natural Gas STAR Program, et al., "Replacing High-Bleed Pneumatic Devices: Lessons Learned from Natural Gas STAR," Small and Medium Sized Producer Technology Transfer Workshop, June 29, 2004 (p. 3). Retrieved from https://www.epa.gov/sites/default/files/2017-09/documents/2-devices_colorado2004.pdf.

[71] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

[72] Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations, Environ. Sci. Technol. Lett. 2019, 6, 6, 348–352. Retrieved from https://pubs.acs.org/doi/abs/10.1021/acs.estlett.9b00158.

[73] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

PC devices function in part by using a continuous small discharge of gas. These types of PCs are classified according to the amount of gas discharged as follows:

- Low bleed (**Figure 19**), which is a bleed rate less than or equal to 6 scfh;
- High bleed, which is a bleed rate greater than 6 scfh;
- Zero bleed; and
- Intermittent bleed (actuating or snap controllers), which vent only when activated. Additionally, gas releases only when these controllers open or close a valve.

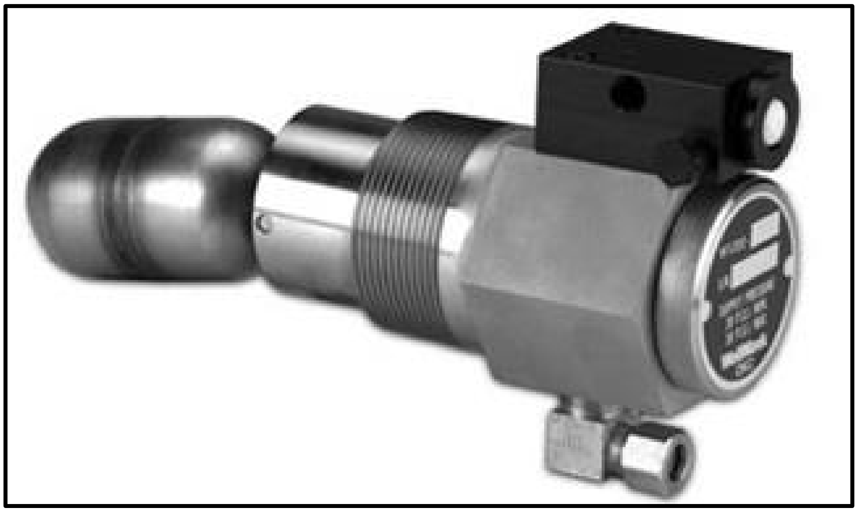


Figure 19: Example Low-Bleed PC (Courtesy of Wellmark)

The volume of natural gas vented from pneumatic devices varies by model and age. A study reported that the average annual natural gas emissions in the transmission sector for high- and low-bleed PCs are 155 and 12 Mcf, respectively.[74]

Figure 20 shows an overview of the gas flow from higher-pressure gas lines to a regulated gas line that supplies gas to system PCs. The process signal strength determines the PC response type for valve activation.

[74] EDF, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries Approach and Methodology," March 2014 (Section B.3.4.6, p. B-13). Retrieved from https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

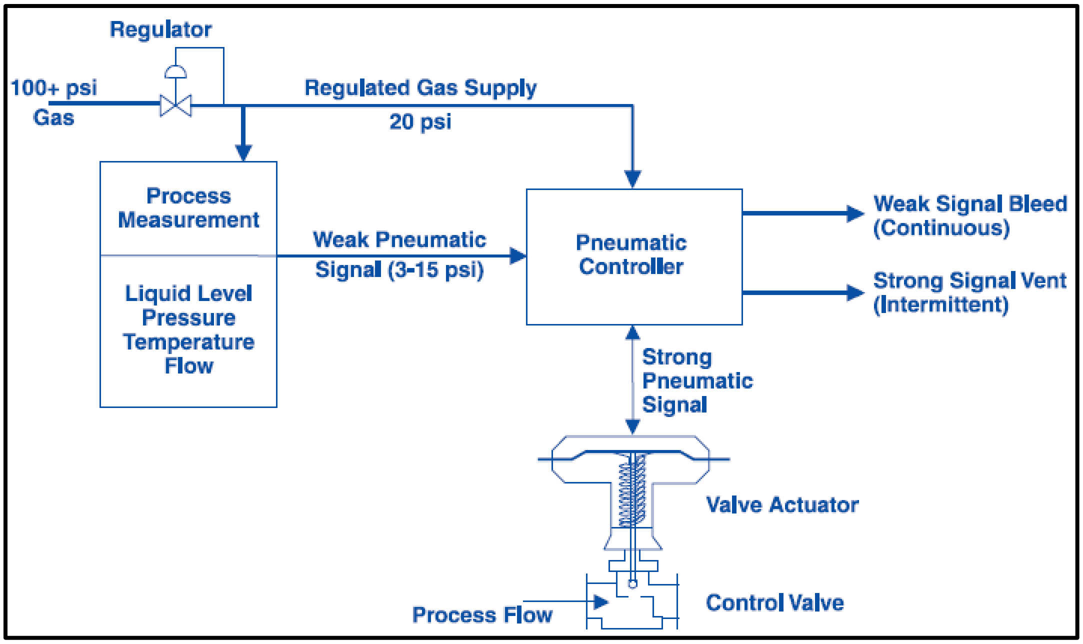


Figure 20: Pneumatic Device Schematic (Courtesy of EPA Natural Gas STAR Partners)

Dump valves, which are commonly used as an intermittent level control device, emit gas only when actuated. These valves typically produce emissions similar to low-bleed controllers but can produce emission levels between those produced by high- and low-bleed controllers.[75]

A study calculated the total emissions for high-, low-, and intermittent-bleed PCs to be 15, 75, and 10 percent, respectively.[76] The annual calculated emission factors per device for high-, low-, and intermittent-bleed PCs were 155, 20, and 12 Mcf, respectively.[77]

Replacing the following provides opportunities to reduce or eliminate natural gas emissions:

- Intermittent PCs with instrument air systems;
- High-bleed devices with low-bleed devices; and
- PCs with electronic controllers.

[75] EDF, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries Approach and Methodology," March 2014. Retrieved from https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.
[76] EDF, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries Approach and Methodology," March 2014. (Section B.3.4.6, p. B-13)
[77] Ibid

5.1.1.3.2 Implementation or System Design Strategy

a. Replacing Intermittent PCs with Instrument Air Systems

PCs can be operated as zero-bleed devices by using compressed air instead of natural gas, eliminating up to 70,000 Mcf of natural gas emissions annually per facility based on the facility size, type of device used, and the control application type.[78]

Instrument air systems, which are typically installed at facilities having high PC valve concentrations and a full-time operator presence, are powered by small electric compressors. Additionally, these systems use dehydrators and volume tanks that filter, dry, and store the air.

b. Replacing High-Bleed Devices with Low-Bleed Devices

Factors for operator consideration when replacing high-bleed devices with low-or zero-bleed devices include those outlined in Paragraphs 5.1.1.3.1 and 5.1.1.3.3b.

c. Replacing PCs with Electronic Controllers

The use of electronic instruments and control devices has increased in recent years. Electronic control systems, which use small electrical motors instead of gas-powered motors to operate valve controllers, adjust the level or position of the end device (e.g., control valves) by sending an electric signal to an electric motor-powered actuator or positioner. These systems typically include a control panel; electric actuators; electronic controllers; control valves; relevant switches; and a power source such as a grid, solar panels and batteries, or power generated onsite.

5.1.1.3.3 Benefits and Limitations

In addition to the following system-specific benefits, converting equipment in gas gathering stations from pneumatic to mechanical has an annual methane emission reduction potential of 11.9 Bcf.[79]

a. Replacing Intermittent PCs with Instrument Air Systems

The benefits of using intermittent PCs with instrument air systems include the following:

- Increased control device life;
- Improved operational efficiency; and
- Increased safety resulting from the elimination of flammable substances.

---

[78] EPA Natural Gas STAR Partners, "Convert Gas Pneumatic Controls to Instrument Air," October 2006. (p. 1). Retrieved from https://19january2021snapshot.epa.gov/sites/static/files/2016-06/documents/ll_instrument_air.pdf.

[79] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

A critical component of an instrument air control system is the power source required to operate the compressor. Generally, cost-effective implementation of instrument air systems is limited to sites with available electrical power.

b. Replacing High-Bleed Devices with Low-Bleed Devices

Retrofitting or switching high-bleed pneumatic devices for low-bleed devices can reduce emissions significantly. The potential benefits include the following:

- Increased operational efficiency. The retrofit or complete replacement of worn units can provide improved system-wide performance and reliability for gas flow, pressure, and liquid level monitoring.
- Lower annual natural gas emissions ranging from 45 to 260 Mcf per device,[80] depending on the device and specific application.

c. Replacing PCs with Electronic Controllers

Electronic controllers (**Figure 21**) can be installed at gas transmission facility sites connected to a reliable electric grid and at remote sites that use alternative energy sources. Additionally, an electronic control system may be designed to completely replace all pneumatically powered devices. Furthermore, recent developments in digital electronic controller technology offer advanced features for process controls, including the following:

- Integration of controller components into SCADA or distributed control systems for controller actuation;
- Use of composite materials for pressure-affected parts to reduce metal-to-metal contact on controller moving parts; and
- Integration of electronic actuators with sensor technology that monitor operating pressures, torque and speed output, and wear of critical parts in real time.

Additionally, each electronic control system (1) is designed on a case-by-case basis; (2) can be customized for every application; and (3) can be as sophisticated—or simple—as required.

Depending on the type of system being evaluated, additional benefits of replacing PCs with electronic control systems include the following:[81]

- The capability to enable or simplify the installation of automated systems such as SCADA; and
- Increased reliability.

[80] EPA Natural Gas STAR Partners, "Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry," October 2006. (p. 3). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_pneumatics.pdf.
[81] Carbon Limits AS, "Zero Emissions for Technologies for Pneumatic Controllers in the USA," August 2016. Retrieved from https://www.catf.us/wp-content/uploads/2019/09/CL2016-ZeroEmitting-Pneumatics-Alts-1Aug2016.pdf.

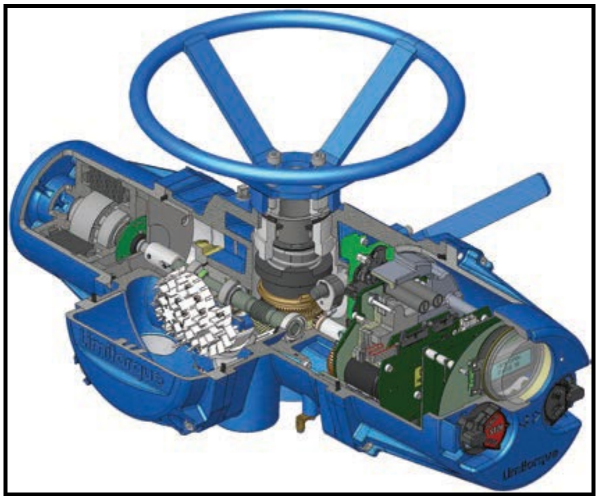


Figure 21: Electronic Valve Controller, Internal View
(Courtesy of Flowserve Corporation)

Electronic control systems rely on a constant electricity source and may require backup power or storage to ensure reliability.

5.1.1.3.4 Safety and Feasibility Impacts

No adverse safety impact is anticipated; however, the presence of a nearby, reliable electric grid is critical for safety. The safety risks are considered acceptable because of the low system voltage.

Electronic control systems rely on a constant electricity source and may require backup power or storage to ensure reliability.

5.1.1.4 Automated Air/Fuel Ratio (AFR) Control Systems

5.1.1.4.1 Emission Source

The AFR[82] affects cold starting capability, idle quality, fuel economy, horsepower requirements, exhaust emissions, and the longevity of natural gas-fueled internal combustion engines.

For a mixture of air and fuel to burn inside an engine, the AFR must be within certain minimum and maximum flammability limits; too much air and not enough fuel (or vice versa) may create a mixture that fails to burn when a spark plug fires. This can result in an ignition misfire, loss of power, or increased emissions. Conversely, a perfectly balanced AFR results in the correct stoichiometric ratio,[83] which is 17.2:1 for natural gas.[84]

Natural gas-fueled internal combustion compressor engines provide continuous operations over a set range of AFRs. Low air-to-fuel mixtures (rich burn) are used when greater horsepower is

---

[82] The AFR, which is expressed by weight or mass (i.e., pounds of air to pounds of fuel), is the mixture ratio or percentage of air and fuel delivered to the engine by the fuel system.
[83] This is the amount of oxygen and hydrocarbons needed to burn all the fuel.
[84] https://www.aa1car.com/library/air_fuel_ratios.htm.

needed; high air-to-fuel mixtures (lean burn) are used when lower horsepower and greater fuel efficiency are desired. Rich conditions result in more unburned fuel (primarily natural gas) and CO_2 emissions.

Older compressors may exhibit problems such as high exhaust emissions, high fuel consumption, excessive engine maintenance, poor compressor throughput, and high shutdown frequency. Each issue can be resolved by adding automated AFR control to the engine system.

5.1.1.4.2 Implementation or System Design Strategy

Automated AFR control systems combine electronic control systems with valve actuation and gas mass flow metering technology into an integrated application for compressor gas engines. Automated AFR controls for existing gas compression engine retrofits can be integrated into compressor station systems during planned shutdowns. New compressor station design should include automated AFR controls for compressors and associated equipment.

For existing compressors, advanced planning is required before installing automated AFR systems to provide smoother execution and recommissioning. Depending on the specific compressor, identifying and procuring components for retrofits may take up to one year. Additionally, procuring long-lead items may be necessary prior to planned shutdowns for retrofits or upgrades.

5.1.1.4.3 Benefits and Limitations

Any natural gas-fired engine of more than 1,000 hp can benefit from AFR control and optimization systems. Operators have found the greatest opportunities for significant system and efficiency improvements in rich-burn, high-speed, turbocharged engines ranging from 1,000 to 3,000 hp.[85] Additionally, an EPA Gas STAR operator reported annual fuel savings of 28,470 Mcf per engine from reduced consumption.[86] Annual per-engine methane emission reductions of 350 to 700 Mcf can be expected, assuming an average engine combustion efficiency of 98 to 99 percent.[87]

An EPA report found that installing an automated AFR control system that automatically adjusts and optimizes the operating parameters of a natural gas-fired internal combustion engine results in significant fuel savings. Additionally, EPA Gas STAR partners reported annual methane emission reductions of 913 to 12,175 Mcf per unit.[88]

Automated AFR control systems also maximize engine performance. Additionally, these systems may allow captured hydrocarbon emissions to be delivered to the engine air intake for use as

---

[85] EPA, PRO Fact Sheet No. 104, "Install Automated Air/Fuel Ratio Controls," Energy STAR Program, 2011. (p. 2). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/auto-air-fuel-ratio.pdf.
[86] Ibid.
[87] Methane Guiding Principles Partnership, "Reducing Methane Emissions: Best Practice Guide Energy Use," November 2019. (p. 8). Retrieved from https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/Reducing-Methane-Emissions-Flaring-Guide_MGP.pdf.
[88] EPA, PRO Fact Sheet No. 104, **"**Install Automated Air/Fuel Ratio Controls, Energy STAR Program," 2011. (p. 2).

fuel; the control system adjusts the fuel intake to account for extra hydrocarbons in the air intake.[89]

Additional benefits of AFR control systems include fewer false starts, lower combustion temperature, longer engine life, lower maintenance, and increased safety.[90]

5.1.1.4.4 Safety and Feasibility Impacts

Because the industry began developing and reporting on this technology in 2001, no adverse safety impact is anticipated. Ensuring the AFR is properly integrated with existing site safety systems and providing proper training to operating personnel is critical. Completing an electrical assessment of the engine/compressor package and reevaluating area classifications to ensure code compliance also may be necessary.

Based on the fuel savings of installing an AFR control system, the primary fuel efficiency improvement opportunity exists at gas facilities with rich-burn engines greater than 1,000 hp in size. Each AFR project, however, is site-specific and should be evaluated based on engine type, size, and operating conditions.

5.1.1.5 Glycol Dehydrators

This technology applies primarily to gathering system compressor stations; specifically it is necessary to remove liquids in the natural gas stream to prevent corrosion in downstream piping and equipment.

In 2021, the U.S. GHGI estimated that gathering system dehydrators in service released approximately 4.0 Bcf of natural gas. Equipping dehydrators with vapor recovery units or replacing dehydrators with zero-emission designs could significantly reduce this total.

5.1.1.5.1 Emission Source

Natural gas is saturated with entrained water and must be dehydrated to prevent hydrate formation, natural gas oversaturation, and equipment corrosion. The primary purpose of glycol dehydrators in the natural gas industry (**Figure 22**) is to remove water from an incoming wet gas stream using monoethylene glycol, diethylene glycol or, most commonly, triethylene glycol (TEG). The glycol is pumped to a gas contactor, where it mixes with the natural gas stream. Then, the glycol absorbs water and natural gas from the gas stream, producing dry gas and "rich" (wet) glycol.

---

[89] Methane Guiding Principles Partnership, "Reducing Methane Emissions: Best Practice Guide Energy Use," November 2019. Retrieved from https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/Reducing-Methane-Emissions-Flaring-Guide_MGP.pdf.
[90] EPA, PRO Fact Sheet No. 104, "Install Automated Air/Fuel Ratio Controls, Energy STAR Program," 2011. Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/auto-air-fuel-ratio.pdf.

