

Guidance Manual for Operators of LP Gas Systems



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April, 2017



US Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

TO THE READER

The U.S. Office of Pipeline Safety promotes the safe transportation of gas by pipeline. This guidance manual for operators of small Liquid Petroleum (LP) gas systems is part of our commitment to pipeline safety. This manual was developed to provide an overview of pipeline compliance responsibilities under the Federal pipeline safety regulations. It is designed for the non-technically trained person who operates an LP gas system.

The Federal government recognizes that many of the safety regulations are written in technical language that addresses generic requirements for both large and small LP gas systems. This manual attempts to simplify the technical language of the regulations.

For certain critical regulations, this manual provides details of methods of operation and selection of materials that will satisfy the pipeline safety regulations. However, this is often only one of several allowable options. This manual provides a set of examples that operators of small LP gas systems can use to meet the minimum requirements of the pipeline safety regulations.

Our aim is to provide basic information to operators of LP gas systems to ensure compliance with the Federal gas pipeline safety regulations. It is hoped that this document will assist operators in achieving and maintaining a safe and efficient system. The result will enhance public safety – the essential goal of the Office of Pipeline Safety.

Alan Mayberry
Associate Administrator for Pipeline Safety

ACKNOWLEDGEMENTS

This guidance manual was revised by the American Public Gas Association (APGA) Security and Integrity Foundation (SIF) under a cooperative agreement with the U.S. Department of Transportation. The manual relies on sources representing the best opinion on the subject at the time of publication. It should not, however, be assumed that all acceptable safety measures and procedures are mentioned in this manual. The reader is referred to the Code of Federal Regulations (49 CFR Parts 190-199 and Part 40) for the complete pipeline safety requirements.

The Office of Pipeline Safety (OPS) gratefully acknowledges the contributions of the many individuals and organizations who contributed their time and expertise to this manual. Most especially, it is a product of close cooperation with the National Association of Pipeline Safety Representatives (NAPSR), National Propane Gas Association (NPGA), LP Operators, State and Federal pipeline safety representatives.

The advisory group involved in the revision of this manual included:

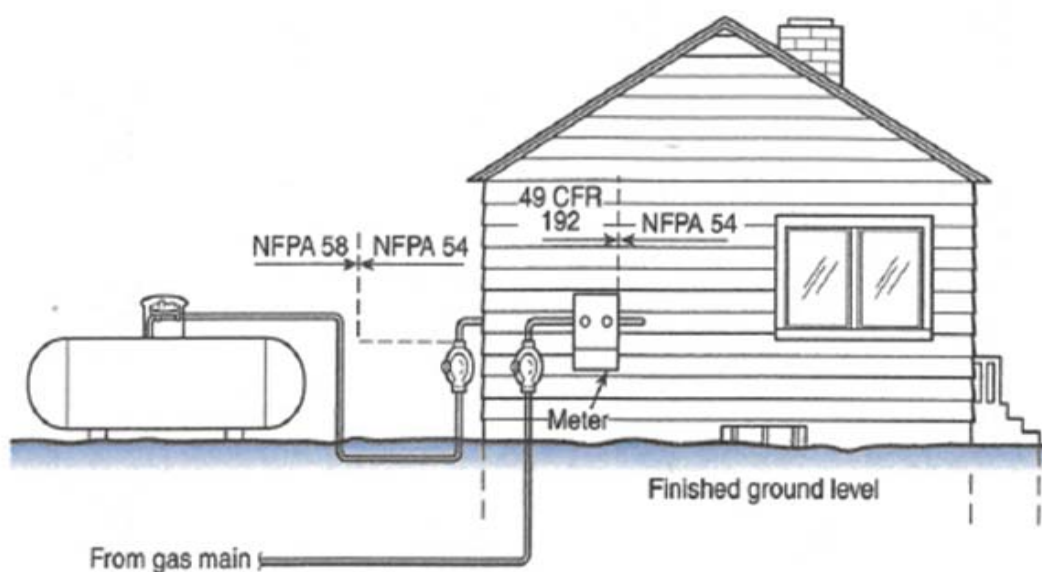
Richard G. Marini, P.E., APGA SIF, Project Manager
John Erickson, APGA Vice President
Bruce Benson, Connecticut Department of Energy & Environmental Protection
Ed Boden, AmeriGas
Mike Deegan, Clearwater Gas System, Florida
James Hilliard, Revere Gas, Virginia
Gerry Lee, APGA SIF
G. C. Morris, Vermont Department of Public Service
Jim Osterhaus, Railroad Commission of Texas
Kevin Streeter, PHMSA Office of Pipeline Safety Central Region
Bruce Swiecicki, National Propane Gas Association
Rufus Youngblood, Ferrell Gas

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INTRODUCTION

The purpose of this guidance manual is to recognize jurisdictional systems requirements and what responsibilities are required of companies that install and service jurisdictional systems. The U.S. Department of Transportation has developed minimum pipeline safety regulations that are published in Title 49 of the Code of Federal Regulations (CFR), Parts 190,191, 192, 199, and Part 40.

“Jurisdictional system” is a term used to describe a propane gas system that is regulated primarily by State and Federal government. A jurisdiction system ends at the outlet swivel of the meter (customer meter) or the connection to a customer’s piping, whichever is further downstream. Propane systems that serve single customers (such as a private residence) are not considered jurisdictional and therefore are not addressed in this guidance manual.



Some jurisdictional systems are served by a master meter. This is a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, a housing project, or an apartment complex where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer, who either purchases the gas directly through a meter or by other means, such as through a rental agreement. The master meter operator is the person or company that engages in the transportation of propane through a pipeline. Often the master meter operator is the propane marketer. However, if the ownership of the propane changes hands at the tank from the propane company to another entity, such as a condo association or mobile home

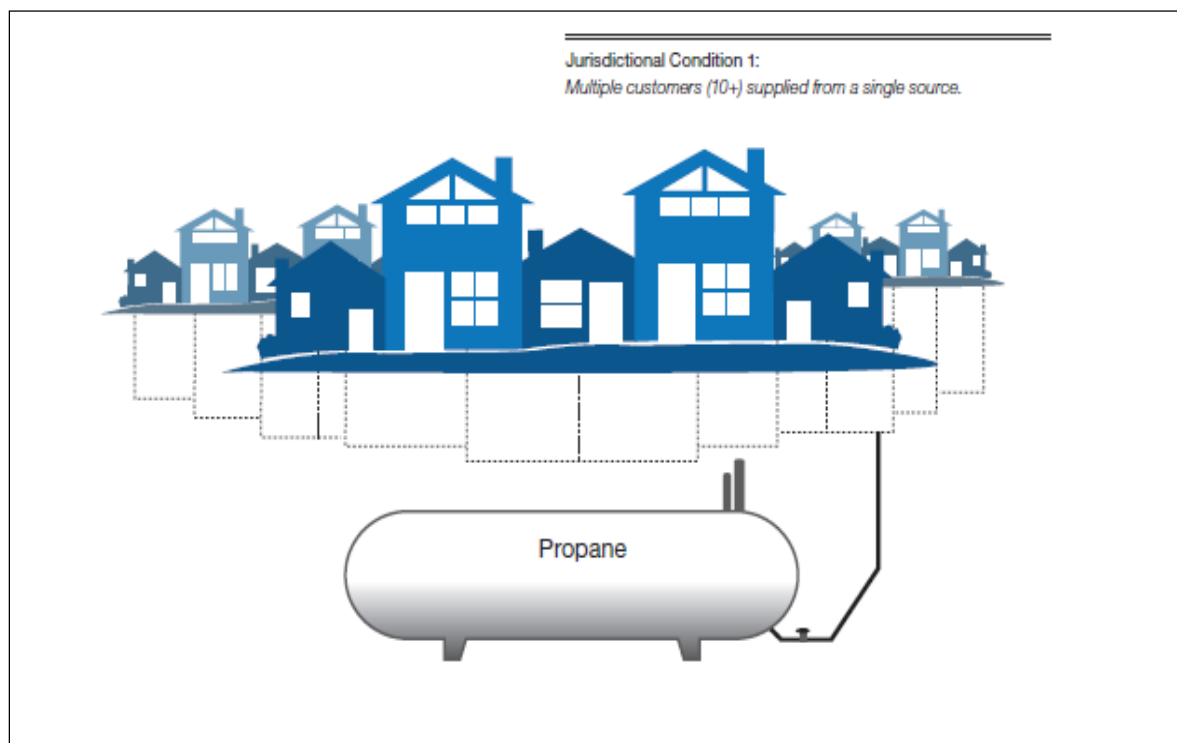
park owner, then that entity (i.e., condo association) is responsible for operating and maintaining the system and becomes the master meter operator.

A propane system is jurisdictional where one of the following conditions exists:

Condition 1: Multiple customers (10+ supplied from a single source).

Ten or more customers are supplied from a single tank or multiple tanks manifolded together. The propane tank's/tanks' location in this scenario does not matter.

This system could be a single apartment building with 10 or more apartments, an apartment complex of two or more buildings, a condominium complex, a mobile home park, a campground, etc. As long as there are 10 or more customers serviced by the system, *it is jurisdictional*.

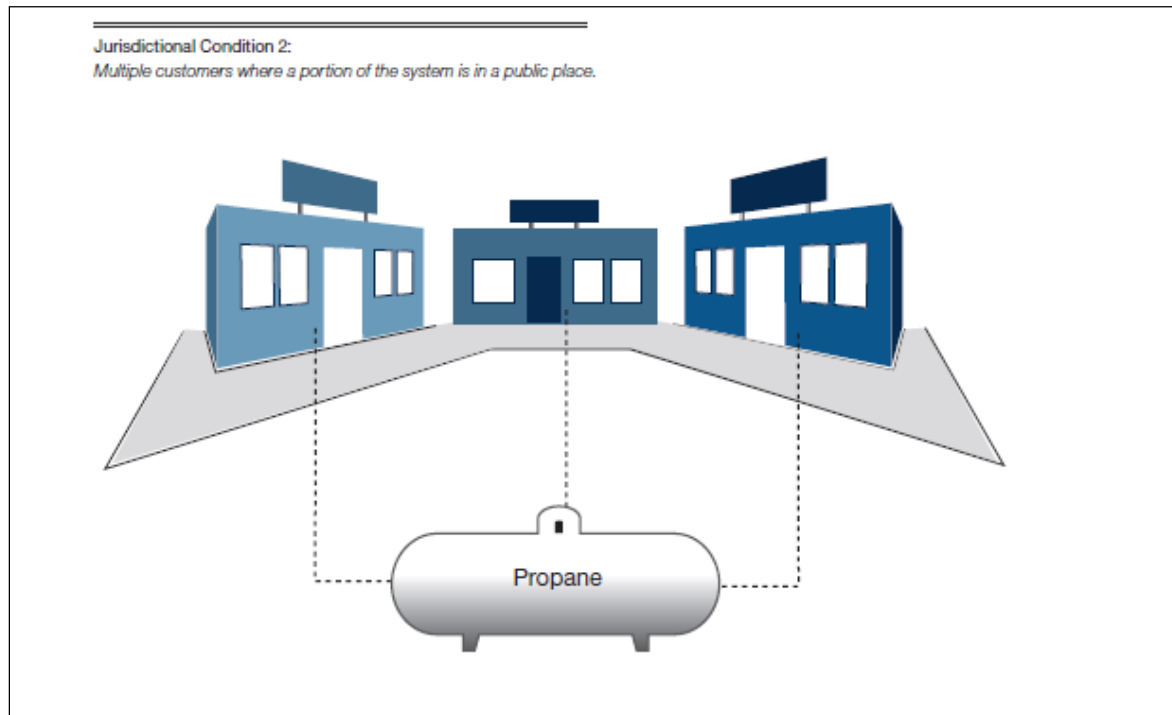


Condition 2: Multiple customers, where a portion of the system is in a public place.

More than one customer is supplied from a single tank or multiple tanks manifolded together, where a portion of the system is located in a public place. A customer is defined as an end user who has control of the gas usage.

This system could consist of a strip mall with several businesses; a manufacturing business that has a credit union within it (the credit union is open to the public); a condominium complex with less than 10 customers, if it has a laundromat open to the public (with gas dryers) and is tied into

the same gas system; or a real estate office and a dentist in the same building, if both have a propane appliance controlled by each individual business.



Note: A container or containers and associated piping supplying a single user is normally not jurisdictional, depending on whether the entire system is located entirely on the customer premises.

The pipeline safety regulations require operators of LP gas systems to:

- Deliver gas safely and reliably to customers;
- Provide training and written procedures for employees;
- Establish written emergency procedures to minimize the hazards resulting from LP gas pipeline incidents; and
- Keep records of periodic inspections and testing

LP gas operators who do not comply with the safety regulations may be subject to civil penalties, compliance orders or both. If safety problems are severe, a "Hazardous Facility Order" may be issued by Federal or State pipeline safety inspectors. This could result in the shutdown of the system.

Often, State agencies enforce pipeline safety regulations under certification by OPS. The State agency is allowed to adopt additional or more stringent safety regulations for intrastate pipeline transportation as long as such regulations are compatible with the Federal minimum regulations. However, if a State agency is not certified, the U.S. Department of Transportation retains jurisdiction over intrastate pipeline systems.

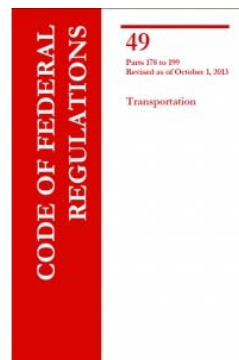
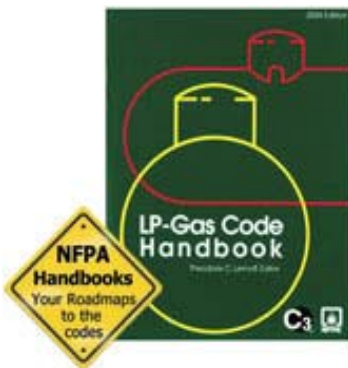
Operators should check with the pipeline safety agency in their State to determine:

- Whether a State agency has safety jurisdiction over their specific type of LP gas system;
- Whether the State agency has pipeline safety requirements that exceed the Federal regulations; and
- The inspection and enforcement procedures of the State agency.

A jurisdictional system that transports only LP gas or LP gas/air mixtures must meet the requirements of the Code of Federal Regulations (49 CFR Parts 190-199 and Part 40) and NFPA 58 and 59.

Additional guidance on determining if an LP piping system is subject to Federal pipeline safety regulations can be found in the “Propane Jurisdictional Systems: A Guide to Understanding Basic Fundamentals and Requirements” available at www.propanecouncil.org.

An operator should check with the authority having jurisdiction in the State where the pipeline is installed to determine the requirements for compliance.



DEFINITIONS AND TERMS

To understand this manual, LP gas system operators need to know the meaning of some commonly used terms in the gas industry. The terms are defined below for the purpose of this guidance manual. The reader is referred to 49 CFR Part 192 and NFPA Standards for additional definitions.

CFR

Code of Federal Regulations

Customer

An end user who has control of the gas usage

Jurisdictional System

A propane system that serves multiple dwellings, buildings, or businesses. It can also include single dwellings, buildings, or businesses when the system is not entirely on the customer's premises and a portion of the system is in a public place. According to OPS enforcement policy, jurisdiction ends at the outlet swivel of the meter (customer meter) or the connection to a customer's piping, whichever is further downstream.

Master Meter System

A master meter system as defined by § 191.3 is a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, a housing project, or an apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer, who purchases the gas directly through a meter or by other means, such as through a rental agreement.

NFPA

National Fire Protection Association

Operator

A person or company who engages in the transportation of gas. An operator could be a propane marketer, a gas utility company, a municipality, or an individual operating a propane system in a housing project, an apartment complex, a condominium, a mobile home park, a shopping center, or another location.

OPS

The Office of Pipeline Safety (OPS) administers the Department of Transportation's Pipeline and Hazardous Material Safety Administration's national regulatory program to ensure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline.

PHMSA

The Department of Transportation's Pipeline and Hazardous Material Safety Administration.

Public Place

A place that is generally open to all persons in a community as opposed to being restricted to specific persons. Examples of public places include churches, schools, and commercial buildings, as well as any publicly owned right-of-way or property frequented by a person.

Public Right-of-Way

A tract of land, paved or unpaved, where the public has a right to walk, and in some cases to ride horses, bicycles, or drive motor vehicles.

Transportation of Gas (as defined in §192.3)

The gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

REGULATORY POSITION OF THIS GUIDANCE MANUAL

The overarching standards utilized in the development of this liquefied petroleum (LP) facilities guidance manual include federal regulation 49 CFR Part 192 (Through Amendment 192-117; 06.06.2011), which “incorporates by reference” (IBR) the 2004 edition of NFPA 58 “LP-Gas Code” and the 2004 edition of NFPA 59 “Utility LP-Gas Plant Code.” Compliance with these requirements, and the application of the concepts found within this guidance manual, are subject to the approval of the authority having jurisdiction (AHJ) who is responsible for enforcing the requirements of 49 CFR Part 192 and applicable IBR’s.

In view of the ongoing regulatory and consensus standard developments between regulatory authorities, industry stakeholders, technical societies, and other interested parties, there exists the potential for revisions to both federal regulations and referenced consensus standards. Consequently, these revisions could impact the applicability of some of the manual’s compliance guidance material, but not the concepts presented within it. Again, the AHJ should always be consulted for final guidance as to what constitutes stakeholder compliance.

Finally, it should be understood that this guidance material was developed to assist primarily small operators who may not have the resources for this scope of work, but are committed to regulatory compliance for the sake of pipeline safety.

CFR TIMELINE FOR PIPELINE AND LPG REGULATIONS UP TO 1970

1880 – ASME was founded for engineers to discuss concerns brought on by industrialization and mechanization.

1884 - ASME established the Boiler Testing Code

1905 – A boiler explosion at the Grover Shoe Factory disaster in Brocton Massachusetts killed 58 and injured 117.

1915 – ASME established the Boiler and Pressure Vessel Code

1916 - The American Institute of Electrical Engineers (now IEEE) invited the American Society of Mechanical Engineers (ASME), the American Society of Civil Engineers (ASCE), the American Institute of Mining and Metallurgical Engineers (AIME) and the American Society for Testing Materials (now ASTM International) to join in establishing an impartial national body to coordinate standards development, approve national consensus standards, and halt user confusion on acceptability. These five organizations, who were themselves core members of the United Engineering Society (UES), subsequently invited the U.S. Departments of War, Navy and Commerce to join them as founders

1919 - The American Engineering Standards Committee (AESC) was founded by six Stanton engineering societies and three government agencies.

1928 – Renamed the American Standards Associations, (ASA)

1935 – ASA issued the document, B31.1 American Tentative Standard Code for Pressure Piping, it later became B31.8 – Gas Transportation Piping

1938 – The Natural Gas Act gave the Federal Power Commission authority over the interstate natural gas industry mainly to control monopolistic pricing

1966 – Renamed the United States of America Standards Institute (USASI)

1969 – Finally renamed the American National Standards Institute (ANSI)

08/12/1968 – Natural Gas Pipeline Safety Act became law

04/08/1970 – NPRM, Section 192.9 sets forth special requirements for liquefied petroleum gas (LPG) systems which are presently contained in section 862 of the B31.8 Code. Although the Act does not apply to “liquefied” gas, it does apply to any pipeline facilities that are used in the transportation of a gaseous product. The USAS B31.8 Code required these systems to comply with both the B31.8 Code and NFPA Standards 58 and 59. This has been clarified slightly by adding a sentence to provide that, in the event of conflicting provisions, Part 192 standards will govern.

<http://www.phmsa.dot.gov/pipeline/historical-rulemaking>

April 8, 1970

OPS-3G, NPRM April 8, 1970 35 FR 5713

“Section 192.9 sets forth special requirements for liquefied petroleum gas (LPG) systems which are presently contained in section 862 of the B31.8 Code. Although the Act does not apply to “liquefied” gas, it does apply to any pipeline facilities that are used in the transportation of a gaseous product. The USAS B31.8 Code required these systems to comply with both the B31.8 Code and NFPA Standards 58 and 59. This has been clarified slightly by adding a sentence to provide that, in the event of conflicting provisions, Part 192 standards will govern.

Appendix C-Documents Incorporated by Reference...

D. National Fire Protection Association:...

2. NFPA Standard 58 is titled “Storage and Handling, Liquefied Petroleum Gases.” (1963 edition).
3. NFPA Standard 59 is titled “LP Gases at Utility Gas Plants.” (1962 and 1963 addendum)”

§ 192.9 Propane and other petroleum gas systems.

(a) No operator may transport propane or other gas, or gas mixture, unless the gas system meets the requirements of this part and of NFPA Standards No. 58 and No. 59. In the event of a conflict, the requirements of this part prevail.

(b) Liquefied petroleum gas systems must comply with the following:

(1) Above ground structures must have open vents near the floor level.

(2) Below ground structures must have forced ventilation that will prevent any accumulation of gas.

(3) Relief valve discharge vents must be located so as to prevent any accumulation of gas at or below ground level.

(4) Special precautions must be taken to provide adequate ventilation where excavations are made to repair an underground system.

Appendix C – Material Incorporated by Reference

2. NFPA Standard 58 is titled “Storage and Handling, Liquefied Petroleum Gases” (1963 edition)

3. NFPA Standard 59 is titled “LP Gases at Utility Gas Plants” (1962 and 1963 addendum)

08/19/1970

§192.11 Petroleum gas systems.

(a) No operator may transport petroleum gas in a system that serves 10 or more customers, or in a system, any portion of which is located in a public place (such as a highway), unless that system meets the requirements of this part and of NFPA Standards No. 58 and No. 59. In the event of a conflict, the requirements of this part prevail.

(b) Each petroleum gas system covered by paragraph (a) of this section must comply with the following:

(1) Aboveground structures must have open vents near the floor level.

(2) Below ground structures must have forced ventilation that will prevent any accumulation of gas.

(3) Relief valve discharge vents must be located so as to prevent any accumulation of gas at or below ground level.

(4) Special precautions must be taken to provide adequate ventilation where excavations are made to repair an underground system.

(c) For the purpose of this section, petroleum gas means propane, butane, or mixtures of these gases, other than a gas air mixture that is used to supplement supplies in a natural gas distribution system.

[Part 192 - Org., 35 FR 13248, Aug. 19, 1970]

2. NFPA Standard 58 “Storage and Handling, Liquefied Petroleum Gases” (1969 edition).

3. NFPA Standard 59 “LP Gases at Utility Gas Plants” (1968 edition).

03/18/ 1993

§192.11 Petroleum gas systems.

(a) No operator may transport petroleum gas in a system that serves 10 or more customers, or in a system, any portion of which is located in a public place (such as a highway), unless that system meets the requirements of this part and of ANSI/NFPA Standards No. 58 and No. 59. In the event of a conflict, the requirements of this part prevail.

(b) Each petroleum gas system covered by paragraph (a) of this section must comply with the following:

(1) Aboveground structures must have open vents near the floor level.

(2) Below ground structures must have forced ventilation that will prevent any accumulation of gas.

(3) Relief valve discharge vents must be located so as to prevent any accumulation of gas at or below ground level.

(4) Special precautions must be taken to provide adequate ventilation where excavations are made to repair an underground system.

(c) For the purpose of this section, petroleum gas means propane, butane, or mixtures of these gases, other than a gas air mixture that is used to supplement supplies in a natural gas distribution system.

[Part 192 - Org., Aug. 19, 1970, as amended by Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-75, 61 FR 18512, Apr. 26, 1996; Amdt. 192-78, 61 FR 28770, June 6, 1996]

06/06/1996

192.1(b)(4) Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—

(i) Fewer than 10 customers, if no portion of the system is located in a public place; or

(ii) A single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-67, 56 FR 63771, Dec. 5, 1991; Amdt. 192-78, 61 FR 28782, June 6, 1996]

§ 192.11 Petroleum gas systems.

(a) Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and ANSI/ NFPA 58 and 59.

(b) Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and of ANSI/NFPA 58 and 59.

(c) In the event of a conflict between this part and ANSI/NFPA 58 and 59, ANSI/NFPA 58 and 59 prevail.

[Amdt. 192-78, 61 FR 28783, June 6, 1996], [Part 192 - Org., 35 FR 13248, Aug. 19, 1970]

REFERENCE MATERIAL

<http://www.eng-tips.com/viewthread.cfm?qid=195650>

In 1919 the American Engineering Standards Committee (AESC) was formed. It was reorganized in 1928 as the American Standards Associations, (ASA) and later became ANSI. It initiated project, B31, to develop a pressure piping Code. The resulting document, "American Tentative Standard Code for Pressure Piping, ASA B31.1 was issued in 1935.

Rulemaking Archives in PHMSA website, <http://www.phmsa.dot.gov/pipeline/historical-rulemaking>

08/10/2010, 75 FR 48595

When a requirement exists in part 192 that does not exist in NFPA 58 or 59, operators are required to comply with it. A conflict only exists when an operator cannot comply with a requirement in NFPA 58 and 59 because it conflicts with a requirement in part 192. When a conflict exists, NFPA 58 or 59 continue to prevail.

06/06/1996, 61 FR 28773

“And, in accordance with 49 U.S.C. § 60104(b), none of the design, installation, construction, initial testing, or initial inspection requirements of NFPA Standards 58 and 59 would apply under part 192 to peak shaving plants now in existence. So, retrofitting existing plants would not be required.”

Grandfather Clause

United States Code, Title 49, Transportation, 49 USC §60104. Requirements and limitations

(a) ...

(b) *Nonapplication.*—A design, installation, construction, initial inspection, or initial testing standard does not apply to a pipeline facility existing when the standard is adopted.

Things that are retroactive Acronym for retroactive SubParts – KILAMOP (in red below).

A. General requirements

B. Materials

C. Pipe Design

D. Design of Pipeline Components

E. Welding of Steel Pipelines

F. Joining of Materials other than by Welding

G. General Constructions Requirements for Transmission and Mains

H. Customer Meters, Service Regulators, and Service Lines

I. Requirements for Corrosion Control

J. Test Requirements

K. Uprating

L. Operations

M. Maintenance

N. Qualification of Pipeline Personnel

O. Gas Transmission Pipeline Integrity Management

P. Gas Distribution Pipeline Integrity Management

DATES OF “INCORPORATED BY REFERENCE” – FOR USE WHEN INSPECTING
FACILITIES BASED ON THEIR DATE OF CONSTRUCTION FOR CERTAIN CODE
SECTIONS THAT ARE NOT RETRO-ACTIVE

FR Publication	FR PUB DATE	EFFECTIVE DATE	NFPA 58 edition	NFPA 59 edition
Original Document	08/11/70	11/20/70	1969	1968
Incorporation By Reference	03/31/76	07/01/76	1969, 1972	1968
Incorporation By Reference	02/02/81	03/04/81	1979	1979
Incorporated By Reference	03/18/93	04/19/93	1992	1992
Incorporation By Reference	05/24/96	06/24/96	1995	1995
Correcting amendments	09/08/04	07/14/04	1998	1998
Update Of Regulatory References To Technical Standards	06/09/06	06/10/06	2004	2004

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CHAPTER I: REPORTS REQUIRED BY THE FEDERAL GOVERNMENT

The Federal Government requires every LP gas operator to telephone a report of any "incident" and, for some operators, to follow it up with a written report. The Federal Government may also require the LP gas operator to file a "safety related condition" report and an "annual report". This chapter describes briefly each of these reports.

INCIDENT REPORTS

NOTE: Check with your State agency for any additional State reporting requirements. These can include lower dollar amounts of damage, media covering the incident, response by local emergency responders, road closure or evacuation.

It is required to telephone an incident report at the earliest possible moment, **but in any case within one hour:**

- of a release of LP gas from a system and results in one or more of the following:
 - A death or personal injury requiring hospitalization;
 - Estimated property damage of \$ 50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;
 - An event that is significant in the judgment of the operator, even though it was not described above.

This telephone report of an incident should include:

- Identity of reporting operator;
- Name and phone number of individual reporting the incident;
- Location of the incident (city, county, State and street address);
- Time of the incident (date and hour);
- Number of fatalities and personal injuries, if any;
- Type and extent of property damage;
- Description of the incident.

The telephone incident report is made to the National Response Center at:

TOLL FREE (800) 424-8802 IN WASHINGTON, D.C. (202) 267-2675 24 HOURS EVERY DAY

REMEMBER, WHEN IN DOUBT MAKE THE CALL! See 49 CFR § 191.5 for further information.

With the exception of master meter systems, operators of LP gas systems making a telephone report of an incident must **follow it up with a written report.**

ADDRESS FOR INCIDENT REPORTS

All required incident reports must be submitted on Form RSPA F7100.1 to:

Information Resources Manager
Office of Pipeline Safety
Research and Special Programs Administration
USDOT, Room 7128
400 Seventh Street, SW
Washington, D.C. 20590

See 49 CFR §§ 191.7 and 191.9 for further information.

SAFETY-RELATED CONDITION REPORTS

OPS may require operators of LP gas systems to report certain safety-related conditions (SRC).

A written report must be filed within five working days after the operator first determines that a SRC exists, but not later than ten working days after the day the operator discovers the condition.

Each operator who is required to file a SRC report is also required to update the operations and maintenance (O&M) plan to include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that may be safety-related conditions.

Typical conditions that would need to be reported by an LP gas operator include:

- Unintended movement or abnormal loading of pipeline facilities by environmental causes such as earthquakes, landslides or floods, that impair the serviceability of a pipeline;
- Any malfunction or operating error that causes the pressure of a pipeline to rise above its maximum allowable operating pressure plus the pressure build-up allowed for operation of pressure limiting or control devices;
- A leak that constitutes an emergency and is not repaired within five days of determination;

Safety-related conditions that do not require a report include:

- A condition on a customer-owned service line;
- A condition resulting in an incident, as defined in 49 CFR § 191.3.;
- A condition on a pipeline more than 220 yards from any building or outdoor place of assembly, unless it is within the right-of-way of an active railroad, paved road or highway;
- A condition that is corrected before the report filing deadline, except for certain corrosion related conditions.

See 49 CFR § 191.23(b) for further information.

ADDRESS FOR SAFETY-RELATED CONDITION REPORTS

All required written reports must be submitted to:

Information Resources Manager
Office of Pipeline Safety
Research and Special Programs Administration
USDOT, Room 7128
400 Seventh Street, SW
Washington, D.C. 20590

In addition, an LP gas system operator may be required to file a report with the State agency participating in the pipeline safety program. For further details on the filing requirements refer to 49 CFR § 191.7. However, an operator must file a written report that contains all the information as specified in 49 CFR § 191.25(b).

ANNUAL REPORTS

Operators of LP gas systems serving 100 or more customers from a single source must submit an annual report for that system. This report must be submitted on DOT Form RSPA F 7100.1-1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

ADDRESS FOR ANNUAL REPORTS

All required annual reports must be submitted to:

Information Resources Manager
Office of Pipeline Safety
Research and Special Programs Administration
USDOT, Room 7128
400 Seventh Street, SW
Washington, D.C. 20590

CHAPTER II: PLANS REQUIRED BY THE FEDERAL GOVERNMENT

All operators of LP gas systems are required to prepare and follow a manual of written procedures for conducting operations, maintenance and emergency response activities. Most operators comply with this requirement by developing and maintaining a manual that incorporates these plans. The manual shall be prepared before operation of an LP gas system commences and shall be reviewed and updated at intervals not exceeding 15 months, but at least once each calendar year. The manual shall be available at locations where operations and maintenance activities are conducted. These plans should include a written statement, procedure, or other document addressing each specific requirement of §192.605.

The following manuals must be prepared before operations of a pipeline system commence:

1. Operations and Maintenance Manual
2. Emergency Plan
3. Damage Prevention Plan
4. Operator Qualification Plan
5. Public Awareness Plan
6. Integrity Management Plan

NOTE: The Federal DOT/OPS or the state agency certified under the Pipeline Safety Act may after due process require the LP gas operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

OPERATIONS AND MAINTENANCE PLAN

An operations and maintenance plan is required of all LP gas operators by the pipeline safety regulations. The operations and maintenance plan shall be written and followed to help the operator comply with the pipeline safety regulations. Reference 49 CFR §192.603 and Chapter 14 in NFPA 58-2004 for further information.

OPERATIONS PLANS

Each operator shall include in its written plan, procedures for all operations which may be performed on the LP gas system by the operator or on behalf of the operator.

The following is a discussion of some of the operations procedures which may be encountered in a typical LP gas distribution system.

The operations topics covered here are:

- Operating pressure,
- Pressure testing,
- Purging of the LP gas pipeline distribution facilities,

- Corrosion control,
- Odorization,
- Testing for reinstating a service line,
- Startup and shutdown procedures,
- Abandonment or deactivation of pipeline or LP gas distribution facilities,
- Construction records, maps and operating history,
- Responding to reports of gas odor,
- Incident reporting,
- Unaccounted for gas.

OPERATING PRESSURE

Pressure Regulating Devices

Per the NFPA 58-2004 (LP Gas Code), first stage regulators shall have an outlet pressure up to 10.0 psig and incorporate an integral pressure relief valve, all in accordance with the Standard for LP Gas Regulators, UL 144. These are typically factory set and non-adjustable. This would limit the operating pressure of a typical newly installed system to a maximum of 10 psig downstream of the first stage regulator. First stage regulators are required to be directly attached or attached by flexible connectors to the LP-gas container's vapor service valve.

Some installations may utilize a liquid service pipe from the container to a vaporizer unit. If this is the case, the liquid pipe fittings shall be rated for a minimum 250 psig service pressure. Once the liquid gas is vaporized by the vaporizer, it can either flow through a first stage regulator or a high pressure regulator. The service pressure rating of the pipe and fittings would be based on the outlet pressure of the regulator (10 psig for first stage regulators, system-dependent for high pressure regulators).

Eventually, the pressure will be reduced to the customer requirements.

Gas Piping System

The LP-Gas Code states that polyethylene piping systems shall be limited to underground vapor service not exceeding 30 psig. As discussed in Chapter III concerning materials, steel piping shall be designed at either 125 psig, 250 psig or 350 psig.

These types of factors, based on material design and LP gas properties, can be used in conjunction with a pressure test conducted to verify the integrity of the piping system to arrive at an operating pressure.

Maximum Allowable Operating Pressure (MAOP) determination should be documented in the operator's written plan.

PRESSURE TESTING

Pressure testing shall be performed to verify the integrity of the piping system prior to placing it into service, when newly constructed or upon subsequent modification. Although the LP-Gas Code states that this pressure test can be done at not less than the normal operating pressure of the system, Part 192 Subpart J specifies a more rigorous test. Operators must follow the requirements of Part 192 Subpart J.

Pressure tests should be documented by the qualified personnel performing the pressure test and copies shall be maintained for the life of the system.

Information documented on the pressure test should include:

- Description of facilities,
- Type of pipe material,
- Length of pipe segment,
- Date, time and location of test,
- Time on and off, duration of test,
- Initial and final pressure or recording chart if available,
- Test medium,
- Person conducting the test,
- Ambient conditions, temperature, weather.

PURGING

Purging operations are necessary to both remove air from the piping system when placing it into operation and to remove fuel gas from the system when removing it from service.

Information documented should include:

- Date and time of purge,
- Time on and off, duration of purge,
- Purge medium,
- Person conducting the purge,
- Ambient conditions,
- Further documentation discussed below in the case of facility abandonment.



Purging operations should be performed in accordance with written procedures by personnel with documented qualification in the use of those procedures (i.e., the LP gas distribution system operator should obtain and maintain copies of the operator qualifications of the individuals performing this operation).

Tapping Pipelines Under Pressure

Each tap made on a gas pipeline under pressure must be performed by a crew qualified to make a hot tap

Hot tapping is an alternative procedure that makes a new pipeline connection while the pipeline remains in service, flowing propane gas under pressure. The hot tap procedure involves attaching a branch connection and valve on the outside of an operating pipeline, and then cutting out the pipeline wall within the branch and removing the wall section through the valve. Hot tapping avoids product loss, hydrocarbon emissions, and disruption of service to customers.

Safety manuals and procedural outlines are available from the American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), and other organizations for welding on in-service pipelines for all sizes, flow rates, and locations. These manuals provide information on what to consider during welding, including burn-through prevention, flow in lines, metal thickness, fittings, post weld heat treatment, metal temperature, hot tap connection and welding design, and piping and equipment contents.

Vendor manuals and equipment catalogues are also good sources for determining which size and type of equipment are most appropriate. Several vendors have published comprehensive outlines and guides for performing hot tap procedures, including information on tapping on various materials, job-site evaluation and preparation, selection and installation of fittings and other equipment, and safety precautions. Most importantly, because this is a hazardous procedure, each potential hot tap must be evaluated on a case-by-case basis and a detailed, written procedure should be prepared or reviewed before starting each job to ensure that all steps are taken properly and safely.

It is recommended that the purging requirements published in ANSI Z223.1/NFPA 54 *National Fuel Gas Code* be utilized to perform the purging operation

ODORIZATION

Operators are required to conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable in accordance with 49 CFR 192.625(f).

The NFPA 58 “LP Gas Code” specifies that LP gas be odorized prior to delivery to the bulk plant. The code also requires verification by “sniff-testing or other means, **and the results shall be documented**” when gas is delivered to the bulk plant or in the case where a delivery bypasses the bulk plant. If the documentation required by the LP-Gas Code is not available to the LP gas system operator, then the operator will need to do his own sniff tests to verify odorization and document the results.

The requirements of NFPA do not relieve operators of the requirement to comply with 192.625(f) and is not “in conflict” with the requirements for sniff testing requirements in NFPA 58. Remember, your state and local codes may require odorant to be detectable at levels lower than one-fifth the LEL.

TESTING FOR REINSTATING SERVICE LINES

The written plan shall contain a provision for testing (before placing in service) each service line that is disconnected from the main in the same manner as a new service line (49 CFR § 192.725). Test procedure and documentation are discussed above.

ABANDONMENT OR DEACTIVATION OF FACILITIES

The written plan shall include provisions for shutdown, abandonment or deactivation of facilities (49 CFR § 192.727). When a gas main or service line is abandoned, it shall be physically disconnected from the piping system and open ends effectively sealed. In addition, the operator shall determine the necessity of purging the line. Note: Take into consideration the location and size of the main or service. As a recommendation, pipelines two inches and larger should be purged using an approved method. Guidance for the abandonment and deactivation of facilities can be found in Appendix 2.1.

CONSTRUCTION RECORDS, MAPS AND OPERATING HISTORY

Construction records should include detailed construction plans, modified as appropriate to show the as-built drawing of the facilities. These plans and maps should show in detail following:

- (1) Location of storage containers, pipe, valves, and other system components,
- (2) Pipe specifications, valve type, and operating pressure,
- (3) Other useful information, including abandoned and out-of-service facilities,
- (4) Location of CP test stations and anodes.