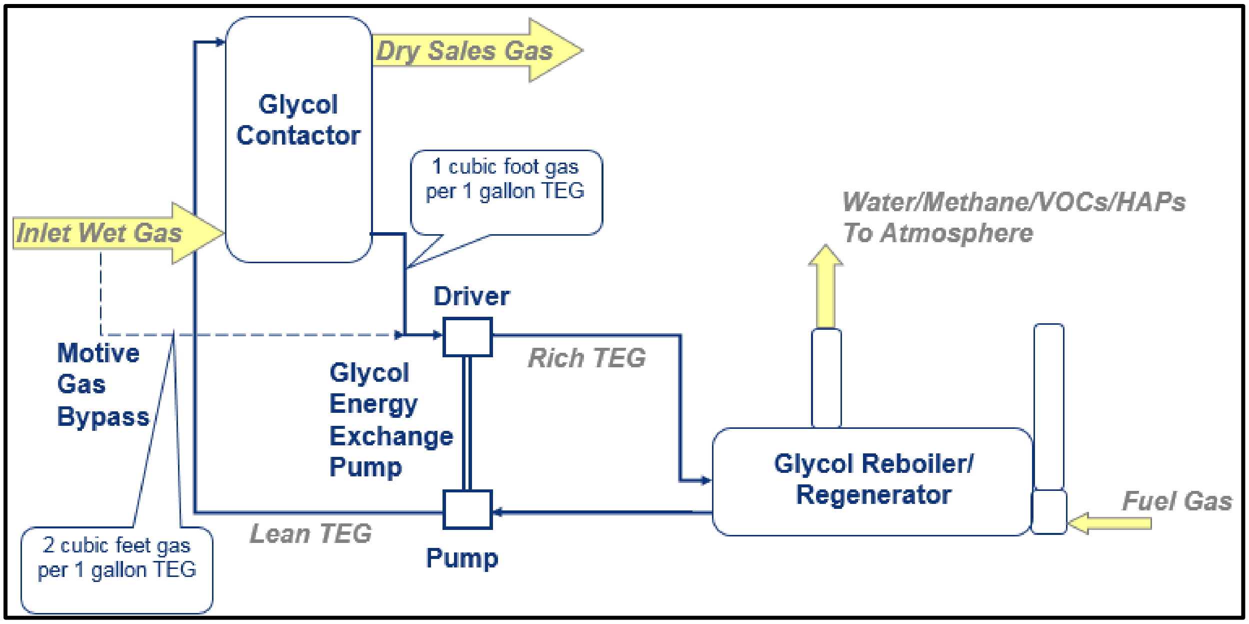


Figure 22: Typical Glycol Dehydrator With Exchange Pump and Without Flash Tank Separator (Courtesy of Climate & Clean Air Coalition Oil and Gas Methane Partnership (CCAC OGMP))

Several dehydrator configurations, including the following, produce varying natural gas emission levels during operation:[91]

- In some configurations, saturated glycol is sent to a reboiler, where it is heated to boil off the water. Natural gas usually is boiled off and routed with the steam into the atmosphere or for flaring.
- Some dehydrators inject gas into the glycol feed to the reboiler to act as a stripping agent that aids in removing water from the glycol at a lower temperature. This gas is vented with the steam.
- For dehydrators with energy exchange pumps, the low-pressure glycol is pumped into the absorber by pistons driven by the high-pressure glycol leaving the absorber. The additional gas necessary for a pneumatic gas-assisted glycol circulation pump passes through the regenerator and vents with the steam.

Natural gas emissions from a dehydrator system are directly proportional to the glycol circulation rate in normal continuous operation. Rich glycol contributes to natural gas emissions from the regenerator vent; with higher circulation rates, these sources generate more emissions. Stripping gas injected into a dehydrator system generates additional natural gas emissions.

[91] CCAC OGMP, "Technical Guidance Document No. 5: Glycol Dehydrators," Modified April 2017 (p. 1). Retrieved from http://www.ccacoalition.org/sites/default/files/resources/2017_OGMP-TGD5-Glycol-Dehydrators_CCAC.pdf.

5.1.1.5.2 Implementation or System Design Strategy

Operators apply dehydrator emission reduction technologies primarily to facilities, where the gas has high water vapor (dew point) content. New facilities can be designed with dehydrators that eliminate natural gas emissions. Existing gathering stations can be retrofitted with zero-emission dehydrators through gas stream piping, valve, pump, and controller modifications.

Emission reduction options for existing facilities can be performed during regularly scheduled maintenance activities. Manufacturer development of packaged glycol dehydration skid units allows operators to install dehydrator units during planned shutdowns.

a. Route Flash Tank and Dehydrator Regenerator Vents

Installing a flash tank separator (**Figure 23)** upstream of the regenerator can capture most of the natural gas entrained in the glycol. Then, the recovered gas can be routed for use as a fuel source, to a low-pressure sales line, or to a vapor recovery unit (VRU). Recovering gas from the regenerator and/or flash tank separator using this technology involves installing additional piping and valves.

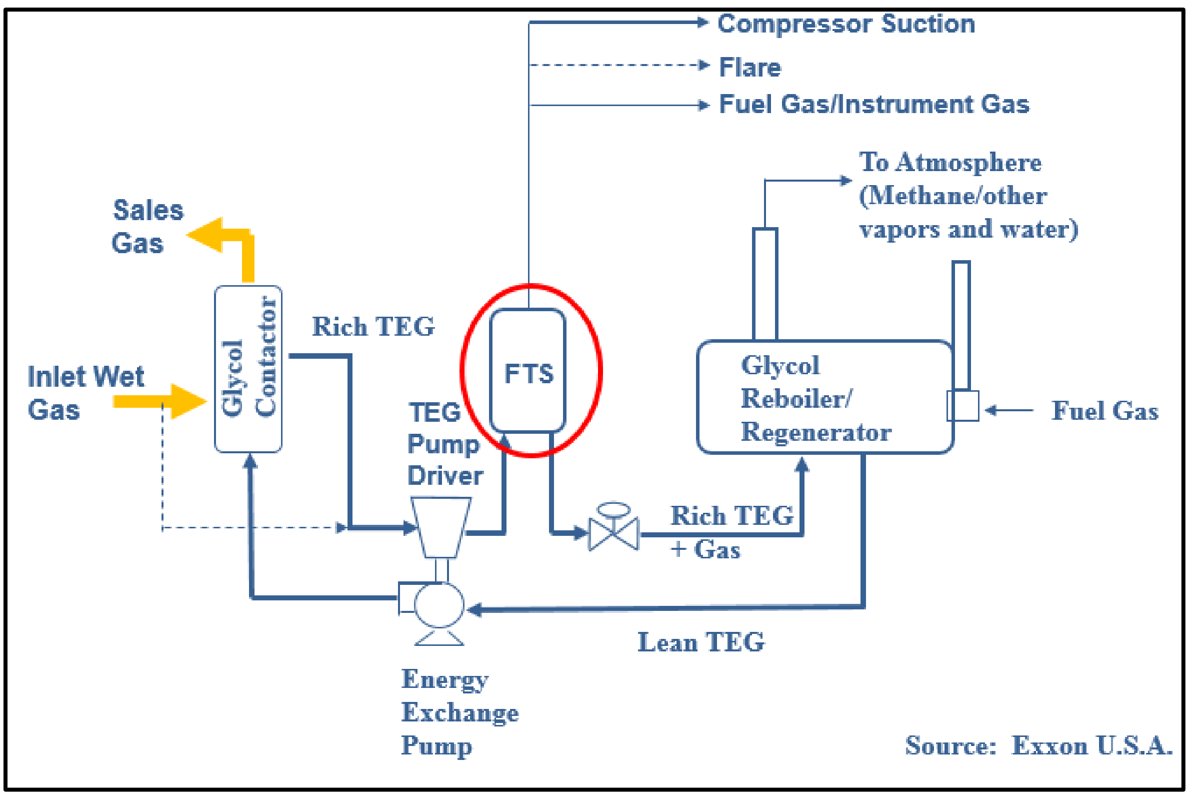


Figure 23: Glycol Dehydrator With Flash Tank Separator
(Courtesy of EPA Natural Gas STAR Workshop Presentation, June 2002)

A flash tank separator can store separated gas and liquid at either the fuel gas system or compressor suction pressure. (At lower pressure, the gas is rich in natural gas.) A flash tank captures approximately 90 percent of the natural gas[92] and 10 to 40 percent of volatile organic compounds (VOCs) entrained by the wet TEG, which flows to the glycol regenerator/reboiler. There, the wet TEG is heated to boil off the absorbed water, remaining natural gas, and VOCs that are normally vented into the atmosphere.[93]

When routing recovered gas to a VRU, operators can reduce methane emissions by approximately 95 percent via stripping gas reboiler venting.[94]

b. Zero-Emissions Dehydrators

Leaking gas-driven circulation pumps produce natural gas emissions; electric circulation equipment can be used to eliminate these emissions. An electric compressed air system with storage vessels for fuel air also can be used to actuate various controls throughout the system. These dehydrators (**Figure 24**) can eliminate 1,951 to 51,750 Mcf of emissions annually from electric glycol circulation pumps, gas strippers (flash tanks), and still column effluent based upon the size and flow volumes through the equipment.[95]

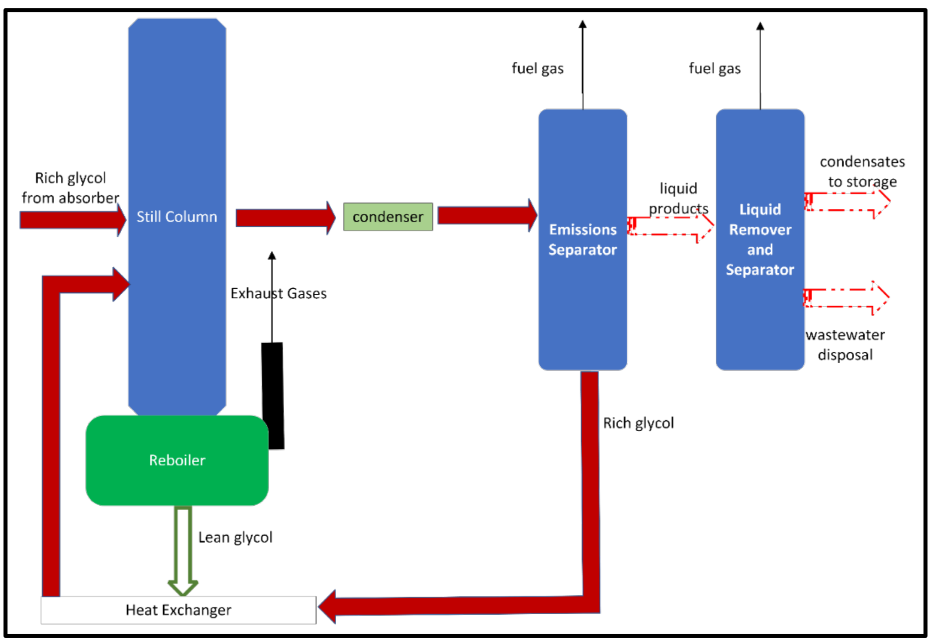


Figure 24: Glycol Dehydrator System with Zero-Emissions Dehydrator (Derived From Flowsheet Provided by the EPA Environmental Technology Verification Program)

---

[92] CCAC OGMP, "Technical Guidance Document No. 5: Glycol Dehydrators," Modified April 2017 (p. 2). Retrieved from http://www.ccacoalition.org/sites/default/files/resources/2017_OGMP-TGD5-Glycol-Dehydrators_CCAC.pdf.
[93] CCAC OGMP, "Technical Guidance Document No. 5: Glycol Dehydrators," Modified April 2017 (p. 5).
[94] Ibid.
[95] EPA Energy STAR Program, PRO Fact Sheet No. 206, "Zero Emissions Dehydrators," 2011. (p. 2). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/zeroemissionsdehy.pdf.

5.1.1.5.3 Benefits and Limitations

Although zero-emissions dehydrators require an electric power source, their additional benefits include increased operational efficiency.[96]

5.1.1.5.4 Safety and Feasibility Impacts

The industry began developing and reporting on this technology in 2001; therefore, no adverse safety impact is anticipated.

The practice of re-routing skimmer gas can be employed on all dehydrators with vent condensers if the gas used as a fuel source exceeds the volume of rerouted skimmer gas. Additionally, existing glycol dehydrators can be retrofitted with zero-emissions technology through piping, valve, pump, and controller modifications. Recent technology includes modular skid-mounted units, which are designed to fit within facility compounds as well as reduce costs and installation duration.

5.1.1.6 Replacing Gas Starters with Air or Electric Starters

This BAT applies to facilities with gas combustion turbine starter motors, such as gas turbine drivers for centrifugal compressors.

5.1.1.6.1 Emission Source

Compressor, generator, and pump engines at natural gas facilities often are started using gas expansion turbine motor starters. The starter motor assembly converts stored energy into mechanical rotation to crank an engine fast enough to begin the engine's ignition sequence. Storage tanks at compressor stations store pressurized natural gas, which is piped into the starter assembly and injected across the starter turbine, initiating engine startup.

The gas used during startup attempts often vents into the atmosphere. Typical compressor engine startups vent 1 to 5 Mcf of gas per attempt,[97] with engines often requiring multiple startup attempts. Each failed engine start wastes gas, produces unnecessary natural gas emissions, and reduces component efficiency. Natural gas leakage from the volume tank also produces natural gas emissions. To eliminate these issues, operators can replace gas starters with either compressed air or electric starters.

---

[96] EPA Energy STAR Program, PRO Fact Sheet No. 206, "Zero Emissions Dehydrators," 2011. (p. 3). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/zeroemissionsdehy.pdf

[97] EPA, PRO Fact Sheet No. 105, "Install Electric Motor Starters," 2011. (p. 2). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/installelectricstarters.pdf. A single startup of a properly tuned engine may require 1 to 5 Mcf of gas at 200 psig average volume tank pressure, depending on engine size (horsepower).

5.1.1.6.2 Implementation or System Design Strategy

a. Compressed Air Starters

The two main types of air starter motors are (1) vane, which uses sliding vanes in a rotor to convert airflow into mechanical movement; and (2) turbine, the rotation of which is created by airflow pushing on the blades of one or more turbine wheels.

For starters using compressed air, pressurized air is injected into the starter turbine, which provides energy to turn the compressor engine crankshaft. This practice involves filling startup storage tanks with compressed air—the supply of which is controlled according to startup frequency—using a stationary or mobile air compressor.

Installing an air starter system in a new compressor facility should be considered during system design. Retrofitting an existing facility is more complex; considerations include the availability of electricity space needs, equipment location, pipe sizing and routing, and control system integration.

The necessary number and sizes of air compressors and storage tanks are determined by how many compressor units are started simultaneously and the time limits for the air system tanks to repressurize after each startup attempt.

b. Electric Starters

An electric starter converts electricity—which can be supplied by power lines, portable or solar-recharged batteries, or onsite backup generators—into torque at the starter pinion gear. The pinion engages with the ring gear that is part of the compressor engine's flywheel, which in turn rotates the engine's crankshaft.

A direct-drive electric starter uses a motor to generate high torque at low speed and operates at high speed with low torque for a short length of time. A solenoid-actuated shift lever pushes the pinion to engage it with the ring gear when the rotating shaft in the motor assembly starts turning.

A gear reduction starter uses a smaller, higher-speed electric motor to produce higher cranking torque using equal or less electrical power than direct-drive starters. Additionally, the weight of a gear reduction starter may be as little as half that of a comparable direct-drive starter.

5.1.1.6.3 Benefits and Limitations

Using air or electric motor starters eliminates the venting of natural gas into the atmosphere and the leakage of natural gas through the gas shutoff valve. Operators reported annual savings of 23 to 600 Mcf, depending on the compressor size, number of startups, and attempts needed per startup.[98] A single startup of a tuned engine requires 1 to 5 Mcf of gas at an average volume tank

[98] Ibid.

pressure of 200 psig, depending on engine size and horsepower.[99] Annual methane emissions savings of 1,356 Mcf apply to one electric motor starter for a compressor engine, assuming 10 annual startups and methane leakage through the gas shutoff valve.[100]

Additional benefits of air-driven starters include the following:

- They are much lighter and have a higher power-to-weight ratio than an electric starter with comparable output.
- The probability of an air starter overheating from excessive cranking is low.
- Their simple design virtually eliminates system problems.

The limitations of electric starters and air compressors include constant and backup sources of electricity are required.

5.1.1.6.4 Safety and Feasibility Impacts

The industry began developing and using this technology in the early 2000s; therefore, no adverse safety impact is anticipated. This practice is feasible for all compressors with natural gas expansion turbine motor starters.

5.1.1.7 Vapor Recovery from Pigging Operations for Gas Transmission and Gathering Systems

This practice applies primarily to gathering and gas transmission pipeline systems to clean the pipeline by removing either gas or water. Numerous production pipelines near the wellhead connect to gas gathering pipelines that convey natural gas to a gathering compressor station, which in turn sends the gas to transmission systems. These pipelines contain produced liquids that must be removed because they would otherwise expose pipelines and equipment to internal corrosion.

Pigging is a method used to purge, clean, and/or inspect pipelines to keep them internally clean for more efficient operations. Devices called "pigs" are inserted into new and existing pipelines for cleaning, maintenance, or integrity inspection activities. The type of pipeline pig used depends on its intended purpose and the type of pipeline. Several types of pipeline pigs are used to perform various functions, including the following:[101]

- Utility or cleaning pigs, which are used to perform functions such as cleaning, separating, or dewatering the pipeline of water and condensate fluids;
- Inline inspection (ILI) pigs, which provide information on the pipeline integrity condition as well as the location and extent of the integrity condition;

---

[99] Ibid.
[100] Ibid..
[101] Dey, A., "Pipeline Pigging: Pig Types, Pig Launcher, and Receiver." Retrieved from https://whatispiping.com/pipeline-pigging/.

- Gel pigs, which are used with conventional cleaning pigs to optimize pipeline dewatering, cleaning, and drying tasks; and
- Cleaning pigs, which are sized for a tight fit with the internal pipeline diameter and constructed of flexible materials that enable it to scrape and remove debris.

The pig is inserted into a pig launcher (**Figure 25**). Then, pressurized flow is applied to the rear of the device, which pushes the pig into the pipeline. The pig is captured in a receiver that is isolated via a shutoff valve when it reaches the end of a pipeline segment to allow for its safe removal. Spherical or bullet-shaped pigs are used to remove the liquids accumulated ahead of the pig, which drain to a vessel before flowing to a low-pressure storage tank (Paragraph 5.1.1.7.1). The recovered liquid "flashes" when depressurized, and vents gas and condensate liquid emissions from the storage tanks. Most of the vented gas and condensate liquid emissions can be recovered by installing a vapor recovery system.

Vapor recovery from pigging operations is a process in which flash gas entrained in the condensate liquids tank is collected to prevent venting into the atmosphere. Recovering the flash gas reduces emissions.

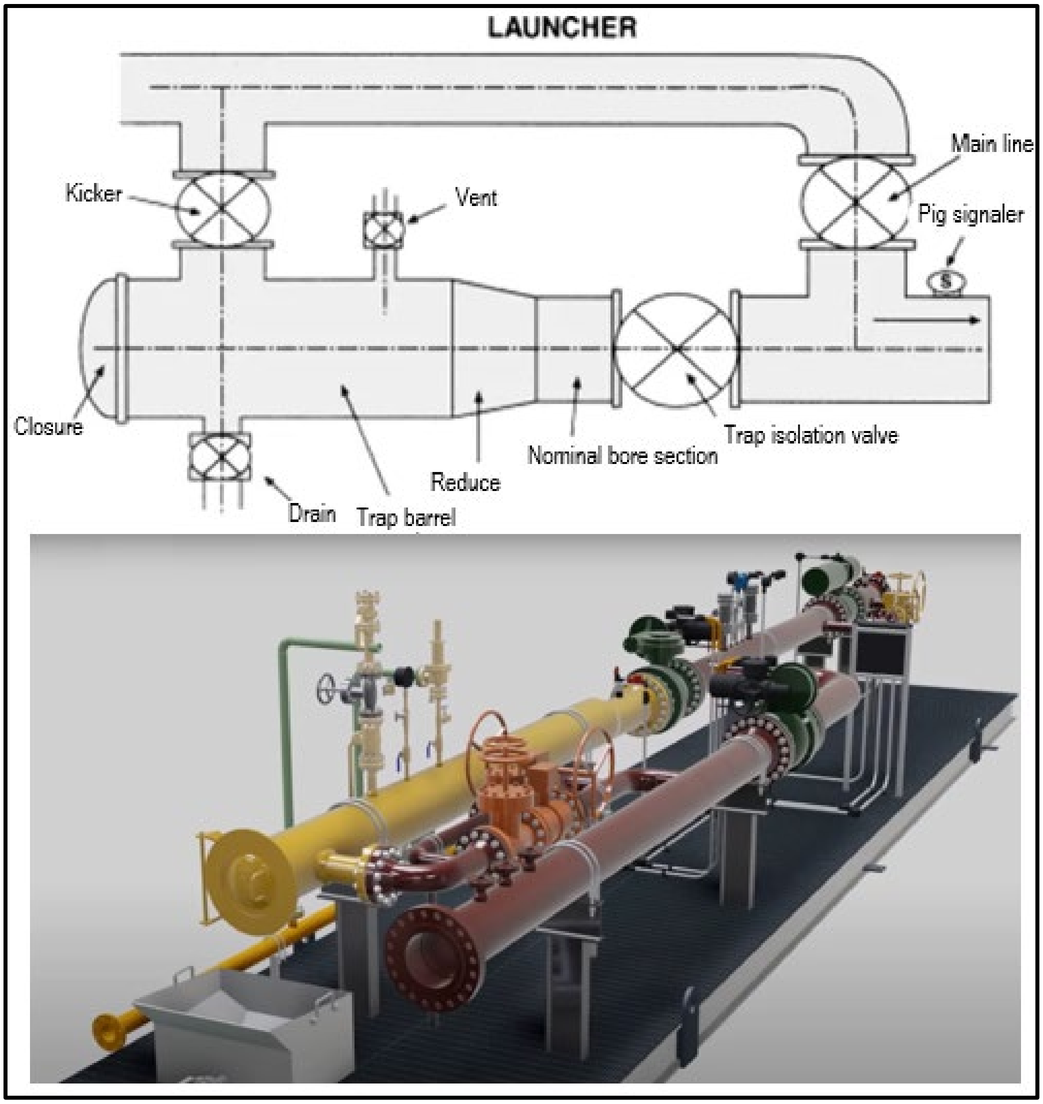


Figure 25: Typical Pig Launcher and Schematic (Courtesy of What Is Piping)

5.1.1.7.1 Emission Source

During pigging operations, natural gas is vented as follows:

- From storage tanks containing pigged liquid; and
- From piping where the pig is inserted or removed from the launcher or receiver.

When pipelines are pigged to remove debris and accumulated liquids, the pigged liquids are separated from the gas and stored in low-pressure storage tanks. During storage, light hydrocarbons that were dissolved in the liquid when the gas was under pressure—including methane, hazardous air pollutants, and inert gases—vaporize (flash) out of the gas and collect in the space between the liquid surface and storage tank roof. The accumulated hydrocarbon gases, including natural gas, often are vented into the atmosphere. Storage tank batteries are reported to vent between 5,000 and 500,000 Mcf of natural gas and light hydrocarbon vapors into the atmosphere each year.[102]

Pig launchers and receivers (**Figure 26**) are equipped with isolation valves for loading, pressurizing, and launching pigs; natural gas is vented into the atmosphere through valves, and hatches on the launcher or receiver during pressurizing and depressurizing for pigging operations.

Figure 26: Example Pig Receiver on a Natural Gas Transmission Pipeline (Courtesy of Metropolitan Engineering, Consulting & Environmental Services)

While there is an implication that pig launchers/receivers are a source of methane emission, such emissions can easily be greatly reduced, if not eliminated, without eliminating the use of launchers and receivers. Pig launcher/receivers are used for integrity management purposes, and overall intended to help prevent pipeline ruptures that can release many hundreds, if not thousands, of tons of methane in the event of a pipeline rupture.

5.1.1.7.2 Implementation or System Design Strategy

A dedicated vapor recovery system can recover most vented gas from storage tanks and vent valves. Equipment required for vapor recovery includes:

- Pig launchers and receivers;
- Pressurized and low-pressure liquid storage tanks; and
- An electric vapor recovery compressor. A liquid/vapor flash tank and low-pressure liquid pump may also be required, depending on system design or existing equipment.

Operators have the option to capture flash gas on site using VRUs, vapor recovery towers (VRTs), or a combination of both (**Figure 27**). VRUs use screw or vane compressors to draw vapors from atmospheric pressure storage tanks. A VRT, which is a tall pressure container installed between the production separators and the liquid storage tanks, is engineered for retention time to allow gas to separate from the condensate. In most installations, the flash gas

---

[102] Chevron Corporation., et al., "Vapor Recovery and Gathering Pipeline Pigging, EPA Producers and Processors Technology Transfer Workshop, Vapor Recovery," Lessons Learned from Natural Gas STAR, Midland, Texas, July 23, 2008. (p. 4). Retrieved from https://www.epa.gov/sites/default/files/2017-07/documents/midland3_2008.pdf.

from the liquids in the VRT flows to a VRU for compression, then connects via piping to a low-pressure gas pipeline or onsite fuel system.

Vented emissions from pig launching and receiving can be recovered by routing vent piping to a VRU or for use as fuel gas. The same VRU used for recovery of storage tank emissions may be used for vent valve emissions.

Figure 27: Typical Tank Battery VRT (Left) and VRU (Right) (Courtesy of Hy-Bon Engineering Inc.)

5.1.1.7.3 Benefits and Limitations

Maintenance pigging operations improve gas flow and pipeline efficiency by reducing system pressure drops from obstructions, liquids, or vapor condensation in pipelines either (1) with unprocessed gas, or (2) where liquids have not been removed from pressure reduction.

Vapor recovery systems can capture up to 95 percent of hydrocarbon vapors from tanks,[103] and can provide significant environmental benefits. The gases flashed from pigged condensate and captured by VRUs can be used for the following:

- Fuel for onsite operations;
- Routing to a stripper unit to separate natural gas liquids and natural gas; or
- Reinjection into sales pipelines as high-British thermal unit (Btu) natural gas—recovered vapors are more valuable than pipeline-quality natural gas because of their higher heat content.

[103] EPA, "DCP Midstream and the Gas Processors Association," EPA Processors Technology Transfer Workshop, Lessons Learned from Natural Gas STAR, Houston, Texas, April 24, 2007. (p. 13). Retrieved from https://www.epa.gov/sites/default/files/2017-07/documents/processor_best_practices_houston_2007.pdf.

The potential limitations of vapor recovery systems include the following:

- A steady source and adequate quantity of condensate vapors is required; and
- Not all sites have access to pipeline connections.

5.1.1.7.4 Safety and Feasibility Impacts

The industry began developing and reporting this technology in 1997; therefore, no adverse safety impact is anticipated.

Frequently pigged gathering lines that recover a large volume of liquid condensate are best suited for vapor recovery.

5.1.2 Distribution Sector

5.1.2.1 No-Blow or Gas-Free Equipment for Pipeline Work

5.1.2.1.1 Emission Source

Blow-by is the release of gas during operations such as transferring service from an existing main to a new main, typically during bagging off,[104] or the installation of new or replacement services—when older, specialized tapping/drilling equipment is used to install taps on pipe operating at low pressures.

This practice, which is still used today, was common during earlier eras (1850s to 1950s) when extensive low-pressure pipeline distribution systems were prevalent. Safety and environmental concerns notwithstanding, many operators still use this older equipment for low- and medium-pressure pipeline drilling, tapping, and maintenance procedures because of its durability, ruggedness, and simple design. Unlike modern no-blow or gas-free drilling/tapping equipment that is designed to eliminate escaping gas throughout its operation, older equipment allows gas to vent into the atmosphere during the following two major phases of operation:

- Drilling of the tap hole into the pipeline. Gas can escape when the combination drill/tap equipment first breaks through the pipeline wall; gaskets on the drill/tap equipment minimize escaping gas.
- Removal of the combination drill/tap equipment and insertion of the threaded fitting into the tap hole to form a gas-tight seal. Considerably more gas vents into the atmosphere during this phase because the tapped hole is fully open for inserting the threaded fitting. After the equipment is fully removed, a rag or duct seal is temporarily placed over the tap hole to reduce the amount of venting gas.

The size of the drilled and tapped hole directly impacts the amount of gas venting into the atmosphere; tap diameters typically range from approximately one to four inches. Generally,

[104] Bagging off or the bag off method is a process where an inflatable bag is inserted into a pipe to help temporarily stop the flow of gas during a repair.

inserting the plug threads onto the tapped hole becomes more difficult as the tap diameter increases.

5.1.2.1.2 Design Strategy

Some operators use no-blow or gas-free equipment for all high-pressure drilling and tapping operations on cast iron (CI) and steel pipelines. To ensure a gas-free environment, interchangeable components used for combination drill/tap equipment allow usage with multiple diameters and applications—including drilling/tapping, plug installation, tee insertion/extraction, sight glass inspection, vent/purge adaptors, camera entry, and system stop-offs—to stop gas flow using a bypass assembly when needed.

5.1.2.1.3 Benefits and Limitations

Using no-blow/gas-free equipment for all pipeline drilling, tapping, and maintenance activities—regardless of pipeline operating pressure—incurs no additional cost. Additionally, using such equipment eliminates any intentional gas releases during these procedures.

5.1.2.1.4 Safety and Feasibility Impacts

Older drilling/tapping equipment that does not prevent blow-by can be retired and replaced with equipment that prevents gas from escaping into the atmosphere. Most utilities have this equipment, which is readily available. Additionally, the removal of a potential ignition source improves safety.

5.1.2.2 Elimination of Jumping for All Distribution System Operating Pressures

5.1.2.2.1 Emission Source

Jumping (also known as catching fittings on the fly) is a distribution pipeline operation where gas blows into the atmosphere when work is performed on a fitting, which is usually connected to the main. Jumping is commonly performed when disconnecting and reconnecting service lines from an existing main to a new main of any diameter; however, this practice intentionally allows gas to escape into the atmosphere. This technique is commonly employed on high-pressure systems (15–60 psig) for which control fittings were not used for the service laterals. Jumping requires the transfer of services to a new main while gas blows into the atmosphere.

In the past, steel mains commonly were installed using threaded couplings welded to the main, and the gas supply was activated through a drilled or burned hole inside the welded coupling area. Finally, the main to which a service tee was installed was gassed in. Because no flow control fitting was used on such mains, limited means exist to safely stop the flow of gas from the main during maintenance activities, such as service line cutoffs, service line disconnects/reconnects, and repairs of leaking service lines lacking a flow control mechanism.

The only alternatives to jumping, therefore, are to either:

- Use stopples to completely shut down a section of pipeline, which may involve installing bypasses on dead-ended systems; or
- Reduce pipeline pressure to an acceptable level for safer fitting removal by jumping.

5.1.2.2.2 Implementation or System Design Strategy

New equipment on the market specifically designed to eliminate the release of natural gas to the environment (e.g., Safe-T-Stopper) can be used for repairing or replacing high-pressure service line tees on steel or CI pipelines that lack an installed flow control mechanism.[105] The stopper is mounted over the tee, and an expandable plug is set below the branch inside the main that stops gas flow to the service line tee after the cap or plug on the tee is removed (**Figure 28**).

[105] The lack of flow control mechanisms on high-pressure service line tees is typical of mains installed in the 1950s and 1960s.

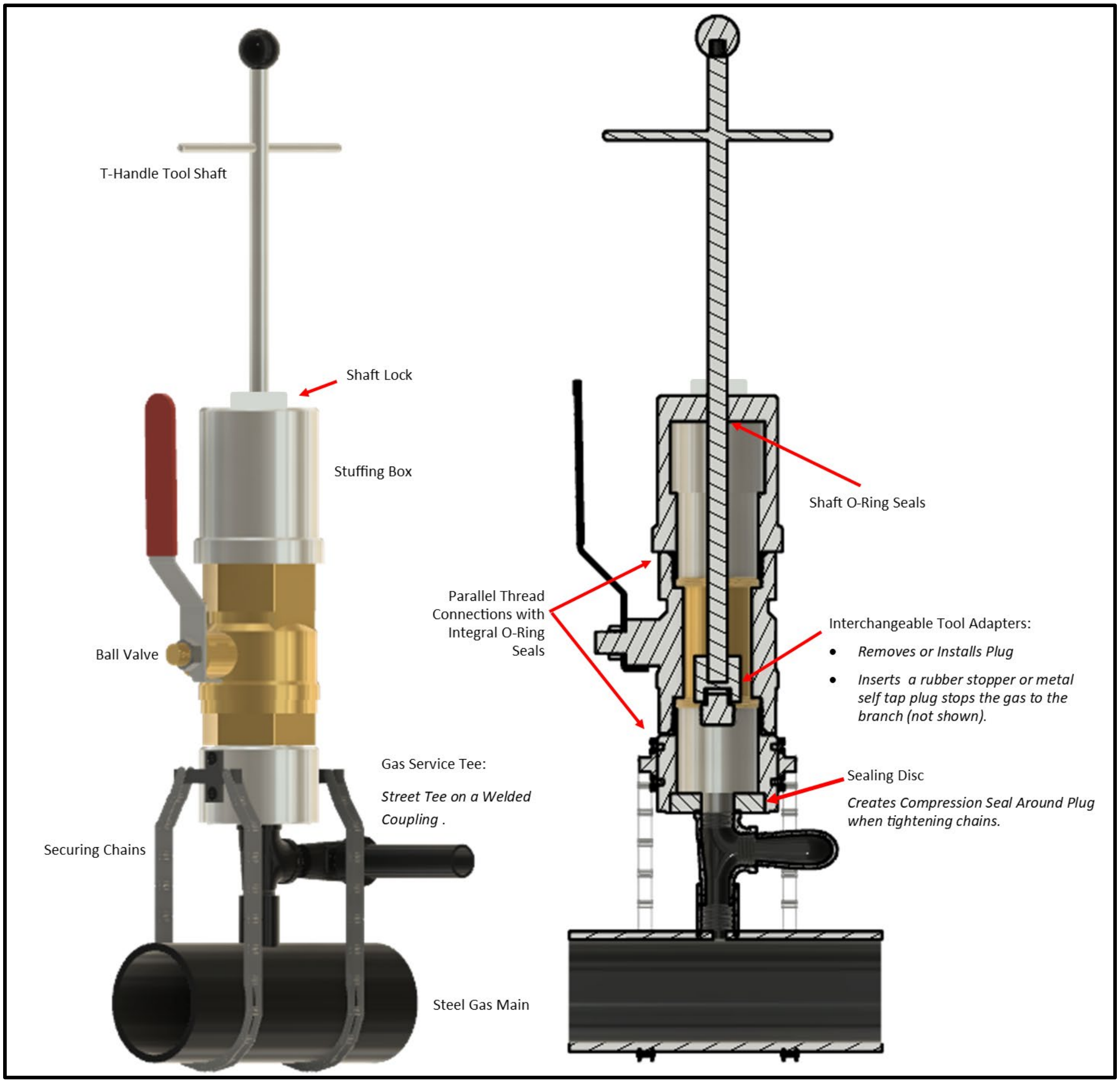


Figure 28: Gas-Free Service Tool (Courtesy of PCLS, LLC)

5.1.2.2.3 Benefits and Limitations

The use of stoppers, as described in Paragraph 5.1.2.2.2, eliminates jumping and the resulting venting of gas to the atmosphere. Additionally, a stopper provides both environmental and safety benefits because it prevents the escape of live gas and the possibility of unintentional ignition. Furthermore, a stopper eliminates the potential need to throttle mains down to a safe working pressure to perform jumping, thus avoiding customers being taken offline and the need to construct a bypass. Finally, a stopper eliminates the need to shut down the main onto which the service tees are directly welded.

5.1.2.2.4 Safety and Feasibility Impacts

Using stoppers prevents gas from escaping to the atmosphere when handling service tee connections that lack flow control mechanisms, thus enhancing safety through the elimination of a potential ignition source.

5.1.2.3 Shutting Off High-Pressure System Valves When Performing Emergency Work

5.1.2.3.1 Emission Source

Throttling is the practice of partially closing a valve to maintain a minimum set point pressure at a repair location. Throttling high-pressure mains to a lower pressure[106] when installing a repair clamp or performing an emergency repair is a common practice used in lieu of closing valves and purging pipeline facilities. Throttling minimizes the costs of service outages and pilot relights in cases where building access is required. Some operators perform throttling under emergency conditions instead of closing pipeline valves to avoid interruption of service to customers and the resulting relighting work. Other operators specifically prohibit this practice because of the safety concerns with working in an uncontrolled gaseous environment and the potential for ignition.

Depending on the number of backfeeds and their locations, the valve closest to the repair typically is closed and the next valve on the opposite side of the repair—usually furthest away from the repair—is throttled. This practice (1) ensures that service is interrupted for the fewest customers possible, and (2) avoids the need to purge the main of air. Because the pipeline is never taken completely out of service, no air enters the pipeline and positive gas pressure is continuously maintained.

Due to the possibility of even a reduced amount of gas leaking into the atmosphere and introducing the risk of unintentional ignition, utilities do not universally practice throttling. This ignition risk increases during longer repairs because the main may begin to leak uncontrollably. Depending on pipeline diameter, crews may need up to 24 hours to:

- Fully assess the situation.
- Confirm backfeeds.
- Target and operate the appropriate valves (assuming the valves are operable).
- Excavate.
- Clean the pipeline and install a repair fitting.

[106] The pressure is dependent on the minimum service regulator pressure requirements to maintain continuous gas service.

5.1.2.3.2 Implementation or System Design Strategy

In an emergency, the pipeline valves closest to the pipeline incident or anomaly location being repaired would be closed. If pipeline backfeeds are involved, as is common in a looped distribution system, the valves closest to the repair on the backfeeds would be closed. With all valves closed, gas flow stops and the pressure in the pipeline segment bordered by the closed valves eventually drops to zero because all gas vents through the leaking section of the main require repair. All gas service to customers within the shutdown area would be temporarily interrupted.

5.1.2.3.3 Benefits and Limitations

The primary benefit of shutting down high-pressure valves under emergency conditions is public and operator safety. Shutting down valves in gas distribution systems takes approximately 30 minutes to two hours instead of the up to 24 hours needed for throttling and making repairs (Paragraph 5.1.2.3.1), thus greatly reducing the opportunity for gas to vent into the atmosphere uncontrollably.

The disadvantages of shutting high-pressure valves include the following:

- Interruption of service to a greater number of customers, which in turn can increase the length of the outage. Before gas service can be brought back online, the service line valves must be closed, the service lines at the curb must be cut off, and/or a curb valve must be installed. Depending on the number of customers affected and the locations of the meter sets (inside or outside), this process can take a considerable amount of time.
- Exacerbated effects of a long shutdown on gas customers during the winter.
- The need to enter each home so that each pilot can be relit.

5.1.2.3.4 Safety and Feasibility Impacts

Closing high-pressure valves significantly enhances safety by the reduction (and eventual elimination) of the following:

- The uncontrolled venting of gas for extended periods before a permanent repair can be made; and
- The potential ignition risk introduced by the venting of uncontrolled gas.