The construction records, maps, and operating history should be made available to operating personnel, especially supervisors or those called on to safely operate pipeline facilities or respond to emergencies, or both. Dispatch or gas control personnel should have maps and operating history available. Communications with knowledgeable personnel should be maintained to respond to questions concerning the records, maps, or history if the need arises.

A detailed list of materials should be included. This should provide specifications of the materials used, including manufacturer, size (diameter, wall thickness, etc.), pressure rating, manufacturing standard, etc.

Additional construction records may include:

- Manufacture specifications,
- Joining procedure qualifications,
- Pipe joiner and other operator personnel qualification records,
- Inspection records for visual, destructive and non-destructive testing,
- Pressure test,
- Date of cathodic protection application for steel.

All system modifications should be recorded in detail.

Operating history should include records of all system modifications and repairs, areas of active corrosion, history of areas susceptible to damage and operating pressure records.

DATA GATHERING FOR INCIDENTS

The operator should designate personnel to gather data at the incident site and other locations where records are retained.

For verification and telephonic reporting that an incident has occurred on the operator's facility, the following information should be gathered as soon as possible.

- (1) Time of the incident,
- (2) Location of the incident,
- (3) Number of fatalities and personal injuries necessitating in-patient hospitalization,
- (4) Estimate of property damage, including gas lost,
- (5) Type of incident: leak, rupture, other,
- (6) Whether there was an explosion,
- (7) Whether there was a fire,
- (8) Whether there was a curtailment or interruption of service,
- (9) Environmental impact,
- (10) Apparent cause,
- (11) Component(s) involved and material specification,
- (12) Pressure at the time of incident,
- (13) Estimated time of repair and return to service,
- (14) A 24-hour staffed telephone number.

Procedures should be established for personnel to determine if the event meets the criteria for the Part 191 definition of an "incident" and to make the telephonic report. Alternate personnel should be included in the procedures in case primary personnel are not available. If some of the information is not available, the notification should be made without that information. Any corrections or additional information may be provided later.

For the written Incident Report, see guide material under §192.617 and Guide Material Appendices G-191-2 and G-191-5.

UNACCOUNTED FOR GAS

LP gas systems serving 100 or more customers from a single source are required to file an annual report per 49 CFR § 191.11. Part of this report shall be the system's percentage of unaccounted for gas. Unaccounted-for-gas can be caused by measurement and control errors, system leakage and theft.

Unaccounted-for gas is the difference between the amount of gas purchased and the quantity of gas sold, whether it is more or less. Unaccounted for gas can be also be caused by an error in calculating the remaining LP Gas in the tank. The Liquid Volume Correction Factors which are located in NFPA 58, Annex F must be utilized to determine the remaining LP Gas. It is also possible to have gauges that are not set properly or may have been read incorrectly. A 1% error in a large tank could make it appear that many gallons have been lost, when in fact, nothing has been lost.

The term, "unaccounted-for gas," does not always indicate a leak. Leakage is only one of a number of factors contributing to unaccounted-for gas. There are varieties of conditions that may contribute to unaccounted-for gas. For a given gas leak, each system will be affected differently by these conditions because there are no two systems exactly the same as to piping and customer mix.

The causes for unaccounted-for gas can be grouped into two categories. One is leaks and the other gas measurement. Leaks are defined as gas escaping to the atmosphere at a given rate at an unknown location. The rate of gas loss is dependent on the pressure and the size of the hole. Normally, gas leakage will be at a fairly constant rate and will increase gradually with time if not located and repaired. Gas lost through measurement or the lack of measurement is very deceptive and at times very difficult to detect. Gas measurement is defined as the accounting of all gas bought and sold.

Temperature and pressure affect gas density. For this reason, temperature-compensating meters are widely used. For customers with high gas usage, the meter can be located upstream of the second stage pressure regulator so that a smaller (less costly) meter can be used. Where the meter is located upstream of the second stage pressure regulator, a constant pressure shall be maintained. Otherwise meter readings will not be accurate and can lead to an amount of unaccounted-for-gas. Pressure-compensating meters are available. The better the control on gas measurement, the easier it is to spot problems in other areas that affect unaccounted-for-gas. Unaccounted-for-gas is a serious problem. By taking a positive approach, the majority of the causes can be determined and corrected.

MAINTENANCE PLANS

During the required periodic maintenance and patrolling checks that are required by the Federal Pipeline Safety Regulations, operators should observe the system to ensure that there are no violations of NFPA 58. Maintenance manuals are required in Chapter 14 of NFPA 58-2004.

Maintenance plans shall address the following components in addition to the applicable requirements of § 192.605:

1. Pressure-limiting devices,
2. Key valves,
3. Patrolling,
4. Accidental ignition of gas,
5. Leakage surveys,
6. Corrosion testing and maintenance,
7. Atmospheric corrosion control monitoring and maintenance,
8. Other requirements of NFPA 58.

PRESSURE LIMITING DEVICES

It is important that all systems operate within their intended acceptable pressure limits. Devices shall be maintained annually to ensure that they are:

- In good mechanical condition,
- Capacity is adequate,
- Set to function at correct pressure,
- Properly installed and protected from vehicular traffic, dirt, liquids, icing and other conditions that might prevent proper operation.

Lock up testing and/or the use of a pressure recording device are ways to prove regulator stability. First stage regulators are now required to have built-in pressure relief devices per NFPA 58, unless the capacity of the regulator is more than 500,000 Btu/hr. In this case a separate pressure relief valve may be used.

Some LP gas systems use vaporizers in their systems. Hydrostatic relief valves and vaporizer relief valves are normally part of a system that uses vaporizers. The O&M plan should include the methods by which all pressure limiting devices are maintained.

KEY VALVES

Key valves, or critical valves, are the valves needed to shut down the LP system, or part of the LP system, in the event of an emergency. For many LP gas systems, this would be the container main valve. Key valves should be checked at least once per year to ensure that they are operable. Procedures for maintaining these valves shall be included in the maintenance section of the O&M Manual.

PATROLLING

Although this is normally not necessary for small LP gas systems, if a condition exists in the area of an LP gas system where anticipated movement of the pipeline could cause failure or leakage (e.g., weight from construction, area prone to wash out, etc.), then the pipeline shall be periodically patrolled until the condition no longer exists. The frequency of the patrolling shall be determined by the severity of the conditions which could cause failure or leakage and consequent hazards to safety, but no fewer than four times each calendar year in the business district or twice each calendar year outside of the business district. Many operators include the patrolling as a requirement during their annual maintenance or during meter reading.

Some critical items to check during patrolling are:

1. Combustible Material - Loose combustible materials are not stacked within ten feet of the LP gas tank.
2. Fencing – Where a security fence is installed to comply with either NFPA 58 or NFPA 59, it shall be an industrial type fence, chain link fence or equivalent protection at least 6 feet high and in adequate condition. All necessary gates shall be accessible in case of an emergency. Gates shall be locked when operator personnel are not present. An exception to the fence can be made where devices that can be locked in place are provided that prevent unauthorized operation of valves, equipment, and appurtenances.
3. Building Distances - Important buildings have not been added closer to the tank(s) than the permitted distance as listed in Table 6.3.1 of NFPA 58-2004.
4. Signage - Signs that are required on some installations are being maintained. Consult your local authorities having jurisdiction for additional signage requirements – ex. Non-smoking signs.
5. Protection from Damage – All utility gas plants and any above ground piping associated with the pipeline facility should be protected from damage. Reasonable precautions should be taken to prevent damage that may occur from vehicles, weather, etc. Examples of above ground equipment that may need protection include the tank, regulators, meters and risers and above ground pipe.

ACCIDENTAL IGNITION OF GAS

The plan shall include provisions to prevent the accidental ignition of gas. LP-gas alone is not explosive but when mixed with air in a concentration of 2.15% to 9.6% for propane, it can ignite or explode. Every precaution should be taken to prevent unintentional ignition of LP gas. When venting gas to the air a dry chemical fire extinguisher shall be available and positioned for immediate use. Note, the LEL (Lower Explosive Limit) of 2.15% and UEL (Upper Explosive Limit) of 9.6%, will vary depending on the particular grade or mixture of the LP Gas you are using. You must know the LEL is correct, for the LP Gas being supplied to the customer, so that the odorization requirements can be met.

LEAK SURVEY

A survey of an LP residential gas distribution system shall be made as frequently as necessary, but at intervals not exceeding **five years**. If part or all of the system is located in a business district, a gas leakage survey shall be conducted at least **once every year**. Procedures on how to conduct leak surveys shall be included in the maintenance section of the O&M manual.

Some LP gas operators use contractors to leak survey their systems. It is the responsibility of the operator to ensure that the survey is conducted in accordance with the pipeline safety regulations. The operator shall retain a report describing the results of each survey.

LP gas operators shall do a subsurface type of survey when using gas detection equipment to perform their survey. Although a Flame Ionization (FI) unit may be used to assist in the survey, a Combustible Gas Indicator (CGI) shall be used for pinpointing leaks and classifying them.

Numerous LP gas operators opt to do a pressure drop test to prove the integrity of their pipeline. This is normally done on smaller systems, where shutting off the customers is not a problem. **A very important thing to consider is, if you do have any drop in pressure, then you shall do a subsurface survey using a CGI meter to pinpoint the leak.** A pressure drop test tells you if you have a leak. It does not tell you the location of the leak or its classification.

Other things to consider when doing a pressure drop test are:

- Pressure used during the test should be at least equal to the operating pressure,
- Volume of the piping system being tested,
- Time duration of the test should consider; the time for the test medium to become temperature stabilized, and
- Sensitivity of the instrument being used.

An advantage of doing this type of test is that the first stage regulator can be tested for lock up at the same time. Some operators use a portable supply tank on certain systems, and temporarily connect it into a tee just before the second stage regulator. With the proper valving installed ahead of time, they can perform a leak test of the piping and lock up on the regulator without shutting down the system.

For more information on performing leak surveys see Chapter X. This chapter includes useful information from **AGA** and the **Gas Pipeline Technology Committee**.

CORROSION TESTING

Underground steel metallic mains, buried steel components, including underground tanks shall be tested annually to prove that the systems are being cathodically protected. Cathodic protection is not required for polyethylene (PE) piping systems. Although there are five acceptable methods of testing, the most common method being used for small systems is the negative 0.85 dc volt criteria as determined by the use of a volt meter and a reference saturated copper sulfate half-cell achieved through the installation of buried sacrificial anodes. For larger

systems impressed current systems utilizing rectifiers are used. Each system that is cathodically protected must be tested annually, but at intervals not exceeding 15 months to determine whether the cathodic protection is adequate. Criteria to ensure that cathodic protection is adequate can be found in Appendix D of 49 CFR Part 192 aboveground piping and tanks shall be inspected for atmospheric corrosion at no longer than three year intervals (or not exceeding 39 months), although for many LP gas systems it is easy and good practice to observe the condition of the aboveground piping during other annual maintenance. For more information on corrosion and compliance refer to 49 CFR Part 192, Subpart I and CHAPTER VII of this manual.

EMERGENCY PLANS

Each operator is required to maintain a written plan of procedures and other necessary information to meet LP gas emergency situations. The federal regulations for emergency plans are contained in 49 CFR § 192.615 of the Federal Pipeline Safety Regulations. It is also the responsibility of the LP gas operator to be familiar with all State and local regulations as they apply to emergency situations regarding their piping systems. Reference Appendix 2.2 for guidance on what should be contained in the emergency plan.

EDUCATION AND TRAINING PLAN – Operating personnel and other emergency responders shall be qualified to ensure understanding of emergency procedures and equipment. It is the responsibility of the operator to conduct adequate training and to keep associated documentation of the training. Training should include:

- Updating of the written emergency plans,
- Review of personal responsibilities in emergency situations,
- Review of location and use of emergency equipment,
- Properties of LP gas,
- Review the locations and use of system maps and records, maintenance records, valve records and operating procedures,
- Review of typical emergency situations to reinforce the step-by-step actions to be followed in emergencies. This includes methods of contacting public officials, firefighters, police and LP gas distributors,
- Review of record keeping requirements, and
- Review the procedures for making telephonic and written reports.

DAMAGE PREVENTION PROGRAM

All operators must maintain written procedures and accurate documents to substantiate compliance with the Code of Federal Regulations 49 CFR § 192.614. See Chapter 6 Damage Prevention which will provide the necessary information to establish required procedures.

OPERATOR QUALIFICATION PLAN

All operators must have written Operator Qualification (OQ) Plans. OQ plans describe how the operator will ensure that individuals performing safety-sensitive tasks have the necessary knowledge, skills and abilities to perform those tasks and recognize and react to any abnormal operating conditions they may encounter. See the OQ Guide for Small LP Distribution Systems for information on OQ programs.

PUBLIC AWARENESS PLAN

The operator shall develop and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter or petroleum gas system is located on property the operator does not control, the operator shall provide similar messages twice annually to persons controlling the property.

The public awareness message shall include:

1. A description of the purpose and reliability of the pipeline,
2. An overview of the hazards of the pipeline and prevention measures used,
3. Information about damage prevention,
4. How to recognize and respond to a leak, and
5. How to get additional information.

Other items to consider on the message:

- Information about the properties of LP gas,
- Recognition of the odorants used in LP gas,
- Actions to take when a strong gas odor is present,
- Applicable One-Call procedures prior to excavation,
- 24-hour telephone numbers for reporting gas leaks.

This educational information may be conveyed to the interested parties by a number of means, including:

- Radio and television,
- Newspapers and newsletters,
- Public meetings and one-on-one encounters,
- Bill stuffers, mailings and handouts,
- Billboards and bulletin boards,
- Electronic Media such as emails, social media and websites.

If a significant percentage of the population in the area of the LP piping system does not speak English, the operator should provide materials in the language understood by the non-English speaking community. The operator must maintain records of the public education program. Many excellent educational pamphlets and other training aids are available from the Propane Education and Research Council. Their address is:

Propane Education and Research Council - www.propanecouncil.org

DISTRIBUTION INTEGRITY MANAGEMENT PLAN (DIMP)

No later than August 2, 2011, the operator of a master meter system or a small LPG operator must develop and implement an Integrity Management (IM) program that includes a written IM plan. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

A written integrity management plan must address, at a minimum, the following elements:

- (1) The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).
- (2) The operator must consider, at minimum, the following categories of threats (existing and potential): Corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.
- (3) The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.
- (4) The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.
- (5) The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.
- (6) The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

The operator must maintain, for a period of at least 10 years, the following records:

- (1) A written IM plan in accordance with this section, including superseded IM plans;
- (2) Documents supporting threat identification; and
- (3) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

Reference Appendix 2.3 for additional guidance on what is recommended to be included in the DIMP.

PHMSA Form 23 – Master Meter and Small LPG Operator DIMP Inspection includes questions related to specific regulatory requirements (See Appendix 2.3 – Guidance for Distribution Integrity Management Plans for the link to PHMSA's DIMP website).

APPENDIX 2.1: GUIDANCE FOR ABANDONMENT OR DEACTIVATION OF FACILITIES

Check prior to abandonment

Office records should be checked and necessary field checks should be made to ensure the pipelines or mains scheduled for abandonment are disconnected from all sources and supplies of gas, such as other pipelines, mains, crossover piping, meter stations, customer piping, control lines, and other appurtenances.

Residual gas or hydrocarbons

Abandonment should not be completed until it has been determined that the volume of gas or liquid hydrocarbons contained within the abandoned section poses no potential hazard. Generally, it is advisable to purge 8-inch and larger pipe and long segments of smaller diameter pipe.

Purging

Pipelines or mains may be purged using air, inert gas, or water. If air is used as the purging agent, precautions should be taken to ensure that no liquid hydrocarbons are present. See §192.629 and AGA XK0101, "Purging Principles and Practice" or ANSI Z223.1/NFPA 54 "National Fuel Gas Code for purging of natural gas and liquid hydrocarbons".

Sealing

Acceptable methods of sealing pipeline or main openings include, as applicable, the following.

- (a) Using normal end closures, such as welded or screwed caps, screwed plugs, blind flanges, and mechanical joint caps and plugs,
- (b) Welding steel plate to pipe ends,
- (c) Filling ends with a suitable plug material,
- (d) Pinching the ends closed.

Additional considerations in addition to purging and sealing.

In addition to purging and sealing, consideration should be given to the following.

- (a) Filling the abandoned segment with water or an inert gas to prevent potential combustion hazard, and
- (b) Other action designed to prevent hazardous cave-ins resulting from pipe collapse caused by corrosion or external loading.

Segmenting the abandoned sections.

All valves left in the abandoned segment should be closed. If the segment is long and there are few line valves, consideration should be given to plugging the segment at intervals.

Removal of above-grade facilities and filling voids.

All above-grade valves, risers, and vault and valve box covers should be removed. Vault and valve box voids should be filled with suitable compacted backfill material.

ABANDONMENT OF DISTRIBUTION SERVICE LINES IN CONJUNCTION WITH MAIN ABANDONMENT

Curb valves and curb boxes.

All curb valves should be closed. The top section of curb boxes located in dirt areas should be removed and the void filled with suitable compacted backfill material. If boxes are set in concrete or asphalt, they should be filled with suitable compacted backfill material to an appropriate distance from the top of the box and the fill completed with suitable paving material.

Meter risers and headers.

Meter risers and headers should be dismantled and removed from the premises.

Service lines below-grade through a basement wall.

Where a service line enters below grade through a basement wall, the end of the service line should be plugged and a cap should be installed as close to the face of the wall as practical. It is not necessary to remove pipe from the wall unless required by particular circumstances.

Outside meter set assembly and above-grade entrances.

Service lines terminating at an outside meter set assembly or an above-grade entrance should be cut and capped at an appropriate depth below-grade.

ABANDONMENT OF SERVICE LINES FROM ACTIVE MAINS

Disconnecting.

Service lines abandoned from active mains should be disconnected as close to the main as practical.

Sealing.

The end of the abandoned portion of the service line nearest the main should be plated, capped, plugged, pinched, or otherwise effectively sealed.

Other actions.

The remainder of the service line should be abandoned as recommended in the Abandonment of Distribution Service Lines in Conjunction with Main Abandonment section above.

When service to a customer is temporarily or permanently discontinued, one of the following shall be done:

- The valve shall be closed to prevent the flow of gas to the customer. This valve shall be secured with a lock or some other device to prevent opening of the valve by unauthorized people. There are numerous locking devices designed for this purpose.
- A mechanical device or fitting that will prevent the flow of gas shall be installed in the service line or in the meter assembly.
- The customer's piping shall be physically disconnected from the gas supply and the open ends sealed. (49 CFR § 192.727).

INACTIVE PIPELINES

General.

Each operator should consider the following elements when determining whether to abandon or continue maintaining an inactive pipeline.

- (a) Location (e.g., business district, urban, suburban, rural),
- (b) Type of piping material,
- (c) Joining method (e.g., welding, fusion, compression couplings),
- (d) Cathodic protection,
- (e) Operating pressure,
- (f) Likelihood of reactivation,
- (g) Leakage and maintenance history,
- (h) Proposed construction.

Continuing maintenance.

Provisions for continuing maintenance of inactive pipelines should be included in the procedural manual for operations, maintenance, and emergencies required under §192.605.

Examples of such maintenance include the following.

- (a) Regularly scheduled leak surveys and patrolling,
- (b) Corrosion control monitoring of cathodically protected systems,
- (c) Maps and records for damage prevention,
- (d) Evaluating aboveground piping for the following:
 - (i) Atmospheric corrosion,
 - (ii) Susceptibility to damage from vehicles and other forces,
 - (iii) Unauthorized activities.

INACTIVE SERVICE LINES

In addition to continuing maintenance as listed above, the operator should consider the following for continuing maintenance of inactive service lines.

- (a) Identifying and documenting the location of inactive service lines in a record management system, and
- (b) Developing criteria for abandonment.

APPENDIX 2.2 – GUIDANCE FOR EMERGENCY PLAN PROCEDURES

The written emergency procedures plan should contain the following information:

The names and telephone numbers of the following personnel:

- System operator,
- Fire department,
- Gas company, and
- Other entities or first responders whose service may be necessary in the event of an emergency.

A copy of this list should be posted in a public area.

A map of the system showing the location of key valves must be included. For a small system that supplies one facility from a single tank, where a portion of the system is located in a public place, the map should show the tank, pipeline and customer location, with the tank valve identified as the key valve.

The operator must determine what emergency equipment is needed and ensure it is available. A description of the emergency equipment and its location must be included.

The operator must have written procedures to be followed in response to gas leaks reported by customers. The operator's responsibility is to ensure that all employees are familiar with procedures for responding to gas leak calls and reports.

In case of an incident, a telephonic report must be made immediately to the National Response Center (800-424-8802). An incident is any event involving the release of gas from a pipeline and the occurrence of the following:

- Death or injury requiring hospitalization,
- Estimated property damage of \$ 50,000 or more, and/or
- Unusual occurrence that the operator deems necessary to report.

Qualified persons must follow proper procedures to safely restore gas service after an outage. These procedures should include details of appliance relighting procedures.

Each operator must establish procedures for investigating incidents and failures including the following:

- Evaluating the situation,
- Protecting life and property,
- Securing the area,
- Conducting a leak survey,
- Conducting meter and regulator checks,
- Questioning persons on the scene,

- Examining burn and debris patterns,
- Testing odorization level,
- Recording meter readings,
- Recording weather conditions, and
- Selecting samples of failed facility or equipment.

Each operator is required to keep a written plan of procedures used to respond to emergencies. The emergency plan should contain at minimum the following information:

Checklist for a Major Emergency

- Fire Department called (911)
- Persons evacuated and affected areas blockaded
- Local or regional police notified
- Repair personnel notified
- Company call list executed
- Communication established
- Outside help requested
- Ambulances called if needed
- Leak shut off or brought under control
- Civil defense authorities notified
- Emergency valves or valves to shut down or reroute gas identified and located
- Individual service of each customer shut off (if an area has been cut off from a supply of gas)
- Situation under control and the possibility of reoccurrence eliminated
- Surrounding area, including buildings adjacent to and across streets checked for the possibility of additional gas leakage
- Proper tag placed on affected meters
- Telephone report made to State officials
- Telephone report made to the Office of Pipe Safety (PHMSA)
- Local radio station, notified if necessary

APPENDIX 2.3 – GUIDANCE FOR DISTRIBUTION INTEGRITY MANAGEMENT PLANS

This document provides guidance to help master meter operators and small LPG operators (i.e., those serving fewer than 100 customers from a single source) implement the requirements of Subpart P of Part 192. Operators of larger distribution pipelines should refer to the Gas Piping Technology Committee (GPTC) guidelines.

DISTRIBUTION INTEGRITY MANAGEMENT PLAN

Master meter and small LPG distribution operators should complete the actions described in the following paragraphs. Retain this document and any records generated through actions suggested in this document. This collection of documents will become your integrity management plan.

KNOWLEDGE OF SYSTEM INFRASTRUCTURE

Identify the approximate location of system piping and equipment on maps, drawings, or sketches using the best-available information.

- Plan to update the maps, drawings, or sketches as better information about the location of the system becomes available through other work (e.g., repairing leaks, excavations to install other utilities),
- Arrange to update the maps, drawings, or sketches to show the kind of pipe and equipment (i.e., bare steel, galvanized steel, coated steel, copper, plastic, cast iron, line valves), and
- Record the location, size and type of pipe (i.e., material of construction), and type of equipment (if applicable) from any new installations of pipe or equipment.

IDENTIFY THREATS

Consider the following questions for each threat category and check all that apply. Each threat category, including at least one check, will be considered a threat of concern to be addressed under the distribution integrity management program.

1. Corrosion
 - a. Does the system include steel pipe that is not protected from corrosion (e.g., pipe that lacks coating, wrapping or galvanic protection?)
 - b. Does the system include non-steel pipe but include steel fittings or connectors that are not protected from corrosion?
 - c. Has the system experienced leaks from corroded pipe?
 - d. Does the system include cast iron pipe?

2. Natural Forces
 - a. Are exterior above-ground steel pipe/equipment not grounded (i.e., protected from lightning)?
 - b. Are portions of the system susceptible to snow or ice slide impacting above-ground piping, meter and regulator sets, or meter header piping?
 - c. Are exterior above-ground portions of the system potentially subject to other forces of nature (e.g., earthquakes, floods or waterway scouring, severe flooding leading to uprooting of near-by trees) due to unique local weather conditions? Are buried portions of the system located in areas where soil movement or subsidence is likely (e.g., earthquakes, landslide, flood-induced erosion)?
 - d. Are there large trees near the pipeline that could be uprooted by high winds and whose roots could be entangled with and damage the pipeline if that happens?
3. Excavation Damage
 - a. Are portions of the system buried in areas where digging might occur without your knowledge or control?
4. Other Outside Force Damage
 - a. Are exterior, above-ground portions of the system located in areas where they could be subject to damage from vehicles or other expected activities?
 - b. Is the system located in an area with greater than usual exposure to the possibility of wildfires?
 - c. Is there a history of vandalism to the pipeline system, or is the local area subject to vandalism of a kind that could damage the pipeline system?
5. Material or welds
 - a. Has any of your piping experienced frequent leakage?
 - b. Has the manufacturer of your piping or fittings (appurtenances) contacted you regarding material defects?
6. Equipment Failure
 - a. Does the system include any equipment other than valves, meters, and service regulators?
7. Incorrect Operations
 - a. Does system operation require the manipulation of any equipment other than valves that are permanently installed as part of the system?
8. Other Threats
 - a. Has your piping system experienced any problems that were not identified in the above 7 threat areas?

EVALUATE AND PRIORITIZE RISK

Risk considers both the relative likelihood of an accident occurring and the consequences that would result if it did.

Leak and incident data from gas distribution systems has been used to determine the following relative likelihood that threats might cause a leak or accident on distribution pipelines (from most-likely to cause a problem to least-likely):

1. Excavation damage,
2. Corrosion,
3. Natural forces,
4. Material or welds,
5. Other outside force damage,
6. Incorrect Operations,
7. Equipment Failure,
8. Other threats.

Delete from this list any threat that does not have at least one box checked in the Identify Threats section above. This is your ranked list of threats.

Are the areas in which the pipeline is located generally similar in terms of the number of people who would be present at most times (e.g., residences of similar size, no schools)? If so, your ranked list of threats becomes your ranked list of risks. Divide your list into 3 groups of roughly equal size, group 1 being the lower-numbered (higher-ranked) threats on your list, number 2 those in the middle, and number 3 the higher-numbered. Continue to section (4).

If there are areas in which more people would be near the pipeline at most times (e.g., commercial buildings or schools), divide the pipeline into two regions, one including areas where more people would be present (call this the higher consequence region), and the other areas where there would be fewer people (call this the lower consequence region). Identify these areas on the maps, drawings, or sketches prepared under paragraph 1 above.

Reconsider your list of threats to determine whether they exist in both regions. For example, there may be equipment other than valves, meters, and service regulators in the higher consequences region, but not in the lower. In this case, the equipment threat would not exist in the lower consequences region.

Consider your remaining threat-region combinations in the following groupings. (These groups have been developed from distribution pipeline leak and accident data to represent those combinations of highest to lowest importance for implementing mitigating actions).

Group 1:

- Excavation damage – high and low consequence regions
- Corrosion – high consequence region
- Natural forces – high consequence region
- Material or welds – high consequence region

Group 2:

- Corrosion – low consequence region
- Other outside force – high consequence region
- Natural forces – low consequence region
- Equipment failure – high consequence region
- Incorrect Operations – high consequence region

Group 3:

- Material or welds – low consequence region
- Other Outside Force – low consequence region
- Equipment failure – low consequence region
- Incorrect Operations – low consequence region

IDENTIFY AND IMPLEMENT MEASURES TO MITIGATE RISKS

For all risks in your ranked list, verify that actions are being taken or requirements are in place intended to protect against the threat. This should include, at a minimum, the actions required by Part 192, the additional general monitoring actions listed below, and for each identified threat (or threat-region combination) of concern the actions listed for that threat. Additional monitoring and threat-specific actions should be focused first on threats (or threat-region combinations) in group 1, then on group 2, and finally on group 3.

General Monitoring, additional patrols:

- Periodically walk the course of pipelines that have experienced problems in the past, to look for signs of damage and to smell for gas.
- Periodically walk the lines to check for active excavation or signs of excavation of which you were unaware.

Corrosion

- Coat and cathodically protect steel pipe installed after August 1, 1971.
- Coat and cathodically protect all areas of steel pipe experiencing active corrosion (as indicated by a history of corrosion-caused leaks or current inspection records – see (vi) below).
- Annually monitor and test cathodic protection.
- Inspect rectifiers six times per year.
- Inspect above-ground steel pipe every three years. Inspect annually for pipe with a history of corrosion-caused leaks.
- Inspect buried steel pipe exposed by any digging for evidence of corrosion.

Natural Forces

- Conduct more frequent patrols to identify conditions that may adversely affect pipe or components, especially following lightning storms, earthquakes, landslide, flood-induced erosion, or high winds leading to uprooting of nearby trees.
- Take actions to eliminate the hazard or reduce the threat.

Excavation Damage

- Physically control access to the pipeline, or
- Implement a damage prevention program including the following elements:
 - A means of receiving and recording notification of planned excavation activities.
 - Requirements to locate and mark the pipe in areas where buried piping exists and excavation is planned.
 - Provision for actual notification of persons who give notice of their intent to excavate in areas where buried pipe is located, of the type of temporary markings and how to identify them.
 - Provision for inspection of pipelines during and after excavation if you have reason to believe they could be damaged.

Other Outside Force Damage

- Identify using signs and/or distinctive colors those portions of the system potentially subject to damage.
- Install vehicle barriers as appropriate.
- Conduct patrols to identify at-risk pipe and components and mitigate the risk to the pipe using means such as in (i) and (ii) above.

Material or Welds

- Replace small diameter cast iron pipe not adequately supported.
- Replace brittle plastic pipe or other materials unsuitable for gas service.
- Implement the recommended actions in any notice received from a pipe/fitting manufacturer regarding material defects.
- Monitor more frequently any portions of the system experiencing frequent leakage.
- Where the system has a history of problems with pipe or fittings, replace the pipe or fittings when practical (e.g., when excavations for other reasons expose the pipe).

Equipment Failure

- Implement a program to qualify personnel who operate equipment under 49 CFR Part 192, Subpart N.

Incorrect Operations

- Implement a program to qualify personnel who operate equipment under 49 CFR Part 192, Subpart N.

- Ensure personnel are aware of the precautions to take to prevent over-pressuring a low pressure system, when stopping the flow of gas, and to prevent unsafe gas-air mixtures.

MEASURE PERFORMANCE, MONITOR RESULTS, AND EVALUATE EFFECTIVENESS

Keep a record of:

1. The number of hazardous leaks either eliminated or repaired including the date and the apparent cause of the leak,
2. Any instances in which the system is damaged by excavation, and
3. Any replacement of materials and components from the gas system. Record the type of pipe/component that was removed and the type/component that replaced it.

PERIODIC EVALUATION AND IMPROVEMENT

Revise this checklist whenever changes are made to the pipeline or significant changes occur in the local environment to determine if threats of concern have been eliminated or if new risks have been introduced. Modify the mitigative measures, as appropriate.

REPORT RESULTS

Consistent with the exclusions in 49 CFR §191.9 (incident reports) and §191.11 (annual reports), operators of master meter and small LPG distribution systems need not report performance measures.

DIMP RESOURCES

Resources including Federal inspection forms and answers to frequently asked questions can be obtained from PHMSA at <http://primis.phmsa.dot.gov/dimp>.

Information on the Simple, Handy, Risk-based Integrity Management Plan Program (SHRIMP) and other DIMP-related information can be obtained from the APGA Security and Integrity Foundation (SIF) at www.apgasif.org.

JURIDITIONAL DIAGRAMS

The following diagrams provide guidance on the jurisdictional status of propane systems in various scenarios.

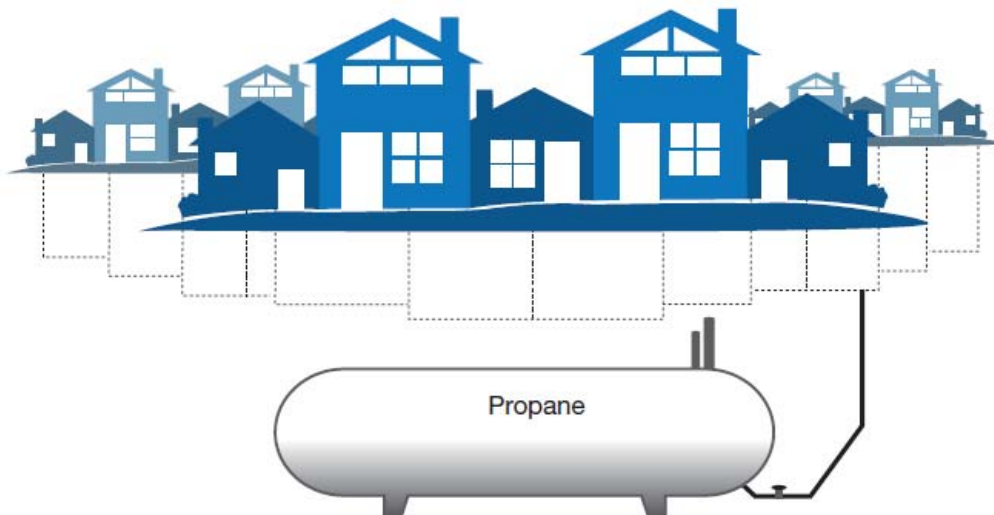
These diagrams are copied with approval from the Propane Education & Research Council's "Propane Jurisdictional Systems: A Guide to Understanding Basic Fundamentals and Requirements". More information is available at www.propanecouncil.org.

Condition 1: Multiple customers (10+ supplied from a single source)

Ten or more customers are supplied from a single tank or multiple tanks manifolded together. The propane tank's/tanks' location in this scenario does not matter.

This system could be a single apartment building with 10 or more apartments, an apartment complex of two or more buildings, a condominium complex, a mobile home park, a campground, etc. As long as there are 10 or more customers serviced by the system, *it is jurisdictional*.

Jurisdictional Condition 1:
Multiple customers (10+) supplied from a single source.



Condition 2: Multiple customers, where a portion of the system is in a public place

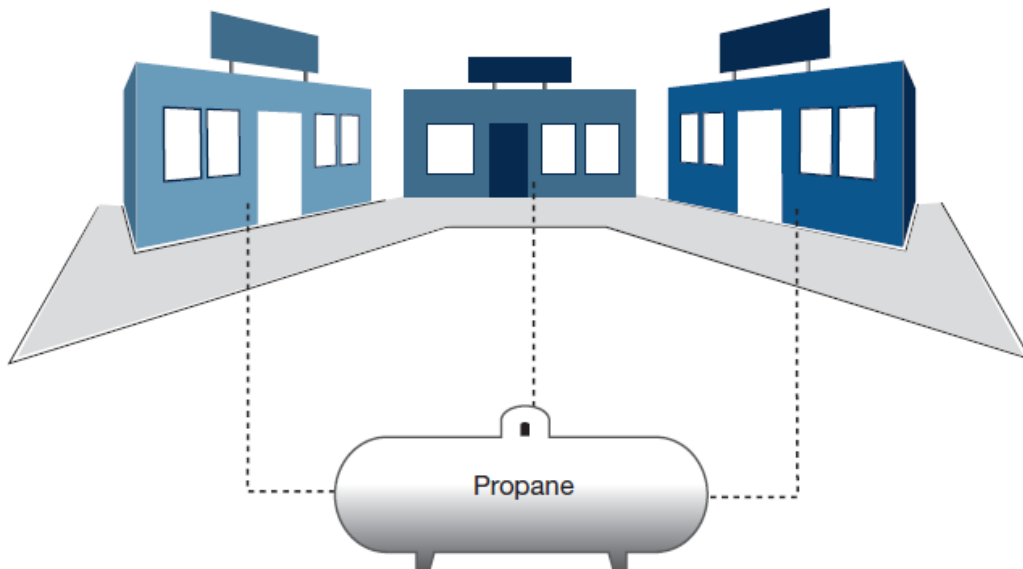
More than one customer is supplied from a single tank or multiple tanks manifolded together, where a portion of the system is located in a public place. A customer is defined as an end user who has control of the gas usage.

This system could consist of a strip mall with several businesses; a manufacturing business that has a credit union within it (the credit union is open to the public); a condominium complex with less than 10 customers, if it has a laundromat open to the public (with gas dryers) and is tied into the same gas system; or a real estate office and a dentist in the same building, if both have a propane appliance controlled by each individual business.

These propane systems commonly have meters that can help to identify them as jurisdictional systems. However, a meter is not always the only condition that identifies a system as jurisdictional.

Jurisdictional Condition 2:

Multiple customers where a portion of the system is in a public place.



Condition 3: Single customer, where a portion of the system is in a public place

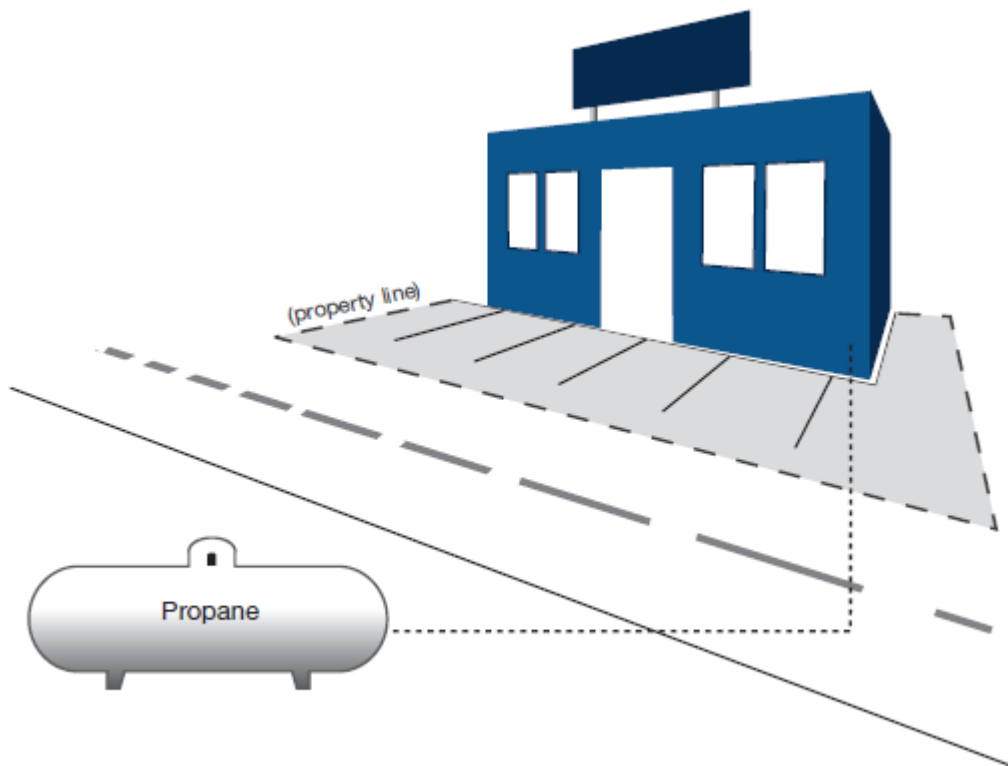
A jurisdictional system can also be present when a single customer's system is not entirely on the customer's premises and a portion of the system is in a public place.