5.1.2.4 Cast-Iron (CI) Mechanically Joined Pipe

CI mechanically joined pipes, which were installed starting in the mid-1940s to expand gas distribution systems during the postwar home construction boom, typically are 16 or more inches in diameter and operate at pressures between 15–60 psig. These pipes are thick by design and thus do not typically break like smaller-diameter (12 inches and less) CI pipes that operate at lower pressure (less than 1 psig). CI pipe larger than 16 inches in diameter has sufficient beam strength to withstand breakage from outside forces (usually frost or other forces that cause uneven loadings on the pipe) due to its wall thickness.[107]

Today, these lines are critical residential gas supply sources and major gas distribution system feeds. Such systems typically operate at different winter and summer control point operating pressure settings, with winter pressure settings being higher by 10–20 psig to provide sufficient gas flow due to increased gas flow loads to customers.

5.1.2.4.1 Emission Source

The joints of CI mechanically joined pipes are susceptible to leakage. The steel mechanical connections (screws, bolts, set rings, follower rings, etc.) of CI mechanically joined pipes compress a rubber gasket in place to form a seal. Over time, the steel components can corrode, and the gaskets dry out. The joints can leak significantly during cold weather because of significant thrust forces created by expansions and contractions from ambient temperature changes that cause gasket movement.

Laboratory work conducted by Cornell University in 2015,[108] which was co-funded by PHMSA and NYSEARCH, concluded that a 40-degree Fahrenheit (°F) seasonal temperature variation at typical cover depths for buried pipes is equivalent to a 0.1-inch joint contraction/expansion. Because contraction occurs during the winter when operating pressures are at their highest, joint leakage and increased gas migration from the pipe are significant issues.

In September 1996, researchers at Cornell University (Appendix B, Section B.2) concluded that low-pressure caulked bell and spigot joints (AGA joints) (**Figure 29**) leak at rates of 4.67–5.50 cfh per joint. These leakage rates were measured at 0.25 psig (eight inches wc) from operator-donated, in-service CI joint samples extracted from the ground. Because of the linear relationship between leak rate and operating pressure, the extrapolated leakage rate for mains operating at 15–60 psig is at least 300 cfh per joint, which is equivalent to gas usage by a large heating furnace.

[107] PSE&G (Ragula, G.), "World Record 42-Inch Gas Main CIPL, Trenchless for Gas Infrastructure," May 22, 2020. Retrieved from https://www.progressivepipe.com/blog/worldrecord42inchgasmaincipl.

[108] Stewart, H.E., et al., "Technology Transfer Demonstrations and Post-Mortem Testing of Cast Iron and Steel Pipe Lined With Cured-in-Place Liners (CIPL), Final Report (Public Version)," Cornell University School of Civil and Environmental Engineering, December 2015. Retrieved from https://cpb-us-w2.wpmucdn.com/sites.coecis.cornell.edu/dist/a/38/files/2014/10/151215-NYSEARCH_NGA-Final-Report-1c06yrj.pdf.

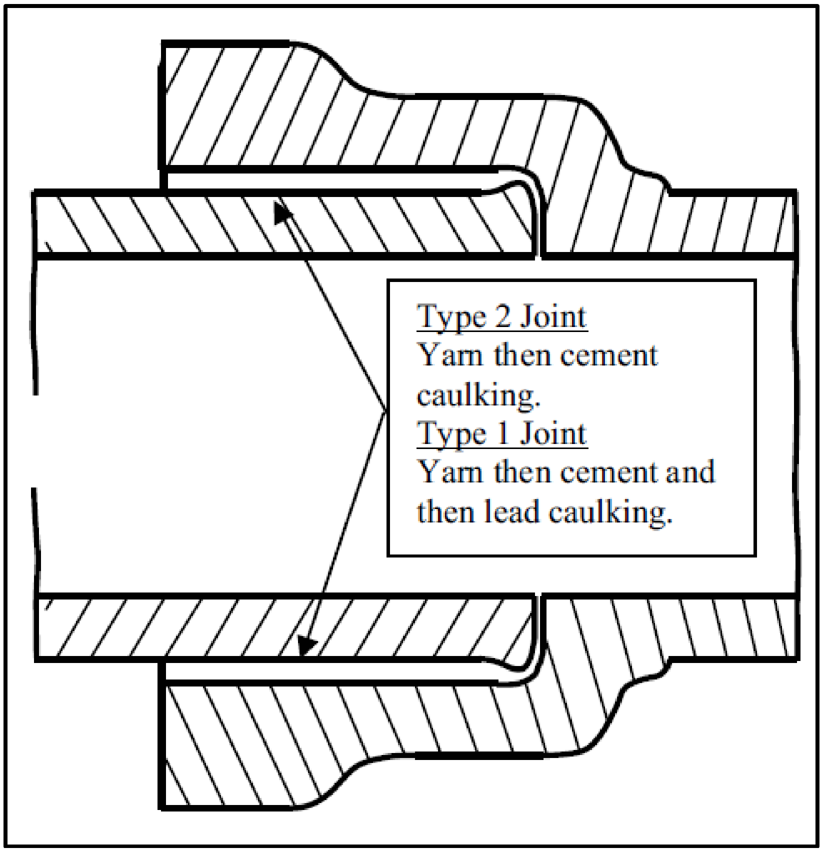


Figure 29: Typical CI Caulked Bell and Spigot Joint (Courtesy of Cast Iron Pipe Research Association)

5.1.2.4.2 Implementation or System Design Strategy

Operators commonly encounter many leaks in mechanical joints (**Figures 30** and **31**) after a bitterly cold winter. These leaking pipeline segments often are (1) repaired using established point repair methods, or (2) rehabilitated throughout its length using internal liners. Although point repair methods resolve the immediate local joint leak and effectively lock the joint in place, thermal expansion/contraction and thrust forces imposed by the pressure of the gas relocate the total forces acting on the pipe to the next weak link in the pipeline system, which is the nearest unrepaired joint.

No clear lanes exist for replacing large-diameter pipe due to congested subsurfaces involving multiple utilities. Furthermore, most CI pipes would require upsizing for flow capacity because of the inherent differences between CI pipe and replacement steel pipe of the same diameter.

49 CFR §§ 192.621 and 192.753 address MAOP in high-pressure distribution systems and CI caulked bell and spigot joints, respectively.

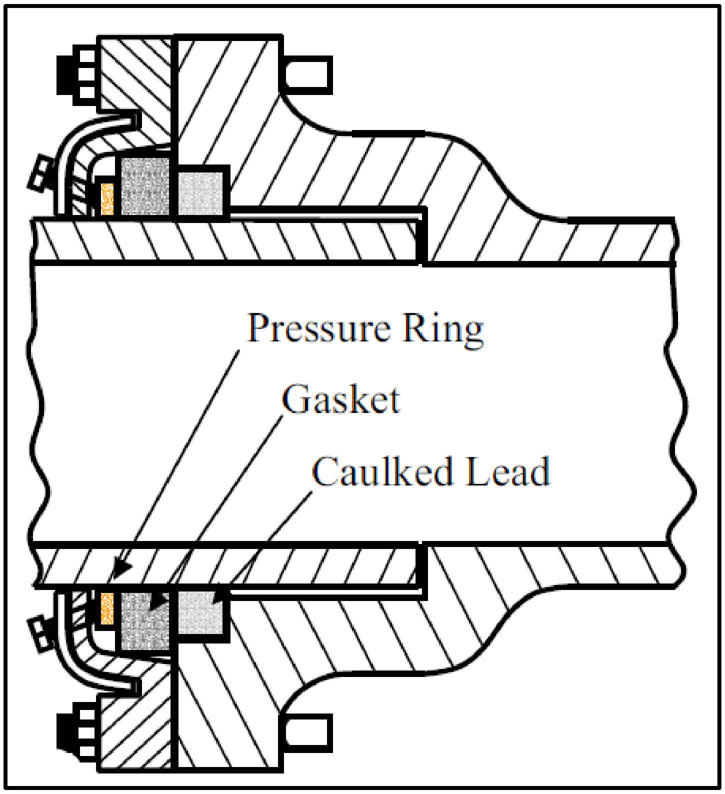


Figure 30: Typical Inner-Tite Mechanical Joint, Circa 1938
(Courtesy of Cast Iron Pipe Research Association)

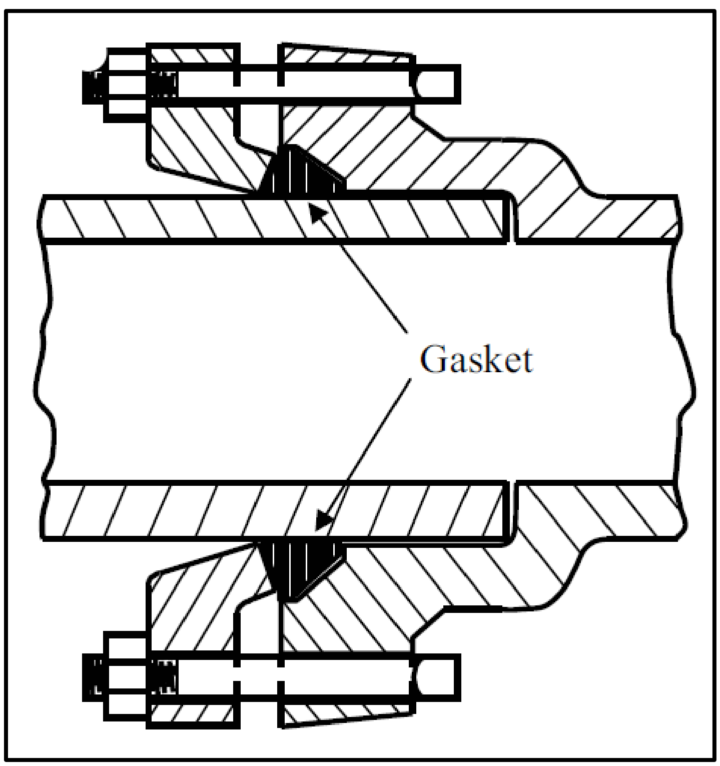


Figure 31: Typical Mechanical Joint, Circa 1950s
(Courtesy of Cast Iron Pipe Research Association)

5.1.2.4.3 Benefits and Limitations

Regulation changes that address the continued safe operation of mechanically joined CI pipe—combined with the use of established repair, replacement, or rehabilitation techniques—could result in safety enhancements and natural gas emission reductions.

Because mechanical joints connecting CI pipelines have been in active service for at least 65 years, any regulatory changes should be consistent with 49 CFR § 192.753, which requires unreinforced caulked bell/spigot joints operating above 25 psig to be reinforced through either of the following:

- A point repair technique (the limitations described in Paragraph 5.1.2.4.2 notwithstanding); or
- Internal sealing consistent with a lining rehabilitation process.

5.1.2.4.4 Safety and Feasibility Impacts

Code updates specifically addressing large-diameter CI pipelines—similar to those that have been developed for caulked bell and spigot joints (49 CFR §§ 192.621 and 192.753, respectively)—would present a significant opportunity to reduce emissions and enhance safety.

5.1.2.5 Pipeline Repair, Renewal, Rehabilitation, or Replacement Programs

Distribution pipelines generally are more difficult to repair and maintain due to development (e.g., freeways, interstate highways, major highways, and railroads) and congestion along the pipeline. PHMSA issued an advisory bulletin in 2012 to remind operators of cast iron pipelines of the need to repair or replace cast iron piping. PHMSA also maintains a cast iron inventory website that includes data of mains and services installed, information on incidents, and previous recommendations and alert notices/advisory bulletins.[109]

5.1.2.5.1 Emission Source

Leak hazards in areas that are difficult to repair and maintain may do the following:

- Contribute to leaks remaining active for long periods.
- Make repairs difficult due to pipeline inaccessibility for construction equipment.

Some states require leaks to be repaired within an established time interval determined by leak grade or degree of hazard consistent with Gas Piping Technology Committee (GPTC) guidance.[110] Facilities thus may leak for extended periods and not be reevaluated until the next scheduled leak survey cycle. PHMSA issued a notice of proposed rulemaking (NPRM) that

[109] PHMSA Cast and Wrought Iron website: https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/cast-and-wrought-iron-inventory.

[110] American National Standards Institute (ANSI) Accredited Standards Committee (ASC) GPTC Z380, "Gas Piping Technology." Retrieved from https://www.aga.org/natural-gas/safety/promoting-safety/ansi-committees/#z380

proposes to require leak grading and repair requirements based on the framework in GPTC guide.[111] PHMSA, however, currently requires enhanced leak detection, grading, and repair standards as a condition for recently issued special permits requested in accordance with 49 CFR § 190.341.

Similarly, the EPA has issued a final rule that includes new source performance standards (NSPS) and emission guidelines (EG) to address greenhouse gas emissions from new and existing emissions sources in the oil and natural gas industries.[112] The NSPS and EG include requirements for emissions monitoring and repair at well sites, gas processing plants, and compressor stations.

5.1.2.5.2 Implementation or System Design Strategy

PHMSA is incorporating enhanced leak detection and leak grading requirements through special permit conditions and proposed rulemakings. These conditions include requiring operators to:

- Conduct gas leakage surveys using instrumented gas leakage detection equipment periodically.
- Repair leaks based upon a grading system similar to GPTC guidance at all valves, flanges, pipeline tie-ins, and ILI launcher and receiver facilities.

The practice of maintaining pipeline leakage backlogs, including mandated minimum leak repair intervals for leaks of all grades, should be further investigated. Additionally, special programs or incentives could be provided for repairing low-grade nonhazardous leaks. Furthermore, having independent contractors conduct periodic leak surveys that confirm the effectiveness of surveys conducted by in-house crews may be worthwhile.

Because leaks and incidents can cause significant safety, social, and environmental hazards, local utility providers should do the following:

- Prioritize these areas when updating infrastructure.
- Implement strategies to prevent or mitigate such incidents.

5.1.2.5.3 Benefits and Limitations

The primary benefit of improved leak grading and repair implementation is fewer leaks resulting in reduced natural gas emissions.

---

[111] PHMSA rulemaking, "Pipeline Safety: Gas Pipeline Leak Detection and Repair," May 18, 2023. Available at https://www.federalregister.gov/documents/2023/05/18/2023-09918/pipeline-safety-gas-pipeline-leak-detection-and-repair.
[112] EPA Final Rule, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," March 8, 2024. Available at https://www.federalregister.gov/documents/2024/03/08/2024-00366/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for.

5.1.2.5.4 Safety and Feasibility Impacts

Increased inspection, repair, and replacement standards are expected to improve pipeline safety. Because this work is already being performed, no feasibility issues are expected.

5.1.2.6 Residential Gas/Methane Detectors

5.1.2.6.1 Emission Source

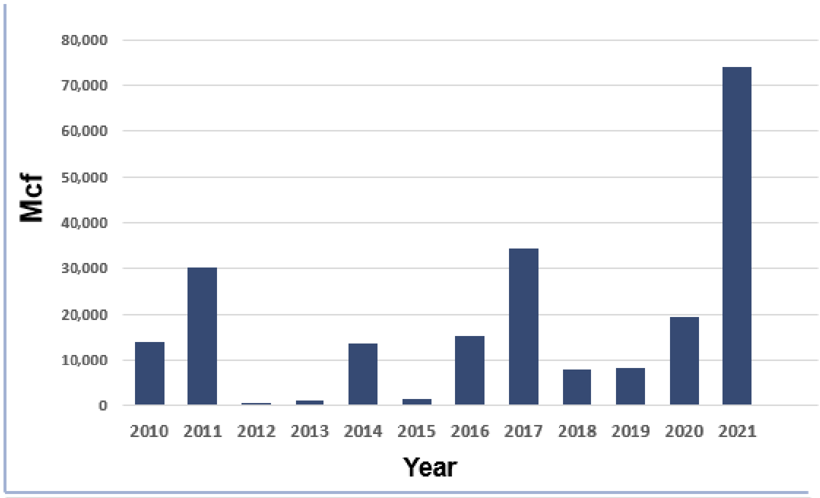
In developing this report, PHMSA reviewed gas distribution pipeline operator incident reports concerning the release of gas/methane in or near structures (**Tables 4** through **7**), National Transportation Safety Board (NTSB) accident investigation reports (Paragraph 5.1.2.6.2), and a successful gas/methane detector installation program implemented by ConEdison (Paragraph 5.1.2.6.2) with a similar reporting period as the EPA Greenhouse Gas Inventory.

The impacts of 267 reportable incidents from 2010 through 2021 that affected structures (**Table 7**) are as follows:

- 219,929 Mcf of gas/methane released (**Table 4**)
- 63 fatalities (**Table 5**)
- 302 injuries (**Table 6**)

Table 4: Gas in Structure—Unintentional Releases

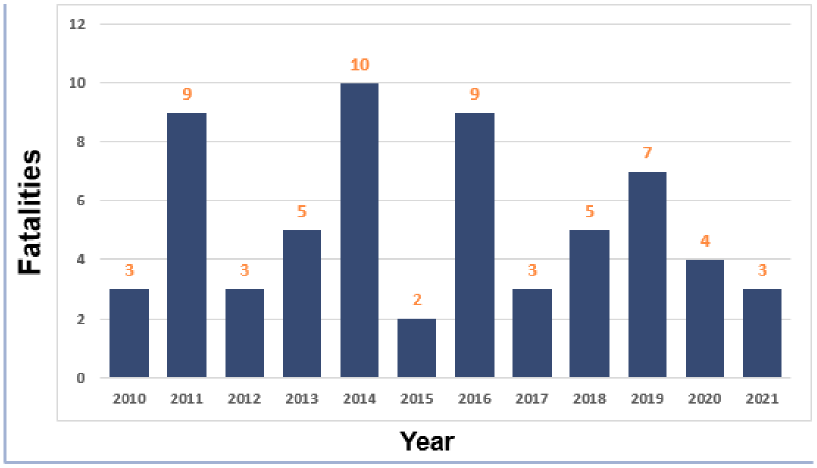
Year	Unintentional Release (Mcf)
2010	14,020
2011	30,159
2012	478
2013	1,148
2014	13,512
2015	1,585
2016	15,303
2017	34,353
2018	7,890
2019	8,050
2020	19,446
2021	73,985
Total	**219,929**



- Release volumes are likely to be more than the volume that entered the structure.
- Mcf is defined as thousand cubic feet of gas.
- Information was acquired from operator incident reports received by PHMSA.

Table 5: Gas in Structure—Fatalities

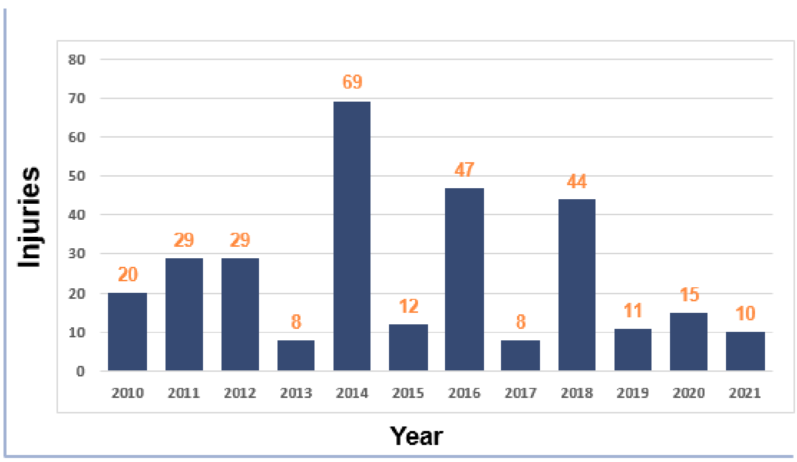
Year	Fatalities
2010	3
2011	9
2012	3
2013	5
2014	10
2015	2
2016	9
2017	3
2018	5
2019	7
2020	4
2021	3
Total	**63**



- Information was acquired from operator incident reports received by PHMSA.