This is typically a system where the tank(s) serving the customer is not located on the customer's property and part of the system is in a public place (e.g., the supply line crosses under a road or public right-of-way).

In this scenario, the customer does not have to be a commercial establishment, retail business, or multiple units. The criterion that makes it a jurisdictional system is the fact that the propane line passes under a public right-of-way.

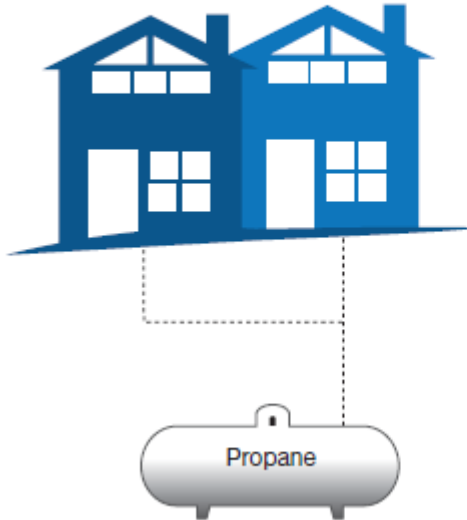
Jurisdictional Condition 3:

Single customer, where a portion of the system is in a public place.



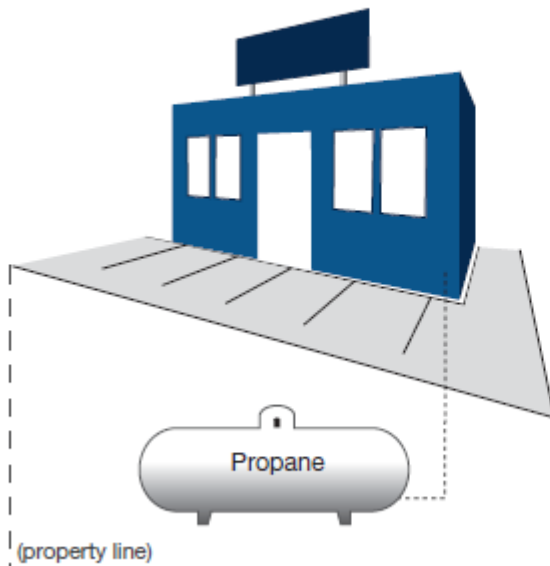
Example 1: Non-Jurisdictional

Multiple customers (less than 10) and no portion of the system is located in a public place.



Example 2: Non-Jurisdictional

Single customer, where the entire system is on the premises of the customer.



Defining a Public Place

The term "public place" is an integral part of determining whether a propane pipeline is a jurisdictional system. The federal government defines a public place as:

A place that is generally open to all persons in a community as opposed to being restricted to specific persons. Examples of public places include churches, schools, and commercial buildings, as well as any publicly owned right-of-way or property frequented by a person.

Often, it may be unclear as to whether a specific system meets the jurisdictional definition. On these occasions, it is suggested that the operator discuss the matter with the local authority having jurisdiction (AHJ) over these systems. In many states, the AHJ is the state public utility commission or comparable agency.

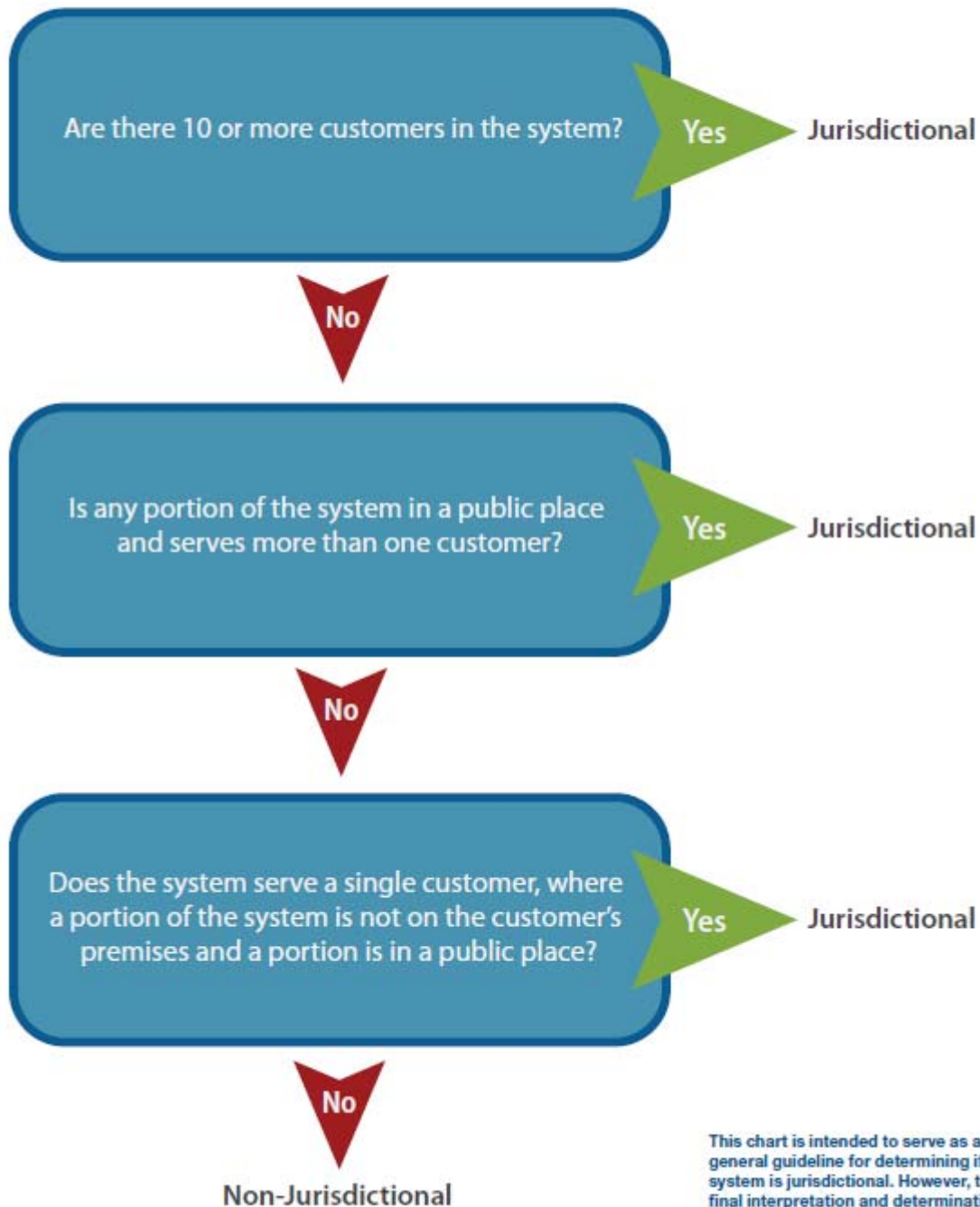
If there is not a designated state agency with jurisdiction, then the AHJ would default to the federal Office of Pipeline Safety (OPS) of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). If there is a difference of opinion between the operator and the state AHJ as to whether a system is jurisdictional, the operator may submit a formal request for interpretation to the OPS. However, this process is often lengthy and there is no certainty that the official response from the OPS will differ from that of the state AHJ.

When Is a System Non-Jurisdictional?

A propane system is considered non-jurisdictional if it has fewer than 10 customers and no portion of the system is located in a public place. Also, it is considered non-jurisdictional if the system is located entirely on a single customer's premises (no matter if a portion of the system is located in a public place).

A good example of a non-jurisdictional system would be a single residential home. Another example would be a small condominium complex with fewer than 10 customers, if the condo association owns the roads within the complex or none of the propane lines cross public roads or right-of-ways (Example 1). Another good example would be a fast food restaurant where the propane tank(s) is on the customer's premises and the lines running under the driveway/parking area are also on the same customer's premises. Because this is a single customer and the entire system is on the same customer's premises, this system is non-jurisdictional (Example 2).

Is It a Jurisdictional System?



This chart is intended to serve as a general guideline for determining if a system is jurisdictional. However, the final interpretation and determination of a jurisdictional system can vary. Always check with the appropriate enforcement agency for your area.

CHAPTER III: MATERIALS AND EQUIPMENT QUALIFIED FOR USE IN PROPANE GAS SYSTEMS

INTRODUCTION

The pipeline safety regulations refer to NFPA 58 and NFPA 59 for materials and equipment used in propane gas systems. Where a topic is not covered by either of those standards, 49 CFR Part 192 is used. In the event of a conflict between 49 CFR Part 192 and either NFPA 58 or NFPA 59, the requirements of either NFPA 58 or NFPA 59 shall prevail. When a requirement exists in part 192 that does not exist in NFPA 58 or 59, operators are required to comply with it. A conflict only exists when an operator cannot comply with a requirement in NFPA 58 and 59 because it conflicts with a requirement in part 192. When a conflict exists, NFPA 58 or 59 continue to prevail.

It is important for an operator to know the piping materials and propane storage tank sizes for all systems. The operator should develop, or have the system installer or consultant develop, a list of qualified materials for construction and repair of the system. This can be accomplished by referring to NFPA 58 and referencing equipment manufacturers' installation manuals.

When purchasing materials for use in a propane pipeline system, it is important to be sure that all materials conform with NFPA 58, and are recommended by the manufacturer for propane service. Of course, a propane pipeline system consists of storage tanks, valves, pressure regulators, pipe, fittings and meters.

TANKS

NFPA 58 permits only pressure vessels built in accordance with:

- The ASME Boiler and Pressure Vessel Code, "Rules for the Construction of Unfired Pressure Vessels," Section VIII, or
- The Regulations of the U.S. Department of Transportation (DOT) to be used in propane gas systems.

NFPA 58 does not contain the specific requirements for the manufacture of these pressure vessels, but does address the valves and other appurtenances installed in the vessels as well as the installation of the vessel on site. ASME containers shall be marked in accordance with the following, per NFPA 58:

- (a) The marking specified shall be on a stainless steel metal nameplate attached to the container, located to remain visible after the container is installed. The nameplate shall be attached in such a way as to minimize corrosion of the

nameplate or its fastening means and not contribute to corrosion of the container. Exception: Where the container is buried, mounded, insulated or otherwise covered so the nameplate is obscured the information contained on the nameplate shall be duplicated and installed on adjacent piping or on a structure in a clearly visible location.

- (b) Service for which the container is designed (for example, underground, aboveground or both)
- (c) Name and address of container supplier or trade name of container
- (d) Water capacity of container in pounds or U.S. gallons
- (e) MAWP in pounds per square inch
- (f) The wording "This container shall not contain a product that has a vapor pressure in excess of ____ psig at 100°F" (See NFPA 58, Table 2-2.2.2.)
- (g) Outside surface area in square feet
- (h) Year of manufacture
- (i) Shell thickness and head thickness
- (j) OL, OD, HD
- (k) Manufacturer's serial number
- (l) ASME Code symbol
- (m) Minimum design metal temperature ____°F at MAWP ____ psi
- (n) Type of construction "W"
- (o) Degree of radiography "RT-____"

NOTE: If the nameplate is not attached, the tank does not meet the ASME Code and cannot be used.

Typically ASME tanks do not have to be retested or inspected after they are placed into service. However, some jurisdictions may have additional requirements. Prior to the installation of a previously used container, it may be prudent to have the container inspected to assure that there is no corrosion or damage that could impair the integrity of the container. Welding repairs to ASME tanks can be made only by repair personnel who have been certified under the ASME Code and have been issued an "R" stamp. Repairs must be stamped with the "R" stamp and the work documented. ASME tanks and DOT cylinders meeting earlier construction standards, may be continued in service if maintained and requalified as needed. NFPA 58, Annex C and D have additional information.

DOT cylinders are designed for transportation, so their weight is an important consideration. They use thinner walls than ASME tanks and must be periodically requalified and so marked. All DOT cylinders have one or more dates stamped on the cylinder, usually on the collar that protects the cylinder valve from damage. Cylinders cannot be filled if the most recent qualification date on the cylinder has expired. A previously filled cylinder can be used after the date has expired.

The largest DOT cylinder for propane service has a water capacity of 1,000 pounds, about 420 pounds of propane. Cylinders are usually found only in smaller systems.



PIPE

NFPA 58 provides a list of pipe and tubing materials and fittings that can be used in propane systems. Be sure to check the latest edition of NFPA 58 referenced in 49 CFR Part 192 for any materials that may have been added or deleted.

Pipe meeting the following specifications can be used:

Wrought-iron pipe	ANSI B36.10M, <u>Welded and Seamless Wrought Steel Pipe.</u>
Steel pipe	ASTM A53, <u>Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated Welded and Seamless.</u>
Steel pipe	ASTM A106, <u>Specification for Seamless Carbon Steel Pipe for High-Temperature Service.</u>
Brass pipe	ASTM B43, <u>Specification for Seamless Red Brass Pipe, Standard Sizes.</u>
Copper pipe	ASTM B42, <u>Specification for Seamless Copper Pipe, Standard Sizes</u>
Polyamide and Polyethylene pipe	ASTM D2513, <u>Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings.</u>

Polyethylene piping systems shall be limited to the following:

- Vapor service not exceeding 30 psig.
- Installation outdoors and underground.

Note that pipe must be recommended by the manufacturer for use with LP-gas. Polyethylene pipe must be marked in compliance with the product marking requirements of ASTM D2513, and must include:

- The manufacturer's name or trademark,
- The Standard Dimensional Ratio (SDR) of the pipe,
- The size of the pipe,
- The designation polyethylene (PE), the date manufactured and the designation ASTM D2513.

TUBING

Tubing meeting the following specifications can be used:

Steel tubing	ASTM A539, <u>Specification for Electric-Resistance-Welded Coiled Steel Tubing for Gas Fuel Oil Lines.</u>
Brass tubing	ASTM B135, <u>Specification for Seamless Brass Tube.</u>
Copper tubing	ASTM B88, Type K or L, <u>Specification for Seamless Copper Water Tube.</u> ASTM B280, <u>Specification for Seamless Copper Tube for Air Conditioning and Refrigeration Field Service.</u>

FITTINGS

Fittings used with Metallic Pipe- Fittings in metallic pipe and tubing must be steel, brass, copper, malleable iron, ductile (nodular) iron or plastic. No cast iron can be used. Pipe joints in wrought iron, steel, brass or copper pipe can only be flanged, threaded, welded or brazed. Brazed fittings must be made using a brazing filler material and must have a melting point exceeding 1,000° F. (All commercially available brazes meet this requirement.) This eliminates solder as a tubing joining material. When a flange is opened, the gasket must be replaced.

<u>Operating Pressure</u>	<u>Fitting design pressure</u>
Higher than container pressure	350 psig,
Liquid propane or vapor over 125 psig	250 psig
Propane vapor less than 125 psig	125 psig

Joining Polyethylene Pipe and Tubing- Joints in polyethylene pipe and tubing must be made using the following procedures:

- a. **Heat fusion.**
ASTM D2683, Specification for Socket-type Polyethylene (PE) Fittings for Outside Diameter Controlled Polyethylene Pipe; or
ASTM D3261, Specification for Butt Heat Fusion Polyethylene (PE) Plastic Pipe and Tubing; or
ASTM F1055, Specification for Electrofusion- Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing.



b. Compression-type mechanical fittings up to 2 inches.

Must comply with Category 1 of ASTM D2513 for mechanical joints and be tested and shown to be acceptable for use with polyethylene pipe and polyethylene tubing and meeting additional requirements in NFPA 58.



c. Factory-assembled transition fittings.

All fittings used to join polyethylene pipe or polyethylene tubing shall be tested and recommended by the manufacturer for use with polyethylene (PE) pipe and shall be installed according to the manufacturer's written procedure.



d. Anodeless risers.

Factory-assembled anodeless risers must be recommended for LP Gas by the manufacturer. Field-assembled anodeless risers are design certified to meet the requirements of Category 1 of ASTM D2513 and the requirements of NFPA 58.

Anodeless risers are used to make the transition between underground PE pipe or tubing and metal pipe aboveground. As PE must be installed below-ground, risers are commonly used to connect the underground PE to aboveground piping materials. Anodeless risers are available as factory assembled units and field assembled kits. Anodeless risers are made from PE pipe inside a protective metal sheath, usually schedule 40 steel pipe. The metal is protected from corrosion by a factory applied coating, and a separate anode is not required, hence the name, “anodeless”. Factory assembled risers usually have a 90 degree bend at the PE connection end and come in several lengths depending on the depth of burial of the PE pipe or tubing.



Polyethylene pipe cannot be joined by a threaded or miter joint.

Installation- All PE fittings must be installed in accordance with the fitting manufactures’ instructions by persons trained in the applicable joining procedure. The training must be documented.

Fittings for polyethylene pipe and tubing must be fabricated from materials listed in ASTM D2513, Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings and must be recommended for LP gas use by the manufacturer.

VALVES

All valves used in metallic piping systems must have pressure containing parts of steel, ductile (nodular) iron, malleable iron or brass. All materials used, including valve seat discs, packing, seals and diaphragms, must be resistant to the action of LP gas under service

conditions. Many valves are listed by independent testing laboratories for use in LP gas service. These can be used as recommended by the manufacturer. Other valves can be used, but must comply with the requirements of NFPA 58 and should be recommended by the manufacturer for LP gas service to be sure that all the component parts of the valve are approved for LP gas service.



Valves used with polyethylene pipe and tubing must meet the requirements of ASTM D2513 and be so marked.



OVERPRESSURE PROTECTION EQUIPMENT

The requirements for two-stage pressure regulators in NFPA 58 incorporate overpressure protection. No additional equipment for overpressure protection is needed when residential systems complying with NFPA 58 are installed. Overpressure protection is accomplished by reference to the requirements of UL 144, Pressure Regulating Valve for LP Gas, which requires integral pressure relief to limit the outlet pressure of the second stage regulator to 2 psig or less in the event of failure of either the first or second stage pressure regulator under failure conditions.

All first stage propane pressure regulators up to a capacity of 500,000 BTU/hr are designed to deliver a maximum of 10 psig to the second stage regulators. This type of regulator incorporates a pressure relief valve which is operated by over-travel of the diaphragm stem. This pressure relief feature actuates when the diaphragm has traveled as far as it can in an effort to maintain the desired 10 psig outlet pressure. Integral pressure relief is required on all first stage regulators of this size. Regulators larger than 500,000 BTU/hr either incorporate integral overpressure protection or can use a separate external pressure relief valve. When specifying regulators larger than 500,000 BTU/hr it is important to specify an integral or separate overpressure protection device. The overpressure protection device can be a pressure relief valve, a second regulator in series (monitor regulator) or an automatic shutdown device. Regulators incorporating an integral pressure regulator are available up to 2,500,000 BTU/hr. Larger regulators use separate pressure relief valves which must be sized to insure that the rated inlet pressure of the second stage regulator is not exceeded. Regulator manufacturers can provide assistance in sizing larger systems.



The second stage pressure regulator, located near each gas user in the system, is designed to reduce the 10 psig propane pressure to 11 inches of water column. This regulator incorporates a full capacity relief valve similar in design to the relief valve in the first stage which will limit the downstream pressure to less than 2 psig in the event of an emergency situation.

The limit of 2 psig was selected to correspond to requirements for appliance pressure controls. The standards for appliance pressure controls have been revised to test for overpressure of up to 2 psig with no leakage out of the appliance control. The control is not required to properly operate following an overpressure of 2 psig, but it must not leak gas into the building.



It must be remembered that this means of accomplishing overpressure protection operates by releasing propane to the atmosphere instead of inside a building in the event of a failure. Operators of small propane systems may elect to advise their customers of the need to report any releases of propane which will be identified by an obvious hissing noise coming from either regulator.

NFPA 58 and UL 144 were revised in the 1995 edition to incorporate this overprotection system. The final date to produce regulators under the previous edition of UL 144 was June 1, 1998. Most manufacturers have revised their regulators to meet the new requirements in 1995. If in doubt, specify that all regulators meet the latest edition of UL 144.

Many regulators in use in LP gas systems are not designed to allow the testing of the relief device and would require a second device. The sections of Part 192, that operators must ensure are addressed are the following:

- §192.195 Protection against accidental over pressuring,
- §192.199 Requirements for design of pressure relief and limiting devices,
- §192.739 Pressure limiting and regulating stations: Inspection and testing,
- §192.741 Pressure limiting and regulating stations: Telemetering or recording gauges,
- §192.743 Pressure limiting and regulating stations: Capacity of relief devices.

CHAPTER IV: CONSTRUCTION AND REPAIR

Chapter IV is provided to assist the LP gas operator in the construction and repair requirements set by the pipeline safety regulations. It identifies the procedures needed to qualify a person to make an acceptable leak free pipe joint. It gives directions for finding "operator qualified companies/persons" to do construction and repair work on a gas system. Remember, it is always the operator's responsibility to see that a contractor follows all requirements of the OQ Rule through personnel qualifications or span of control (For additional information, refer to ASME-B31Q).

Manufacturers of pipe, valves, fittings and other gas system components must design and test them to mandatory industry specifications and be approved for gas use. The specifications are incorporated in NFPA 58 by reference into 49 CFR Part 192, the gas pipeline safety regulations. Components meeting the requirements are qualified for gas service and are marked with the "approved" markings (see Chapter III). In addition, manufacturers develop procedures for joining their products exclusively and integrating the joining of other materials to their product systems. Manufacturers' product manuals provide procedures for installation and operation that should be incorporated in the operator's O&M plans and OQ task list.

PLANNING AHEAD

The operator must select components for the system that meet all applicable standards and that comply with the pipeline safety regulations.

All parts of those physical facilities through which gas moves in transportation include pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

An operator needs to ensure the materials used for a propane distribution system are appropriate for their use and in accordance with 49 CFR Part 192, Subpart B. In addition, historical records of the types and locations of system components are critical. Operators who are uncertain of the type of material in their gas piping system must identify the materials. This may be done in one or more of the following ways:

- Contact previous owners of the system,
- Contact the contractor who installed and/or maintained the system,
- Check state, city or county permits, and/ or
- Carefully expose the pipe in certain locations to determine and document the size, type of materials and components.

Operators unfamiliar with the types of materials and various elements of the gas piping system must rely on a qualified person to identify the components. These investigations may require the operator to engage a consultant if in-house expertise is inadequate.

PIPE INSTALLATION, REPAIR AND REPLACEMENT:

Each transmission line or main must be inspected during construction or repair to ensure that it is constructed in accordance with Part 192. Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

The maintenance or repair of gas pipes must be conducted by qualified personnel. Local gas utilities, contractor associations and trade associations (PGANE or NPGA) may be able to recommend qualified persons/contractors who have the necessary background for gas pipe installation. However, contractor work must be supervised carefully by an operator qualified inspector. Refer to Chapter 2 for more information regarding maintenance activities that require operator qualification.

GAS MAIN INSTALLATION

Main means a distribution line that serves as a common source of supply for more than one service line.

Each buried gas main must be installed with at least 24 inches (610 millimeters) of cover. A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:

- (1) Establishes a minimum cover of less than 24 inches (610 millimeters);
- (2) Requires that mains be installed in a common trench with other utility lines; and,
- (3) Provides adequately for prevention of damage to the pipe by external forces.

SERVICE LINE INSTALLATION

Service line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load. Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line. Each service line must be installed so as to minimize anticipated piping strain and external loading.

Each underground service line installed below grade through the outer foundation wall of a building must:

- (1) In the case of a metal service line, be protected against corrosion;

- (2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and
- (3) Be sealed at the foundation wall to prevent leakage into the building.

Where an underground service line is installed under a building:

- (1) It must be encased in a gas-tight conduit;
- (2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and,
- (3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with §192.321(e).

METALLIC PIPE INSTALLATION

All the conditions listed below must be met when installing metallic pipe:

- Make each joint in accordance with written procedures that have been proven by test or experience to produce strong, gas-tight joints,
- Specific class locations shall require non-destructive testing of the welds (x-ray),
- Obtain and follow the manufacturer's recommendations for each specific fitting used. See Figure IV-1 for examples of manufacturer's instructions for a mechanical coupling. Include the manufacturer's procedures in the operations and maintenance plans,
- Handling pipe properly without damaging the outside coating is imperative. If the coating is damaged, accelerated corrosion can occur in that area,
- Jeep (electrical device used to detect abnormalities/holidays in pipeline coating) all coated steel pipe for holidays or imperfections in the coating and make the necessary repairs with factory epoxy repair kits or other approved repair methods,
- Coat or wrap steel pipe at all welded and mechanical joints before backfilling as well as all areas of damaged coating per the coating manufacturer's directions. Insure the welded and mechanical joints are properly coated by additional jeeping,
- Test new pipe systems for leaks before backfilling,
- Support the pipe along its length with proper backfill. Make certain that backfill material does not contain any large or sharp rocks, broken glass or other objects which could damage or scrape the coating or dent the pipe,
- Cathodically protect steel pipes, and
- Electrically insulate dissimilar metals. (See Chapter VII for illustrations).

All metallic LP Gas piping shall be installed in accordance with ASME B 31.3, Process Piping, or NFPA 58 Section 6.8. Welding must be performed by a qualified welder in accordance with welding procedures section IX of the ASME Boiler and Pressure Vessel Code "Welding and Brazing Qualifications" (incorporated by reference, see §192.7) to produce welds meeting the

requirements of this subpart. The quality of the test welds used to qualify welding procedures shall be determined by destructive testing in accordance with the applicable welding standard(s). Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

Each welder must be qualified in accordance with section IX of the ASME Boiler and Pressure Vessel Code (incorporated by reference, see § 192.7). However, a welder qualified under an earlier edition than listed in § 192.7 of this part may weld but may not requalify under that earlier edition. No welder may weld with a particular welding process unless, within the preceding 6 calendar months, he has engaged in welding with that process.

Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that:

- (1) The welding is performed in accordance with the welding procedure; and
- (2) The weld is acceptable under paragraph (c) of this section.

Welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if the pipe has a nominal diameter of less than 6 inches (152 millimeters).

Both the procedures and the personnel must be qualified for the type of weld performed. If welding is done on a gas system, qualified welders can be referred by:

- The local gas utility,
- Local gas associations, and/or
- Consultants.

PLASTIC PIPE INSTALLATION

Plastic pipe is commonly used for distribution mains and services by the gas industry. Polyethylene (PE) or Polyamide (PA) pipe currently can be used for LP gas piping. Plastic pipe must be manufactured according to standard ASTM D 2513 and marked with that number.

Plastic pipe is not permitted for aboveground installation. Plastic pipe must be buried or completely encased in a gastight metal pipe. Plastic pipe is not allowed to be exposed within the dome of a tank. The operator must include written joining procedures in the operations and maintenance plan. Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gas tight joints. Plastic pipe joining procedures can be obtained from qualified manufacturers. It is important to only install products that are listed and certified by a recognized national consensus standard organization for use on LP gas with qualified joining procedures.

If a contractor installs plastic pipe, the operator is still responsible to ensure that only pipe manufactured according to ASTM D 2513 is installed. All PE pipe and tubing must be inspected

for damage (e.g., scratches, kinks, gouges). Scratches that are about 10% or more of pipe diameter must be cut-out (personnel make determination based on visual inspection).

In addition, the operator must verify that the contractor is qualified to perform heat fusion and follows written joining procedures which meet the manufacturers' recommended joining procedures for each type of pipe and fitting used. Only qualified personnel are allowed to fuse (annual qualification). Fusion equipment should be inspected prior to making each fuse. Temperature of heating iron must be verified with pyrometer checking both sides of the heater plates prior to fusing and re-verified several times per day (450-500 degrees Fahrenheit).

To qualify an individual to fuse plastic pipe, the specimen joint must be visually examined during and after joining and found to have the same appearance as a joint or photograph of a joint that is acceptable under the procedure. In the case of heat fusion, the specimen must be cut into at least three longitudinal straps, each of which is:

- Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area;
- Deformed by bending, torque or impact and if failure occurs, it must not initiate in the joint area.

§192.285(c) requires that a person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.

Below is a butt fusion procedure sample.

1. Inspect equipment prior to use.
2. Verify proper heating iron temperature (450 to 500 degrees F.).
3. Clean pipe ends, inside and outside, with 90% Isopropyl Alcohol.
4. Secure pipe ends into jaws of fusion and tighten clamp knobs tight enough to prevent slippage, but avoid over tightening of clamp knobs (flares pipe ends).
5. Square off pipe ends with facer.
6. Check for proper alignment. If adjustments are needed, re-facing is required.
7. Check for slippage.
8. Clean pipe ends again with 90% Isopropyl Alcohol.
9. Insert heating iron into fusion unit.
10. Engage locking-cam (on fusion units so equipped).
11. Bring pipe ends together against heater plate, applying finger-tip pressure only (0 psi on pressure gauge). Excessive pressure applied during the heat cycle will result in a concave melt pattern (no good)!
12. Melt pipe ends until appropriate melt bead size is observed.
13. Remove heating iron from fusion unit.
14. Bring pipe ends together, applying just enough pressure to achieve proper roll-back and maintain pressure for 30 seconds.
15. Allow the proper cool-down time before removing fuse from fusion unit.
16. Insert heating iron into fusion unit.

17. Engage locking-cam (on fusion units so equipped).
18. Bring pipe ends together against heater plate, applying finger-tip pressure only (0 psi on pressure gauge). Excessive pressure applied during the heat cycle will result in a concave melt pattern (no good)!
19. Melt pipe ends until appropriate melt bead size is observed.
20. Remove heating iron from fusion unit. Bring pipe ends together, applying just enough pressure to achieve proper roll-back and maintain pressure for 30 seconds.
21. Allow the proper cool-down time before removing fuse from fusion unit.

Visually inspect the entire fusion joint checking for proper alignment and uniform double roll-back, v-shaped melt or signs of contamination. **Any joint not passing visual inspection shall be cutout!**

Troubleshooting

Concave Melt

Cause: Excessive pressure during heating cycle

Observation: Race track effect

Solution: Contact pressure only during heating cycle



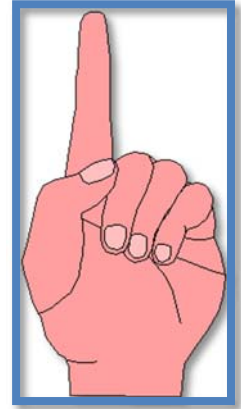
V-shaped Roll-back Beads

Cause: PIPE SLIPPAGE (e.g., when the heated ends of the pipe were joined together to form a fusion bond, the pipe slipped in the jaws of the fusion unit because the jaw clamp knobs were not tightened sufficiently)



Butt Fusion Cooldown Procedure Touch – Method

- Once the fusion is cool to the touch, (by using the back of your fingers) wait three minutes before removing the pipe from the machine.
- Wait an additional 10 minutes before pressure testing or back-filling.



ELECTROFUSION PROCESS

An electrofusion joint shall be joined utilizing the equipment and techniques of the fittings manufacturer or equipment, by testing joints to the requirements of §192.283(a)(1)(iii), and to be at least equivalent to those of the fittings manufacturer. Only properly trained and qualified personnel may make fusions.

Prior to assembling joints, all fittings must be conditioned to work-site temperatures. When couplings are used to repair or replace short sections of main, the replacement section must be vented to prevent any build-up of gas pressure which may adversely affect the fusion quality.



The pipe ends shall be cut to provide square ends. Clean the pipe with a minimum of 90% isopropyl alcohol solution to remove contaminants. The outside of the pipe needs to be scraped to remove the oxidation and other contaminants from the surface of the pipe. The print line of the pipe should be removed or a distinct feathering of the stripes on the pipe can assist as a visual guide for proper scraping. The pipe shall be marked to ensure proper stab depth of the pipe into the coupling. The coupling is installed and located properly on the pipe with a clamping tool or restraints to avoid movement. The electrofusion control box is attached and started. Ensure an adequate AC power source or 4000 watt generator is used. Allow the coupling to remain in the clamps for the proper cooling time.

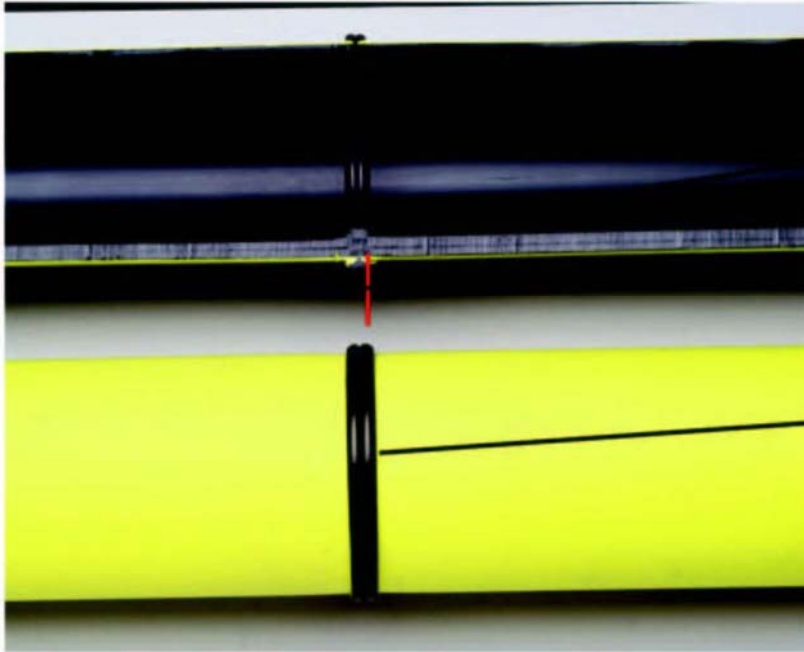


Visually inspect the completed fusion and confirm that the interface is clean with no evidence of melt or wire extrusion. Never allow a questionable fusion to remain installed. Do not pressure test, tap or energize the fitting until the total cooling time of the fusion has elapsed.

Types of Heat Fusion:

Butt Fusion Joint:

Acceptable Appearance



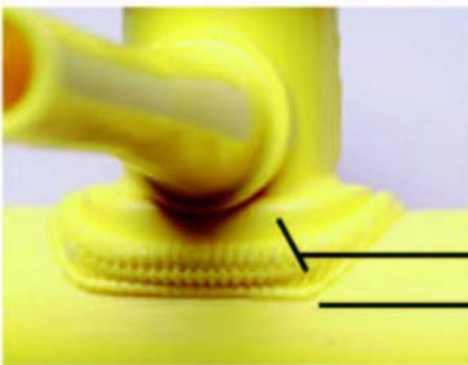
Proper alignment – no gaps or voids

Proper melt, pressure and

Proper double roll-back



Saddle Fusion Joint:



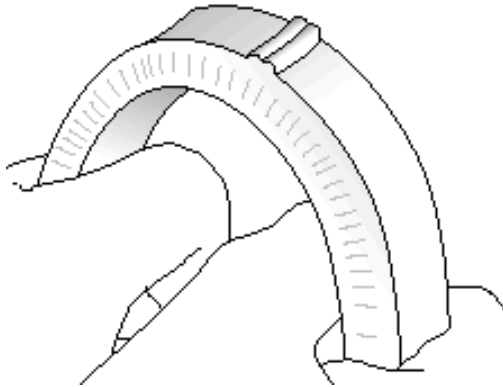
Proper alignment, force

Proper pipe surface

Socket Fusion Joint:

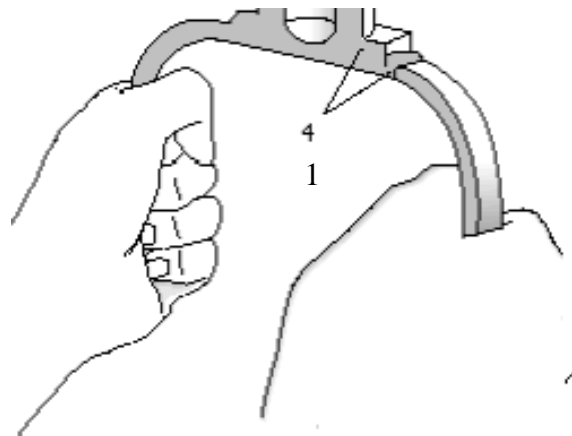


Butt Fusion of Pipe: Acceptable Appearance



Proper Alignment – no gaps or voids

Sidewall Fusion: Acceptable Appearance



1. No Gaps or Voids

The general guidelines to follow when installing plastic pipe are listed below:

1. Install plastic pipe manufactured under the ASTM D2513 specification. The pipe must have ASTM D2513 marked on it.



This is an illustration of a properly marked PE pipe. ASTM D2513 is clearly marked on the pipe. If ASTM D2513 is not marked on a pipe, do not install it.

2. Make each joint in accordance with written procedures that have been proven by test to produce strong gas tight joints.

The manufacturer of the pipe or fitting should supply the operator with the procedures for each product in the manufacturer's manual. When installing the pipe, make certain that these procedures are followed. All joints must be made by a qualified person.

3. Install properly designed valves in a manner which will protect the plastic material. Protect the pipe from excessive twisting, shearing or cutting loads when the valve is operated. Protect from any secondary stresses which might be induced through the valve or its enclosure.

4. Prevent pullout and joint separation. Plastic pipe must be installed in such a manner that expansion and contraction of the pipe will not cause pullout or separation of the joint. Operators unfamiliar with plastic pipe should have a qualified person perform all joining procedures.

5. When inserting plastic pipe in a metal pipe, make allowance for thermal expansion and contraction. Make an allowance at lateral and end connections on inserted plastic pipes, particularly those over 50 feet in length. End connections must be designed to prevent pullout caused by thermal contraction. Fittings used must be able to restrain a force equal to or greater than the strength of the pipe. To minimize the stresses caused by thermal contraction, pipes inserted in the summer should be allowed to cool to ground temperature before tie-ins are made. Inserted pipes, especially those pulled in, should be relaxed, mechanically compressed or cooled to avoid initial tensile stress. Operators unfamiliar with proper insertion techniques must have a qualified person develop the procedures.

Plastic pipe expands and contracts more than steel pipe with changes in temperature. After plastic pipe has been installed, allow a reasonable time for the pipe to approach the ambient ground temperature before making the final cut and tie-in.

Also be aware that expansion and contraction affect not just the final tie-in, but also each individual butt fusion along the entire length of pipeline as installed. Whenever pipe or tubing is exposed to direct sunlight, you may backfill the trench partially and let the pipe cool before cutting it to the

proper length or tying it in. You may also “snake” the pipe into the trench to allow for expansion and contraction.

6. Repair or replace imperfections or damages before placing the pipe in service.

7. Install all plastic mains and service lines below ground level. Where the pipe is installed in a vault or other below-grade enclosure (dome), it must be completely encased in a gas-tight metal pipe with fittings that are protected from corrosion. Plastic pipe installation must minimize shear and other stresses. Plastic mains and service lines that are not encased must have an electrically conductive wire or other means of locating the pipe. NFPA 58 requires that the wire not be in direct contact with the pipe. It is recommended that a 6" separation be maintained. In addition, warning tape should be installed above any buried piping facility. Warning tape should be placed at least 1-foot above the buried pipe to give adequate separation to minimize the chance of damage.

8. There should always be a physical separation from foreign objects and other piping, since damage by foreign objects is even more critical in the case of softer plastic than it is with steel. In metropolitan areas, be aware of steam and hydronic heating lines to prevent the melting of plastic. Several considerations in protecting plastic pipe from such foreign objects and other pipes include:

- Maintain adequate clearance separation if possible (general practice is at least 1 foot). Piping must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe. In addition, consideration should be given to the requirements of the National Electric Code (NEC) for distances from buried electrical lines.
- Where conditions prohibit a one foot separation, take additional precautions to protect the main and service line.

Plastic lines must not be used to support external loads. Backfill the trench as soon as possible after the pipe is lowered into the trench. Provide as much fill support along the sides and under the pipe as practical. Lay plastic pipe and backfill with material that does not contain any large or sharp rocks, broken glass or other objects which could cut or puncture the pipe. Where such conditions exist, suitable bedding (sand) and backfill must be provided.

Pipe locators can detect metal but not plastic. Therefore, metallic wire must be buried along with the plastic pipe. The locating wire / tracer wire is electrically conductive, and installing it with the plastic pipe enables the pipe locator to pinpoint the pipe's location. Ensure the ends of tracer wire are adequately joined by the use of an approved water tight connector, as tape eventually fails allowing a corrosive connection that will lead to the inability to readily locate the line. A pipe locator can then detect the buried metallic wire and the adjacent plastic pipe. Keep in mind that tracer wires can break or be damaged. This could make it very difficult to locate the pipe. It is important to take measurements and create maps to document the locations of buried facilities. The ability to locate plastic mains and serve lines by as-built drawings and measurements is critical. If you cannot locate the plastic pipes by use of the tracer wire, having maps with measurements would be very beneficial to mark the facility for repairs, expansion or for damage prevention.

9. Ensure that plastic pipe is continually supported along its entire length by properly tamped and compacted soil. To prevent any shear or other stress concentrations, use external stiffeners at connections to mains, anchoring of valves, meter risers and other places where compression fittings might be used.
10. In laying plastic pipe, ensure adequate slack (snaking) in the pipe to prevent pullout due to thermal contraction.
11. Install plastic pipe and backfill with material that does not contain any large or sharp rocks, broken glass or other objects which could cut or puncture the pipe. Where such conditions exist, suitable bedding (sand) and backfill must be provided.
12. Take special care to prevent coal tar type coatings or petroleum base tape from contacting the plastic pipe. It can cause plastic pipe to deteriorate.
13. Static electricity can ignite a flammable gas-air atmosphere. When working with plastic pipe of any kind, there may be the possibility of a flammable gas-air atmosphere; therefore, take the following precautions:
 - Use a grounded wet tape conductor wound around or laid in contact with the entire section of the exposed piping.
 - If gas is already present, wet the pipe starting from the ground end with an approved solution recommended by the pipe manufacturer. Apply tape immediately and leave it in place.
 - Wet the tape occasionally with water. Where temperatures are below freezing (0°C/32°F), add glycol to the water to maintain tape flexibility. Ground the tape with a metal pin driven into the ground.
 - **NEVER UTILIZE ANY PLASTIC PIPE FOR VENTING!** Even with grounded metal piping, venting gas with high scale or dust content could generate an electric charge in the gas and an arc could result from the dusty gas cloud back to the pipe and ignite the gas. Vent gas only at a downwind location remote from people or flammable material.
 - NOTE: Dissipating the static charge buildup with wet rags, a bare copper wire or other similar techniques may not be as effective as the above procedure. In all cases, use appropriate safety equipment such as flame resistant and static free clothing, breathing apparatus, etc.
14. After installation, ensure that adequate and appropriate maps and records are retained.

GUIDELINES FOR PERFORMING A PRESSURE TEST ON MAINS AND SERVICE LINES

1. Please refer to 49CFR Part 192, Subpart J for the complete requirements for minimum leak-test and strength-test requirements for pipelines. Sections are included below for convenience:

§192.509 Test requirements for pipelines to operate below 100 psi (689 kPa) gage. Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 psi (689 kPa) gage must be leak tested in accordance with the following:

(a) The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) Each main that is to be operated at less than 1 psi (6.9 kPa) gage must be tested to at least 10 psi (69 kPa) gage and each main to be operated at or above 1 psi (6.9 kPa) gage must be tested to at least 90 psi (621 kPa) gage.

§192.511 Test requirements for service lines.

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 psi (6.9 kPa) gage but not more than 40 psi (276 kPa) gage must be given a leak test at a pressure of not less than 50 psi (345 kPa) gage.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 psi (276 kPa) gage must be tested to at least 90 psi (621 kPa) gage, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with §192.507 of this subpart.

§192.513 Test requirements for plastic pipelines.

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 psi (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than three times the pressure determined under §192.121, at a temperature not less than the pipe temperature during the test.

- (d) During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification.
2. Pressure test all new steel and plastic mains and service lines before placing them in service to establish a Maximum Allowable Operating Pressure (MAOP). If this is an existing newly acquired gas distribution system, refer to chapter 2 for Operations and Maintenance Plans.
 3. Connect the pressure test equipment to the line according to the manufacturer's instructions and your company's procedures; keep the test equipment clean and treat it with care.
 4. Avoid shocks to test equipment from – rapid pressurizing and rapid release of pressure.
 5. Ensure additional requirements of the Authority Having Jurisdiction (AHJ) are met with regard to test requirements and establishing an MAOP.
 6. Maintain the test pressure for a period of at least ten (10) minutes.
 7. Pressure test documentation to include:
 - Name of the company or contractor performing the test,
 - Test pressure,
 - Test medium,
 - Duration of the test, and
 - Signature, initials and or ID number of the person conducting the test.
 8. Documentation must be retained for the life of the facility.

REPAIR METHODS - PLASTIC AND METAL

Replacement of gas lines and repair of leaks are highly specialized and potentially hazardous operations. They shall be accomplished only by persons with adequate LP gas pipeline qualifications.

Leaks in service lines or mains may be repaired by cutting out a short length of pipe containing the leak and replacing it with a new segment of pipe. The pipe segment is commonly attached to the existing line with mechanical couplings, welds, PE fusion, etc. at each end. NFPA 58 requires, if PE pipe is used to replace a section of steel pipe, a tracer wire should be installed to connect the steel pipe ends in order to maintain continuity. Remember that written procedures are required to be followed for each joint. The procedures can be obtained from the manufacturer of the mechanical coupling. If the operator intends to make the repair with a mechanical coupling, then the written procedures must be incorporated into the O&M plan.



The following are repair methods.

Permanent repair methods:

- Remove and replace: The best way to make a permanent repair is to cut out the damaged pipe section and install a new section that has already been pressure tested. You can use heat fusion, crimp and stab fittings or mechanical compression fittings for plastic pipe.
- Fusion repair patch or saddles: You can use these patches or service saddles to make a permanent repair of small (less than 1”) punctures and gouges that do not completely penetrate the pipe wall



Temporary repair methods:

- Clamps and compression fittings: Can be used for temporary repairs. Temporary repair is made to restore service until a permanent repair can be made.

To avoid having to return to the same location, and for cost savings, it is usually best to make a permanent repair immediately.

Small leaks in steel service lines or mains, such as those resulting from corrosion pitting, must be repaired with an appropriate leak clamp applied directly over the leak, by replacing a section of pipe or by another acceptable engineering method that can restore the serviceability of the pipe. All steel pipe and fittings installed below ground must be properly coated and cathodically protected before backfilling.



If several leaks are found and extensive corrosion has taken place, the most effective solution is to replace the entire length of deteriorated pipe. The normal installation practices must be followed. They include priming and wrapping of all steel piping, fittings, cathodic protection, etc.

Leaking metal pipe can often be replaced by inserting polyethylene pipe manufactured according to ASTM D2513 in the existing line and making the appropriate connections at both ends. Again, operators are cautioned that allowance for thermal expansion and contraction must be made at lateral and end connections. Operators unfamiliar with insertion techniques, including proper anchoring and offset connections, should have a qualified contractor perform this work. Some of the polyethylene pipe manufacturers provide procedures for installation of their products by insertion.

One source of failure in plastic pipe is breaks associated with the transition between plastic and metal pipes at mechanical fittings. The primary source of the problem is inadequate support of the plastic pipe. It is critical to firmly compact soil under plastic pipe to provide proper support. In practice, however, it is laborious, time consuming and difficult to achieve adequate compaction under such joints. Further, as the soil settles, stress may build and the insert sleeve will cut through the pipe.

For example, an insert sleeve must be used in the plastic pipe to provide proper resistance to the clamping pressure of mechanical fittings. This internal tubular sleeve must extend beyond the end of the mechanical fitting. If the pipe is not properly supported at that point, the end of the insert sleeve will create shear stress. This source of failure in plastic pipe can be reduced or eliminated by using a properly designed outer sleeve to prevent stress concentrations at the point where the plastic pipe leaves the mechanical fitting.

The most prevalent cause of breaks or leaks in plastic pipe is "third-party" damage. This is usually caused by an excavator breaking or cutting the pipe. Plastic pipe is more vulnerable to such breaks than steel pipe. The lower strength of plastic pipe, however, is not necessarily a disadvantage. For example, if digging equipment hooks and pulls a steel pipe it may not break, but may be pulled loose from a connection at some distance from the digging. The resulting leaks could go undetected for a period of time and may result in a serious incident. Although there is no assurance that the plastic pipe will not also pull out, it is more likely to break at the point of digging. Then, the break can be detected and repaired. After a leak has been repaired with a coupling or a clamp, a soap-bubble test must be conducted. A CGI / bar-hole survey of the piping in the vicinity may be considered after the repair is made to ensure no other remote pullouts / leaks have occurred.

ALL SOURCES OF IGNITION SHOULD BE KEPT AWAY FROM THE LEAK REPAIR AREA. OPEN FLAMES MUST NEVER BE USED TO DETECT A GAS LEAK OR TO TEST THE ADEQUACY OF A REPAIR JOB.

LOCATION OF CONTAINERS

One of the most common issues with propane installation is the distance requirements for propane tanks. Distance rules are applicable to propane tanks and their connections in relation to what surrounds them, whether it is a house or another propane tank. Care and consideration of surrounding buildings, driveways, awnings, house or building openings, property lines and more need to be taken into account when placing a propane tank in a legal and safe location.

Container Distance Requirements

The distance requirements for propane tank locations are dependent upon the container type and the container size. Generally, the majority of tanks fall under a ten foot rule with regard to buildings and houses. Cylinders are allowed to be placed adjacent to a building.

Point of Transfer Distance Requirements

The point of transfer is defined as "the location where connections and disconnections are made or where LP Gas is vented to the atmosphere in the course of transfer operations." The transfer of propane during the filling process results in residual liquid release between the tank fill valve and the hose end connection upon completion of transfer. When the hose is unhooked from the tank, liquid propane is released into the atmosphere. For this reason, the point of transfer is subject to distance requirements.

Relief Valve Distances

Safety relief valves are subject to distance rules for the simple fact that if the relief valve opens allowing propane to vent, the vicinity above and around the relief valve needs to be clear of obstructions and ignition sources. A safety relief valve on an ASME propane tank, if fully activated, will vent propane vertically up and for this reason, propane tanks have to be installed out from under an awning or part of a building overhang.

Once the proper size of the ASME storage tank or the proper number of cylinders has been determined, careful attention must be given to the most convenient, yet safe place for their location on the customer's property.

Containers should be placed in a location that does not conflict with Federal regulation 49 CFR Part 192, state and local regulations, and NFPA 58 Storage and Handling of Liquefied Petroleum Gases. NFPA 59 (2004) "Utility LP-Gas Plant Code" should also be consulted for applicability, as appropriate.

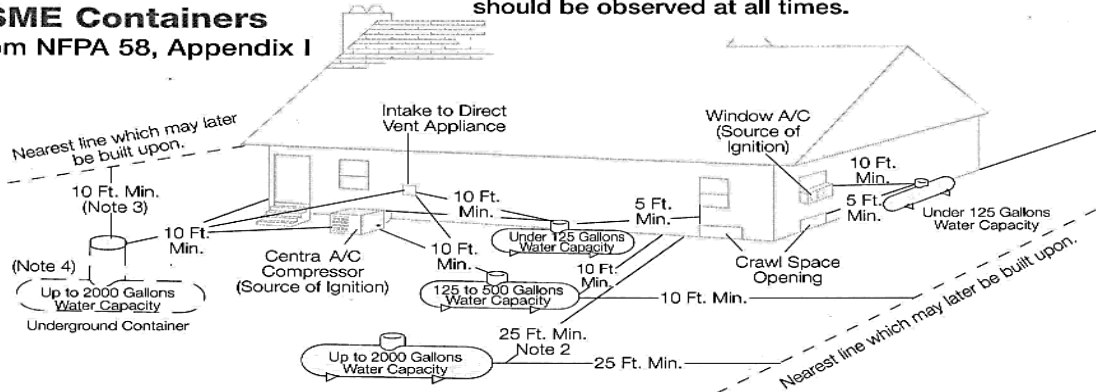
Containers shall comply with NFPA 58 (2004 edition) with respect to their location to adjacent containers, buildings, and line of adjoining property. In general, storage tanks should be placed in an accessible location for filling, supported by blocks of appropriate size and reinforcement, and located away from vehicular traffic. NFPA 59 (2004) "Utility LP-Gas Plant Code" should also be consulted for applicability, as appropriate.

LP-Gas containers shall be located outside of buildings. Container name plates need to be maintained readable and atmospheric corrosion must be monitored and minimized by painting.

For both ASME and DOT containers, the distance from any building openings, external sources of ignition and intakes to direct vented gas appliances or mechanical ventilation systems are a critical consideration.

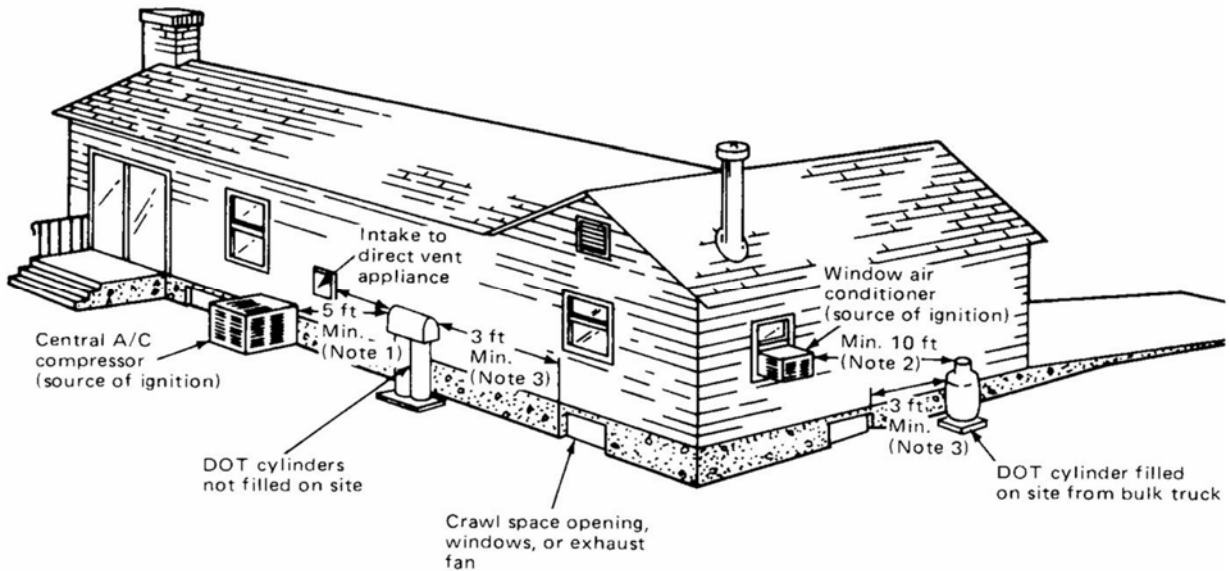
Location of ASME Containers
From NFPA 58, Appendix I

Federal, state, and local ordinances and regulations should be observed at all times.



Notes:

- 1) Regardless of its size, any ASME tank filled on-site must be located so that the filling connection and fixed liquid level gauge are at least 10 feet from external source of ignition (i.e. open flame, window A/C, compressor, etc.), intake to direct vented gas appliance, or intake to a mechanical ventilation system.
- 2) May be reduced to 10 feet minimum for a single container of 1200 gallons water capacity or less if it is located at least 25 feet from any other LP-Gas container of more than 125 gallons water capacity.
- 3) Minimum distances from underground containers shall be measured from the relief valve and filling or level gauge vent connection at the container, except that no part of an underground container shall be less than 10 feet from a building or line of adjoining property which may be built upon.
- 4) Where the container may be subject to abrasive action or physical damage due to vehicular traffic or other causes it must be either a) placed not less than 2 feet below grade or b) otherwise protected against such physical damage.



LP Gas containers shall be located outside of buildings.

Containers shall comply with NFPA 58 (2004) with respect to their location to adjacent containers, buildings, and line of adjoining property.

A single ASME container of 1200 gallons or less can be located a minimum of 10 feet from building walls or line of adjoining property. Containers shall be placed on firm foundations so as the tank is not to be in contact with the ground.

Distances for all underground and mounded ASME containers shall be measured from the pressure relief valve and the filling connection.

No part of an underground ASME container shall be less than 10 ft. (3 m) from a building or line of adjoining property that can be built upon.

Cylinders installed alongside of buildings shall be positioned so that the discharge from the cylinder pressure relief device is located as follows:

1. At least 3 ft. (1 m) horizontally away from any building opening that is below the level of such discharge
2. At least 5 ft. (1.5 m) in any direction away from any exterior source of ignition, openings into direct-vent (sealed combustion system) appliances, or mechanical ventilation air intakes.

Cylinders shall not be located and installed underneath any building unless the space is open to the atmosphere for 50 percent of its perimeter or more.

CHAPTER V: PROPER LOCATION AND DESIGN OF METERS, SERVICE LINES AND REGULATORS

PURPOSE

The goal of this guidance document is to provide operators with the necessary information to establish procedures for designing and installing meters, service lines and regulators. These procedures should describe the proper installation practices for vapor meters, service regulators, service lines, service line valves and service line connections to mains and should be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

SCOPE

These guidelines describe the minimum requirements for installing and the replacement of customer meters, service regulators, service lines, service line valves, and service line connections to mains.

CUSTOMER METERS AND REGULATORS

HANDLING OF METERS

When meters are disconnected or removed from service, meter caps must be placed on the meter openings to keep debris from entering the meter. Meters must be transported in the upright position and always handled with care. If a meter is dropped or has been exposed to moisture or other contaminants, the meter must be tagged and sent out for repair or it needs to be disposed of.

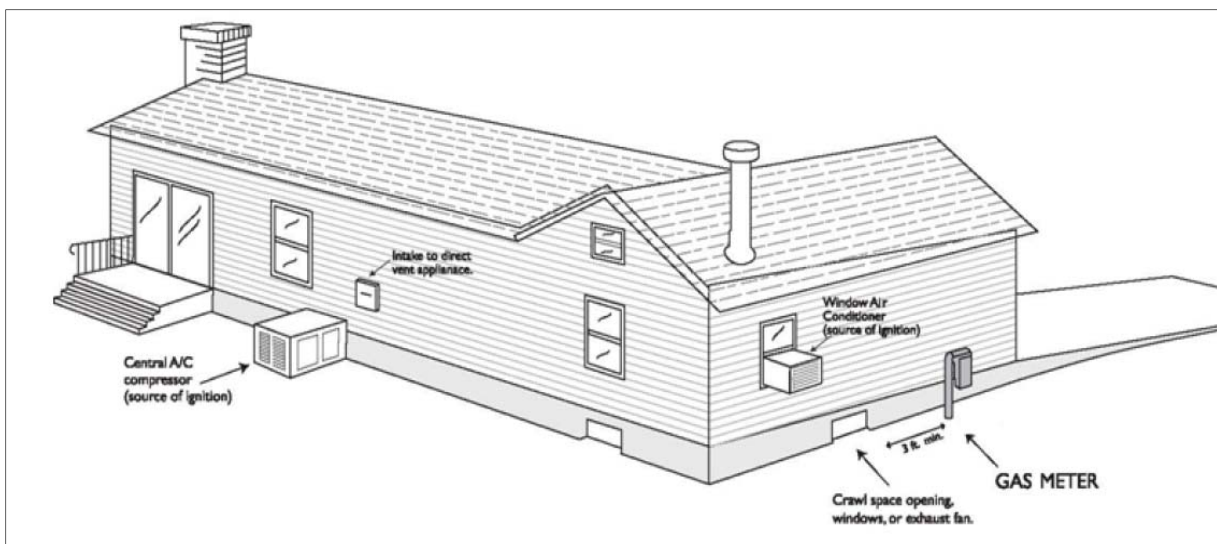
Location (Requirement § 192.353)

Meters (indoors and outdoors) must be installed a minimum of three (3) feet from:

Any source of heat - Rapid changes in temperature could cause the meter from accurately measuring the gas flow.

The point of discharge from pressure relief devices installed on service regulator or external relief valves must be installed a minimum of:

- Three feet horizontally away from any building opening located below the point of discharge, such as a window or door, and
- Five feet in any direction away from any source of ignition, opening into a direct vent appliance, or mechanical air intakes.



Service regulator vents or termination ends must be directed downward to drain condensate and have a vent screen or retainer to prevent insects from entering to protect the service regulator so that the operation will not be affected.

The piping or tubing used to vent a service regulator or an external relief valve must be one of the following:

- Metallic pipe or tubing: Steel or Wrought Iron, Brass, Copper, or
- Schedule 40 or 80 rigid electrical conduit (ANSI/UL 651). Other PVC piping materials must not be used to vent regulators or external relief valves.

Note: Other PVC piping materials, polyethylene pipe, and polyamide pipe and tubing must not be used to vent regulators.



PROTECTION FROM DAMAGE

Meters and service regulators should be installed in locations that are readily accessible for reading, replacement and maintenance. The operator should avoid locations where the meter or service regulator can be subject to snow or ice damage and any area where physical damage can occur (example: near driveways or loading docks). If the meter and/or service regulator are located in an area that they can be subject to heavy snow or ice the operator should include procedures to:



- Initiate a patrol of the system after a heavy snow fall in areas where heavy snow is not expected for the accumulation of moisture in equipment and snow or ice blocking regulator or relief valve vents which could prevent regulators and relief valves from functioning properly.

- Install protection over the meter and/or service regulator to protect the meter from:
 - The accumulation of snow or ice blocking regulator or relief valve vents which could prevent regulators and relief valves from functioning properly.
 - Physical damage from falling snow or ice.
- Meters installed indoors must be located in ventilated spaces.

The following are some general types of vehicular protection:

- Crash posts that are a minimum of four-inch schedule 40 pipe filled with concrete. Posts should be buried a minimum of three feet and extend three feet above-ground. Posts are to be encased below grade with concrete.
- Guide Rails or Jersey Barriers.
- All other protection must be approved by the pipeline manager or regional safety manager.



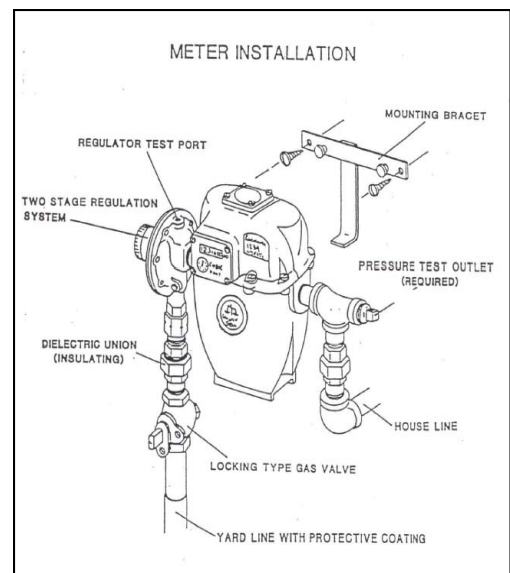
Installation (Requirement (§ 192.357))

Meters and service regulators must be installed and located where they are protected from damage. Meters must be properly supported by a mounting bracket or by pipe supports. The riser should not be used as the sole support for the meter. Meters must be mounted in a level position to ensure its accuracy.

Large commercial meters may require additional supporting and may require the installation of a firm base for the meter to set on.

Meters and service regulators must be installed with the following:

- A locking type shut-off valve,
- If the service line is metallic piping or tubing, dielectric isolation is required. This normally accomplished by an insulating union on the inlet side of the meter.



Meters sets and associated piping must be painted to prevent atmospheric corrosion. Care should be taken not to paint over the meter ID tag.

Each pit or vault housing service regulators and customer meters in a road, driveway or parking area must be able to support the vehicular traffic. If there is a question on the design of the pit or vault, it is best to contact a competent construction engineering consultant.

Operating Pressure (Requirement (§ 192.359))

Die cast or iron case vapor meters can be used at pressures equal to or less than the design pressure, but not to exceed 67% of the manufacturer's shell test pressure. The design pressure or MAOP must be marked on the meter housing.

Tin or brass type vapor meters must not have operating pressures exceeding 1 psig.



Meters installed after November 12, 1970, must be tested to a minimum of 10 psi.

SERVICE LINES - INSTALLATION (REQUIREMENT (§ 192.361))

The material used as backfill for the trench must not damage the service line and the use of sand or screenings may be necessary. Polyethylene and buried metallic pipe or tubing service lines must be buried as follows:

- With a minimum of 12 inches of cover in private property,
- With a minimum of 18 inches of cover in streets and roads,
- If a minimum of 12 inches of cover cannot be maintained the service line must be installed in conduit or bridged (shielded) to withstand any anticipated external load.

Polyethylene service lines must be supported along their entire length by properly tamping and compacting the soil around the PE pipe. Provide 6 inches of slack for every 100 ft of service line to allow adequate slack in the pipe to prevent pullout due to thermal contraction.

A tracer wire (minimum AWG14) must be buried immediately above or directly next to, but not wrapped around or in contact with, the PE pipe to facilitate underground gas pipe location in the future. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means and one end of the tracer wire must be brought aboveground at the riser.

The service line must be sized properly to supply adequate pressure to the customer's maximum demand. Diversity in demand may be considered when it is obvious the equipment will not operate simultaneously (Example: Pool Heater and a Furnace).

Service lines should not routinely be installed under buildings. Where installation under a building is necessary, specific measures are required:

- (1) The piping must be encased in a gas tight conduit,
- (2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

Steel service lines that are newly installed or if an existing steel line needs to be replaced, it must be cathodically protected if installed after August 1, 1971, and services installed prior to if active corrosion is observed on the service.

Copper tubing service lines must be Type K or L and must be installed to compensate for expansion, jarring and settling. Dielectric isolation must be installed at the tank location and at the meter location to separate the dissimilar metals from each other. Fittings must be brass and connections made with heavy duty forged flare nuts.

Requirements for service line materials and installations are specified in 49 CFR Part 192, Subpart H and Chapter 5 and 6 in NFPA 58. All newly installed or repaired service lines should be documented on a pipeline test report (see page 8).

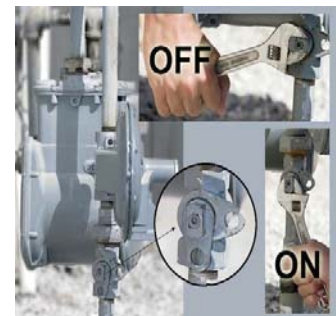
NEW SERVICE LINES NOT IN USE (REQUIREMENT (§ 192.379))

Each service line that is installed, but not placed into service, must be secured to prevent the flow of gas and unauthorized use. If the meter has not been installed, the locking valve on the service riser must be locked in a closed position and the open end of the locking valve must be plugged or capped. If the meter has been installed, the locking valve on the service riser or the locking valve on the meter bar must be locked in the closed position.



SERVICE LINE VALVE (REQUIREMENT § 192.365)

- Relation to regulator or meter. Each service line valve must be installed upstream of the regulator. If there is no regulator, install the valve upstream of the meter.
- Outside valves. Each service line must have a shutoff valve in a readily accessible location outside the building.
- Underground valves. Each underground service line valve must be located in a covered durable curb box or standpipe that allows easy operation of the valve. The curb box or standpipe must not put stress on the service line.



PRESSURE TEST

1. Select the appropriate test gauge for the system pressure test. Isolate the section and cap off the end, if necessary.

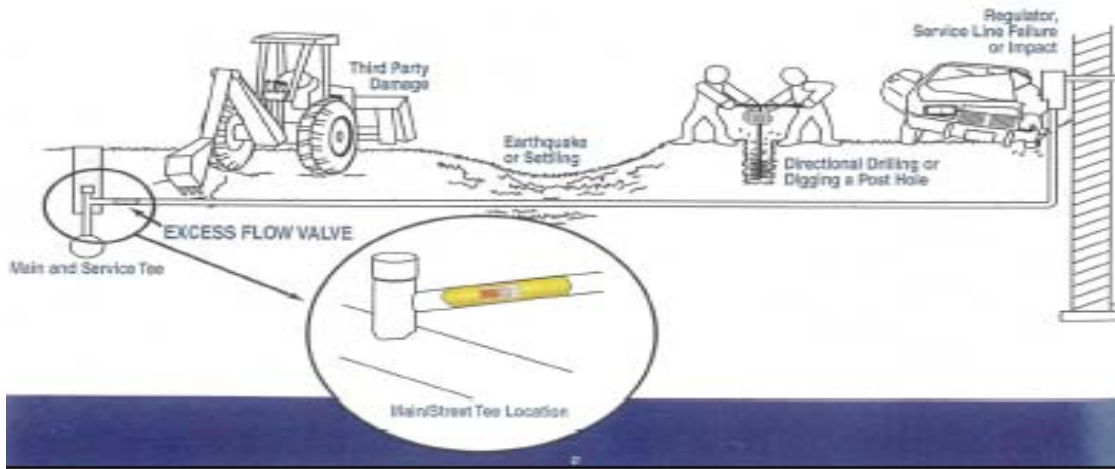


2. Hook up pressure test head and secure if needed.
3. If feasible, the service line connection to the main must be included in the test.
4. If not feasible, it must be given a leakage test at the operating pressure when placed into service.
5. Connect test pressure source.
6. Pressurize pipe to the required test pressure. If establishing the MAOP of a system follow the MAOP procedure to establish test pressure.
7. Allow pressure to stabilize.
8. Shut valve, disconnect source and plug outlet.
9. The test pressure must be maintained as long as required to identify leaks or prove that the system is leak free.
10. A leak test must be performed on any section of pipe that was not part of the test.
11. Record the test.
12. Blow down the pressure.

EXCESS FLOW VALVES (REQUIREMENT § 192.383)

Excess flow valves (EFV) must be installed on any new service line or a service line that is being replaced serving a single family residence that operates at 10 psig or greater throughout the year. EFV are not required to be installed retroactively on existing service lines installed prior to February 12, 2010, unless they are being replaced. EFV are also not required if one or more of the following conditions are present:

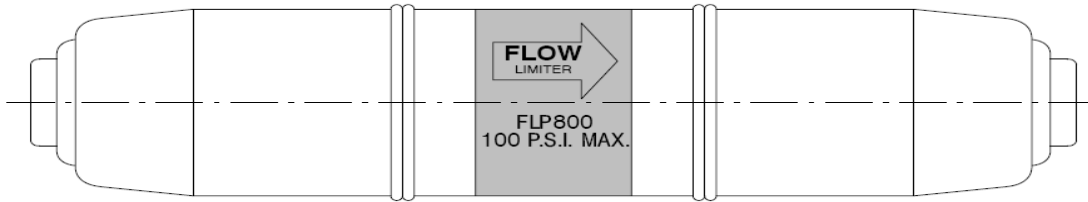
- The service line does not operate at a pressure of 10 psig or greater throughout the year,
- The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence, and/or
- The service line is only partially replaced, such as making a repair on a service line.



The EFV must be installed as near as practical to the service line tap at the gas main.

The EFV must be installed with respect to the direction of the gas flow in order for it to work. The flow direction arrow located on each device should always point the way the gas would flow to the load.

Be sure to leak test all connections and introduce gas slowly from the main to prevent the EFV from tripping. Allow approximately five minutes for the EFV to reset.



Excess flow valves must be selected based on the anticipated maximum demand and minimum line pressure.

When pressure testing a service line with an EFV installed, the test medium must be entered in slowly to avoid damaging the EFV.

PIPELINE TEST REPORT

Frequency - For each newly installed or repaired main or service line.

System Name: _____ **System Address:** _____

Location:

Type of Line: Main or Service: _____

Type of Pipe: _____ Size: _____ Length: _____

Test Medium: Air _____ Nitrogen _____ CO2 _____ Propane Vapor _____

Test Pressure: _____ Time Test Started: _____ Stopped _____

Pressure Loss Noted During Any Test? Yes ___ No _____

Leak(s) Corrected? Yes _____ No _____

Actions

Taken

Location of Line - (Draw sketch of lines tested below or on back of this sheet.)

Person Performing Test: _____ Date: _____

CHAPTER VI: DAMAGE PREVENTION PROGRAM

PURPOSE

The goal of this guidance document is to provide operators of buried propane pipeline facilities with the necessary information to establish procedures to:

- Protect the public, the excavator, first responders and employee's from excavation related hazards,
- Prevent damage from excavation activities,
- Prevent damage to other facilities when the operator is performing excavation activities, and
- Produce and maintain documentation to substantiate compliance with the damage prevention requirements of the federal gas pipeline safety code.

Please note: Many other significant practices exist to protect public safety related to underground facility damage which are not included in the scope of this chapter. The reader is urged to actively research related reference materials (some of which are listed in this chapter's appendix) and to establish regular interaction with other local damage prevention stakeholders and local damage prevention consortiums, such as an applicable Common Ground Alliance Regional Partner organization.

SCOPE

This guidance describes necessary activities for most small propane pipeline operators to comply with Damage Prevention regulations. These operators must maintain relevant written procedures and accurate documents to substantiate compliance with the Code of Federal Regulations 49CFR192.614, Damage Prevention Program and applicable State gas pipeline safety laws. When performing excavation, operators must follow applicable State and local regulations. This chapter provides guidance to comply with the specific sections of federal regulations (listed below) and provides other general practices related to excavation.

Code Reference	Topic	See-Chapter/Section
49 CFR § 192.614 (a)	Carry out written program/plan	Procedures and Qualifications
49 CFR § 192.614 (b)	Participation in a One-Call system	One Call Systems
49 CFR § 192.614 (c)	Written program/plan requirements	Procedures and Qualifications
49 CFR § 192.614 (c)(1)	List excavators which may be active in area(s) where pipeline is located	Procedures and Qualifications
49 CFR § 192.614 (c)(2)	Outreach to specific public, outreach to specific excavators	Chapter II, Plans Required by the Federal Government, Public Awareness

Code Reference	Topic	See-Chapter/Section
49 CFR § 192.614 (c)(2) (i)&(ii)	Outreach message requirements	Chapter II, Plans Required by the Federal Government, Public Awareness
49 CFR § 192.614 (c)(3)	Means to receive and record notification(s) of planned excavation	Response to One Call Requests
49 CFR § 192.614 (c)(4)	Operator notification of marking/symbol interpretation(s) to excavators which propose activity near pipeline location	Flags, Paint & Temporary Markings. Also see CGA Best Practices, 10.0, Uniform Color Code & Guidelines, for set of marking symbols
49 CFR § 192.614 (c)(5)	Pipeline location & marking prior to excavation	Flags, Paint & Temporary Markings
49 CFR § 192.614 (c)(6)	Pipeline facility inspection	Response to One Call Requests and Continuing Surveillance
49 CFR § 192.614 (c)(6)(i)	Inspection frequency	See AGA GPTC Guide, Damage Prevention Program
49 CFR § 192.614 (c)(6)(ii)	Pipeline inspection related to blasting activity	See AGA GPTC Guide, Damage Prevention Program
State Regulations for performing excavation activities	Pre-excavation and excavation practices	Precautions to Avoid Damage

PROCEDURES AND QUALIFICATIONS

Operators must establish a written Damage Prevention Program and procedures to safeguard company facilities from damage either by excavation or demolition activities. These procedures must be carried out by, or under the direction of, a person qualified in Damage Prevention methods. (See Appendix 6.1, Documents to Substantiate Damage Prevention Program Effectiveness)

(Operators of some pipelines, specified in 49 CFR § 192.614(e), including master meter systems, are not required to utilize a written plan, maintain a current list of local excavators nor notify the public and local excavators of the operator's damage prevention program. However, these operators must carry out all the other Damage Prevention Program requirements of 49 CFR § 192.614. Operators, other than propane marketers, which are considering their company's status for this partial exemption, are advised to thoroughly review the criteria of § 192.614(e), the definition of Master Meter System in § 191.3 and consult the applicable Jurisdiction Having Authority).

ONE-CALL SYSTEMS

The One-Call notification system provides a communication link between excavators and operators of underground pipeline and facilities. The core of the system is an operational center whose main function is to transfer information from excavators about their intended excavation activities to the operators of underground pipelines and facilities participating in the system.

It is important to note a single notification of proposed excavation to a “One Call” Center will not ensure all operators (or owners) of underground facilities will receive the notice. Many water systems, industrial communication systems and other underground facilities (including most propane single-user facilities) are owned and operated by entities which do not participate in a One-Call System. Excavators should make individual notifications to each private property owner, institutional/commercial campus, municipalities with water systems, propane marketer and other “Non-One-Call-System-Members” associated with any proposed excavation location. (See link to “Whitepaper: Call before you dig, but beware – not every utility gets marked” in Appendix 6.6 List of Reference materials)

Upon receipt of the information, operators of pipelines and facilities that could be affected by the excavation activity arrange for the timely identification and marking of underground facilities that are in the vicinity of the intended activity. When necessary, some underground operators will inspect the site being excavated and advise the excavator of the need for special measures to protect buried or exposed facilities. One-Call notification systems may perform various other functions relevant to protecting underground pipelines and facilities from damage, such as record keeping and public awareness programs.

It is required that LP Gas operators be members of and participate in a qualified One-Call damage prevention system. It is recommended that LP operators check with their State and local One-Call systems to determine the laws and regulations that would apply to them.