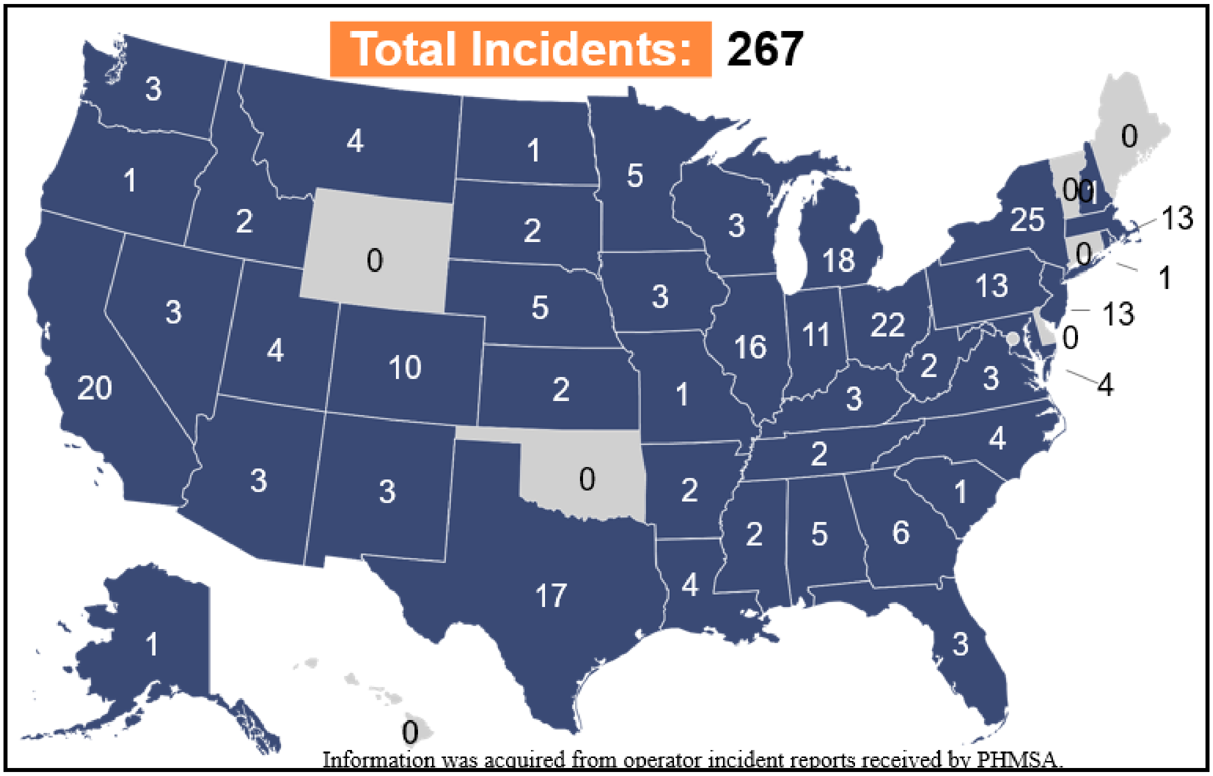
Table 6: Gas in Structure—Injuries

Year	Injuries
2010	20
2011	29
2012	29
2013	8
2014	69
2015	12
2016	47
2017	8
2018	44
2019	11
2020	15
2021	10
Total	**302**



- Information was acquired from operator incident reports received by PHMSA.

Table 7: Gas in Structure—Incidents by State, 2010 to 2021



5.1.2.6.2 Implementation or System Design Strategy

Gas/methane detectors installed inside structures could ensure that the public and operators are alerted to potential leaks before they become a hazard. Similar to a smoke detector, these devices sound an alarm when they detect methane or other flammable gases. Some systems can also send information to the operator's control room and to emergency services.

In an April 2019 pipeline accident report detailing an August 2016 incident in Silver Spring, Maryland, NTSB concluded the following:[113]

> The scope of NFPA 54, IFGC, and their widespread adoption by local authorities appear to be the most appropriate standards for requiring methane detector alarms, with local jurisdictions enforcing the requirements and making them feasible. Therefore, the NTSB recommends that, in coordination with NFPA and ICC, the GTI work to develop standards for methane detection systems for all types of residential occupancies in both the IFGC and the National Fuel Gas Code, NFPA 54. At a minimum, the provisions should cover the installation, maintenance, placement of the detectors, and testing requirements. Further, the NTSB recommends that, in coordination with GTI and ICC, the NFPA revise the National Fuel Gas Code, NFPA 54 to require methane detection systems for all types of residential occupancies with gas service. At a minimum, the

[113] NTSB, "Pipeline Accident Report: Building Explosion and Fire, Silver Spring, Maryland, August 16, 2016," adopted April 24, 2019 (p. 38). Retrieved from https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1901.pdf.

provisions should cover the installation, maintenance, placement of the detectors, and testing requirements. Lastly, the NTSB recommends that, in coordination with GTI and NFPA, the ICC incorporate provisions in the IFGC that requires methane detection systems for all types of residential occupancies with gas service. At a minimum, the provisions should cover the installation, maintenance, placement of the detectors, and testing requirements.

NTSB first recommended that "gas detectors" be required to provide early warning of gas leaks in buildings as a result of an investigation into an April 22, 1974, gas explosion that occurred in a New York City, New York, commercial building.[114] Additionally, NTSB recommended that regulators require methane detection systems in residential occupancies with gas service. Furthermore, NTSB recommended that industry groups—in addition to revising the National Fuel Gas Code (National Fire Protection Association (NFPA) 54) to require methane detection systems for all types of residential occupancies with gas service—develop additional guidance that identifies steps gas distribution operators can take to safely respond to leaks, fires, explosions, and emergency calls.[115]

An example of a gas distribution company requiring the installation of gas/methane detectors in structures with appliances that use gas or methane is ConEdison, which will provide an "unprecedented level of protection against potentially dangerous leaks" by installing 376,000 smart-technology natural gas detectors for customers in New York City and Westchester County, New York. The distribution of these detectors follows a successful pilot in which ConEdison provided 9,000 detectors that sounded 250 alarms since the first installations in October 2018.[116]

5.1.2.6.3 Benefits and Limitations

PHMSA realizes that even though gas/methane detectors in human-occupied structures will not prevent all such incidents captured in **Tables 4** through **7** and Paragraph 5.1.2.6.2, these detectors should ensure the early detection and repair of hazardous and potentially hazardous leaks as well as warn building occupants of unsafe conditions. Although PHMSA lacks the regulatory jurisdiction to require gas/methane detectors in homes or other human-occupied structures, the data support the need for updating local building codes to require these detectors.

5.1.2.6.4 Safety and Feasibility Impacts

PHMSA supports the following:

---

[114] NTSB, "Pipeline Accident Report: Building Explosion and Fire, Silver Spring, Maryland, August 16, 2016," adopted April 24, 2019 (pp. 34–35). Retrieved from https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1901.pdf.

[115] https://www.ntsb.gov/Advocacy/mwl/Pages/mwl-21-22/mwl-rph-01.aspx

[116] ConEdison, "ConEdison Providing Smart Gas Detectors in Major Breakthrough for Customer Safety," September 28, 2020. Retrieved from https://www.coned.com/en/about-us/media-center/news/2020/09-28/con-edison-providing-smart-gas-detectors-in-major-breakthrough-for-customer-safety.

- NTSB recommendations updating local building codes to require the installation of gas/methane detectors in structures intended for human occupancy that use natural gas for utilities, such as hot water heaters, heating units, stoves, and fireplaces.
- The ConEdison gas/methane detector program (Paragraph 5.1.2.6.2), which is a forward-looking safety program for mitigating incidents that cause injuries and fatalities as well as gas/methane losses into the environment.

5.2 Release Minimization

This section (1) identifies BATs or practices that can be implemented to minimize the release of gas during planned repairs, replacements, or maintenance; and (2) includes research into technologies and processes currently in use or under development. Practices presented in this section include the following:

- Natural gas infrastructure components impacted by O&M activities;
- Directed Inspection and Maintenance (DI&M) programs;[117] and
- Shutdown management procedures for planned releases.

5.2.1 Transmission and Gathering Sectors

5.2.1.1 Directed Inspection and Maintenance Programs (DI&M) Programs

This practice applies to the transmission, gathering, and distribution sectors.

5.2.1.1.1 Emission Source

Operators can develop a DI&M program that not only achieves maximum cost-effective natural gas savings but also suits the unique characteristics of a facility. Operators have reported using DI&M programs at compressor stations to achieve significant natural gas emissions reduction and gas savings by focusing maintenance efforts on the largest emissions sources.[118]

5.2.1.1.2 Implementation or System Design Strategy

A DI&M program typically is implemented in the following four steps:[119]

- Conduct a baseline survey. A DI&M program begins with baseline emission measurements to identify leaking components.

---

[117] The EPA describes DI&M programs as a “proven, cost-effective way to detect, measure, prioritize, and repair equipment leaks to reduce methane emissions.” Description obtained from EPA document titled, “Directed Inspection and Maintenance at Compressor Stations,” Lessons Learned From Natural Gas STAR Partners, Air and Radiation, October 2003 (p. 1). Retrieved from this link.
[118] EPA, “Directed Inspection and Maintenance at Compressor Stations,” Lessons Learned From Natural Gas STAR Partners, Air and Radiation, October 2003. Retrieved from this link.
[119] Ibid.

- Record the results and identify repair candidates. Emission measurements from the survey or inspection are evaluated to target the leaking components that are most cost-effective to repair.
- Analyze the data.
- Develop a survey plan for future inspections and maintenance. This final step is to use the results of the initial baseline survey to direct future inspection and maintenance practices, and integrate those results into a data collection system.

Resources are prioritized and allocated based on the largest emission sources that can most effectively be repaired. An effective DI&M survey plan also should include the following elements:[120]

- A list of components to be screened and tested;
- A list of components to be excluded from the survey;
- Leak measurement tools and data collection, recording, and access procedures;
- A leak measurement schedule; and
- An analysis of previous inspection and maintenance work to direct future DI&M surveys.

Several EPA-compliant methods and equipment can be used to measure equipment emission rates and/or volumes, including the following:

- Toxic vapor analyzers, which can measure methane concentrations in a large area with emission rates over 10,000 parts per million (ppm);
- Bagging methods that involve placing an enclosure in the form of a bag or tent around an emission source;
- High-volume samplers, which is a battery-operated instrument carried in a backpack, that measure emission rates by drawing in air through a hose at a sufficiently high flow rate to capture all emissions;[121] and
- Rotameters, which are devices that measure the following:
    - Volumetric flow rate of gas in a closed tube; and
    - Extremely large leaks.

For some equipment components, leak measurement can be efficiently accomplished during a regularly scheduled DI&M survey program. For other components, simple and rapid leak

[120] Ibid.
[121] Johnson, D.R., et al., "Design and Use of a Full Flow Sampling System (FFS) for the Quantification of Methane Emissions; *J Vis Exp*. 2016; (112):54179; Published January 12, 2016. Retrieved from https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4927792/.

screening can be incorporated into ongoing O&M procedures. Effective measurement techniques must be used to ensure accurate natural gas leakage rate data, which should include the following:

- Identifiers for leaking components;
- Component types;
- Measured emission rates;
- Survey dates;
- Estimated annual gas loss; and
- Estimated repair cost.

5.2.1.1.3 Benefits and Limitations

The benefits of implementing a DI&M program at compressor stations include the following:

- Emissions and gas savings. A 1999 study of 13 compressor stations reported that an annual average of 29,413 Mcf was recovered.[122]
- Maintenance efforts that focus on monitoring and repairing the largest emission leaks.

The potential gas savings from implementing DI&M programs vary depending on compressor station size, age, equipment, and operating characteristics. An Interstate Natural Gas Association of America (INGAA) report indicated that mitigating less than three percent of leaks associated with compressor seals, isolation valves, and blowdown valves can reduce total compressor station natural gas emissions by 60 percent.[123]

5.2.1.1.4 Safety and Feasibility Impacts

No adverse safety impact is anticipated as inspections are currently required in Part 192.

5.2.1.2 Compressor Shutdown Operating Practices

Compressors used throughout the natural gas system are cycled online periodically to meet fluctuating gas demand and for compressor maintenance, operational standby, or testing. To ensure reliable operation, most compressor stations are equipped with systems comprising multiple compressors that limit the impact of any single compressor shutdown or failure.[124] If a single compressor is lost and no backup is available, the total flow through the station may be

---

[122] EPA, "Directed Inspection and Maintenance at Compressor Stations," Lessons Learned From Natural Gas STAR Partners, Air and Radiation, October 2003. (p. 1). Retrieved from this link.
[123] INGAA, "Improving Methane Emissions from Natural Gas Storage and Transmission," August 2018 (p. 10). Retrieved from https://www.ingaa.org/File.aspx?id=34990&v=56603504.
[124] National Energy Technology Laboratory, "Natural Gas Compressors and Processors – Overview and Potential Impact on Power System Reliability," July 2017. Retrieved from https://netl.doe.gov/projects/files/NGCompressorsandProcessors–OverviewandPotentialImpactonPowerSystemReliability_071817.pdf.

reduced by an amount equivalent to the capacity of that compressor. If an entire compressor station becomes incapacitated, the transmission pipeline may experience a pressure drop along the line until the next compressor station.[125]

Additionally, safety systems—which are required by 49 CFR Part 192 and designed to trigger an alarm when a preset limit is exceeded—often trigger single-compressor or entire-station shutdowns to protect personnel, the compressor units, and the station.

5.2.1.2.1 Emission Source

During shutdowns, a major source of natural gas emissions associated with taking compressors offline is from blowing down or venting the high-pressure gas remaining within the compressor and associated piping. Significant emission savings can be gained by modifying operating practices to minimize the amount of natural gas emitted.

5.2.1.2.2 Implementation or System Design Strategy

Controlled compressor station shutdowns enable emission reduction or elimination. During planning, key compressor station components are identified to facilitate shutdown efficiency. Once the station section is isolated and secured, natural gas emission reduction can be achieved using the following methods:

- Keeping offline compressors pressurized. Large isolation valves that isolate the compressor from piping and equipment during shutdowns can vent significant amounts of natural gas, especially when not maintained properly. The isolation valves are estimated to leak at average rates of 1.4 Mcfh.[126]
- Keeping compressors pressurized and connecting the blowdown vent lines to the fuel gas system to recover vented gas as a lower-pressure (100–150 psig) fuel source for compressor turbines.
- Installing static seals on each rod shaft on the outside of the compressor packing. An automatic controller activates during compressor shutdown to wedge a seal around the shaft, then deactivates the seal on startup. With static seals installed, emissions from the closed isolation valves of depressurized and pressurized systems are 1.40 and 0.15 Mcfh, respectively—which is an 89 percent reduction.[127]

---

[125] National Energy Technology Laboratory, "Natural Gas Compressors and Processors – Overview and Potential Impact on Power System Reliability," July 2017. Retrieved from https://netl.doe.gov/projects/files/NGCompressorsandProcessors–OverviewandPotentialImpactonPowerSystemReliability_071817.pdf.

[126] EPA, "Reducing Emissions When Taking Compressors Off-Line," Lessons Learned from Natural Gas STAR Partners, October 2006. (p. 3). Retrieved from: https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_compressorsoffline.pdf

[127] Ibid. (p. 5).

5.2.1.2.3 Benefits and Limitations

The benefits of avoiding compressor blowdown to atmosphere (depressurization) include the following:

- Fewer natural gas releases by routing compressor blowdown gas to the fuel gas system to reduce the volume of emissions while recovering gas for powering compressor engines.
- Lower emission rates. Maintaining fully pressurized compressors can avoid leaks across isolation valves as follows:[128]
    - 475 Mcf annually for base load units; and
    - 3,800 Mcf annually for peak load units (**Table 8**).
- Lower operating fuel costs. Routing compressor gas to the fuel system uses natural gas that otherwise would be vented, thus reducing fuel costs and increasing the volume of gas available for sale or use.

Table 8: Natural Gas Savings from Keeping Compressors Pressurized During Shutdowns

Emission Reduction Method	Annual Volume of Natural Gas Savings for Peak Load Units (Mcf)
Keeping offline compressors pressurized	3,800
Recovering vented gas	5,100
Installing static seals on compressor packing rod shafts outside the compressor packing	5,000

The aforementioned modified shutdown practices present several issues that merit consideration, including the following:

- Maintaining gas pressure on idle compressors and valves causes increased emissions through the equipment inside the compressor station. Appropriate precautions must be taken within the facility for gas detection, the potential energy hazards of high-pressure vessels, and adequate ventilation to prevent gas accumulation.
- Routing emissions to fuel gas is effective only when sufficient fuel demand exists.

5.2.1.2.4 Safety and Feasibility Impacts

No adverse safety impact is anticipated as inspections are currently required in Part 192.

[128] Ibid. (p. 1).