RESPONSE TO ONE CALL REQUESTS

Propane operators must follow the State One-Call requirements and be qualified to perform locates along with the following guidelines:

- Screen the One-Call ticket to determine if the pipeline facility is by the excavation site,
- Verify that the geographical location of the locate request and company records are correct,
- Verify locate and preferably connect transmitter directly to the pipe or wire,
- Locate and mark area that is part of the locate request with highly visible yellow paint or yellow flags or stakes directly above the main or service,
- Marks should extend a reasonable distance beyond the bounds of the requested area,
- Review the marks against system the system drawing, map or sketch. If there is a conflict, determining the exact location of the pipeline will require the pipe to be exposed by hand digging or vacuum excavating,



- Complete appropriate locate documentation (See Appendix 6.3 One Call Locate Request Form). Retain paperwork and call ticket,
- Establish set of marking symbols and ensure these are available to excavators. (See CGA Best Practices, Uniform Color Code & Marking Guidelines).

Revisit locates:

- Go to site and inspect previous markings and make sure they are visible,
- Check all excavations for pipe damage,
- Speak with job site foreman or supervisor. Verify the following:
 1. Were all markings identified by the supervisor?
 2. Were the current markings accurate?
 3. Is there a need for additional markings?
- Complete appropriate paperwork.

Note: Caution should be taken while locating near vehicular traffic. Where applicable, wear an approved safety traffic vest and use a vehicle as a barrier.

If locates are to be performed by a third-party contractor, the contractor must be Operator Qualified to perform locates.

FLAGS, PAINT & TEMPORARY MARKINGS

Operators normally mark the location of underground pipelines using yellow flags, paint or stakes. Other types of underground lines will be marked in different colors. Refer to the color code chart for more information regarding what each color represents. Paint Marks, markings, and symbols and abbreviations must be accurate and should provide facility information to excavators related to facility operating company (company identifier), tolerance zone, number of facilities, width of facility, description of facility, connections (such as service tees or branch connections, structures (such as vaults) and changes of direction (bends, tees, ells, etc.). These designated color/symbol conventions, similar to map legends, must be available to the excavator for the purpose of precise interpretation. (See Appendix 6.8 for specific marking symbol guidelines)

RED	ELECTRIC
YELLOW	GAS, OIL, STEAM
ORANGE	COMMUNICATIONS
BLUE	POTABLE WATER
PURPLE	RECLAIMED WATER
GREEN	SEWER / DRAINAGE
PINK	SURVEY MARKS
WHITE	PROPOSED EXCAVATION

EXCAVATION ACTIVITIES

Always call your local One-Call Center directly or call 811 before digging

Always call 811 or your local One-Call Center to notify operators of underground facilities of prior to digging, excavating or any subsurface activity. One-Call notification (of proposed excavation activity) is required in most States and is typically a free service.



“Calling before You Dig” initiates the One-Call center to notify member companies (typically utility operators) of an upcoming excavation project and begins the period (which varies by State; typically 2-3 days, excluding weekends and holidays.) for operators to mark the location of their underground infrastructure before the excavation begins. For this reason, State regulations typically specify calls to the One Call Center be made prior to a minimum “waiting period” of a few days.

Most states also require excavators to call within a specific (maximum-time) period prior to excavation. (for example, some states require a notice of excavation to occur within 10 days of beginning excavation activity) Because of this requirement, the excavator should record the time and confirmation number of the call. If excavation activity has not started within the applicable time frame, the One Call center must be re-notified of the planned excavation.

Note: Notification of a proposed excavation (except emergencies) should be made so operator/owners of underground facilities have reasonable time to schedule locators accordingly avoiding last minute preparations, rushed travel and inadequate facility location markings.

Pipelines and other facilities that are maintained and owned by the resident or building owner rather than a pipeline operator are typically not located through the One-Call process. These “customer-owned” lines often include pipelines and piping that are downstream of the meter or other connection points to a customer’s gas appliances or manufacturing equipment.

Customer-owned lines are rarely maintained or located by the pipeline or utility company. If you are planning to excavate near customer-owned lines, contact a local professional who is qualified to verify the location of these lines before digging.

EXCAVATOR WHITE LINING (PRE-MARKING)

White lining (pre-marking) is required in many states, and is a recommended best practice. Excavators prepare for accurate pipeline and other underground utility location-marks prior to digging by white lining, or pre-marking, a job site with white paint, flags or stakes to show the exact excavation area before calling the One Call center.



- Listed below are steps for how to white line an excavation area:
- Use the paint, flags or stakes in a continuous line, dots marking the radius, dashes in each of the four corners or dashes outlining the project perimeter
- Make each dot at least one inch in diameter
- Make each dash at least one inch wide and six to 12 inches in length
- Excavators are responsible for providing access to the excavation site. Make sure that gates are unlocked or that personnel are on site to provide access for the operator (or their designee) to locate and mark the facility they operate/own.

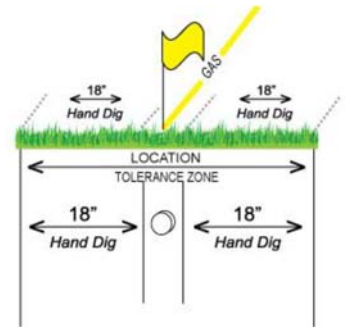
EXCAVATION AND PRECAUTIONS TO AVOID DAMAGE

Excavation activities include excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means and other earth moving operations.

All excavation must be performed with procedures and equipment in a manner to prevent damage to the pipeline or other facilities. Employees or contractors must exercise care and take all reasonable steps to avoid damage or interference to any buried gas lines or cables. Consider the following methods when digging near a pipeline or other facilities.

The following methods are designed to decrease the likelihood of damage to the pipeline during excavation:

- Respect the marks and dig with care.
 - Hand digging
 - Soft digging
 - Vacuum excavation methods
 - Pneumatic hand tools
 - Non-invasive methods may be used for pavement removal.
- If you have questions regarding proper digging techniques near a pipeline, ask the pipeline operator for assistance.
- When excavating within a tolerance zone, (typically an area within 18 or 24 inches from the underground structure) prudent excavating techniques must be used, such as refraining from the use of mechanized equipment. Utilize “soft excavation” such as hand digging or vacuum excavation in tolerance zones.
- Provide support for underground facilities in and near the construction area during excavation and backfilling operations to protect the facility.
- Dig test pits as necessary to verify the actual location of LP gas facilities if these facilities or utilities are to be exposed or crossed.
- When unmarked facilities are found during excavation activities, the excavator or other entity making this discovery should notify the company believed to operate the facilities. The operator should then acknowledge the finding and make appropriate corrections and or other record revisions to accurately document field conditions.



When digging directly next to a pipeline, excavators should consider alternate methods depending on climate and geography. Always follow the excavation requirements of your State One-Call Law and Common Ground Alliance Best Practices.

Communication is a critical element of Damage Prevention; Excavators and Operators must be available to discuss job site situations related to facilities near the project location. Both parties should maintain current contact information of the other, necessary for effective exchange of information. Many pipeline operators request to be present during excavation that occurs close

to their pipeline. Coordination with the operator keeps everyone safe and prevents project delays.

Depending on the location of the pipeline in relation to the excavation, a gas company field representative may be required at the job site to monitor excavation activity and can help you determine the most appropriate digging method.

See further best practices for excavation and recommendations for Trenchless Technology / Directional Boring, Hammering etc. in [CGA Best Practices, Excavation](#).

EMERGENCY EXCAVATION

An emergency excavation is an excavation performed to eliminate an imminent danger to life, health or property. Telephonic notice of the emergency excavation must be given as soon as possible to the One-Call Center. If necessary, emergency assistance should be requested from each operator to locate and protect its underground facilities.

REPAIR OF EXCAVATION DAMAGE

All reports of leaks and pipeline damage must be considered to be an emergency. If it is suspected that the pipeline was damaged, either by excavating or natural forces, the pipeline must be inspected using one or more of the following methods:

- Visual inspection,
- Pressure test utilizing an approved method,
- Leak survey.

Note: If upon arrival, an employee discovers an unplanned release of gas which may endanger life or property, the employee must call 911, provide necessary evacuations if deemed necessary and establish a “Hot Zone”.



Any damage that is found must be isolated or repaired and any other utility that is damaged must be reported to the facility owner.

Never bury a damaged facility. Even a minor scrape, nick, cut, tear, break or dent should be reported to the facility owner immediately. If not promptly repaired, it could result in a future leak, service outage, explosion, accident, injury, or death.

Each person responsible for excavation operations which results in damage to an underground facility must, immediately upon discovery of the damage, notify the operator of the facility of the location and nature of the damage. The operator must be given reasonable time to make the necessary repairs before the excavation or backfilling in the immediate area of damage is continued.

Each person responsible for an excavation activity that damages an underground facility and permits the escape of any flammable or toxic gas shall, immediately upon discovery of the damage, analyze the situation to determine if anyone is in immediate danger and then take necessary action to protect that person. Remember, the one providing the assistance must not perform any actions which would endanger themselves. If all people are out of immediate danger, then the person must notify the operator, local police and the local fire department. Then take any actions necessary to protect persons, first, and then property from possible further danger and to minimize the hazards until arrival of the operator personnel or police and fire department personnel.

PERMANENT PIPELINE MARKERS (REQUIREMENT § 192.707)

The pipeline markers must provide the public with emergency contact information and indicates that a pipeline facility is in the vicinity. This procedure describes the installation of pipeline markers to all distribution mains and is generally not applicable to service lines.

INSTALLATION

Markers styles may include round posts, flat posts and curb markers. Markers must be replaced or repaired if damaged, not legible or missing. The following information must be visible on the marker:

- The words —"Caution", —"Danger" or —"Warning" followed by the words —"Gas Pipeline". The letters must be at least 1" high written in black with a yellow background or yellow with black background,
- Company name with their emergency telephone number, and
- The appropriate One Call telephone number. Normally 811.



Markers are required to be placed as close as practical over buried distribution lines:

- At each crossing of a public road or railroad,
- Whenever it is necessary to identify the location of the line or main to reduce the possibility of damage or interference, and
- Pipeline markers are **not** required if the distribution system is registered with One-Call **unless** one of the following exists and where permitted by the owner, line markers are recommended at the following locations:
 - o At crossings of other pipeline or utilities,
 - o Agricultural areas in which deep plowing will occur,
 - o Waterways or bodies of water where gas lines cross,
 - o Drainage ditches where gas lines cross,
 - o Temporarily in active construction zones,
 - o Encroachments or right-of-ways.

Line markers are required along each side of an aboveground section of a main line in an area accessible to the public. Other methods of line marking can be considered, such as, signage or decals, or painted markings.

Operators place signs along the pipeline route to identify the general location of a pipeline and specify the type of product transported along with the operator's name and an emergency contact number. Pipeline markers *do not* identify the exact location of a pipeline and should not be used to locate pipelines prior to excavation.

CONTINUING SURVEILLANCE (REQUIREMENT § 192.613)

All personnel must monitor and report any excavation activity by or near the pipeline. All personnel must inform and instruct of the location of the pipeline and verification of the locates must be visible. When conducting surveillance look for visual signs of leaks or potential leaks. Visual signs may include:

- Soil subsidence,
- Damaged or corroded equipment,
- Encroachment or diversions,
- Vegetation changes may indicate a sub-soil leak,
- Recent excavation in the immediate area of the pipeline may have caused damage,
- Visually inspect for gas that is venting to the atmosphere,
- Visually inspect condition of the regulators and meters and for external corrosion of the aboveground piping, tank(s), meter and valves.

Surveillance should be performed after severe weather conditions (floods, earthquakes, etc.).

APPENDICES AND REFERENCE MATERIALS

- 6.1 Chart Documents to substantiate Damage Prevention Program effectiveness
- 6.2 Check list: Written Facility Operator Underground Facility Damage Prevention Plan
- 6.3 One Call Locate Request Form
- 6.4 Excavator Meet Agreement/Documentation Form
- 6.5 AGA White paper. Natural Gas Pipelines & Unmarked Sewer Laterals
- 6.6 Damage Prevention Resources

APPENDIX 6.1 - CHART DOCUMENTS TO SUBSTANTIATE DAMAGE PREVENTION PROGRAM EFFECTIVENESS

Documents to substantiate Damage Prevention Program effectiveness					
Requirement	Requirement Description	Document(s) to substantiate compliance	Identify the <u>Company</u> Document(s) which contains material to substantiate compliance with each requirement in left column.	Identify <u>Specific Area(s)</u> of document (such as: pg. #, section name and/or #)	Notes
49CFR192, State rules, etc.					
	Annual Meetings w/ Emergency Responders and Public Officials.	Written Procedure(s) Meeting documentation			
192.614(a)	Written program	Written Procedure(s)			Pipeline Operator Company directive to implement specific step-by-step processes, identifications of equipment, personnel qualifications and documentation methods
192.614(b) 192.614(b)(1) 192.614(b)(2) 198.37 198.39	One Call Center Qualification Confirmation.				
192.614(b)	Pipeline Operator Participation in a One Call Center.	Written Procedure(s)			
192.614(c)(1)	Means of establishing and maintaining a list of Excavators.	Written Procedure List of Excavators			List must include all excavators retained by company and any other which may do business in pipeline area. List and a specific indication of list annual review must be available.
192.614(c)(2)	Means of maintaining public awareness of the specific pipeline system and the damage prevention system.	Written Procedure Notification message			List of Specific parties receiving messages, dissemination methods and dates messages made Specific messages (complete content) must be available.
192.614(3)	Means of receiving notices of proposed excavation	Written Procedure			Step-by-step process, identification of equipment and personnel qualifications
192.614(3)	Means of recording notices of proposed excavation	Written Procedure			
192.614(4)	Notice of location marking(s) and how to identify those marking(s), legend for symbols, colors, abbreviations, etc.	Written Procedure Example of actual notification			
192.614(5)	Means of locating Underground facilities	Written Procedure			Step-by-step process, identification of equipment and personnel qualifications
192.614(6)	Means to inspect pipelines which could be damaged by excavation activity in area.	Written Procedure			Step-by-step process, identification of equipment and personnel qualifications

APPENDIX 6.2: CHECK LIST: WRITTEN FACILITY OPERATOR UNDERGROUND
FACILITY DAMAGE PREVENTION PLAN

Check list: Facility Operator's Written Underground Facility Damage Prevention Plan (DPP)

Date:

Operator Name:

The outline format of this checklist itemizes elements of a compliant DPP and components to consider for each. It does not reflect the actual organization or content of the Operator's written DPP. Specific comments regarding the substance of the particular DPP are underlined below each element. Additional specific comments may be included in notes below the outline.

1. Plan Adoption and most recent Revision dates

.....

2. Program objective/purpose: utilize proactive procedures to:

- 1) Protect Operator's underground facility from damage caused by any excavation activities.
- 2) Ensure the Operator's, or Operator's agent/contractor excavation activities do not damage any underground facilities, regardless of ownership.
- 3) Comply with State of Vermont "digsafe law"

.....

3. A method to annually review the plan for corrections and/or improvements

- 1) Review history regarding damage to the Operator's facilities
- 2) Review history of any damage occurring to other underground facilities during Operator excavation work.
- 3) Consider comments from employees regarding procedure improvement
- 4) Consider other indicators of work performance from homeowners, other facility companies etc.
- 5) Revise or insert written procedures to comply with the current Vermont digsafe law and best practices to prevent underground facility damage.

.....

4. Operator individual(s) contact information of for issues related to damage prevention

.....

5. Procedure to maintain underground facility records for all segments of the Operator's buried system.

- 1) Location
- 2) Status: active, reserved for future use, abandoned, etc.
- 3) Update as new underground facilities are installed
- 4) Confirm and/or correct Existing Facilities Records when the mark-out indicates possible erroneous documentation

.....

Check list: Facility Operator's Written Underground Facility Damage Prevention Plan (DPP)

Date:

Operator Name:

6. Operator shall maintain membership with Dig Safe System Inc.

.....

7. Operator will provide current "base-map" information to Dig Safe System Inc.

- 1) Operator will revise/increase the specific base-map territory area if new facilities are installed outside the region of the current base-map utilities by the one-call center system. (The base-map registers the region in which any notice of proposed excavation will be relayed to the Operator.)

.....

8. Procedures to receive, process and record notices of proposed excavation, blasting and demolition

- 1) From the one-call center, Dig Safe System Inc.
- 2) Calls from homeowners should be received for dispatching a locator and redirected to the one-call center
- 3) Requests for a service shut-off should be considered as a possible excavation
- 4) Procedure to process a notice of excavation in the area of a privately owned underground service. (when a facility owner is not a Dig Safe System Inc. member, yet is served by a member utility)
- 5) Method to ensure all excavation notices are addressed and documented
 - a) Scrub-out techniques, if used, should be included

.....

9. Procedures to locate and mark facilities within the area of proposed excavation

- 1) Methods for:
 - a) Locator equipment operation
 - b) Marking techniques
- 2) Procedure to confirm each applicable mark-out is completed within 48 hrs
- 3) Procedure to communicate with excavator if there are problems with locating facilities
- 4) Procedure to make an agreement with an excavator for a mark-out schedule other than with-in 48 hrs of a notice of proposed excavation.

.....

10. Procedures to receive communications from, and promptly respond to, excavators requesting to resolve job site issues or notifications of damage to underground facilities.

- 1) Method to assist excavator when it appears Operator facilities exist but have not been marked or are incorrectly marked.
- 2) Method to assist an excavator who can not verify the location of a facility within the tolerance zone of the markings.
- 3) Method to implement a planned outage, before excavation commences, when it is determined that prudent excavation will damage facilities and/or be dangerous
- 4) Procedure to promptly make area safe to the public and/or repair damage before excavator backfills area.

.....

Operator Name:

11. Procedures to investigate and document damages to underground facilities

- 1) Record all information necessary to complete and process a Vermont Underground Facility Damage Report (UFDR)
- 2) Plan view sketch including
 - a) nearest road
 - b) nearest building(s)
 - c) above ground facilities
 - i. poles
 - ii. pedestals
 - iii. valve boxes
 - d) underground facility
 - e) underground facility location marks
- 3) Produce photographic evidence
 - a) "full-site" wide angle photograph with identifiable landmarks
 - b) "in-line" view of marks and damage
 - c) View of damaged facility, including excavation tool marks
 - d) View with indication of distance between marks and damage

.....

12. Procedures to recover costs associated with damage repair and service restoration.

.....

13. Procedure to plan an excavation project/job

- A. Perform pre-excavation site review
- B. Document site particulars
 - a. Above-ground indicators of facilities
 - i. Sunken areas / ditches / divots
 - ii. Poles / pedestals / stub-ups
 - iii. Vaults / covers / standpipes
 - iv. Buildings with utility connections or meters
 - v. Possible water/sewer facilities
 - vi. Propane / fuel tanks, access domes, lines
- C. Consider inclusion of alternate excavation locations, in the notice of proposed excavation, if the first choice is found to be inadequate due to unexpected factors found during the job.

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14. Procedure to Premark

- A. Determine where and how premarks will be made.
 - a. Include excavation Operator name or initials (not DS or Digsafe)

.....

Operator Name:

15. Procedure to notify Dig Safe System Inc. of the proposed excavation

- A. Description of excavation activity
- B. Notice of proposed excavation will precede all excavation activities by at least 48 hours but no more than 30 days, excluding weekends and holidays
- C. Each notification to Dig Safe Systems Inc. or any other entity will be documented and the Digsafe ticket number retained.

.....

16. Procedure to communicate with the facility operator regarding facility locate/mark-out and specific excavation work schedule

- A. When contacted by a utility stating they are unable to complete the location and mark-out for the complete proposed excavation area (described in the notice of excavation) within 48 hours, [excavation co.] will inform the locator where excavation will first occur.
- B. Document the agreement and include the contact individual, geographic areas and dates.

.....

17. Method to consider facilities that may not be marked and/or may not receive notice from Dig Safe System Inc.

- A. Compare the following to ensure specific locations of all facilities are marked.
 - a. Pre-excavation notes
 - b. the list of companies (provided by Dig Safe System Inc.) who will receive a relayed notice of the proposed excavation
 - c. the marks made by utilities following 48 hours.
- B. Notify certain operators directly.
 - a. water/sewer systems
 - i. Notify the Town Public Works Department
 - ii. Discuss private water/sewer with property owner/manager
 - b. Propane systems

.....

18. Procedures to communicate with operator/locator any issues found in the field before taking a chance/risk

- 1) Evidence of unmarked facilities or prior knowledge of facilities in the area
- 2) Conduct pre-construction meetings when appropriate
- 3) Method to arrange a planned shut-down.
 - A. Procedures to communicate directly with a facility operator to determine, by agreement, if and when facilities will be safely shut-down before excavation begins.
 - a. This should occur if:
 - i. It is determined that a facility will be damaged by excavation (e.g., a facility is in contact with an object to be removed by excavation)

Check list: Facility Operator's Written Underground Facility Damage Prevention Plan (DPP)

Date:

Operator Name:

- ii. It is determined that excavation can not be performed safely (e.g., excavation precautions can not be taken when a facility is not marked)
- B. DPP Manual should include instructions to document the communication and the actual shut-down including the dates and the persons contacted.

.....

19. Procedures to Maintain Marks

- A. Confirm understanding of all marks, contact utility if the meaning of the marks are unknown or ambiguous
- B. Ensure all on-site personnel understand marks
- C. Document marks, soon after they are placed, through photographs and drawings.
- D. Methods to "freshen-up" marks
- E. Methods to make offset marks
- F. Call Dig Safe System Inc. for remark if marks are lost

.....

20. Excavation Precautions

- A. Respect of the marks
- B. Excavation in or near Tolerance Zone
- C. Facility Verification
 - i. When excavation crosses the tolerance zone of an underground facility,
 - ii. When excavation parallels an existing underground facility
 - iii. When horizontal or directional boring
 - iv. When removing pavement or concrete slabs
- D. Support and protection of exposed facilities
- E. Methods to address frozen ground

.....

21. Procedures following damage made to an underground facility

- A. Description of Damage: any nick, dent, scrape, etc
- B. Immediate actions to protect public safety
 - i. This must not include repair or reburial
- C. Immediate notification to the facility operator
- D. Investigate and document circumstances leading to and regarding the damage.
- E. Possible use of UFDR to the Vermont Department of Public Service

.....

22. Procedure to remove marks following excavation

.....

23. Emergency procedures related to damage prevention

- A. Description of an emergency dig

Check list: Facility Operator's Written Underground Facility Damage Prevention Plan (DPP)

Date:

Operator Name:

B. Immediate Notice of excavation is required to be made to Dig Safe System Inc.

.....
24. Methods for employee and contractor training

- A. New hires
- B. Continuing schedule
- C. Ad hoc, refresher, and after at-fault damage
- D. Training materials
 - a. The Operator's plan
 - b. State and or Federal Regulations
 - i. VSA 30 chap. 86
 - ii. Vermont PSB rules 3.800
 - c. Mark-out colors and symbols
 - d. Print Reading
 - e. Operation of location equipment
 - f. "soft excavation techniques
 - g. Contractor qualifications
- E. Training documentation, including personnel trained, personnel titles and date trained
- F. Review training program in response to comments, complaints and history

.....
25. Employee/Contractor/(subcontractor) reconciliation of tasks implemented/completed and performance tracking

- 1) Scrub-out center
- 2) Locating
 - i. How many locates are accurate?
 - ii. How many locates are late? Damage investigation
- 3) Excavation contractors
- 4) Quality assurance program
- 5) Contracts should include performance measures with corresponding and meaningful incentives/penalties
- 6) Conduct regular field audits of locators/contractors
- 7) Regularly meet with contract senior management to review results

.....
26. Customer Awareness/public education

- 1) Participate in training excavators working around the Operator's system/facilities
 - 2) Customer education, bill stuffers and other outreach
-

APPENDIX 6.3: ONE CALL LOCATE REQUEST FORM

One Call Locate Request Form

One Call Ticket Number: _____ System Name: _____

Is the Work Site Marked In White? YES NO

Ticket Response

- | | |
|--|---|
| <input type="checkbox"/> Clear – No Facilities | <input type="checkbox"/> Insufficient Information – DO NOT DIG |
| <input type="checkbox"/> Conflict – Lines Nearby | <input type="checkbox"/> Not Marked Due to No Access |
| <input type="checkbox"/> Contact Excavator | <input type="checkbox"/> Scheduled Date & Time Lines will be Marked |
| <input type="checkbox"/> Marked | <input type="checkbox"/> Voice Message |

Make of Locator Used: _____ Locator Serial #: _____

Active/Conductive Mode Used? NO YES

Marking Methods Used: FLAGS PAINT OTHER (Ex: Stake)

Facilities Involved: Service Line Distribution Main

Is On-Site Inspection of Excavation Required? NO YES Date: _____ Time: _____ am pm

Reason: _____

Excavator/Owner Contacted? NO YES Date: _____ Time: _____ am pm

Name of Excavator/Owner: _____

Excavator/Owner Signature: _____

Does Flagged Location Match Mapped Location? NO YES

If "NO", check for interference and other utilities and confirm marked location.

If "NO", provide sketch and sufficient details to allow maps to be updated.

If "NO", hand dig to verify line location.

Comments/Sketches:

Employee: _____ Date: _____ Time: _____ am pm

Supervisor's (or designee's) Signature: _____ Date: _____

APPENDIX 6.4: EXCAVATOR MEET AGREEMENT/DOCUMENTATION FORM

Excavator Meet Agreement / Documentation Form
To be completed by Excavator with input from Locator
Suggestions: Make in duplicate, separate set for each Locator; Give a copy to Locator

GSOC#: _____ Meet Date: _____ Meet Time: _____

Specific location of Meet: _____

Excavator Name: _____ Phone #: _____ Company _____

Locator Name: _____ Phone #: _____ Company _____

Utility responsible for: CATV _____ Electric _____ Gas _____ Oil _____
 Steam _____ Phone _____ Water _____ San. Sewer _____ Storm Sewer _____

Entire geographic area of proposed excavation:

Proposed excavation area delineated by white markings: Yes No; why is it not practical? _____

Prints / map attached: Yes No

Agreed upon locating schedule: _____

Agreed schedule of future meets or communications: _____

Signature, Excavator: _____ Date: _____

Signature, Locator: _____ Date: _____

Sketch of Request (as needed)

Excavation Start Date: _____ Excavation Start Time: _____

*The excavation start date and time must be at least 24 hours after the proposed meet date and time specified on the notice, excluding Saturdays, Sundays, and holidays. Unless provided for in a written agreement with all affected facility operators.

APPENDIX 6.5

AGA White Paper: Natural Gas Pipelines and Unmarked Sewer Lines – A Damage Prevention Partnership, © American Gas Association, 2010, republished with permission.

**AGA White Paper:
Natural Gas Pipelines
and Unmarked Sewer Lines –
A Damage Prevention Partnership**

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**April 2010
AGA Distribution Construction & Maintenance Committee**

Purpose

The purpose of this white paper is to provide a discussion of the issues related to trenchless pipeline installations in the vicinity of sewer lines. This paper includes reference to existing material related to damage prevention with an emphasis on sewer mains and lateral lines that are not marked. This paper does not imply acceptance of any responsibility or liability of any owner/operator to locate and mark sewer lines; it simply accepts whatever the current condition is in each location and offers guidelines to minimize existing exposure.

On December 30, 2004, AGA published an Engineering Technical Note: “*Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry.*” Attached in the appendix of this document, it shares specific guidelines and practices, which can be considered by natural gas utilities to improve safety. This particular paper seeks to build upon that information by providing insights into how natural gas utilities can collaborate with other stakeholders in getting sewer lines marked on a going-forward basis and in finding ways to effectively deal with existing sewer lines.

Background

Unlike gas, electric, water and telecommunications lines, cross-bored sewer laterals can go undetected for extended periods. These cross-bored sewer laterals are typically found when someone is attempting to unclog a sewer lateral and discovers the bored line inside the sewer lateral. Educating the public, regulatory bodies, sewer operators, developers, and plumbing associations of their roles in getting sewer lines marked will be essential in reducing the dangers associated with unmarked sewer lines. Information and support may also be provided by the local One-Call Agency. The need for this paper is based upon the elevated risk associated with unmarked sewer lines and the increased use of trenchless technology.

Resources / References

Available resources include: i) federal, state and local laws and regulations; ii) guidelines from Common Ground Alliance, American Gas Association, and other organizations; iii) various industry articles; and iv) manufacturer equipment instructions. Although the references listed below may be designed for directional drilling, many of the practices are applicable for other types of trenchless installation procedures.

This section provides specific reference material and sites. References range from general statements, guidelines and practices to specific recommendations. It is designed to provide the reader with a range of material depending on the needs and requirements.

American Gas Association (AGA)

Technical Note

December 30, 2004

“Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry”

www.aga.org

Above document provides detailed recommendations and specific references to sewer lateral lines and recommended processes. **Note: It is included in the appendix of this document.**

Common Ground Alliance

Best Practices Version 6.0

March 2009

“Excavation Practice Statements and Description”

<http://commongroundalliance.com>

Above document is a reference guide with very general statements. No specific reference to sewer lateral lines.

Cross Bore Safety Association

www.crossboresafety.org

This site has a multitude of information.

Distribution Contractors Association

DCA Position Paper – Marking Sewer Laterals

November 16, 2006

<https://dcaweb.org/>

HDD Consortium

2001, 2004, 2008

“Horizontal Directional Drilling – Good Practice Guidelines”

Retail literature through North American Society for Trenchless Technology

<http://www.nastt.org/>

This manual is very detailed with specific recommendations and minimum guidelines. It is specifically related to directional drilling technology with references to preventative measures around sewer facilities.

National Underground Contractors Association

NUCA Position Paper – Locating and Marking Service Laterals

September 26, 2006

www.nuca.com

Office of Pipeline Safety

August 1999

“Study of One-Call Systems and Damage Prevention Best Practices”

Excavation Task Team Best Practices

<http://commongroundalliance.com>

Above document is a reference guide with very general statements. No specific reference to sewer lateral lines.

Definitions

Cross Bore: A utility cross bore is an intersection of an existing underground utility or underground structure by a second utility installed by trenchless technology that results in direct contact between the transactions of the utilities that compromises the integrity of either utility or underground structure.

Sewer Line: Includes any system to remove waste water from a structure including the sanitary sewer lateral, sewer main, or septic system line. This also includes combined sanitary sewer and storm water systems.

Trenchless Technology: includes use of the following:

1. Directional drills
2. Piercing tools (hogs, moles, missiles, etc.)
3. Water boring equipment
4. Augur boring equipment, including pipe jacking
5. Plowing
6. Insertion or pipe-splitting

Verify: To determine or test the accuracy of, as by comparison, investigation or reference.

The Regulatory Environment

All states have One-Call system(s) to distribute planned excavation information to utilities and most state One-Call laws have some type of penalty for non-compliance. However, since each state's enforcement mechanism varies as defined by its particular law, the effectiveness of enforcement varies widely, ranging from extremely active and effective to non-existent. An additional concern is that some states exempt all or portions of sewer systems from their regulations. Some state regulatory agencies are even precluded from assessing fines or penalties on a municipality that may be operating a sewer system.

Some state and local governments own and operate the sewer lines only from the property line to the waste water treatment facility. As a result, sewer lines on private property may either be owned by the property owner or owned and/or operated by the municipality.

From a municipality's perspective, there may be political implications associated with these regulatory and ownership issues. Elected officials are often faced with priorities associated with keeping sewer rates and taxes as low as possible, while simultaneously protecting the safety of their constituencies and the public.

Regardless of future changes in the regulatory environment, each sewer line operator must adhere to all current laws and regulations related to the location and marking of underground facilities in the particular state and locality where the project is located.

A Partnership Model

Natural gas owner/operators and sewer line owner/operators have shared interests:

- Safety of the general public and their customers
- Providing the service at the lowest cost
- Preventing damage to their infrastructure

Sewer line owners/operators face some challenges as portions of their systems can predate piped water or natural gas systems and most are not electronically locatable. Legacy sewer installation records are often inadequate, incomplete, or non-existent and the organizations that support those systems vary in size. Their resources may also vary according to the size of the systems.

Sewer and natural gas utilities should explore mutual damage prevention efforts and sewer system owner/operators may be able to learn from the natural gas utilities that have successfully addressed similar challenges in the past. Both should seek to understand each other's operating policies, practices, requirements and priorities. For example,

- What is the mark-out policy?
- Who owns the service line laterals?
- Who operates and maintains the service line laterals, on and off the public right of way?
- How are sewer lines located?
- What can be done to ensure that all sewer lines (whether new or replacement installations) are constructed in a manner that allows them to be electronically locatable?
- What is the level of involvement in the One Call process?
- Who is responsible for locates of buried facilities on private property?
- What communications, if any, are sent to customers to alert them, especially if they have a responsibility in marking customer-owned facilities under the local state statute?
- Will the sewer owner/operator install an outside cleanout on a homeowner's line if one is not available? (this is sometimes at a cost to the customer)
- How can the sewer owner/operator and the natural gas utility share information on sewer locations?
- What is the sewer owner/operator's typical response to a blocked sewer lateral?

The remainder of this paper focuses on other important steps that may be considered by the natural gas utility and the local sewer owner/operator.

Communication and Education with Other Stakeholders

In some circumstances, a communication and education strategy may be appropriate to help mitigate risk. The natural gas owner/operator can develop their own strategy based upon the unique requirements of each situation. It may be appropriate to encourage sewer system owner/operators (municipalities, city, etc.) to develop their own communication and education strategy to mitigate the risks that may exist for them in relation to their facilities regarding the use of trenchless technologies. **Specific communication examples are listed below, but the list is not intended to be all-inclusive, and not all of the suggestions listed below may be appropriate in all situations.**

- Communicate with and educate municipalities, public works departments, owner/operators of private sewer systems, plumbing industry, companies that rent rotary cutting tools, trade unions, contractors, state regulatory boards, homeowners, and the public.
- Include the trenchless technology topic related to sewer laterals and mains in mailings, letters, and/or bill inserts.
- Work cooperatively with the local One-Call Center to identify a list of locating firms that are available to stake privately owned underground facilities. This will provide property owners a reasonable method to fulfill any responsibility they may have to mark their buried facilities.
- Provide contact information for the facility owner and ask for notification prior to reaming sewer lines.
- As part of an operator's Public Education Program, network with plumbers, equipment rental businesses, owners of private sewer systems (e.g.- mobile home parks, commercial campuses, school complexes, hospitals), and state regulatory boards to develop best practices for investigating blocked sewer lateral lines.
- Work with state licensing boards to ensure that a thorough understanding of unmarked sewer line issues is required of individuals who are endeavoring to obtain or renew a business, plumbing, or contractor's license.

Practices to Consider in Using Trenchless Technologies

The 2004 technical note "*Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry*," identified practices that should be considered when using trenchless technology. The practices will not be applicable or effective for all utilities.

For example:

- Some states and municipalities require a plumber's license to access sewer systems; these licenses are generally not held by the natural gas distribution companies.
- Natural gas distribution companies may have difficulty accessing non-customer premises which are outside of the utility easement in which a trenchless technology was used.
- In many parts of the country, the sewer lateral is owned by the homeowner up to the sewer main and there is no information available for mark-out purposes.
- Many of the practices identified in the 2004 technical note apply to directional drilling, and not to other forms of trenchless technology.

When trenchless technology is used by a contractor working for a natural gas distribution company, additional safety language may be appropriate in the contract to clearly convey that the contractor needs to exercise prudent steps in assuring that all utility lines have been located. Additional insurance requirements may also be considered to ensure the appropriate levels of liability insurance are maintained to cover associated risk. Actual insurance requirements should be reviewed by appropriate personnel.

For simple work efforts where the natural gas distribution company or its contractor is the only entity involved in the construction, the practices outlined in the 2004 technical note "*Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry*" may be sufficient when

using trenchless technology. For more complex work efforts or for when there are multiple companies, agencies, or municipalities involved, the 2004 technical note and the following additional practices may be considered by natural gas operators and sewer operators during the planning and installation effort:

1. Planning

The following are some additional practices for consideration during the planning stages for use of trenchless technology:

- Proper Engineering Design, determining a path of installation which will reduce the likelihood of utility interference
- Use of sub-surface utility engineering methods
- Participation in utility coordinating committees
- Participation in municipal coordinating committees
- Depending on the size and complexity of a project or activity, hold pre-bid / construction meetings with utilities and public works officials, prior to the start and during construction
- Use experienced contractors

2. Installation

Reminder: Follow applicable state one-call and dig-safe laws.

Below are some additional practices for consideration during a natural gas installation project that uses trenchless technology. (The local sewer operator may be able to assist.)

- Consider pre-location of sewer laterals where an exterior clean-out is available:
 - Measure the depth of the sewer line lateral. Caution should be taken because a sewer lateral may not have consistent grade or path from the building entrance to the sewer main.
 - Run a fish tape down through the exterior clean-out, use a line locator in the conductive mode, and verify location and depth by pothole; or
 - Insert a sonde in the exterior clean-out and use a drill head locator to verify location and depth; or
 - Pre-camera through the exterior clean-out to verify location and depth.
- Pot hole along the path, as appropriate for conditions
 - Establish criteria for which every sewer line must be pot holed (such as privately owned sewer systems including trailer parks, schools, college campuses, shopping malls, etc.)
 - Establish criteria for spaced verification of sewer laterals including:
 - Conditions that allow the practice (long, known depth sewer mains, etc.)
 - Verification at some set distance (for example, every 200' when laterals are 4' deep or every 400' when laterals are 6' deep)

3. Post-installation Records and Metrics

The following practice is for consideration during the documentation stages when using trenchless technology:

- Natural gas pipelines installed with trenchless technology can be identified on field work orders or company mapping systems as such.

NOTE: This technical note is a suggested guide only, and the use of these Guidelines or any variation thereof, shall be at the sole discretion and risk of the user parties. See Notice and Disclaimer on final page.

Appendix

Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry

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December 30, 2004
AGA Distribution, Construction & Maintenance Committee

DCM – 2004 – 4-1

DIRECTIONAL DRILLING DAMAGE PREVENTION GUIDELINES FOR THE NATURAL GAS INDUSTRY

PURPOSE

The purpose of this paper is to provide general guidelines for natural gas operators to use in the enhancement of their company's damage prevention programs for directional drilling operations. This paper provides parameters for protecting existing natural gas facilities from damage during directional drilling activities, as well as includes general guidance on underground damage prevention procedures when installing new natural gas facilities by directional drilling.

Each natural gas operator is responsible for developing their own damage prevention program with guidelines, policies and procedures that are specific to the application of directional drilling within the region of their facilities. The information in this document is not intended to replace local, state, federal or private company rules or regulations. These guidelines are a suggested guide only, and the use of these guidelines or any variation thereof, shall be at the sole discretion and risk of the user parties.

BACKGROUND

The background of the need for the development of these safety guidelines is based on suggestions from two governmental agencies associated with the natural gas pipeline industry and a request from a natural gas industry association:

- National Transportation Safety Board (NTSB) Safety Recommendation P-99-1, dated April 28, 1999, which directed that the Research & Special Programs Administration (RSPA) ensure that the natural gas operators' damage prevention programs include actions to protect their facilities when directional drilling operations are conducted in proximity to those facilities.
- In follow-up to this advisory, RSPA issued a Pipeline Safety Advisory Bulletin ADB-99-04, dated August 23, 1999 to all owners and operators of hazardous liquid and natural gas pipeline facilities. This advisory urged these operators to review, and amend if

necessary, their written damage prevention program to minimize the risks associated with directional drilling and other trenchless technology operations near buried pipelines. Its purpose was to ensure that pipeline operators take actions to recognize the dangers associated with directional drilling and other trenchless technology operations, and to ensure that underground pipeline facilities are adequately located and protected from inadvertent damage.

- The American Gas Association (AGA) Operating Section Managing Committee requested that general safety guidelines for directional drilling operations in the proximity of natural gas facilities be developed.

RESOURCES

There are numerous articles, guidelines and instructions on the practice of directional drilling from various trade associations and manufacturers of equipment. Those documents are excellent resources for understanding the full extent of safe directional drilling practices. Though this paper will incorporate many of the already documented practices for safe directional drilling, its main purpose is to highlight the appropriate safety practices for natural gas operators to ensure that their underground facilities are adequately located and protected from damage.

The sources used for this paper include excerpts from materials prepared by the directional drilling trade associations, along with suggested practices that are in-development and in-place by member companies of the AGA.

DESCRIPTION OF PROCESS

Directional drilling is a trenchless method of installing underground facilities that can reduce the expense and difficulties that are experienced in open trench construction practices. The usage of directional drilling will be determined by the operator based on many factors. Some of these factors may include the site conditions, size of job, soil conditions, environmental considerations, subsurface interference, traffic disruption, and disruption to the public. It is typically used on river or stream crossings, railroad crossings, highway crossings, well-developed areas and environmentally sensitive areas.

The typical technique for installing pipe by directional drilling uses a surface mounted drill rig that launches drill rods creating a string of rods (called the drill string) below the ground guided by a drill head that is directionally controlled by the drill operator. The direction of the drill is along a pre-determined path (called the drill path) based upon the above ground and below ground, pre-construction investigations of the site. A locating device is used during the drill to track the location of the drill head so that the operator may make adjustments as necessary. A small diameter pilot hole is drilled from the entrance point (typically in a sending pit) to the desired exit point (receiving pit). It is necessary to use a drilling fluid during drilling to lubricate and protect the pipe, and to maintain the size of the hole being opened. Following the exit of the pilot drill bit, the hole is then enlarged by the use of a backreamer attached to the end of the drill string which is pulled back through the pilot hole. As the backreaming takes place, the pipe

being installed is also pulled into the hole. Directional drilling may require the use of a casing pipe to protect the carrier pipe where required and/or dictated by an outside agency.

DIRECTIONAL DRILLING GUIDELINES

General

The listed guidelines are general in nature and contain some suggested procedures. Precautions recommended by manufacturers of trenchless technology equipment should be reviewed prior to construction. Applicable state and local requirements for damage prevention should be followed.

Employee Safety

- Directional drilling, whether by the operator in installing new natural gas pipelines or by a third party installing facilities in the proximity of natural gas pipelines, should follow normal construction safety practices that are in accordance with local and federal safety guidelines.
- In addition, all recommended safety practices by directional drilling equipment manufacturers should be adhered to.
- The primary safety issue for field personnel is striking underground utilities. Proper planning and adequate protective measures will provide a safe work environment for the crews and minimize utility damage.
- Employees involved in any aspect of a directional drilling project should wear the appropriate protective equipment based on the conditions they are operating in and required by federal, state, local and company regulations. Appropriate personal protective equipment for directional drilling operations may include, but is not limited to, the following items: hard hat, gloves, safety glasses, hearing protection, flagger/traffic vests, dust masks, and electrical-protection gloves and boots.
- All drill machines should be equipped with an electrical strike detector in the event that the drill rods strike an energized underground utility. Field personnel should make sure that the strike detector is fully operational prior to the start of any directional drilling activities. The strike detector shall be entered into the ground prior to setting the anchor stakes into the ground.
- The drilling machine shall be properly grounded to assure operator protection in the event that the drill rod hits an electric line. Should the alarm go off, the operator should remain on the grounded machine until the drill rod is disconnected from the electrical line or the electric line is shut down.
- Only employees who have been trained and qualified should be permitted to operate the drilling equipment. Personnel should familiarize themselves with any safety concerns addressed in the operator's manual.

Planning

- If directional drilling must be used in streets with parallel runs of gas transmission mains, electric transmission lines, hazardous liquid pipelines, fiber optic lines and other similar facilities, it is advised that a minimum separation between the various underground facilities be established that ensures the safety of the facilities.
- The separation between the gas pipeline and other facilities must be sufficient to allow for maintenance activities on both utilities. Be sure to check local regulations for the minimum separation distances between the gas pipeline and the other facilities.
- Design and installation of metallic structures should be done in such a manner to minimize and mitigate damage from stray current and to prevent interference with existing cathodic protection current distribution on adjacent or crossed facilities.
- Drill paths that are parallel to within 3 feet of any utility, including gas lines, should be avoided. However, when deemed necessary to drill within 3 feet of a utility, the drill head should be physically located at regular intervals dependent on soil type and surrounding conditions.
- Drilling contractor should have a plan in place in the event of a utility strike. This plan should also include the notification of the utility owner.

Site Investigation

- Establish a proposed drill path and visually inspect the potential site for suitability for directional drilling by walking the area.
- Be alert to any obstructions and indications of the presence of other underground facilities or structures such as catch basins, sewers, water boxes, manhole covers, valve box covers, meter pits, telephone and cable television boxes, electrical transformers, conduit or drop lines from utility poles, pavement patches, previous locate marks, ditch line depressions, out buildings that may have unmarked utilities serving them, underground shutoffs, etc.
- Consider talking with local residents who may have knowledge of subsurface activities in the area.
- Review available underground facility maps.
- Depending on the scope of the project, most directionally drilled natural gas main installations should be straight, with a 3 feet minimum cover, and not vary by more than 2 feet horizontally. However, each utility will need to determine the appropriate minimum cover based on their company's operating specifications as well as the actual physical operating conditions where the pipe is installed.

- Establish a site where there is sufficient room for entrance and exit tie-in pits, drill equipment, and safe operation.
- After determining the proposed drill path and delineating the work area with white paint, contact the appropriate utility One-Call provider to ensure that all underground facilities are located and marked accordingly by their owners. Request through the One-Call provider the location of other underground utilities. If possible, identify the presence of utilities not located through One-Call and attempt to determine their location by contacting the owner(s) of those facilities or employing other means to identify the path in which they are running. Note: not all One-Call Centers will send mark-out requests for design purposes.
- In locating facilities, it should be noted that One-Call providers will only help to notify owners of active utility services. Since there may be abandoned and private services that are not located, it is worthwhile to check with utility companies or local residents to determine if their knowledge will reveal any helpful information for critical situations.
- In finalizing the drill path, determine the depth and location of all underground facilities along that path to the extent practicable. Test holing should be considered.
- Establish locations of all entrance and exit pits to ensure that there are not any aboveground or subsurface structures that would interfere with the drilling equipment's operation. Ensure that there is adequate clearance of overhead electric, telephone or cable lines for these locations.
- Establish by test holes or from experience the suitability of soil conditions for directional drilling along the proposed drill path. Directional drilling may not be suitable if the subsoil is composed of large grain material (e.g., gravel and cobble fragments, rock, buried debris, abandoned foundations).

Pre-construction

- Call the local One-Call provider with sufficient advance notice to ensure that all underground facilities are marked, or verified that they are not in the location of the proposed work.
- Notification to all underground utilities through the local One-Call provider must be typically made 48 to 72 hours prior to the start of any directional drilling, depending on the requirements in the state where work is taking place.
- Notify residential and business neighbors, along with privately owned services (e.g., gas, water, and electric) in the area of impending work.
- Proper jobsite setup and layout are essential to ensure safe directional drilling operations. The following should be considered when preparing the jobsite: work area protection,

flagger requirements, barricades or other methods to safeguard the public and employees, applicable safety and excavation requirements, marking and locating hazards, verifying One-Call markings, checking location and depth of underground facilities, checking for signs of venting associated with underground tanks, etc.

- There should be a briefing for all employees on the jobsite prior to beginning operations and periodically during the project. The briefing should include:
 - Overview of project plans and identification of field supervision
 - Location and access to local emergency facilities
 - Location and type of buried services and overhead obstructions
 - Jobsite safety: warnings, barriers, emergency procedures, personal protective equipment
- Review the selected locations for the boring machine and the entrance/exit pits to ensure that there are no subsurface or aboveground interferences.
- A visual inspection should be made for the proposed drill path just prior to the drilling operation to ensure that all utilities are marked and that there are no subsurface interferences.
- Expose all underground utilities that are perpendicular or parallel to the bore path, and verify the depth of the facilities. Efforts to locate the existing facility may utilize such techniques as electronic location devices, hand digging, pot holing when practical, vacuum excavation methods, use of pressurized air or water, pneumatic hand tools or other noninvasive methods. Note: some HDD methods use slurry, and digging void in the drill path causes the drill slurry to rise to the surface.
- Existing underground facilities should be exposed with sufficient space around the facility so that the drilling operation can be visually checked to ensure that it will not impact the facility.
- If in the course of excavation the location of the existing facility is found to be incorrect, the facility owner should be contacted so they can correct their records.
- The crew leader should visually inspect the planned drill path, just prior to proceeding with the drilling operation, to ensure that all utility services and underground structures have been identified and test holes made as required.
- Avoid sinking anchor stakes for the boring machine within 24 inches of any utility. If this requirement is impossible to meet, then test holes should be made at a depth equal to 12 inches deeper than the length of the anchor stakes to ensure no strike will occur when anchoring the machine.

Construction

- **Parallel installations:** Test holes should be excavated at intervals along the existing underground facility closest to the drill path to positively locate and inspect this facility throughout drilling operations to assure no direct or incidental contact. Test holes should be a minimum of 12” deeper than the desired depth of the facility that is to be installed. The minimum intervals for these test holes are dependent on the proximity of the existing facility to the drill path, as well as the type of facility being paralleled. The drilling path should be continuously monitored and it is suggested that the location of the drill head is marked at least every 10 feet.
- **Paralleling gas installations:** For existing gas facilities, a typical suggestion is to excavate a test hole every 50 feet if the drill path is within 5 feet of a distribution gas pipeline. If an existing gas pipeline that is being paralleled crosses under pavement, the pipeline should be exposed at each curb for monitoring. The intervals for the test holes will be dependent on the proximity of the existing pipeline to the drill path, as well as the type of gas pipeline in operation.
- **Crossing installations:** Consider excavating test holes at all crossing locations to the extent practicable. The existing facility should be completely exposed with sufficient visual area so that it can be assured that the drilling operations do not impact the facility. A typical practice is to excavate at least 12 inches below the existing facility and 24 inches on either side of the located position of the facility to be crossed. The 24 inches on either side is in addition to the facility width marked by the line locator.
- The test holes can be used to observe the drill head as it passes exposed substructures. Test holes are also used to ensure adequate clearance for the back-reamer (pull-back head). Note that the backreaming process will be a larger hole size and should be taken into consideration when specifying minimum separation distances from existing facilities.
- Establish, check and maintain proper radio communication between the operator and locator at all times before and during directional drilling operations. Communication between the drill operator, locator and operating personnel is critical. Adequate communications should be established between the operator of the drill rig and the crew member that is tracking the location of the drill string during these operations. Appropriate hand signals should be agreed upon in case the electronic communication fails.
- Appropriate locate and guidance equipment for steering and maintaining accurate location of the drilling head should be used during all drilling operations. Using electronic locating equipment, the location of the drill head during the drilling operation should be continuously monitored to ensure that the drill path follows the design profile. Locations should be marked or staked as required. The drill head should be inspected at test holes previously made at substructure locations to ensure adequate clearance.

- If possible, maintain a minimum separation of 12" when crossing gas facilities; however, if facilities are fully exposed, then a separation of less than 12" may be considered where regulations allow.
- The aboveground drill path should be sufficiently accessible to allow the locator to be able to monitor the progress of the drill head. Overhead structures or wire lines may present potential problems in the accuracy of the electronic locator along the drill path. Steel-reinforced concrete (e.g., sidewalks, driveways, roads, etc.), invisible dog fences, underground power cables and fiber optic cable can also present problems and may interfere in use of the locator. Walking the drill path with the locator prior to the drill string being started can reveal interference problems.
- The horizontal and vertical position of the drill head should be closely monitored as the drilling progresses. The location of the reaming tool should also be closely monitored during the backreaming process to ensure that the reaming tool follows the path of the pilot hole.
- Directional drilling crews should perform periodic sweeps of the area during the project to further ensure that all possible attempts to avoid damage to marked and unmarked facilities have been made.
- Cease drilling operations if an unidentifiable, abnormal or unanticipated resistance or sudden movement of the drill string is encountered. Also, cease operations if other conditions develop (lightning, etc.) that could affect the safe operation of the equipment and personnel. Proceed only after the source of the disturbance has been identified and/or eliminated. Particular care should be taken to ensure that existing substructures are not penetrated. If any underground facility is known to be damaged during the project, notify the appropriate operator and/or emergency response personnel immediately, as appropriate.
- If determined to be needed following the completion of a directional drill near an existing gas pipeline, perform a leak survey of the pipeline to ensure that it was not impacted by the new installation.

Directional Drilling in Proximity of Sewer Facilities

- Sewer systems are especially vulnerable to damage from directional drilling operations for the following reasons:
 - Lines are often non-metallic, making them difficult to locate.
 - Clean-outs or other indications of laterals may be hidden or non-existent.
 - Damage may not be readily apparent when a sewer, particularly a gravity flow system, is pierced by a drilling machine.
- Additional efforts should be considered in determining whether sewer lines and laterals are within the proposed construction area of a directional drilling project. Some of these efforts may include the following:

- Contact the city, building owners, local plumbers, and other persons that can provide assistance with identifying the existence and location of sewer lines.
 - Obtain maps and drawings of the sewer system from the city or other entity. Maps can provide the depth of the sewer lines and other valuable information that can assist in determining the location of the sewer lines within the proposed drill path.
 - Visually check the job site for sewer cleanouts, manhole covers, and any markings on curbs or gutters that may exist for sewer facilities.
 - Use internal camera systems, if available, that travel down the main sewer line and allow the laterals to be located visually.
 - Use electronic technology, if available, to track a locating transmitter inserted into a sewer and/or lateral to determine its path and depth.
 - Use ground penetrating radar, if available, to assist in locating sewer lines and laterals.

- In determining the depth of the sewer and laterals, the following guidelines should be considered:
 - If a sewer line is located, check the direction of the flow of the water and the direction of the pipe. The flow direction will tell the grade of the sewer. It will help judge whether the sewer will be shallower or deeper where the drill is being made.
 - Access manhole covers and measure the depth of the main sewer line.
 - Access outside clean-outs and measure the depth of the sewer line lateral. Caution should be taken because a sewer lateral may not have a consistent grade from the building entrance to the sewer line.
 - Obtain access to buildings that do not have an outside clean-out and visually identify where the sewer exits the structure. Visually determine the depth of the sewer lateral by identifying where the lateral exits the building versus the depth of the sewer main at the street.

- If known sewer facilities cannot be positively located, then consider the following alternatives:
 - Do not use directional drilling or other trenchless equipment for installing the gas main or service.
 - Use the directional drilling equipment and perform a post-construction camera inspection of possibly affected sewer lines.
 - Use directional drilling equipment only in those areas where the location and depth of sewer lines have been determined to be safely outside the drill path and use open trench equipment for areas where the sewer line conflicts have not been ruled out.
 - Use a sewer listening device where sewer lines are not physically exposed. It is important that a person monitoring the sewer for penetration be alert to any unusual noise and immediately communicates the information to the equipment operator. It is possible that the drill penetration will coincide with a resistance felt by the operator.

NOTE: These "Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry" are a suggested guide only, and the use of these Guidelines or any variation thereof, shall be at the sole discretion and risk of the user parties. See Notice and Disclaimer on final page.

SOURCES

- National Transportations Safety Board (NTSB) Safety Recommendation P-99-1, dated April 28, 1999
- RSPA Pipeline Safety Advisory Bulletin ADB-99-04, dated August 23, 1999
- GPTC Guide for Gas Transmission and Distribution Piping Systems: 2003 Edition - Guide Material Appendix G-192-6 - "Subsurface Damage Prevention Guidelines for Directional Drilling and Other Trenchless Technologies"
- "Common Ground: Study of One-Call Systems and Damage Prevention Best Practices", August 1999
- HDD Consortium, "Horizontal Directional Drilling - Good Practice Guidelines", May 2001
- Directional Crossing Contractors Association, "Horizontal Drilling Safe Operations Guidelines", 2000
- Various member companies of the American Gas Association - specifications, operations guidelines, procedures manuals, etc.

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APPENDIX 6.6: RESOURCES

Find your local One Call Center

<https://call811.com/811-In-Your-State>

Whitepaper: Call before you dig, but beware – not every utility gets marked

<https://dps.mn.gov/divisions/ops/forms-documents/Documents/MNOPS%20Private%20Facilities.pdf>

Excavation Safety Guide

www.ExcavationSafetyGuide.com

Crossbore Safety Association (CBSA)

<http://www.crossboresafety.org/>

Common Ground Alliance (CGA)

<http://www.commongroundalliance.com>

CGA Best Practices

<http://www.commongroundalliance.com/programs/best-practices>

American Gas Association Gas Piping Technology Committee (GPTC) Guide (Ordering Information)

<http://www.techstreet.com/aga>

CHAPTER VII CORROSION CONTROL

PURPOSE

The purpose of this guidance document is to provide operators with the necessary information to establish procedures for corrosion monitoring, remedial action and the operation and maintenance of cathodic protection systems. Procedures developed using the information provided in this chapter should include information for monitoring and controlling external, internal and atmospheric corrosion. See the appendix to this chapter for information on methods for compliance.

REQUIREMENTS (49 CFR PART 192)

This chapter contains a basic description of the corrosion control requirements contained in the pipeline safety regulations. The complete text of the corrosion control requirements can be found in 49 CFR Part 192, Subpart I- Requirements of Corrosion Control. This guidance document is not a substitute for the requirements contained therein.

QUALIFIED PERSON (§ 192.453)

The procedures developed using the information in this chapter should be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods. The information in this chapter is insufficient to qualify an individual to perform the necessary design or installation.

SCOPE (§ 192.452)

Written procedures should address the protection of all metallic pipelines including service and main lines from external, internal, and atmospheric corrosion. If a buried or submerged pipeline was installed before August 1, 1971, these procedures may be applicable where active corrosion is found. The areas of active corrosion must be cathodically protected.

BURIED PIPELINES INSTALLED AFTER JULY 31, 1971 (§ 192.455)

Buried metallic pipelines installed after July 31, 1971, must be provided with the following:

- External protective coating meeting 192.461, and
- Cathodic protection (CP) system installed and operating within one year of pipeline completion

The exception to this requirement requires detailed demonstration that a corrosive environment does not exist. However, any pipeline that is externally coated must have a CP system installed, regardless of the exception.

BURIED PIPELINES INSTALLED BEFORE AUGUST 1, 1971 (§ 192.457)

Except for cast iron or ductile iron, any buried pipeline installed before August 1, 1971, must be cathodically protected where active corrosion is found on the following:

- Bare or coated distribution lines
- Bare or ineffectively coated transmission lines
- Bare or coated pipes at compressor, regulator and measuring stations

EXAMINATION OF EXPOSED PIPE (§ 192.459)

Whenever buried pipe is exposed or dug up, the operator is required to examine the exposed portion of the pipe for evidence of corrosion on bare pipe or for deterioration of the coating on coated pipe. A record of this examination must be maintained. If the coating has deteriorated or the bare pipe has evidence of corrosion, remedial action must be taken.



PROTECTIVE COATINGS (§ 192.461)

Any external coating applied for the purpose of external corrosion control must

- Be applied on a properly prepared surface,
- Have sufficient adhesion to the metal surface to resist underfilm migration of moisture,
- Resist cracking, and
- Be compatible with CP systems

Each installation of coating must be inspected just prior to lowering the pipe into the trench before backfilling. Any damage to the coating must be repaired and provisions should be made to prevent damage from backfill and other adverse conditions.

CATHODIC PROTECTION (§ 192.463)

Each CP system must provide a level of protection that meets one of five criteria listed in Appendix D of 49 CFR Part 192 to comply with the pipeline safety regulations for CP of steel, cast iron and ductile iron structures. Of these, two methods are typically used, the first being the achievement of a negative (cathodic) voltage of at least -0.85 VDC with reference to a saturated copper-copper sulfate half-cell; the second being the achievement of a negative -100 mVDC shift from a depolarized state. The other methods are rarely if ever used to confirm sufficient CP.

CATHODIC PROTECTION MONITORING (REQUIREMENT § 192.465)

Sacrificial Anode Systems

A piping system that is under CP must be systematically monitored. Tests for effectiveness of sacrificial anode CP systems must be done at least once every year, but with intervals not exceeding 15 months. Records of this monitoring must be maintained. An operator must establish procedures to monitor the level of CP being provided. Some general guidelines for monitoring CP can be found in the appendix to this Chapter.

Rectifier Test and Inspection

When using rectifiers to provide cathodic protection, each rectifier must be inspected six times every year to ensure that the rectifier(s) is operating properly. The intervals must not exceed 2-1/2 months. Records must be maintained. Guidelines for rectifier inspection can be found in the appendix to this Chapter.

Following are general guidelines for a rectifier inspection:

- Ensure that the power company meter is turning. If the meter has not moved since last inspection, that could be an indication that the rectifier is not working. An exception might be if the rectifier is solar powered. →
- Unlock the rectifier and clean rectifier screens of insects, nests, etc. to allow for proper cooling. Be sure the area around rectifier is clear of high weeds and not in need of any other maintenance.
- Turn off the breaker and inspect all connections for tightness. If any of the connections are warm to the touch, this could indicate a loose connection. →
- Measure the rectifier's current amperage output and record the reading. →
- If the reading was taken with the panel shunt, the DC millivolt reading must be converted utilizing the appropriate shunt correction factor to get the actual rectifier current output.
- Measure the rectifier voltage output and record reading. →
- Relock the rectifier.

If upon inspection, the rectifier has zero output, or if its output is less than 50% of its normal output, prompt remedial action is required to correct any deficiencies indicated by the inspection.



Periodic Monitoring of Older Systems

Where the pipeline was installed prior to August 1, 1971, and active corrosion was found per 192.457(b), the operator must re-evaluate the unprotected pipeline not less than every 3 years at intervals not exceeding 39 months, using an electrical survey to determine areas of active corrosion. However, on distribution lines and where electrical surveys are otherwise impractical, other means can be used to determine areas of active corrosion.

Testing Short Sections

Short, separately protected service lines or short, protected mains may be surveyed on a sampling basis. At least 10 percent of these short sections and services must be checked each year so that all short sections in the system are tested in a 10-year period. An Operator should establish procedures to test and remediate short sections.

Examples of short, separately protected pipe in an LP gas system would be:

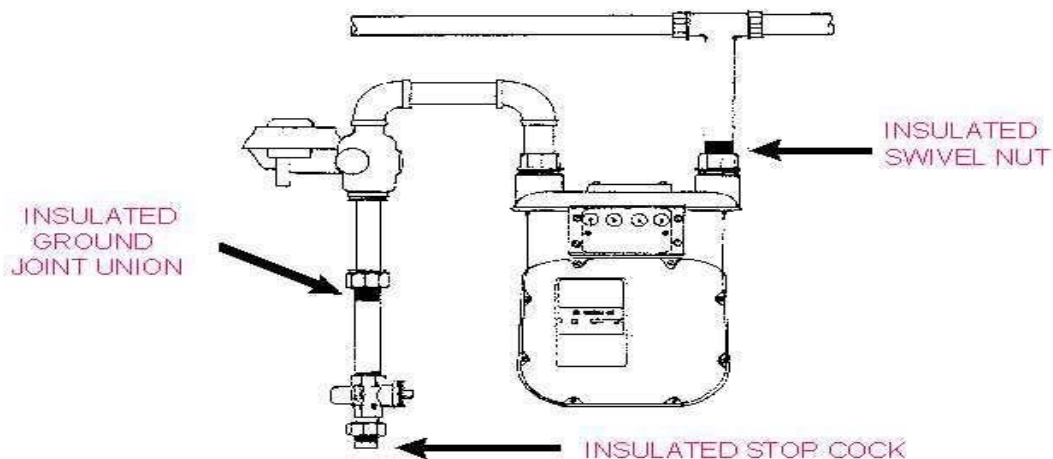
- Steel service lines connected to, but electrically isolated from, the main,
- Steel service risers that have cathodic protection provided by an anode and that are used to transition from underground plastic service lines.

ELECTRICAL ISOLATION (§ 192.467)

Pipelines must be electrically isolated from other underground metallic structures (unless electrically interconnected and cathodically protected as a single unit).

Dielectric isolation devices are typically installed:

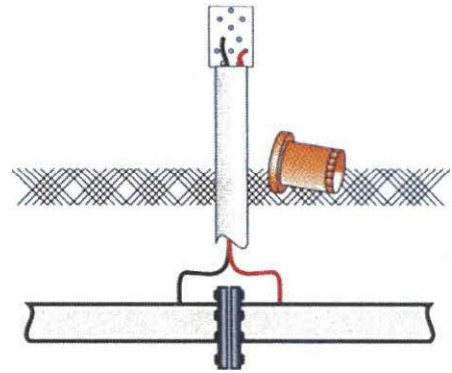
- On meter installations or regulators to isolate the underground piping.



- To separate dissimilar metals from each other,
- To electrically isolate sections of pipeline into manageable sections, and/or
- To separate cathodically protected lines from unprotected lines.

TEST STATIONS (§§ 192.469 AND 192.471)

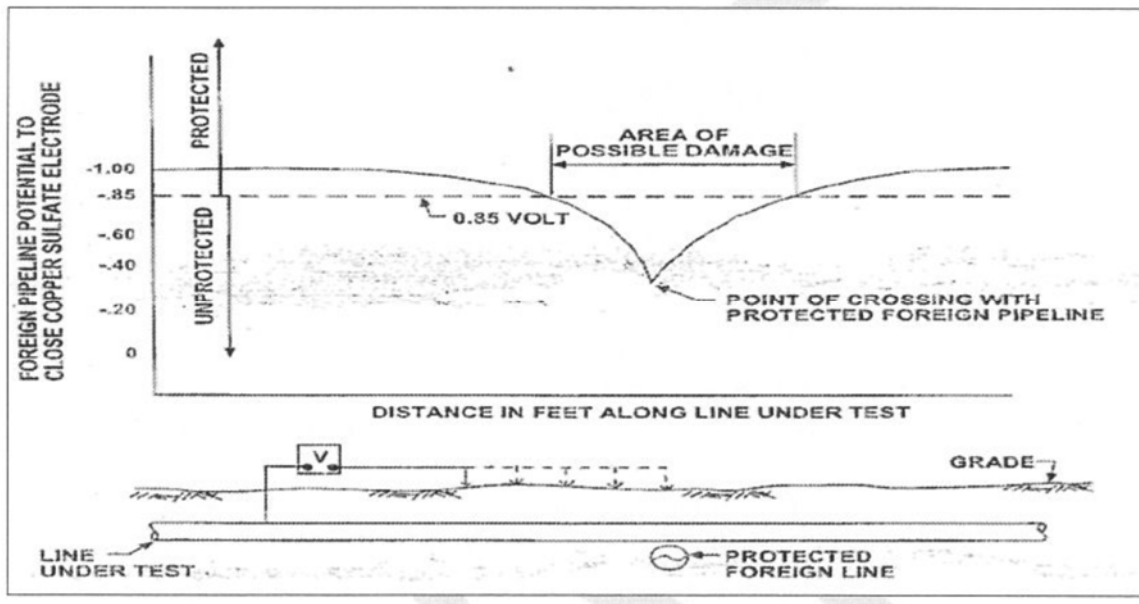
Each pipeline under CP should have sufficient test stations or other contact points for electrical measurement to determine the adequacy of CP. Test points should be shown on a CP system map. A test lead wire must be connected to the pipeline so as to remain secure and electrically conductive. The test lead wire at the point of connection to the pipeline must be coated to insulate the wire and the exposed bared metallic area.



INTERFERENCE TESTING (§ 192.473)

An operator should establish procedures to minimize the adverse effects from stray currents on underground piping systems. Where interference currents are suspected, one or more of the following test methods can be used.

- Measurements of the pipe-to-soil potential with a recording or indicating instrument;
- Measurements of the current flowing on the pipeline with a recording or indicating instrument;
- Measurements of the variations in current output of the suspected source of interference current and correlation with measurements obtained from the pipeline.



REMIEDIATING INTERFERENCE PROBLEMS

The following methods may be used individually or in combination to solve an interference problem:

- The installation of an electrical bond(s) of proper resistance between the affected structures. The bond will electrically conduct interference current from an affected structure (pipeline) to the interfering structure or current source, preventing corrosion. The following must also be considered:
 - If fluctuating current is present, unidirectional control devices such as diodes or reverse control switches may be required in conjunction with the electrical bond to prevent reversal of current,
 - A resistor may be necessary in the bond circuit to control flow of electrical current from the affected structure to the interfering structure,
 - The attachment of electrical bonds can reduce the level of CP on the interfering structure. Supplementary CP may then be required on the interfering structure to compensate for this effect.

INTERNAL CORROSION INSPECTION (§ 192.475)

Whenever a section of pipe is removed from the system, the internal surface must be inspected for evidence of corrosion. Where internal corrosion is found, the following steps must be taken:

- Investigate adjacent pipe to determine the extent of internal corrosion, and
- The operator must decide on the repair steps and actions to monitor and minimize future internal corrosion.



Be sure to keep records of this inspection.

ATMOSPHERIC CORROSION CONTROL AND MONITORING (§§ 192.479 AND 192.481)

Newly installed aboveground pipelines must be cleaned and coated with a material suitable for the prevention of atmospheric corrosion, unless the pipeline can comply with 192.479 (c).

All the aboveground piping, tanks, valves, regulators and meter installations must be inspected at least once every 3 calendar years, but with intervals not exceeding 39 months for evidence of corrosion. An operator must establish procedures to monitor atmospheric corrosion which gives particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings and at pipe supports.



The following provides some general guidelines for atmospheric corrosion inspection:

- Visually inspect all above-ground piping, tanks, valves and meter installations for evidence of corrosion.
- When tank(s), meter, valves, regulators and piping are observed, determine the corrosion condition and document the findings on the Atmospheric Corrosion Control Inspection Form:
 - None- No corrosion evident or visible
 - Mild - Slight surface rust present
 - Moderate-Slight surface rust visible with localized (non-uniform) pitting present in specified areas
 - Severe- Surface rust visible with General (uniform) pitting present

Any evidence of corrosion, whether its condition is determined to be mild, moderate or severe, must be protected by a suitable coating to prevent atmospheric corrosion. Severe corrosion must have prompt remedial action taken in accordance with § 192.483 and either § § 192.485, 192.487 or 192.489. See the appendix to this chapter for examples of protective methods.



Example: Atmospheric corrosion at a meter riser can be prevented by either jacketing the exposed pipe or by keeping it properly painted. Corrosion is usually more severe at the point the pipe comes out of the ground and this area may have to be exposed to determine the severity of the atmospheric corrosion.

REMEDIAL MEASURES (§§ 192.483 AND 192.487)

If any coating damage is observed such as holidays or disbonded coating, the damaged coating shall be repaired.

If the pipe segment is replaced, the new replacement segment must meet the following:

- Each segment of buried or submerged metallic pipe that replaces pipe removed because of external corrosion must have a properly prepared surface and be coated with an approved coating,
- Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected, and
- Each segment of replacement pipe must be pressure tested.

Each distribution line segment, other than for cast iron and ductile iron pipelines, with a wall loss greater than 70% of the nominal wall thickness must be replaced or repaired. Localized corrosion pitting with wall loss greater than 70% is likely to result in leaks and must be repaired or replaced. When the remaining wall is less than 30% of the nominal wall thickness, and the line segment cannot immediately be repaired or replaced, the line pressure shall be reduced to a safe operating pressure.

CORROSION CONTROL RECORDS (REQUIREMENT § 192.491)

Operators must maintain records or maps of their CP system to show the location of cathodically protected piping, CP facilities, galvanic anodes, and neighboring structures bonded to the CP system. These records must be maintained for as long as the pipeline remains in service.

Records of all tests, surveys, or inspections required by the pipeline safety code must be maintained. Records must be retained for at least 5 years, except that records related to cathodic protection surveys and internal corrosion must be retained for as long as the pipeline remains in service.

APPENDIX: SOME PRINCIPLES AND PRACTICES OF CATHODIC PROTECTION

This appendix supplements the information in Chapter VII -Corrosion by giving operators with little or no experience in CP, a review of the general principles and practices of CP. Common causes of corrosion, types of pipe coatings and criteria for CP are among the topics. A checklist of steps included. Basic definitions and illustrations are used to clarify the subject. This section does not go into great depth. Therefore, reading this section alone will not qualify an operator to design and implement CP systems.

QUALIFICATION OF PERSONNEL (§ 192.453)

This appendix does not provide requirements for qualifying individuals to design, install or maintain corrosion protection systems. The determination of whether an individual is qualified to perform such work can be made with assistance from the National Association of Corrosion Engineers.

Techniques for Compliance

The following is a list of sources where operators of LP gas systems may find qualified personnel to develop and carry out a corrosion control program:

- There are many consultants and experts who specialize in cathodic protection. Many advertise in gas trade journals,
- Another source, for LP operators, is an experienced corrosion engineer or technician working for a local gas utility company. Such experts may be able to implement cathodic protection for LP gas operators or refer them to local qualified corrosion engineers,
- OPS suggests that operators of LP gas systems encourage their respective trade associations to gather and maintain records of available consultants or contractors who are qualified in their specific region,
- The local chapter of the National Association of Corrosion Engineers (NACE) may be able to provide useful information.

Operators who are unsure of a consultant's qualification in corrosion control should ask for references to previous jobs.

CORROSION CONTROL REQUIREMENTS FOR PIPELINES INSTALLED AFTER JULY 31, 1971 (§ 192.455)

All buried metallic pipe installed after July 31, 1971, must be properly coated and have a cathodic protection system designed to protect the pipe in its entirety as per 49 CFR Part 192.

Newly constructed metallic pipelines must be coated before installation and must have a CP system installed and placed in operation in its entirety within one year after construction of the pipeline.

Cathodic protection requirements do not apply to electrically isolated, metal alloy fittings in plastic pipelines if the alloy of the fitting provides corrosion control and if corrosion pitting will not cause leakage (this must be documented with either experimental data or data from the fitting manufacturer).

CORROSION CONTROL REQUIREMENTS FOR PIPELINES INSTALLED BEFORE AUGUST 1,
1971 (§ 192.457)

For LP gas systems, the pipeline safety regulations require that underground bare or ineffectively coated distribution pipelines and underground tanks be cathodically protected in areas of active corrosion. The system operator must have a definition of what is considered active corrosion.

The operator must determine areas of active corrosion by (a) electrical survey, (b) where electrical survey is impractical, (c) by the study of corrosion and (d) leak history records or by leak detection surveys.

Active corrosion means continuing corrosion, which, unless controlled, could result in a condition that is detrimental to public safety.

As a guideline for operators when determining corrosion to be detrimental to public safety (active corrosion), the following can be used:

- For LP gas operators, all continuing corrosion occurring on underground metallic pipes and tanks should be considered active and pipes should be cathodically protected, repaired or replaced,
- Operators of LP-gas systems and their consultants may consider the following guidelines in determining where it is impractical to do electrical surveys to find areas of active corrosion:
 - Areas of fluctuating stray dc currents, such as those caused by electrical railway systems,
 - Where the pipeline is more than 2 feet from the edge of and under a paved street or within wall-to-wall pavement areas,
 - Pipelines in a common trench with other metallic structures which cannot be isolated.

Electrical surveys may prove to be impractical due to conditions other than those listed above. The operator must demonstrate the impracticability of an electrical survey.

In areas where electrical surveys cannot be run to determine corrosion, the operator should run leakage surveys on a more frequent basis. These surveys should be run at least once a year.

Electrical surveys to find active corrosion must be run by a person qualified in pipeline corrosion control methods.

PROTECTIVE COATINGS (§ 192.461)

All metallic pipe installed below ground, as a new or replacement pipeline system must be coated in its entirety.

Following are some general guidelines for installing a pipe coating:

- Clean all surfaces to be coated with wire brushes or sand paper so that the metal is free from dirt, rust, or loose mill scale. →
- Surfaces must be cleaned with a solvent to remove any oils or adhesives. →
- Keep surface to be coated clean and dry until ready to apply primer.
- Never apply coating in wet weather unless protection from moisture is considered.
- Apply approved primer by brush in thin uniform coats, brushing out vigorously. → Check primer by scratching with fingernail. It should curl and not flake or gum up. If primer does flake or gum up, remove by using approved solvent and re-prime.
- Primer should be allowed to dry until adhesive is tacky (approx. 3-10 minutes). After primer has achieved tacky state, begin application of tape or paint.
- Tape to be applied per manufacturer's instruction in a spiral manner with fifty percent overlap. →



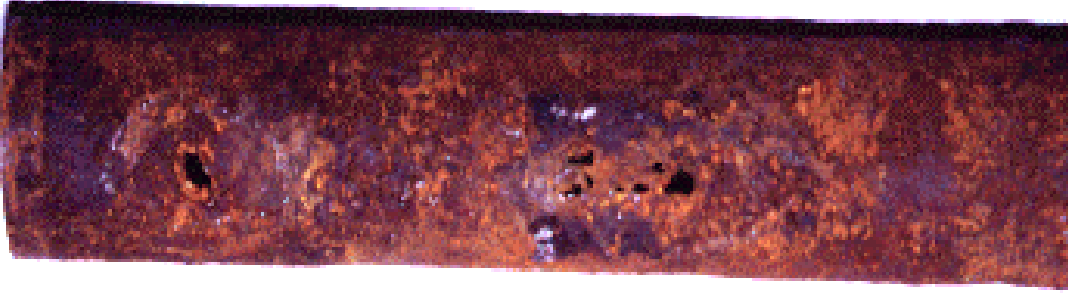
CRITERIA FOR CATHODIC PROTECTION (§ 192.463)

Operators must meet one of five criteria listed in Appendix D of 49 CFR Part 192 to comply with the pipeline safety regulations for CP of steel, cast iron and ductile iron structures. Of these, two methods are typically used, the first being the achievement of a negative (cathodic) voltage of at least 0.85 VDC with reference to a saturated copper-copper sulfate half-cell; the second being the achievement of a negative 100 mVDC shift from a depolarized state. The other methods are rarely if ever used to confirm sufficient CP.