5.2.1.2.5 Increased Isolation Valve Maintenance

5.2.1.2.6 Emission Source

Unit isolation valves, which isolate compressor facilities from a pipeline, are an additional source of significant natural gas emissions from offline depressurized compressors (**Figure 32**). A typical leak rate for unit isolation valves is 1.4 Mcfh.[129]

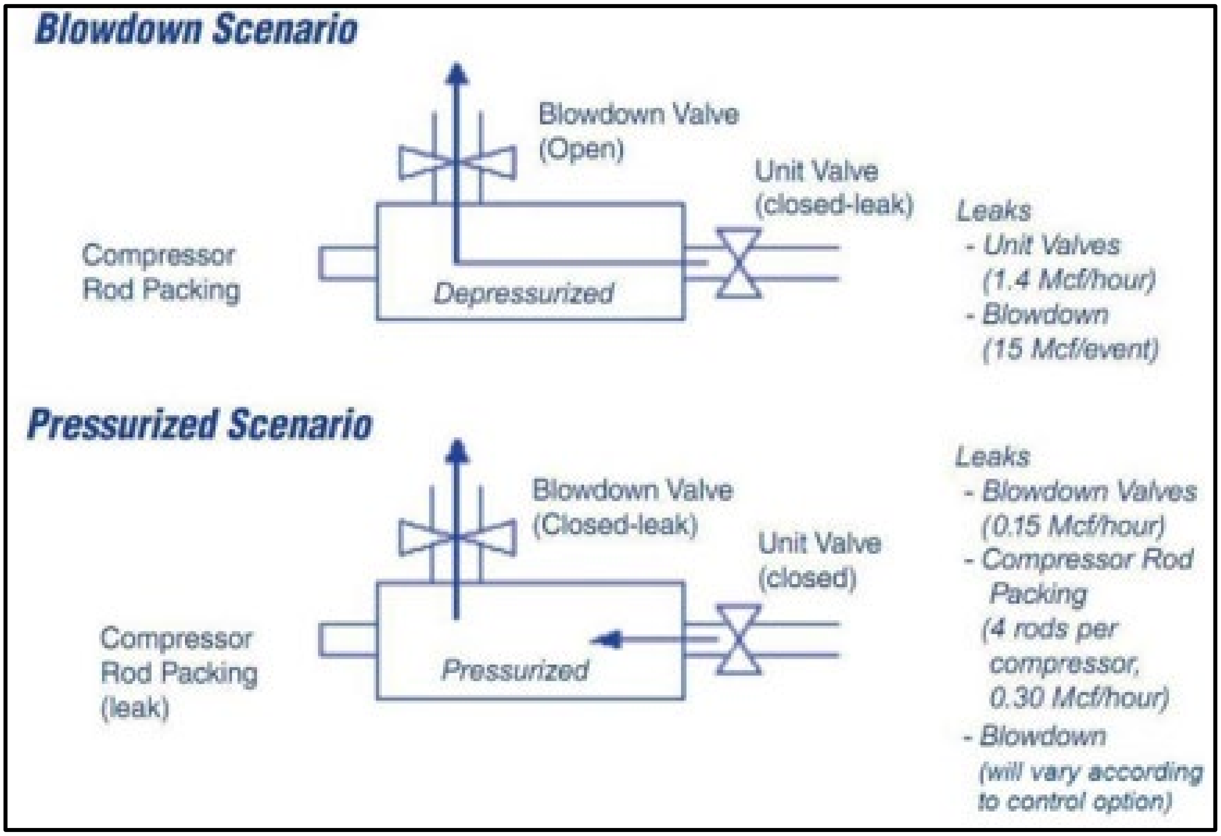


Figure 32: Compressor Schematic and Unit Isolation Valve Leak Rates (Courtesy of Pipeline Research Council International (PRCI) via EPA)

5.2.1.2.7 Implementation or System Design Strategy

Unit isolation valves are maintained periodically to reduce emissions. Increased maintenance schedules, appropriate valve selection, and unit isolation valve maintenance can reduce emissions during shutdowns.

Some isolation valve maintenance or replacements must be performed only during a blowdown when isolating the piping from system pressures. Isolation valve maintenance and replacements are also performed during compressor maintenance. A leaking isolation valve should be analyzed to determine the consequent safety and environmental hazards. If a leak is determined to not be hazardous to people nor the environment, and its repair is not environmentally justifiable when

[129] Ibid. (p. 5).

discovered, repairs should be scheduled during the next scheduled system blowdown. An additional blowdown to repair a minimal and otherwise safe leak should be avoided.

5.2.1.2.8 Benefits and Limitations

In addition to increasing isolation valve maintenance intervals, selecting appropriate valves and maintaining unit isolation valve seal integrity can eliminate up to 90 percent of annual emissions from typical shutdowns and blowdowns.[130]

5.2.1.2.9 Safety and Feasibility Impacts

Increasing external valve maintenance and leak inspection intervals will increase operator costs. Decreased leaks and lost product will comprise the cost savings from more frequent inspection intervals; however, these savings will be minimal and will not offset the added inspection costs. No approach exists to ease additional costs or workloads—the cost of additional inspections will increase in proportion to the increased frequency of inspections. For example, doubling the number of inspections will double inspection costs. New technologies that allow for external valve maintenance and inspections without service interruption and gas venting should be considered and implemented.

5.2.1.3 Pipeline Drawdown Techniques to Lower Gas Line Pressure Before Maintenance

To complete repair and maintenance activities, a pipeline must be depressurized to remove gas from the affected pipe section.

Applicable blowdown mitigation practices are influenced by whether the interstate transmission pipeline is a looped or single-barrel configuration.

- A looped system includes two or more pipelines laid in parallel to increase capacity along a right-of-way; both ends connect to the original pipeline. In these systems, diversion is a mitigation option because of the availability of multiple lines in the right-of-way. Inline compression may provide only limited benefit, however, because the other lines in the right-of-way rely on the inline compression to maintain a constant pipeline pressure.
- Single pipeline systems may be larger-diameter, long-haul trunkline systems that tend to contain fewer receipt and delivery points depending on the location. Although these systems provide fewer diversion options, using inline compression to reduce pipeline pressure before blowdown may not be feasible if service interruption cannot be reduced.

5.2.1.3.1 Emission Source

During pipeline depressurization, a section of pipeline is isolated by closing the isolation valves at both ends. Operators frequently depressurize the pipeline by venting the gas into the

[130] Ibid. (p. 8).

atmosphere. A 2014 Environmental Defense Fund (EDF)/ICF International study[131] identified 22 emission source categories that accounted for approximately 80 percent of the total 2018 projected onshore emissions, which was 404 Bcf. Pipeline venting in the transmission sector was reported as one of the top 22 emission sources, accounting for 1.6 percent (6.6 Bcf) of total 2018 emissions.[132]

5.2.1.3.2 Implementation or System Design Strategy

The total volume of gas released during planned blowdowns depends on pipeline diameter and pressure as well as other factors. These emissions can be avoided by directing the gas to a connected or nearby low-pressure system, or by rerouting the gas using a mobile electric compressor (**Figure 33**). Operators can use inline and/or mobile compressors to reduce pipeline pressure during pumpdown, the procedure of which **Figure 34** illustrates.[133]

Figure 33: Mobile Electric Compressor (Courtesy of the EDF)

[131] EDF, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries Approach and Methodology" (Figure 3-4, p. 3-8), March 2014. Retrieved from https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.
[132] EDF, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries Approach and Methodology" (Table 3-2, p. 3-7), March 2014. Retrieved from https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.
[133] EPA, "Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure Before Maintenance," Lessons Learned From Natural Gas STAR Partners, Air and Radiation, October 2006. Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_pipeline.pdf.

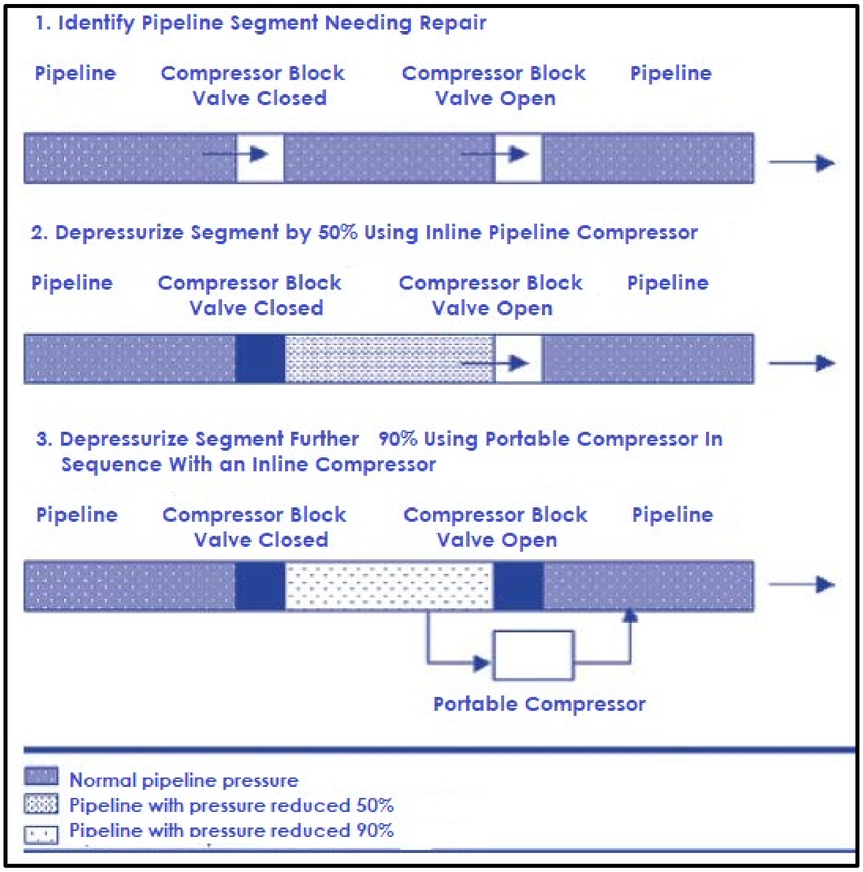


Figure 34: Pipeline Depressurization Sequence (Courtesy of EPA)

By blocking the upstream valve of the isolated pipeline section while continuing to run a downstream compressor, pipeline pressure can be reduced to approximately 50 percent of the operating pressure. Then, the downstream compressor can be shut down and the pipeline segment fully isolated.

For more extensive repairs, testing, or maintenance, operators can use mobile compressors to achieve additional pressure reduction. When used with an inline compressor, a mobile compressor can lower pipeline pressure by an additional 40 percent—a total of up to 90 percent of its original pressure—without venting. Pipeline gas recovery using mobile compressors is best implemented during planned maintenance or repairs to recover as much of the pipeline gas as possible.

5.2.1.3.3 Benefits and Limitations

The benefits of this practice include the following:

- On average, 50 to 90 percent of the vented gas from pipeline sections may be recovered by using drawdown techniques to depressurize pipelines.[134] The volume of natural gas used by inline compressors is much less than is vented into the atmosphere.
- EPA Natural Gas STAR Partners reported gas savings of 4.1 Bcf in 2004 using pumpdown techniques.[135]

Safety during a blowdown event is a significant concern because of the volatile content of natural gas emissions. Additional factors regarding blowdown events include the following:

- Not all gas from a blowdown may be recovered.
- The time to reduce the pipeline segment pressure and its effects on the customer, the public, and pipeline safety must be considered.
- Not all blowdowns are candidates for mitigation.
- Existing downstream inline compressors can reduce the minimum suction pressure to only 50 percent of the operating pressure.
- Natural gas emission reductions are site-specific and depend on the operating pressure of the compressors or pipelines being blown down.

5.2.1.3.4 Safety and Feasibility Impacts

The industry began developing and reporting this technology in 1996; therefore, no adverse safety impact is anticipated. The type of drawdown process described in this subsection should be performed only in a manner consistent with safety management policies.

Reduced gas throughput during shutdowns should be a feasibility consideration.

5.2.2 Distribution Sector—Ventless Stop-off Procedures for High-Pressure and Polyethylene Mains

5.2.2.1 Emission Source

During a shutdown, gas must vent (Item 7 in **Figure 35**) between the primary and secondary bags/stoppers (Items 1, 3, 4, and 6 in **Figure 35**) or similar devices to prevent pressure buildup. This is primarily due to debris (sand, tar, rust, oxide buildups, drill cuttings, etc.) that makes obtaining an escape-proof seal on the bags/stoppers difficult or impossible. Additional factors preventing sealing include pipe geometry, internal condition, and manufacturing tolerances. The gas, therefore, has an opportunity to escape into the atmosphere.

[134] Ibid. (p. 7).
[135] Ibid. (p. 1).

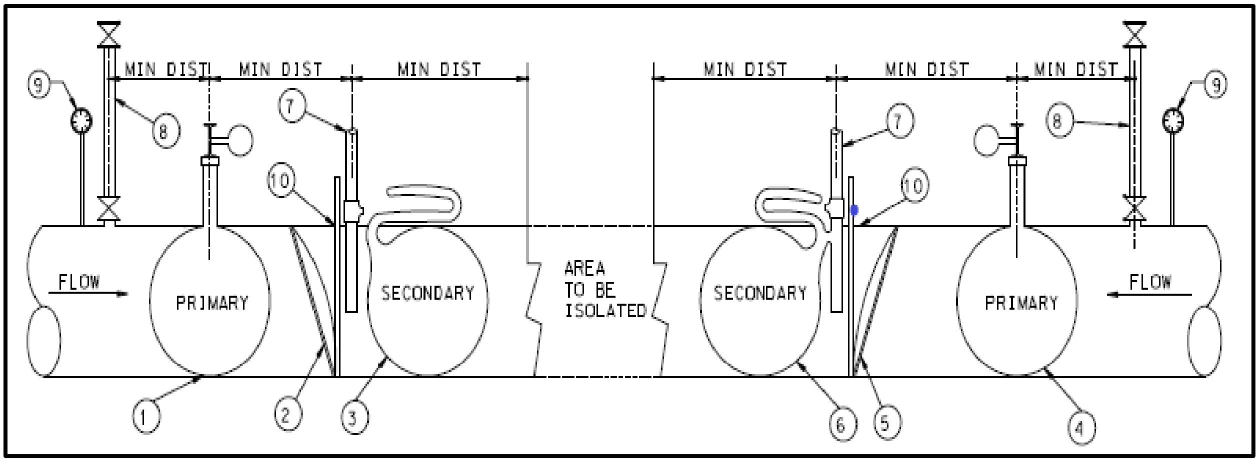


Figure 35: Typical Stop-off Arrangement for CI and Steel Mains (Courtesy of Brooklyn Union Gas)

5.2.2.2 Implementation or System Design Strategy

For safety reasons, operators commonly use a double bag-and-stopper stop-off technique—which employs a primary stopper that is backed up by a secondary stopper—after drilling and tapping operations are completed in preparation for the stop-off procedures required for gas main tie-ins. This technique prevents gas pressure from building and potentially blowing out downstream bags and stoppers via a vent that releases any gas passing the upstream bag/stopper into the atmosphere. The vent installation concept for low-pressure procedures also can apply to high-pressure stop-offs (1) for both steel and CI pipelines using control fittings, and (2) to squeezed- or stopped-off polyethylene mains (**Figure 36**).

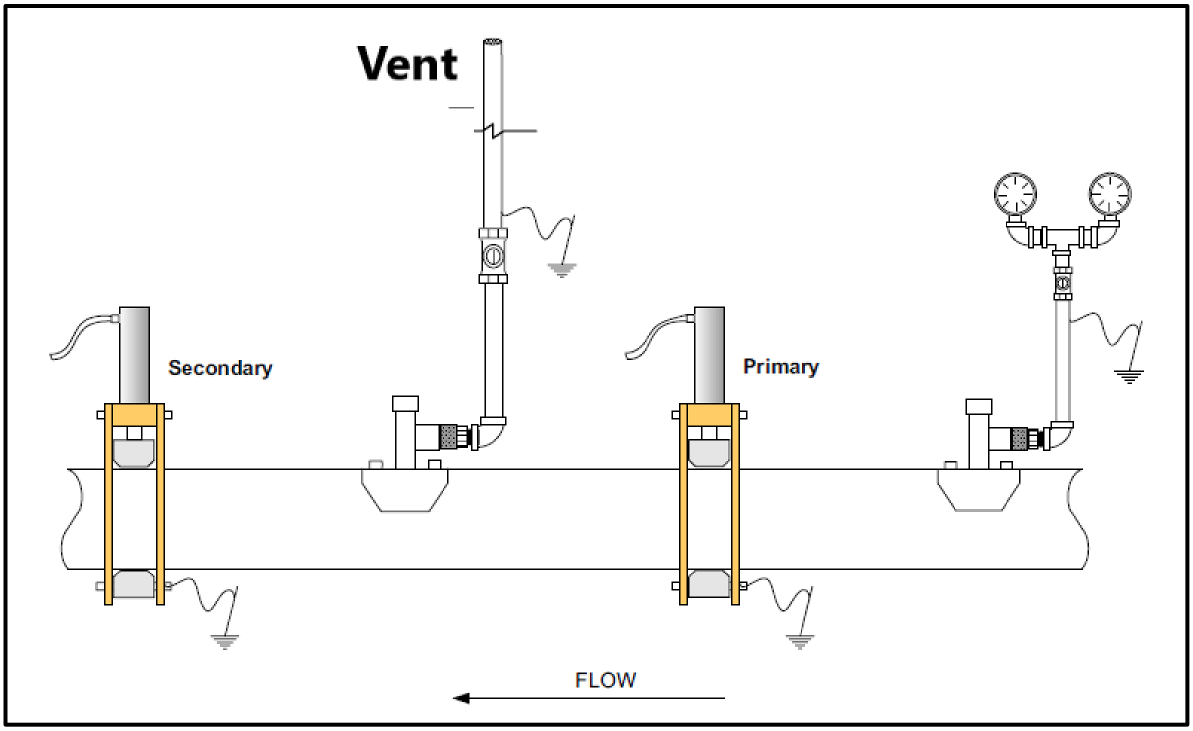


Figure 36: Typical Stop-off Arrangement for Polyethylene Mains (Courtesy of Brooklyn Union Gas)

Operators can use multiple types of stoppers to stop off gas flow, including a variety of inflatable bags, folding mechanical stoppers, line valves, stopple plugs, and plugging trains or similar devices.

A considerable volume of escaping gas can be safely directed up the vent, depending on the internal condition of the pipeline and the time needed to make the necessary connections. Larger-diameter pipe takes significantly more time to line up and connect using heavy lifting equipment than smaller-diameter pipe.

For routine stop-offs performed when making connections to new pipeline, an opportunity exists to capture gas escaping through the vent using a capture mechanism (compressor) and redirect it into the pipeline, compress the gas into a storage cylinder, or burn the gas through a flameless catalytic heater installed at the top of the vent. For polyethylene pipeline mains, escaping gas can be captured using a combination of mandatory vents between bags/stoppers and specially designed stopping equipment.

Because operators perform stop-off work daily, further investigation into available technologies for this purpose through a request for proposal process may be beneficial.

5.2.2.3 Benefits and Limitations

New processes and procedures, combined with new technologies yet to be developed, could eliminate venting gas to atmosphere during stop-off procedures without compromising safety.

5.2.2.4 Safety and Feasibility Impacts

Because this is an emerging technology, further research into safety and feasibility impacts should be conducted.

6 BATs and Practices when Intentionally Releasing or Venting Gas, including Blowdowns

This section focuses on identified BATs and practices that prevent or minimize the release of natural gas when venting[136] is required, without compromising pipeline safety. Venting, which should be restricted to unavoidable circumstances such as preventing safety risks, is performed to relieve pipeline pressure so that maintenance, testing, or other activities can occur. Pipe length, pressure, and diameter—and the diameter of the gas venting pipe—affect gas venting time and the amount of natural gas released into the atmosphere.

In addition to planned operator releases, gas is intentionally vented as part of many processes to enhance pipeline operation safety. These planned releases include pressure regulation, excess flow control, and blowdowns.

Most emissions from intentional venting occur during gas transport through transmission and distribution as well as to consumer markets. The gas transmission sector includes compressors and large pressurized pipelines that transport gas to industrial customers, distribution networks, and storage facilities. During transmission, emissions are created (1) by compressors, and (2) through venting associated with pipeline blowdowns for maintenance and pipeline replacement. The distribution sector of the supply chain refers to the system of smaller pipelines, service lines, and meters that connect long-distance transmission lines to individual consumers.[137]

Many components are designed to intentionally vent gas, which increases pipeline system safety via pressure reduction. One example is pneumatic valves, which are used throughout natural gas systems (Paragraph 5.1.1.3). These valves operate using pressurized natural gas and bleed small quantities of natural gas by design during normal operation. Additionally, gas often is vented from storage tanks and dehydrators (Paragraph 5.1.1.5).