BASIC TERMS

Corrosion - The deterioration of metal pipe. Corrosion is caused by a reaction between the metallic pipe and its surroundings. As a result, the pipe deteriorates and may eventually leak. Although corrosion cannot be eliminated, it can be substantially reduced with CP. (See Figure VII-1.)

Figure VII-1 Bare Pipe - not under cathodic protection

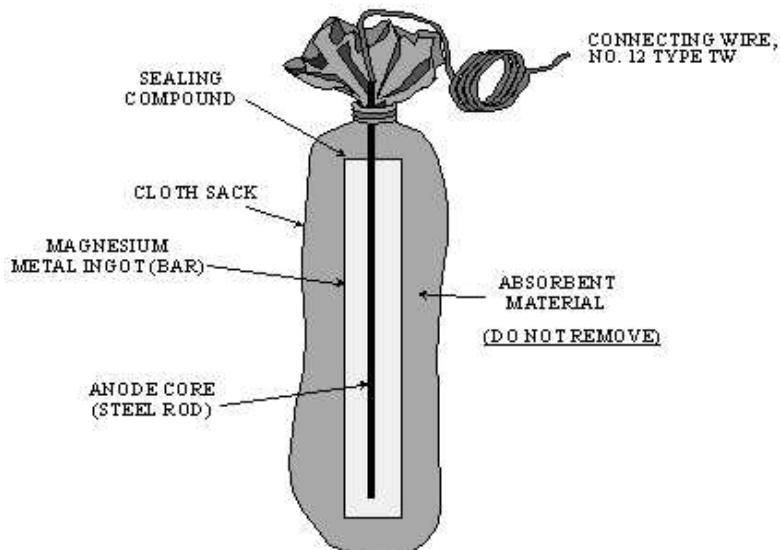


An example of bare steel pipe installed for gas service. Note the deep external corrosion pits that have formed. Operators are no longer allowed to install bare steel pipe or bare tanks underground. Operators should use either polyethylene pipe manufactured according to ASTM D2513 or coated steel pipe as new or replacement pipe. If steel pipe is installed, it must be coated and cathodically protected to meet one of the requirements in Appendix D as mentioned earlier.

Cathodic protection - A procedure by which an underground metallic pipe is protected against corrosion. A direct current is impressed onto the pipe by means of a sacrificial anode or a rectifier. Corrosion will be reduced where sufficient current flows onto the pipe while the sacrificial anodes or the rectifier anodes will corrode rather than the pipe or other buried metallic structure.

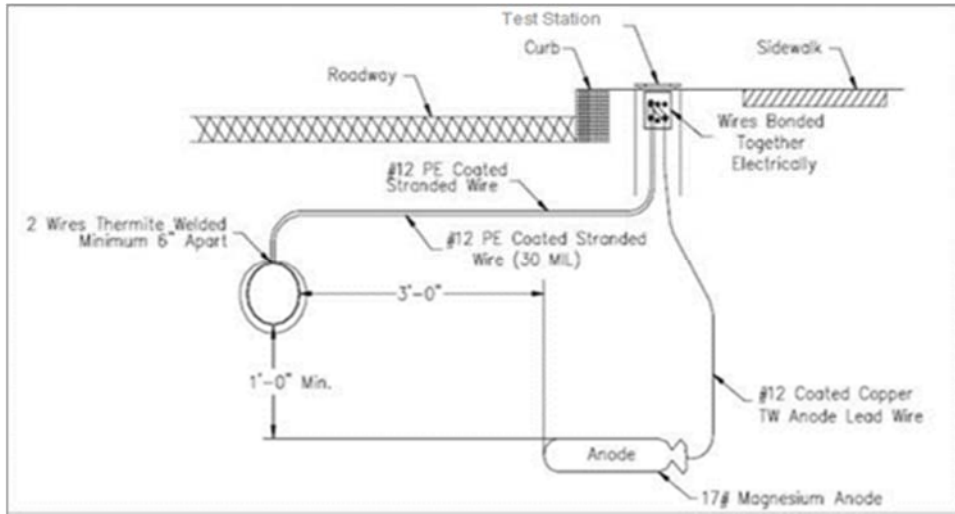
Anode (sacrificial) - An assembly consisting of a bag usually containing a magnesium or zinc ingot and other chemicals which is connected by wire to an underground metal piping system. It functions as a battery that impresses a direct current on the piping system to retard corrosion. These anodes should be buried near the structure to be protected and should have a connection to that structure that can be disconnected. (See Figure VII-2.)

Figure VII-2 Typical Magnesium (Mg) Anode



Sacrificial protection - The reduction of corrosion of a metal (usually steel in a gas system) in an electrolyte (soil) by galvanically coupling the metal (steel) to a more anodic metal (magnesium or zinc.) (See Figure VII-3.) The magnesium or zinc will sacrifice itself (corrode) to retard corrosion in the steel pipe.

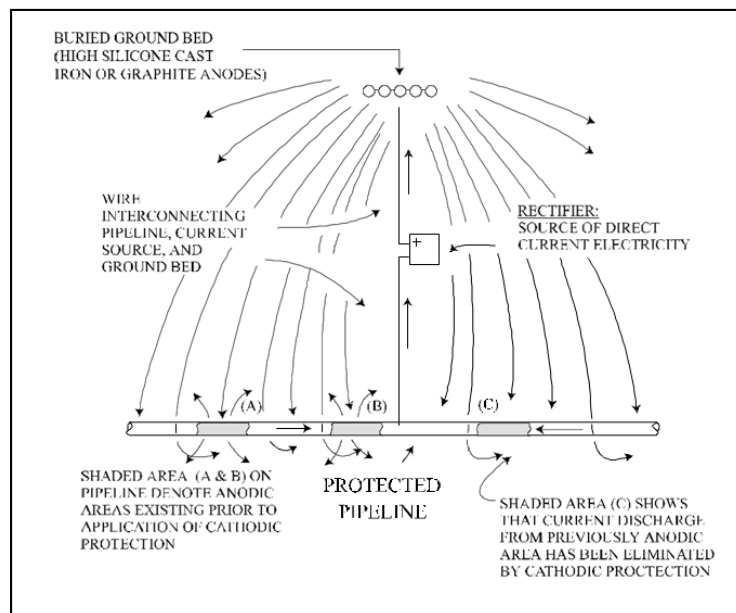
Figure VII-3



Zinc and magnesium are more anodic than steel. Therefore, they will corrode to provide cathodic protection for steel pipe.

Rectifier - An electrical device that changes alternating current (ac) into direct current (dc). This current is then impressed on an underground metallic piping system to protect it against corrosion. (See Figure VII-4.)

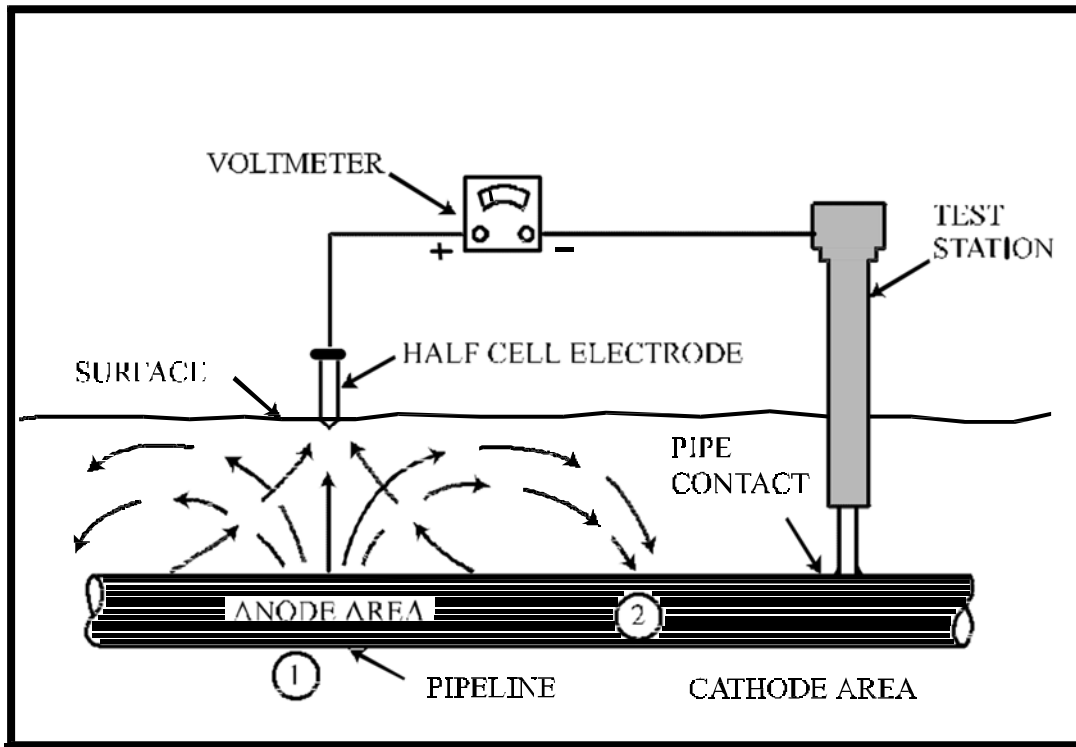
Figure VII-4



This illustrates how CP can be achieved by use of a rectifier. Make certain the negative terminal of the rectifier is connected to the pipe. NOTE: If the reverse occurs (positive terminal to pipe), the pipe will corrode much faster while protecting the anodes.

Potential - The difference in voltage between two points of measurement. (See Figure VII-5.)

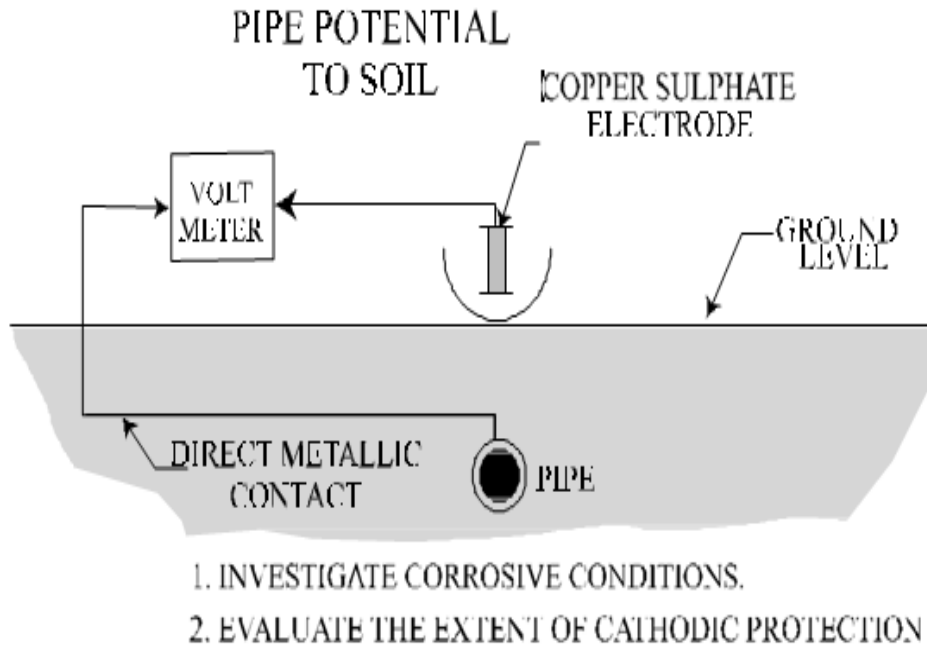
Figure VII-5



The voltage potential in this example is the difference between points 1 and 2. Therefore, the current flow is from the anodic area (1) of the pipe to the cathodic area (2). The half-cell is an electrode made up of copper immersed in copper-copper sulfate (CuCuSO_4). Other materials can be used but they must be corrected to a CuCuSO_4 reference cell reading (silver chloride is used in salt water applications).

Pipe-to-soil potential - The potential difference between a buried metallic structure (piping system) and the soil surface. The difference is measured with a half-cell reference electrode (see definition of reference electrode that follows) in contact with the soil. (See Figure VII-6.)

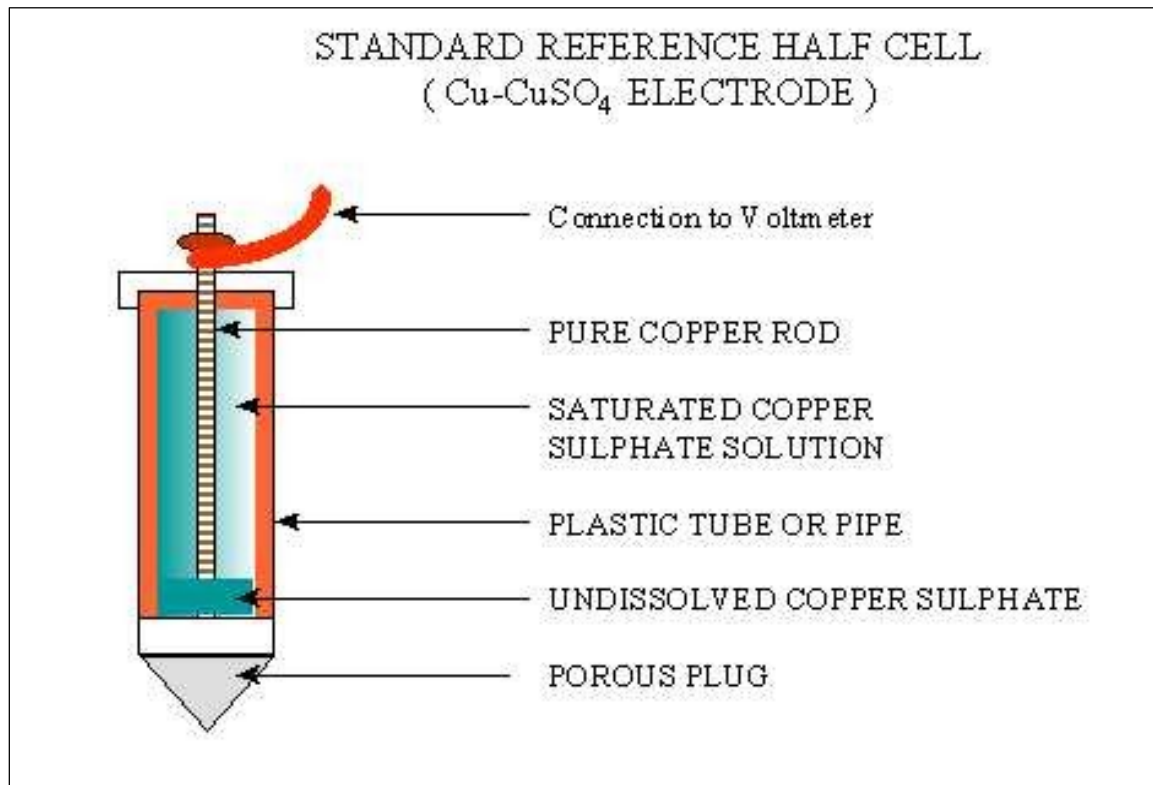
Figure VII-6



If the voltmeter reads at least -0.85 volt DC, the operator can usually consider that the steel pipe has CP. NOTE: Be sure to take into consideration the voltage (IR) drop that is the difference between the voltage at the top of the pipe and the voltage at the surface of the earth. In reading systems with sacrificial anodes, the reading over the pipe must be taken remotely to where the anodes are buried. For rectified systems, an 'on' reading and an 'off' reading should be taken by having the rectifier momentarily interrupted. This 'off' reading is the actual CP reading taking IR drop into account.

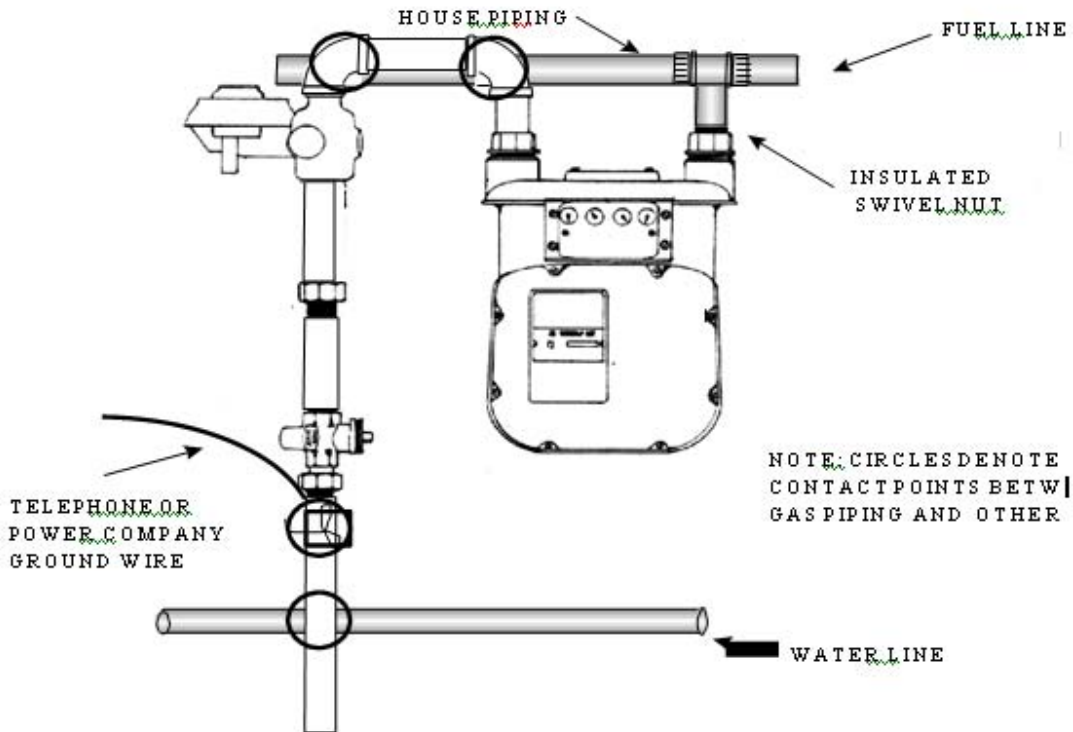
Reference electrode (commonly called a **half-cell**) - A device which usually has copper immersed in a copper sulfate solution. The open circuit potential is constant under similar conditions of measurement. (See Figure VII-7.)

Figure VII-7 Reference Electrode – A saturated copper-copper sulfate half-cell.



Short or corrosion fault - An accidental or incidental contact between a cathodically protected section of a piping system and other metal structures (water pipes, buried tanks or unprotected section of a gas piping system.) (See Figure VII-8.)

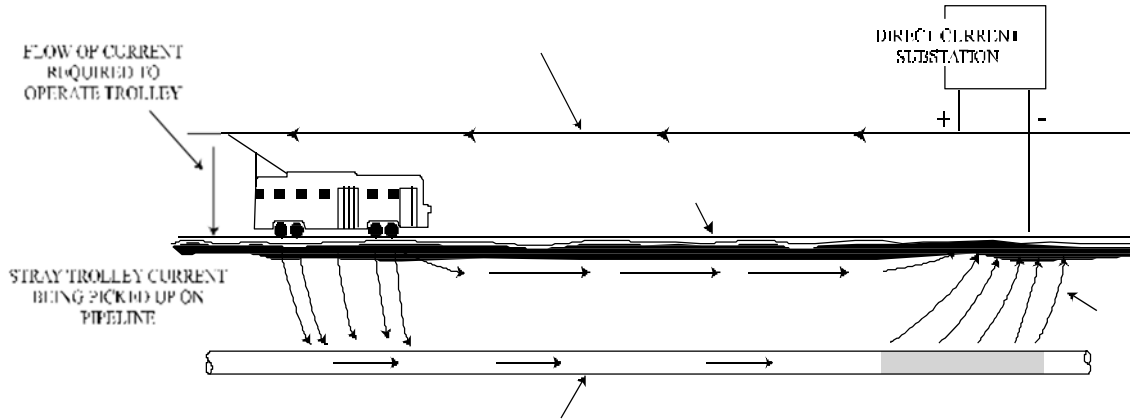
Figure VII-8 Typical Meter Installation Accidental Contacts
(Meter Insulator Shorted Out by House Piping, etc.)



Unshaded piping shows company piping from service entry to meter insulator at location shown on sketch above. Shaded areas show house piping, electrical cables, etc. The circled locations are typical points where the company piping (unshaded) can come in metallic contact with house piping. This causes shorting out or "bypassing" of the meter insulator. The only way to clear these contacts permanently is to move the piping that is in contact. The use of wedges, etc., to separate the piping is not acceptable. If the piping cannot be moved, install a new insulator between the accidental contact and the service entry.

Stray current - Current flowing through paths other than the intended circuit. (See Figure VII-9.)

Figure VII-9



This drawing illustrates an example of stray dc current getting onto a pipeline from an outside source. This can cause severe corrosion in the area where the current eventually leaves the pipe at a location with a coating holiday. Expert help is needed to correct this type of problem.

Stray current corrosion - Metal destruction or deterioration caused primarily by stray dc current in the soil around a pipeline.

Galvanic series - A list of metals and alloys arranged according to their relative potentials in a given environment. (See below)

METAL	POTENTIAL (VOLTS)	Anodic ↑ ↓ Cathodic
Commercially pure magnesium	-1.75	
Magnesium alloy (6% Al, 3% Zn, 0.15% Mn)	-1.6	
Zinc	-1.1	
Aluminum alloy (5% zinc)	-1.05	
Commercially pure aluminum-	0.8	
Mild steel (clean and shiny)	-0.5 to -0.8	
Mild steel (rusted)	-0.2 to -0.5	
Cast iron (not graphitized)	-0.5	
Lead	-0.5	
Mild steel in concrete	-0.2	
Copper, brass, bronze	-0.2	
High silicon cast iron	-0.2	
Mill scale on steel	-0.2	
Carbon, graphite, coke	+0.3	

* Typical potential in natural soils and water, measured with respect to a copper-copper sulfate reference electrode.

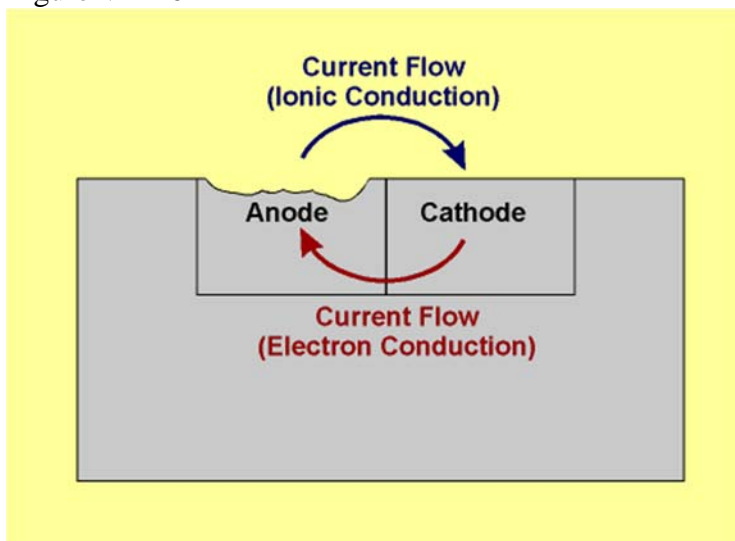
Galvanic corrosion - Occurs when any two of the metals are connected in an electrolyte (soil). Galvanic corrosion is caused by the difference in the potentials of the two metals.

When electrically connected in an electrolyte, any metal in the table will be anodic (corrode relative to) to any metal below it. That is, the more anodic metal sacrifices itself to protect the metal (pipe) lower in the table. This is the process that is used for sacrificial anodes that corrode in place of steel.

FUNDAMENTAL CORROSION THEORY

For corrosion to occur, there must be four elements: electrolyte, anode, cathode and a metallic return circuit. A metal will corrode at the point where current leaves the anode. (See Figure VII-10.) NOTE: Dissimilar soils may create an environment that enhances corrosion. In the case of steel, the iron in the steel is looking to return to its native state, iron oxide and thus needs to have energy impressed upon it to remain as pure metal (think of a car rusting if it is exposed to salt and water)

Figure VII-10



A corrosion cell may be described as follows:

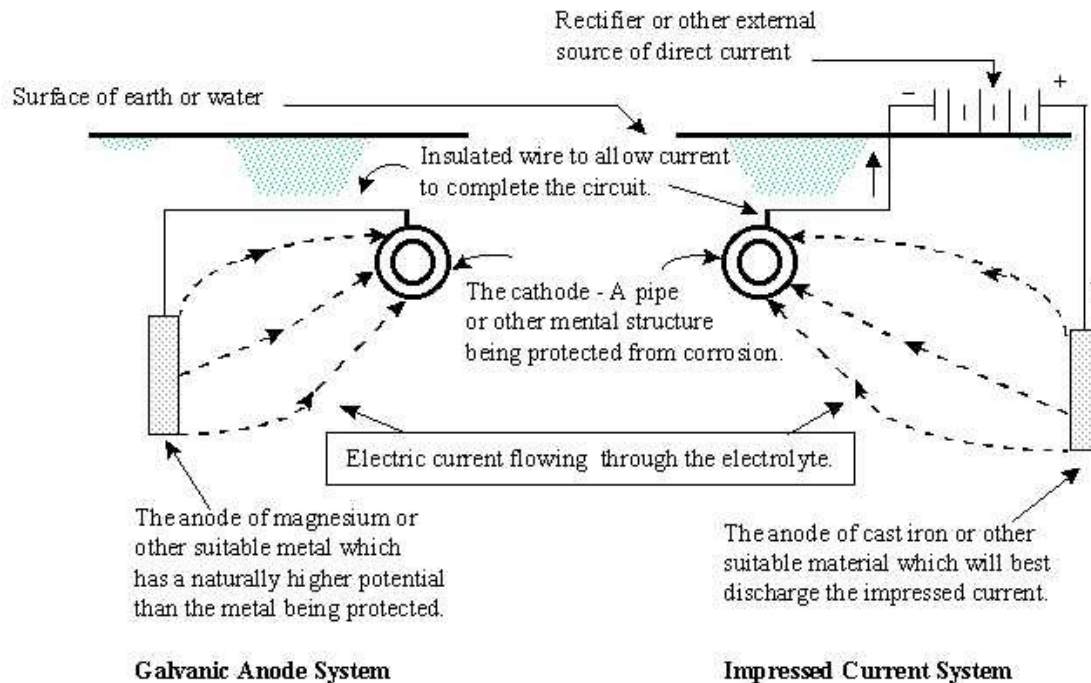
- Current flows through the electrolyte from the anode to the cathode. It returns to the anode through the return circuit.
- Corrosion occurs whenever current leaves the metal (pipe, fitting, etc.) and enters the soil (electrolyte). The area where current leaves is said to be anodic. Corrosion, therefore, occurs in the anodic area.
- Current is picked up at the cathode. No corrosion occurs here. The cathode is protected against corrosion. Polarization (hydrogen film buildup) occurs at the cathode. When the film of hydrogen remains on the cathode surface, it acts as an insulator and reduces the corrosion current flow.
- The flow of current is caused by a potential (voltage) difference between the anode and the cathode.

TYPES OF CATHODIC PROTECTION

There are two basic methods of CP: the galvanic (sacrificial) anode system and the impressed current system.

Galvanic anodes are commonly used to provide CP on gas distribution systems. Impressed current systems are normally used for transmission lines or piping with older and/or poor quality coatings which require additional energy to protect. However, if properly designed, impressed current can be used on a distribution system. (See Figure VII-11.)

Figure VII-11

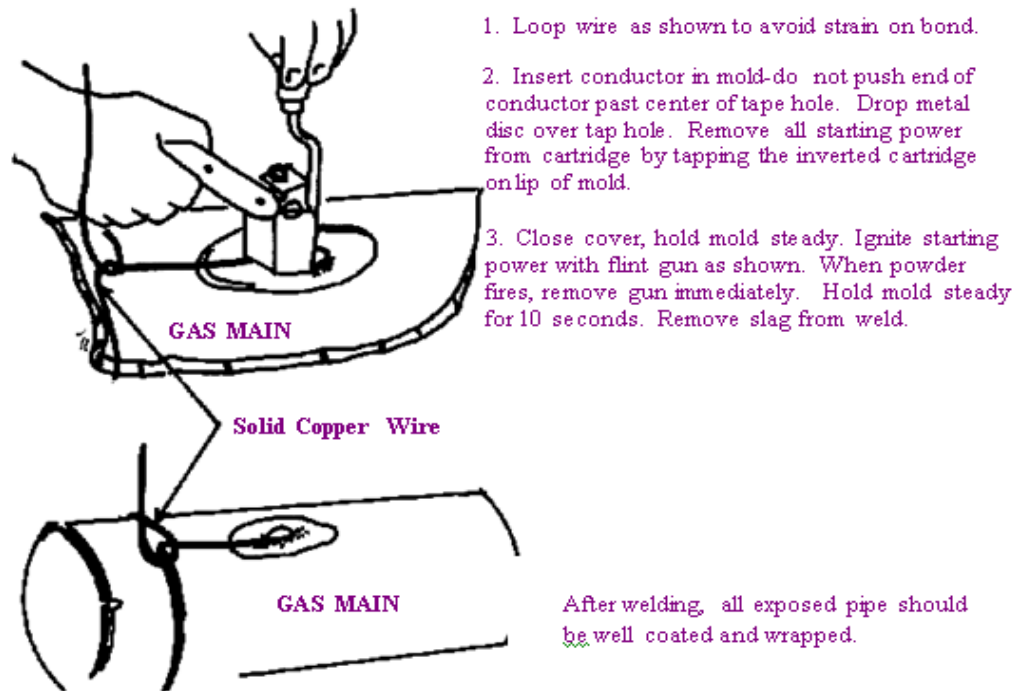


Any current, whether galvanic or stray, that leaves the pipeline causes corrosion. In general, corrosion control is obtained as follows:

Galvanic Anode Systems

Anodes are "sized" to meet current requirements of the resistivity of the environment (soil) and the condition of coating. Anodes are made of materials such as magnesium (Mg), zinc (Zn) or aluminum (Al). They are usually installed near the pipe and connected to the pipe with an insulated conductor via a test station lead. They are sacrificed (corroded) instead of the pipe. (See Figures VII-3, VII-11 and VII-12.)

Figure VII-12 Typical procedure for installing a test station for use on a Mg Anode



Impressed Current Systems

Anodes are connected to a direct current source, such as a rectifier or generator. These systems are normally used along transmission pipelines where there is less likelihood of interference with other pipelines. The principle is the same except that the anodes are made of material such as graphite, high silicon cast iron, lead-silver alloy, platinum or scrap steel and are surrounded by an electrolyte to assist in obtaining the most output from the anodes.

INITIAL STEPS IN DETERMINING THE NEED TO CATHODICALLY PROTECT A SMALL GAS DISTRIBUTION SYSTEM

1. Determine type(s) of pipe in the system: bare steel, coated steel, cast iron, plastic, galvanized steel, ductile iron or other.

2. Date the gas system was installed:

Year the pipe was installed (steel pipe installed after July 1, 1971, must be cathodically protected in its entirety).

Who installed the pipe? By contacting the contractor and other operators who had pipe installed by the same contractor, operators may be able to obtain valuable information as:

- Type of pipe in the ground.
- If pipe is electrically isolated.

- If the gas pipe is in a common trench with other utilities.
3. Pipe location - map/drawing. Locate old construction drawings or current system maps. If no drawings are available, a metallic pipe locator may be used.
 4. Before the corrosion engineer arrives, it is a good idea to make sure customer meters are electrically insulated. If the system has no meter, check to see if the gas pipe is electrically insulated from house or mobile home piping. (See Figure VII-13.)
 5. Contact an experienced corrosion engineer or consulting firm. Try to complete steps 1 through 4 before contracting a consultant.
 6. Use of Consultant.

A sample method, which may be used by a consultant to determine CP needs, is the following:

An initial pipe-to-soil reading will be taken to determine if the system is under cathodic protection.

- If the system is not under cathodic protection, the consultant should clear underground shorts or any missed meter shorts. (The consultant will probably use a tone test.)
 - After the shorts are cleared, another pipe-to-soil test should be taken. If the system is not under cathodic protection, a current requirement test should be run to determine how much electrical current is needed to protect the system.
 - Additional tests such as a soil resistivity test, bar hole examination and other electrical tests may be needed. The types of tests needed will vary for each gas system.
 - Remember to retain copies of all tests run by the corrosion engineer.
7. Cathodic Protection Design

The experienced corrosion engineer or gas consultant, based on the results of testing, will design a cathodic protection system that best suits the gas piping system.

Figure VII-13

Places where a meter installation may be electrically isolated.

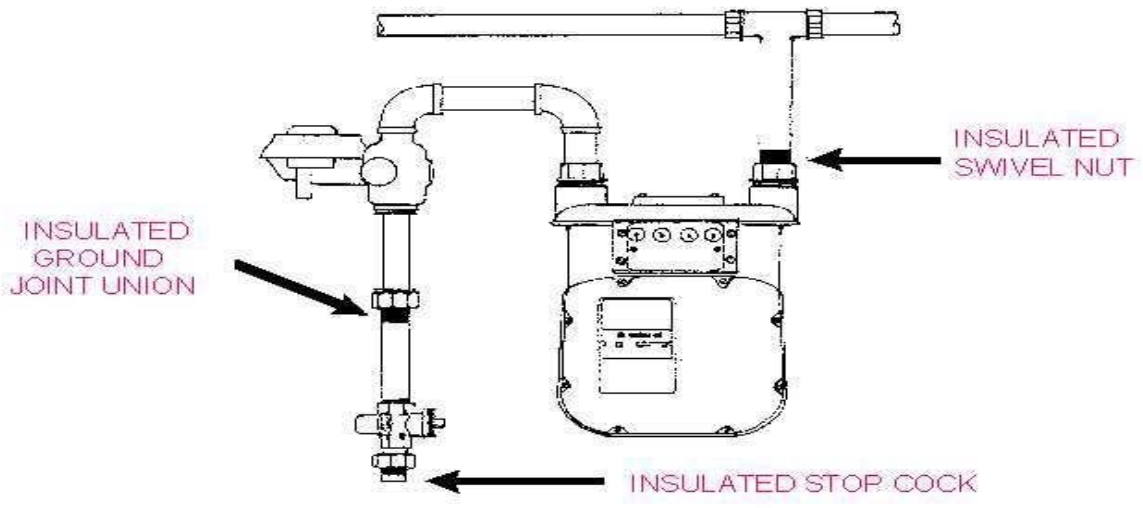


Figure VII-14

Illustration of an insulated compression coupling used on meter sets to protect against corrosion. Pipe connection by this union will be electrically insulated between the piping located on side one (1) and the piping located on side two (2).

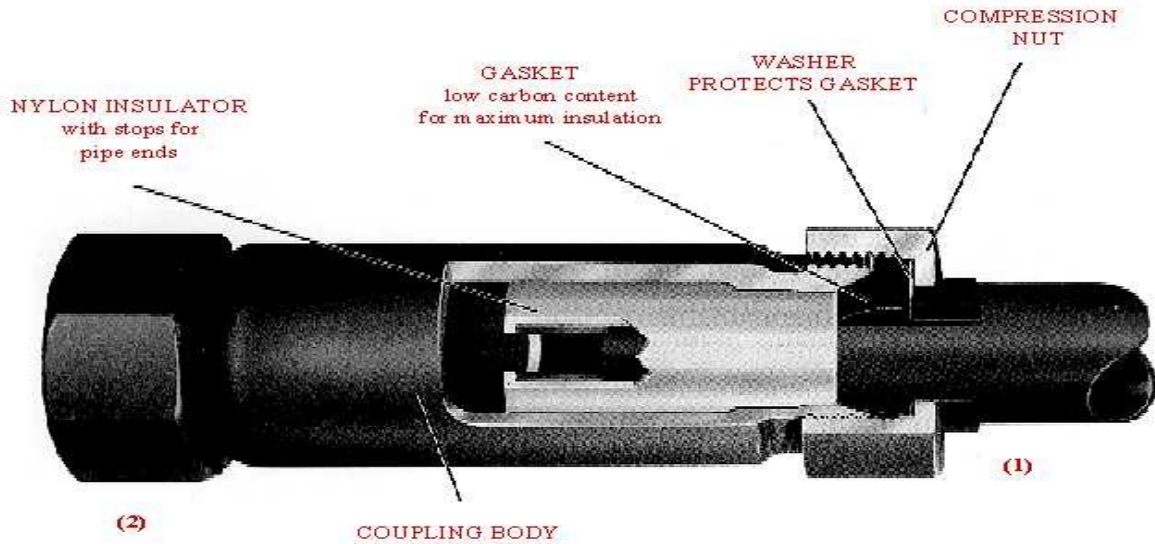
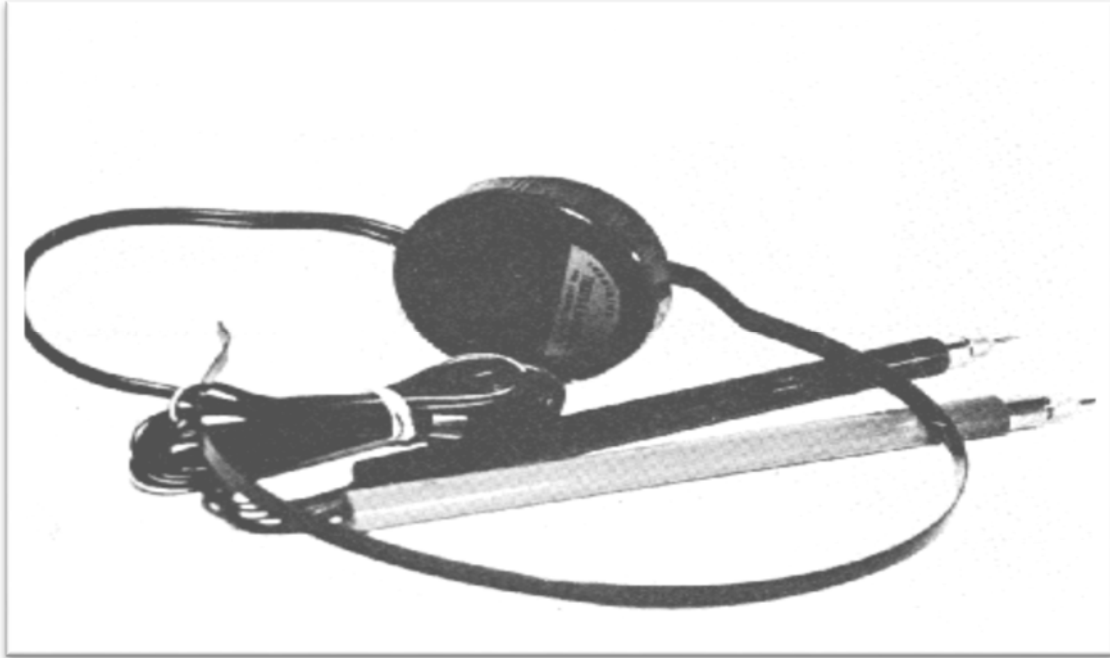


Figure VII-15 Insulation tester



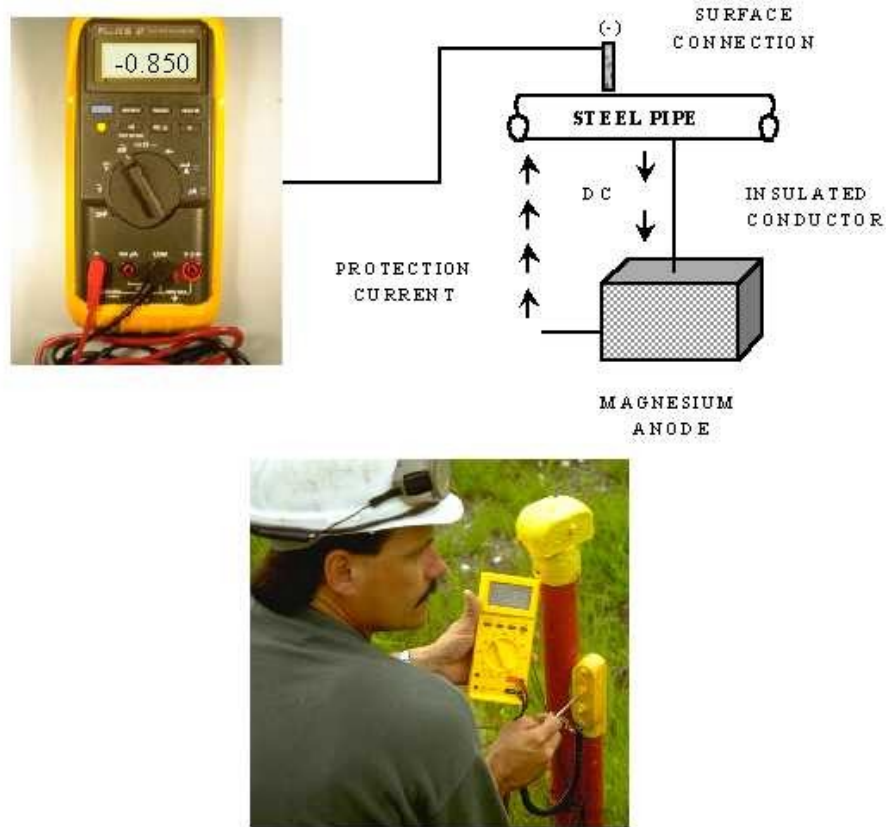
This insulation tester consists of a magnetic transducer mounted in a single earphone headset with connecting needlepoint contact probes. It is a "go" or "no go" type tester which operates from low voltage current present on all underground piping systems, thus eliminating the necessity of outside power sources or costly instrumentation and complex connections. By placing the test probes on the metallic surface on either side of the insulator a distinct audible tone will be heard if the insulator is performing properly. Absence of an audible tone indicates a faulty insulator. Insulator effectiveness can be determined quickly using this simple, easy-to-operate tester.