6.1 Release Prevention

This section focuses on identified BATs and practices that prevent natural gas release during O&M activities that require either intentional venting or blowdown activities. Current and developing technologies and processes were researched. Options for preventing natural gas releases from transmission, gathering, and distribution systems were evaluated using collected data on intentional natural gas releases and summarized in the subsequent BATs and practices.

[136] The intentional release of natural gas into the atmosphere via a pressure control device or pressure regulator.
[137] https://www.iea.org/fuels-and-technologies/methane-abatement.

6.1.1 Transmission, Gathering, and Distribution Sectors

6.1.1.1 Pressure Relief Valve Inspection and Repair Programs

6.1.1.1.1 Emission Source

In addition to compressor seals and packing, pipeline relief valves and connections can be sources of natural gas emissions. Pressure relief valves (**Figure 37**) are designed to vent natural gas into the atmosphere in a controlled manner and release excess pressure; these vents open only when excess pressure in the gas system exists. Over time, however, the internal components can become worn or clogged with debris and can be affected by other operational and environmental conditions. Improper design of pressure sensing lines and blowdown line sizing also can negatively impact valve function. When clogging or wearing occurs, these components malfunction and cause the pressure relief valves to stay open and vent natural gas into the atmosphere continuously.

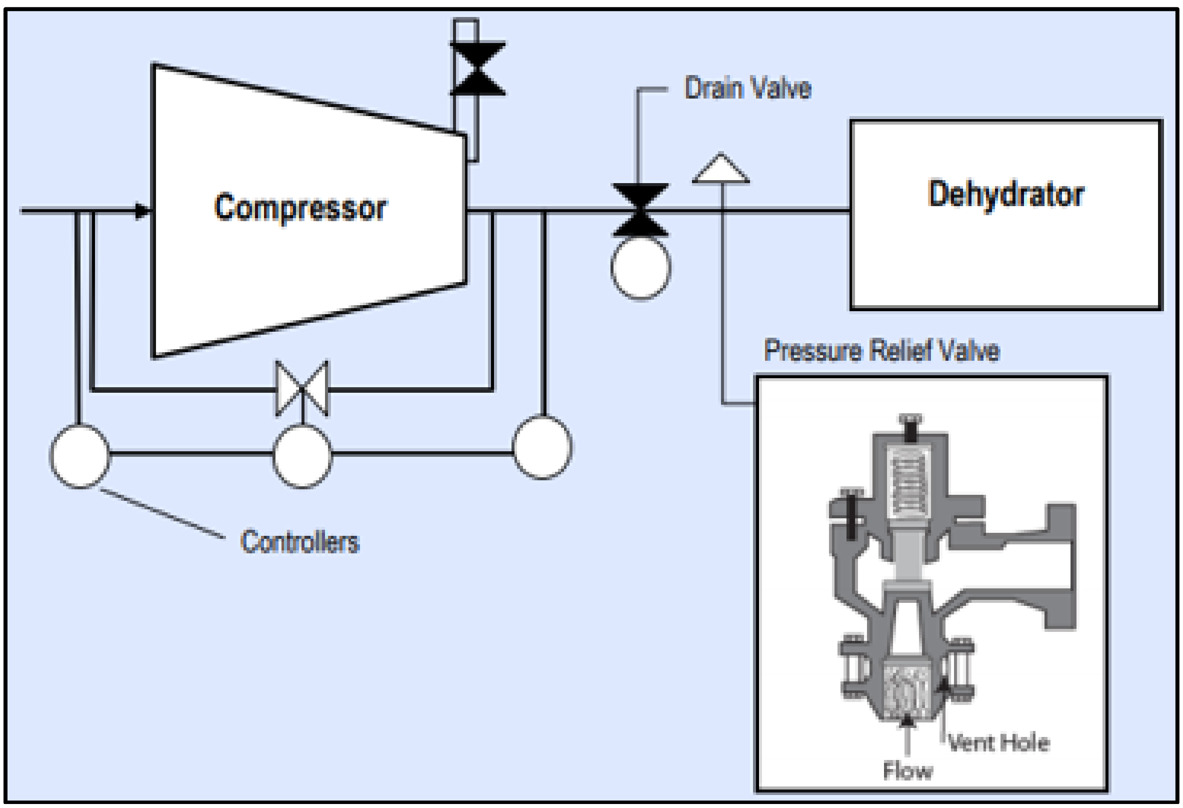


Figure 37: Pressure Relief Valve on Compressor Piping (Courtesy of EPA)

6.1.1.1.2 Implementation or System Design Strategy

In accordance with 49 CFR § 192.745 Valve Maintenance: Transmission Lines, valves must be inspected and partially operated "at intervals not exceeding 15 months, but at least once each calendar year." Similarly, 49 CFR §192.747 Valve Maintenance: Distribution Systems requires valves to be checked and serviced at the same 15-month interval.

To reduce the amount of natural gas emitted from pressure relief valves, operators could increase external leak detection and inspection frequency for early detection. Some suggestions include:

- All pressure relief valves on all systems—12 months; and
- Pressure relief valves that may be affected by debris from an immediately upstream repair or pipe alteration[138]—when upstream work is complete. This will ensure that no loose debris or other foreign bodies have entered the pipeline and blocked the internal functions of the pressure relief valve.

Pressure relief valve inspection can be completed by either or both of the following:

- Testing the pressure relief valve vent for emissions; and/or
- Checking the line pressure on the pressure relief valve inlet and outlet to ensure proper pressure regulation.

6.1.1.1.3 Benefits and Limitations

A proactive testing and repair program can reduce annual natural gas losses. In one study conducted by the EPA, 25 of 100 inspected pressure relief valves were found to be leaking, the repairs of which yielded total annual savings of approximately 500 Mcf (approximately 20 Mcf per valve).[139] In another EPA-sponsored study, a single one-inch pressure relief valve leaked 36,744 Mcf of natural gas annually. Five man-hours of labor were needed to repair and eliminate the leak.[140]

Implementing a proactive testing and repair program could require increased accessibility to pipelines in remote or low-access areas. Additionally, manpower requirements will vary based on the system being inspected; the expected inspector workload increase is 1:1.

6.1.1.1.4 Safety and Feasibility Impacts

The increased exterior maintenance and leak inspections performed in a pressure valve and inspection program are expected to increase overall pipeline safety, with no adverse safety impact is anticipated.

6.1.1.2 Capture Purged Gas from Pipeline Facilities Using Drawdown Compressors

6.1.1.2.1 Emission Source

Pipeline facilities are purged on transmission, gathering, and distribution lines when facilities are newly installed, replaced, or abandoned. Purging (1) requires the safe replacement of some volume of gas with air—or of air with gas—in a pipeline, and (2) allows gas volumes directly

[138] This is an action that may allow debris to enter the pipeline.
[139] EPA Natural Gas STAR Program, PRO Fact Sheet No. 602, "Test and Repair Pressure Safety Valves," 2011. (p. 2). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/testandrepairpressuresafetyvalves_0.pdf.
[140] Ibid.

proportional to the diameter and length of the pipes in a pipeline facility to be safely vented into the atmosphere to replace the air in the pipeline with natural gas.

All purging, either via the inert slug or complete fill method, is in accordance with 49 CFR § 192.629 Purging of Pipelines.

In the inert slug method, an inert gas slug of a specified volume is discharged into the pipeline at one end while the air present in the pipeline is vented at the other end(s). Then, the combustible gas is fed into the pipeline immediately after the inert gas has been discharged into the pipeline.

In the complete fill method, a volume of inert gas greater than the volume of the pipeline being purged is rapidly discharged into one end of the pipeline while the air or gas present in the pipeline is vented at the other end(s). Introduction of the inert gas and venting is continued until all vents indicate 95 to 100 percent inert gas.

In both methods, inert gas (either nitrogen or CO_2) is used to separate the combustible gas and air and prevent direct contact and mixing. Primarily due to availability and cost, CO_2 (a GHG) is normally used on smaller projects (5,000 or fewer cubic feet) and nitrogen is used on larger projects.[141] Commercially prepared nitrogen and CO_2, which are supplied as either liquid or gas, are satisfactory for purging systems of nearly all descriptions and sizes. Operators have complete flexibility in inert gas selection because of standard delivery containers that range in size from single cylinders to tank cars.

Clearing, which involves replacing air within a pipeline with combustible gas or vice versa, is another established, acceptable method for placing short lengths of smaller-diameter pipeline facilities into service (and taking them out of service). Caution is required to ensure that (1) purging is performed in a controlled manner, and (2) the hazards associated with flammable gas-air mixtures are minimized. Clearing also vents gas to atmosphere to remove air from the pipeline.

6.1.1.2.2 Implementation or System Design Strategy

The gas vented into atmosphere as part of the purging process should be captured, collected, and contained where practical. Drawdown compressors currently being evaluated by several pipeline operators may reduce the gas volume in a pipeline while safely reinjecting the gas either (1) into an adjoining pipeline facility, or (2) upstream of where the facilities have been isolated.

6.1.1.2.3 Benefits and Limitations

The major benefit of using drawdown compressors in pipeline purging operations is the significant reduction of gas released into the atmosphere. The use of drawdown compressors to minimize gas blowdown volumes is becoming more widely accepted. Additionally, drawdown compressors can recover product from various pipeline operations, including pipeline

[141] AGA, Purging Manual, 4th Edition, September 2018. Available only through purchase or subscription.

replacement, pipeline abandonment, pipeline repair, new facility commissioning, and maintenance-related work. The use of drawdown compressors will impact the amount of time an existing pipeline segment will be out of operational service.

The most significant concern with use of this technology is that purging adds potentially prohibitive manpower/labor and equipment costs because it takes much longer to accomplish than venting or blowing down gas into the atmosphere. These costs are not offset by the product recovered at typical distribution operating pressures.

Additionally, reinjecting gas into a nearby pipeline facility will take substantially longer in the summer than in the winter due to minimal customer gas loads on the system. This necessitates the following:

- Additional manpower and labor to reduce outlet flows and pressures at nearby supply sources; and
- System monitoring to ensure overall safe operation.

6.1.1.2.4 Safety and Feasibility Impacts

Various pipeline companies are further evaluating drawdown compressor usage on a pilot basis to better understand the process, the equipment involved, and its impact to operations. Although no safety issues have been identified, there appear to be practicality issues with implementation on single line systems (i.e., lines that are single feeds to the customer). The process adds significant overall project time compared to current blowdown techniques and may require additional manpower to ensure that safe system pressures are maintained.

6.1.2 Transmission and Gathering Sectors

6.1.2.1 Pipeline Purging

6.1.2.1.1 Emission Source

A common practice when taking pipeline segments out of service for operational or maintenance purposes is to depressurize the pipeline and vent the natural gas into the atmosphere (i.e., purge).[142]

6.1.2.1.2 Implementation or System Design Strategy

To prevent gas emissions, operators reported the purging of its pipelines using an inert gas and pigs (**Figure 38**). First, a pig is inserted into the isolated section of the pipeline. Then, inert gas is pumped in behind the pig, which pushes natural gas out of the pipeline segment. At the appropriate shutoff point, the pig is caught in a pig trap and the pipeline is blocked off. Finally, the inert gas is vented to the atmosphere once the pipeline is "gas-free."

[142] Natural Gas STAR Program, PRO Fact Sheet No. 403, "Use Inert Gases and Pigs to Perform Pipeline Purges," 2011. Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/useinertgases.pdf.

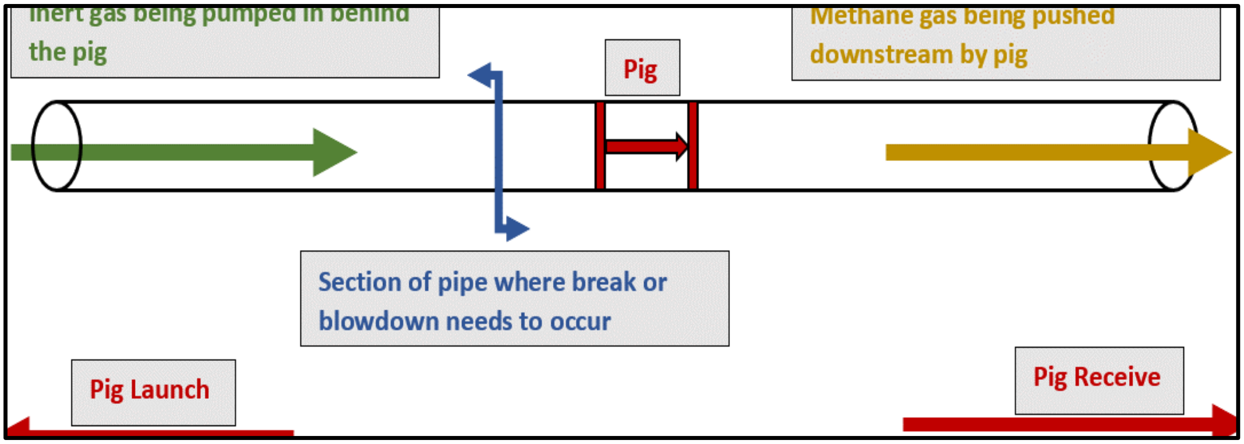


Figure 38: Pipeline Purging Process (Courtesy of ABS Group)

6.1.2.1.3 Benefits and Limitations

The following are required considerations for any pipeline to be purged:

- A preexisting pig launch and trap facility; and
- Access for a mobile nitrogen or inert gas supply to backfill the space being purged.

6.1.2.1.4 Safety and Feasibility Impacts

Purging is addressed in Part 192 and no safety impact is anticipated. The practice reviewed here applies only to pipeline segments into which a pig can be used.

6.1.2.2 Hot Tapping for Service Line Connections or Tie-Ins

6.1.2.2.1 Emission Source

Natural gas operators install new pipeline lateral connections to expand or modify existing pipeline systems with gas receipts or deliveries. This can be accomplished safely either by shutting down part of the system and installing a new connection (line purging or shutdown interconnect) or by hot tapping the live line. A general process for each is outlined below:

- Shutdown interconnect
  - The existing line is shut down.
  - The natural gas is purged from the line.
  - The line is cut.
  - The new service connection is welded on.
- Hot tapping
  - The live gas line is at a reduced or full operating pressure.

- o No shutdown, live purging, or venting occurs.

A shutdown interconnect procedure results in venting natural gas from the pipeline section blocked for new installation or modification. This venting, in turn, results in customer inconvenience, and the costs incurred from (1) product loss and (2) evacuation, if necessary, from the area containing the vented gas.

Hot tapping, while it can avoid emissions, is an existing technology that has been performed for decades by transmission and distribution companies. Additionally, the uncertainty and complications of hot tapping designs experienced by operators in the past have been improved.[143]

6.1.2.2.2 Implementation or System Design Strategy

Hot tapping can be performed on any gas pipeline size (0.5–72 inches in diameter) or type, including those that are offshore (subsea). Because the procedure is controlled by a valve that is installed before the pipe is tapped, natural gas emissions can be controlled and limited to the small amounts of gas that become trapped in the valve and released into the atmosphere when the valve is opened.

A detailed project analysis encompassing safety, operational, and technical considerations is performed before any hot tapping operation. The following should be considered when determining whether to perform hot tapping:

- Pipeline MAOP;
- Pipe material;
- Condition of the parent pipeline;
- Local demand for gas; and
- Costs of the hot tap.

The basic hot tapping procedure is performed as follows:

- Excavate the pipeline segment where the hot tap is to be installed and inspect the pipe for anomalies such as corrosion and cracking.
- Connect the fitting on the existing pipeline by welding (steel), bolting (CI), or bonding (plastic). Then, install the valve.
- Install the hot tap machine (**Figure 39**) through the permanent valve.[144]

[143] EPA, "Using Hot Taps for In Service Pipeline Connections, Lessons Learned from Natural Gas STAR Partners," October 2006. Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_hottaps.pdf.
[144] Furmanite IPSCO Specialist Hot Tapping and Line Stopping Techniques. Retrieved from https://furmanitehk.com/wp-content/uploads/2020/11/Hot-Tapping-and-Line-Stopping.pdf.

- Cut the coupon from the pipeline through the open valve. (A special device retains the coupon for removal after the hot tap operation.) Then, withdraw the coupon through the valve and close the valve.
- Remove the tapping machine, then add the branch pipeline.
- Purge the oxygen, then open the valve.

Additionally, hot tapping combined with line plugging[145] can be used to divert flow around a pipeline or piping section that is under repair or maintenance. Furthermore, operators can reduce natural gas emissions and increase revenue by using hot taps.[146]

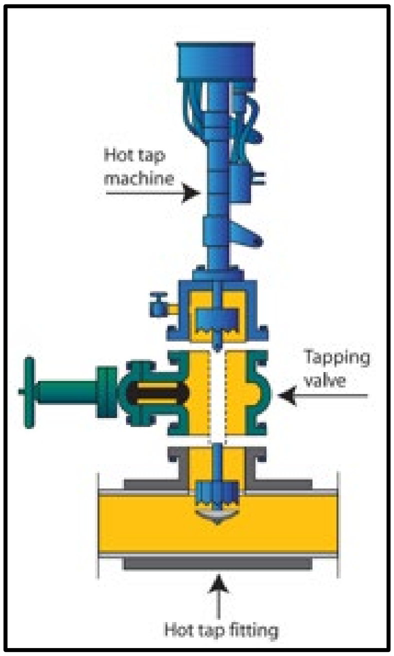


Figure 39: Hot Tapping on a Natural Gas Line
(Courtesy of Furmanite/IPSCO)

6.1.2.2.3 Benefits and Limitations

Hot tapping provides the following advantages over shutdown interconnect procedures:

- Continuous system operation and no shutdown required;
- Minimal or no gas released into the atmosphere;
- No cutting, realigning, and/or rewelding of pipeline segments; and
- Reduced planning and coordination costs and efforts.

[145] Line plugging is the use of inflatable plugs (stopples) or other devices as a temporary means by which to isolate sections of a system.
[146] EPA, "Using Hot Taps for In Service Pipeline Connections," Lessons Learned from Natural Gas STAR Partners, October 2006. Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_hottaps.pdf.

6.1.2.2.4 Safety and Feasibility Impacts

Hot tapping is an existing technology that is both considered acceptable under current regulations and widely used in the industry; therefore, no adverse safety impact is anticipated. Limitations for hot tapping are determined by individual companies considering pipe material, thickness, temperature, pressure drop, and flow rate.

6.1.3 Distribution Sector—Capture Purged Gas-Air Mixture from Customer Fuel Gas Piping

6.1.3.1 Emission Source

New or renewed service lines have gas up to the valve before the meter, meaning that the customer-owned gas piping must be purged of air and the subsequent gas-air mixture when appliances are checked or relit. This purging is normally accomplished through the appliance.

Because customer fuel gas piping is typically small in diameter (0.75 to 1.25 inches), the volume of such gas mixtures is relatively low on an individual basis. That volume becomes substantial, however, when applied to the total number of homes that contain gas piping.

6.1.3.2 Implementation or System Design Strategy

As when purging gas from pipeline facilities (Paragraph 6.1.1.2), the gas-air mixture from the purging of customer piping should be captured, collected, and contained to eliminate venting into the atmosphere. Regulation changes in the heating, ventilation, and cooling (HVAC) industry several years ago, for example, resulted in the elimination of venting harmful refrigerants into the atmosphere during routine maintenance procedures. Currently, those refrigerants instead are captured, collected, and contained using vacuum technology.

6.1.3.3 Benefits and Limitations

The primary benefit of this practice would be the elimination of venting such gas-air mixtures into the atmosphere when purging customer pipelines. This task, however, could incur additional equipment and labor costs. The specific purging process/procedure and appropriate support equipment will need to be determined.

6.1.3.4 Safety and Feasibility Impacts

This is an emerging practice and further research into safety and feasibility impacts should be conducted.

6.2 Release Minimization—Transmission and Gathering Sectors

This section focuses on identified BATs and practices that minimize intentional natural gas release during venting or blowdown activities. Current and developing technologies and processes were researched. Options for minimizing releases of natural gas in transmission and gathering systems were evaluated using collected data on intentional natural gas releases and summarized in the subsequent subsections.

The gas transmission and gathering sectors have the opportunity to incorporate into their operating procedures ways to reduce the release of gas into the environment when conducting maintenance or replacing pipe or valves.

The release of gas into the environment can be minimized by using one or more of the following methods, all of which are consistent with pipeline safety:

- Isolate a smaller pipeline segment length using valves and/or installing control fittings near the pipe being replaced.
- Flare the gas released from the pipeline from the nearest isolation valves or control fittings on the pipe being replaced.
- Reduce pressure in the pipeline segment using inline compression.
- Reduce pressure using mobile compression from the nearest isolation valves on the pipe being replaced.
- Transfer the gas to a lower-pressure pipeline system or segment from the isolation valves nearest to the pipe being replaced, such as through a lateral delivering gas to another pipeline facility.
- Use an alternative method demonstrated to minimize the release of gas into the environment similar to those discussed above.

On May 18, 2023, PHMSA published an NPRM titled “Pipeline Safety: Gas Pipeline Leak Detection and Repair,” which included a proposal to require operators to mitigate gas releases from non-emergency blowdowns of gas transmission pipelines.[147]

6.2.1 Emergency Shutdown (ESD) Systems and Practices

In June 2021, PHMSA issued an advisory bulletin[148] reminding operators of their obligation to comply with Section 114 of the PIPES Act of 2020, by updating inspection and maintenance plans to identify procedures that prevent and mitigate both vented (intentional) and fugitive (unintentional) pipeline emissions. As part of the updated inspection process, opportunities exist for identifying and incorporating measures to minimize the frequency of emergency natural gas releases as part of owner/operator planning updates to PHMSA.

[147] PHMSA rulemaking, “Pipeline Safety: Gas Pipeline Leak Detection and Repair,” May 18, 2023. Available at https://www.federalregister.gov/documents/2023/05/18/2023-09918/pipeline-safety-gas-pipeline-leak-detection-and-repair. See proposed § 192.770.

[148] PHMSA Advisory Bulletin: “Pipeline Industry Must Take Actions to Address Methane Leaks from Pipelines and Pipeline Facilities,” June 7, 2021. Available at https://www.phmsa.dot.gov/news/phmsa-advisory-bulletin-pipeline-industry-must-take-actions-address-methane-leaks-pipelines.

Considerable natural gas emissions occur when operators vent gas (blowdown) into the atmosphere to relieve pipe or compressor station pressure during ESDs. A formal maintenance program that coordinates activities with periods of low demand, system inventories, and system pressures can reduce vented gas emission volumes.

6.2.1.1 Emission Source

ESD systems (previously described in **Figure 11**) are designed to automatically vent natural gas to the atmosphere during station emergencies for safety reasons or when equipment malfunctions. Some ESD systems route the vented gas to a flare stack; other systems simply vent the gas into the atmosphere via a vent stack. In 2021, the U.S. GHGI estimated pipeline blowdown emissions of approximately 11.0 Bcf from pipeline blowdowns in the transmission sector and 0.8 Bcf in the gathering sector.[149]

6.2.1.2 Implementation or System Design Strategy

To reduce ESD frequency, operators can use monitoring tools to proactively detect abnormal operating conditions that may result in a hazard to people, property, or the environment. Operators can later use this information during planning to identify measures needed to address these conditions before a scheduled shutdown. The capability to predict equipment or pipe deficiencies provides operators advance notice of possible impending ESDs and time to repair problem areas before an ESD is necessary.

During planning for a controlled shutdown, operators can identify system components needing repair or replacement, thus serving as an additional preventive measure for reducing ESD frequency. During the planned shutdown, system component modifications that reduce emissions are installed when equipment maintenance or repairs are performed.

Table 9 lists several emission reduction design and maintenance projects and practices in the transmission sector.[150] The goal of these design and maintenance projects is to reduce the frequency of emergency and unplanned shutdowns through equipment function upgrades and improvements.

---

[149] U.S. Environmental Protection Agency (EPA), Draft Inventory of Greenhouse Gas Emissions and Sinks, 1990–2021, April 2023. Retrieved from https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg. Annex 3.6-1. (U.S. GHGI).

[150] California Climate Action Reserve, "Operations and Maintenance of Natural Gas Transmission and Distribution Systems Emission Reductions Projects," December 2009. Retrieved from https://www.climateactionreserve.org/wp-content/uploads/2009/03/O_M_of_Natural_Gas_T_D_Systems_Issue_Paper.pdf.

Table 9: Emission Reduction Projects and Practices in Transmission Sector

Project Type	Description
Design	Fuel gas recovery blowdown valve for compressor blowdowns
	Design vented fuel capture and recovery systems
	Automate systems operation to reduce venting
	Design of additional block valves on new pipelines
Maintenance	Lower purge pressure in shutdown controls for gas-actuated pneumatic valves
	Use inert gases, plugs, and pigs to perform pipeline purges
	Pipeline survey frequency increase

Additionally, portable modularized trailer units for pipeline gas blowdown (**Figure 40**) are available for pipeline gas blowdown and maintenance activities. These trailers, which can be purchased or leased in advance of a planned shutdown, can perform the following functions for newer designs:

- Pressure reduction
- Gas flow rate measurements
- Separation of gas, liquids, and solids

Figure 40: Modularized Trailer Unit for Pipeline Blowdown (Courtesy of EN-FAB, Inc.)

6.2.1.3 Benefits and Limitations

Practices such as modifying blowdown piping can enable the collection and rerouting of vented gas to sales lines, fuel boxes, or lower-pressure mains. Operators also reported the potential reduction of gas volumes to be vented during compressor station shutdowns by placing station isolation valves closer to the compressor equipment.

EPA Natural Gas STAR Partners reported annual emission reductions ranging from less than 100 to more than 72,000 Mcf.[151] Gas recovery from rerouting vented gas from blowdown systems either (1) to a sales line or (2) for fuel use usually justifies the additional piping and operating

[151] EPA, PRO Fact Sheet 908, "Redesign Blowdown Systems and Alter ESD Practices," September 2011 (p. 2). Retrieved from https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/redesignblowdownsystems.pdf.

costs. Emission savings will vary by compressor station size, operating pressure, and facility complexity; the degree of emission reduction will depend on length, size, and operating pressure.

Rerouting combustible gases also eliminates potential hazards including explosions or fires in the operating area, such as in compressor station buildings.

6.2.1.4 Safety and Feasibility Impacts

Any blowdown system redesign and revision of ESD practices should be completed in accordance with 49 CFR Part 192 and industry safety standards such as those outlined by the following:

- The U.S. Occupational Health and Safety Administration (OSHA)
- The American Petroleum Institute (API)
- The American National Standards Institute (ANSI)
- The American Society of Mechanical Engineers (ASME)
- Public safety management (i.e., local codes and regulations for hazards and fire emergencies)

6.2.2 Integrity Management Plans (IMPs)

6.2.2.1 Emission Source

Implementation of an IMP in accordance with 49 CFR Part 192, Subparts O and P (Gas Transmission Pipeline Integrity Management and Gas Distribution Pipeline Integrity Management, respectively), can help minimize potential failures along systems and during associated blowdown events. Operators of certain gas transmission pipelines (HCAs) and gas distribution pipelines must develop and implement an IMP that:

- Contains all elements described in 49 CFR §§ 192.911 or 192.1007, as applicable.
- Addresses the risks on each covered pipeline segment to identify, assess, and mitigate integrity threats for specific pipeline sections in HCAs.

The Gas Transmission Pipelines Safety Rule[152] also introduced the term *moderate consequence areas* (MCAs) into 49 CFR § 192.3.[153] IMP regulations could be extended beyond HCAs to MCAs as part of a natural gas emission reduction strategy.

---

[152] PHMSA rulemaking, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," October 1, 2019. Available at https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf.

[153] An MCA is an onshore area that is within a potential impact circle as defined in 49 CFR § 192.903 containing either five or more buildings intended for human occupancy or any portion of a paved surface, including shoulders, of a designated interstate, other freeway, expressway, as well as any other principle arterial roadway with four or more lanes.

6.2.2.2 Implementation or System Design Strategy

6.2.2.2.1 IMP Overview

The goal of an IMP is to assess the integrity of pipeline systems by identifying threats and implementing programs to monitor pipeline conditions to minimize potential incidents and blowdowns. A comprehensive IMP can be used to assess pipeline risks and initiate measures to prevent intentional venting before it is necessary.

An IMP includes a set of fully integrated safety management, operations, maintenance, and risk assessment and mitigation processes to ensure that operators provide enhanced safety measures and pipeline protection, especially for HCAs. Operators manage IMPs to consider all stages of a pipeline lifecycle—from conception to engineering and design, construction, operation, inspection, assessment, maintenance, and repair/replacement as needed.

Information detailing risks to a pipeline system can come from a variety of sources, such as ILI tools, direct assessment, and construction data. Integrating data is essential to properly manage system integrity; operators must ensure that they are collecting and analyzing the appropriate information to make prudent risk reduction decisions.

Pipeline assessments include ILIs, direct assessments, guided-wave ultrasonics, or pressure testing. During pipeline assessments, operators analyze data collected on pipeline operations—including flow rates and pressures from SCADA systems (Paragraph 4.1.3.2)—to assess pipeline risks through risk models. Based on the results of the risk model assessments, operators may implement necessary changes to the pipeline system to mitigate those risks and prevent incidents from occurring.

Additionally, geographic information systems (GIS), which map attributes along a pipeline, can collect thousands of pipeline integrity data sets that operators can record and analyze to assess pipeline conditions.

Operators use GIS data to assess pipeline threats, assess risk through risk models, and plan for remediation ahead of pipeline blowdowns and pipeline failures.[154] Pipeline upsets and failures can be prevented by proactive integration of these various datasets, in turn reducing the frequency of ESDs and the resulting natural gas emissions.

A key to reducing natural gas emissions is identifying all emission sources, the specific methods of which vary depending on pipeline design, operational, and environmental characteristics.

[154] Additional information on how SCADA information and GIS integrate into risk models is available through PHMSA's report titled, "Pipeline Risk Modeling Overview of Methods and Tools for Improved Implementation," 2020. Available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2020-03/Pipeline-Risk-Modeling-Technical-Information-Document-02-01-2020-Final.pdf.

6.2.2.2.2 Pipeline Integrity Using a Pipeline Integrity Management System (PIMS)

Several commercially available software tools assist operators in maintaining pipeline integrity. One example is an IMP that may be linked with a management system in a PIMS.[155] The software in a PIMS enables safe and efficient pipeline operation, documents risk, tracks regulatory compliance, and provides a clear overview of pipeline network component integrity.

A PIMS allows operators to manage an entire system—including pig launchers and receivers, ESD devices, valves, relief systems, chemical injection facilities, corrosion monitoring, and upstream/downstream equipment—from a central location, increasing efficiency and cost-effectiveness. A full-bodied integrity management system that includes all asset types is critical for prolonging the equipment lifecycle and extending inspection intervals.

An effective PIMS provides the capabilities to:

- Import new pipeline construction data.
- Import ILI data directly.
- Map and plot geographical features or defects, providing a global view of a pipeline system.
- Visually represent completed tasks on a pipeline.
- Offer seamless connectivity to GIS mapping.
- Manage all organization-owned equipment types from a single software platform.
- Perform risk-based inspection assessments.

6.2.2.3 Benefits and Limitations

IMPs can improve pipeline system integrity and efficiency, reduce unplanned downtime, and minimize maintenance and repair costs. Their consistent use also can accomplish the following:

- Document pipeline risk for prioritization and focus on maintenance and repair activities.
- Save money by preventing excessive inspections.
- Increase operator knowledge of pipeline conditions and risk exposure.
- Reduce natural gas emissions during maintenance activities via advanced management practices.

As a result of IMP implementation by pipeline operators, the transmission and storage sectors have significantly reduced natural gas emissions. One success reported by INGAA member

[155] A PIMS is a comprehensive and integrated electronic monitoring framework for examining pipeline integrity under normal operating and upset conditions, and for selecting the appropriate activity to reduce leaks or ruptures when required.

companies used pipeline integrity and maintenance programs to reduce the number of natural gas pipeline emission leaks by approximately 90 percent from 1986 to 2016.[156]

6.2.2.4 Safety and Feasibility Impacts

IMPs are required for integrity assessments in HCAs.

7 Conclusion

Opportunities to reduce natural gas emissions exist across all sectors. For example, compressor stations and equipment—such as compressors and blowdown systems—can be designed for new installations or modified in existing systems to reduce natural gas emissions. Beginning to replace gas-fired compressor engines with electric compressors, to the extent possible, can address a significant source of natural gas emissions. Additionally, gas from an idle compressor that is bled into a compressor station's fuel gas system can reduce natural gas emissions. Furthermore, natural gas emission reduction can be achieved by using a wet seal degassing recovery system in centrifugal compressors, or by replacing wet seals in centrifugal compressors with dry seals that do not use oil.

Current technologies and practices that reduce or eliminate natural gas emissions are required for several applications. For example, 49 CFR § 192.383 mandates the installation of EFVs on residential and small commercial service lines in certain situations. Installing EFVs on new or renewed high-pressure polyethylene service lines can result in lower volumes of blowing gas after excavation damage and the decreased potential of ignition from static electricity.

Another example is the practice of pipeline purging, a routine process during which gas from new mains and service lines as well as replaced or abandoned facilities is vented into the atmosphere. Capturing this gas from pipeline facilities by using equipment such as drawdown compressors can significantly reduce the amount of gas released into the atmosphere during purging; however, an evaluation of logistical issues is needed to assess viability and safety impacts to operations.

Implementing BATs and practices through new or expanded programs can also significantly reduce or even eliminate harmful GHG emissions. PHMSA is in the process of issuing rulemakings that can help address the reduction of natural gas emissions.

[156] INGAA, "Improving Methane Emissions from Natural Gas Transmission and Storage," August 2018. (p. 5). Retrieved from https://www.ingaa.org/File.aspx?id=34990&v=56603504.

Appendix A BATs for UNGS and LNG

In addition to relevant BATs highlighted in this report that would apply to UNGS and LNG sectors, this Appendix includes either additional BATs specific to those sectors or expands on discussion in the body of the report.

The following can also be used for UNGS to assist with reduction of natural gas releases directly or indirectly:

- Gamma Ray Neutron for gas accumulation
- Mechanical Integrity Testing for pressure testing
- Spinner Logging for leak detection
- Wireline logging - Magnetic Flux Logs (MFL) - *Corrosion detection*
- Wireline logging - Temperature Logs - *Leak detection*
- Wireline logging - Caliper Logs - Corrosion *detection*
- Wireline logging - Cement Bond Logs (CBL) - I*ntegrity of seal detection*
- Wireline logging - Downhole Camera - Corrosion*/Leak detection*
- Leak detection Surface - Combustible Gas Indicator (CGI) - *Leak detection*
- Leak detection Surface – Forward-looking Infrared (FLIR) Optical Gas Imaging - *Leak detection Handheld/Vehicle/Airborne*
- Leak detection Surface - Remote Methane Leak Detector (RMLD) - Leak *detection Handheld/Vehicle*

For LNG, methods to minimize planned and unplanned venting from equipment at an LNG facility include installing a closed vapor handling system to route the gas to a flare, fuel gas handling system, or low-pressure pipeline. The largest pressure safety valves (PSVs) at LNG plants are those used to protect the LNG tanks, compressors, and vaporizers, and these PSVs are vented directly to the atmosphere. It would help to reduce emission during operation if these large PSVs are routed to a closed vapor handling system and then to the flare, pipeline, or fuel gas.

Appendix B Acronyms and Abbreviations

§	Section
°F	Degrees Fahrenheit
AFR	Air/Fuel Ratio
AGA	American Gas Association
ANSI	American National Standards Institute
API	American Petroleum Institute
ASC	Accredited Standards Committee
ASME	American Society for Mechanical Engineers
BAT	Best Available Technology
Bcf	Billion Cubic Feet
Btu	British thermal unit
CCAC OGMP	Climate & Clean Air Coalition Oil and Gas Methane Partnership
cfh	Cubic Feet per Hour
cfm	Cubic Feet per Minute
CI	Cast-Iron
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DI&M	Directed Inspection and Maintenance
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EDF	Environmental Defense Fund
EFV	Excess Flow Valve
EIA	U.S. Energy Information Administration
EO	Executive Order
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
GHG	Greenhouse Gas
GHGI	Greenhouse Gas Inventory
GHGRP	EPA GHG Reporting Program
GIS	Geographic Information Systems
GPTC	Gas Piping Technology Committee
GWP	Global Warming Potential
HCA	High-Consequence Area
hp	Horsepower
HVAC	Heating, Ventilation, and Cooling
ILI	Inline Inspection
IMP	Integrity Management Program
INGAA	Interstate Natural Gas Association of America
kt	Kiloton
LNG	Liquefied Natural Gas
MAOP	Maximum Allowable Operating Pressure

MCA	Moderate Consequence Area
Mcf	Thousand Cubic Feet
Mcfh	Thousand Cubic Feet per Hour
Mcfm	Thousand Cubic Feet per Minute
MMT	Million Metric Tons
MT	Metric Ton
NA	Not Applicable
NFPA	National Fire Protection Association
NPRM	Notice of Proposed Rulemaking
NTSB	National Transportation Safety Board
OAQPS	Office of Air Quality Planning and Standards (EPA)
O&M	Operations and Maintenance
OSHA	U.S. Occupational Health and Safety Administration
PC	Pneumatic Controller
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIMS	Pipeline Integrity Management System
PIPES Act of 2020	Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020
ppm	Parts per Million
PRCI	Pipeline Research Council International
PRO	Partner Reported Opportunities
PSE&G	Public Service Electric and Gas
PSEP	PHMSA Pipeline Safety Enhancement Program
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
R&D	Research and Development
SCADA	Supervisory Control and Data Acquisition (system)
scf	Standard Cubic Feet
scfh	Standard Cubic Feet per Hour
scfm	Standard Cubic Feet per Minute
scm	Standard Cubic Meter
TEG	Triethylene Glycol
VOC	Volatile Organic Compound
VRT	Vapor Recovery Tower
VRU	Vapor Recovery Unit
wc	Water Column (inches)