CRITERIA FOR CATHODIC PROTECTION

There are five criteria listed in Appendix D of Part 192, to qualify a pipeline as being cathodically protected. Operators can meet the requirements of any one of the five to be in compliance with the pipeline safety regulations. Most systems will be designed to Criterion 1.

Criterion 1: With the protective current applied, a voltage more negative than -0.85 volt DC measured between the pipeline and a saturated copper-copper sulfate half-cell. This measurement is called the pipe-to-soil potential reading. (See Figure VII-16)

Figure VIII-16 Pipe-to-soil potential reading



This is a pipe-to-soil voltage meter with reference cell attached. This is a simple meter to use and is excellent for simple "go-no-go" type monitoring of a CP system. If meter reaches at least -0.85 volt*, the operator knows that the steel pipe is under CP. If not, remedial action must be taken promptly.

***NOTE: Be sure to take into consideration the voltage drop (IR drop) that is the difference between the voltage at the top of the pipe and the voltage at the surface of the earth.**

COATINGS

There are many different types of coatings on the market. The better the coating application, the less electrical current needed to cathodically protect the pipe.

MILL COATED PIPE

When purchasing steel pipe for underground gas services, operators should purchase mill coated pipe (i.e., pipe coated during the manufacturing process). Some examples of mill coatings are:

- Extruded polyethylene or polypropylene plastic coatings,
- Coal tar coatings,

- Enamels,
- Mastics,
- Fusion bonded epoxy.

A qualified (corrosion) person can help select the best coating for an LP gas system. A coating consultant will be able to give master meter operators the names and locations of nearby suppliers of mill coated gas pipe. When purchasing steel pipe, remember to verify that the pipe was manufactured according to one of the specifications listed in Chapter III of this manual. This can be verified by a bill of lading or by the markings on mill coated pipe.

PATCHING

Tape material is a good choice for external repair of mill coated pipe. Tape material is also a good coating for both welded and mechanical joints made in the field. One advantage is that these types may be applied cold. Some tapes in use today are:

- PE and PVC tapes with self-adhesive backing applied to a primed pipe surface.
- Plastic films with butyl rubber backing applied to a primed surface.
- Plastic films with various bituminous backings.

Consult a pipe supplier before purchasing tapes. Tapes must be compatible with the mill coating on the pipe.

COATING APPLICATION PROCEDURES

When repairing and installing metal pipe, be sure to coat bare pipes, fittings, etc. It is absolutely essential that the instructions supplied by the manufacturer of the coating be followed precisely. Time and money is wasted if the instructions are not followed.

Some general guidelines for installation of pipe coatings:

- Properly clean the pipe surface (remove soil, oil, grease and any moisture),
- Use careful priming techniques. Avoid moisture and follow the manufacturer's recommendations,
- Properly apply the coating materials (be sure pipe surface is dry - follow manufacturer's recommendations). Make sure soil or other foreign material does not get under coating during installation,
- Backfill with material that is free of objects capable of damaging the coating. Severe coating damage can be caused by careless backfilling when rocks and debris strike and break the coating.

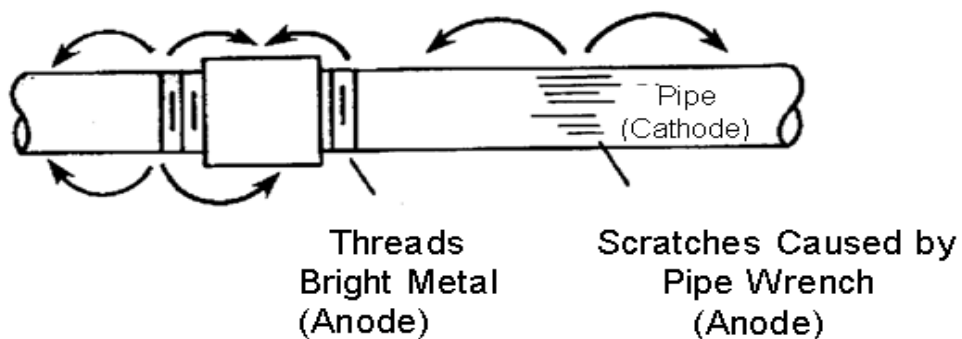
COMMON CAUSES OF CORROSION IN GAS PIPING SYSTEMS

Figure VII-17 Shorted meter set



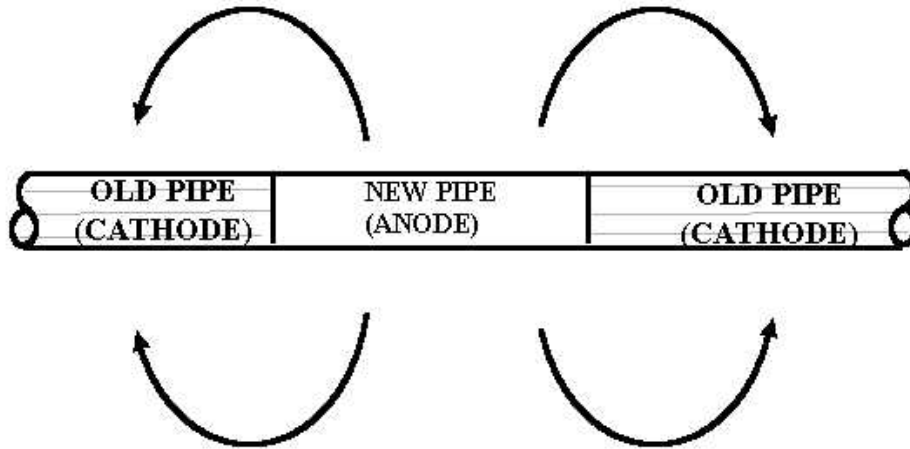
An example of a galvanic corrosion cell. The tenants of this building have "shorted" out this meter by storing metallic objects on the meter set. Never allow customers or tenants to store material on or near a meter installation.

Figure VII-18 Corrosion caused by dissimilar surface conditions



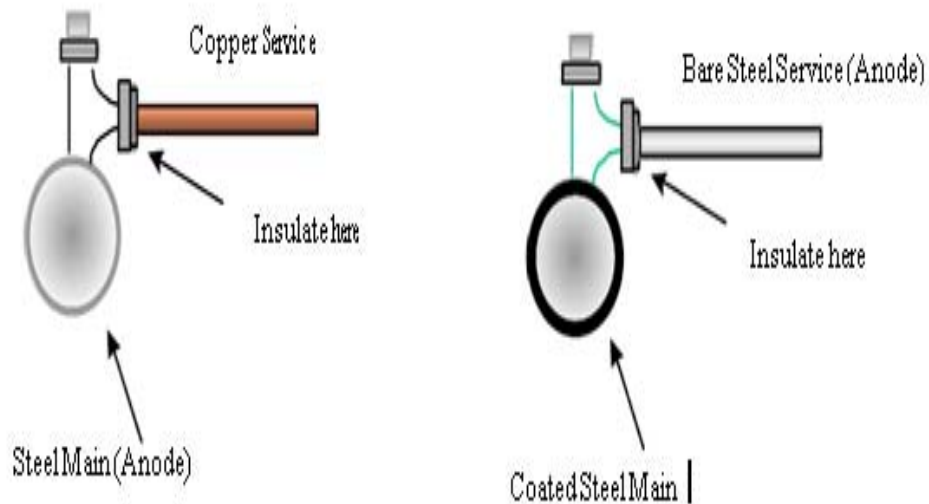
This pipe will corrode at the threads or where it is scratched. Remember to repair all cuts or scratches in the coating before burying the pipe. Always coat and/or wrap pipe at all threaded or weld connections before burying the pipe.

Figure VII-19 Galvanic Corrosion



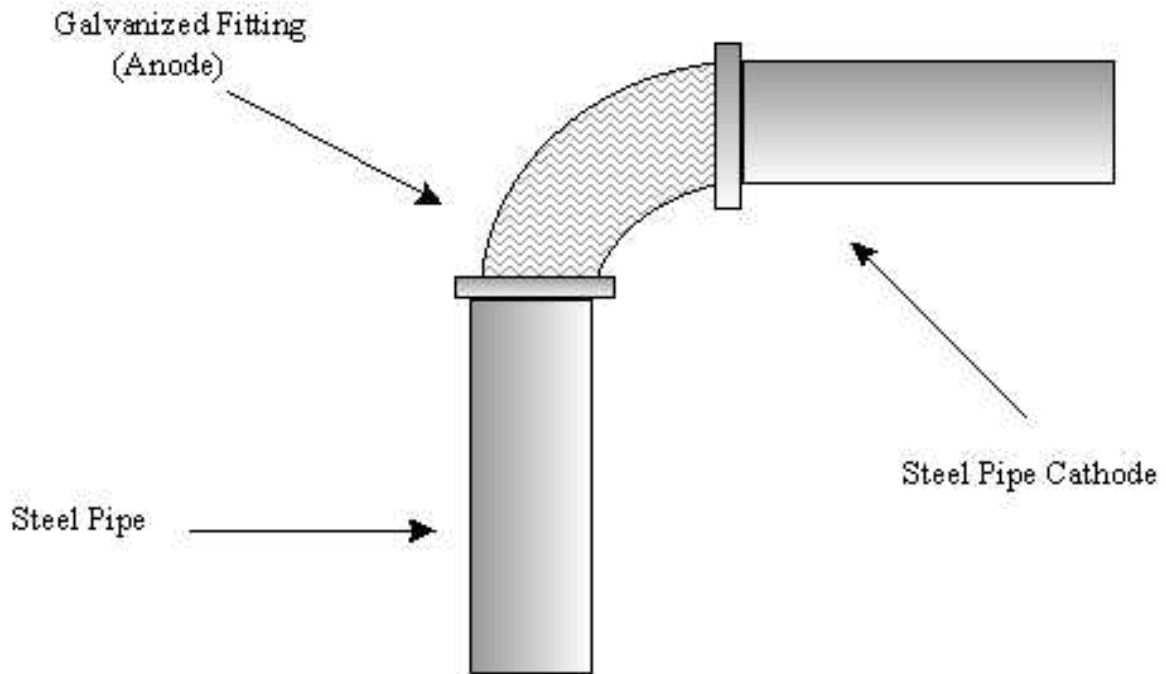
Remember, all new steel pipe must be coated and cathodically protected. The new pipe can either be electrically isolated from old pipe or the new and old pipe must be cathodically protected as a unit.

Figure VII-20 Galvanic Corrosion caused by dissimilar metals.



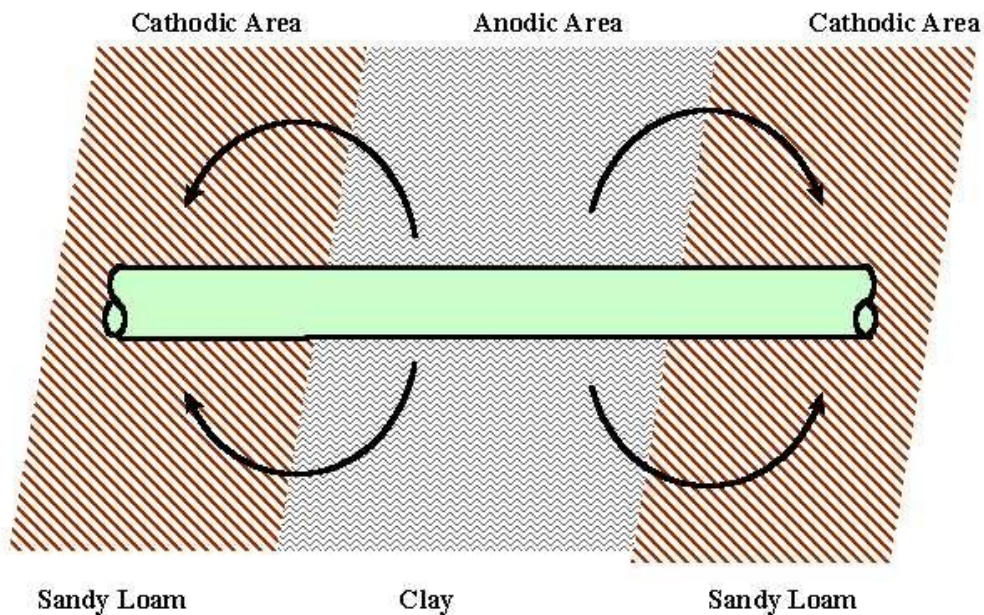
Steel is above copper in the galvanic series in Table 1 of this chapter. Therefore, steel will be anodic to the copper service. That means the steel pipe will corrode. The copper service should be electrically isolated from the steel main. Remember, steel and cast iron or ductile iron should not be tied in directly. Steel and cast iron should be electrically isolated. Also, coated steel pipe should be electrically isolated from bare steel pipe.

Figure VII-21 Galvanic Corrosion



The galvanized elbow will act as an anode to steel and will corrode. Do not install galvanized pipe or fittings in a system, if possible. However, when using galvanized fittings, the fittings must be electrically isolated.

Figure VII-22 Galvanic Corrosion



A corrosion cell can be set up when pipe is in contact with dissimilar soils. This problem can be avoided by the installation of a well-coated pipe under CP.

Figure VII-23 Poor Construction Practice



An example of a main which was buried without a coating or wrapping at the service connection. This corrosion problem could have been avoided with proper coating and CP.

CHAPTER VIII LP GAS REGULATORS

PROCEDURES AND QUALIFICATIONS

Operators must establish procedures for LP Gas regulators and should include the selection, installation, support and protection. These procedures must be carried out by, or under the direction of, a person qualified in pipe line corrosion control methods.

REGULATOR HANDLING AND STORAGE

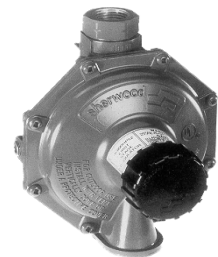
When regulators are disconnected or removed from service and intended to be reused, they must have their inlet and outlet openings plugged to keep debris from entering the regulator. If a regulator has been exposed to moisture or other contaminants, the regulator must be tagged or disposed of. All regulators that are being disposed of must have the casing damaged to make them unfit for further service.

REGULATOR SELECTION

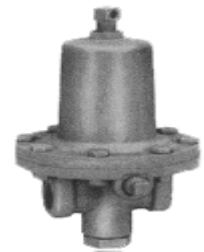
The following are steps in selecting a regulator system:

Step 1: Determine the regulator type and typical application.

- *Integral 2-stage Regulator:* Integral 2-stage regulator for half-pound systems. Most frequently used for manufactured homes with relatively small demand loads and short piping runs. In a Domestic or Commercial installation an integral 2-stage Regulator may only be used when the line sizing is of proper and adequate size and the regulator is able to handle the total BTU demand.
- *First-stage Regulator:* First-stage regulators are used at the propane storage tank on medium to large Btu/hr demand systems. It reduces container vapor pressure to approximately 10 psig and delivers it to the distribution line(s) connecting it to the second-stage regulator(s).
- *Second-stage Regulator:* Second-stage regulator used at building service entrance(s) to reduce the approximately 10 psig vapor pressure supplied by the first-stage regulator to approximately 11 inches water column supply to the half-pound distribution piping. Body styles available are the straight-through body shown to the right, and the back-mount for a 90° change in flow direction for horizontal service entrances.



- *2-PSI service Regulator:* 2-PSI service regulator used at building service entrance(s) to reduce the approximately 10 psig vapor pressure supplied by the first-stage regulator to 2 psig vapor pressure supply to the distribution piping. Line regulators further reduce the 2 psig pressure to the required appliance input pressures, usually measured in inches water column.
- *Automatic Changeover Regulators:* Automatic changeover regulators combine first-stage and second-stage regulators with a check valve to receive vapor from manifold cylinders. Cylinder vapor pressure is reduced to approximately 11 inches water column at the second-stage regulator outlet
- *High-Pressure Regulator:* High-Pressure (pounds to pounds) regulator for relatively high Btu/hr demand systems and unusually long buried piping distribution lines. Used at the container to reduce container pressure to a lower pressure, usually 12 to 15 psig. Downstream first-stage regulator(s) are used to reduce the pressure to 10 psig or less for delivery to one or more second-stage regulators.
- *Line Regulators:* Line regulators are used in hybrid pressure systems to reduce 2 or 5 psig outlet pressure from the 2 or 5 pound service regulator to required appliance inlet pressures, measured in inches water column. They are installed just before manifold piping or tubing runs, or just before individual appliances. Consult manufacturer brochures to determine appropriate line regulator to meet system Btuh load and pressure requirements.



Step 2: Calculate the total demand on the regulator.

Step 3: Determine the delivery or outlet pressure required downstream of the regulator for the appliance(s) or equipment.

Step 4: Determine the inlet pressure being supplied to the inlet of the regulator.

Note: When determining tank pressure the minimum pressure should be used.

Step 5: Select the regulator body size.

Note: Regulator body size should never be larger than the pipe size.

Step 6: Determine the accuracy required by the amount of flow a regulator can pass using Manufacturer's specifications, performance charts and capacity charts.

Step 7: Ensure that the regulator selected has adequate relief capacity. Remember some regulators do not have overpressure protection and will require a separate external/in-line relief valve or be incorporated in a monitoring system.



SERVICE REGULATORS

If the service regulator is located in areas where they may be subject to heavy snow or ice, a patrol of the system must be conducted after a heavy snowfall or protection should be installed over the meter and/or service regulator.

The vent terminations of service regulators and external relief valves must be a minimum of three (3) feet horizontally away from any building opening such as a window or door and a minimum of five (5) feet in any direction away from any source of ignition, opening into a direct vent appliance, or mechanical air intakes. Service regulator vents or termination ends must be directed downward to drain condensate and have a vent screen or retainer to prevent insects from entering.

The piping or tubing used to vent a service regulator or an external relief valve must be one of the following:

- Metallic pipe or tubing: Steel or Wrought Iron, Brass, Copper.
- Schedule 40 or 80 rigid electrical conduit (ANSI/UL 651). **Only PVC piping materials that are UV rated are permitted to be used to vent regulators or external relief valves.**

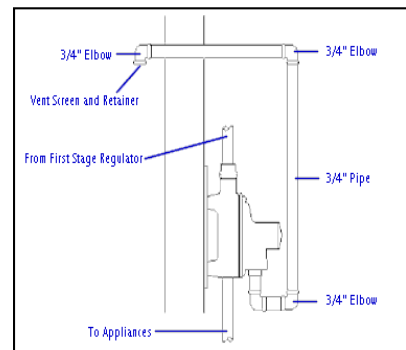
Note: Other PVC piping materials and polyethylene and polyamide pipe and tubing must not be used to vent regulators.



Where a vent line is used to comply with the point of discharge requirements, it must comply with (1) through (7).

The discharge from the required pressure relief device of a second-stage regulator other than a line pressure regulator, installed **inside of buildings** in piping systems, must comply with the following:

- (1) The discharge must be directly vented with



supported piping to the outside air.

- (2) The vent line must be at least the same nominal pipe size as the regulator vent connection pipe size and be metallic pipe. PVC is not permitted inside a structure.
- (3) Where there is more than one regulator at a location, each regulator must have a separate vent to the outside or the vent lines must be manifolded in accordance with accepted engineering practices to minimize back pressure in the event of high vent discharge.
- (4) The material of the vent line must be as stated above.
- (5) The discharge outlet must be located not less than 3 feet horizontally from any building opening below the level of such discharge.
- (6) The discharge outlet must also be located not less than 5 ft in any direction away from any source of ignition, openings into direct-vent appliances, or mechanical ventilation air intakes.
- (7) The discharge outlet must be designed, installed, or protected from blockage so it will not be affected by the elements (freezing rain, sleet, snow, ice, mud, or debris) or insects.

The requirement in this section must not apply to appliance regulators otherwise protected, to line pressure regulators listed as complying with ANSI Z-21.80/CSA 6.22, *Standard for Line Pressure Regulators*, or to regulators used in connection with containers in buildings (refer to NFPA 58 section 6.2.2).

The requirement in this section must not apply to vaporizers.

REGULATOR PROTECTION

Regulators must be installed in locations that are readily accessible for replacement and maintenance. Try to avoid locations where the meter can be subject to snow or ice damage and any area where physical damage can occur (example: near driveways or loading docks).

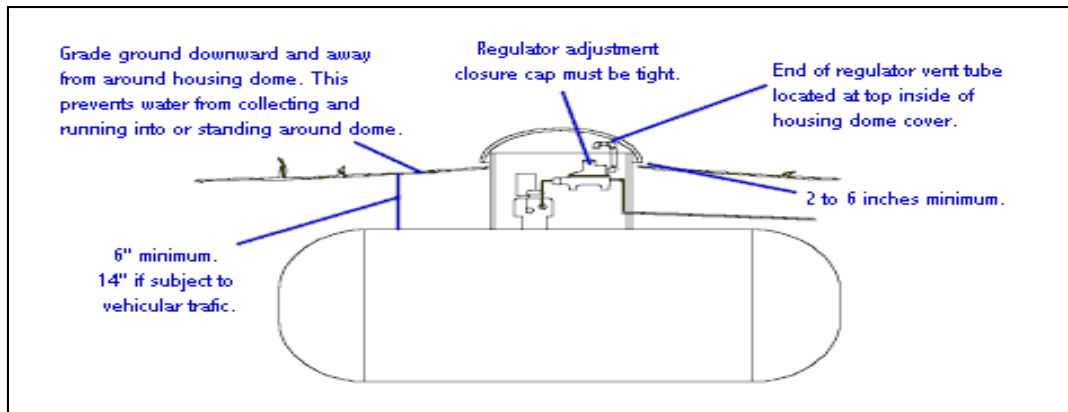
REGULATOR SUPPORT

First-stage or high-pressure regulators must be directly attached or attached by flexible metallic connectors, to the vapor service valve used on stationary (permanent) container installations, and to interconnecting piping of manifolded stationary (permanent) container installations, or to a vaporizer outlet.

Note: First-stage regulators installed downstream of high-pressure regulators must be exempt from this requirement.

UNDERGROUND INSTALLATION

Regulator vent(s) must be above the highest probable water level on underground tank installations. This reduces the potential of water entering the regulator and causing performance problems and internal corrosion of the main and relief spring and other regulator components.



REGULATOR INSPECTION, TESTING AND REPLACEMENT

Regulators must be carefully inspected whenever service is performed. Any regulator that is damaged or malfunctions that cannot be corrected must be replaced. The inspection must include the following:

- Corrosion,
- Vent blockage,
- Deterioration,
- Age (Manufacturer's recommendation should be considered),
- Improper operation or other damage, and
- Climatic and other environmental factors. Example: Salt air, moisture, humidity, etc.

OVERPRESSURE PROTECTION (REQUIREMENT § 192.195)

Each pipeline that is connected to a gas source where failure of a pressure control device, or other type failure, might result in a pressure which would exceed the maximum allowable operating pressure (MAOP) of a facility, must be equipped with suitable pressure relieving or pressure limiting devices. A pipeline MAOP is determined using the methods outlined in the MAOP procedure in this manual.

MONITOR REGULATOR SYSTEMS

A monitoring regulator system provides overpressure protection with no release of gas like a relief valve would. A monitor system consists of two regulators in series. The “worker” regulator controls downstream pressure during normal operating conditions. If the worker regulator allows the pressure to build up downstream, the “monitor” regulator takes over control by sensing the higher pressure through the pilot control line and keeping the downstream pressure to a safe maximum pressure. The monitor regulator is usually set approximately 2 psig to 5 psig higher than the working regulator. The monitor regulator will remain wide open unless the operating regulator loses pressure control and its outlet pressure climbs approximately 15 psig. The monitor regulator will start to function and limit downstream pressure to approximately 15 psig.



Unlike relief valves, monitor stations provide for containment of a system so that no gas is released to atmosphere during a failure. This containment by the monitor is both an advantage and disadvantage. The venting gas can create public relations problems that must be dealt with. The monitor, by containing the system, eliminates this problem, but also makes failure detection more difficult. The monitoring regulator may sustain system pressure so well that no effects are sensed downstream. Typically, failure of the primary regulator is discovered through visual inspection and slightly rising system control pressure. Therefore, if inspection of the monitoring station is not performed regularly, the station may be operating with no over pressure protection for a period of time depending upon when the primary regulator failed.



There are several different ways to achieve the monitoring or standby regulator station design. The most common monitor/regulator station designs are:

- Wide - Open Upstream Monitor
- Wide - Open Downstream Monitor
- Series Regulation

MONITOR REGULATOR (WIDE OPEN UPSTREAM MONITOR)

In a Wide Open Upstream Monitor system the monitor regulator is installed upstream of the operating (called the worker) regulator and has the control line connected into a tee downstream of the worker regulator. The worker regulator is usually set at 8-10 psig and the monitor regulator set at 13-15psig. Because the monitor regulator is sensing the 8-10psig setting of the operating regulator it remains wide open due to its 15psig set pressure. The monitor regulator will remain wide open unless the operating regulator loses pressure control and its outlet pressure

climbs to 15psig. The monitor regulator will start to function and limit the downstream pressure to 15 psig.

There are three significant advantages of this system.

1. There is no gas released to the atmosphere if the worker regulator can no longer control pressure,
2. The monitor regulator is located on the tank pressure line where there will be very little impact from a pressure drop across the monitor regulator, and
3. Both the worker and monitor regulators can be checked while the system continues to operate.

When selecting regulators for use in a monitor system, the upstream regulator must have a control line. When determining the capacity of a monitor system you will get approximately 70% to 73% of the capacity of a single regulator when using the same regulator for both regulators in the system. To verify monitor operation, slowly increase the outlet pressure of the worker regulator above the set point of the monitor regulator. When the worker regulator outlet pressure exceeds the monitor regulator set point, the monitor regulator should begin regulating downstream pressure at its set point and additional adjustment of the worker regulator setting will not change downstream pressure. In terms of pressure ratings, it is important to note that the intermediate pressure has the potential of reaching full system inlet pressure when the upstream regulator fails. Therefore, the outlet pressure side of the upstream regulator and the inlet pressure side of the downstream regulator must be rated for full inlet pressure.

MONITOR REGULATOR (WIDE-OPEN DOWNSTREAM MONITOR)

In a wide-open downstream monitor system, the monitor regulator is installed downstream of the worker regulator and has the control line connected into a tee in the downstream piping. The worker regulator is usually set at 8-10 psig and the monitor regulator set at 13-15psig. Because the monitor regulator is sensing the 8-10psig setting of the operating regulator it remains wide open due to its 15psig set pressure. The monitor regulator will remain wide open unless the operating regulator loses pressure control and its outlet pressure climbs to 15psig. The monitor regulator will start to function and limit the downstream pressure to 15 psig.

Again, the intermediate pressure has the potential of reaching full system inlet pressure when the upstream regulator fails. Therefore, the outlet pressure side of the upstream regulator and the inlet pressure side of the downstream regulator must be rated for full inlet pressure.

Note that both the upstream and downstream wide-open monitoring installations will provide the same maximum capacity. When the system is at full capacity, both the monitor and regulator will be wide-open. Although no recommendation is made on using wide-open upstream over wide-open downstream monitor stations and vice-versa, there are pros and cons to both. Downstream monitors are sometimes considered more “protected” by the upstream regulator from whatever might be causing the upstream worker to fail. One suggestion is to use a single type of monitoring system throughout the company, so that when going to troubleshoot an installation, it will be known what type of monitoring installation it is.

HIGH PRESSURE REGULATORS IN SERIES

A system with the first upstream high pressure regulator set at 10psig and the second downstream high pressure regulator set at a higher pressure, usually 15psig, will have the first regulator function as the working regulator feeding the system with 10psig. The second regulator remains wide-open unless the operating regulator fails and outlet pressure exceeds 15psig. When this happens the second regulator will start to regulate with a 15psig outlet delivery pressure.

The advantage of this method of over-pressure protection is its simplicity and the use of the same model regulators with the only difference being the pressure setting. The largest disadvantage to this system is the pressure ratings required on the products that are used. If the first regulator with a set point of 10 psig fails it will allow full inlet pressure downstream to the second regulator set at 15 psig. This means that the inlet side of the second regulator must be rated to full inlet pressure, typically 250 psig. Also, the diaphragm casing or outlet side of the first regulator must have a pressure rating high enough to handle full inlet pressure. The other disadvantage is that the flow across the wide open regulator will be at 10psig and the regulator will cause a minor pressure drop in the system. In addition, the normal working regulator is controlling the pressure between the first and second regulator in the system and the pressure after the wide open regulator will fluctuate with changes in flow.

APPENDIX: BASIC CONCEPTS FOR LP GAS REGULATORS

This appendix supplements the information in Chapter VIII -Regulators by giving operators with little or no experience with regulators, a review of the general information and usage. LP gas systems use two- stage regulators to reduce container pressure down to appliance delivery pressure, which is a nominal 11 inches water column (w.c.). Regulators are installed in accordance with NFPA 58.

There are a few terms, units and concepts that are useful when discussing LP gas regulating equipment. These are described as follows:

psig - pounds per square inch gauge. The unit of measure that uses the actual atmospheric pressure as a zero point in a specific geographic area. It is used to describe container pressure and delivery pressure from first-stage and high pressure regulators.

Psig is typically measured with a spring loaded gauge that can be attached to a container outlet connection and downstream of first-stage or high pressure regulators.

w.c. - inches of water column. Unit of measure for delivery pressure from single, second and integral twin stage regulators (27.71"w.c.=1.0 psig). Inches of water column are measured with the use of a U-Tube device called a water manometer that is filled with water with 1" markings typically up to 16". As pressure is introduced in one side of the tube, the water is forced up the other side; the end reading is then doubled to get the measured delivery pressure.

Inches of water column are typically measured at regulator pressure ports and inlet ports at appliance control valves.

Btu - British thermal unit. Measure of heat value. One Btu will raise the temperature of one pound of water one degree Fahrenheit. Btu is used to describe gas input to an appliance and the capacity of the LP gas regulator. Regulators are rated at the amount of Btu's per hour they can deliver at a specific inlet and outlet pressure.

Set point - a point where the regulator is set for a specific pressure, either psig or inches of water column at a specific inlet pressure and a Btu delivery to downstream appliance(s).

Lock up - a point where there is no demand from the appliances and the regulator stops flow. It will always be higher than the set point. On single, second and integral twin stage regulators, it is 120% of the set point, i.e., set point of 10 psig inlet, 11"w.c. at 75,000 Btu/hr is 13.2"w.c.

Components of a Typical Regulator

Underwriters Laboratories – Listing -Underwriter Laboratories (UL) is a not-for-profit organization that maintains laboratories for the examination and testing of devices, systems and materials to determine their relation to hazards to life and property. They also publish standards for materials, devices, products, equipment, etc. that affect the above described hazards.

UL-144 is the Standard for LP-Gas Regulators. It defines temperature/pressure ratings, relief valve performance, materials of construction, lock-up ranges, adjustment range, operation/performance and marking requirements to name a few items covered. UL listed regulators conform to the requirements of NFPA 58. Look for the UL mark before installing on a system. On large commercial or industrial systems, UL listed regulators are not always available. The local authority having jurisdiction acts as final approval in these cases.

HOW A REGULATOR WORKS

Typical positive back pressure regulator

Gas enters through the inlet and flows through an orifice. As pressure builds under the diaphragm, which moves upward, the adjustment spring compresses and pushes the seat disc attached to the lever assembly against the inlet nozzle or orifice. If there is no gas demand, the seat disc will stay against the nozzle and gas flow will stop. This is called lock-up. When gas demand from the appliance begins, pressure under the diaphragm is reduced, the adjustment spring pushes the lever/seat disc away from the seat and gas flow is allowed through the seat. The diaphragm will continue to sense the pressure under it, and will compress or relax the adjustment spring, which will move the seat lever/seat disc assembly against or away from the seat. This constant movement controls the pressure to downstream regulators or appliances. The design of the adjustment spring determines the pressure setting.

Relief operation

A relief valve is installed in all first, second and integral twin-stage regulators and operates per the requirements of UL-144. It is designed to protect downstream equipment and appliances from overpressure.

When gas enters through orifice, as described above, and downstream demand is reduced or stops, the lever/seat disc will move toward the nozzle to the lock-up position. If the regulator seat disc cannot fully contact the orifice, pressure will continue to build until diaphragm moves up to the point where relief spring begins to compress, allowing gas flow through the relief area into the bonnet and out through the vent. The relief valve will automatically close once the pressure under the diaphragm is reduced to a nominal pressure.

There are two designs of LP gas regulators typically used in systems across the country:

Positive back pressure regulators

This style is a positive back pressure regulator. It is used as a first stage, second stage, single stage, integral twin-stage and, in some cases, a high pressure regulator. The positive back pressure regulator provides good flow characteristics over a wide range of inlet pressures. LP-Gas vapor pressures change based on temperature.

The regulator delivery pressure is affected by the changes in inlet pressure, as well as demand from a downstream appliance(s). The seat disc is on the downstream side of the seat. As inlet pressure rises, the delivery pressure rises; as inlet pressure drops, delivery pressure drops.

Negative direct acting regulators

This style is a negative direct acting regulator. The seat disc is on the upstream side of the seat. As inlet pressure increases, delivery pressure decreases a small amount; as inlet pressure decreases, delivery pressure increases. The seat disc retainer assembly is directly attached to the stem.

TYPES OF REGULATOR SYSTEMS

Regulators and systems control gas pressure from the container to the appliance, reducing the tank pressure which can range from 10-250 psig to the required outlet pressure. There are several types that can range in style and combinations of regulators that can be used to accomplish this task.

Beginning with the 1995 Edition of NFPA 58, single-stage regulators may no longer be installed on fixed piping systems.

First stage: A pressure regulator for LP gas vapor service designed to reduce container pressure to 10 psig or less. It is used as the container regulator in a two-stage system. This regulator can be either of the two styles described above and is UL listed for use as a first stage regulator with an inlet pressure rating of 250 psig. This regulator utilizes a type I relief valve which is a limited capacity; operating range is from 14 psig to 25 psig.

Second Stage: A pressure regulator for LP gas vapor service designed to reduce first stage regulator outlet pressure to 14" water column or less (typically 11" w.c.). This may be either of the two styles and is UL listed for use in LP gas with an inlet pressure marked at 10 psig, but a rating of 250 psig. This regulator utilizes a type II relief valve - a high capacity type for final stage regulators; operating range is from 18.7" to 33" WC.

High pressure regulator - a pressure regulator for either LP gas vapor or liquid service designed to reduce pressure in excess of 1 psig. The liquid regulating style is usually negative direct acting; the vapor style can be either. Both are usually UL listed with at least a 250 psig inlet pressure rating. This regulator may or may not utilize a type I relief valve. In some cases an additional external relief valve might be required. See NFPA 58 for more information.

Integral two-stage regulator - a pressure regulator that combines both a high pressure and a second-stage regulator into a single unit. It is UL listed with a 250 psig inlet pressure rating, no relief in the high pressure section and a type II relief valve in the second stage section.

Automatic Changeover: An integral two-stage regulator that combines two high pressure regulators and a second-stage regulator into a single unit. There are two inlet connections and a service/reserve indicator designed for use with dual- or multiple-cylinder installation. The system automatically changes the LP gas vapor withdrawal from empty designated service cylinder(s) to the designated reserve cylinders, without interruption of service. The service/reserve indicator gives a visual indication of which cylinders are supplying the system. The second stage in an UL listed automatic changeover contains a type II relief valve with the same setting parameters as in the integral twin-stage unit.

Two-Stage Regulator System: An LP gas vapor delivery system that combines a first-stage regulator and second-stage regulator, integral two-stage regulator or an automatic changeover regulator.

Two-stage regulator system with a first-stage regulator rated at more than 500,000 BTU/HR set at 10 psig or less, with no integral relief valve. In this case the first-stage regulator is permitted to have a separate relief valve. It must operate within specified start-to-discharge limits of UL #144 (140%-200%) of the regulator set pressure.

Note: These systems are usually found where a number of second-stage regulators are connected to a single container utilizing one first-stage regulator. In order to comply with NFPA 58 overpressure requirements for second-stage regulators, an integral twin-stage regulator can be used for the second-stage regulator. This will reduce the higher delivery pressure from the first-stage regulator to 10 psig or less. The second-stage will supply the required appliance pressure.